Electricity Invercargill Ltd

INFORMATION DISCLOSURE PREPARED IN ACCORDANCE WITH ELECTRICITY INFORMATION DISCLOSURE DETERMINATION UNDER PART 4 OF THE COMMERCE ACT 1986

FOR THE YEAR ENDED 31 MARCH 2019

CONTENTS

1. INTRODUCTION

These Information Disclosure documents are submitted by Electricity Invercargill Limited 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 2014), issued 30 March 2015,

2. INFORMATION DISCLOSURE DISCLAIMER

The information disclosed in this Information Disclosure package issued by Electricity Invercargill Limited 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	Electricity Invercargill Limited
For Year Ended	31 March 2019

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	19,420	283	78,295	7,504	33,230
Network	6,322	92	25,490	2,443	10,818
Non-network	13,097	191	52,805	5,061	22,411
Expenditure on assets	18,969	277	76,479	7,330	32,459
Network	18,969	277	76,479	7,330	32,459
Non-network	–	–	–	–	–

1(ii): Revenue metrics

	Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
Total consumer line charge revenue	80,795	1,179
Standard consumer line charge revenue	80,795	1,179
Non-standard consumer line charge revenue	–	–

1(iii): Service intensity measures

Demand density	93	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
Volume density	386	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
Connection point density	26	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
Energy intensity	14,597	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*

1(iv): Composition of regulatory income

	($000)	% of revenue
Operational expenditure	4,938	24.08%
Pass-through and recoverable costs excluding financial incentives and wash-ups	6,510	31.75%
Total depreciation	3,120	15.21%
Total revaluations	1,245	6.07%
Regulatory tax allowance	1,683	8.21%
Regulatory profit/(loss) including financial incentives and wash-ups	5,501	26.82%
Total regulatory income	20,506	

1(v): Reliability

Interruption rate	4.56	*Interruptions per 100 circuit km*

pwc

Company Name	Electricity Invercargill Limited
For Year Ended	31 March 2019

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

2(i): Return on Investment

	CY-2	CY-1	Current Year CY
	31 Mar 17	31 Mar 18	31 Mar 19
ROI – comparable to a post tax WACC	%	%	%
Reflecting all revenue earned	6.76%	5.78%	6.29%
Excluding revenue earned from financial incentives	6.76%	5.81%	6.15%
Excluding revenue earned from financial incentives and wash-ups	6.69%	5.73%	6.08%
Mid-point estimate of post tax WACC	4.77%	5.04%	4.75%
25th percentile estimate	4.05%	4.36%	4.07%
75th percentile estimate	5.48%	5.72%	5.43%
ROI – comparable to a vanilla WACC			
Reflecting all revenue earned	7.31%	6.37%	6.80%
Excluding revenue earned from financial incentives	7.31%	6.40%	6.66%
Excluding revenue earned from financial incentives and wash-ups	7.23%	6.32%	6.58%
WACC rate used to set regulatory price path	7.19%	7.19%	7.19%
Mid-point estimate of vanilla WACC	5.31%	5.60%	5.26%
25th percentile estimate	4.59%	4.92%	4.58%
75th percentile estimate	6.03%	6.29%	5.94%

2(ii): Information Supporting the ROI

			($000)	
	Total opening RAB value	84,072		
plus	Opening deferred tax	(3,434)		
Opening RIV			80,638	
Line charge revenue			20,545	
	Expenses cash outflow	11,448		
add	Assets commissioned	4,533		
less	Asset disposals	126		
add	Tax payments	1,228		
less	Other regulated income	(38)		
Mid-year net cash outflows			17,122	
Term credit spread differential allowance			–	
	Total closing RAB value	86,605		
less	Adjustment resulting from asset allocation	0		
less	Lost and found assets adjustment	–		
plus	Closing deferred tax	(3,889)		
Closing RIV			82,716	
ROI – comparable to a vanilla WACC				6.80%
	Leverage (%)			42%
	Cost of debt assumption (%)			4.33%
	Corporate tax rate (%)			28%
ROI – comparable to a post tax WACC				6.29%

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	6.35%
Year-end ROI – comparable to a post tax WACC	5.84%

** 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	153	
Other financial incentives		
Financial incentives		153
Impact of financial incentives on ROI		0.14%
Input methodology claw-back		
CPP application recoverable costs		
Catastrophic event allowance		
Capex wash-up adjustment	86	
Transmission asset wash-up adjustment		
2013–15 NPV wash-up allowance		
Reconsideration event allowance		
Other wash-ups		
Wash-up costs		86
Impact of wash-up costs on ROI		0.08%

Company Name	Electricity Invercargill Limited
For Year Ended	31 March 2019

SCHEDULE 3: REPORT ON REGULATORY PROFIT

This schedule requires information on the calculation of regulatory profit for the EDB for the disclosure year. All EDBs must complete all sections and provide explanatory comment on their regulatory profit in Schedule 14 (Mandatory Explanatory Notes).

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

sch ref			($000)
7		**3(i): Regulatory Profit**	($000)
8		**Income**	
9		Line charge revenue	20,545
10	*plus*	Gains / (losses) on asset disposals	(101)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)	63
12			
13		**Total regulatory income**	20,506
14		**Expenses**	
15	*less*	Operational expenditure	4,938
16			
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups	6,510
18			
19		**Operating surplus / (deficit)**	9,058
20			
21	*less*	Total depreciation	3,120
22			
23	*plus*	Total revaluations	1,245
24			
25		**Regulatory profit / (loss) before tax**	7,183
26			
27	*less*	Term credit spread differential allowance	–
28			
29	*less*	Regulatory tax allowance	1,683
30			
31		**Regulatory profit/(loss) including financial incentives and wash-ups**	5,501
32			

sch ref			
33	**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	($000)	
34	**Pass through costs**		
35	Rates	123	
36	Commerce Act levies	34	
37	Industry levies	59	
38	CPP specified pass through costs	–	
39	**Recoverable costs excluding financial incentives and wash-ups**		
40	Electricity lines service charge payable to Transpower	5,900	
41	Transpower new investment contract charges	394	
42	System operator services	–	
43	Distributed generation allowance	–	
44	Extended reserves allowance	–	
45	Other recoverable costs excluding financial incentives and wash-ups	–	
46	**Pass-through and recoverable costs excluding financial incentives and wash-ups**		6,510
47			

sch ref				
48	**3(iii): Incremental Rolling Incentive Scheme**		($000)	
49			CY-1	CY
50			31 Mar 18	31 Mar 19
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 14	–	–
58	CY-4	31 Mar 15	–	–
59	CY-3	31 Mar 16	–	–
60	CY-2	31 Mar 17	–	–
61	CY-1	31 Mar 18	–	–
62	**Net incremental rolling incentive scheme**			–
63				
64	**Net recoverable costs allowed under incremental rolling incentive scheme**			–

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

Company Name	Electricity Invercargill Limited
For Year Ended	31 March 2019

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

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

sch ref

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

for year ended	RAB 31 Mar 15 ($000)	RAB 31 Mar 16 ($000)	RAB 31 Mar 17 ($000)	RAB 31 Mar 18 ($000)	RAB 31 Mar 19 ($000)
Total opening RAB value	64,392	74,188	77,667	80,292	84,072
less Total depreciation	2,539	2,789	2,885	2,925	3,120
plus Total revaluations	54	435	1,676	882	1,245
plus Assets commissioned	12,354	5,869	4,103	5,907	4,533
less Asset disposals	73	36	269	85	126
plus Lost and found assets adjustment					–
plus Adjustment resulting from asset allocation					0
Total closing RAB value	74,188	77,667	80,292	84,072	86,605

