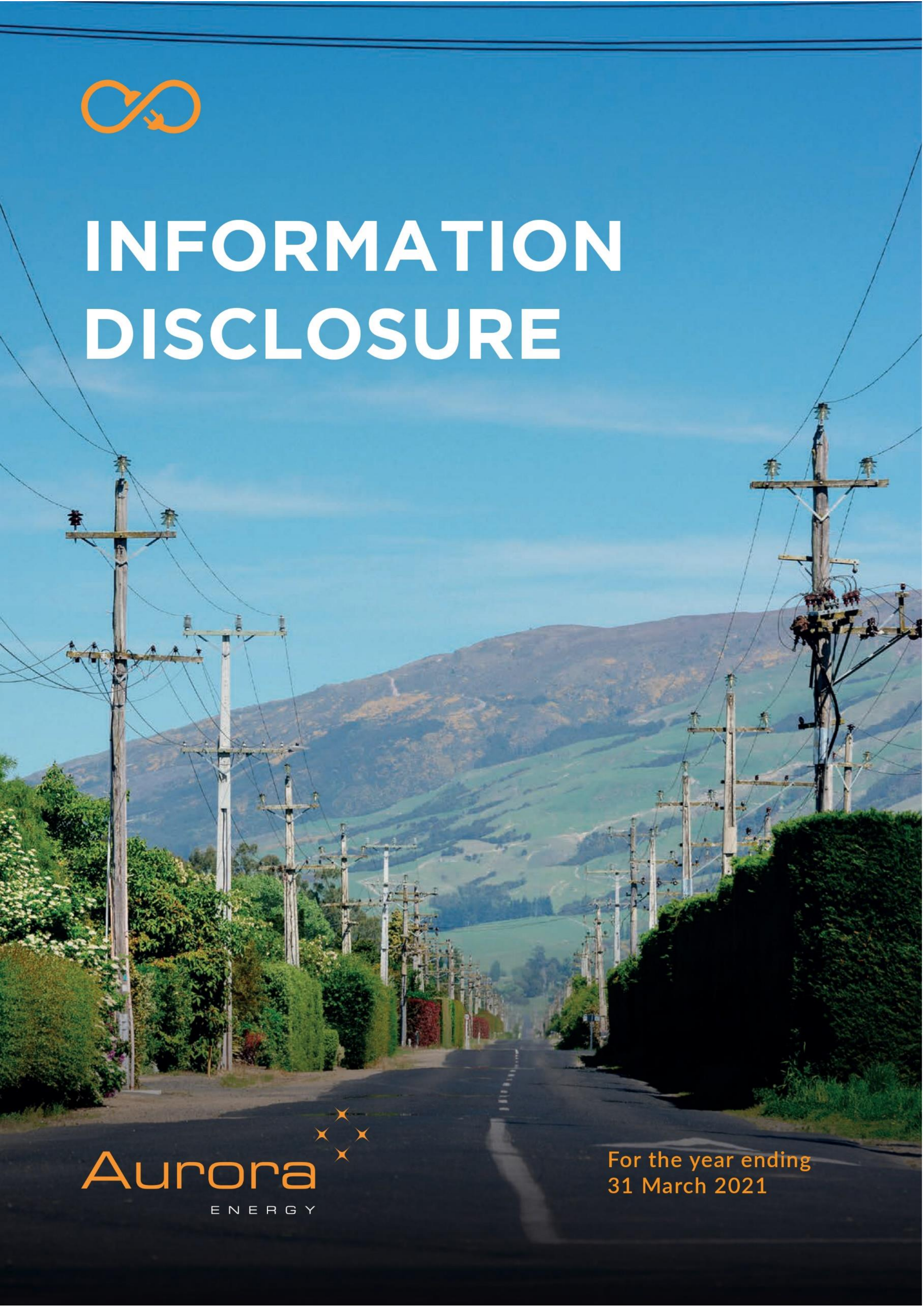

INFORMATION DISCLOSURE

Aurora ENERGY

For the year ending
31 March 2021

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Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**

SCHEDULE 1: ANALYTICAL RATIOS

This schedule calculates expenditure, revenue and service ratios from the information disclosed. The disclosed ratios may vary for reasons that are company specific and, as a result, must be interpreted with care. The Commerce Commission will publish a summary and analysis of information disclosed in accordance with the ID determination. This will include information disclosed in accordance with this and other schedules, and information disclosed under the other requirements of the determination.

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

sch ref

1(i): Expenditure metrics

	Expenditure per GWh energy delivered to ICPs ($/GWh)	Expenditure per average no. of ICPs ($/ICP)	Expenditure per MW maximum coincident system demand ($/MW)	Expenditure per km circuit length ($/km)	Expenditure per MVA of capacity from EDB-owned distribution transformers ($/MVA)
Operational expenditure	35,432	502	154,917	7,507	49,676
Network	14,924	212	65,250	3,162	20,923
Non-network	20,508	291	89,666	4,345	28,752
Expenditure on assets	50,671	718	221,544	10,736	71,040
Network	48,843	692	213,551	10,348	68,478
Non-network	1,828	26	7,993	387	2,563

1(ii): Revenue metrics

	Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
Total consumer line charge revenue	75,388	1,069
Standard consumer line charge revenue	75,871	1,066
Non-standard consumer line charge revenue	18,532	98,995

1(iii): Service intensity measures

Demand density	49	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
Volume density	212	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
Connection point density	15	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
Energy intensity	14,174	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*

1(iv): Composition of regulatory income

	($000)	% of revenue
Operational expenditure	46,252	46.95%
Pass-through and recoverable costs excluding financial incentives and wash-ups	29,748	30.20%
Total depreciation	20,358	20.67%
Total revaluations	7,402	7.51%
Regulatory tax allowance	715	0.73%
Regulatory profit/(loss) including financial incentives and wash-ups	8,837	8.97%
Total regulatory income	98,508	

1(v): Reliability

Interruption rate	23.13	*Interruptions per 100 circuit km*

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

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

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

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

sch ref			CY-2	CY-1	Current Year CY
7	**2(i): Return on Investment**				
8			**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
9	**ROI – comparable to a post tax WACC**		**%**	**%**	**%**
10		Reflecting all revenue earned	2.05%	2.23%	1.46%
11		Excluding revenue earned from financial incentives	2.12%	2.32%	4.30%
12		Excluding revenue earned from financial incentives and wash-ups	2.24%	2.44%	4.30%
13					
14		**Mid-point estimate of post tax WACC**	4.75%	4.27%	3.72%
15		25th percentile estimate	4.07%	3.59%	3.04%
16		75th percentile estimate	5.43%	4.95%	4.40%
17					
18					
19	**ROI – comparable to a vanilla WACC**				
20		Reflecting all revenue earned	2.55%	2.65%	1.79%
21		Excluding revenue earned from financial incentives	2.63%	2.74%	4.63%
22		Excluding revenue earned from financial incentives and wash-ups	2.75%	2.86%	4.63%
23					
24		**WACC rate used to set regulatory price path**	7.19%	7.19%	4.57%
25					
26		**Mid-point estimate of vanilla WACC**	5.26%	4.69%	4.05%
27		25th percentile estimate	4.58%	4.01%	3.37%
28		75th percentile estimate	5.94%	5.37%	4.73%
29					
30	**2(ii): Information Supporting the ROI**			**($000)**	
31					
32		Total opening RAB value	489,854		
33	*plus*	Opening deferred tax	(24,294)		
34	**Opening RIV**			465,560	
35					
36	**Line charge revenue**			98,409	
37					
38		Expenses cash outflow	76,000		
39	*add*	Assets commissioned	61,073		
40	*less*	Asset disposals	830		
41	*add*	Tax payments	(2,138)		
42	*less*	Other regulated income	99		
43	**Mid-year net cash outflows**			134,006	
44					
45	**Term credit spread differential allowance**			–	
46					
47		Total closing RAB value	539,722		
48	*less*	Adjustment resulting from asset allocation	(0)		
49	*less*	Lost and found assets adjustment	2,581		
50	*plus*	Closing deferred tax	(27,147)		
51	**Closing RIV**			509,994	
52					
53	**ROI – comparable to a vanilla WACC**				1.79%
54					
55		Leverage (%)			42%
56		Cost of debt assumption (%)			2.82%
57		Corporate tax rate (%)			28%
58					
59	**ROI – comparable to a post tax WACC**				1.46%
60					

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

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

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

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

sch ref

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	5.63%
Year-end ROI – comparable to a post tax WACC	5.30%

** 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	(18,470)	
Purchased assets – avoided transmission charge	–	
Energy efficiency and demand incentive allowance		
Quality incentive adjustment	(614)	
Other financial incentives	–	
Financial incentives		(19,084)
Impact of financial incentives on ROI		–2.84%
Input methodology claw-back	–	
CPP application recoverable costs	–	
Catastrophic event allowance	–	
Capex wash-up adjustment	–	
Transmission asset wash-up adjustment	–	
2013–15 NPV wash-up allowance	–	
Reconsideration event allowance	–	
Other wash-ups	–	
Wash-up costs		–
Impact of wash-up costs on ROI		–

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**

SCHEDULE 3: REPORT ON REGULATORY PROFIT

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

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

sch ref				
7		**3(i): Regulatory Profit**		**($000)**
8		**Income**		
9		Line charge revenue		98,409
10	*plus*	Gains / (losses) on asset disposals		(830)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)		929
12				
13		**Total regulatory income**		98,508
14		**Expenses**		
15	*less*	Operational expenditure		46,252
16				
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups		29,748
18				
19		**Operating surplus / (deficit)**		22,508
20				
21	*less*	Total depreciation		20,358
22				
23	*plus*	Total revaluations		7,402
24				
25		**Regulatory profit / (loss) before tax**		9,552
26				
27	*less*	Term credit spread differential allowance		–
28				
29	*less*	Regulatory tax allowance		715
30				
31		**Regulatory profit/(loss) including financial incentives and wash-ups**		8,837
32				
33		**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34		**Pass through costs**		
35		Rates	937	
36		Commerce Act levies	157	
37		Industry levies	340	
38		CPP specified pass through costs	–	
39		**Recoverable costs excluding financial incentives and wash-ups**		
40		Electricity lines service charge payable to Transpower	21,504	
41		Transpower new investment contract charges	462	
42		System operator services	–	
43		Distributed generation allowance	6,309	
44		Extended reserves allowance	–	
45		Other recoverable costs excluding financial incentives and wash-ups	39	
46		**Pass-through and recoverable costs excluding financial incentives and wash-ups**		29,748
47				

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**

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				
48	**3(iii): Incremental Rolling Incentive Scheme**		**($000)**	
49			**CY-1**	**CY**
50			**31 Mar 20**	**31 Mar 21**
51	Allowed controllable opex			
52	Actual controllable opex			
53				
54	Incremental change in year			
55				
56			**Previous years' incremental change**	**Previous years' incremental change adjusted for inflation**
57	CY-5	31 Mar 16		
58	CY-4	31 Mar 17		
59	CY-3	31 Mar 18		
60	CY-2	31 Mar 19		
61	CY-1	31 Mar 20		
62	**Net incremental rolling incentive scheme**			–
63				
64	**Net recoverable costs allowed under incremental rolling incentive scheme**			–
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	**Aurora Energy Limited**
For Year Ended	**31 March 2021**

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)

sch ref			RAB	RAB	RAB	RAB	RAB
8		for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
9			**($000)**	**($000)**	**($000)**	**($000)**	**($000)**
10		**Total opening RAB value**	341,025	354,222	394,155	447,072	489,854
11							
12	*less*	**Total depreciation**	12,762	13,710	15,058	16,809	20,358
13							
14	*plus*	**Total revaluations**	7,365	3,878	5,824	11,277	7,402
15							
16	*plus*	**Assets commissioned**	18,594	50,335	63,004	49,227	61,073
17							
18	*less*	**Asset disposals**	–	570	853	912	830
19							
20	*plus*	**Lost and found assets adjustment**	–	–	–	–	2,581
21							
22	*plus*	**Adjustment resulting from asset allocation**	–	–	–	–	(0)
23							
24		**Total closing RAB value**	354,222	394,155	447,072	489,854	539,722
25							

4(ii): Unallocated Regulatory Asset Base

sch ref			Unallocated RAB *		RAB	
28			**($000)**	**($000)**	**($000)**	**($000)**
29		**Total opening RAB value**		489,897		489,854
30	*less*					
31		**Total depreciation**		20,367		20,358
32	*plus*					
33		**Total revaluations**		7,403		7,402
34	*plus*					
35		Assets commissioned (other than below)	27,218		27,218	
36		Assets acquired from a regulated supplier	–		–	
37		Assets acquired from a related party	33,855		33,855	
38		**Assets commissioned**		61,073		61,073
39	*less*					
40		Asset disposals (other than below)	830		830	
41		Asset disposals to a regulated supplier	–		–	
42		Asset disposals to a related party	–		–	
43		**Asset disposals**		830		830
44						
45	*plus*	**Lost and found assets adjustment**		3,418		2,581
46						
47	*plus*	**Adjustment resulting from asset allocation**				(0)
48						
49		**Total closing RAB value**		540,594		539,722

