OtagoNet

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 2020

CONTENTS

1. INTRODUCTION

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

- The Electricity Information Disclosure Determination 2012, (Consolidated in 2018), issued 3 April 2018,
- The Electricity Distribution Services Input Methodologies Determination 2012 (Consolidated in 2014), issued 30 March 2015.

2. INFORMATION DISCLOSURE DISCLAIMER

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

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

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

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

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

3. SCHEDULES

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2020

SCHEDULE 1: ANALYTICAL RATIOS

This schedule calculates expenditure, revenue and service ratios from the information disclosed. The disclosed ratios may vary for reasons that are company specific and, as a result, must be interpreted with care. The Commerce Commission will publish a summary and analysis of information disclosed in accordance with the ID determination. This will include information disclosed in accordance with this and other schedules, and information disclosed under the other requirements of the determination.
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

1(i): Expenditure metrics

	Expenditure per GWh energy delivered to ICPs ($/GWh)	Expenditure per average no. of ICPs ($/ICP)	Expenditure per MW maximum coincident system demand ($/MW)	Expenditure per km circuit length ($/km)	Expenditure per MVA of capacity from EDB-owned distribution transformers ($/MVA)
Operational expenditure	19,713	514	130,668	1,916	39,888
Network	12,648	330	83,834	1,229	25,591
Non-network	7,066	184	46,834	687	14,297
Expenditure on assets	43,770	1,141	290,121	4,254	88,563
Network	36,700	957	243,261	3,567	74,258
Non-network	7,070	184	46,860	687	14,305

1(ii): Revenue metrics

	Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
Total consumer line charge revenue	81,514	2,125
Standard consumer line charge revenue	136,155	1,905
Non-standard consumer line charge revenue	18,264	1,265,612

1(iii): Service intensity measures

Demand density	15	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
Volume density	97	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
Connection point density	4	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
Energy intensity	26,069	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*

1(iv): Composition of regulatory income

	($000)	% of revenue
Operational expenditure	8,842	24.20%
Pass-through and recoverable costs excluding financial incentives and wash-ups	9,032	24.72%
Total depreciation	7,994	21.88%
Total revaluations	4,923	13.47%
Regulatory tax allowance	2,759	7.55%
Regulatory profit/(loss) including financial incentives and wash-ups	12,836	35.13%
Total regulatory income	36,540	

1(v): Reliability

Interruption rate	12.87	*Interruptions per 100 circuit km*

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2020

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

This schedule requires information on the Return on Investment (ROI) for the EDB relative to the Commerce Commission's estimates of post tax WACC and vanilla WACC. EDBs must calculate their ROI based on a monthly basis if required by clause 2.3.3 of the ID Determination or if they elect to. If an EDB makes this election, information supporting this calculation must be provided in 2(iii).

EDBs must provide explanatory comment on their ROI in Schedule 14 (Mandatory Explanatory Notes).

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

sch ref

sch ref		CY-2	CY-1	Current Year CY
7	**2(i): Return on Investment**			
8		31 Mar 18	31 Mar 19	31 Mar 20
9	**ROI – comparable to a post tax WACC**	%	%	%
10	Reflecting all revenue earned	7.19%	6.46%	6.57%
11	Excluding revenue earned from financial incentives	6.90%	6.12%	6.63%
12	Excluding revenue earned from financial incentives and wash-ups	6.33%	5.54%	6.04%
13				
14	**Mid-point estimate of post tax WACC**	5.04%	4.75%	4.27%
15	25th percentile estimate	4.36%	4.07%	3.59%
16	75th percentile estimate	5.72%	5.43%	4.95%
17				
18				
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	7.79%	6.96%	6.99%
21	Excluding revenue earned from financial incentives	7.49%	6.63%	7.06%
22	Excluding revenue earned from financial incentives and wash-ups	6.92%	6.05%	6.47%
23				
24	**WACC rate used to set regulatory price path**	7.19%	7.19%	7.19%
25				
26	**Mid-point estimate of vanilla WACC**	5.60%	5.26%	4.69%
27	25th percentile estimate	4.92%	4.58%	4.01%
28	75th percentile estimate	6.29%	5.94%	5.37%
29				

sch ref				($000)	
30	**2(ii): Information Supporting the ROI**				
31					
32		Total opening RAB value	194,442		
33	*plus*	Opening deferred tax	(14,783)		
34	**Opening RIV**			179,659	
35					
36	**Line charge revenue**			36,561	
37					
38		Expenses cash outflow	17,874		
39	*add*	Assets commissioned	19,339		
40	*less*	Asset disposals	111		
41	*add*	Tax payments	424		
42	*less*	Other regulated income	(21)		
43	**Mid-year net cash outflows**			37,547	
44					
45	**Term credit spread differential allowance**			–	
46					
47		Total closing RAB value	210,599		
48	*less*	Adjustment resulting from asset allocation	(0)		
49	*less*	Lost and found assets adjustment	–		
50	*plus*	Closing deferred tax	(17,118)		
51	**Closing RIV**			193,481	
52					
53	**ROI – comparable to a vanilla WACC**				6.99%
54					
55		Leverage (%)			42%
56		Cost of debt assumption (%)			3.61%
57		Corporate tax rate (%)			28%
58					
59	**ROI – comparable to a post tax WACC**				6.57%
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	6.09%
Year-end ROI – comparable to a post tax WACC	5.66%

** these year-end ROI values are comparable to the ROI reported in pre 2012 disclosures by EDBs and do not represent the Commission's current view on ROI.*

2(v): Financial Incentives and Wash-Ups

Net recoverable costs allowed under incremental rolling incentive scheme	–	
Purchased assets – avoided transmission charge	–	
Energy efficiency and demand incentive allowance		
Quality incentive adjustment	(161)	
Other financial incentives	–	
Financial incentives		(161)
Impact of financial incentives on ROI		–0.06%
Input methodology claw-back	–	
CPP application recoverable costs	–	
Catastrophic event allowance	–	
Capex wash-up adjustment	1,470	
Transmission asset wash-up adjustment	–	
2013–15 NPV wash-up allowance	–	
Reconsideration event allowance	–	
Other wash-ups	–	
Wash-up costs		1,470
Impact of wash-up costs on ROI		0.59%

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2020**

SCHEDULE 3: REPORT ON REGULATORY PROFIT

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

sch ref			
7		**3(i): Regulatory Profit**	**($000)**
8		**Income**	
9		Line charge revenue	36,561
10	*plus*	Gains / (losses) on asset disposals	(101)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)	80
12			
13		**Total regulatory income**	36,540
14		**Expenses**	
15	*less*	Operational expenditure	8,842
16			
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups	9,032
18			
19		**Operating surplus / (deficit)**	18,666
20			
21	*less*	Total depreciation	7,994
22			
23	*plus*	Total revaluations	4,923
24			
25		**Regulatory profit / (loss) before tax**	15,594
26			
27	*less*	Term credit spread differential allowance	–
28			
29	*less*	Regulatory tax allowance	2,759
30			
31		**Regulatory profit/(loss) including financial incentives and wash-ups**	12,836
32			

33	**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34	**Pass through costs**		
35	Rates	154	
36	Commerce Act levies	93	
37	Industry levies	81	
38	CPP specified pass through costs	–	
39	**Recoverable costs excluding financial incentives and wash-ups**		
40	Electricity lines service charge payable to Transpower	7,086	
41	Transpower new investment contract charges	244	
42	System operator services	–	
43	Distributed generation allowance	1,376	
44	Extended reserves allowance	–	
45	Other recoverable costs excluding financial incentives and wash-ups	–	
46	**Pass-through and recoverable costs excluding financial incentives and wash-ups**		9,032
47			

48	**3(iii): Incremental Rolling Incentive Scheme**		**($000)**	
49			**CY-1**	**CY**
50			**31 Mar 19**	**31 Mar 20**
51	Allowed controllable opex		–	–
52	Actual controllable opex		–	–
53				
54	Incremental change in year			–
55				
56			**Previous years' incremental change**	**Previous years' incremental change adjusted for inflation**
57	CY-5	31 Mar 15	–	–
58	CY-4	31 Mar 16	–	–
59	CY-3	31 Mar 17	–	–
60	CY-2	31 Mar 18	–	–
61	CY-1	31 Mar 19	–	–
62	**Net incremental rolling incentive scheme**			–
63				
64	**Net recoverable costs allowed under incremental rolling incentive scheme**			–

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

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2020

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

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

sch ref

7 4(i): Regulatory Asset Base Value (Rolled Forward)

sch ref		RAB	RAB	RAB	RAB	RAB
8	for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20
9		($000)	($000)	($000)	($000)	($000)
10	**Total opening RAB value**	163,642	168,273	179,022	186,531	194,442
12	*less* **Total depreciation**	7,291	7,496	6,647	7,712	7,994
14	*plus* **Total revaluations**	960	3,641	1,967	2,766	4,923
16	*plus* **Assets commissioned**	11,027	14,776	12,346	12,937	19,339
18	*less* **Asset disposals**	65	173	157	80	111
20	*plus* **Lost and found assets adjustment**	–	–	–	–	–
22	*plus* **Adjustment resulting from asset allocation**	0	(0)	(0)	(0)	(0)
24	**Total closing RAB value**	168,273	179,022	186,531	194,442	210,599

26 4(ii): Unallocated Regulatory Asset Base

sch ref		Unallocated RAB *		RAB	
28		($000)	($000)	($000)	($000)
29	**Total opening RAB value**		194,442		194,442
30	*less*				
31	**Total depreciation**		7,994		7,994
32	*plus*				
33	**Total revaluations**		4,923		4,923
34	*plus*				
35	Assets commissioned (other than below)	–		–	
36	Assets acquired from a regulated supplier	–		–	
37	Assets acquired from a related party	19,339		19,339	
38	**Assets commissioned**		19,339		19,339
39	*less*				
40	Asset disposals (other than below)	111		111	
41	Asset disposals to a regulated supplier	–		–	
42	Asset disposals to a related party	–		–	
43	**Asset disposals**		111		111
45	*plus* **Lost and found assets adjustment**		–		–
47	*plus* **Adjustment resulting from asset allocation**				(0)
49	**Total closing RAB value**		210,599		210,599

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

50

51

52 4(iii): Calculation of Revaluation Rate and Revaluation of Assets

sch ref		
54	CPI_4	1,052
55	CPI_4^{-4}	1,026
56	Revaluation rate (%)	2.53%

sch ref		Unallocated RAB *		RAB	
59		($000)	($000)	($000)	($000)
60	Total opening RAB value	194,442		194,442	
61	*less* Opening value of fully depreciated, disposed and lost assets	167		167	
63	Total opening RAB value subject to revaluation	194,275		194,275	
64	**Total revaluations**		4,923		4,923

66 4(iv): Roll Forward of Works Under Construction

sch ref		Unallocated works under construction		Allocated works under construction	
68	**Works under construction—preceding disclosure year**		6,572		6,572
69	*plus* Capital expenditure	18,734		18,734	
70	*less* Assets commissioned	19,339		19,339	
71	*plus* Adjustment resulting from asset allocation			–	
72	**Works under construction - current disclosure year**		5,967		5,967
74	Highest rate of capitalised finance applied				–

4(v): Regulatory Depreciation

	Unallocated RAB *		RAB	
	($000)	($000)	($000)	($000)
Depreciation - standard	7,994		7,994	
Depreciation - no standard life assets	–		–	
Depreciation - modified life assets	–		–	
Depreciation - alternative depreciation in accordance with CPP	–		–	
Total depreciation		7,994		7,994

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	22,843	1,196	31,946	94,437	9,667	20,898	9,596	2,723	1,136	194,442
less	Total depreciation	1,178	25	1,434	3,764	257	763	472	91	11	7,994
plus	Total revaluations	586	58	819	2,316	259	516	255	85	28	4,923
plus	Assets commissioned	2,980	1,605	4,018	5,020	1,491	1,626	1,728	871	–	19,339
less	Asset disposals	–	–	8	–	–	103	–	–	–	111
plus	Lost and found assets adjustment										–
plus	Adjustment resulting from asset allocation										–
plus	Asset category transfers										–
	Total closing RAB value	25,231	2,834	35,341	98,010	11,159	22,175	11,108	3,588	1,153	210,599

Asset Life

	Subtransmission lines	Subtransmission cables	Zone substations	Distribution and LV lines	Distribution and LV cables	Distribution substations and transformers	Distribution switchgear	Other network assets	Non-network assets	
Weighted average remaining asset life	29.6	50.3	37.9	30.0	43.7	28.4	24.8	27.1	21.8	(years)
Weighted average expected total asset life	55.2	54.6	51.3	56.6	49.7	50.0	38.8	40.4	32.8	(years)

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2020**

SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

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

sch ref					
7	**5a(i): Regulatory Tax Allowance**				**($000)**
8	**Regulatory profit / (loss) before tax**				15,594
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	1,342		
13		Amortisation of revaluations	635		
14					1,977
15					
16	*less*	Total revaluations	4,923		
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	120	*	
20		Notional deductible interest	2,676		
21					7,719
22					
23	**Regulatory taxable income**				9,852
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income			9,852
27					
28		Corporate tax rate (%)	28%		
29	**Regulatory tax allowance**				2,759
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	28,173		
37	*less*	Amortisation of initial differences in asset values	1,342		
38	*plus*	Adjustment for unamortised initial differences in assets acquired	–		
39	*less*	Adjustment for unamortised initial differences in assets disposed	78		
40		Closing unamortised initial differences in asset values			26,753
41					
42		Opening weighted average remaining useful life of relevant assets (years)			21
43					

5a(iv): Amortisation of Revaluations

			($000)
	Opening sum of RAB values without revaluations	179,100	
	Adjusted depreciation	7,359	
	Total depreciation	7,994	
	Amortisation of revaluations		635

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	(14,783)	
plus	Tax effect of adjusted depreciation	2,061	
less	Tax effect of tax depreciation	4,281	
plus	Tax effect of other temporary differences*	281	
less	Tax effect of amortisation of initial differences in asset values	376	
plus	Deferred tax balance relating to assets acquired in the disclosure year	–	
less	Deferred tax balance relating to assets disposed in the disclosure year	20	
plus	Deferred tax cost allocation adjustment	0	
	Closing deferred tax		(17,118)

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	93,210	
less	Tax depreciation	15,288	
plus	Regulatory tax asset value of assets commissioned	20,194	
less	Regulatory tax asset value of asset disposals	168	
plus	Lost and found assets adjustment	–	
plus	Adjustment resulting from asset allocation	–	
plus	Other adjustments to the RAB tax value	–	
	Closing sum of regulatory tax asset values		97,948

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2020

SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

This schedule provides information on the valuation of related party transactions, in accordance with clause 2.3.6 of the ID determination.
This information is part of audited disclosure information (as defined in clause 1.4 of the ID determination), and so is subject to the assurance report required by clause 2.8.

sch ref

7	**5b(i): Summary—Related Party Transactions**	**($000)**	**($000)**
8	**Total regulatory income**		–
9			
10	**Market value of asset disposals**		–
11			
12	Service interruptions and emergencies	2,208	
13	Vegetation management	1,289	
14	Routine and corrective maintenance and inspection	1,838	
15	Asset replacement and renewal (opex)	338	
16	**Network opex**		5,673
17	Business support	1,637	
18	System operations and network support	712	
19	**Operational expenditure**		8,022
20	Consumer connection	5,657	
21	System growth	855	
22	Asset replacement and renewal (capex)	6,998	
23	Asset relocations	–	
24	Quality of supply	457	
25	Legislative and regulatory	–	
26	Other reliability, safety and environment	2,494	
27	**Expenditure on non-network assets**		–
28	**Expenditure on assets**		16,461
29	Cost of financing		–
30	Value of capital contributions		–
31	Value of vested assets		–
32	**Capital Expenditure**		16,461
33	**Total expenditure**		24,482
34			
35	**Other related party transactions**		–