4(ii): Unallocated Regulatory Asset Base

	Unallocated RAB * ($000)	Unallocated RAB * ($000)	RAB ($000)	RAB ($000)
Total opening RAB value		84,072		84,072
less				
Total depreciation		3,120		3,120
plus				
Total revaluations		1,245		1,245
plus				
Assets commissioned (other than below)	–		–	
Assets acquired from a regulated supplier	–		–	
Assets acquired from a related party	4,533		4,533	
Assets commissioned		4,533		4,533
less				
Asset disposals (other than below)	126		126	
Asset disposals to a regulated supplier			–	
Asset disposals to a related party			–	
Asset disposals		126		126
plus Lost and found assets adjustment				
plus Adjustment resulting from asset allocation				0
Total closing RAB value		86,605		86,605

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

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

CPI_4	1,026
CPI_4^{-4}	1,011
Revaluation rate (%)	1.48%

	Unallocated RAB * ($000)	Unallocated RAB * ($000)	RAB ($000)	RAB ($000)
Total opening RAB value	84,072		84,072	
less Opening value of fully depreciated, disposed and lost assets	158		158	
Total opening RAB value subject to revaluation	83,914		83,914	
Total revaluations		1,245		1,245

4(iv): Roll Forward of Works Under Construction

	Unallocated works under construction	Unallocated works under construction	Allocated works under construction	Allocated works under construction
Works under construction—preceding disclosure year		883		883
plus Capital expenditure	4,653		4,653	
less Assets commissioned	4,533		4,533	
plus Adjustment resulting from asset allocation			–	
Works under construction - current disclosure year		1,003		1,003
Highest rate of capitalised finance applied				

4(v): Regulatory Depreciation

	Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
Depreciation - standard	3,120		3,120	
Depreciation - no standard life assets				
Depreciation - modified life assets				
Depreciation - alternative depreciation in accordance with CPP				
Total depreciation		3,120		3,120

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	56	7,020	16,329	2,068	40,961	9,776	4,606	3,255	–	84,072
less	Total depreciation	2	204	557	94	1,429	411	247	177		3,120
plus	Total revaluations	1	105	243	32	606	144	67	48		1,245
plus	Assets commissioned	–	–	600	75	2,335	534	847	143		4,533
less	Asset disposals	–	–	–	–	–	57	69	–		126
plus	Lost and found assets adjustment										–
plus	Adjustment resulting from asset allocation										–
plus	Asset category transfers										–
	Total closing RAB value	54	6,921	16,615	2,081	42,473	9,986	5,205	3,269	–	86,605

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	27.3	39.4	35.0	29.5	35.4	26.1	20.0	19.6		(years)
Weighted average expected total asset life	47.2	57.4	52.8	59.4	58.6	45.0	39.3	38.7		(years)

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2019**

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**		7,183	
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	1,268		
13		Amortisation of revaluations	275		
14				1,543	
15					
16	*less*	Total revaluations	1,245		
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	36		*
20		Notional deductible interest	1,436		
21				2,716	
22					
23		**Regulatory taxable income**		6,010	
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income		6,010	
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**		1,683	
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	24,099		
37	*less*	Amortisation of initial differences in asset values	1,268		
38	*plus*	Adjustment for unamortised initial differences in assets acquired	–		
39	*less*	Adjustment for unamortised initial differences in assets disposed	88		
40		Closing unamortised initial differences in asset values		22,743	
41					
42		Opening weighted average remaining useful life of relevant assets (years)		19	
43					

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5a(iv): Amortisation of Revaluations

		($000)
Opening sum of RAB values without revaluations	77,250	
Adjusted depreciation	2,845	
Total depreciation	3,120	
Amortisation of revaluations		275

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	(3,434)	
plus	Tax effect of adjusted depreciation	797	
less	Tax effect of tax depreciation	928	
plus	Tax effect of other temporary differences*	20	
less	Tax effect of amortisation of initial differences in asset values	355	
plus	Deferred tax balance relating to assets acquired in the disclosure year	–	
less	Deferred tax balance relating to assets disposed in the disclosure year	(11)	
plus	Deferred tax cost allocation adjustment	(0)	
	Closing deferred tax		(3,889)

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	41,317	
less	Tax depreciation	3,314	
plus	Regulatory tax asset value of assets commissioned	4,697	
less	Regulatory tax asset value of asset disposals	55	
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		42,645

Company Name	Electricity Invercargill Limited
For Year Ended	31 March 2019

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	449	
13	Vegetation management	1	
14	Routine and corrective maintenance and inspection	1,033	
15	Asset replacement and renewal (opex)	124	
16	**Network opex**		1,608
17	Business support	1,689	
18	System operations and network support	401	
19	**Operational expenditure**		3,698
20	Consumer connection	296	
21	System growth	–	
22	Asset replacement and renewal (capex)	4,329	
23	Asset relocations	90	
24	Quality of supply	2	
25	Legislative and regulatory	–	
26	Other reliability, safety and environment	107	
27	**Expenditure on non-network assets**		–
28	**Expenditure on assets**		4,824
29	Cost of financing		
30	Value of capital contributions		
31	Value of vested assets		
32	**Capital Expenditure**		4,824
33	**Total expenditure**		8,521
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	Routine and corrective maintenance and inspection	1,033
39	PowerNet Limited	Asset replacement and renewal (opex)	124
40	PowerNet Limited	Service interruptions and emergencies	449
41	PowerNet Limited	Vegetation management	1
42	PowerNet Limited	System operations and network support	401
43	PowerNet Limited	Business Support	1,533
44	Invercargill City Holdings	Business Support	155
45	PowerNet Limited	Consumer connection	296
46	PowerNet Limited	Asset replacement and renewal (capex)	4,329
47	PowerNet Limited	Asset relocations	90
48	PowerNet Limited	Other reliability, safety and environment	107
49	PowerNet Limited	Quality of supply	2
50			
51			
52			
53			
55	**Total value of related party transactions**		8,521

56 ** include additional rows if needed*
57

Company Name: Electricity Invercargill Limited
For Year Ended: 31 March 2019

SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

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

sch ref

7

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

9

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

17

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

sch ref			
19			
20	**Gross term credit spread differential**		–
21			
22	Total book value of interest bearing debt		
23	Leverage	42%	
24	Average opening and closing RAB values		
25	**Attribution Rate (%)**		–
26			
27	**Term credit spread differential allowance**		–

Company Name	Electricity Invercargill Limited
For Year Ended	31 March 2019

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		449			
Not directly attributable	–	–	–	–	–
Total attributable to regulated service		449			
Vegetation management					
Directly attributable		1			
Not directly attributable	–	–	–	–	–
Total attributable to regulated service		1			
Routine and corrective maintenance and inspection					
Directly attributable		1,033			
Not directly attributable	–	–	–	–	–
Total attributable to regulated service		1,033			
Asset replacement and renewal					
Directly attributable		124			
Not directly attributable	–	–	–	–	–
Total attributable to regulated service		124			
System operations and network support					
Directly attributable		1,084			
Not directly attributable	–	–	–	–	–
Total attributable to regulated service		1,084			
Business support					
Directly attributable		1,836			
Not directly attributable	–	410	28	438	–
Total attributable to regulated service		2,246			
Operating costs directly attributable		4,528			
Operating costs not directly attributable	–	410	28	438	–
Operational expenditure		4,938			

5d(ii): Other Cost Allocations

	($000)
Pass through and recoverable costs	
Pass through costs	
Directly attributable	216
Not directly attributable	–
Total attributable to regulated service	216
Recoverable costs	
Directly attributable	6,294
Not directly attributable	–
Total attributable to regulated service	6,294