50 ** 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.*

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**

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						
51						
52		**4(iii): Calculation of Revaluation Rate and Revaluation of Assets**				
53						
54		CPI_4				1,068
55		CPI_4^{-4}				1,052
56		Revaluation rate (%)				1.52%
57						
58			**Unallocated RAB ***		**RAB**	
59			**($000)**	**($000)**	**($000)**	**($000)**
60		Total opening RAB value	489,897		489,854	
61	*less*	Opening value of fully depreciated, disposed and lost assets	3,172		3,172	
62						
63		Total opening RAB value subject to revaluation	486,725		486,682	
64		**Total revaluations**		7,403		7,402
65						
66		**4(iv): Roll Forward of Works Under Construction**				
67			**Unallocated works under construction**		**Allocated works under construction**	
68		**Works under construction—preceding disclosure year**		51,412		51,411
69	*plus*	Capital expenditure	58,412		58,412	
70	*less*	Assets commissioned	61,073		61,073	
71	*plus*	Adjustment resulting from asset allocation			–	
72		**Works under construction - current disclosure year**		48,751		48,750
73						
74		Highest rate of capitalised finance applied				3.50%
75						

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**

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

76 **4(v): Regulatory Depreciation**

sch ref		Unallocated RAB *		RAB	
78		($000)	($000)	($000)	($000)
79	Depreciation - standard	18,589		18,589	
80	Depreciation - no standard life assets	1,778		1,769	
81	Depreciation - modified life assets	–		–	
82	Depreciation - alternative depreciation in accordance with CPP	–		–	
83	**Total depreciation**		20,367		20,358

85 **4(vi): Disclosure of Changes to Depreciation Profiles**

($000 unless otherwise specified)

sch ref	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
87					
88					
89					
90					
91					
92					
93					
94					

95 ** include additional rows if needed*

96 **4(vii): Disclosure by Asset Category**

97 **($000 unless otherwise specified)**

sch ref			Subtransmission lines	Subtransmission cables	Zone substations	Distribution and LV lines	Distribution and LV cables	Distribution substations and transformers	Distribution switchgear	Other network assets	Non-network assets	Total
99		**Total opening RAB value**	16,633	15,704	83,367	128,559	139,270	56,960	24,518	18,415	6,429	489,854
100	*less*	Total depreciation	682	535	3,317	4,315	4,546	2,143	1,327	1,724	1,769	20,358
101	*plus*	Total revaluations	245	239	1,245	1,944	2,118	866	372	278	95	7,402
102	*plus*	Assets commissioned	2,131	5,991	11,511	19,746	7,222	8,115	3,790	934	1,633	61,073
103	*less*	Asset disposals	–	–	–	757	3	–	70	–	–	830
104	*plus*	Lost and found assets adjustment	–	–	–	–	–	–	–	2,581	–	2,581
105	*plus*	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–	–	–
106	*plus*	Asset category transfers	–	–	–	–	–	–	–	–	–	–
107		**Total closing RAB value**	18,327	21,398	92,806	145,176	144,062	63,798	27,283	20,483	6,388	539,722
109		**Asset Life**										
110		Weighted average remaining asset life	24.4	29.3	25.1	29.6	30.6	26.6	18.4	12.4	3.9	(years)
111		Weighted average expected total asset life	48.7	53.7	48.8	53.0	51.6	51.9	39.6	15.4	9.3	(years)

Company Name	**Aurora Energy Limited**
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SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

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

sch ref

7	**5a(i): Regulatory Tax Allowance**			**($000)**	
8		**Regulatory profit / (loss) before tax**		9,552	
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	13		*
12		Amortisation of initial differences in asset values	4,968		
13		Amortisation of revaluations	2,103		
14				7,084	
15					
16	*less*	Total revaluations	7,402		
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	1,243		*
20		Notional deductible interest	5,438		
21				14,083	
22					
23		**Regulatory taxable income**		2,553	
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income		2,553	
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**		715	
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	84,014	
37	*less*	Amortisation of initial differences in asset values	4,968	
38	*plus*	Adjustment for unamortised initial differences in assets acquired	–	
39	*less*	Adjustment for unamortised initial differences in assets disposed	193	
40		Closing unamortised initial differences in asset values		78,853
41				
42		Opening weighted average remaining useful life of relevant assets (years)		17
43				

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**

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

sch ref				
44		**5a(iv): Amortisation of Revaluations**		**($000)**
46		Opening sum of RAB values without revaluations	443,376	
48		Adjusted depreciation	18,255	
49		Total depreciation	20,358	
50		Amortisation of revaluations		2,103
52		**5a(v): Reconciliation of Tax Losses**		**($000)**
54		**Opening tax losses**	–	
55	*plus*	Current period tax losses	–	
56	*less*	Utilised tax losses	–	
57		**Closing tax losses**		–
58		**5a(vi): Calculation of Deferred Tax Balance**		**($000)**
60		**Opening deferred tax**	(24,294)	
62	*plus*	Tax effect of adjusted depreciation	5,111	
64	*less*	Tax effect of tax depreciation	7,697	
66	*plus*	Tax effect of other temporary differences*	1,239	
68	*less*	Tax effect of amortisation of initial differences in asset values	1,391	
70	*plus*	Deferred tax balance relating to assets acquired in the disclosure year	(190)	
72	*less*	Deferred tax balance relating to assets disposed in the disclosure year	(74)	
74	*plus*	Deferred tax cost allocation adjustment	0	
76		**Closing deferred tax**		(27,147)
78		**5a(vii): Disclosure of Temporary Differences**		
79		*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).*		
81		**5a(viii): Regulatory Tax Asset Base Roll-Forward**		
82				**($000)**
83		**Opening sum of regulatory tax asset values**	291,105	
84	*less*	Tax depreciation	27,488	
85	*plus*	Regulatory tax asset value of assets commissioned	66,509	
86	*less*	Regulatory tax asset value of asset disposals	566	
87	*plus*	Lost and found assets adjustment	1,903	
88	*plus*	Adjustment resulting from asset allocation	–	
89	*plus*	Other adjustments to the RAB tax value	–	
90		**Closing sum of regulatory tax asset values**		331,463

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**

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		($000)	($000)
7	**5b(i): Summary—Related Party Transactions**		
8	**Total regulatory income**		–
9			
10	**Market value of asset disposals**		–
11			
12	Service interruptions and emergencies	3,037	
13	Vegetation management	5,570	
14	Routine and corrective maintenance and inspection	8,996	
15	Asset replacement and renewal (opex)	–	
16	**Network opex**		17,603
17	Business support	526	
18	System operations and network support	115	
19	**Operational expenditure**		18,245
20	Consumer connection	6,477	
21	System growth	3,130	
22	Asset replacement and renewal (capex)	18,681	
23	Asset relocations	1,127	
24	Quality of supply	433	
25	Legislative and regulatory	33	
26	Other reliability, safety and environment	668	
27	**Expenditure on non-network assets**		657
28	**Expenditure on assets**		31,206
29	Cost of financing		–
30	Value of capital contributions		3,707
31	Value of vested assets		–
32	**Capital Expenditure**		27,499
33	**Total expenditure**		45,744
34			
35	**Other related party transactions**		751

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	Delta Utility Services Ltd	Service interruptions and emergencies	3,037
39	Delta Utility Services Ltd	Vegetation management	5,570
40	Delta Utility Services Ltd	Routine and corrective maintenance and inspection	8,996
41	Delta Utility Services Ltd	System operations and network support	115
42	Delta Utility Services Ltd	Business support	437
43	Dunedin City Holdings Ltd	Business support	50
44	Dunedin City Council	Business support	39
45	Delta Utility Services Ltd	Consumer connection	6,477
46	Delta Utility Services Ltd	System growth	3,130
47	Delta Utility Services Ltd	Asset replacement and renewal (capex)	18,681
48	Delta Utility Services Ltd	Asset relocations	1,127
49	Delta Utility Services Ltd	Quality of supply	433
50	Delta Utility Services Ltd	Legislative and regulatory	33
51	Delta Utility Services Ltd	Other reliability, safety and environment	668
52	Delta Utility Services Ltd	Expenditure on non-network assets	657
53	**Total value of related party transactions**		49,451

54 ** include additional rows if needed*

55

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**

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	**Aurora Energy Limited**
For Year Ended	**31 March 2021**

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref						
7	**5d(i): Operating Cost Allocations**					
8			**Value allocated ($000s)**			
9		**Arm's length deduction**	**Electricity distribution services**	**Non-electricity distribution services**	**Total**	**OVABAA allocation increase ($000s)**
10	**Service interruptions and emergencies**					
11	Directly attributable		3,688			
12	Not directly attributable		–		–	
13	**Total attributable to regulated service**		3,688			
14	**Vegetation management**					
15	Directly attributable		5,570			
16	Not directly attributable		–		–	
17	**Total attributable to regulated service**		5,570			
18	**Routine and corrective maintenance and inspection**					
19	Directly attributable		10,224			
20	Not directly attributable		–		–	
21	**Total attributable to regulated service**		10,224			
22	**Asset replacement and renewal**					
23	Directly attributable		–			
24	Not directly attributable		–		–	
25	**Total attributable to regulated service**		–			
26	**System operations and network support**					
27	Directly attributable		13,779			
28	Not directly attributable		–		–	
29	**Total attributable to regulated service**		13,779			
30	**Business support**					
31	Directly attributable		–			
32	Not directly attributable		12,992	291	13,283	
33	**Total attributable to regulated service**		12,992			
34						
35	**Operating costs directly attributable**		33,260			
36	**Operating costs not directly attributable**	–	12,992	291	13,283	–
37	**Operational expenditure**		46,252			
38						

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**

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		
39	**5d(ii): Other Cost Allocations**	
40	**Pass through and recoverable costs**	**($000)**
41	**Pass through costs**	
42	Directly attributable	1,434
43	Not directly attributable	–
44	**Total attributable to regulated service**	1,434
45	**Recoverable costs**	
46	Directly attributable	28,314
47	Not directly attributable	–
48	**Total attributable to regulated service**	28,314
49		

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

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

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

sch ref

5e(i): Regulated Service Asset Values

	Value allocated ($000s) Electricity distribution services
Subtransmission lines	
Directly attributable	18,327
Not directly attributable	–
Total attributable to regulated service	18,327
Subtransmission cables	
Directly attributable	21,398
Not directly attributable	–
Total attributable to regulated service	21,398
Zone substations	
Directly attributable	92,806
Not directly attributable	–
Total attributable to regulated service	92,806
Distribution and LV lines	
Directly attributable	145,176
Not directly attributable	–
Total attributable to regulated service	145,176
Distribution and LV cables	
Directly attributable	144,062
Not directly attributable	–
Total attributable to regulated service	144,062
Distribution substations and transformers	
Directly attributable	63,798
Not directly attributable	–
Total attributable to regulated service	63,798
Distribution switchgear	
Directly attributable	27,283
Not directly attributable	–
Total attributable to regulated service	27,283
Other network assets	
Directly attributable	17,902
Not directly attributable	2,581
Total attributable to regulated service	20,483
Non-network assets	
Directly attributable	5,962
Not directly attributable	426
Total attributable to regulated service	6,388
Regulated service asset value directly attributable	536,715
Regulated service asset value not directly attributable	3,007
Total closing RAB value	539,722

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	**Aurora Energy Limited**
For Year Ended	**31 March 2021**

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

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

sch ref				
7		**6a(i): Expenditure on Assets**	**($000)**	**($000)**
8		Consumer connection		10,019
9		System growth		3,725
10		Asset replacement and renewal		44,519
11		Asset relocations		1,614
12		Reliability, safety and environment:		
13		Quality of supply	551	
14		Legislative and regulatory	127	
15		Other reliability, safety and environment	3,202	
16		**Total reliability, safety and environment**		3,880
17		**Expenditure on network assets**		63,758
18		Expenditure on non-network assets		2,386
19				
20		**Expenditure on assets**		66,145
21	*plus*	Cost of financing		400
22	*less*	Value of capital contributions		8,133
23	*plus*	Value of vested assets		–
24				
25		**Capital expenditure**		58,412

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		All consumers	10,019	
33				
34				
35				
36				
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		10,019
39				
40	*less*	Capital contributions funding consumer connection expenditure	7,251	
41		**Consumer connection less capital contributions**		2,768

42		**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset Replacement and**
43			**System Growth**	**Renewal**
44			**($000)**	**($000)**
45		Subtransmission	591	8,472
46		Zone substations	2,498	4,567
47		Distribution and LV lines	76	20,306
48		Distribution and LV cables	312	2,709
49		Distribution substations and transformers	131	6,179
50		Distribution switchgear	46	1,612
51		Other network assets	72	675
52		**System growth and asset replacement and renewal expenditure**	3,725	44,519
53	*less*	Capital contributions funding system growth and asset replacement and renewal	2	58
54		**System growth and asset replacement and renewal less capital contributions**	3,723	44,461
55				

56		**6a(v): Asset Relocations**		
57		*Project or programme**	**($000)**	**($000)**
58		Overhead line to underground cable conversion, Remarkables Park	417	
59		Relocation of 11kv line, Rutherford Lane and Moa Creek Road	180	
60		Overhead line to underground cable conversion, Fryatt Street	133	
61		Overhead line to underground cable conversion, Grants Road	121	
62				
63		** include additional rows if needed*		
64		All other projects or programmes - asset relocations	764	
65		**Asset relocations expenditure**		1,614
66	*less*	Capital contributions funding asset relocations	816	
67		**Asset relocations less capital contributions**		799