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

37	**Name of related party**	**Nature of opex or capex service provided**	**Total value of transactions ($000)**
38	PowerNet Limited	Service interruptions and emergencies	2,208
39	PowerNet Limited	Vegetation management	1,289
40	PowerNet Limited	Routine and corrective maintenance and inspection	1,838
41	PowerNet Limited	Asset replacement and renewal (opex)	338
42	PowerNet Limited	System operations and network support	712
43	PowerNet Limited	Business support	1,637
44	PowerNet Limited	Consumer connection	5,657
45	PowerNet Limited	System growth	855
46	PowerNet Limited	Asset replacement and renewal (capex)	6,998
47	PowerNet Limited	Quality of supply	457
48	PowerNet Limited	Other reliability, safety and environment	2,494
49			
50			
51			
52			
53	**Total value of related party transactions**		24,482
54	** include additional rows if needed*		
55			

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2020

SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

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

sch ref

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

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

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

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

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2020

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

5d(i): Operating Cost Allocations

	Value allocated ($000s)				
	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
Service interruptions and emergencies					
Directly attributable		2,208			
Not directly attributable				–	
Total attributable to regulated service		2,208			
Vegetation management					
Directly attributable		1,289			
Not directly attributable				–	
Total attributable to regulated service		1,289			
Routine and corrective maintenance and inspection					
Directly attributable		1,838			
Not directly attributable				–	
Total attributable to regulated service		1,838			
Asset replacement and renewal					
Directly attributable		338			
Not directly attributable				–	
Total attributable to regulated service		338			
System operations and network support					
Directly attributable		1,007			
Not directly attributable		–		–	
Total attributable to regulated service		1,007			
Business support					
Directly attributable		2,162			
Not directly attributable		–		–	
Total attributable to regulated service		2,162			
Operating costs directly attributable		8,842			
Operating costs not directly attributable	–	–	–	–	–
Operational expenditure		8,842			

5d(ii): Other Cost Allocations

Pass through and recoverable costs	($000)
Pass through costs	
Directly attributable	328
Not directly attributable	–
Total attributable to regulated service	328
Recoverable costs	
Directly attributable	8,706
Not directly attributable	–
Total attributable to regulated service	8,706

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

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

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

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

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

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2020**

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

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

sch ref

7 5e(i): Regulated Service Asset Values

sch ref		Value allocated ($000s) Electricity distribution services
10	**Subtransmission lines**	
11	Directly attributable	25,231
12	Not directly attributable	–
13	**Total attributable to regulated service**	25,231
14	**Subtransmission cables**	
15	Directly attributable	2,834
16	Not directly attributable	–
17	**Total attributable to regulated service**	2,834
18	**Zone substations**	
19	Directly attributable	35,341
20	Not directly attributable	–
21	**Total attributable to regulated service**	35,341
22	**Distribution and LV lines**	
23	Directly attributable	98,010
24	Not directly attributable	–
25	**Total attributable to regulated service**	98,010
26	**Distribution and LV cables**	
27	Directly attributable	11,159
28	Not directly attributable	–
29	**Total attributable to regulated service**	11,159
30	**Distribution substations and transformers**	
31	Directly attributable	22,175
32	Not directly attributable	–
33	**Total attributable to regulated service**	22,175
34	**Distribution switchgear**	
35	Directly attributable	11,108
36	Not directly attributable	–
37	**Total attributable to regulated service**	11,108
38	**Other network assets**	
39	Directly attributable	3,588
40	Not directly attributable	–
41	**Total attributable to regulated service**	3,588
42	**Non-network assets**	
43	Directly attributable	1,153
44	Not directly attributable	–
45	**Total attributable to regulated service**	1,153
47	**Regulated service asset value directly attributable**	210,599
48	**Regulated service asset value not directly attributable**	–
49	**Total closing RAB value**	210,599

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

sch ref				($000) CY-1	Current Year (CY)
53	**Change in asset value allocation 1**				
54	Asset category		Original allocation	–	–
55	Original allocator or line items		New allocation	–	–
56	New allocator or line items		Difference	–	–
58	Rationale for change				

sch ref				($000) CY-1	Current Year (CY)
62	**Change in asset value allocation 2**				
63	Asset category		Original allocation	–	–
64	Original allocator or line items		New allocation	–	–
65	New allocator or line items		Difference	–	–
67	Rationale for change				

sch ref				($000) CY-1	Current Year (CY)
71	**Change in asset value allocation 3**				
72	Asset category		Original allocation	–	–
73	Original allocator or line items		New allocation	–	–
74	New allocator or line items		Difference	–	–
76	Rationale for change				

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

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2020**

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

This schedule requires a breakdown of capital expenditure on assets incurred in the disclosure year, including any assets in respect of which capital contributions are received, but excluding assets that are vested assets. Information on expenditure on assets must be provided on an accounting accruals basis and must exclude finance costs.
EDBs must provide explanatory comment on their expenditure on assets in Schedule 14 (Explanatory Notes to Templates).
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref			
7	**6a(i): Expenditure on Assets**	**($000)**	**($000)**
8	Consumer connection		5,657
9	System growth		855
10	Asset replacement and renewal		6,998
11	Asset relocations		–
12	Reliability, safety and environment:		
13	Quality of supply	457	
14	Legislative and regulatory	–	
15	Other reliability, safety and environment	2,494	
16	**Total reliability, safety and environment**		2,951
17	**Expenditure on network assets**		16,461
18	Expenditure on non-network assets		3,171
19			
20	**Expenditure on assets**		19,632
21	*plus* Cost of financing		–
22	*less* Value of capital contributions		898
23	*plus* Value of vested assets		–
24			
25	**Capital expenditure**		18,734
26	**6a(ii): Subcomponents of Expenditure on Assets (where known)**		**($000)**
27	Energy efficiency and demand side management, reduction of energy losses		–
28	Overhead to underground conversion		–
29	Research and development		–
30	**6a(iii): Consumer Connection**		
31	*Consumer types defined by EDB**	**($000)**	**($000)**
32	Customer Connections < 20 kVA	763	
33	Customer Connections 21 - 99 kVA	98	
34	Customer Connections > 100 kVA	314	
35	New Subdivisions	4,482	
36			
37	** include additional rows if needed*		
38	**Consumer connection expenditure**		5,657
39			
40	*less* Capital contributions funding consumer connection expenditure	773	
41	**Consumer connection less capital contributions**		4,884
42	**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset Replacement**
43		**System Growth**	**and Renewal**
44		**($000)**	**($000)**
45	Subtransmission	–	2,398
46	Zone substations	666	358
47	Distribution and LV lines	9	4,110
48	Distribution and LV cables	180	30
49	Distribution substations and transformers	–	4
50	Distribution switchgear	–	67
51	Other network assets	–	31
52	**System growth and asset replacement and renewal expenditure**	855	6,998
53	*less* Capital contributions funding system growth and asset replacement and renewal	–	11
54	**System growth and asset replacement and renewal less capital contributions**	855	6,987
55			
56	**6a(v): Asset Relocations**		
57	*Project or programme**	**($000)**	**($000)**
58		–	
59		–	
60		–	
61		–	
62		–	
63	** include additional rows if needed*		
64	All other projects or programmes - asset relocations	–	
65	**Asset relocations expenditure**		–
66	*less* Capital contributions funding asset relocations	–	
67	**Asset relocations less capital contributions**		–

6a(vi): Quality of Supply

	Project or programme*	($000)	($000)
	Finegand 33kV Smart Network Automation	126	
	Waipiata & Hyde Smart Network Automation	132	
	* include additional rows if needed		
	All other projects programmes - quality of supply	199	
	Quality of supply expenditure		457
less	Capital contributions funding quality of supply	–	
	Quality of supply less capital contributions		457

6a(vii): Legislative and Regulatory

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

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

	Project or programme*	($000)	($000)
	Substation Structure and Seismic Upgrades	102	
	Substation NERs and 33kV Transformer Circuit Breakers	796	
	Clydevale 33kV Ring Rebuild and Protection	1,259	
	Substation arc-flash upgrades	116	
	* include additional rows if needed		
	All other projects or programmes - other reliability, safety and environment	221	
	Other reliability, safety and environment expenditure		2,494
less	Capital contributions funding other reliability, safety and environment	114	
	Other reliability, safety and environment less capital contributions		2,380

6a(ix): Non-Network Assets

Routine expenditure

Project or programme*	($000)	($000)
	–	
	–	
	–	
	–	
	–	
* include additional rows if needed		
All other projects or programmes - routine expenditure	–	
Routine expenditure		–

Atypical expenditure

Project or programme*	($000)	($000)
Balclutha Depot	3,171	
* include additional rows if needed		
All other projects or programmes - atypical expenditure		
Atypical expenditure		3,171
Expenditure on non-network assets		3,171

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2020**

SCHEDULE 6b: REPORT ON OPERATIONAL EXPENDITURE FOR THE DISCLOSURE YEAR

This schedule requires a breakdown of operational expenditure incurred in the disclosure year.
EDBs must provide explanatory comment on their operational expenditure in Schedule 14 (Explanatory notes to templates). This includes explanatory comment on any atypical operational expenditure and assets replaced or renewed as part of asset replacement and renewal operational expenditure, and additional information on insurance.
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref			
7	**6b(i): Operational Expenditure**	**($000)**	**($000)**
8	Service interruptions and emergencies	2,208	
9	Vegetation management	1,289	
10	Routine and corrective maintenance and inspection	1,838	
11	Asset replacement and renewal	338	
12	**Network opex**		5,673
13	System operations and network support	1,007	
14	Business support	2,162	
15	**Non-network opex**		3,169
16			
17	**Operational expenditure**		8,842
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	Energy efficiency and demand side management, reduction of energy losses		–
20	Direct billing*		–
21	Research and development		–
22	Insurance		168
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2020**

SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

This schedule compares actual revenue and expenditure to the previous forecasts that were made for the disclosure year. Accordingly, this schedule requires the forecast revenue and expenditure information from previous disclosures to be inserted.
EDBs must provide explanatory comment on the variance between actual and target revenue and forecast expenditure in Schedule 14 (Mandatory Explanatory Notes). This information is part of the audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8. For the purpose of this audit, target revenue and forecast expenditures only need to be verified back to previous disclosures.

sch ref				
7	**7(i): Revenue**	**Target ($000) [1]**	**Actual ($000)**	**% variance**
8	Line charge revenue	35,953	36,561	2%
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	6,138	5,657	(8%)
11	System growth	934	855	(8%)
12	Asset replacement and renewal	6,975	6,998	0%
13	Asset relocations	19	–	(100%)
14	Reliability, safety and environment:			
15	Quality of supply	837	457	(45%)
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	1,880	2,494	33%
18	**Total reliability, safety and environment**	2,717	2,951	9%
19	**Expenditure on network assets**	16,783	16,461	(2%)
20	Expenditure on non-network assets	7,005	3,171	(55%)
21	Expenditure on assets	23,788	19,632	(17%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	1,818	2,208	21%
24	Vegetation management	1,219	1,289	6%
25	Routine and corrective maintenance and inspection	1,930	1,838	(5%)
26	Asset replacement and renewal	233	338	45%
27	**Network opex**	5,200	5,673	9%
28	System operations and network support	1,375	1,007	(27%)
29	Business support	2,221	2,162	(3%)
30	**Non-network opex**	3,596	3,169	(12%)
31	**Operational expenditure**	8,796	8,842	1%
32	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
33	Energy efficiency and demand side management, reduction of energy losses	–	–	–
34	Overhead to underground conversion	–	–	–
35	Research and development	–	–	–
36				
37	**7(v): Subcomponents of Operational Expenditure (where known)**			
38	Energy efficiency and demand side management, reduction of energy losses	–	–	–
39	Direct billing	–	–	–
40	Research and development	–	–	–
41	Insurance	477	168	(65%)
42				

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

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

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2020
Network / Sub-Network Name	OtagoNet Network

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the EDB in its pricing schedules. Information is also required on the number of ICPs that are included in each consumer group or price category code, and the energy delivered to these ICPs.

sch ref

8(i): Billed Quantities by Price Component

sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)	Billed quantities by price component — Price component: Variable day energy sales	Variable night energy sales	Variable day energy purchases	Variable night energy purchases	Variable energy sales	
13					Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kWh	KWh	kWh	kWh	kWh	
15	1	Domestic	Standard	6,453	44,291			35,059,484	13,202,264		
16	2	Commerical	Standard	3,292	55,261			43,742,784	16,472,112		
17	4	Major Customers	Standard	102	81,121	56,819,444					
18	5	Unmetered	Standard	76	128			101,024	38,042		
19	6	Street lights	Standard	9	641			507,606	191,148		
20	7 & 8	Low user	Standard	5,192	27,273	20,454,662	6,818,221				
21	Non Standard	Commerical	Non-standard	3	207,886	138,195,995					
22	LLNW	Domestic	Standard	1,712	11,758					11,757,789	
23	LLNW	Non Domestic	Standard	356	10,722						
24	LLNW	Half Hour	Standard	10	9,444						
25	*Add extra rows for additional consumer groups or price category codes as necessary*										
26			Standard consumer totals	17,202	240,638	77,274,106	6,818,221	79,410,897	29,903,566	11,757,789	–
27			Non-standard consumer totals	3	207,886	138,195,995	–	–	–	–	–
28			Total for all consumers	17,205	448,524	215,470,101	6,818,221	79,410,897	29,903,566	11,757,789	–

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

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

Line charge revenues ($000) by price component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)	Fixed	Variable - Day	Variable Night	Kva	Fixed	Variable
						Rate (eg, $ per day, $ per kWh, etc.)	$/Day	$/kwh	$/kWh	Per/kVa	$/kW	$/kWh
1	Domestic	Standard	$9,686		$8,603	$1,083		$5,079	$220	$4,386		
2	Commerical	Standard	$10,619		$9,428	$1,191		$6,335	$275	$4,010		
4	Major Customers	Standard	$3,588		$1,817	$1,771	$2,600	$988				
5	Unmetered	Standard	$36		$32	$4	$20	$15	$1			
6	Street lights	Standard	$181		$161	$20	$105	$74	$3			
7 & 8	Low user	Standard	$5,482		$4,883	$599	$285	$5,022	$175			
Non Standard	Commerical	Non-standard	$3,797		$563	$3,234	$3,797					
Generation		Standard	$349		$348	$1	$349					
LLNW	Domestic	Standard	$1,351		$1,062	$289	$93					$1,259
LLNW	Non Domestic	Standard	$927		$719	$208	$444				$484	
LLNW	Half Hour	Standard	$545		$235	$310	$545					
Add extra rows for additional consumer groups or price category codes as necessary												
		Standard consumer totals	$32,764	–	$27,288	$5,476	$4,440	$17,511	$674	$8,396	$484	$1,259
		Non-standard consumer totals	$3,797	–	$563	$3,234	$3,797	–	–	–	–	–
		Total for all consumers	$36,561	–	$27,851	$8,710	$8,237	$17,511	$674	$8,396	$484	$1,259

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

8(iii): Number of ICPs directly billed

Check: OK

Number of directly billed ICPs at year end	1

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2020
Network / Sub-Network Name	Otago Sub-Network

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the EDB in its pricing schedules. Information is also required on the number of ICPs that are included in each consumer group or price category code, and the energy delivered to these ICPs.

sch ref

8 **8(i): Billed Quantities by Price Component**

9

10

11 **Billed quantities by price component**

sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)	Variable day energy sales	Variable night energy sales	Variable day energy purchases	Variable night energy purchases	Variable energy sales	
12					Price component	Variable day energy sales	Variable night energy sales	Variable day energy purchases	Variable night energy purchases	Variable energy sales	
13					Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kWh	Kwh	kwh	kwh	kwh	
14											
15	1	Domestic	Standard	6,453	44,291			35,059,484	13,202,264		
16	2	Commerical	Standard	3,292	55,261			43,742,784	16,472,112		
17	4	Major Customers	Standard	102	81,121	56,819,444					
18	5	Unmetered	Standard	76	128			101,024	38,042		
19	6	Street lights	Standard	9	641			507,606	191,148		
20	7 & 8	Low user	Standard	5,192	27,273	20,454,662	6,818,221				
21	Non Standard	Commerical	Non-standard	3	207,886	138,195,995					
22											
23											
24											
25	*Add extra rows for additional consumer groups or price category codes as necessary*										
26			**Standard consumer totals**	15,124	208,714	77,274,106	6,818,221	79,410,897	29,903,566	–	–
27			**Non-standard consumer totals**	3	207,886	138,195,995	–	–	–	–	–
28			**Total for all consumers**	15,127	416,601	215,470,101	6,818,221	79,410,897	29,903,566	–	–