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

Change in cost allocation 1

			($000) CY-1	Current Year (CY)
Cost category		Original allocation	–	–
Original allocator or line items		New allocation	–	–
New allocator or line items		Difference	–	–

Rationale for change

Change in cost allocation 2

			($000) CY-1	Current Year (CY)
Cost category		Original allocation	–	–
Original allocator or line items		New allocation	–	–
New allocator or line items		Difference	–	–

Rationale for change

Change in cost allocation 3

			($000) CY-1	Current Year (CY)
Cost category		Original allocation	–	–
Original allocator or line items		New allocation	–	–
New allocator or line items		Difference	–	–

Rationale for change

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

Company Name	Electricity Invercargill Limited
For Year Ended	31 March 2019

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

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

sch ref

5e(i): Regulated Service Asset Values

	Value allocated ($000s) Electricity distribution services
Subtransmission lines	
Directly attributable	54
Not directly attributable	
Total attributable to regulated service	54
Subtransmission cables	
Directly attributable	6,921
Not directly attributable	
Total attributable to regulated service	6,921
Zone substations	
Directly attributable	16,615
Not directly attributable	
Total attributable to regulated service	16,615
Distribution and LV lines	
Directly attributable	2,081
Not directly attributable	
Total attributable to regulated service	2,081
Distribution and LV cables	
Directly attributable	42,473
Not directly attributable	
Total attributable to regulated service	42,473
Distribution substations and transformers	
Directly attributable	9,986
Not directly attributable	
Total attributable to regulated service	9,986
Distribution switchgear	
Directly attributable	5,205
Not directly attributable	
Total attributable to regulated service	5,205
Other network assets	
Directly attributable	3,269
Not directly attributable	
Total attributable to regulated service	3,269
Non-network assets	
Directly attributable	
Not directly attributable	
Total attributable to regulated service	–
Regulated service asset value directly attributable	86,605
Regulated service asset value not directly attributable	–
Total closing RAB value	86,605

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

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

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

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

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

Company Name: Electricity Invercargill Limited
For Year Ended: 31 March 2019

SCHEDULE 5f: REPORT SUPPORTING COST ALLOCATIONS

This schedule requires additional detail on the asset allocation methodology applied in allocating asset values that are not directly attributable, to support the information provided in Schedule 5d (Cost allocations). This schedule is not required to be publicly disclosed, but must be disclosed to the Commission.
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

Line Item*	Allocation methodology type	Cost allocator	Allocator type	Allocator Metric (%) Electricity distribution services	Allocator Metric (%) Non-electricity distribution services	Value allocated ($000) Arm's length deduction	Value allocated ($000) Electricity distribution services	Value allocated ($000) Non-electricity distribution services	Value allocated ($000) Total	OVABAA allocation increase ($000)
Service interruptions and emergencies										
									-	
									-	
									-	
									-	
Not directly attributable						-	-	-	-	-
Vegetation management										
									-	
									-	
									-	
									-	
Not directly attributable						-	-	-	-	-
Routine and corrective maintenance and inspection										
									-	
									-	
									-	
									-	
Not directly attributable						-	-	-	-	-
Asset replacement and renewal										
									-	
									-	
									-	
									-	
Not directly attributable						-	-	-	-	-
System operations and network support										
									-	
									-	
									-	
									-	
Not directly attributable						-	-	-	-	-
Business support										
Administration Expenses	ABAA	Revenue	Proxy	93.67%	6.33%		410	28	438	
									-	
									-	
									-	
Not directly attributable						-	410	28	438	-
Operating costs not directly attributable						-	410	28	438	-
Pass through and recoverable costs										
Pass through costs										
									-	
									-	
									-	
									-	
Not directly attributable						-	-	-	-	-
Recoverable costs										
									-	
									-	
									-	
									-	
Not directly attributable						-	-	-	-	-

** include additional rows if needed*

SCHEDULE 5g: REPORT SUPPORTING ASSET ALLOCATIONS

This schedule requires additional detail on the asset allocation methodology applied in allocating asset values that are not directly attributable, to support the information provided in Schedule 5e (Report on Asset Allocations). This schedule is not required to be publicly disclosed, but must be disclosed to the Commission.

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

sch ref	Line Item*	Allocation methodology type	Allocator	Allocator type	Allocator Metric (%) Electricity distribution services	Allocator Metric (%) Non-electricity distribution services	Value allocated ($000) Arm's length deduction	Value allocated ($000) Electricity distribution services	Value allocated ($000) Non-electricity distribution services	Value allocated ($000) Total	OVABAA allocation increase ($000)
11	**Subtransmission lines**										
12										-	
13										-	
14										-	
15										-	
16	Not directly attributable						-	-	-	-	-
17	**Subtransmission cables**										
18										-	
19										-	
20										-	
21										-	
22	Not directly attributable						-	-	-	-	-
23	**Zone substations**										
24										-	
25										-	
26										-	
27										-	
28	Not directly attributable						-	-	-	-	-
29	**Distribution and LV lines**										
30										-	
31										-	
32										-	
33										-	
34	Not directly attributable						-	-	-	-	-
35	**Distribution and LV cables**										
36										-	
37										-	
38										-	
39										-	
40	Not directly attributable						-	-	-	-	-
41											
42	**Distribution substations and transformers**										
43										-	
44										-	
45										-	
46										-	
47	Not directly attributable						-	-	-	-	-
48											
49	**Distribution switchgear**										
50										-	
51										-	
52										-	
53										-	
54	Not directly attributable						-	-	-	-	-
55	**Other network assets**										
56										-	
57										-	
58										-	
59										-	
60	Not directly attributable						-	-	-	-	-
61	**Non-network assets**										
62										-	
63										-	
64										-	
65										-	
66	Not directly attributable						-	-	-	-	-
67											
68	Regulated service asset value not directly attributable						-	-	-	-	-

69 ** include additional rows if needed*

Company Name	Electricity Invercargill Limited
For Year Ended	31 March 2019

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		296
9		System growth		–
10		Asset replacement and renewal		4,329
11		Asset relocations		90
12		Reliability, safety and environment:		
13		Quality of supply	2	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	107	
16		**Total reliability, safety and environment**		109
17		**Expenditure on network assets**		4,824
18		Expenditure on non-network assets		–
19				
20		**Expenditure on assets**		4,824
21	*plus*	Cost of financing		–
22	*less*	Value of capital contributions		170
23	*plus*	Value of vested assets		–
24				
25		**Capital expenditure**		4,653
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		20403 - Customer Connections < 20 kVA	53	
33		20404 - Customer Connections 21 - 99 kVA	70	
34		20405 - Customer Connections > 100 kVA	165	
35		20402 - New Subdivisions	8	
36				
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		296
39				
40	*less*	Capital contributions funding consumer connection expenditure	103	
41		**Consumer connection less capital contributions**		194
42		**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset Replacement**
43			**System Growth**	**and Renewal**
44			**($000)**	**($000)**
45		Subtransmission	–	–
46		Zone substations	–	330
47		Distribution and LV lines	–	81
48		Distribution and LV cables	–	–
49		Distribution substations and transformers	–	3,119
50		Distribution switchgear	–	–
51		Other network assets	–	799
52		**System growth and asset replacement and renewal expenditure**	–	4,329
53	*less*	Capital contributions funding system growth and asset replacement and renewal	–	21
54		**System growth and asset replacement and renewal less capital contributions**	–	4,308
55				
56		**6a(v): Asset Relocations**		
57		*Project or programme**	**($000)**	**($000)**
58		20478 - Asset Relocation Projects - Distribution	90	
59				
60				
61				
62				
63		** include additional rows if needed*		
64		All other projects or programmes - asset relocations	–	
65		**Asset relocations expenditure**		90
66	*less*	Capital contributions funding asset relocations	47	
67		**Asset relocations less capital contributions**		43