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**

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

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

sch ref				
68				
69	**6a(vi): Quality of Supply**			
70		*Project or programme**	**($000)**	**($000)**
71		Remote switching project, Arthurs Point	156	
72		Generator installation, Glenorchy	318	
73				
74				
75				
76		** include additional rows if needed*		
77		All other projects programmes - quality of supply	77	
78		**Quality of supply expenditure**		551
79	*less*	Capital contributions funding quality of supply		
80		**Quality of supply less capital contributions**		551
81	**6a(vii): Legislative and Regulatory**			
82		*Project or programme**	**($000)**	**($000)**
83		Low span conductor	67	
84				
85				
86				
87				
88		** include additional rows if needed*		
89		All other projects or programmes - legislative and regulatory	60	
90		**Legislative and regulatory expenditure**		127
91	*less*	Capital contributions funding legislative and regulatory	6	
92		**Legislative and regulatory less capital contributions**		121
93	**6a(viii): Other Reliability, Safety and Environment**			
94		*Project or programme**	**($000)**	**($000)**
95		Seismic strengthing of zone substations	2,464	
96				
97				
98				
99				
100		** include additional rows if needed*		
101		All other projects or programmes - other reliability, safety and environment	738	
102		**Other reliability, safety and environment expenditure**		3,202
103	*less*	Capital contributions funding other reliability, safety and environment		
104		**Other reliability, safety and environment less capital contributions**		3,202
105				
106	**6a(ix): Non-Network Assets**			
107	**Routine expenditure**			
108		*Project or programme**	**($000)**	**($000)**
109		Additions - Right-of-use assets	663	
110		Computer equipment	193	
111		General office equipment	65	
112				
113				
114		** include additional rows if needed*		
115		All other projects or programmes - routine expenditure	119	
116		**Routine expenditure**		1,040
117	**Atypical expenditure**			
118		*Project or programme**	**($000)**	**($000)**
119		External portable office	341	
120		Development of Asset Management System	396	
121		GIS Enterprise software development	216	
122		Data warehouse solution	93	
123		Stationware software	93	
124		** include additional rows if needed*		
125		All other projects or programmes - atypical expenditure	207	
126		**Atypical expenditure**		1,346
127				
128		**Expenditure on non-network assets**		2,386

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**

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

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

sch ref			
7	**6b(i): Operational Expenditure**	**($000)**	**($000)**
8	Service interruptions and emergencies	3,688	
9	Vegetation management	5,570	
10	Routine and corrective maintenance and inspection	10,224	
11	Asset replacement and renewal	–	
12	**Network opex**		19,481
13	System operations and network support	13,779	
14	Business support	12,992	
15	**Non-network opex**		26,771
16			
17	**Operational expenditure**		46,252
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	Energy efficiency and demand side management, reduction of energy losses		–
20	Direct billing*		–
21	Research and development		–
22	Insurance		369
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**

SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

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

sch ref				
7	**7(i): Revenue**	**Target ($000) [1]**	**Actual ($000)**	**% variance**
8	Line charge revenue	97,374	98,409	1%
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	9,241	10,019	8%
11	System growth	5,355	3,725	(30%)
12	Asset replacement and renewal	50,850	44,519	(12%)
13	Asset relocations	1,962	1,614	(18%)
14	Reliability, safety and environment:			
15	Quality of supply	242	551	128%
16	Legislative and regulatory	–	127	–
17	Other reliability, safety and environment	–	3,202	–
18	**Total reliability, safety and environment**	242	3,880	1,503%
19	**Expenditure on network assets**	67,650	63,758	(6%)
20	Expenditure on non-network assets	6,379	2,386	(63%)
21	Expenditure on assets	74,029	66,145	(11%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	4,805	3,688	(23%)
24	Vegetation management	5,440	5,570	2%
25	Routine and corrective maintenance and inspection	9,073	10,224	13%
26	Asset replacement and renewal	–	–	–
27	**Network opex**	19,318	19,481	1%
28	System operations and network support	16,129	13,779	(15%)
29	Business support	15,195	12,992	(14%)
30	**Non-network opex**	31,324	26,771	(15%)
31	**Operational expenditure**	50,642	46,252	(9%)
32	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
33	Energy efficiency and demand side management, reduction of energy losses	–	–	–
34	Overhead to underground conversion	–	–	–
35	Research and development	–	–	–
36				
37	**7(v): Subcomponents of Operational Expenditure (where known)**			
38	Energy efficiency and demand side management, reduction of energy losses	–	–	–
39	Direct billing	–	–	–
40	Research and development	–	–	–
41	Insurance	–	369	–
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	**Aurora Energy Limited**
For Year Ended	**31 March 2021**
Network / Sub-Network Name	**Total Network**

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

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

sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)
15	Residential	Residential	Standard	77,158	629,103
16	Load Group 0	General	Standard	306	80
17	Load Group 0A	General	Standard	716	1,676
18	Load Group 1A	General	Standard	903	2,791
19	Load Group 1	General	Standard	5,709	40,707
20	Load Group 2	General	Standard	6,739	255,101
21	Load Group 2	General	Non-standard	0	132
22	Load Group 3	General	Standard	219	54,991
23	Load Group 3	General	Non-standard	0	498
	Load Group 3A	General	Standard	174	79,565
	Load Group 3A	General	Non-standard	0	1,398
	Load Group 4	General	Standard	137	160,570
	Load Group 4	General	Non-standard	1	3,364
	Load Group 5	General	Standard	9	58,246
	Load Group 5	General	Non-standard	1	5,615
	Street Lighting	General	Standard	13	8,291
	DUML, excl Street Lighting	General	Standard	–	4
24	Distributed Generation (Large)	General	Standard	12	3,246
25	*Add extra rows for additional consumer groups or price category codes as necessary*				
26			**Standard consumer totals**	92,094	1,294,370
27			**Non-standard consumer totals**	2	11,006
28			**Total for all consumers**	92,096	1,305,375

Billed quantities by price component

Price component		Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease, Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Transmission)
Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)		LS	Lamp	kWh	kVA	kVA x km	kW	kVA	LS	kWh	kVA	kW
Residential	Standard	28,179,678	–	629,103,137	–	–	–	–	–	628,335,611	–	–
Load Group 0	Standard	111,833	–	–	95	–	–	–	111,833	–	–	–
Load Group 0A	Standard	261,655	–	–	302	–	–	–	55,095	–	–	–
Load Group 1A	Standard	329,752	–	–	2,635,520	–	325,287	–	–	–	2,632,600	324,922
Load Group 1	Standard	2,085,365	–	–	31,253,522	–	5,225,443	–	–	–	31,253,522	5,225,443
Load Group 2	Standard	2,461,635	–	–	122,747,284	–	17,783,877	(511)	–	–	122,711,875	17,780,997
Load Group 2	Non-standard	36	–	–	–	–	–	–	–	–	–	–
Load Group 3	Standard	80,085	–	–	15,470,078	252,403,097	3,494,930	(140)	–	–	15,470,078	3,494,930
Load Group 3	Non-standard	24	–	–	–	–	–	–	–	–	–	–
Load Group 3A	Standard	63,655	–	–	19,544,520	267,854,366	5,014,110	(543)	–	–	19,544,520	5,014,110
Load Group 3A	Non-standard	24	–	–	–	–	–	–	–	–	–	–
Load Group 4	Standard	50,140	–	–	36,129,100	531,456,108	9,145,060	90,113	–	–	36,129,100	9,145,060
Load Group 4	Non-standard	334	–	–	–	–	–	–	–	–	–	–
Load Group 5	Standard	3,235	–	–	9,722,000	111,206,765	2,603,975	8,167	–	–	9,722,000	2,603,975
Load Group 5	Non-standard	334	–	–	–	–	–	–	–	–	–	–
Street Lighting	Standard	730	2,699,469	2,086,861	–	–	–	–	730	2,079,128	–	–
DUML, excl Street Lighting	Standard	–	–	3,614	–	–	–	–	–	3,614	–	–
Distributed Generation (Large)	Standard	–	–	3,246	–	–	–	–	–	–	–	–
Standard consumer totals		33,627,765	2,699,469	631,196,858	237,502,421	1,162,920,336	43,592,682	97,086	167,658	630,418,353	237,463,695	43,589,437
Non-standard consumer totals		752	–	–	–	–	–	–	–	–	–	–
Total for all consumers		33,628,518	2,699,469	631,196,858	237,502,421	1,162,920,336	43,592,682	97,086	167,658	630,418,353	237,463,695	43,589,437

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**
Network / Sub-Network Name	**Total Network**

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

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)
Residential	Residential	Standard	$57,883	–	$52,085	$5,798
Load Group 0	General	Standard	$57	–	$58	($1)
Load Group 0A	General	Standard	$251	–	$279	($28)
Load Group 1A	General	Standard	$353	–	$347	$6
Load Group 1	General	Standard	$4,542	–	$4,245	$298
Load Group 2	General	Standard	$17,004	–	$15,688	$1,316
Load Group 2	General	Non-standard	–	–	–	–
Load Group 3	General	Standard	$3,473	–	$3,287	$187
Load Group 3	General	Non-standard	–	–	–	–
Load Group 3A	General	Standard	$4,302	–	$3,884	$418
Load Group 3A	General	Non-standard	–	–	–	–
Load Group 4	General	Standard	$7,515	–	$6,185	$1,330
Load Group 4	General	Standard	$130	–	$75	$55
Load Group 5	General	Standard	$1,453	–	$954	$499
Load Group 5	General	Non-standard	$204	–	$88	$116
Street Lighting	General	Standard	$622	–	$586	$36
DUML, excl Street Lighting	General	Standard	$0	–	$0	$0
Distributed Generation (Large)	General	Standard	$620	–	$620	–
Add extra rows for additional consumer groups or price category codes as necessary						
		Standard consumer totals	$98,205	–	$88,292	$9,913
		Non-standard consumer totals	$204	–	$88	$116
		Total for all consumers	$98,409	–	$88,380	$10,029

Line charge revenues ($000) by price component

Price component	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease, Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Transmission)
Rate (eg, $ per day, $ per kWh, etc.)	$ / annum	$ / Lamp	$ / kWh	$ / kVA	$ / kVA x km	$ / kW	$ / kVA	$ / annum	$ / kWh	$ / kVA	$ / kW
Residential	$4,195	–	$47,889	–	–	–	–	–	$5,798	–	–
Load Group 0	$58	–	–	–	–	–	–	($1)	–	–	–
Load Group 0A	$279	–	–	–	–	–	–	($28)	–	–	–
Load Group 1A	$14	–	–	$194	–	$139	–	–	–	($61)	$67
Load Group 1	$91	–	–	$2,052	–	$2,102	($0)	–	–	($811)	$1,109
Load Group 2	$215	–	–	$8,619	–	$6,859	($6)	–	–	($2,651)	$3,967
Load Group 2 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
Load Group 3	$140	–	–	$1,699	$315	$1,134	($2)	–	–	($499)	$685
Load Group 3 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
Load Group 3A	$110	–	–	$2,006	$328	$1,447	($7)	–	–	($612)	$1,029
Load Group 3A (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
Load Group 4	$221	–	–	$2,219	$657	$2,341	$747	–	–	($504)	$1,834
Load Group 4	$75	–	–	–	–	–	–	$55	–	–	–
Load Group 5	$14	–	–	$356	$134	$359	$91	–	–	($109)	$608
Load Group 5 (Non-standard)	$88	–	–	–	–	–	–	$116	–	–	–
Street Lighting	$414	$101	$72	–	–	–	–	$40	($4)	–	–
DUML, excl Street Lighting	$0	–	$0	–	–	–	–	–	$0	–	–
Distributed Generation (Large)	$620	–	–	–	–	–	–	–	–	–	–
Standard consumer totals	$6,447	$101	$47,961	$17,145	$1,434	$14,380	$824	$65	$5,794	($5,247)	$9,300
Non-standard consumer totals	$88	–	–	–	–	–	–	$116	–	–	–
Total for all consumers	$6,535	$101	$47,961	$17,145	$1,434	$14,380	$824	$181	$5,794	($5,247)	$9,300

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 5

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**
Network / Sub-Network Name	**Dunedin Sub-network**

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

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

sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)
15	Residential	Residential	Standard	48,940	408,722
16	Load Group 0	General	Standard	95	29
17	Load Group 0A	General	Standard	151	236
18	Load Group 1A	General	Standard	410	1,263
19	Load Group 1	General	Standard	2,894	20,380
20	Load Group 2	General	Standard	3,111	126,201
21	Load Group 2	General	Non-standard	–	–
22	Load Group 3	General	Standard	102	28,982
23	Load Group 3	General	Non-standard	–	–
	Load Group 3A	General	Standard	90	47,506
	Load Group 3A	General	Non-standard	–	–
	Load Group 4	General	Standard	74	97,587
	Load Group 4	General	Non-standard	–	–
	Load Group 5	General	Standard	7	46,799
	Load Group 5	General	Non-standard	–	–
	Street Lighting	General	Standard	2	6,204
	DUML, excl Street Lighting	General	Standard	–	4
24	Distributed Generation (Large)	General	Non-standard	1	–
25	*Add extra rows for additional consumer groups or price category codes as necessary*				
26			**Standard consumer totals**	55,876	783,913
27			**Non-standard consumer totals**	1	–
28			**Total for all consumers**	55,877	783,913