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

29

30

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

Line charge revenues ($000) by price component

						Price component	Fixed	Variable - Day	Variable Night	Kva	Fixed	Variable
						Rate (eg, $ per day, $ per kWh, etc.)	$/Day	$/kwh	$/kWh	Per/kVa	$/kW	$/kWh
Consumer group name or price category code	**Consumer type or types (eg, residential, commercial etc.)**	**Standard or non-standard consumer group (specify)**	**Total line charge revenue in disclosure year**	**Notional revenue foregone from posted discounts (if applicable)**	**Total distribution line charge revenue**	**Total transmission line charge revenue (if available)**						
1	Domestic	Standard	$9,686		$8,603	$1,083		$5,079	$220	$4,386		
2	Commerical	Standard	$10,619		$9,428	$1,191		$6,335	$275	$4,010		
4	Major Customers	Standard	$3,588		$1,817	$1,771	$2,600	$988				
5	Unmetered	Standard	$36		$32	$4	$20	$15	$1			
6	Street lights	Standard	$181		$161	$20	$105	$74	$3			
7 & 8	Low user	Standard	$5,482		$4,883	$599	$285	$5,022	$175			
Non Standard	Commerical	Non-standard	$3,797		$563	$3,234	$3,797					
Generation	Generation	Standard	$349		$348	$1	$349					
			–									
			–									
		Standard consumer totals	$29,941	–	$25,272	$4,669	$3,359	$17,511	$674	$8,396	–	–
		Non-standard consumer totals	$3,797	–	$563	$3,234	$3,797	–	–	–	–	–
		Total for all consumers	$33,738	–	$25,835	$7,903	$7,156	$17,511	$674	$8,396	–	–

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

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

Check OK

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	1

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2020**
Network / Sub-Network Name	**Lakeland Frankton Sub-Network**

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the EDB in its pricing schedules. Information is also required on the number of ICPs that are included in each consumer group or price category code, and the energy delivered to these ICPs.

sch ref

8 **8(i): Billed Quantities by Price Component**

sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)	Billed quantities by price component					
12					Price component	Variable day energy sales	Variable night energy sales	Variable day energy purchases	Variable night energy purchases	Variable energy sales	
13					Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kWh	kWh	kWh	kWh	kWh	
15	LLNW	Domestic	Standard	1,522	10,991					10,991,301	
16	LLNW	Non Domestic	Standard	339	10,461						
17	LLNW	Half Hour	Standard	10	9,444						
18											
19											
20											
21											
22											
23											
24											
26			**Standard consumer totals**	1,871	30,897	–	–	–	–	10,991,301	–
27			**Non-standard consumer totals**	–	–	–	–	–	–	–	–
28			**Total for all consumers**	1,871	30,897	–	–	–	–	10,991,301	–

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

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

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

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)	Line charge revenues ($000) by price component					
						Price component	Fixed	Variable - Day	Variable Night	Kva	Fixed	Variable
						Rate (eg, $ per day, $ per kWh, etc.)	$/Day	$/kwh	$/kWh	Per/kVa	$/kW	$/kWh
LLNW	Domestic	Standard	$1,264		$975	$289.14	$83					$1,182
LLNW	Non Domestic	Standard	$911		$703	$208.41	$436				$475	
LLNW	Half Hour	Standard	$545		$235	$310	$545					
			–									
			–									
			–									
			–									
			–									
			–									
			–									
		Standard consumer totals	$2,720	–	$1,912	$807	$1,063	–	–	–	$475	$1,182
		Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–
		Total for all consumers	$2,720	–	$1,912	$807	$1,063	–	–	–	$475	$1,182

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

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

Check OK

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2020**
Network / Sub-network Name	**OtagoNet Network**

SCHEDULE 9a: ASSET REGISTER

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

sch ref

8	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
9	All	Overhead Line	Concrete poles / steel structure	No.	34,109	34,501	392	3
10	All	Overhead Line	Wood poles	No.	15,381	15,139	(242)	3
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	659	659	0	3
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	47	47	(0)	3
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	9	17	8	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.	1	1	–	3
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	8	8	–	3
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	179	182	3	2
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	7	7	–	3
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	32	43	11	3
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	116	116	–	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	3	3	–	3
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	45	45	–	3
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2,346	2,343	(3)	2
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	911	912	1	2
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	73	76	2	1
39	HV	Distribution Cable	Distribution UG PILC	km	5	5	(0)	1
40	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	N/A
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	24	29	5	2
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	N/A
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	4,859	4,862	3	1
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	N/A
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	72	86	14	2
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	4,061	4,021	(40)	1
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	271	326	55	2
48	HV	Distribution Transformer	Voltage regulators	No.	42	43	1	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	18	16	(2)	3
50	LV	LV Line	LV OH Conductor	km	470	468	(2)	1
51	LV	LV Cable	LV UG Cable	km	86	97	11	1
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	84	89	5	1
53	LV	Connections	OH/UG consumer service connections	No.	17,766	18,433	667	1
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	228	243	15	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	4	5	1	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 2020**
Network / Sub-network Name	**Otago Sub-Network**

SCHEDULE 9a: ASSET REGISTER

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

sch ref

8	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
9	All	Overhead Line	Concrete poles / steel structure	No.	34,109	34,501	392	3
10	All	Overhead Line	Wood poles	No.	15,381	15,139	(242)	3
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	659	659	0	3
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	47	47	(0)	3
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	3	3	(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.	1	1	–	3
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	8	8	–	3
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	179	182	3	2
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	7	7	–	3
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	32	43	11	3
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	106	106	–	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	3	3	–	3
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	43	43	–	3
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2,346	2,343	(3)	2
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	911	912	1	2
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	32	32	(1)	1
39	HV	Distribution Cable	Distribution UG PILC	km	4	4	(0)	1
40	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	N/A
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	24	29	5	2
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	N/A
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	4,859	4,862	3	1
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	N/A
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	9	9	–	2
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	4,061	4,021	(40)	1
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	213	254	41	2
48	HV	Distribution Transformer	Voltage regulators	No.	42	43	1	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	18	16	(2)	3
50	LV	LV Line	LV OH Conductor	km	470	468	(2)	1
51	LV	LV Cable	LV UG Cable	km	43	45	1	1
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	75	77	1	1
53	LV	Connections	OH/UG consumer service connections	No.	15,845	15,983	138	1
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	218	233	15	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	4	5	1	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 2020**
Network / Sub-network Name	**Lakeland Frankton Sub-Network**

SCHEDULE 9a: ASSET REGISTER

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

sch ref

8	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
9	All	Overhead Line	Concrete poles / steel structure	No.	–	–	–	N/A
10	All	Overhead Line	Wood poles	No.	–	–	–	N/A
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	–	N/A
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	6	14	8	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	40	43	3	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.	58	69	11	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	–	–	N/A
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	55	67	12	2
48	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	N/A
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.		–	–	N/A
50	LV	LV Line	LV OH Conductor	km	–	0	0	2
51	LV	LV Cable	LV UG Cable	km	39	48	9	2
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	9	12	3	4
53	LV	Connections	OH/UG consumer service connections	No.	1,754	2,193	439	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 2020
Network / Sub-network Name	OtagoNet Network

SCHEDULE 9b: ASSET AGE PROFILE

This schedule requires a summary of the age profile (based on year of installation) of the assets that make up the network, by asset category and asset class. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

8 Disclosure Year (year ended): 31 March 2020

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.	259	779	4,529	3,977	4,928	6,542	1,945	135	240	70	276	120	124	48	47	197	946	1,008	1,086	1,058	875	899	863	629	1,011	690	383	2	–	–	–	–	–	835	34,501	–	3
11	All	Overhead Line	Wood poles	No.	22	338	1,843	1,414	865	733	3,657	423	743	529	547	268	511	576	803	650	220	34	10	16	24	90	60	52	67	58	34	2	–	–	–	–	–	550	15,139	–	3
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	13	71	157	117	87	67	0	4	3	19	1	–	1	2	–	2	2	–	48	1	–	13	2	–	–	–	–	–	–	–	–	–	49	659	–	3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	47	47	–	3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	0	–	0	–	–	–	0	1	–	–	1	–	6	–	–	–	0	–	1	–	–	–	–	8	–	–	–	–	–	0	17	–	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.	–	–	1	10	7	5	7	–	–	–	–	–	–	1	1	2	1	–	1		1	–	–	3	–	–	–	–	–	–	–	–	–	5	45	–	3
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	3
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	7	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	8	–	3
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	11	24	18	46	29	–	1	1	8	–	6	2	3	5	–	3	2	6	–	2	4	2	1	3	3	–	–	–	–	–	–	2	182	–	3
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7	–	3
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	2	1	11	6	–	–	–	–	–	–	1	1	–	–	–	2	1	1	–	1	2	–	3	–	11	–	–	–	–	–	–	43	–	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	3	11	8	41	–	1	–	–	2	6	11	2	–	1	10	–	–	9	1	–	8	2	–	–	–	–	–	–	–	–	–	116	–	3
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	3	–	3
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	3	8	6	7	2	–	–	–	–	–	–	6	3	1	–	1	–	2	2	2	–	1	1	–	–	–	–	–	–	–	–	–	45	–	3
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	4	32	163	226	257	315	338	78	94	46	42	25	50	33	63	58	66	101	50	61	76	33	41	22	18	4	5	–	–	–	–	–	–	42	2,343	–	2
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
38	HV	Distribution Line	SWER conductor	km	–	–	194	115	99	156	106	4	2	3	10	3	5	22	3	11	20	11	44	42	15	15	2	0	3	23	1	–	–	–	–	–	–	4	912	–	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	11	5	10	3	2	–	–	–	–	–	–	3	76	–	1
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	1	–	–	–	–	–	–	–	0	0	0	–	0	0	–	–	1	–	0	1	0	–	–	0	–	–	–	–	–	–	–	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	–	3	–	–	–	–	7	3	2	6	4	2	–	–	–	–	–	–	29	–	2
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	–	25	705	711	746	515	498	26	88	83	60	61	92	100	115	108	101	101	76	82	48	72	101	66	66	88	56	8	–	–	–	–	–	64	4,862	–	1
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	–	–	–	4	–	–	1	2	–	–	–	–	1	5	3	1	3	4	8	12	11	8	13	8	1	–	–	–	–	–	1	86	–	2
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	1	25	695	566	565	422	460	24	77	73	53	52	81	80	100	97	78	79	60	59	36	52	80	48	49	66	38	5	–	–	–	–	–	–	4,021	–	1
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	–	4	34	7	22	4	9	6	4	3	14	11	15	14	18	11	6	14	11	16	21	21	16	13	25	5	–	–	–	–	–	2	326	–	2
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	1	1	4	–	–	–	1	2	2	–	–	1	2	2	–	2	2	2	11	3	2	2	1	2	–	–	–	–	–	–	43	–	3
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	–	7	3	–	–	–	–	–	–	–	–	1	–	1	2	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	16	–	3
51	LV	LV Line	LV OH Conductor	km	1	5	159	51	69	40	34	2	5	7	5	2	4	4	4	3	2	3	2	2	2	2	3	2	1	2	1	–	–	–	–	–	–	50	468	–	1
52	LV	LV Cable	LV UG Cable	km	–	–	0	1	4	3	1	0	0	0	1	2	2	2	6	2	2	1	3	1	3	8	7	10	11	10	5	1	–	–	–	–	–	10	97	–	1
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	0	0	1	–	–	–	–	–	–	–	–	0	0	1	–	0	0	0	1	0	4	3	2	1	1	0	–	–	–	–	–	73	89	–	1
54	LV	Connections	OH/UG consumer service connections	No.	–	–	–	–	–	–	11,023	921	107	101	487	549	522	513	444	216	139	104	107	92	114	191	338	382	458	691	621	82	–	–	–	–	–	231	18,433	–	1
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	–	11	33	38	–	4	–	1	7	4	9	9	16	7	13	3	2	14	1	11	18	4	14	18	6	–	–	–	–	–	–	243	–	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	–	–	–	–	–	–	2	–	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 2020**
Network / Sub-network Name	**Otago Sub-Network**

SCHEDULE 9b: ASSET AGE PROFILE

This schedule requires a summary of the age profile (based on year of installation) of the assets that make up the network, by asset category and asset class. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

8 **Disclosure Year (year ended)** 31 March 2020

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.	259	779	4,529	3,977	4,928	6,542	1,945	135	240	70	276	120	124	48	47	197	946	1,008	1,086	1,058	875	899	863	629	1,011	690	383	2	–	–	–	–	–	835	34,501	–	3
11	All	Overhead Line	Wood poles	No.	22	338	1,843	1,414	865	733	3,657	423	743	529	547	268	511	576	803	650	220	34	10	16	24	90	60	52	67	58	34	2	–	–	–	–	–	550	15,139	–	3
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	13	71	157	117	87	67	0	4	3	19	1	–	1	2	–	2	2	–	48	1	–	13	2	–	–	–	–	–	–	–	–	–	49	659	–	3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	47	47	–	3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	0	–	0	–	–	–	0	1	–	–	1	–	0	–	–	–	0	–	1	–	–	–	–	–	–	–	–	–	–	0	3	–	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.	–	–	1	10	7	5	7	–	–	–	–	–	–	–	1	2	1	–	1		1	–	–	3	–	–	–	–	–	–	–	–	–	5	44	–	3
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	3
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	7	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	8	–	3
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	11	24	18	46	29	–	1	1	8	–	6	2	3	5	–	3	2	6	–	2	4	2	1	3	3	–	–	–	–	–	–	2	182	–	3
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7	–	3
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	2	1	11	6	–	–	–	–	–	–	1	1	–	–	–	2	1	1	–	1	2	–	3	–	11	–	–	–	–	–	–	43	–	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	3	11	8	41	–	1	–	–	2	6	1	2	–	1	10	–	–	9	1	–	8	2	–	–	–	–	–	–	–	–	–	106	–	3
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	3	–	3
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	3	8	6	7	2	–	–	–	–	–	–	4	3	1	–	1	–	2	2	2	–	1	1	–	–	–	–	–	–	–	–	–	43	–	3
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	4	32	163	226	257	315	338	78	94	46	42	25	50	33	63	58	66	101	50	61	76	33	41	22	18	4	5	–	–	–	–	–	–	42	2,343	–	2
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
38	HV	Distribution Line	SWER conductor	km	–	–	194	115	99	156	106	4	2	3	10	3	5	22	3	11	20	11	44	42	15	15	2	0	3	23	1	–	–	–	–	–	–	4	912	–	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	5	1	3	0	0	–	–	–	–	–	–	0	32	–	1
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	1	–	–	–	–	–	–	–	–	0	0	–	–	0	–	–	1	–	0	1	0	–	–	0	–	–	–	–	–	–	–	4	–	1
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	3	–	–	–	–	7	3	2	6	4	2	–	–	–	–	–	–	29	–	2
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	–	25	705	711	746	515	498	26	88	83	60	61	92	100	115	108	101	101	76	82	48	72	101	66	66	88	56	8	–	–	–	–	–	64	4,862	–	1
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	–	–	–	4	–	–	–	2	–	–	–	–	1	–	1	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	9	–	2
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	25	695	566	565	422	460	24	77	73	53	52	81	80	100	97	78	79	60	59	36	52	80	48	49	66	38	5	–	–	–	–	–	1	4,021	–	1
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	–	4	34	7	22	4	9	6	4	3	13	11	14	12	11	8	6	14	7	10	9	14	6	4	15	5	–	–	–	–	–	2	254	–	2
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	1	1	4	–	–	–	1	2	2	–	–	1	2	2	–	2	2	2	11	3	2	2	1	2	–	–	–	–	–	–	43	–	3
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	–	7	–	3	–	–	–	–	–	–	–	1	–	1	2	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	16	–	3
51	LV	LV Line	LV OH Conductor	km	1	5	159	51	69	40	34	2	5	7	5	2	4	4	4	3	2	3	2	2	2	2	3	2	1	2	1	–	–	–	–	–	–	50	468	–	1
52	LV	LV Cable	LV UG Cable	km	–	–	0	1	4	3	1	0	0	0	1	1	2	2	6	2	1	1	3	1	2	0	3	2	3	2	1	–	–	–	–	–	–	3	45	–	1
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	0	0	1	–	–	–	–	–	–	–	–	0	0	1	–	0	0	0	–	–	1	0	0	0	0	0	–	–	–	–	–	71	77	–	1
54	LV	Connections	OH/UG consumer service connections	No.	–	–	–	–	–	–	11,023	921	107	101	475	538	494	480	402	196	134	90	101	87	74	96	126	85	104	122	148	10	–	–	–	–	–	69	15,983	–	1
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	–	11	33	38	–	4	–	1	7	4	5	5	16	5	13	3	2	14	1	11	18	4	14	18	6	–	–	–	–	–	–	233	–	3
56	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	3
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	–	1	–	1	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	1	1	–	–	–	–	–	–	5	–	3
59	All	Load Control	Relays	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A