6a(vi): Quality of Supply

	Project or programme*	($000)	($000)
	20350 - Network Automation Projects	2	
	** include additional rows if needed*		
	All other projects programmes - quality of supply	–	
	Quality of supply expenditure		2
less	Capital contributions funding quality of supply	–	
	Quality of supply less capital contributions		2

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)
	20458 - Pillar Box Lid Upgrade	63	
	20459 - Neutral Earth Resistor Protection Upgrade	44	
	** include additional rows if needed*		
	All other projects or programmes - other reliability, safety and environment	–	
	Other reliability, safety and environment expenditure		107
less	Capital contributions funding other reliability, safety and environment	–	
	Other reliability, safety and environment less capital contributions		107

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)
** include additional rows if needed*		
All other projects or programmes - atypical expenditure	–	
Atypical expenditure		–
Expenditure on non-network assets		–

Company Name: Electricity Invercargill Limited
For Year Ended: 31 March 2019

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		($000)	($000)
7	**6b(i): Operational Expenditure**		
8	Service interruptions and emergencies	449	
9	Vegetation management	1	
10	Routine and corrective maintenance and inspection	1,033	
11	Asset replacement and renewal	124	
12	**Network opex**		1,608
13	System operations and network support	1,084	
14	Business support	2,246	
15	**Non-network opex**		3,330
16			
17	**Operational expenditure**		4,938
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	Energy efficiency and demand side management, reduction of energy losses		125
20	Direct billing*		–
21	Research and development		–
22	Insurance		127
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2019**

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	20,559	20,545	(0%)
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	526	296	(44%)
11	System growth	–	–	–
12	Asset replacement and renewal	4,447	4,329	(3%)
13	Asset relocations	26	90	246%
14	Reliability, safety and environment:			
15	Quality of supply	68	2	(98%)
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	103	107	4%
18	**Total reliability, safety and environment**	171	109	(37%)
19	**Expenditure on network assets**	5,170	4,824	(7%)
20	Expenditure on non-network assets	–	–	–
21	Expenditure on assets	5,170	4,824	(7%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	492	449	(9%)
24	Vegetation management	2	1	(47%)
25	Routine and corrective maintenance and inspection	1,051	1,033	(2%)
26	Asset replacement and renewal	211	124	(41%)
27	**Network opex**	1,756	1,608	(8%)
28	System operations and network support	1,244	1,084	(13%)
29	Business support	2,278	2,246	(1%)
30	**Non-network opex**	3,522	3,330	(5%)
31	**Operational expenditure**	5,278	4,938	(6%)
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	20	–	(100%)
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	125	125	–
39	Direct billing	–	–	–
40	Research and development	–	–	–
41	Insurance	109	127	17%
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	Electricity Invercargill Limited
For Year Ended	31 March 2019
Network / Sub-Network Name	

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

8(i): Billed Quantities 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)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)
Low user	Residential	Standard	5,871	36,758
Domestic	Residential	Standard	9,413	91,856
Non-Domestic	Commerical	Standard	1,958	52,041
Individual non half hour	Commerical	Standard	51	7,690
Individual half hour	Commerical	Standard	127	65,935

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

Standard consumer totals	17,420	254,280
Non-standard consumer totals	–	–
Total for all consumers	17,420	254,280

Billed quantities by price component

Price component	Variable day energy sales	Variable day energy purchases				
Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kWh	Kwh				
Low user		28,920,179				
Domestic		73,384,888				
Non-Domestic		41,545,895				
Individual non half hour		6,137,341				
Individual half hour	47,669,286					
Standard consumer totals	47,669,286	149,988,303	–	–	–	–
Non-standard consumer totals	–	–	–	–	–	–
Total for all consumers	47,669,286	149,988,303	–	–	–	–

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

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

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)	Line charge revenues ($000) by price component					
						Price component	Fixed	Variable				
						Rate (eg, $ per day, $ per kWh, etc.)	$/Day	$/kwh				
Low user	Residential	Standard	$3,533		$2,546	$987	$228.3	$3,305				
Domestic	Residential	Standard	$8,592		$6,192	$2,400	$3,159	$5,433				
Non Domestic	Commerical	Standard	$5,017		$3,615	$1,401	$1,941	$3,076				
Individual non half hour	Commerical	Standard	$513		$327	$186	$59	$454				
Individual half hour	Commerical	Standard	$2,890		$1,570	$1,320	$1,465	$1,426				
			–									
			–									
			–									
			–									
			–									
		Standard consumer totals	$20,545	–	$14,251	$6,294	$6,852	$13,693	–	–	–	–
		Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–
		Total for all consumers	$20,545	–	$14,251	$6,294	$6,852	$13,693	–	–	–	–

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	Electricity Invercargill Limited
For Year Ended	31 March 2019
Network / Sub-network Name	

SCHEDULE 9a: ASSET REGISTER

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

sch ref

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.	666	721	55	3
10	All	Overhead Line	Wood poles	No.	278	225	(53)	3
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	1	1	–	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	15	15	(0)	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	12	12	0	4
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.	5	5	–	4
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.	2	2	–	4
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	16	16	–	4
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	4
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	5	5	–	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	2	2	–	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	30	50	20	4
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.	6	6	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	23	23	0	3
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	55	54	(0)	3
39	HV	Distribution Cable	Distribution UG PILC	km	99	99	(0)	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.	2	2	–	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	47	61	14	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	61	50	(11)	3
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	N/A
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	457	456	(1)	4
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	11	10	(1)	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	431	429	(2)	4
48	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	N/A
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	43	43	N/A
50	LV	LV Line	LV OH Conductor	km	30	30	(0)	3
51	LV	LV Cable	LV UG Cable	km	422	423	1	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	167	167	(0)	3
53	LV	Connections	OH/UG consumer service connections	No.	17,805	17,840	35	3
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	155	167	12	4
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	1	1	–	4
56	All	Capacitor Banks	Capacitors including controls	No	–	–	–	N/A
57	All	Load Control	Centralised plant	Lot	1	1	–	4
58	All	Load Control	Relays	No	–	–	–	N/A
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name	Electricity Invercargill Limited
For Year Ended	31 March 2019
Network / Sub-network Name	