Billed quantities by price component

Price component	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease, Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Transmission)
Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	LS	Lamp	kWh	kVA	kVA x km	kW	kVA	LS	kWh	kVA	kW
Residential	17,863,041	–	408,721,745	–	–	–	–	–	408,721,745	–	–
Load Group 0	34,673	–	–	95	–	–	–	34,673	–	–	–
Load Group 0A	55,095	–	–	302	–	–	–	55,095	–	–	–
Load Group 1A	149,584	–	–	1,196,672	–	136,565	–	–	–	1,196,672	136,565
Load Group 1	1,056,251	–	–	15,843,047	–	2,556,023	–	–	–	15,843,047	2,556,023
Load Group 2 (Standard)	1,135,484	–	–	57,884,263	–	8,829,649	–	–	–	57,884,263	8,829,649
Load Group 2 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
Load Group 3 (Standard)	37,403	–	–	7,324,750	41,064,306	1,945,058	–	–	–	7,324,750	1,945,058
Load Group 3 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
Load Group 3A (Standard)	32,811	–	–	10,017,246	53,420,504	3,220,183	(263)	–	–	10,017,246	3,220,183
Load Group 3A (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
Load Group 4 (Standard)	27,030	–	–	19,245,500	108,106,350	5,460,280	48,613	–	–	19,245,500	5,460,280
Load Group 4 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
Load Group 5 (Standard)	2,535	–	–	7,897,000	49,978,015	2,361,980	8,167	–	–	7,897,000	2,361,980
Load Group 5 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
Street Lighting	730	–	–	–	–	–	–	730	–	–	–
DUML, excl Street Lighting	–	–	3,614	–	–	–	–	–	3,614	–	–
Distributed Generation (Large)	–	–	–	–	–	–	–	–	–	–	–
Standard consumer totals	20,394,637	–	408,725,359	119,408,875	252,569,175	24,509,738	56,517	90,498	408,725,359	119,408,478	24,509,738
Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–	–
Total for all consumers	20,394,637	–	408,725,359	119,408,875	252,569,175	24,509,738	56,517	90,498	408,725,359	119,408,478	24,509,738

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**
Network / Sub-Network Name	**Dunedin Sub-network**

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

31 **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)
37	Residential	Residential	Standard	$32,780	–	$26,693	$6,087
38	Load Group 0	General	Standard	$18	–	$16	$2
39	Load Group 0A	General	Standard	$63	–	$53	$9
40	Load Group 1A	General	Standard	$148	–	$128	$20
41	Load Group 1	General	Standard	$2,339	–	$1,832	$507
42	Load Group 2	General	Standard	$8,264	–	$7,285	$979
43	Load Group 2	General	Non-standard	–	–	–	–
44	Load Group 3	General	Standard	$1,632	–	$1,417	$215
45	Load Group 3	General	Non-standard	–	–	–	–
	Load Group 3A	General	Standard	$2,382	–	$1,951	$431
	Load Group 3A	General	Non-standard	–	–	–	–
	Load Group 4	General	Standard	$4,025	–	$2,855	$1,170
	Load Group 4	General	Non-standard	–	–	–	–
	Load Group 5	General	Standard	$1,237	–	$739	$498
	Load Group 5	General	Non-standard	–	–	–	–
	Street Lighting	General	Standard	$453	–	$414	$40
	DUML, excl Street Lighting	General	Standard	$0	–	$0	$0
46	Distributed Generation (Large)	General	Non-standard	$131	–	$131	–
47	*Add extra rows for additional consumer groups or price category codes as necessary*						
48			**Standard consumer totals**	$53,343	–	$43,384	$9,959
49			**Non-standard consumer totals**	$131	–	$131	–
50			**Total for all consumers**	$53,474	–	$43,515	$9,959

Line charge revenues ($000) by price component

#	Consumer group name or price category code	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease, Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Transmission)
34/35	Rate (eg, $ per day, $ per kWh, etc.)	$ / annum	$ / Lamp	$ / kWh	$ / kVA	$ / kVA x km	$ / kW	$ / kVA	$ / annum	$ / kWh	$ / kVA	$ / kW
37	Residential	$2,658	–	$24,035	–	–	–	–	–	$6,087	–	–
38	Load Group 0	$16	–	–	–	–	–	–	$2	–	–	–
39	Load Group 0A	$53	–	–	–	–	–	–	$9	–	–	–
40	Load Group 1A	$6	–	–	$71	–	$51	–	–	–	($14)	$34
41	Load Group 1	$46	–	–	$841	–	$945	–	–	–	($129)	$635
42	Load Group 2	$106	–	–	$3,913	–	$3,266	–	–	–	($1,216)	$2,195
43	Load Group 2	–	–	–	–	–	–	–	–	–	–	–
44	Load Group 3	$64	–	–	$817	$45	$491	–	–	–	($258)	$473
45	Load Group 3	–	–	–	–	–	–	–	–	–	–	–
	Load Group 3A	$56	–	–	$1,027	$59	$813	($3)	–	–	($353)	$783
	Load Group 3A	–	–	–	–	–	–	–	–	–	–	–
	Load Group 4	$115	–	–	$1,055	$119	$1,165	$401	–	–	($158)	$1,328
	Load Group 4	–	–	–	–	–	–	–	–	–	–	–
	Load Group 5	$11	–	–	$287	$55	$316	$70	–	–	($77)	$574
	Load Group 5	–	–	–	–	–	–	–	–	–	–	–
	Street Lighting	$414	–	–	–	–	–	–	$40	–	–	–
	DUML, excl Street Lighting	$0	–	$0	–	–	–	–	–	$0	–	–
46	Distributed Generation (Large)	$131	–	–	–	–	–	–	–	–	–	–
48	**Standard consumer totals**	$3,545	–	$24,035	$8,011	$278	$7,047	$469	$51	$6,087	($2,203)	$6,023
49	**Non-standard consumer totals**	$131	–	–	–	–	–	–	–	–	–	–
50	**Total for all consumers**	$3,676	–	$24,035	$8,011	$278	$7,047	$469	$51	$6,087	($2,203)	$6,023

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

Check OK

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

53 **Number of directly billed ICPs at year end** 1

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**
Network / Sub-Network Name	**Central Otago and Wanaka Sub-network**

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

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

sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)
15	Residential	Residential	Standard	17,180	121,656
16	Load Group 0	General	Standard	106	20
17	Load Group 0A	General	Standard	356	869
18	Load Group 1A	General	Standard	313	988
19	Load Group 1	General	Standard	1,749	12,158
20	Load Group 2	General	Standard	1,931	69,973
21	Load Group 2	General	Non-standard	0	132
22	Load Group 3	General	Standard	87	17,522
23	Load Group 3	General	Non-standard	0	498
	Load Group 3A	General	Standard	51	20,183
	Load Group 3A	General	Non-standard	0	1,398
	Load Group 4	General	Standard	38	31,102
	Load Group 4	General	Non-standard	–	–
	Load Group 5	General	Standard	1	8,633
	Load Group 5	General	Non-standard	–	–
	Street Lighting	General	Standard	5	1,186
	DUML, excl Street Lighting	General	Standard	–	–
24	Distributed Generation (Large)	General	Non-standard	9	2,426
25	*Add extra rows for additional consumer groups or price category codes as necessary*				
26			**Standard consumer totals**	21,820	284,290
27			**Non-standard consumer totals**	9	4,452
28			**Total for all consumers**	21,829	288,743

Billed quantities by price component

sch ref	Consumer group name or price category code / Price component	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease, Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Transmission)
13	**Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)**	LS	Lamp	kWh	kVA	kVA x km	kW	kVA	LS	kWh	kVA	kW
15	Residential (Standard)	6,288,021	–	121,656,446	–	–	–	–	–	121,656,446	–	–
16	Load Group 0 (Standard)	38,949	–	–	–	–	–	–	38,949	–	–	–
17	Load Group 0A (Standard)	130,400	–	–	–	–	–	–	–	–	–	–
18	Load Group 1A (Standard)	114,709	–	–	915,168	–	117,437	–	–	–	915,168	117,437
19	Load Group 1 (Standard)	640,286	–	–	9,578,055	–	1,409,577	–	–	–	9,578,055	1,409,577
20	Load Group 2 (Standard)	706,707	–	–	36,029,414	–	4,063,241	(385)	–	–	36,029,414	4,063,241
21	Load Group 2 (Non-standard)	36	–	–	–	–	–	–	–	–	–	–
22	Load Group 3 (Standard)	31,978	–	–	5,922,816	186,655,515	958,867	(140)	–	–	5,922,816	958,867
23	Load Group 3 (Non-standard)	24	–	–	–	–	–	–	–	–	–	–
	Load Group 3A (Standard)	18,784	–	–	5,572,538	164,468,087	813,129	(280)	–	–	5,572,538	813,129
	Load Group 3A (Non-standard)	24	–	–	–	–	–	–	–	–	–	–
	Load Group 4 (Standard)	13,993	–	–	9,792,600	359,527,034	1,403,200	22,042	–	–	9,792,600	1,403,200
	Load Group 4 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
	Load Group 5 (Standard)	366	–	–	912,500	60,133,750	38,325	–	–	–	912,500	38,325
	Load Group 5 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
	Street Lighting (Standard)	–	1,630,045	1,186,102	–	–	–	–	–	1,186,102	–	–
	DUML, excl Street Lighting (Standard)	–	–	–	–	–	–	–	–	–	–	–
24	Distributed Generation (Large) (Non-standard)	–	–	2,426	–	–	–	–	–	–	–	–
25		0	0	0	0	0	0	0	0	0	0	0
26	**Standard consumer totals**	7,984,196	1,630,045	122,842,548	68,723,091	770,784,386	8,803,776	21,237	38,949	122,842,548	68,723,091	8,803,776
27	**Non-standard consumer totals**	84	–	2,426	–	–	–	–	–	–	–	–
28	**Total for all consumers**	7,984,280	1,630,045	122,844,974	68,723,091	770,784,386	8,803,776	21,237	38,949	122,842,548	68,723,091	8,803,776

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**
Network / Sub-Network Name	**Central Otago and Wanaka Sub-network**

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

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

Row	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)
37	Residential	Residential	Standard	$15,579	–	$17,253	($1,674)
38	Load Group 0	General	Standard	$17	–	$26	($9)
39	Load Group 0A	General	Standard	$101	–	$166	($65)
40	Load Group 1A	General	Standard	$152	–	$170	($18)
41	Load Group 1	General	Standard	$1,446	–	$1,786	($340)
42	Load Group 2	General	Standard	$4,787	–	$5,065	($277)
43	Load Group 2	General	Non-standard	–	–	–	–
44	Load Group 3	General	Standard	$1,338	–	$1,409	($72)
45	Load Group 3	General	Non-standard	–	–	–	–
	Load Group 3A	General	Standard	$1,093	–	$1,172	($80)
	Load Group 3A	General	Non-standard	–	–	–	–
	Load Group 4	General	Standard	$1,942	–	$2,095	($152)
	Load Group 4	General	Non-standard	–	–	–	–
	Load Group 5	General	Standard	$128	–	$155	($27)
	Load Group 5	General	Non-standard	–	–	–	–
	Street Lighting	General	Standard	$115	–	$121	($6)
	DUML, excl Street Lighting	General	Standard	–	–	–	–
46	Distributed Generation (Large)	General	Non-standard	$489	–	$489	–
48			Standard consumer totals	$26,698	–	$29,417	($2,719)
49			Non-standard consumer totals	$489	–	$489	–
50			Total for all consumers	$27,187	–	$29,906	($2,719)

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

Line charge revenues ($000) by price component

Row	Consumer group name or price category code	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease, Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Transmission)
35	Rate (eg, $ per day, $ per kWh, etc.)	$ / annum	$ / Lamp	$ / kWh	$ / kVA	$ / kVA x km	$ / kW	$ / kVA	$ / annum	$ / kWh	$ / kVA	$ / kW
37	Residential	$937	–	$16,316	–	–	–	–	–	($1,674)	–	–
38	Load Group 0	$26	–	–	–	–	–	–	($9)	–	–	–
39	Load Group 0A	$166	–	–	–	–	–	–	($65)	–	–	–
40	Load Group 1A	$5	–	–	$95	–	$70	–	–	–	($37)	$19
41	Load Group 1	$30	–	–	$917	–	$838	($0)	–	–	($574)	$234
42	Load Group 2	$70	–	–	$2,915	–	$2,085	($5)	–	–	($937)	$659
43	Load Group 2	–	–	–	–	–	–	–	–	–	–	–
44	Load Group 3	$60	–	–	$575	$243	$533	($2)	–	–	($203)	$131
45	Load Group 3	–	–	–	–	–	–	–	–	–	–	–
	Load Group 3A	$35	–	–	$477	$214	$450	($3)	–	–	($191)	$111
	Load Group 3A	–	–	–	–	–	–	–	–	–	–	–
	Load Group 4	$69	–	–	$683	$467	$693	$183	–	–	($344)	$191
	Load Group 4	–	–	–	–	–	–	–	–	–	–	–
	Load Group 5	$2	–	–	$56	$78	$19	–	–	–	($32)	$5
	Load Group 5	–	–	–	–	–	–	–	–	–	–	–
	Street Lighting	–	$61	$60	–	–	–	–	–	($6)	–	–
	DUML, excl Street Lighting											
46	Distributed Generation (Large)	$489	–	–	–	–	–	–	–	–	–	–
48	Standard consumer totals	$1,401	$61	$16,376	$5,718	$1,002	$4,687	$173	($74)	($1,679)	($2,317)	$1,351
49	Non-standard consumer totals	$489	–	–	–	–	–	–	–	–	–	–
50	Total for all consumers	$1,889	$61	$16,376	$5,718	$1,002	$4,687	$173	($74)	($1,679)	($2,317)	$1,351