Company Name: OtagoNet Joint Venture
For Year Ended: 31 March 2020
Network / Sub-network Name: Lakeland Frankton Sub-Network

SCHEDULE 9b: ASSET AGE PROFILE

This schedule requires a summary of the age profile (based on year of installation) of the assets that make up the network, by asset category and asset class. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

8 Disclosure Year (year ended): 31 March 2020

Number of assets at disclosure year end by installation date

sch ref	Voltage	Asset category	Asset class	Units	pre-1940	1940–1949	1950–1959	1960–1969	1970–1979	1980–1989	1990–1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
11	All	Overhead Line	Wood poles	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	6	–	–	–	–	–	0	–	–	–	–	8	–	–	–	–	–	–	14	–	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	6	3	2	–	–	–	–	–	–	3	43	–	2
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	–	–	–	–	–	–	–	–	0	0	–	–	0	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	3
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	5	2	1	3	4	8	12	10	4	13	6	–	–	–	–	–	–	–	69	–	3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	–	–	–	–	–	–	–	–	–	–	1	–	1	2	7	2	–	–	4	6	12	7	8	9	8	–	–	–	–	–	–	–	67	–	2
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
51	LV	LV Line	LV OH Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0	0	–	2
52	LV	LV Cable	LV UG Cable	km	–	–	–	–	–	–	–	–	–	–	–	1	0	0	0	0	0	0	–	–	2	7	4	9	6	7	4	1	–	–	–	–	–	6	48	–	2
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0	–	–	–	–	1	0	3	3	2	1	1	0	–	–	–	–	–	2	12	–	4
54	LV	Connections	OH/UG consumer service connections	No.	–	–	–	–	–	–	–	–	–	–	12	11	28	33	42	20	5	14	6	5	40	95	212	297	329	464	367	62	–	–	–	–	–	151	2,193	–	3
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	4	4	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	10	–	3
56	All	SCADA and communications	SCADA and communications equipment operating as a single 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 2020**
Network / Sub-network Name	**OtagoNet Network**

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref				
9				
10	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
11	> 66kV	47	–	47
12	50kV & 66kV	75	–	75
13	33kV	584	9	594
14	SWER (all SWER voltages)	908	4	912
15	22kV (other than SWER)	0	40	40
16	6.6kV to 11kV (inclusive—other than SWER)	2,343	40	2,383
17	Low voltage (< 1kV)	468	97	565
18	**Total circuit length (for supply)**	4,425	190	4,615
19				
20	Dedicated street lighting circuit length (km)	74	15	89
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			–
22				
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**	
24	Urban	327	7%	
25	Rural	887	20%	
26	Remote only	586	13%	
27	Rugged only	1,816	41%	
28	Remote and rugged	679	15%	
29	Unallocated overhead lines	129	3%	
30	**Total overhead length**	4,425	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	1,113	24%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	628	14%	

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2020**
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

		Overhead (km)	Underground (km)	Total circuit length (km)
9				
10	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
11	> 66kV	47	–	47
12	50kV & 66kV	75	–	75
13	33kV	584	3	587
14	SWER (all SWER voltages)	908	4	912
15	22kV (other than SWER)	0	–	0
16	6.6kV to 11kV (inclusive—other than SWER)	2,343	36	2,379
17	Low voltage (< 1kV)	468	45	513
18	**Total circuit length (for supply)**	4,424	88	4,512
19				
20	Dedicated street lighting circuit length (km)	74	3	77
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			–
22				

		Circuit length (km)	(% of total overhead length)
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**
24	Urban	327	7%
25	Rural	887	20%
26	Remote only	586	13%
27	Rugged only	1,816	41%
28	Remote and rugged	679	15%
29	Unallocated overhead lines	129	3%
30	**Total overhead length**	4,424	100%
31			
32		**Circuit length (km)**	**(% of total circuit length)**
33	Length of circuit within 10km of coastline or geothermal areas (where known)	1,113	25%
34		**Circuit length (km)**	**(% of total overhead length)**
35	Overhead circuit requiring vegetation management	628	14%

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2020
Network / Sub-network Name	Lakeland Frankton Sub-Network

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref				
9				
10	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
11	> 66kV	–	–	–
12	50kV & 66kV	–	–	–
13	33kV	–	6	6
14	SWER (all SWER voltages)	–	–	–
15	22kV (other than SWER)	–	40	40
16	6.6kV to 11kV (inclusive—other than SWER)	–	3	3
17	Low voltage (< 1kV)	0	48	48
18	**Total circuit length (for supply)**	0	98	98
19				
20	Dedicated street lighting circuit length (km)	–	12	12
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			–
22				
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**	
24	Urban	–	–	
25	Rural	–	–	
26	Remote only	–	–	
27	Rugged only	0	100%	
28	Remote and rugged	–	–	
29	Unallocated overhead lines	–	–	
30	**Total overhead length**	0	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	–	–	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	–	–	

Company Name **OtagoNet Joint Venture**
For Year Ended **31 March 2020**

SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

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

sch ref	Location *	Number of ICPs served	Line charge revenue ($000)
8			
9	Lakeland Wanaka GXP NLK0111 [used Average ICP Count as per Schedule 8(i)]	207	103
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			

26 ** Extend embedded distribution networks table as necessary to disclose each embedded network owned by the EDB which is embedded in another EDB's network or in another embedded network*

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2020**
Network / Sub-network Name	**OtagoNet Network**

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref

9e(i): Consumer Connections

Number of ICPs connected in year by consumer type

*Consumer types defined by EDB**	**Number of connections (ICPs)**
Domestic	549
Half Hour Individual	3
Non Domestic	65

** include additional rows if needed*

Connections total	617	
Distributed generation		
Number of connections made in year	38	connections
Capacity of distributed generation installed in year	0.21	MVA

9e(ii): System Demand

		Demand at time of maximum coincident demand (MW)
	Maximum coincident system demand	
	GXP demand	49
plus	Distributed generation output at HV and above	18
	Maximum coincident system demand	68
less	Net transfers to (from) other EDBs at HV and above	–
	Demand on system for supply to consumers' connection points	68

		Energy (GWh)	
	Electricity volumes carried		
	Electricity supplied from GXPs	364	
less	Electricity exports to GXPs	–	
plus	Electricity supplied from distributed generation	103	
less	Net electricity supplied to (from) other EDBs	(1.02)	
	Electricity entering system for supply to consumers' connection points	468	
less	Total energy delivered to ICPs	449	
	Electricity losses (loss ratio)	19	4.1%
	Load factor	0.79	

9e(iii): Transformer Capacity

	(MVA)
Distribution transformer capacity (EDB owned)	222
Distribution transformer capacity (Non-EDB owned, estimated)	42
Total distribution transformer capacity	264
Zone substation transformer capacity	172

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2020**
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**			
9	*Number of ICPs connected in year by consumer type*			
10	*Consumer types defined by EDB**		**Number of connections (ICPs)**	
11		Domestic	108	
12		Half Hour Individual	3	
13		Non Domestic	26	
14				
15				
16		** include additional rows if needed*		
17	**Connections total**		137	
18				
19	**Distributed generation**			
20		Number of connections made in year	31	**connections**
21		Capacity of distributed generation installed in year	0.18	**MVA**
22	**9e(ii): System Demand**			
23				
24			**Demand at time of maximum coincident demand (MW)**	
25	**Maximum coincident system demand**			
26		GXP demand	43	
27	*plus*	Distributed generation output at HV and above	18	
28	**Maximum coincident system demand**		61	
29	*less*	Net transfers to (from) other EDBs at HV and above	–	
30	**Demand on system for supply to consumers' connection points**		61	
31	**Electricity volumes carried**		**Energy (GWh)**	
32		Electricity supplied from GXPs	332	
33	*less*	Electricity exports to GXPs	–	
34	*plus*	Electricity supplied from distributed generation	103	
35	*less*	Net electricity supplied to (from) other EDBs	–	
36	**Electricity entering system for supply to consumers' connection points**		435	
37	*less*	Total energy delivered to ICPs	417	
38	**Electricity losses (loss ratio)**		19	4.3%
39				
40	**Load factor**		0.81	
41	**9e(iii): Transformer Capacity**			
42			**(MVA)**	
43		Distribution transformer capacity (EDB owned)	193	
44		Distribution transformer capacity (Non-EDB owned, estimated)	42	
45	**Total distribution transformer capacity**		235	
46				
47	**Zone substation transformer capacity**		147	

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2020**
Network / Sub-network Name	**Lakeland Frankton Sub-Network**

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref				
8	**9e(i): Consumer Connections**			
9	*Number of ICPs connected in year by consumer type*			
10	*Consumer types defined by EDB**		**Number of connections (ICPs)**	
11		Domestic	346	
12		Half Hour Individual	–	
13		Non Domestic	36	
14				
15				
16		** include additional rows if needed*		
17	**Connections total**		382	
18				
19	**Distributed generation**			
20		Number of connections made in year	5	**connections**
21		Capacity of distributed generation installed in year	0.03	**MVA**
22	**9e(ii): System Demand**			
23				
24			**Demand at time of maximum coincident demand (MW)**	
25	**Maximum coincident system demand**			
26		GXP demand	6	
27	*plus*	Distributed generation output at HV and above	–	
28	**Maximum coincident system demand**		6	
29	*less*	Net transfers to (from) other EDBs at HV and above		
30	**Demand on system for supply to consumers' connection points**		6	
31	**Electricity volumes carried**		**Energy (GWh)**	
32		Electricity supplied from GXPs	32	
33	*less*	Electricity exports to GXPs	–	
34	*plus*	Electricity supplied from distributed generation	–	
35	*less*	Net electricity supplied to (from) other EDBs	–	
36	**Electricity entering system for supply to consumers' connection points**		32	
37	*less*	Total energy delivered to ICPs	31	
38	**Electricity losses (loss ratio)**		1	2.6%
39				
40	**Load factor**		0.60	
41	**9e(iii): Transformer Capacity**			
42			**(MVA)**	
43		Distribution transformer capacity (EDB owned)	28	
44		Distribution transformer capacity (Non-EDB owned, estimated)	–	
45	**Total distribution transformer capacity**		28	
46				
47	**Zone substation transformer capacity**		25	

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2020**
Network / Sub-network Name	**OtagoNet Network**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

8 10(i): Interruptions

sch ref		Number of interruptions
9	**Interruptions by class**	
10	Class A (planned interruptions by Transpower)	1
11	Class B (planned interruptions on the network)	373
12	Class C (unplanned interruptions on the network)	219
13	Class D (unplanned interruptions by Transpower)	–
14	Class E (unplanned interruptions of EDB owned generation)	–
15	Class F (unplanned interruptions of generation owned by others)	–
16	Class G (unplanned interruptions caused by another disclosing entity)	1
17	Class H (planned interruptions caused by another disclosing entity)	–
18	Class I (interruptions caused by parties not included above)	–
19	**Total**	594
20		

sch ref		≤3Hrs	>3hrs
21	**Interruption restoration**		
22	Class C interruptions restored within	162	57
23			

sch ref		SAIFI	SAIDI
24	**SAIFI and SAIDI by class**		
25	Class A (planned interruptions by Transpower)	0.01	0.2
26	Class B (planned interruptions on the network)	0.96	180.7
27	Class C (unplanned interruptions on the network)	1.80	164.5
28	Class D (unplanned interruptions by Transpower)	–	–
29	Class E (unplanned interruptions of EDB owned generation)	–	–
30	Class F (unplanned interruptions of generation owned by others)	–	–
31	Class G (unplanned interruptions caused by another disclosing entity)	0.01	1.5
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	–	–
34	**Total**	2.78	346.8
35			

sch ref		Normalised SAIFI	Normalised SAIDI
36	**Normalised SAIFI and SAIDI**		
37	Classes B & C (interruptions on the network)	2.66	339.6
38			

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

sch ref		SAIFI	SAIDI
40			
41	**Cause**		
42	Lightning	0.01	1.1
43	Vegetation	0.17	30.9
44	Adverse weather	0.19	27.3
45	Adverse environment	0.00	0.7
46	Third party interference	0.16	8.8
47	Wildlife	0.09	7.0
48	Human error	0.03	3.8
49	Defective equipment	0.75	68.0
50	Cause unknown	0.40	16.9
51			

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

sch ref		SAIFI	SAIDI
53			
54	**Main equipment involved**		
55	Subtransmission lines	0.31	25.8
56	Subtransmission cables	–	–
57	Subtransmission other	–	–
58	Distribution lines (excluding LV)	0.62	146.0
69	Distribution cables (excluding LV)	0.00	0.0
60	Distribution other (excluding LV)	0.03	8.8

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

sch ref		SAIFI	SAIDI
62			
63	**Main equipment involved**		
64	Subtransmission lines	0.68	50.9
65	Subtransmission cables	–	–
66	Subtransmission other	0.09	2.6
67	Distribution lines (excluding LV)	0.87	104.2
68	Distribution cables (excluding LV)	0.09	4.0
69	Distribution other (excluding LV)	0.07	2.8

70 10(v): Fault Rate

sch ref		Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
71	**Main equipment involved**			
72	Subtransmission lines	18	705.88	2.55
73	Subtransmission cables	–	9.20	–
74	Subtransmission other	1		
75	Distribution lines (excluding LV)	181	3,250.73	5.57
76	Distribution cables (excluding LV)	1	84.64	1.18
77	Distribution other (excluding LV)	18		
78	**Total**	219		

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2020**
Network / Sub-network Name	**Otago Sub-Network**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

8 10(i): Interruptions

sch ref	Interruptions by class	Number of interruptions
10	Class A (planned interruptions by Transpower)	1
11	Class B (planned interruptions on the network)	369
12	Class C (unplanned interruptions on the network)	217
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**	587

sch ref	Interruption restoration	≤3Hrs	>3hrs
22	Class C interruptions restored within	161	56

sch ref	SAIFI and SAIDI by class	SAIFI	SAIDI
25	Class A (planned interruptions by Transpower)	0.00	0.2
26	Class B (planned interruptions on the network)	1.07	201.1
27	Class C (unplanned interruptions on the network)	1.94	180.9
28	Class D (unplanned interruptions by Transpower)	–	–
29	Class E (unplanned interruptions of EDB owned generation)	–	–
30	Class F (unplanned interruptions of generation owned by others)	–	–
31	Class G (unplanned interruptions caused by another disclosing entity)	–	–
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	–	–
34	**Total**	3.01	382.1

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

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

sch ref	Cause	SAIFI	SAIDI
42	Lightning	0.01	1.3
43	Vegetation	0.19	35.1
44	Adverse weather	0.21	31.0
45	Adverse environment	0.01	0.8
46	Third party interference	0.18	10.0
47	Wildlife	0.10	8.0
48	Human error	0.03	4.4
49	Defective equipment	0.74	71.2
50	Cause unknown	0.47	19.2

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

sch ref	Main equipment involved	SAIFI	SAIDI
55	Subtransmission lines	0.35	29.3
56	Subtransmission cables	–	–
57	Subtransmission other	–	–
58	Distribution lines (excluding LV)	0.71	165.8
69	Distribution cables (excluding LV)	–	–
60	Distribution other (excluding LV)	0.01	5.9