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

8 Disclosure Year (year ended): 31 March 2019

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.	–	–	–	357	6	–	2	2	13	7	–	6	3	3	1	9	3	17	92	31	69	15	21	31	28	6	–	–	–	–	–	–	–	2	721	–	3
11	All	Overhead Line	Wood poles	No.	–	–	–	174	1	–	3	11	12	5	7	6	4	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	225	–	3
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	–	–	0	–	–	1	0	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0	1	–	3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	–	4	2	5	–	–	–	–	–	–	–	0	–	–	–	–	–	–	4	–	–	–	–	–	–	–	–	–	–	–	15	–	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	5	7	–	0	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	12	–	3
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	1	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	5	–	4
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	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.	–	–	–	–	–	–	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	4
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	–	10	1	–	1	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	3	–	–	–	–	–	–	–	–	–	–	–	16	–	4
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	5	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	5	–	4
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	1	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	5	11	11	1	1	–	–	1	–	–	–	–	–	1	–	–	–	1	1	17	–	–	–	–	–	–	–	–	–	–	–	50	–	4
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.	–	–	–	1	1	1	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	1	1	–	–	–	–	–	–	–	–	–	–	6	–	4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0	–	0	11	5	2	3	0	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	0	–	–	–	–	–	–	–	–	0	23	–	3
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	–	–	–	0	1	1	2	5	8	6	1	2	2	1	2	2	5	2	2	1	2	0	4	3	1	0	0	–	–	–	–	–	–	–	54	–	3
40	HV	Distribution Cable	Distribution UG PILC	km	2	–	1	14	24	23	19	2	2	–	0	–	–	–	0	2	–	–	–	–	–	–	0	–	–	–	–	–	–	–	–	–	–	0	99	–	3
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	–	–	–	–	–	–	–	2	–	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	7	3	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4	10	17	8	10	–	–	–	–	–	–	–	61	–	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	–	–	2	8	2	3	–	–	1	1	1	–	–	1	–	1	1	1	3	–	2	–	5	2	3	6	1	–	–	–	–	–	–	6	50	–	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	15	42	126	57	13	19	17	5	6	15	7	15	26	17	19	13	6	5	4	19	10	11	7	–	–	–	–	–	–	–	–	456	–	3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	–	1	2	1	–	–	–	1	1	–	–	–	1	–	1	1	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	10	–	3
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	7	30	31	64	70	7	12	15	10	8	16	11	9	10	13	15	20	19	10	15	13	6	10	4	4	–	–	–	–	–	–	–	429	–	3
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	3	9	3	18	5	1	2	1	–	1	1	1	–	–	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	43	–	N/A
51	LV	LV Line	LV OH Conductor	km	–	–	0	4	0	2	1	16	–	1	1	0	0	0	–	0	0	–	0	0	0	0	0	0	0	0	–	–	–	–	–	–	–	0	30	–	3
52	LV	LV Cable	LV UG Cable	km	1	–	9	48	74	111	65	12	16	21	8	10	6	7	5	7	6	3	5	2	1	1	7	3	4	2	1	–	–	–	–	–	–	1	423	–	3
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	2	0	1	15	4	23	88	19	2	1	0	0	1	0	1	2	1	1	1	0	2	1	0	1	0	0	0	–	–	–	–	–	–	1	167	–	3
54	LV	Connections	OH/UG consumer service connections	No.	–	3	114	2,249	4,007	3,654	5,528	41	55	62	203	263	280	201	211	132	100	105	98	85	60	63	77	86	62	55	18	–	–	–	–	–	–	28	17,840	–	2
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	34	31	29	1	4	–	–	1	–	–	–	–	–	–	–	–	1	–	1	27	10	4	5	7	–	–	–	–	–	–	2	167	–	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	–	4
59	All	Load Control	Relays	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A

Company Name	Electricity Invercargill Limited
For Year Ended	31 March 2019
Network / Sub-network Name	

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref		Overhead (km)	Underground (km)	Total circuit length (km)
9				
10	**Circuit length by operating voltage (at year end)**			
11	> 66kV	–	–	–
12	50kV & 66kV	–	–	–
13	33kV	1	26	28
14	SWER (all SWER voltages)	–	–	–
15	22kV (other than SWER)	–	–	–
16	6.6kV to 11kV (inclusive—other than SWER)	23	155	177
17	Low voltage (< 1kV)	30	423	453
18	**Total circuit length (for supply)**	54	604	658
19				
20	Dedicated street lighting circuit length (km)	25	142	167
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			–
22				

sch ref		Circuit length (km)	(% of total overhead length)
23	**Overhead circuit length by terrain (at year end)**		
24	Urban	50	94%
25	Rural	2	3%
26	Remote only	–	–
27	Rugged only	2	3%
28	Remote and rugged	–	–
29	Unallocated overhead lines	–	–
30	**Total overhead length**	54	100%
31			

sch ref		Circuit length (km)	(% of total circuit length)
32			
33	Length of circuit within 10km of coastline or geothermal areas (where known)	658	100%

sch ref		Circuit length (km)	(% of total overhead length)
34			
35	Overhead circuit requiring vegetation management	4	7%

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2019**

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			
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	Electricity Invercargill Limited
For Year Ended	31 March 2019
Network / Sub-network Name	

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref				
8	**9e(i): Consumer Connections**			
9	*Number of ICPs connected in year by consumer type*			
10	*Consumer types defined by EDB**		**Number of connections (ICPs)**	
11	Domestic		46	
12	Low User		4	
13	Non Domestic		12	
14	Individual half hour		–	
15				
16	** include additional rows if needed*			
17	**Connections total**		62	
18				
19	**Distributed generation**			
20	Number of connections made in year		12	connections
21	Capacity of distributed generation installed in year		0.05	MVA
22	**9e(ii): System Demand**			
23				
24			**Demand at time of maximum coincident demand (MW)**	
25	**Maximum coincident system demand**			
26	GXP demand		61	
27	Distributed generation output at HV and above	*plus*	–	
28	**Maximum coincident system demand**		61	
29	Net transfers to (from) other EDBs at HV and above	*less*	(2)	
30	**Demand on system for supply to consumers' connection points**		63	
31	**Electricity volumes carried**		**Energy (GWh)**	
32	Electricity supplied from GXPs		253	
33	Electricity exports to GXPs	*less*	–	
34	Electricity supplied from distributed generation	*plus*	0.2	
35	Net electricity supplied to (from) other EDBs	*less*	(14)	
36	**Electricity entering system for supply to consumers' connection points**		267	
37	Total energy delivered to ICPs	*less*	254	
38	**Electricity losses (loss ratio)**		13	4.9%
39				
40	**Load factor**		0.48	
41	**9e(iii): Transformer Capacity**			
42			**(MVA)**	
43	Distribution transformer capacity (EDB owned)		149	
44	Distribution transformer capacity (Non-EDB owned, estimated)		2	
45	**Total distribution transformer capacity**		150	
46				
47	**Zone substation transformer capacity**		82	

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2019**
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref			
8	**10(i): Interruptions**		
9	**Interruptions by class**	**Number of interruptions**	
10	Class A (planned interruptions by Transpower)	–	
11	Class B (planned interruptions on the network)	8	
12	Class C (unplanned interruptions on the network)	19	
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)	3	
17	Class H (planned interruptions caused by another disclosing entity)	–	
18	Class I (interruptions caused by parties not included above)	–	
19	**Total**	30	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	15	4
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.02	3.4
27	Class C (unplanned interruptions on the network)	0.31	18.2
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)	0.37	20.8
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	–	–
34	**Total**	0.70	42.4
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	0.33	21.6
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	0.07	4.4
47	Wildlife	–	–
48	Human error	0.02	0.5
49	Defective equipment	0.23	13.3
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)	0.02	2.7
69	Distribution cables (excluding LV)	0.00	0.1
60	Distribution other (excluding LV)	0.00	0.6
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)	0.02	2.6
68	Distribution cables (excluding LV)	0.21	10.3
69	Distribution other (excluding LV)	0.08	5.3

sch ref				
70	**10(v): Fault Rate**			
71	**Main equipment involved**	**Number of Faults**	**Circuit length (km)**	**Fault rate (faults per 100km)**
72	Subtransmission lines	–	1	–
73	Subtransmission cables	–	26	–
74	Subtransmission other	–		
75	Distribution lines (excluding LV)	8	23	35.23
76	Distribution cables (excluding LV)	6	155	3.88
77	Distribution other (excluding LV)	5		
78	**Total**	19		

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
Electricity Invercargill Limited achieved a post-tax WACC of 6.29% which is above the 75th percentile estimate of post-tax WACC of 5.43% and a 6.8% vanilla WACC which is above with the 75th percentile estimate of vanilla WACC of 5.94%. 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 $62k for line charges to another lines company. 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 2018 closing figure of $84,072k as a starting point with inflationary indexing over the year to 31 March 2019 plus additions less disposals. This resulted in a closing RAB balance of $86,605k.