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

Check: **OK**

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

53 **Number of directly billed ICPs at year end**: 2

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**
Network / Sub-Network Name	**Queenstown Sub-network**

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

8(i): Billed Quantities by Price Component

					Billed quantities by price component										
				Price component	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease, Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Transmission)
Consumer group name or price category code	**Consumer type or types (eg, residential, commercial etc.)**	**Standard or non-standard consumer group (specify)**	**Average no. of ICPs in disclosure year**	**Energy delivered to ICPs in disclosure year (MWh)** / **Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)**	LS	Lamp	kWh	kVA	kVA x km	kW	kVA	LS	kWh	kVA	kW
Residential	Residential	Standard	10,908	97,957	3,981,477	–	97,957,420	–	–	–	–	–	97,957,420	–	–
Load Group 0	General	Standard	105	30	38,211	–	–	–	–	–	–	38,211	–	–	–
Load Group 0A	General	Standard	206	571	75,131	–	–	–	–	–	–	–	–	–	–
Load Group 1A	General	Standard	178	536	65,095	–	–	520,760	–	70,920	–	–	–	520,760	70,920
Load Group 1	General	Standard	1,065	8,169	388,828	–	–	5,832,420	–	1,259,843	–	–	–	5,832,420	1,259,843
Load Group 2	General	Standard	1,694	58,891	618,209	–	–	28,798,198	–	4,888,107	(126)	–	–	28,798,198	4,888,107
Load Group 2	General	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
Load Group 3	General	Standard	29	8,486	10,704	–	–	2,222,512	24,683,276	591,005	–	–	–	2,222,512	591,005
Load Group 3	General	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
Load Group 3A	General	Standard	33	11,876	12,060	–	–	3,954,736	49,965,775	980,798	–	–	–	3,954,736	980,798
Load Group 3A	General	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
Load Group 4	General	Standard	25	31,882	9,117	–	–	7,091,000	63,822,724	2,281,580	19,458	–	–	7,091,000	2,281,580
Load Group 4	General	Non-standard	1	3,364	334	–	–	–	–	–	–		–	–	–
Load Group 5	General	Standard	1	2,814	334	–	–	912,500	1,095,000	203,670	–	–	–	912,500	203,670
Load Group 5	General	Non-standard	1	5,615	334	–	–	–	–	–	–		–	–	–
Street Lighting	General	Standard	5	893	–	1,042,370	893,026	–	–	–	–	–	893,026	–	–
DUML, excl Street Lighting	General	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
Distributed Generation (Large)	General	Non-standard	2	821	–	–	821	–	–	–	–	–	–	–	–
Add extra rows for additional consumer groups or price category codes as necessary															
		Standard consumer totals	14,249	222,106	5,199,166	1,042,370	98,850,446	49,332,126	139,566,775	10,275,923	19,332	38,211	98,850,446	49,332,126	10,275,923
		Non-standard consumer totals	4	9,799	668	–	821	–	–	–	–	–	–	–	–
		Total for all consumers	14,253	231,906	5,199,834	1,042,370	98,851,267	49,332,126	139,566,775	10,275,923	19,332	38,211	98,850,446	49,332,126	10,275,923

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**
Network / Sub-Network Name	**Queenstown Sub-network**

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

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

Line charge revenues ($000) by price component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)	**Price component**	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease, Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Transmission)
							Rate (eg, $ per day, $ per kWh, etc.)	$ / annum	$ / Lamp	$ / kWh	$ / kVA	$ / kVA x km	$ / kW	$ / kVA	$ / annum	$ / kWh	$ / kVA	$ / kW
Residential	Residential	Standard	$9,423	–	$8,039	$1,384		$593	–	$7,446	–	–	–	–	–	$1,384	–	–
Load Group 0	General	Standard	$22	–	$16	$6		$16	–	–	–	–	–	–	$6	–	–	–
Load Group 0A	General	Standard	$86	–	$58	$28		$58	–	–	–	–	–	–	$28	–	–	–
Load Group 1A	General	Standard	$52	–	$48	$4		$3	–	–	$28	–	$18	–	–	–	($10)	$14
Load Group 1	General	Standard	$758	–	$626	$131		$16	–	–	$293	–	$318	–	–	–	($109)	$240
Load Group 2	General	Standard	$3,948	–	$3,334	$614		$40	–	–	$1,789	–	$1,506	($2)	–	–	($498)	$1,113
Load Group 2	General	Non-standard	–	–	–	–		–	–	–	–	–	–	–	–	–	–	–
Load Group 3	General	Standard	$504	–	$461	$43		$17	–	–	$308	$27	$110	–	–	–	($38)	$82
Load Group 3	General	Non-standard	–	–	–	–		–	–	–	–	–	–	–	–	–	–	–
Load Group 3A	General	Standard	$827	–	$760	$67		$19	–	–	$502	$55	$184	–	–	–	($68)	$135
Load Group 3A	General	Non-standard	–	–	–	–		–	–	–	–	–	–	–	–	–	–	–
Load Group 4	General	Standard	$1,547	–	$1,235	$312		$36	–	–	$482	$70	$484	$163	–	–	($3)	$315
Load Group 4	General	Non-standard	$130	–	$75	$55		$75	–	–	–	–	–	–	$55	–	–	–
Load Group 5	General	Standard	$88	–	$60	$28		$1	–	–	$12	$1	$25	$21	–	–	($0)	$28
Load Group 5	General	Non-standard	$204	–	$88	$116		$88	–	–	–	–	–	–	$116	–	–	–
Street Lighting	General	Standard	$52	–	$50	$2		–	$39	$11	–	–	–	–	–	$2	–	–
DUML, excl Street Lighting	General	Standard	–	–	–	–		–	–	–	–	–	–	–	–	–	–	–
Distributed Generation (Large)	General	Standard	–	–	–	–		–	–	–	–	–	–	–	–	–	–	–
Add extra rows for additional consumer groups or price category codes as necessary																		
		Standard consumer totals	$17,307	–	$14,688	$2,619		$798	$39	$7,457	$3,414	$154	$2,644	$183	$34	$1,386	($727)	$1,926
		Non-standard consumer totals	$334	–	$163	$171		$163	–	–	–	–	–	–	$171	–	–	–
		Total for all consumers	$17,641	–	$14,851	$2,789		$961	$39	$7,457	$3,414	$154	$2,644	$183	$204	$1,386	($727)	$1,926

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	2

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**
Network / Sub-network Name	**Total Network**

SCHEDULE 9a: ASSET REGISTER

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

sch ref

8	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
9	All	Overhead Line	Concrete poles / steel structure	No.	27,329	28,150	821	4
10	All	Overhead Line	Wood poles	No.	26,615	25,757	(858)	4
11	All	Overhead Line	Other pole types	No.	1		(1)	3
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	524	524	(0)	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km			–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	28	34	7	3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	25	25	–	3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	22	16	(6)	3
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	11	11	–	3
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.	35	35	–	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.	14	14	–	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.			–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	150	144	(6)	4
29	HV	Zone substation switchgear	33kV RMU	No.		1	1	4
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	9	9	–	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	48	49	1	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	332	334	2	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	21	22	1	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	66	67	1	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2,295	2,289	(6)	4
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km			–	N/A
37	HV	Distribution Line	SWER conductor	km	9	9	–	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	679	715	36	3
39	HV	Distribution Cable	Distribution UG PILC	km	423	421	(2)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	1	1	–	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	46	54	8	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	6	6	–	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	6,615	6,678	63	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	581	553	(28)	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	782	834	52	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	3,997	3,987	(10)	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	3,137	3,206	69	4
48	HV	Distribution Transformer	Voltage regulators	No.	28	28	–	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	359	354	(5)	4
50	LV	LV Line	LV OH Conductor	km	1,041	1,040	(2)	4
51	LV	LV Cable	LV UG Cable	km	1,049	1,076	27	4
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	1,061	1,064	3	4
53	LV	Connections	OH/UG consumer service connections	No.	92,989	94,261	1,272	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	856	803	(53)	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	3	3	–	4
57	All	Load Control	Centralised plant	Lot	21	21	–	4
58	All	Load Control	Relays	No	2,280	2,286	6	2
59	All	Civils	Cable Tunnels	km			–	N/A

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**
Network / Sub-network Name	**Dunedin Sub-network**

SCHEDULE 9a: ASSET REGISTER

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

sch ref

	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
8	**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.	17,490	17,815	325	4
10	All	Overhead Line	Wood poles	No.	11,897	11,568	(329)	4
11	All	Overhead Line	Other pole types	No.			–	3
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	144	144	–	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km			–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	7	14	6	3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	25	25	–	3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	22	16	(6)	3
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	11	11	–	3
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.	21	21	–	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.			–	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.			–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	81	75	(6)	4
29	HV	Zone substation switchgear	33kV RMU	No.			–	4
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	3	3	–	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	18	18	–	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	246	246	–	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.			–	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	34	34	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	728	726	(2)	4
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km			–	N/A
37	HV	Distribution Line	SWER conductor	km	9	9	–	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	44	47	3	3
39	HV	Distribution Cable	Distribution UG PILC	km	277	276	(1)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	1	1	–	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	14	15	1	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	6	6	–	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	2,613	2,631	18	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	364	338	(26)	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	365	383	18	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	1,682	1,673	(9)	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	979	987	8	4
48	HV	Distribution Transformer	Voltage regulators	No.	2	2	–	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	359	354	(5)	4
50	LV	LV Line	LV OH Conductor	km	818	817	(1)	4
51	LV	LV Cable	LV UG Cable	km	290	297	7	4
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	681	682	1	4
53	LV	Connections	OH/UG consumer service connections	No.	56,525	56,846	321	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	667	603	(64)	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	3	3	–	4
57	All	Load Control	Centralised plant	Lot	18	18	–	4
58	All	Load Control	Relays	No	1,127	1,128	1	2
59	All	Civils	Cable Tunnels	km			–	N/A

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**
Network / Sub-network Name	**Central Otago and Wanaka Sub-network**

SCHEDULE 9a: ASSET REGISTER

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

sch ref

	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
9	All	Overhead Line	Concrete poles / steel structure	No.	8,349	8,803	454	4
10	All	Overhead Line	Wood poles	No.	11,473	11,007	(466)	4
11	All	Overhead Line	Other pole types	No.	1		(1)	3
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	301	301	(0)	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km			–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	8	8	0	3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km			–	3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km			–	3
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	0	0	–	3
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.	9	9	–	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.	14	14	–	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.			–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	50	50	–	4
29	HV	Zone substation switchgear	33kV RMU	No.		1	1	4
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.			–	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	19	20	1	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	46	48	2	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	11	12	1	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	18	19	1	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1,278	1,275	(4)	4
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km			–	N/A
37	HV	Distribution Line	SWER conductor	km			–	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	446	472	26	3
39	HV	Distribution Cable	Distribution UG PILC	km	62	61	(1)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km			–	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	24	25	1	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.			–	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	3,106	3,141	35	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	93	91	(2)	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	203	223	20	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	1,853	1,855	2	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	1,348	1,395	47	4
48	HV	Distribution Transformer	Voltage regulators	No.	18	18	–	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.			–	4
50	LV	LV Line	LV OH Conductor	km	177	177	0	4
51	LV	LV Cable	LV UG Cable	km	456	470	14	4
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	239	241	2	4
53	LV	Connections	OH/UG consumer service connections	No.	21,905	22,502	597	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	111	122	11	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			–	4
57	All	Load Control	Centralised plant	Lot	2	2	–	4
58	All	Load Control	Relays	No	685	687	2	2
59	All	Civils	Cable Tunnels	km			–	N/A

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**
Network / Sub-network Name	**Queenstown Sub-network**

SCHEDULE 9a: ASSET REGISTER

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

sch ref

8	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
9	All	Overhead Line	Concrete poles / steel structure	No.	1,490	1,532	42	4
10	All	Overhead Line	Wood poles	No.	3,245	3,182	(63)	4
11	All	Overhead Line	Other pole types	No.			–	3
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	79	79	–	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km			–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	12	12	–	3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km			–	3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km			–	3
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km			–	3
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.			–	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.			–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	19	19	–	4
29	HV	Zone substation switchgear	33kV RMU	No.			–	4
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	6	6	–	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	11	11	–	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	40	40	–	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	10	10	–	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	14	14	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	289	288	(1)	4
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km			–	N/A
37	HV	Distribution Line	SWER conductor	km			–	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	188	196	7	3
39	HV	Distribution Cable	Distribution UG PILC	km	84	83	(1)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km			–	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	7	13	6	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.			–	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	896	906	10	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	123	123	–	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	213	227	14	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	462	459	(3)	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	805	819	14	4
48	HV	Distribution Transformer	Voltage regulators	No.	8	8	–	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.			–	4
50	LV	LV Line	LV OH Conductor	km	47	46	(1)	4
51	LV	LV Cable	LV UG Cable	km	297	303	6	4
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	139	140	1	4
53	LV	Connections	OH/UG consumer service connections	No.	14,423	14,773	350	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	78	78	–	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			–	4
57	All	Load Control	Centralised plant	Lot	1	1	–	4
58	All	Load Control	Relays	No	463	466	3	2
59	All	Civils	Cable Tunnels	km			–	N/A