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

sch ref	Main equipment involved	SAIFI	SAIDI
64	Subtransmission lines	0.77	57.9
65	Subtransmission cables	–	–
66	Subtransmission other	0.10	2.9
67	Distribution lines (excluding LV)	1.00	118.4
68	Distribution cables (excluding LV)	–	–
69	Distribution other (excluding LV)	0.07	1.7

70 10(v): Fault Rate

sch ref	Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
72	Subtransmission lines	18	705.88	2.55
73	Subtransmission cables	–	3.07	–
74	Subtransmission other	1		
75	Distribution lines (excluding LV)	181	3,250.73	5.57
76	Distribution cables (excluding LV)	–	40.15	–
77	Distribution other (excluding LV)	17		
78	**Total**	217		

pwc

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2020**
Network / Sub-network Name	**Lakeland Frankton Sub-Network**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

8	**10(i): Interruptions**		
9	**Interruptions by class**	**Number of interruptions**	
10	Class A (planned interruptions by Transpower)	–	
11	Class B (planned interruptions on the network)	2	
12	Class C (unplanned interruptions on the network)	2	
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**	4	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	1	1
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.08	17.9
27	Class C (unplanned interruptions on the network)	0.91	48.9
28	Class D (unplanned interruptions by Transpower)	–	–
29	Class E (unplanned interruptions of EDB owned generation)	–	–
30	Class F (unplanned interruptions of generation owned by others)	–	–
31	Class G (unplanned interruptions caused by another disclosing entity)	–	–
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	–	–
34	**Total**	0.99	66.9
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	n/a	n/a
38			

39	**10(ii): Class C Interruptions and Duration by Cause**		
40			
41	**Cause**	**SAIFI**	**SAIDI**
42	Lightning	–	–
43	Vegetation	–	–
44	Adverse weather	–	–
45	Adverse environment	–	–
46	Third party interference	–	–
47	Wildlife	–	–
48	Human error	–	–
49	Defective equipment	0.91	48.9
50	Cause unknown	–	–
51			
52	**10(iii): Class B Interruptions and Duration by Main Equipment Involved**		
53			
54	**Main equipment involved**	**SAIFI**	**SAIDI**
55	Subtransmission lines	–	–
56	Subtransmission cables	–	–
57	Subtransmission other	–	–
58	Distribution lines (excluding LV)	–	–
69	Distribution cables (excluding LV)	–	–
60	Distribution other (excluding LV)	0.08	17.9
61	**10(iv): Class C Interruptions and Duration by Main Equipment Involved**		
62			
63	**Main equipment involved**	**SAIFI**	**SAIDI**
64	Subtransmission lines	–	–
65	Subtransmission cables	–	–
66	Subtransmission other	–	–
67	Distribution lines (excluding LV)	–	–
68	Distribution cables (excluding LV)	0.85	37.4
69	Distribution other (excluding LV)	0.06	11.5

70	**10(v): Fault Rate**			
71	**Main equipment involved**	**Number of Faults**	**Circuit length (km)**	**Fault rate (faults per 100km)**
72	Subtransmission lines	–	–	–
73	Subtransmission cables	–	6.13	–
74	Subtransmission other	–		
75	Distribution lines (excluding LV)	–	–	–
76	Distribution cables (excluding LV)	1	43.59	2.29
77	Distribution other (excluding LV)	1		
78	**Total**	2		

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 WACC of 6.57% is above the 75th percentile estimate of post-tax WACC of 4.95% and 7.00% vanilla WACC is above the 75th percentile estimate of vanilla WACC of 5.37%. No items were reclassified.

Regulatory Profit (Schedule 3)

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

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

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

Box 2: Explanatory comment on regulatory profit
Included in other regulated income is an amount of $77k for rental income on Balclutha Depot. 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 2019 closing figure of $194,442k as a starting point with inflationary indexing over the year to 31 March 2020 plus additions less disposals resulting to $210,599k 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 $120k 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:	$ 1,004
	$ 1,004
Tax Rate:	28%
Temporary Differences	$ 281

Cost allocation (Schedule 5d)

10. In the box below, comment on cost allocation as disclosed in Schedule 5d. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

Box 7: Cost allocation

All costs are directly attributable as all costs were either passed through by PowerNet Limited as agent or were invoiced to OtagoNet Joint Venture.

No items were reclassified.

Asset allocation (Schedule 5e)

11. In the box below, comment on asset allocation as disclosed in Schedule 5e. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

Box 8: Commentary on asset allocation

All network assets are directly attributable.

No items were reclassified.

Capital Expenditure for the Disclosure Year (Schedule 6a)

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

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

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

Box 9: Explanation of capital expenditure for the disclosure year

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

No items were reclassified during the disclosure year.

Operational Expenditure for the Disclosure Year (Schedule 6b)

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

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

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

    13.3 Commentary on any material atypical expenditure included in operational expenditure disclosed in Schedule 6b, a including the value of the expenditure the purpose of the expenditure, and the operational expenditure categories the expenditure relates to.

Box 10: Explanation of operational expenditure for the disclosure year

Reactive and minor maintenance is performed on OtagoNet transformers and lines that are classified as refurbishment and renewal maintenance when the work performed is not material in relation to the overall value of the asset.

No items were reclassified during the disclosure year.

There was no material atypical expenditure disclosed in Schedule 6b.

Variance between forecast and actual expenditure (Schedule 7)

14. In the box below, comment on variance in actual to forecast expenditure for the disclosure year, as reported in Schedule 7. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

Box 11: Explanatory comment on variance in actual to forecast expenditure

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

Capital Expenditure on Assets:

The actual expenditure on network assets was 2% below budget.

Consumer connection:

- Only 92% of the budget was spent, while continued growth and high demand for new customer connections in the Frankton area exceeded expectations, a planned major new connections project did not proceed.

System Growth:

- Only 92% of the budget was spent, the shortfall was due to another EDB's microwave backbone project being delayed, impacting on the Remarkables substation communications upgrade.

Asset replacement and renewal:

- On budget, additional line replacement work offset under spending due to the cancellation of the Glenore substation rebuild and Transpower project delays affecting the HWB-PAL 2 110/33 kV Conversion.

Asset Relocations:

- Nothing spent due to no asset relocations requested by third parties.

Quality of supply:

- Only 55% of the budget spent due to equipment procurement delaying the Finegand Automation project.

Other reliability, safety and environment:

- 33% overspend attributed to higher than anticipated costs for detailed design, cable installation and plant commissioning of the Clydevale 33 kV Ring Rebuild & Protection project.

Non-network assets:

- Only 45% of the budget spent during the year due to the change in the engineering design resulting to delays in the construction.

<u>Operational Expenditure:</u>

Network opex was 9% above budget. Overall opex was 1% above budget.

Service interruptions and emergencies:

- 21% overspent due to a larger amount of distribution and technical faults than allowed for.

Vegetation management:

- 6% overspend due to the deployment of additional resources to work on larger jobs and support job safety.

Routine and corrective maintenance and inspection:

- Only 95% of the budget spent, the shortfall mainly due to resources not being available for all planned line inspections and earth testing.

Asset replacement and renewal:

- 45% overspent due to additional maintenance on zone substation transformers.

System Operations and Network Support:

- 27% underspent mainly due to the deferral of the proposed insurance captive for the network lines and cables.

Business Support:

- 3% underspent which is a minor variation representing $59k savings in operating expenditure during the year.

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 2019-20 year was $35.953 million. The total billed revenue for the 2019-20 year was $36.561 million, which is $608k (2%) above.

The increase in revenue is attributable to the higher chargeable volumes than forecast in Otago region due to the unseasonable weather in the last quarter.

Network Reliability for the Disclosure Year (Schedule 10)

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

Box 13: Commentary on network reliability for the disclosure year

The SAIDI assessed value for 2019/20 at 242.7 was below the applicable Commerce Commission Limit of 254.9, and above the Commerce Commission Target level (224.6) that represents the average performance of the network over the last ten years.

The SAIFI assessed value for 2019/20 at 2.26 was below the applicable Commerce Commission Limit of 2.93 and also below the Commerce Commission Target level of 2.52.

However in accordance with the Issues Register for Electricity and Gas Information Disclosure issues 447 and 458, OJV has disclosed normalised SAIDI/SAIFI calculated according to the 2012 EDB ID while disclosing limits calculated according to the 2015 DPP.

The difference in methodology between the calculation of normalised SAIDI (339.6) and the calculation of the SAIDI limit (254.9) creates the misleading impression that OJV has exceeded its SAIDI limit. However as described above there is no exceedance when normalised SAIDI is calculated according to the 2015 DPP, so as to be consistent with the SAIDI limit.

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

Changing work practices resulting from the Health and Safety at Work Act 2015, including reduced utilisation of live line working techniques continue to contribute to an increased level of planned SAIDI and SAIFI.

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

Insurance cover

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

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

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

Box 14: Explanation of insurance cover

OtagoNet insures its substations, network equipment and buildings.

- Substations and network equipment are insured for $49.9 million.
- Buildings are insured for $16.4 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) 2018 report released in December 2018:

	2020	2021	2022	2023	2024
Inflator (CAPEX & OPEX)	2.0%	2.0%	2.0%	2.0%	2.4%

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

SCHEDULE 15 VOLUNTARY EXPLANATORY NOTES

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

    1.1 additional explanatory comment to reports prepared in accordance with clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1 and 2.5.2;

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

2. Information in this schedule is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

3. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information

Schedule 3
Excluded from other regulated income is an amount of $490k for Transpower Losses and Constraints.

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

APPENDICES

APPENDIX A:

Related Party Transactions:

Additional Information Disclosures

1. INTRODUCTION

For the purpose of meeting the 2020 Related Party Transaction reporting requirements, in accordance with section 2.3.6 of the Electricity Information Disclosure Determination 2012, (Consolidated in 2018), issued 3 April 2018, the following information is provided in support of:

- **OtagoNet Joint Venture's 2020 Information Disclosure**, for the year ended 31 March 2020 - Schedule 5(b) Related party Transactions

2. INFORMATION DISCLOSURE REQUIREMENTS

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

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

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

3. RELATED PARTY RELATIONSHIPS

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

The OJV Regulated Network is comprised of OtagoNet Joint Venture (OJV) and Electricity Southland Limited (ESL). The OJV (including ESL) network and the network management company PowerNet Limited (PowerNet), are all 100% wholly owned by Electricity Invercargill Limited (EIL) and The Power Company Limited (TPCL), through their respective wholly owned subsidiary companies Pylon Limited and Last Tango Limited. PowerNet held a 90% interest in electricity distribution maintenance company PowerNet Central Limited (PCL) for the majority of the 2019/20 year. Following acquisition of the remaining shareholding, PCL was amalgamated with PowerNet Limited on 31 March 2020.

During the year ending 31 March 2020, OJV Regulated Network had related party transactions with the following entities:

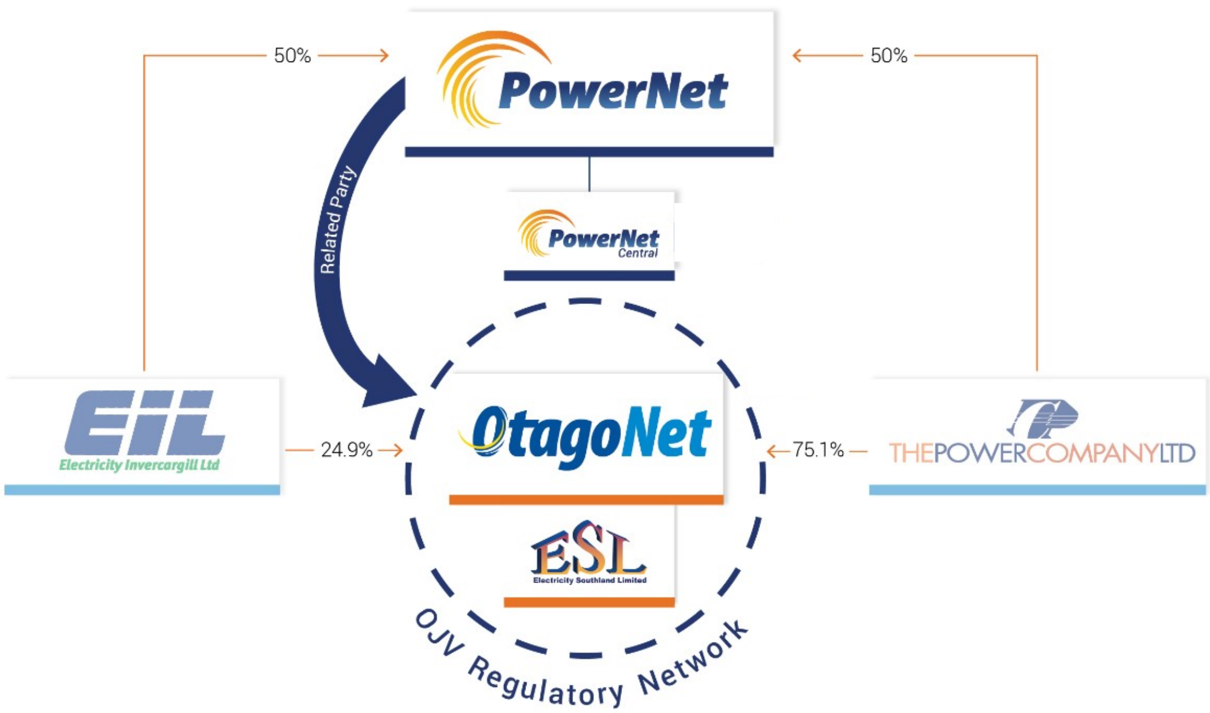
- Goods and services provided by – PowerNet Limited

Company Structure

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

ID Determination reference: 2.3.8

- Engineering & Asset Management
- Admin & corporate services
- Network operations
- Project management & delivery



a. **PowerNet Limited**

EIL and TPCL jointly hold a 100% interest in electricity network management company PowerNet Limited and the regulated OJV network (OJV and ESL). PowerNet provides a range of field contracting, asset management, system control and finance and commercial services to the regulated OJV network. The value of the related party transactions for the year ended 31 March 2020 is categorised as follows:

		($000)
Operating Expenditure:		
i.	Service interruptions and emergencies	2,208
ii.	Vegetation management	1,289
iii.	Routine and corrective maintenance and inspection	1,838
iv.	Asset replacement and renewal (opex)	338
v.	System operations and network support	712
vi.	Business support	1,637
Capital Expenditure:		
vii.	Consumer connection	5,657
viii.	System growth	855
ix.	Asset replacement and renewal (capex)	6,998
x.	Quality of supply	457
xi.	Other reliability, safety and environment	2,494
	Total Related Party expenditure from PowerNet	**24,482**

In the year to 31 March 2020, PowerNet provided 100% of the OJV and ESL Lines Business Capital Expenditure, and 91% of all Operating Expenditure. The high percentage of related party transactions relative to total expenditure is due to PowerNet operating under a Network Management Agreement (NMA) with OJV and ESL, in the form of "agency agreements".

Services provided under the agreement include:

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

b. PowerNet Central Limited

Following the introduction of a new ESL Network Management Agreement on 1 April 2019, all PowerNet Central expenditure was charged to PowerNet, rather than directly charged to ESL, therefore there is no network associated related party transactions between ESL and PowerNet Central during the year ended 31 March 2020.

Network Management Agreement (‘Agency Agreement’)

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

While OJV & ESL own the Network Assets and provide electricity distribution services through their electricity network in Clutha and Central Otago Region, under the agreement PowerNet will manage the network assets, will carry out an agreed Capital Works programme, has the exclusive right to provide Line Function Services, and will provide the business administration services on behalf of OJV and ESL.

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

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

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

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

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

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

4. PROCUREMENT POLICY

ID Determination 2.3.10 & 2.3.11

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

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

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

Procurement Policy (FNPO-035-Policy)

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

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

Asset 'whole-of-life' cost focus

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

Sourcing of labour

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

Sourcing of materials and equipment

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

External party works

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

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

5. APPLICATION OF PROCUREMENT POLICY

ID Determination 2.3.12 (1)

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

The **Procurement Policy** adopted by OJV and ESL 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 parties of OJV (including ESL) for reporting purposes, they are structured as separate legal entities, operating on an 'arms-length' basis.

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

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

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

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

Resourcing

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

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

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

ESL: PowerNet undertakes 100% of the Annual Works Programme projects.