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 $36k cost of easements which is a tax deductible expense.

Income included in regulatory profit / (loss) before tax but not taxable is the $1,245k revaluations for the year

There are no other permanent differences.

- *Regulatory tax allowance: disclosure of temporary differences (5a(vi) of Schedule 5a)*

9. In the box below, provide descriptions and workings of material items recorded in the asterisked category 'Tax effect of other temporary differences' in 5a(vi) of Schedule 5a.

Box 6: Tax effect of other temporary differences (current disclosure year)

Box 6: Temporary differences / Tax effect of other temporary differences (current disclosure year)

Temporary differences are the tax effect of the difference between the tax and disclosure treatment of capital contribution income.

Taxable Capital Contributions:	$	71
	$	71
Tax Rate:		28%
Temporary Differences	$	20

- *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

With the exception of some Business support costs (which have been apportioned using the ABAA method), all other costs are directly attributable as they were either passed through by PowerNet as agent or were invoiced to Electricity Invercargill Limited

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 operational 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 Electricity Invercargill Limited's transformers and cables and this is 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 13 and 14 above.

The actual expenditure on network assets was 7% below budget.

Consumer connection:

- Net 44% variance was lower than forecast due to customer delays impacting construction start. This timing difference was reforecast as part of the 2019/20 AMP, and will show in the 2019/20 spend.

System Growth:

- No spend in this category for FY18/19

Asset replacement and renewal:

- Net 3% underspend due to due to field staff vacancies

Asset Relocations:

- 246% overspend due to: budget line error showing net of customer contributions; significant costs due to archeological finds during excavations

Quality of Supply:

- 98% underspend due to less customer initiated investigations within the year.

Reliability, Safety and Environment:

- 4% overspend due to neutral earth resistor protection communications costs over budget, offset by lower pillar box lid upgrades

Operational Expenditure:

Network opex was 8% below budget.

Service interruptions and emergencies:

- 9% underspend due to less number of faults than long term average.

Vegetation management:

- Small reactive budget, went largely unspent.

Routine and corrective maintenance and inspection:

- 2% underspend due to less corrective maintenance.

Asset replacement and renewal:

- 41% underspend due to field staff vacancies.

System Operations and Network Support:

- 13% underspend due to the Insurance Captive which was budgeted to be operational during the year but not yet operational.

Business Support:

Within 1% of budget

- *Information relating to revenues 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

Year ended 31 March 2019:

- Target revenue for the 2018-19 year was $20,559k. The total billed revenue for the 2018-19 year was $20,545k, which is $14k below.
- Fixed charge revenue was down due to a migration of residential customers to the low fixed charge option. A warm end to winter impacted on energy consumption resulting in variable charges being below budget for the year

- *Network Reliability for the Disclosure Year (Schedule 10)*

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

Box 13: Commentary on network reliability for the disclosure year

The SAIDI assessed value for 2018/19 at 17.98, was below the applicable Commerce Commission Limit of 31.13, and below the Commerce Commission target level of 24.08.

The SAIFI assessed value for 2018/19 at 0.31 was well below the applicable Commerce Commission Limit of 0.77, and below the Commerce Commission target level of 0.59.

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

EIL has disclosed a normalised SAIDI at 21.6 and normalised SAIFI at 0.33 for 2018/19.

2018/19 SAIDI and SAIFI were on par with the expected long term averages. Outages for 2018/19 were characterised by:

- high customer numbers impacted for third-party caused incidents
- high customer numbers impacted for cable failure events

The information has been prepared on a basis consistent with the previous year's disclosure and has not recorded successive interruptions.

Due to the small footprint and underground nature of the network. The probability of an interruption is relatively low. However, in the event of an interruption, the number of customers affected tends to be high as a percentage of the total customer base. This inherent variance makes SAIDI & SAIFI difficult to predict for any given year.

Network reliability is compliant with quality requirements under the default price-quality path, however there are inherent limitations in the ability of Electricity Invercargill Limited 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

Electricity Invercargill Limited insures its substations, network equipment and buildings.

- Substations and network equipment are insured for $27.1 million.

Lines and cables are not insured. Electricity Invercargill Limited 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
Disclosure of amendment to previously disclosed information No amendments were disclosed.

Schedule 14a Mandatory Explanatory Notes on Forecast Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 3 April 2018.)

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

20. 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)

21. 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)

22. 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 Budget Economic and Fiscal Update report released in December 2016:

	2019	2020	2021	2022	2023
Inflator (CAPEX & OPEX)	1.9%	2.1%	2.2%	2.2%	2.0%

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

Schedule 15 Voluntary Explanatory Notes

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 3 April 2018.)

1. This schedule enables 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 10 - The information has been prepared on a basis consistent with the previous year's disclosure and has not recorded successive interruptions. Schedule 10 will be reviewed to be in line with the determination in future years.

The SAIDI assessed value for 2018/19 at 17.98, was below the applicable Commerce Commission Limit of 31.13, and below the Commerce Commission target level of 24.08.

The SAIFI assessed value for 2018/19 at 0.31 was well below the applicable Commerce Commission Limit of 0.77, and below the Commerce Commission target level of 0.59.

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

EIL has disclosed a normalised SAIDI at 21.6 and normalised SAIFI at 0.33 for 2018/19.

2018/19 SAIDI and SAIFI were on par with the expected long term averages. Outages for 2018/19 were characterised by:

- high customer numbers impacted for third-party caused incidents
- high customer numbers impacted for cable failure events

Due to the small footprint and underground nature of the network. The probability of an interruption is relatively low However, in the event of an interruption, the number of customers affected tends to be high as a percentage of the total customer base. This inherent variance makes SAIDI & SAIFI difficult to predict for any given year.

Network reliability is compliant with quality requirements under the default price-quality path, however there are inherent limitations in the ability of Electricity Invercargill Limited 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.

4. APPENDIX - Related Party Transaction: Additional Information Disclosure

4.1 INTRODUCTION

For the purpose of meeting the 2019 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 reference to and support of:

- **Electricity Invercargill Limited's 2019 Information Disclosure**, for the year ended 31 March 2019 - Schedule 5(b) Related party Transactions

4.2 INFORMATION DISCLOSURE REQUIREMENTS

The Related Party Transaction information disclosed on the following pages has been prepared in accordance with **Limited Disclosure** requirements, due to the level of expenditure by a related party on the Electricity Invercargill Limited's (EIL) network assets being less than $20 million, for the year ending 31 March 2019.

Limited Disclosure requires additional information be provided associated with related party transactions, limited to details of related party relationships and nature of work undertaken.

This information is also subject to the Information Disclosure assurance opinion and Director Certification.

4.3 RELATED PARTY RELATIONSHIPS

Electricity Invercargill Limited (EIL) has an interest in PowerNet Limited, the OtagoNet Joint Venture, Electricity Southland Limited, and the Southern Generation Limited Partnership through their wholly owned subsidiary company Pylon Limited. PowerNet Limited has an interest in PowerNet Central Limited.