Company Name	Aurora Energy Limited
For Year Ended	31 March 2021
Network / Sub-network Name	Total Network

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

8 **Disclosure Year (year ended)** 31 March 2021

Number of assets at disclosure year end by installation date

9	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	No. with age unknown	Items at end of year	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.		18	1,609	6,230	4,541	3,038	1,700	102	74	124	154	140	66	111	176	183	163	114	134	349	542	444	737	633	958	2,251	1,486	1,036	1,037						28,150		4
11	All	Overhead Line	Wood poles	No.	710	856	1,529	6,279	4,551	3,361	2,966	307	229	228	435	313	313	243	300	300	279	352	346	246	141	91	102	95	135	632	186	127	105						25,757		4
12	All	Overhead Line	Other pole types	No.																																			–		4
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	71	3	62	117	74	38	125	0					0		6		1	6	11		0	1	3	2		1	1	0							524		3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km																																			–		N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km						1	7					0	1	1	0	1	2	1	0	0	1	4		1	0	3	10		0						34		3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km					22	3																													25		3
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km				16																															16		3
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km			8		0	0	1	0		0	0	0	1		0	0				0															11		3
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	4	3	8	7	4											1	1			1	1	1	1	1	1								35		3
25	HV	Zone substation Buildings	Zone substations 110kV+	No.																																			–		N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.																																			–		N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.												3							1				2	1			7								14		3
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.																																			–		N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.			39	16	4	23	17	1				1		2			15		2			18		1			3		2						144		3
30	HV	Zone substation switchgear	33kV RMU	No.																													1						1		4
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.							6																				3								9		3
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.					5	7	10			1	1		3		3	4	1	2		3	2	3			1	1			2						49		3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.			46	38	62	24	26				11	17		10		8		19	20	12	2	10	6	5			16		2						334		3
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.				2	3		2				4	2		4					1	1					1		1		1						22		3
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.			4	12	12	6	6	1		1	3	1	1			1		2	4	1	2	1	1	2			2	1	3						67		3
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	71	127	283	416	399	368	340	13	9	14	7	11	30	8	12	7	11	13	13	6	8	6	15	22	10	13	11	27	17						2,289		3
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km																																			–		N/A
38	HV	Distribution Line	SWER conductor	km			6	2	0	1	0																0												9		3
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km				0	6	11	66	12	24	25	30	53	32	39	51	35	21	15	14	10	10	29	40	40	27	29	34	29	34						715		3
40	HV	Distribution Cable	Distribution UG PILC	km	0	8	34	49	70	74	67	6	7	9	13	6	9	12	15	5	8	9	7	5	3	4	1	1	0	–	0		–						421		3
41	HV	Distribution Cable	Distribution Submarine Cable	km		1																																	1		4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionaliser:	No.							2					2	4	2	4	7	7	1	1		3			8	1	3		1	8						54		4
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.			3		2														1																6		4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1	20	88	557	535	685	1,117	131	127	145	162	181	137	158	142	143	153	156	164	108	114	116	172	149	132	221	286	265	313						6,678		4
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.			1	82	62	71	71	7	3	19	24	16	25	18	33	19	27	23	11	13	16	2	2	1	1	2	2	2							553		3
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.				1	36	59	136	11	19	17	40	11	24	24	18	20	24	17	22	24	12	18	18	33	39	31	55	60	65						834		3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.		6	32	237	405	527	946	113	92	105	113	105	80	75	71	76	75	58	53	59	82	63	84	65	41	87	92	112	133						3,987		3
48	HV	Distribution Transformer	Ground Mounted Transformer	No.			1	42	164	183	456	60	97	98	118	153	172	169	146	125	127	56	85	61	65	85	103	105	100	99	116	104	116						3,206		3
49	HV	Distribution Transformer	Voltage regulators	No.					1									3	3	2	4	5			3		4						3						28		3
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.				2	109	95	126	8	2	4	1		2	1		1			1			1	1												354		3
51	LV	LV Line	LV OH Conductor	km	52	41	106	236	217	161	174	5	4	3	4	5	3	3	3	2	2	3	2	1	2	2	2	1	1	1	1	2	2						1,040		3
52	LV	LV Cable	LV UG Cable	km	0	0	1	22	43	160	157	19	21	25	41	48	51	49	46	40	36	22	14	20	15	20	23	28	31	32	41	40	28						1,076		3
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	13	11	32	140	152	243	288	7	7	8	9	10	10	9	10	11	9	9	7	10	7	7	4	12	8	11	9	8	4						1,064		3
54	LV	Connections	OH/UG consumer service connections	No.	12,376	3,523	6,851	8,667	7,088	4,497	21,918	1,017	957	1,208	1,380	1,572	1,570	1,747	1,535	1,669	1,236	1,102	1,018	889	1,026	1,040	1,203	1,253	1,663	1,507	1,537	1,423	1,559					230	94,261		3
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.			147	111	154	34	44			7	18	25	3	22		3		43	5	15	1	30	7	10	4	9	40	13	58						803		3
56	All	SCADA and communications	SCADA and communications equipment operating as a single sys	Lot																											1								1		3
57	All	Capacitor Banks	Capacitors including controls	No																				3															3		4
58	All	Load Control	Centralised plant	Lot			3	6	5		1										1	1	3				1												21		3
59	All	Load Control	Relays	No		1	3	41	80	107	255	24	45	43	58	102	134	121	112	86	62	30	27	28	16	22	9	519	242	28	26	38	27						2,286		2
60	All	Civils	Cable Tunnels	km																																			–		N/A

Company Name	Aurora Energy Limited
For Year Ended	31 March 2021
Network / Sub-network Name	Dunedin Sub-network

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

8 **Disclosure Year (year ended)** 31 March 2021 **Number of assets at disclosure year end by installation date**

9	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	No. with age unknown	Items at end of year	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.		3	1,525	5,844	2,842	2,048	766	24	12	42	51	24	17	25	31	19	18	25	27	79	155	167	309	292	519	1,047	876	582	446						17,815		4
11	All	Overhead Line	Wood poles	No.	710	834	1,415	2,487	1,001	1,185	1,551	175	156	121	113	91	115	102	111	148	129	89	82	102	61	37	20	19	37	485	99	56	37						11,568		4
12	All	Overhead Line	Other pole types	No.																																			–		4
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	62		51	26	3		2																												144		3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km																																			–		N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km																0			0	0		3		0	0	3	6								14		3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km					22	3																													25		3
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km				16																															16		3
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km			8		0	0	1	0		0	0	0	1		0	0				0															11		3
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	4	3	6	4	1																			1	1								21		3
25	HV	Zone substation Buildings	Zone substations 110kV+	No.																																			–		N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.																																			–		N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.																																			–		3
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.																																			–		N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.			25	16	4		5												2			18					3		2						75		3
30	HV	Zone substation switchgear	33kV RMU	No.																																			–		4
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.																											3								3		3
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.					4						1		1		3	4				3	2														18		3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.			46	38	62	17	13					17		9				11	17								16								246		3
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.																																			–		3
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.			3	10	10	2	2									1			2		2						2								34		3
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2	30	104	248	130	73	62	6	3	8	3	4	5	5	2	5	5	5	1	1	0	2	2	0	0	0	0	14	6						726		3
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km																																			–		N/A
38	HV	Distribution Line	SWER conductor	km			6	2	0	1	0																0												9		3
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km				0	0	0	4	1	1	2	2	2	2	3	3	2	1	0	2	1	1	1	1	2	4	2	2	4	3						47		3
40	HV	Distribution Cable	Distribution UG PILC	km	0	8	34	49	69	48	30	2	1	1	1	1	2	3	1	1	3	3	6	3	3	3	1	1	0	–	0		–						276		3
41	HV	Distribution Cable	Distribution Submarine Cable	km		1																																	1		4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionaliser:	No.															3		3		1		1			4		1		1	1						15		4
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.			3		2														1																6		4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.		16	57	466	369	362	459	16	12	19	29	37	32	56	34	26	25	22	20	19	23	33	41	37	41	57	75	123	125						2,631		4
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.			1	82	62	71	54	5		9	4	5		3	2	4	9	1	6	5	10	1				1	1	2							338		3
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.				1	36	56	95	10	8	3	8	6	10	5	3	3	9	7	11	8	8	9	8	8	15	4	11	16	25						383		3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.			4	162	222	257	450	44	28	29	43	28	31	35	26	21	16	16	13	19	22	17	30	14	19	27	24	37	39						1,673		3
48	HV	Distribution Transformer	Ground Mounted Transformer	No.			1	42	148	132	218	16	10	16	21	15	20	36	18	13	21	14	21	20	16	17	19	22	27	28	15	32	29						987		3
49	HV	Distribution Transformer	Voltage regulators	No.					1																								1						2		3
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.				2	109	95	126	8	2	4	1		2	1		1			1			1	1												354		3
51	LV	LV Line	LV OH Conductor	km	49	26	67	172	172	142	151	4	3	2	3	4	3	2	2	1	1	2	2	0	2	1	1	1	1	1	1	1	1						817		3
52	LV	LV Cable	LV UG Cable	km	0	0	1	22	42	34	40	4	3	4	5	8	9	13	11	7	8	8	4	8	7	8	7	6	8	8	7	8	7						297		3
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	13	6	19	115	136	106	219	3	3	2	4	3	4	2	3	3	4	6	4	6	4	3	2	5	4	2	1	1	1						682		3
54	LV	Connections	OH/UG consumer service connections	No.	12,376	3,523	6,851	8,663	7,080	4,492	4,852	311	284	249	362	490	434	528	506	538	365	435	377	380	365	354	409	365	445	426	455	429	459					43	56,846		3
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.			147	110	148	3	14					22		12		3		28	1			20		4	4	2	26	13	46						603		3
56	All	SCADA and communications	SCADA and communications equipment operating as a single sys	Lot																											1								1		3
57	All	Capacitor Banks	Capacitors including controls	No																				3															3		4
58	All	Load Control	Centralised plant	Lot			3	6	5		1												3																18		3
59	All	Load Control	Relays	No		1	3	37	62	58	94	6	2	4	4	4	2	3	5	6	7	5	5	14	4	4	4	509	234	14	5	14	18						1,128		2
60	All	Civils	Cable Tunnels	km																																			–		N/A

Company Name: Aurora Energy Limited
For Year Ended: 31 March 2021
Network / Sub-network Name: Central Otago and Wanaka Sub-network

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

8 Disclosure Year (year ended): 31 March 2021

Number of assets at disclosure year end by installation date

sch ref	Voltage	Asset category	Asset class	Units	pre-1940	1940–1949	1950–1959	1960–1969	1970–1979	1980–1989	1990–1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	No. with age unknown	Items at end of year	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.		15	84	350	1,474	749	720	65	48	72	85	100	39	71	129	129	132	85	77	217	377	252	382	320	391	1,008	510	403	519						8,803		4
11	All	Overhead Line	Wood poles	No.		17	113	3,222	2,690	1,510	965	96	49	86	296	179	161	110	157	104	105	217	220	106	50	51	71	69	81	119	61	54	48						11,007		4
12	All	Overhead Line	Other pole types	No.																																			–		4
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	0		9	67	59	34	104	0							4			6	11			1	2	2		1	1	0							301		3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km																																			–		N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km						1	1					0	0	1	0			1				0		1			3		0						8		3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km																																			–		3
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km																																			–		3
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km							0																												0		3
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	2	1												1			1	1	1	1										9		3
25	HV	Zone substation Buildings	Zone substations 110kV+	No.																																			–		N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.																																			–		N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.												3							1				2	1			7								14		3
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.																																			–		N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.			14			19	12	1				1		2										1											50		3
30	HV	Zone substation switchgear	33kV RMU	No.																													1						1		4
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.																																			–		3
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.						7	4			1			1				1					3			1				2						20		3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.						7					11			1		8			3		2	3	6	5					2						48		3
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.				2	1		1				4	2													1				1						12		3
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.			1	1	1	2	1			1	3	1							1			1	1	2					3						19		3
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	58	96	170	125	254	202	194	5	5	5	2	7	24	1	6	1	5	6	11	2	7	5	12	22	4	11	10	13	11						1,275		3
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km																																			–		N/A
38	HV	Distribution Line	SWER conductor	km																																			–		3
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km				0	5	8	35	7	14	14	21	33	17	22	35	17	15	10	8	7	9	28	34	32	16	22	22	18	25						472		3
40	HV	Distribution Cable	Distribution UG PILC	km	–				0	13	16	2	3	4	3	4	5	2	6	1	0	2	1	1	0	0													61		3
41	HV	Distribution Cable	Distribution Submarine Cable	km																																			–		4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionaliser:	No.							2					2	2		1	7	2	1			1			3	1	2			1						25		4
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.																																			–		4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1	4	29	83	141	255	448	76	72	80	100	105	75	75	80	96	93	99	117	64	77	80	118	95	77	139	181	121	160						3,141		4
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.							7	1		8	6	2	11	1	15	2	11	10	2	7	4		1	1	1		1								91		3
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.						1	16	1	4	8	11	1	9	4	6	6	3	6	7	8	3	6	5	11	8	17	26	30	26						223		3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.		6	26	66	155	219	361	48	47	55	57	60	38	35	38	46	41	27	34	35	49	43	45	42	18	51	59	65	89						1,855		3
48	HV	Distribution Transformer	Ground Mounted Transformer	No.					9	33	123	19	49	46	56	76	92	73	83	61	69	29	31	28	38	58	77	58	51	58	67	53	58						1,395		3
49	HV	Distribution Transformer	Voltage regulators	No.																2	2	5			3		4						2						18		3
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.																																			–		3
51	LV	LV Line	LV OH Conductor	km	3	14	31	51	32	17	17	1	1	0	1	1	1	0	1	0	1	1	0	0	0	0	0	0	0	0	0	1	1						177		3
52	LV	LV Cable	LV UG Cable	km					1	71	64	5	8	13	18	21	29	21	17	22	15	11	6	8	5	9	11	16	17	18	27	22	14						470		3
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	0	5	10	20	11	86	34	2	2	5	2	3	4	4	3	7	5	2	2	3	3	3	2	3	3	4	4	5	2						241		3
54	LV	Connections	OH/UG consumer service connections	No.				3	5	4	10,767	343	322	489	572	608	589	590	582	701	544	365	343	279	347	392	498	611	759	701	673	653	649					113	22,502		3
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.				1	6	20	3			4	16	3		10				4	4		1	5	7	6		7	13		12						122		3
56	All	SCADA and communications	SCADA and communications equipment operating as a single sys	Lot																											1								1		3
57	All	Capacitor Banks	Capacitors including controls	No																																			–		4
58	All	Load Control	Centralised plant	Lot																	1						1												2		3
59	All	Load Control	Relays	No				4	12	31	90	7	22	23	29	57	79	66	68	43	38	16	10	8	9	13	5	6	6	7	14	21	3						687		2
60	All	Civils	Cable Tunnels	km																																			–		N/A