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

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

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

Cost of assets, goods or services from Related Party

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

6. PURCHASES REQUIRED FROM A RELATED PARTY

ID Determination 2.3.12 (2)

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

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

Fault Response and Reactive Maintenance

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

PowerNet provides on-call line mechanics and technicians, located across the Southland and Otago region, able to respond in a very short period of time to a fault call out, to provide a reliable and efficient fault response service, and minimise the impact of a power outage on network customers. Without these remote depot locations the duration (SAIDI) of outages on the OJV 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 and PowerNet Central provide the fault response services internally, rather than outsourcing.

New Connections

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

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

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

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

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

Using an Independent Contractor

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

Arborist/Tree Management

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

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

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

Approved Contractors

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

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

Asplundh – Quotes:
Invercargill Office on 03 216 8051
Wayne, Contract Manager on 0275 533 250
enquiry@asplundh.co.nz or visit Asplundh at www.asplundh.co.nz

Bruce Dickens Tree Topping – Quotes:
Phil, Operations Manager, on 0274 441 008 or 03 212 8686
Bruce on 0274 756 732

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

7. PROCUREMENT REPRESENTATIVE EXAMPLES

ID Determination 2.3.12 (3)

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

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

Significant large-scale projects are managed by the PowerNet Asset Management – Major Projects team. These projects are often long term (greater than 12 months), complex in design, and usually greater than $1m 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: Clydevale 33kV Ring Protection Project

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

Project Name:	Clydevale 33kV Ring Rebuild & Protection
Project Date:	June 2018 – February 2020
Project Number:	30595
Total Expenditure:	$ 841,000 External labour & materials $ 418,000 PowerNet services (incl. mark-up) ---------------- $ 1,259,000 Total Cost (2019/20)
Expenditure Classification:	Reliability, Safety & Environment (Capital Expenditure)
Project Manager:	PowerNet Ltd
Subcontractors:	Greg Donaldson Contracting, Andrew Haulage, Mitton Electronet and Linetech Consulting

The network consumption and customer numbers in the Clydevale area are increasing with highlighted importance on a reliable supply to the individual dairy farms, irrigation and commercial businesses. This project was prioritised as part of the initiative to improve the OJV's SAIDI and SAIFI performance.

The Clydevale 33kV Ring Rebuild & Protection project is a network reliability project that had been identified for implementation in the 2018-19 Asset Management Plan.

The Clydevale 33kV Ring Rebuild & Protection project was completed in February 2020.

ID Determination 2.3.12 (5)

Market Testing: The majority of the Clydevale 33kV Ring Rebuild & Protection project cost was outsourced by PowerNet. The rates provided by the external contractors were consistent with recent tender prices. Materials were provided through the Corys supply agreement. The PowerNet project management and internal labour cost is benchmarked to local market rates.

ii. New Connection / Capacity Upgrade (System Growth)

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

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

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

EXAMPLE: 8 Lot Subdivision – Milton

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

Project Name:	Customer Connection (OJV Works programme)
Completion Date:	June 2019
Project Number:	CC 343913 / 343915
Project Expenditure:	$ 21,000 External Materials $ 13,000 PowerNet services (incl. mark-up) ------------ $ 34,000 Total Cost (2019/20)
Project Classification:	Consumer Connection (Capital Expenditure)
Project Manager:	PowerNet Ltd
Construction:	PowerNet - Distribution Team
Subcontractors:	N/a

PowerNet received an application for the supply capacity of 10 kVA single phase electricity connections for a new subdivision project. The connection required an 11kV extension to connect the subdivision to the nearest existing feeder and a 3 phase 100kVA transformer to meet the capacity requirementnot begin until acceptance of the quote and 50% payment of the customer contribution is received.

Market Testing: The prices charged by PowerNet have been benchmarked against similar Line Mechanic or Technician roles from other available external suppliers. Of the $5.7M capital expenditure spent on New Connections and Capacity Upgrades, 75% 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. The recent benchmarking of PowerNet business and network support services provided rated well on a cost per ICP basis, against other equivalent EDB's to OJV.

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

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

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

EXAMPLE: 11 kV Line Replacement & Renewal

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

Project Name:	Upgrade Powerline in Taumata 11kV Feeded (from P133860 to P149861)
Completion Date:	January 2020
Project Number:	CC 350690
Project Expenditure:	$ 43,000 External labour & materials $ 107,000 PowerNet services (incl. mark-up) -------------- $ 150,000 Total Cost (2019/20)
Regulatory Classification:	Asset Replacement & Renewal (Capital Expenditure)
Project Manager:	PowerNet Ltd
Construction:	PowerNet - Distribution Team
Subcontractors:	None

PowerNet undertook Project CC350690 to replace poles, cross arms and insulators as they were at the end of their useful life. This work is identified through PowerNet inspection and testing programmes to identify assets that are reaching the end of their economic life and was deemed essential to maintain security of supply within the area. A PowerNet Project Manager was assigned to plan and oversee the work. Consideration is given to the timing, to make sure resources are available, and to minimise the impact of a power outage to effected OJV customers. PowerNet was assigned to undertake the work, being able to provide the skilled distribution services and equipment required. Materials were sourced through the Corys Supply Agreement.

Market Testing: The prices charged by PowerNet have been benchmarked against similar roles from other external Suppliers utilised during 2018-2020. The materials sourced through Corys Electrical supply agreement includes a range of contractual mechanisms to ensure efficient prices are being provided to PowerNet. The recent benchmarking of PowerNet business and network support services provided rated favourably on a cost per ICP basis, against other equivalent EDB's to OJV.

iv. Faults Response (Service interruptions and emergencies)

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

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 2018-2020.

v. Arborist Work (Vegetation Management)

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

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

EXAMPLE: Vegetation Management (OJV Works Programme and External Chargeable Work)

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

Project Description:	Vegetation Control (OJV Works Programme)	External Chargeable Work
Project Name:	Fell Trees Dunback – Morrisons 11kV Feeder	Trim Trees at Kaitangata
Project Completion Date:	September 2019	November 2019
Project Number:	350950	352829
Total Expenditure:	$15,000	$1,800
Regulatory Classification:	Vegetation Management (Operational Expenditure)	Fully Chargeable to Customer
Project Manager:	PowerNet Ltd.	PowerNet Ltd.
Customer:	OJV Network	External Customer

Chargeable to OJV Network
The PowerNet Arborist team became aware of trees growing within the regulatory distance of power lines during a routine Lines inspection in the rural Waitati area. Details of the location and work required (trees to be felled) were noted on the PowerNet Cut/Trim Notice (CTN 202124).

In this case, for 'first cut' notification, the cost of the work is collated by PowerNet (and on-charged to OJV), rather than the property owner.

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

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

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

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

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

APPENDIX B:

MAP OF NETWORK EXPENDITURE AND CONSTRAINTS

ID Determination 2.3.13 - 2.3.16

Regulatory requirements

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

The purpose of this section is to identify on a map the anticipated network expenditure and network constraints in accordance with the OJV network 2020-2030 Asset Management Plan.

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

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

The 10 largest forecast Operating Expenditure projects in the 2020-2030 Asset Management Plan for OJV regulated network are explained below, and indicated on the Network map above where relative to a single area:

1. Incident Response – Distribution - $14.30M

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

2. Vegetation Management - $11.18M

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

3. Distribution Routine Inspections - $6.79M

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

4. Technical Routine Maintenance $3.34M

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

5. Incident Response – Technical - $1.89M

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

6. Distribution Routine Maintenance - $1.87M

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

7. Technical Routine Inspections - $1.74M

   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.

8. General Distribution Refurbishment - $1.14M

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

9. Transmission Line Minor Maintenance - $1.03M

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

10. Earth Testing and Review - $1.00M

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

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 -

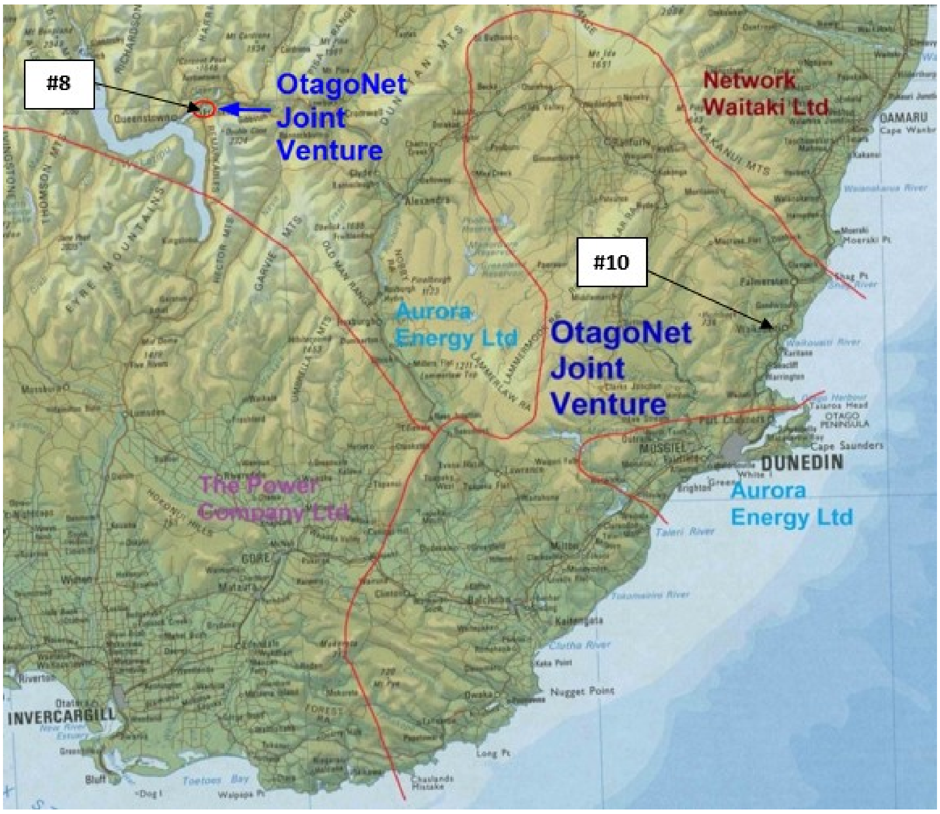
- Are network wide (apply to entire area as shown on map below).
- Have a contract in place that is with PowerNet Limited through a network management agreement (related party).
- Are forecast to require the supply of assets/goods or services by PowerNet Limited (related party).

Possible future constraints related to OJV network Operating Expenditure projects:

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

OJV - 10 largest forecast Network Capital Expenditure projects

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



The 10 largest forecast Capital Expenditure projects in the 2020-2030 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 Project - $48.41M

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

   $5.4M has been budgeted under Consumer Connection in the short term for projects that have relative certainty; plus an allowance of approximately $4.4M-5.8M p.a. in the medium to long term where the location and/or scale of projects is relatively unknown.

2. 11 kV Line Replacement and Renewal - $31.11M

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

3. 33 kV Line Replacement and Renewal - $18.63M

   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. LV Line Replacement and Renewal - $7.58M

   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.

5. Unspecified System Growth Projects - $7.37M

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

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

   This provision is for system growth projects that are yet to be identified and are expected to be implemented in 2025-30.

6. Unspecified Replacement and Renewal Projects - $7.10M

   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 2025-30.

7. Customer Connections (≤ 20kVA) - $6.81M

   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.

8. Remarkables Substation Relocation - $5.61M

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

   $5.61M has been allocated under Asset Relocations towards relocating the substation over the 2021-2024 period.

9. SWER Line Replacement and Renewal - $5.05M

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

10. Quarry Road Substation - $4.47M

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

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

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

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 #8 and #10 which are pinpointed on the map above.
- Have a contract in place that is with PowerNet Limited through an agency agreement (related party).
- Are forecast to require the supply of assets/goods or services by PowerNet Limited (related party).

Possible future constraints related to OJV network Capital Expenditure projects:

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

5. Unspecified System Growth Projects

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

10. Quarry Road Substation

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

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

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

Project	Project description[1]	Likely timing[2]	Value[3]	Location[4]	Contract in place[5]	Is contract with RP[6]	Forecast to include RP[7]	Currently not indicated for RP[8]
#1	Incident Response - Distribution	Every year	$14.30M	Network Wide	Yes	Yes	Very likely	N/A
#2	Vegetation Management	Every year	$11.18M	Network Wide	Yes	Yes	Very likely	N/A
#3	Distribution Routine Inspections	Every year	$6.79M	Network Wide	Yes	Yes	Very likely	N/A
#4	Technical Routine Maintenance	Every year	$3.34M	Network Wide	Yes	Yes	Very likely	N/A
#5	Incident Response - Technical	Every year	$1.89M	Network Wide	Yes	Yes	Very likely	N/A
#6	Distribution Routine Maintenance	Every year	$1.87M	Network Wide	Yes	Yes	Very likely	N/A
#7	Technical Routine Inspections	Every year	$1.74M	Network Wide	Yes	Yes	Very likely	N/A
#8	General Distribution Refurbishment	Every year	$1.14M	Network Wide	Yes	Yes	Very likely	N/A
#9	Transmission Line Minor Maintenance	Every year	$1.03M	Network Wide	Yes	Yes	Very likely	N/A
#10	Earth Testing and Review	Every year	$1.00M	Network Wide	Yes	Yes	Very likely	N/A

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

OJV - 10 largest forecast Network Capital Expenditure projects

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

Project	Project description	Likely timing	Value	Location	Contract in place?	Is contract with RP?	Forecast to include RP?	Currently not indicated for RP
#1	Major New Connections Projects	Every year	$48.41M	Network Wide	Yes	Yes	Very likely	N/A
#2	11 kV Line Replacement and Renewal	Every year	$31.11M	Network Wide	Yes	Yes	Very likely	N/A
#3	33 kV Line Replacement and Renewal	Every year	$18.63M	Network Wide	Yes	Yes	Very likely	N/A
#4	LV Line Replacement and Renewal	Every year	$7.58M	Network Wide	Yes	Yes	Very likely	N/A
#5	Unspecified System Growth Projects	2025-2030	$7.37M	Network Wide	No	N/A	Very likely	N/A
#6	Unspecified Replacement & Renewal Projects	2025-2030	$7.10M	Network Wide	No	N/A	Very likely	N/A
#7	Customer Connections (≤ 20kVA)	Every year	$6.81M	Network Wide	Yes	Yes	Very likely	N/A
#8	Remarkables Substation Relocation	2021-2024	$5.61M	#8	No	N/A	Very likely	N/A
#9	SWER Line Replacement and Renewal	Every year	$5.05M	Network Wide	Yes	Yes	Very likely	N/A
#10	Quarry Road Substation	2025-29	$4.47M	#10	No	N/A	Very likely	N/A

Possible future constraints related to OJV network Capital Expenditure projects:

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

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

Independent Appraiser's Report

To the Governing Committee Members of OtagoNet Joint Venture, the Directors of Electricity Southland Limited and the Commerce Commission

Independent Appraiser Report on Related Party Transactions Pursuant to Electricity Distribution Information Disclosure Determination 2012

This report is for the OJV Regulatory Network ('the Network') which includes:

- Electricity Southland Limited ('ESL') which operates the ESL network; and
- OtagoNet Joint Venture ('OJV'), consisting of a joint venture between Electricity Invercargill ('EIL') and The Power Company ('TPC'), which operates the OJV network.

The Governing Committee for OJV mirrors the Board of ESL. Any reference to the Governing Committee of the Network in this report therefore includes reference to those charged with governance of both OJV and ESL.

We have completed our reasonable assurance engagement in respect of the compliance of the Network with the related party requirements, as set out in the Electricity Distribution Information Disclosure Determination 2012 as amended by the Information Disclosure exemption: Disclosure and auditing of reliability information within schedule 10, issued by the Commerce Commission on 9 April 2020 (the 'Information Disclosure Determination, as amended') for the disclosure year ended 31 March 2020 where we are required to report on:

- whether the Network'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 Information Disclosure Determination, as amended, and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012 ('the Input Methodologies Determination'); and
- whether the steps taken by the Network, as specified under the *"Summary of steps and analysis undertaken by the Network to test compliance"* are considered to be, in all material respects, reasonable in the circumstances.