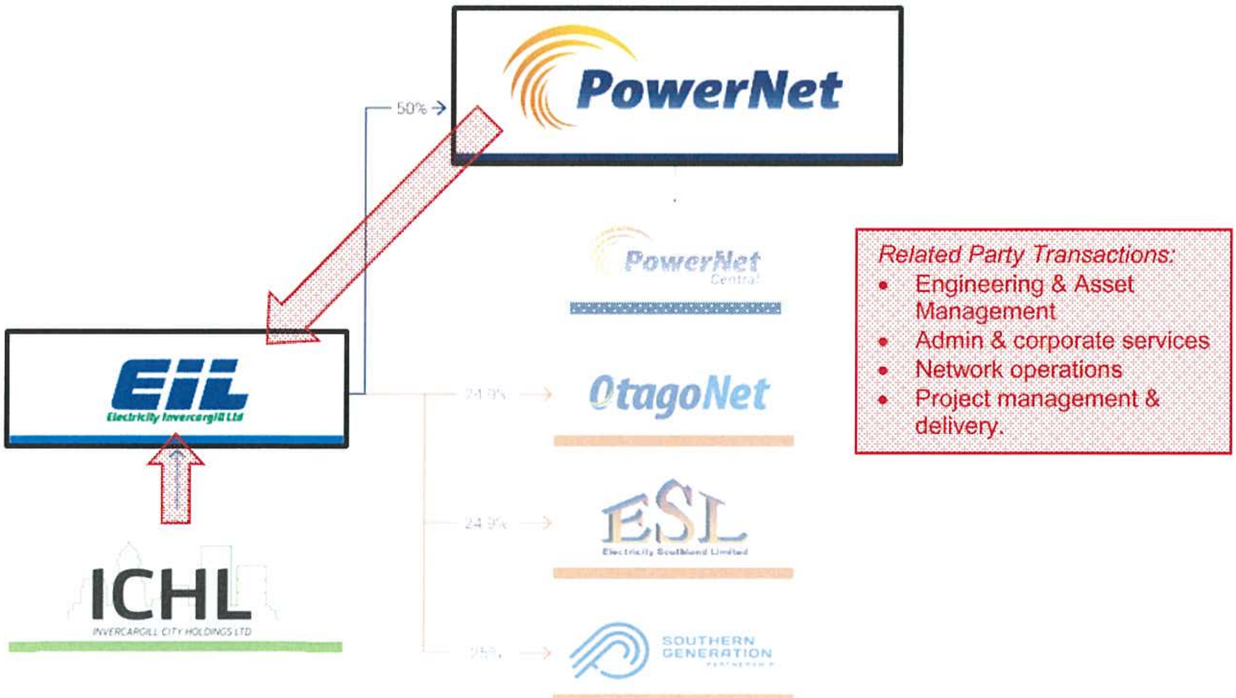
During the year ending 31 March 2019, EIL had related party transactions with the following entities:

- Goods and services provided by – PowerNet Limited; Invercargill City Holdings Limited
- Goods and services provided to – PowerNet Limited,

The transactions between EIL and PowerNet are subject to Related Party reporting.

Company Structure

Electricity Invercargill Limited (EIL) is wholly-owned by Invercargill City Holdings Limited. The following diagram illustrates EIL's ownership interests in PowerNet and other related entities in the EIL Group, and the nature of related party transaction work undertaken.



a. **PowerNet Limited**

EIL holds a 50% shareholding in electricity network management company PowerNet Limited. PowerNet provides a range of field contracting, asset management, system control and finance and commercial services to EIL. The value of the related party transactions for the year ended 31 March 2019 is categorised as follows:

		($'000)
Operating Expenditure:		
i.	Service interruptions and emergencies	449
ii.	Vegetation management	1
iii.	Routine and corrective maintenance and inspection	1,033
iv.	Asset replacement and renewal (opex)	124
v.	System operations and network support	401
vi.	Business support	1,533
Capital Expenditure:		
vii.	Consumer connection	297
viii.	System growth	-
ix.	Asset replacement and renewal (capex)	4,329
x.	Asset relocations	90
xi.	Quality of supply	2
xii.	Other reliability, safety and environment	107
	Total Related Party expenditure from PowerNet	**8,366**

In the year to 31 March 2019, PowerNet provided 100% of the EIL Lines Business Capital Expenditure, and 72% 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 EIL, in the form of an "agency agreement".

Services provided under the agreement include:

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

PowerNet holds an ownership interest of approximately 90% in PowerNet Central Ltd (formerly Peak Power Services Ltd), a Central Otago based electricity distribution maintenance contracting business, servicing the Electricity Southland Ltd network assets.

b. Invercargill City Holdings Limited

EIL is owned 100% by Invercargill City Holdings Limited (ICHL). The role of ICHL is to provide governance, funding and treasury support to the subsidiary companies they own.
The value of the related party transactions between ICHL and EIL for the year ended 31 March 2019 is categorised as follows:

	($'000)
Operating Expenditure:	
i. Business support	155
Total Related Party expenditure from ICHL	**155**

In the year to 31 March 2019, ICHL provided 6.9% of all Operating Expenditure relating to management fees.

c. OtagoNet Joint Venture

EIL has a 24.9% ownership interest in the OtagoNet electricity distribution network (OJV), based in coastland and inland Otago, via a joint venture arrangement with The Power Company Limited (TPCL).
There were no related party transactions between OJV and EIL during the reporting period.

d. Electricity Southland Limited

EIL has a 24.9% ownership interest in the Electricity Southland Ltd (ESL) electricity distribution network, based in Central Otago. The ESL network is consolidated within the OtagoNet JV network for regulatory reporting purposes.
There only related party transactions between ESL and EIL during this period was the interest charged on Loans advanced to ESL form EIL during the reporting period.

e. Southern Generation Limited Partnership

EIL has 25% ownership interest in Southern Generation Limited Partnership, investing in wind and hydro electricity generation – clean, green renewable energies that fit with EIL's other strategies.
There were no related party transactions between SGLP and EIL during the reporting period.

Network Management Agreement

EIL incurs 100% of its capital expenditure and a high percentage of its operating costs for its electricity distribution and metering businesses from PowerNet, in accordance with the explicit terms and conditions of the PowerNet Network Management Agreement (NMA).

While EIL owns the Network Assets and provides Line Function Services in Invercargill city and the Bluff township area, under the agreement PowerNet will manage the network assets, have right to carry out an agreed Capital Works programme, have the exclusive right to provide Line Function Services, and have the right to provide the business administration services on behalf of EIL.

PowerNet was established in 1994 to extract operational efficiencies from the merger of field work management, asset management and office based functions performed by EIL and The Power Company Limited (TPCL). In 1993, there were two autonomous Lines Companies in Southland (EIL and TPCL). 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 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.

Arm's Length Requirement

EIL believes the related party work performed by PowerNet is performed on an 'arm's-length' basis as if EIL and PowerNet were acting as willing buyer and willing seller, acting with independence and in pursuit of their own interests.

This view is based on the following reasons and best intent:

- Cost efficiencies and operating efficiencies generated from economies of scale;
- Cost efficiencies gained through supplier agreements eg Corys Electrical supply agreement with pricing mechanisms ensuring prices are maintained at a market competitive level;
- Separate entities operating with clear separation of duties and responsibilities;
- Two independent EDB entities with independent Directors acting in the best interests of their own business, owning and governing PowerNet;
- Relative labour costs benchmarking closely (+/-13%) within the average of alternate external supplier rates provided over the past two years;
- Market testing through tendering processes;
- External non-network customer work being awarded to PowerNet based on the same internal rates as charged to the EDB customers;
- Large percentage of Works Programme costs charged to EIL (almost 50% of Capital and Maintenance work) sourced from external suppliers, on a traditional arm's length transaction basis;
- Transparency of cost allocation process and mark-up rate agreed between the PowerNet EDB customers;
- Independent assessments of PowerNet performance and rates charged to EIL, providing favourable outcomes.