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**
Network / Sub-network Name	**Queenstown Sub-network**

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

8 **Disclosure Year (year ended)** 31 March 2021

Number of assets at disclosure year end by installation date

sch ref	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	No. with age unknown	Items at end of year	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.				36	225	241	214	13	14	10	18	16	10	15	16	35	13	4	30	53	10	25	46	21	48	196	100	51	72						1,532		4
11	All	Overhead Line	Wood poles	No.		5	1	570	860	666	450	36	24	21	26	43	37	31	32	48	45	46	44	38	30	3	11	7	17	28	26	17	20						3,182		4
12	All	Overhead Line	Other pole types	No.																																			–		4
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	9	3	2	25	12	4	19						0		2		1				0		1												79		3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km																																			–		N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km							5						1	0	0	1	2	0		0	1						1								12		3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km																																			–		3
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km																																			–		3
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km																																			–		3
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	2											1																	5		3
25	HV	Zone substation Buildings	Zone substations 110kV+	No.																																			–		N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.																																			–		N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.																																			–		3
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.																																			–		N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.						4											15																		19		3
30	HV	Zone substation switchgear	33kV RMU	No.																																			–		4
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.							6																												6		3
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.					1		6						1					2								1									11		3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.							13											8		12		7													40		3
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.					2		1							4					1	1							1								10		3
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.				1	1	2	3	1					1					2	1	1								1							14		3
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	11	2	9	43	14	94	85	2	2	1	1	0	0	3	4	2	1	3	1	3	0		1	0	5	2	0	0	1						288		3
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km																																			–		N/A
38	HV	Distribution Line	SWER conductor	km																																			–		3
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km						2	27	4	9	10	7	18	12	12	14	16	5	4	4	2	1	1	5	6	8	5	11	6	7						196		3
40	HV	Distribution Cable	Distribution UG PILC	km					0	13	21	3	2	5	10	1	2	6	8	3	5	4	0	0	0	0		0	0										83		3
41	HV	Distribution Cable	Distribution Submarine Cable	km																																			–		4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionaliser:	No.													2	1			2				1			1					6						13		4
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.																																			–		4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.			2	8	25	68	210	39	43	46	33	39	30	27	28	21	35	35	27	25	14	3	13	17	14	25	30	21	28						906		4
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.							10	1	3	2	14	9	14	13	16	13	7	12	3	1	2	1	1			1									123		3
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.						2	25		7	6	21	4	5	14	9	11	12	4	4	8	1	3	5	14	16	10	18	14	14						227		3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.			2	9	28	51	135	21	17	21	13	17	11	5	7	9	18	15	6	5	11	3	9	9	4	9	9	10	5						459		3
48	HV	Distribution Transformer	Ground Mounted Transformer	No.					7	18	115	25	38	36	41	62	60	55	45	51	37	13	33	13	11	10	7	25	22	13	34	19	29						819		3
49	HV	Distribution Transformer	Voltage regulators	No.														3	3		2																		8		3
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.																																			–		3
51	LV	LV Line	LV OH Conductor	km		1	8	13	14	2	6	0	0	1	0	0	0	–		0	0		0	0	0	0	0	0		0		0							46		3
52	LV	LV Cable	LV UG Cable	km				0	1	55	53	10	10	8	19	19	13	10	18	11	13	3	5	5	3	3	5	6	6	6	7	10	6						303		3
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km			4	5	5	51	34	2	2	1	2	5	2	1	4	1	0	1	1	1	1	0		4	1	4	4	1	1						140		3
54	LV	Connections	OH/UG consumer service connections	No.				1	3	1	6,299	363	351	470	446	474	547	621	435	414	314	294	285	220	306	289	292	274	449	372	402	332	447					72	14,773		3
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.						11	27			3	2		3					11		15		5					1								78		3
56	All	SCADA and communications	SCADA and communications equipment operating as a single sys	Lot																											1								1		3
57	All	Capacitor Banks	Capacitors including controls	No																																			–		4
58	All	Load Control	Centralised plant	Lot																		1																	1		3
59	All	Load Control	Relays	No					6	18	71	11	21	16	25	41	53	47	39	37	17	9	12	6	3	5		4	2	7	7	3	6						466		2
60	All	Civils	Cable Tunnels	km																																			–		N/A

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**
Network / Sub-network Name	**Total Network**

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref				
9				
10	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
11	> 66kV			–
12	50kV & 66kV	127	3	129
13	33kV	397	84	482
14	SWER (all SWER voltages)	9		9
15	22kV (other than SWER)			–
16	6.6kV to 11kV (inclusive—other than SWER)	2,289	1,137	3,426
17	Low voltage (< 1kV)	1,040	1,076	2,115
18	**Total circuit length (for supply)**	3,861	2,300	6,161
19				
20	Dedicated street lighting circuit length (km)	532	532	1,064
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			58
22				
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**	
24	Urban	1,166	30%	
25	Rural	2,607	68%	
26	Remote only		–	
27	Rugged only	88	2%	
28	Remote and rugged		–	
29	Unallocated overhead lines		–	
30	**Total overhead length**	3,861	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	1,476	24%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	3,609	93%	

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**
Network / Sub-network Name	**Dunedin Sub-network**

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref				
9				
10	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
11	> 66kV			–
12	50kV & 66kV			–
13	33kV	144	66	210
14	SWER (all SWER voltages)	9		9
15	22kV (other than SWER)			–
16	6.6kV to 11kV (inclusive—other than SWER)	726	324	1,050
17	Low voltage (< 1kV)	817	297	1,113
18	**Total circuit length (for supply)**	1,696	687	2,383
19				
20	Dedicated street lighting circuit length (km)	460	222	682
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			4
22				
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**	
24	Urban	969	57%	
25	Rural	716	42%	
26	Remote only		–	
27	Rugged only	10	1%	
28	Remote and rugged		–	
29	Unallocated overhead lines		–	
30	**Total overhead length**	1,696	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	1,476	62%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	1,582	93%	

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**
Network / Sub-network Name	**Central Otago and Wanaka Sub-network**

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref

sch ref				
9				
10	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
11	> 66kV			–
12	50kV & 66kV	127	3	129
13	33kV	175	6	180
14	SWER (all SWER voltages)			–
15	22kV (other than SWER)			–
16	6.6kV to 11kV (inclusive—other than SWER)	1,275	533	1,807
17	Low voltage (< 1kV)	177	470	647
18	**Total circuit length (for supply)**	1,753	1,011	2,764
19				
20	Dedicated street lighting circuit length (km)	56	185	241
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			31
22				
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**	
24	Urban	129	7%	
25	Rural	1,570	90%	
26	Remote only		–	
27	Rugged only	54	3%	
28	Remote and rugged		–	
29	Unallocated overhead lines		–	
30	**Total overhead length**	1,753	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	–	–	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	1,651	94%	

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**
Network / Sub-network Name	**Queenstown Sub-network**

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref

9				
10	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
11	> 66kV			–
12	50kV & 66kV			–
13	33kV	79	12	91
14	SWER (all SWER voltages)			–
15	22kV (other than SWER)			–
16	6.6kV to 11kV (inclusive—other than SWER)	288	279	567
17	Low voltage (< 1kV)	46	303	349
18	**Total circuit length (for supply)**	413	595	1,008
19				
20	Dedicated street lighting circuit length (km)	16	124	140
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			23
22				
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**	
24	Urban	68	16%	
25	Rural	321	78%	
26	Remote only		–	
27	Rugged only	24	6%	
28	Remote and rugged		–	
29	Unallocated overhead lines		–	
30	**Total overhead length**	413	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	–	–	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	376	91%	

Company Name **Aurora Energy Limited**
For Year Ended **31 March 2021**

SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

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

sch ref

sch ref	Location *	Number of ICPs served	Line charge revenue ($000)
9	Heritage Estate (Te Anau)	137	108
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	**Aurora Energy Limited**
For Year Ended	**31 March 2021**
Network / Sub-network Name	**Total Network**

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref

sch ref				
8		**9e(i): Consumer Connections**		
9		*Number of ICPs connected in year by consumer type*		
10		*Consumer types defined by EDB**	**Number of connections (ICPs)**	
11		Residential	954	
12		Load Group 0	19	
13		Load Group 0A	14	
14		Load Group 1A	18	
		Load Group 1	(86)	
		Load Group 2	162	
		Load Group 3	2	
		Load Group 3A	1	
		Load Group 4	3	
		Load Group 5	(1)	
		Street Lighting	2	
15		Distributed Unmetered Load (excl. Street Lighting)	–	
16		** include additional rows if needed*		
17		**Connections total**	1,088	
18				
19		**Distributed generation**		
20		Number of connections made in year	221	**connections**
21		Capacity of distributed generation installed in year	1.34	**MVA**
22		**9e(ii): System Demand**		
23				
24				
25		**Maximum coincident system demand**	**Demand at time of maximum coincident demand (MW)**	
26		GXP demand	241	
27	*plus*	Distributed generation output at HV and above	58	
28		**Maximum coincident system demand**	299	
29	*less*	Net transfers to (from) other EDBs at HV and above	0	
30		**Demand on system for supply to consumers' connection points**	299	
31		**Electricity volumes carried**	**Energy (GWh)**	
32		Electricity supplied from GXPs	1,073	
33	*less*	Electricity exports to GXPs	53	
34	*plus*	Electricity supplied from distributed generation	367	
35	*less*	Net electricity supplied to (from) other EDBs	1	
36		**Electricity entering system for supply to consumers' connection points**	1,385	
37	*less*	Total energy delivered to ICPs	1,305	
38		**Electricity losses (loss ratio)**	80	5.8%
39				
40		**Load factor**	0.53	
41		**9e(iii): Transformer Capacity**		
42			**(MVA)**	
43		Distribution transformer capacity (EDB owned)	931	
44		Distribution transformer capacity (Non-EDB owned, estimated)	68	
45		**Total distribution transformer capacity**	999	
46				
47		**Zone substation transformer capacity**	958	

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**
Network / Sub-network Name	**Dunedin Sub-network**

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref

sch ref		Number of connections (ICPs)	
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	Residential	280	
12	Load Group 0	9	
13	Load Group 0A	(1)	
14	Load Group 1A	5	
	Load Group 1	(59)	
	Load Group 2	6	
	Load Group 3	–	
	Load Group 3A	(2)	
	Load Group 4	1	
	Load Group 5	(1)	
	Street Lighting	–	
15	Distributed Unmetered Load (excl. Street Lighting)	–	
16	** include additional rows if needed*		
17	**Connections total**	238	
18			
19	**Distributed generation**		
20	Number of connections made in year	43	**connections**
21	Capacity of distributed generation installed in year	0.25	**MVA**

sch ref			Demand at time of maximum coincident demand (MW)	
22	**9e(ii): System Demand**			
23				
24				
25		**Maximum coincident system demand**	**Demand at time of maximum coincident demand (MW)**	
26		GXP demand	142	
27	*plus*	Distributed generation output at HV and above	50	
28		**Maximum coincident system demand**	192	
29	*less*	Net transfers to (from) other EDBs at HV and above	–	
30		**Demand on system for supply to consumers' connection points**	192	
31		**Electricity volumes carried**	**Energy (GWh)**	
32		Electricity supplied from GXPs	658	
33	*less*	Electricity exports to GXPs	0	
34	*plus*	Electricity supplied from distributed generation	172	
35	*less*	Net electricity supplied to (from) other EDBs	–	
36		**Electricity entering system for supply to consumers' connection points**	829	
37	*less*	Total energy delivered to ICPs	784	
38		**Electricity losses (loss ratio)**	45	5.5%
39				
40		**Load factor**	0.49	

sch ref		(MVA)
41	**9e(iii): Transformer Capacity**	
42		**(MVA)**
43	Distribution transformer capacity (EDB owned)	483
44	Distribution transformer capacity (Non-EDB owned, estimated)	43
45	**Total distribution transformer capacity**	526
46		
47	**Zone substation transformer capacity**	581