PricewaterhouseCoopers, The PwC Centre, 60 Cashel Street, PO Box 13244, Christchurch, New Zealand
T: +64 3 374 3000, F: +64 3 374 3001, pwc.co.nz

Opinion

In our opinion:

- the basis for valuation of related party transactions for the disclosure year ended 31 March 2020 complies, in all material respects, with the Information Disclosure Determination, as amended and the Input Methodologies Determination; and

- the steps undertaken by the Network, as specified under the *"Summary of steps and analysis undertaken by the Network to test compliance"* are considered to be, in all material respects, reasonable in the circumstances.

Basis for Opinion

We conducted our engagement in accordance with ISAE (NZ) 3000 (Revised), *Assurance Engagements Other than Audits or Reviews of Historical Financial Information* and SAE 3100 (Revised) *Compliance Engagements* to obtain reasonable assurance that the Network has complied in all material respects with the relevant related party valuation requirements as set out in the Information Disclosure Determination, as amended and the Input Methodologies Determination for the year ended 31 March 2020.

In forming our opinion we have obtained sufficient recorded evidence and all the information and explanations we have required.

Our Independence and Quality Control

We are independent of the Network in accordance with Professional and Ethical Standard 1 *International Code of Ethics for Assurance Practitioners (including International Independence Standards) (New Zealand)* (PES 1) issued by the New Zealand Auditing and Assurance Standards Board and the *International Code of Ethics for Professional Accountants (including International Independence Standards)* issued by the International Ethics Standards Board for Accountants (IESBA Code), and we have fulfilled our other ethical responsibilities in accordance with these requirements.

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

We are independent of the Network. Other than our role as financial statement auditors our firm carries out other services for the Network in the areas of compliance with regulatory requirements of the Commerce Act 1986 and the provision of regulatory advisory services. The provision of these other services has not impaired our independence as Appraiser of the Network.

Our approach

Materiality

Our assurance engagement is designed to obtain reasonable assurance about the Network's qualitative and quantitative compliance, in all material respects, with the Information Disclosure Determination, as amended and Input Methodologies Determination.

Quantitative materiality level was determined as 2% of total related party transactions. Qualitative factors were also considered when assessing the arm's length valuation rules on related party transactions.

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 related party information as a whole.

Key assumptions we made in carrying out our procedures

In carrying out our procedures we have relied on the internal controls at OJV and ESL relating to the identification of related party transactions and the valuation of related party transactions that we tested, and placed reliance on, during our audits of the financial statements for the year ended 31 March 2020 in relation to our work as the independent appraiser for the disclosure year ended 31 March 2020.

Basis used for sampling of related party transactions

We obtained the Network's assessment of their compliance with the relevant related party valuation requirements in the Information Disclosure Determination, as amended and Input Methodologies Determination.

We selected a sample of related party transactions on a haphazard basis across a range of transactions and services, and agreed these to the supporting information provided by the Network to demonstrate the independent and objective measure used for those transactions and services, to determine whether it has been valued in accordance with the related party valuation requirements in the Information Disclosure Determination, as amended and Input Methodologies Determination.

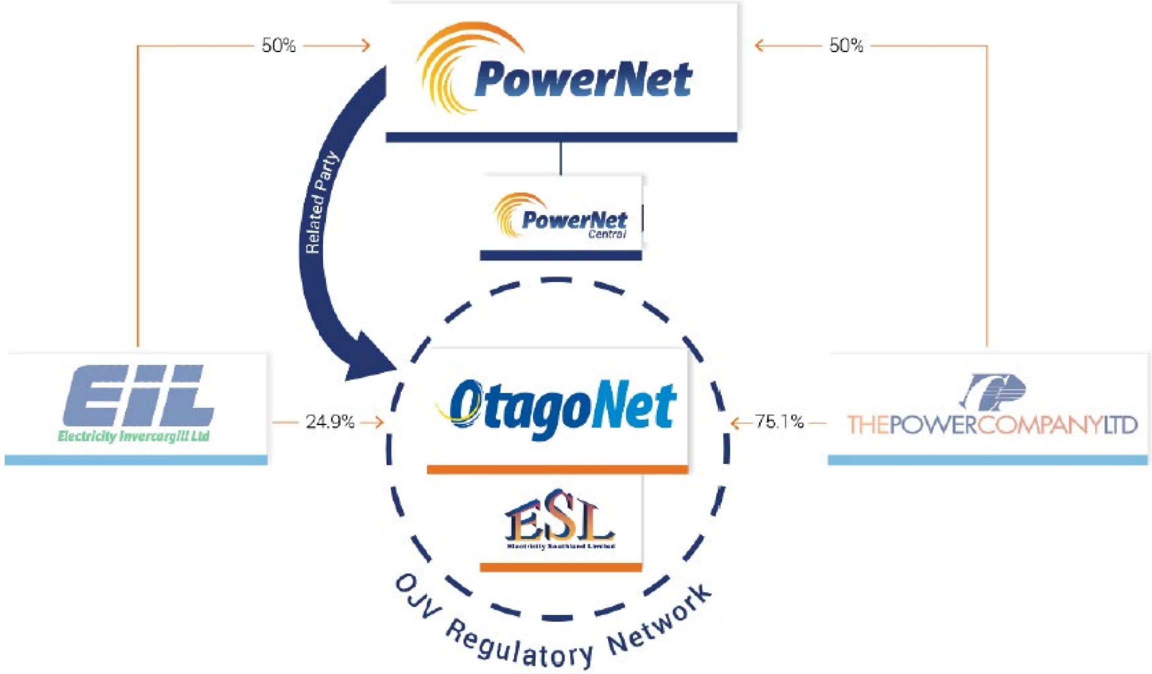
Steps and analysis undertaken in testing compliance

Step 1) Identifying related party relationships and transactions

Summary of steps undertaken by the Network to demonstrate compliance

The Network identified all related party relationships in accordance with the Information Disclosure Determination, as amended, and disclosed these in Appendix A to the 2020 Information Disclosure Schedules as prepared and published under the Information Disclosure Determination, as amended.

The parties to the Network are related. PowerNet Limited ('PowerNet') and PowerNet Central Limited ('PCL') are related parties due to common ownership.



During the year related party transactions occurred with PowerNet. No related party transactions occurred with PCL directly.

- PowerNet provides network management services to OJV, EIL, ESL and TPC, under equivalent Network Management Agreements.
- PowerNet subcontracts external parties to assist it in providing these services where appropriate.
- PowerNet recovers its costs from OJV, ESL and the other network companies through an agency fee for network management/business support services, direct pass through of labour and material charges, and a commercial mark-up on capital and maintenance to recover PowerNet's costs and contribute to profit.
- PowerNet also undertakes contestable works for other customers on similar terms.

Related party transactions between ***the Network and PowerNet*** during the year ended 31 March 2020:

Operating Expenditure (opex):		***$'000***
i.	Service interruption and emergencies	2,208
ii.	Vegetation management	1,289
iii.	Routine & corrective maintenance	1,838
iv.	Asset replacement and renewal	338
v.	System operations & network support	712
vi.	Business support	1,637
Total opex		**8,022**
Capital Expenditure (capex):		
vii.	Consumer connection	5,657
viii.	System growth	855
ix.	Asset replacement and renewal	6,998
x.	Quality of supply	457
xi.	Other reliability, safety and environment	2,494
Total capex		**16,461**
Total PowerNet Related Party Expenditure		**24,482**

Our procedures undertaken

We have tested the completeness and accuracy of the related party relationships and transactions by:

- Agreeing the disclosures within Appendix A and Schedule 5b of the 2020 Information Disclosure schedules to the aggregate disclosures in the audited financial statements of OJV and ESL for the year ended 31 March 2020 and to their respective accounting records, investigating any differences and determining whether any such differences are justified; and
- Applying our understanding of the business structures against the related party definition in the Input Methodologies Determination clause 1.1.4(2)(b) to assess OJV and ESL's identification of any "unregulated parts" of the entities respectively.

Step 2) Outlining the intent behind the OJV and ESL agency agreements with PowerNet

Summary of steps undertaken by the Network to demonstrate compliance of the Network's related party transactions with PowerNet

The Network incurred 100% of its capex and the vast majority of its operating costs for its electricity distribution business from PowerNet, in accordance with the explicit terms and conditions of the PowerNet Network Management Agreement ('NMA').

While OJV and ESL own the network assets, under the NMA's PowerNet manage the network assets, carry out an agreed capital works programme, have the exclusive right to provide line function services and provide the business administration services on behalf of OJV and ESL.

PowerNet was established in 1994 to extract operational efficiencies from the merger of field work management, asset management and office based functions performed by TPC and EIL. In 1993, there were two autonomous lines companies in Southland (TPC and EIL). Each had separate staff, management and Board of Directors, and each had a different ownership structure. We understand the Board 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 we understand a single lines company was not considered possible, however a single network management entity was a viable option.

PowerNet increased its operations to include OJV and ESL, and therefore extended its scale and opportunity for efficiency. Part of the policy intent of the new related party rules is to address concerns that related parties may be inefficient which may cause the Network to overcharge consumers. OJV and ESL note that the intent of the PowerNet Group structure and NMA's was to generate cost efficiencies and savings through economy of scale, improve network reliability and secure qualified staff to efficiently maintain the network assets within the region.

Our procedures undertaken
The background information provided by the Network is in line with our understanding of the intent behind the group structure and agency/management agreement between the Network and PowerNet.

We obtained the minutes of OJV's Governing Committee and ESL Board meetings and noted:

- The ESL Board is consistent with the OJV Governing Committee;
- Approval of the NMA's and annual business plan by the OJV Governing Committee and ESL Board;
- A focus on ensuring efficient cost and effective management of the network with regular measurement of performance and monitoring in the monthly reports;
- External reports obtained and presented to the OJV Governing Committee on prudency and efficiency of forecast spends and benchmarking of operational cost efficiency; and
- An independent report obtained focussed on the appropriate allocation of PowerNet costs between the four network customers.

We obtained all PowerNet's NMAs and note the agreements are consistent for TPC, EIL, ESL and OJV. This equivalence demonstrates that the transactions with OJV and ESL are consistent with the regional market.

Step 3) Assessing compliance with the definition of an arm's length transaction (in accordance with ISA (NZ) 550)

From 1 April 2018, a principles based approach to the valuation of related party transactions is being applied. All related party transactions must meet the arm's length valuation rule for ID disclosures, based on the following definition of arm's length transaction from the International Standard for Auditing (NZ) 550: *"a transaction conducted on such <u>terms and conditions</u> as between a <u>willing buyer and a willing seller who are unrelated</u> and are <u>acting independently</u> of each other and <u>pursuing their own best interests</u>"*.

Summary of steps undertaken by the Network to demonstrate compliance

The Network acknowledges that meeting the 'arm's length' valuation criteria, as defined above, is challenging due to the ownership structure and significant amount of work PowerNet manages on behalf of the Network under the NMA's.

The Network performed an analysis of the arm's length definition and have set out its interpretation in Appendix A to the 2020 Information Disclosure Schedules. Key points are summarised below:

i. *Terms and conditions*

The purchasing terms and conditions applied to PowerNet, are the same as applied to other suppliers. In turn, the purchasing terms and conditions PowerNet applies, are the same to OJV and ESL as any other customer.

ii. *Willing buyer and willing seller who are unrelated*

The internal labour rates applied by PowerNet, and commercial mark-up rates are the same to all other customers for similar services, indicating that the parties are acting consistent with the principle of willing buyer and willing seller who are unrelated.

iii. *Acting independently*

OJV and ESL are related to PowerNet by way of common ownership, however with regards to acting independently, PowerNet operates with the level of independence of a separate entity, as the ownership is held by two shareholders with differently ownership structures. Each entity has its own Governing Committee/Board of Directors who act independently in their roles.

iv. *Pursuing their own best interests*

Both shareholders of PowerNet have different ownership structures (TPC owned by a Consumer Trust, and EIL owned by the Invercargill City Council), and different regulatory requirements. This unrelated ownership ensures a review process when preparing budgets and analysing performance, to make sure one shareholder is not disadvantaged over the other with each entity pursuing their own best interest.

Our procedures undertaken

PowerNet performed 100% of the Network's capex and 91% of the Network's opex during the year ended 31 March 2020. Whilst PowerNet performs the majority of the capex and opex work, we note that 43% of the costs relate to external materials and labour obtained at arm's length.

We have performed the following procedures over the Network's arm's length definition assessment:

i. *Terms and conditions*

Agreed the OJV and ESL standard terms and conditions to the PowerNet standard terms and conditions (applied to both OJV, ESL and external customers) and noted no variation.

ii. *Willing buyer and willing seller who are unrelated*

Obtained a copies of contracts with an unrelated PowerNet customers and agreed the internal labour rates and commercial mark-up to that charged to OJV and ESL is at or below the charges to external customers.

iii. *Acting independently*

We note that the PowerNet Board has obligations to all of its customers, through its terms and conditions of supply. From a PowerNet perspective, Directors must meet their fiduciary duties by honouring those obligations. They cannot favour OJV or ESL because PowerNet has multiple customers.

iv. *Pursuing their own best interest*

We considered evidence obtained through our other procedures which indicates how each entity pursues its own best interest below:

How does PowerNet pursue its own best interests?

- It ensures all customers have the same terms of trade;
- It seeks customer approval of its annual works programme;
- It sub-contracts work where there are better outcomes for its customers; and
- It negotiates wholesale purchase agreements to minimise costs.

How OJV and ESL pursue their own best interests?

- It ensures PowerNet's other customers do not receive favourable terms;
- It monitors the performance of PowerNet; and
- It approves PowerNet's work plans for its network.

Step 4) Obtaining independent and objective measures to support the arm's length principle for transactions with PowerNet

Summary of steps undertaken by the Network to demonstrate compliance of the related party transactions with PowerNet

The independent and objective measures used by Network to demonstrate prices paid to PowerNet are no more than arm's length transaction value are as follows.

External labour & materials (opex and capex)

- Sourced from external suppliers, on a traditional arm's length basis
- Cost efficiencies gained through supplier agreements e.g. electrical supply agreements ensure prices are no more than market rates due to wholesale agreements consistent with the scale of PowerNet's operations

Mark-up external labour & materials (opex)

- Cost efficiencies gained through economies of scale
- Transparency of cost allocation process based on cost drivers and consistent mark-up rates for customers
- External non-network customer work being awarded to PowerNet based on the same opex rates as charged to Electricity Distribution Business (EDB) customers

Mark-up external labour and materials (capex)

- Cost efficiencies gained through economies of scale
- Transparency of cost allocation process based on cost drivers and consistent mark-up rates for customers
- External non-network customer work being awarded to PowerNet based on the same capex rates as charged to Electricity Distribution Business (EDB) customers

Internal labour & equipment charges (opex and capex)

- Unit rates are consistent for each EDB and PowerNet's other customers
- Labour rates are benchmarked against competitors, and fall within expected ranges
- Independent engineer review of prudency and efficiency of works programme

Business, system, network support (opex)

- Shared services model provides scale efficiencies to OJV
- Share of PowerNet's costs assigned to OJV based on measurable and transparent cost drivers, applied consistently across all of PowerNet's customers

Our procedures undertaken
We obtained the Network's assessment of the available independent and objective measures used in supporting the arm's length valuation principle.

We noted that procedures are in place for monitoring of costs. We performed the following procedures over a sample of transactions at the work order level:

- Agreed the make-up of costs (as reported by the Network above) to the work order within the Tech1 system;
- Agreed individual costs to supporting invoices (from external suppliers) or agreed rates (such as labour and equipment rates);
- Agreed the internal labour rates and mark-ups charged to those used in the labour rates benchmarking analysis;
- Tested appropriate approval of project costs at completion of the project by the project manager; and
- Tested compliance with the procurement policy/process as disclosed in Appendix A to the Information Disclosure Schedules.

We performed the following procedures on the individual components of costs as outlined by the Network to obtain evidence regarding the appropriateness of and level of comfort obtained from the independent and objective measures provided:

External labour and material (Opex - $785k and Capex - $9.6m)

- Obtained a copy of the electrical supply agreement, which covers a significant portion of the costs and noted quarterly reviews of prices and performance; and
- Agreed external costs, for a sample of work orders, to supporting invoices from external suppliers.