Independent Assurance Report

To the Directors of Electricity Invercargill Limited and the Commerce Commission

Assurance Report Pursuant to Electricity Distribution Information Disclosure Determination 2012

The Auditor-General is the auditor of Electricity Invercargill Limited (the Company). The Auditor-General has appointed me, Nathan Wylie, using the staff and resources of PricewaterhouseCoopers, to provide an opinion, on his behalf, on:

- whether the information required to be disclosed in accordance with the Electricity Distribution Information Disclosure Determination 2012 ('the Information Disclosure Determination') for the disclosure year ended 31 March 2019, has been prepared, in all material respects, in accordance with the Information Disclosure Determination.
- The disclosure information required to be reported by the Company, and audited by the Auditor-General, under the Information Disclosure Determination is in schedules 1 to 4, 5a to 5g, 6a and 6b, 7, the disclosure that shows the connection between the Company and the related parties with which it has had related party transactions in the disclosure year, the disclosures about related party transactions required under clause 2.3.12 of the Information Disclosure Determination, and the explanatory notes in boxes 1 to 11 in Schedule 14 ('the Disclosure Information').
- whether the Company's basis for valuation of related party transactions ('the Related Party Transaction Information') for the disclosure year ended 31 March 2019, has been prepared, in all material respects, in accordance with clause 2.3.6 of the Information Disclosure Determination, 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 an examination of them, proper records to enable the complete and accurate compilation of the Disclosure Information have been kept by the Company;
- The information used in the preparation of the Disclosure Information has been properly extracted from the Company's accounting and other records and has been sourced, where appropriate, from the Company's financial and non-financial systems;
- The Company has complied, in all material respects, with the Information Disclosure Determination in preparing the Disclosure Information; and
- The basis for valuation of related-party transactions complies, in all material respects, with the Information Disclosure Determination and the Input Methodologies Determination.

Basis for Qualified Opinion

The information provided by the Company to support the arm's length valuation for certain related party expenditures could not be verified against independent objective measures. Sufficient appropriate audit evidence could therefore not be obtained to conclude on whether the basis for valuation of these related party expenditures complies, in all material respects, with the Information Disclosure Determination and Input Methodologies Determination. This limitation in evidence is in respect of the related party expenditure amounts included in schedule 5b of the Disclosure Information:

- Operating expenditure of $187,000
- Capital expenditure of $612,000

Consequently, we were unable to determine whether any adjustments to these amounts would be necessary to ensure compliance with the Information Disclosure Determination and Input Methodologies Determination.

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 Company has complied in all material respects with the Information Disclosures Determination and Input Methodologies Determination in the preparation of the Schedules for the year ended 31 March 2019.

We have performed procedures to obtain evidence about the amounts and disclosures in the Disclosure Information and the basis of valuation in the Related Party Transaction Information. The procedures selected depend on our judgement, including the assessment of the risks of material misstatement of the Disclosure Information and Related Party Transaction Information, whether due to fraud or error or non-compliance with the Information Disclosure Determination or the Input Methodologies Determination. In making those risk assessments, we considered internal control relevant to the Company's preparation of the Disclosure Information and Related Party Transaction Information in order to design procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.

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.

Scope and inherent limitations

Because of the inherent limitations of a reasonable assurance engagement, and the test basis of the procedures performed, it is possible that fraud, error or non-compliance may occur and not be detected.

We did not examine every transaction, adjustment or event underlying the Disclosure Information or the Related Party Transaction Information, nor do we guarantee complete accuracy of the Disclosure Information or the Related Party Transaction Information. Also we did not evaluate the security and controls over the electronic publication of the Disclosure Information or the Related Party Transaction Information.

The opinion expressed in this independent assurance report has been formed on the above basis.

Key Assurance Matters

Key assurance matters are those matters that, in our professional judgement, required significant attention when carrying out the assurance engagement during the current disclosure year. These matters were addressed in the context of our compliance engagement, 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 Company's electricity distribution assets. These are valued using an indexed historic cost methodology prescribed by the Information Disclosure Determination. It is a measure which is used widely and is key to measuring the Company'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 property, plant and equipment 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 (ID Determination) and the Input Methodologies (IMs). 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 ID 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 IMs; • For assets with no standard asset lives we assessed the reasonableness of the lives used by reference to the accounting depreciation rates; • We tested the mathematical accuracy of the depreciation calculation on a sample basis and that it is performed in line with IM clause 2.2.5; *Revaluation* • We recalculated the revaluation rate set out in the Input Methodologies using the relevant Consumer Price Index indices taken from the Statistics New Zealand website; • We tested the mathematical accuracy of the revaluation calculation performed by management; *Disposals* • We inspected the asset disposals within the accounting fixed asset register to ensure disposals in the RAB meet the definition of a disposal per the IMs; We have no matters to report from undertaking those procedures.

Directors' responsibility for the preparation of the Disclosure Information and the Related Party Transaction Information

The Directors of the Company are responsible for:

- the preparation of the Disclosure Information in accordance with the Information Disclosure Determination, and
- the Related Party Transaction Information in accordance with the Information Disclosure Determination and the Input Methodologies Determination

and for such internal control as the directors determine is necessary to enable the preparation of the Disclosure Information and the Related Party Transaction Information that are free from material misstatement.

Our responsibility for the audit of the Disclosure Information and the Related Party Transaction Information

Our responsibility is to express an opinion that provides reasonable assurance on whether:

- the Disclosure Information has been prepared, in all material respects, in accordance with the Information Disclosure Determination; and
- the Related Party Transaction Information has been prepared, in all material respects, in accordance with the Information Disclosure Determination and the Input Methodologies Determination.

Independence and quality control

When carrying out the engagement, we complied with:

- the Auditor-General's independence and other ethical requirements, which incorporate the independence and ethical requirements of Professional and Ethical Standard 1 (Revised) issued by the New Zealand Auditing and Assurance Standards Board;
- the independence requirements specified in the Information Disclosure Determination; and
- the Auditor-General's quality control requirements, which incorporate the quality control requirements of Professional and Ethical Standard 3 (Amended) issued by the New Zealand Auditing and Assurance Standards Board.

The Auditor-General, and his employees, and PricewaterhouseCoopers and its partners and employees may deal with the Company on normal terms within the ordinary course of trading activities of the Company. In addition to this engagement, we have performed the annual audit, provided regulatory compliance advice and other advisory services to the Company. These assignments were compatible with the Auditor General's independence requirements. Other than the provision of these assignments, we have no relationship or interests in the Company.

Use of this report

This independent assurance report has been prepared solely for the directors of the Company and for the Commerce Commission for the purpose of providing those parties with reasonable assurance about whether the Disclosure Information has been prepared, in all material respects, in accordance with the Information Disclosure Determination and whether the Related Party Transaction Information has been prepared, in all material respects, in accordance with the Information Disclosure Determination and the Input Methodologies Determination. We disclaim any assumption of responsibility for any reliance on this report to any person other than the directors of the Company or the Commerce Commission, or for any other purpose than that for which it was prepared.

Nathan Wylie
PricewaterhouseCoopers
On behalf of the Auditor-General
Christchurch, New Zealand
30 August 2019

5. DIRECTORS' CERTIFICATE

Schedule 18: Certification for Year-End Disclosures

Clause 2.9.2

We, Thomas Campbell and Sarah Jane Brown, being directors of Electricity Invercargill Limited 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 Electricity Invercargill Limited'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.

Thomas Campbell **Sarah Jane Brown**

30 August 2019