Mark-up external labour & materials (Opex - $600k and Capex - $2.1m)

- Obtained the NMA's and minutes of OJV Governing Committee and ESL Board meetings and noted approval of the cost allocation methods;
- Obtained all of the PowerNet NMAs and note consistent terms and mark-up rates are applied to PowerNet's EDB customers; and
- Obtained an independent advisor report prepared on the reasonableness of the allocation of costs between the PowerNet EDB customers. We note the report supports the transparent and consistent application of cost allocation between PowerNet's EDB customers.
- Obtained PowerNet's contracting mark-up rates for a sample of external customer projects undertaken during the year and note mark-up rates applied to PowerNet's EDB customers are at or below those market rates charged to external customers.
- Obtained the capital project indirect labour allocation analysis and tested a sample of the inputs to supporting documentation and verified the nature of tasks performed and estimated FTE allocation through interviews with a sample of employees.

Internal labour & equipment charges (Opex - $4.3m and Capex - $4.6m)

- Obtained a copy of the independent electrical engineer's report on the 2019/20 works programme review which assessed the forecast spend of a sample of projects for prudency and efficiency;
- We obtained subsequent benchmarking performed by the Network over opex and capex labour and equipment rates;
- Agreed PowerNet labour and equipment rates to a sample of work orders to ensure they agree to rates charged to the Network during the year;
- Agreed market/competitor rates to supporting documentation such as quotes or invoices;
- Recalculated the variances and average percentages between PowerNet rates and other market rates;

- Considered the reasonableness of the variance of labour rates between PowerNet and market rates and accept the PowerNet rates as within an acceptable range when compared to the industry benchmarking performed by the Network. The majority of the rates are below the benchmarked market rates with the remaining rates considered within an acceptable range of up to 15%.

Business, system and network support (Opex - $2.3m)

- Obtained copies of the NMA's and understood how costs are recovered through the agency fee;
- Obtained the NMA's and minutes of OJV's Governing Committee and ESL's Board meetings and note approval of the agency fee;
- Obtained the business plans for FY19/20 and note approval by the OJV Governing Committee and ESL Board of the basis for allocation of the agency fee;
- Obtained an independent advisor report prepared on the reasonableness of the allocation of costs between the PowerNet EDB customers. We note the report supports the transparent and consistent application of cost allocation between PowerNet's EDB customers;
- Obtained benchmarking performed on business and system support costs through the use of the historic information disclosure schedules and note OJV's business and system support costs per Installation Control Point (ICP) rate well in comparison to its peer group (by size and ICP density). These costs have also reduced over the past five years, whereas industry and peer group averaged costs per ICP have remained relatively constant, in nominal terms.

Governing Committee Member's Responsibilities

The Governing Committee Members are responsible on behalf of the Network for:

- compliance with the Information Disclosure Determination, as amended and the valuation of related party transactions in accordance with the Information Disclosure Determination, as amended and the Input Methodologies Determination; and
- the identification of risks that threaten such compliance and controls which will mitigate those risks and monitor ongoing compliance.

Appraisers' Responsibilities

Our responsibility is to prepare an independent appraiser report in accordance with clause 2.8.4 of the Information Disclosure Determination, as amended. In preparing the report we are required to express an opinion on whether, for the disclosure year ended 31 March 2020, the basis for valuation of related party transactions complies, in all material respects, with the Information Disclosure Determination, as amended and the Input Methodologies Determination, and whether the steps taken by the Network to test whether it complies, are considered to be, in all material respects, reasonable in the circumstances.

Our engagement has been conducted in accordance with ISAE (NZ) 3000 (Revised), *Assurance Engagements Other than Audits or Reviews of Historical Financial Information* and SAE 3100 (Revised) *Compliance Engagements* which require that we plan and perform our procedures to obtain reasonable assurance.

An assurance engagement to report on the Network's compliance with the Information Disclosure Determination, as amended and the Input Methodologies Determination involves performing procedures to obtain evidence about the compliance activity and controls implemented to meet the relevant related party valuation requirements of the Information Disclosure Determination, as amended and the Input Methodologies Determination. The procedures selected depend on our judgement, including the identification and assessment of risks of material non-compliance with the relevant related party valuation requirements of the Information Disclosure Determination, as amended and the Input Methodologies 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 with compliance requirements may occur and not be detected.

A reasonable assurance engagement for the disclosure year ended 31 March 2020 does not provide assurance on whether compliance with the relevant related party valuation requirements of the Information Disclosure Determination, as amended and the Input Methodologies Determination will continue in the future.

Who we report to

This report has been prepared for the Governing Committee of OtagoNet Joint Venture, the Board of Directors of Electricity Southland Limited and the Commerce Commission ('the Parties') in accordance with clause 2.8.4 of the Information Disclosure Determination, as amended 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 Parties, or for any purpose other than that for which it was prepared.

The engagement partner on the assurance engagement resulting in this independent appraiser's report is Elizabeth Adriana (Adri) Smit, who is a licensed auditor with the New Zealand Institute of Chartered Accountants which forms part of Chartered Accountants Australia and New Zealand.

PricewaterhouseCoopers.

Chartered Accountants
27 August 2020

Christchurch, New Zealand

Independent Auditor's Report

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

Assurance Report Pursuant to Electricity Distribution Information Disclosure Determination 2012, as amended

We have completed our reasonable assurance engagement in respect of the compliance of OtagoNet Joint Venture (the 'Joint Venture') with the Electricity Distribution Information Disclosure Determination 2012 as amended by the Information Disclosure exemption: Disclosure and auditing of reliability information within schedule 10, issued by the Commerce Commission on 9 April 2020 (the 'Information Disclosure Determination, as amended') for the disclosure year ended 31 March 2020 where we are required to opine on:

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

Qualified Opinion

In our opinion, except for the matters described in the *Basis for Qualified Opinion* section of our report:

- As far as appears from our examination, proper records have been kept by the Joint Venture to enable the complete and accurate compilation of the Disclosure Information;
- 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 Joint Venture has complied, in all material respects, with the Information Disclosure Determination, as amended in preparing the Disclosure Information; and
- The basis for valuation of related-party transactions complies, in all material respects, with the Information Disclosure Determination, as amended and the Input Methodologies Determination.

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

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

There are no practical audit procedures that we could adopt to independently confirm the accuracy of the ICP data used to record the number of ICP's affected and duration of the interruption for the purposes of inclusion in the amounts relating to SAIDI and SAIFI outage statistics set out in Schedules 10(i) to 10(iv). Because of the potential effect of the limitations described above, we are unable to form an opinion as to the accuracy of the data that forms the basis of the compilation of Schedules 10(i) to 10(iv). In this respect alone we have not obtained all the recorded evidence and explanations that we have required.

We conducted our engagement in accordance with ISAE (NZ) 3000 (Revised), *Assurance Engagements Other than Audits or Reviews of Historical Financial Information* and SAE 3100 (Revised) *Compliance Engagements* to obtain reasonable assurance that the Joint Venture has complied in all material respects with the Information Disclosure Determination, as amended and Input Methodologies Determination in the preparation of the Schedules for the year ended 31 March 2020.

In forming our qualified opinion, except as explained in the *Basis for qualified opinion* section of our report, we have obtained sufficient recorded evidence and all the information and explanations we have required.

Our Independence and Quality Control

We are independent of the Joint Venture in accordance with Professional and Ethical Standard 1 *International Code of Ethics for Assurance Practitioners (including International Independence Standards) (New Zealand)* (PES 1) issued by the New Zealand Auditing and Assurance Standards Board and the *International Code of Ethics for Professional Accountants (including International Independence Standards)* issued by the International Ethics Standards Board for Accountants (IESBA Code), and we have fulfilled our other ethical responsibilities in accordance with these requirements.

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

We are independent of the Joint Venture. Our firm carries out other services for the Joint Venture in the areas of compliance with regulatory requirements of the Commerce Act 1986, financial statement audit and the provision of regulatory advisory services. The provision of these other services has not impaired our independence as auditor of the Joint Venture.

Our audit approach

Overview

Our assurance engagement is designed to obtain reasonable assurance about the Joint Venture's qualitative and quantitative compliance, in all material respects, with the Information Disclosure Determination, as amended and Input Methodologies Determination.

Quantitative materiality levels are determined for individual schedules included in the Disclosure Information based on the nature of the information set out in the schedules.

Profit based schedules –10% of Regulatory profit before tax
Asset based schedules – 3% of Regulatory asset base
Performance based schedules – 5% of non-financial measures
Related party transactions – 2% of total related party transactions. Qualitative factors were also considered when assessing the arm's length valuation rules on related party transactions.

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 Information Disclosure Determination, as amended in the preparation of the Disclosure Information for the year ended 31 March 2020, and whether the basis for valuation of related party transactions complies, in all material respects, with the Information Disclosure Determination, as amended and the Input Methodologies 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 determine the matters described below to be Key Assurance Matters.

Key assurance matter	How our procedures addressed the key assurance matter
Regulatory Asset Base The Regulatory Asset Base (RAB), as set out in Schedule 4, reflects the value of the Joint Venture's electricity distribution assets. These are valued using an indexed historic cost methodology prescribed by the Information Disclosure Determination, as amended. It is a measure which is used widely and is key to measuring the Joint Venture's return on investment and therefore important when monitoring financial performance or setting electricity distribution prices. The RAB inputs, as set out in the Input Methodologies, 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 Information Disclosure Determination, as amended and the Input Methodologies Determination. We have performed the following procedures: *Assets commissioned* • We reconciled the assets commissioned as per the regulatory fixed asset register to the asset additions disclosed in the audited annual financial statements, and investigated any reconciling items; • We inspected the assets commissioned during the period, as per the regulatory fixed asset register, to identify any specific cost or asset type exclusions, as set out in the Information Disclosure Determination, which are required to be removed from the RAB; • We tested a sample of assets commissioned during the disclosure period for appropriate asset category classification; *Depreciation* • We compared the standard asset lives by asset category to those set out in the Input Methodologies Determination; • We verified the spreadsheet formula utilised to calculate regulatory depreciation expense is in line with Input Methodologies Determination clause 2.2.5; *Revaluation* • We recalculated the revaluation rate set out in the Input Methodologies Determination using the relevant Consumer Price Index indices taken from the Statistics New Zealand website;

Key assurance matter	How our procedures addressed the key assurance matter
	• We tested the mathematical accuracy of the revaluation calculation performed by management; *Disposals* • We inspected the asset disposals within the accounting fixed asset register to ensure disposals in the RAB meet the definition of a disposal per the Input Methodologies Determination; We have no matters to report from undertaking those procedures.
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 Information Disclosure Determination, as amended and the Input Methodologies Determination are set out in Appendix A. The Information Disclosure Determination and the Input Methodologies Determination require the Joint Venture to value its transactions with related parties, disclosed in Schedule 5b, in accordance with the principles-based approach to the arm's length valuation rule. This rule states that the value of goods or services acquired from a related party cannot be greater than if it had been acquired under the terms of an arm's length transaction with an unrelated party, nor may it exceed the actual cost to the related party. A sale or supply to a related party cannot be valued at an amount less than if it had been sold or supplied under the terms of an arm's-length transaction with an unrelated party. Arm's-length valuation, as defined in the Input Methodologies Determination, is the value at which a transaction, with the same terms and conditions, would be entered into between a willing seller and a willing buyer who are unrelated and who are acting independently of each other and pursuing their own best interests. The Joint Venture is required to use an objective and independent measure to demonstrate compliance with the arm's-length principle. In the absence of an active market for similar transactions, assigning an objective arm's length value to a related party transaction is difficult and requires significant judgement.	We have obtained an understanding of the compliance requirements relevant to related party transactions as set out in the Information Disclosure Determination, as amended, and the Input Methodologies Determination. We have ensured Schedule 5(b) and Appendix A includes all required disclosures including current procurement policies, descriptions of how they are applied in practice, representative example transactions and when and how market testing was last performed. We have performed the following procedures over Schedule 5(b) and Appendix A. *Completeness and accuracy of related party relationships and transactions* We have tested the completeness and accuracy of the related party relationships and transactions by: • Agreeing the disclosures within Schedule 5(b) to the audited financial statements for the year ended 31 March 2020 and to the accounting records, investigating any differences and determining whether any such differences are justified; and • Applying our understanding of the business structure against the related party definition in Input Methodologies Determination clause 1.1.4(2)(b) to assess management's identification of any "unregulated parts" of the entity. *Practical application of procurement policies* • Testing a sample of operating expenditure and capital expenditure transactions disclosed in Schedule 5(b) by inspecting supporting documentation to determine compliance with the disclosed procurement policy and practices. *Arm's length valuation rule* We obtained the Joint Venture's assessment of the available independent and objective measures used in supporting the arm's length valuation principle and performed the following procedures: • Re-performed the calculations and agreed key inputs and assumptions to supporting documentation;

Key assurance matter	How our procedures addressed the key assurance matter
We have identified related party transactions at arm's-length as a key audit matter due to the judgement involved.	• Where benchmarking or other market information was used as independent and objective measures we assessed whether the related party transaction values fell within an acceptable range. Qualitative factors were considered in determining the appropriate acceptable range. We have no matters to report from undertaking those procedures.

Governing Committee Members' Responsibilities

The Governing Committee Members are responsible on behalf of the Joint Venture for

- compliance with the Information Disclosure Determination, as amended and the valuation of related party transactions in accordance with the Information Disclosure Determination, as amended and the Input Methodologies Determination; and
- the identification of risks that threaten such compliance and controls which will mitigate those risks and monitor ongoing compliance.

Auditors' Responsibilities

Our responsibility is to express an opinion on whether the Joint Venture has complied, in all material respects, with the Information Disclosure Determination, as amended in the preparation of the Disclosure Information for the disclosure year ended 31 March 2020 and on whether the basis for valuation of related party transactions complies, in all material respects, with the Information Disclosure Determination, as amended and the Input Methodologies Determination.

Our engagement has been conducted in accordance with ISAE (NZ) 3000 (Revised), *Assurance Engagements Other than Audits or Reviews of Historical Financial Information* and SAE 3100 (Revised) *Compliance Engagements* which require that we plan and perform our procedures to obtain reasonable assurance about whether the Joint Venture has complied in all material respects with the Information Disclosure Determination, as amended in the preparation of the Disclosure Information for the disclosure year ended 31 March 2020, and whether the basis for valuation of related party transactions complies, in all material respects, with the Information Disclosure Determination, as amended and the Input Methodologies Determination.

An assurance engagement to report on the Joint Venture's compliance with the Information Disclosure Determination, as amended and the Input Methodologies Determination involves performing procedures to obtain evidence about the compliance activity and controls implemented to meet the requirements of the Information Disclosure Determination, as amended and the Input Methodologies Determination. The procedures selected depend on our judgement, including the identification and assessment of risks of material non-compliance with the requirements of the Information Disclosure Determination, as amended and the Input Methodologies 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 with compliance requirements may occur and not be detected.

A reasonable assurance engagement for the disclosure year ended 31 March 2020 does not provide assurance on whether compliance with the requirements of the Information Disclosure Determination, as amended and the Input Methodologies Determination will continue in the future.

Who we report to

This report has been prepared for the Governing Committee Members and the Commerce Commission in accordance with clause 2.8.1(1) of the Information Disclosure Determination, as amended and is provided solely to assist you in establishing that compliance requirements have been met. Our report should not be used for any other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility for any reliance on this report to anyone other than the Governing Committee Members 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
27 August 2020

Christchurch, New Zealand

Schedule 18: Certification for Year-End Disclosures

Clause 2.9.2

We, Duncan Varnham Fea and Sarah Jane Brown, 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.

Duncan Varnham Fea **Sarah Jane Brown**

26 August 2020

Footnote:
The Governing Committee of OtagoNet Joint Venture (OtagoNet) note the amendment to the Information Disclosure exemption: Disclosure and auditing of reliability information within Schedule 10, issued by the Commerce Commission on 9 April 2020 that has removed the auditor report requirements relating to the treatment of successive interruptions for reporting SAIDI, SAIFI, and interruptions, because of potential inconsistencies in treatment approaches across the industry.

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