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**
Network / Sub-network Name	**Central Otago and Wanaka Sub-network**

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref			
8	**9e(i): Consumer Connections**		
9	*Number of ICPs connected in year by consumer type*		
10	*Consumer types defined by EDB**	**Number of connections (ICPs)**	
11	Residential	456	
12	Load Group 0	4	
13	Load Group 0A	–	
14	Load Group 1A	10	
	Load Group 1	8	
	Load Group 2	83	
	Load Group 3	1	
	Load Group 3A	2	
	Load Group 4	1	
	Load Group 5	–	
	Street Lighting	2	
15	Distributed Unmetered Load (excl. Street Lighting)	–	
16	** include additional rows if needed*		
17	**Connections total**	567	
18			
19	**Distributed generation**		
20	Number of connections made in year	141	**connections**
21	Capacity of distributed generation installed in year	0.85	**MVA**
22	**9e(ii): System Demand**		
23			
24			
25	**Maximum coincident system demand**	**Demand at time of maximum coincident demand (MW)**	
26	GXP demand	41	
27	*plus* Distributed generation output at HV and above	21	
28	**Maximum coincident system demand**	62	
29	*less* Net transfers to (from) other EDBs at HV and above	0	
30	**Demand on system for supply to consumers' connection points**	61	
31	**Electricity volumes carried**	**Energy (GWh)**	
32	Electricity supplied from GXPs	186	
33	*less* Electricity exports to GXPs	53	
34	*plus* Electricity supplied from distributed generation	181	
35	*less* Net electricity supplied to (from) other EDBs	2	
36	**Electricity entering system for supply to consumers' connection points**	312	
37	*less* Total energy delivered to ICPs	289	
38	**Electricity losses (loss ratio)**	23	7.4%
39			
40	**Load factor**	0.58	
41	**9e(iii): Transformer Capacity**		
42		**(MVA)**	
43	Distribution transformer capacity (EDB owned)	279	
44	Distribution transformer capacity (Non-EDB owned, estimated)	20	
45	**Total distribution transformer capacity**	299	
46			
47	**Zone substation transformer capacity**	215	

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**
Network / Sub-network Name	**Queenstown Sub-network**

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref				
8	**9e(i): Consumer Connections**			
9	*Number of ICPs connected in year by consumer type*			
10	*Consumer types defined by EDB**		**Number of connections (ICPs)**	
11	Residential		210	
12	Load Group 0		6	
13	Load Group 0A		21	
14	Load Group 1A		3	
	Load Group 1		(35)	
	Load Group 2		71	
	Load Group 3		1	
	Load Group 3A		1	
	Load Group 4		1	
	Load Group 5		–	
	Street Lighting		–	
15	Distributed Unmetered Load (excl. Street Lighting)		–	
16	** include additional rows if needed*			
17	**Connections total**		279	
18				
19	**Distributed generation**			
20	Number of connections made in year		37	**connections**
21	Capacity of distributed generation installed in year		0.24	**MVA**
22	**9e(ii): System Demand**			
23				
24			**Demand at time of maximum coincident demand (MW)**	
25	**Maximum coincident system demand**			
26		GXP demand	60	
27	*plus*	Distributed generation output at HV and above	2	
28	**Maximum coincident system demand**		62	
29	*less*	Net transfers to (from) other EDBs at HV and above	–	
30	**Demand on system for supply to consumers' connection points**		62	
31	**Electricity volumes carried**		**Energy (GWh)**	
32		Electricity supplied from GXPs	229	
33	*less*	Electricity exports to GXPs	–	
34	*plus*	Electricity supplied from distributed generation	14	
35	*less*	Net electricity supplied to (from) other EDBs	–	
36	**Electricity entering system for supply to consumers' connection points**		244	
37	*less*	Total energy delivered to ICPs	232	
38	**Electricity losses (loss ratio)**		12	4.8%
39				
40	**Load factor**		0.45	
41	**9e(iii): Transformer Capacity**			
42			**(MVA)**	
43		Distribution transformer capacity (EDB owned)	168	
44		Distribution transformer capacity (Non-EDB owned, estimated)	5	
45	**Total distribution transformer capacity**		174	
46				
47	**Zone substation transformer capacity**		162	

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**
Network / Sub-network Name	**Total Network**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

sch ref			
8	**10(i): Interruptions**		
9	**Interruptions by class**	**Number of interruptions**	
10	Class A (planned interruptions by Transpower)	1	
11	Class B (planned interruptions on the network)	928	
12	Class C (unplanned interruptions on the network)	490	
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)	2	
16	Class G (unplanned interruptions caused by another disclosing entity)	–	
17	Class H (planned interruptions caused by another disclosing entity)	–	
18	Class I (interruptions caused by parties not included above)	4	
19	**Total**	1,425	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	385	105
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)	0.00	0.1
26	Class B (planned interruptions on the network)	0.68	134.6
27	Class C (unplanned interruptions on the network)	1.54	113.8
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)	0.01	0.6
31	Class G (unplanned interruptions caused by another disclosing entity)	–	–
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	0.01	0.2
34	**Total**	2.24	249.3
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	2.22	248.4
38			

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**
Network / Sub-network Name	**Total Network**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

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

Cause	SAIFI	SAIDI
Lightning	0.01	0.6
Vegetation	0.31	20.9
Adverse weather	0.00	0.5
Adverse environment	0.00	0.0
Third party interference	0.13	10.2
Wildlife	0.03	4.2
Human error	0.15	5.0
Defective equipment	0.57	47.3
Cause unknown	0.34	25.1

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	–	–
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.42	90.8
Distribution cables (excluding LV)	0.03	8.3
Distribution other (excluding LV)	0.23	35.6

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.16	11.2
Subtransmission cables	–	–
Subtransmission other	0.09	11.3
Distribution lines (excluding LV)	0.83	63.8
Distribution cables (excluding LV)	0.10	12.2
Distribution other (excluding LV)	0.37	15.2

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	22	524	4.20
Subtransmission cables	–	87	–
Subtransmission other	4		
Distribution lines (excluding LV)	237	2,298	10.31
Distribution cables (excluding LV)	21	1,135	1.85
Distribution other (excluding LV)	134		
Total	418		

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**
Network / Sub-network Name	**Dunedin Sub-network**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

sch ref			
8	**10(i): Interruptions**		
9	**Interruptions by class**	**Number of interruptions**	
10	Class A (planned interruptions by Transpower)	1	
11	Class B (planned interruptions on the network)	420	
12	Class C (unplanned interruptions on the network)	186	
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)	1	
16	Class G (unplanned interruptions caused by another disclosing entity)	–	
17	Class H (planned interruptions caused by another disclosing entity)	–	
18	Class I (interruptions caused by parties not included above)	2	
19	**Total**	610	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	158	28
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)	0.00	0.1
26	Class B (planned interruptions on the network)	0.59	87.1
27	Class C (unplanned interruptions on the network)	1.01	59.3
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)	0.02	0.7
31	Class G (unplanned interruptions caused by another disclosing entity)	–	–
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	0.00	0.0
34	**Total**	1.62	147.2
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	N/A	N/A
38			

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**
Network / Sub-network Name	**Dunedin Sub-network**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

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

40

	Cause	SAIFI	SAIDI
41			
42	Lightning	–	–
43	Vegetation	0.11	8.0
44	Adverse weather	–	–
45	Adverse environment	0.00	0.0
46	Third party interference	0.10	11.2
47	Wildlife	0.01	0.7
48	Human error	0.16	2.2
49	Defective equipment	0.45	26.3
50	Cause unknown	0.18	11.0

51

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

53

	Main equipment involved	SAIFI	SAIDI
54			
55	Subtransmission lines	–	–
56	Subtransmission cables	–	–
57	Subtransmission other	–	–
58	Distribution lines (excluding LV)	0.34	68.2
69	Distribution cables (excluding LV)	0.01	1.2
60	Distribution other (excluding LV)	0.24	17.6

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

62

	Main equipment involved	SAIFI	SAIDI
63			
64	Subtransmission lines	0.07	3.3
65	Subtransmission cables	–	–
66	Subtransmission other	0.12	7.7
67	Distribution lines (excluding LV)	0.48	39.1
68	Distribution cables (excluding LV)	0.02	0.8
69	Distribution other (excluding LV)	0.31	8.4

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

	Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
71				
72	Subtransmission lines	8	144	5.57
73	Subtransmission cables	–	66	–
74	Subtransmission other	2		
75	Distribution lines (excluding LV)	76	735	10.34
76	Distribution cables (excluding LV)	5	324	1.54
77	Distribution other (excluding LV)	79		
78	**Total**	170		

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**
Network / Sub-network Name	**Central Otago and Wanaka Sub-networ**

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

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)	394	
12	Class C (unplanned interruptions on the network)	216	
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)	1	
16	Class G (unplanned interruptions caused by another disclosing entity)	–	
17	Class H (planned interruptions caused by another disclosing entity)	–	
18	Class I (interruptions caused by parties not included above)	2	
19	**Total**	613	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	152	64
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.99	218.6
27	Class C (unplanned interruptions on the network)	2.72	238.5
28	Class D (unplanned interruptions by Transpower)	–	–
29	Class E (unplanned interruptions of EDB owned generation)	–	–
30	Class F (unplanned interruptions of generation owned by others)	0.00	0.5
31	Class G (unplanned interruptions caused by another disclosing entity)	–	–
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	0.02	1.0
34	**Total**	3.73	458.5
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	N/A	N/A
38			

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**
Network / Sub-network Name	**entral Otago and Wanaka Sub-networ**

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.

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

40

	Cause	SAIFI	SAIDI
41			
42	Lightning	0.04	2.5
43	Vegetation	0.56	30.7
44	Adverse weather	0.01	2.1
45	Adverse environment	0.00	0.0
46	Third party interference	0.14	5.5
47	Wildlife	0.11	16.0
48	Human error	0.13	9.9
49	Defective equipment	1.13	123.3
50	Cause unknown	0.61	48.3

51

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

53

	Main equipment involved	SAIFI	SAIDI
54			
55	Subtransmission lines	–	–
56	Subtransmission cables	–	–
57	Subtransmission other	–	–
58	Distribution lines (excluding LV)	0.73	151.7
69	Distribution cables (excluding LV)	0.06	13.3
60	Distribution other (excluding LV)	0.20	53.6

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

62

	Main equipment involved	SAIFI	SAIDI
63			
64	Subtransmission lines	0.38	30.0
65	Subtransmission cables	–	–
66	Subtransmission other	0.08	28.2
67	Distribution lines (excluding LV)	1.40	103.0
68	Distribution cables (excluding LV)	0.33	47.2
69	Distribution other (excluding LV)	0.53	30.0

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

	Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
71				
72	Subtransmission lines	12	301	3.99
73	Subtransmission cables	–	8	–
74	Subtransmission other	2		
75	Distribution lines (excluding LV)	130	1,275	10.20
76	Distribution cables (excluding LV)	10	531	1.88
77	Distribution other (excluding LV)	34		
78	**Total**	188		

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**
Network / Sub-network Name	**Queenstown Sub-network**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

8 **10(i): Interruptions**

sch ref		Number of interruptions
9	**Interruptions by class**	
10	Class A (planned interruptions by Transpower)	–
11	Class B (planned interruptions on the network)	114
12	Class C (unplanned interruptions on the network)	88
13	Class D (unplanned interruptions by Transpower)	–
14	Class E (unplanned interruptions of EDB owned generation)	–
15	Class F (unplanned interruptions of generation owned by others)	–
16	Class G (unplanned interruptions caused by another disclosing entity)	–
17	Class H (planned interruptions caused by another disclosing entity)	–
18	Class I (interruptions caused by parties not included above)	–
19	**Total**	202
20		

sch ref		≤3Hrs	>3hrs
21	**Interruption restoration**		
22	Class C interruptions restored within	75	13
23			

sch ref		SAIFI	SAIDI
24	**SAIFI and SAIDI by class**		
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.55	193.7
27	Class C (unplanned interruptions on the network)	1.85	137.6
28	Class D (unplanned interruptions by Transpower)	–	–
29	Class E (unplanned interruptions of EDB owned generation)	–	–
30	Class F (unplanned interruptions of generation owned by others)	–	–
31	Class G (unplanned interruptions caused by another disclosing entity)	–	–
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	–	–
34	**Total**	2.40	331.4
35			

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2021**
Network / Sub-network Name	**Queenstown Sub-network**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

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

40

		SAIFI	SAIDI
41	**Cause**		
42	Lightning	–	–
43	Vegetation	0.72	56.4
44	Adverse weather	–	–
45	Adverse environment	–	–
46	Third party interference	0.22	13.7
47	Wildlife	0.00	0.1
48	Human error	0.12	8.4
49	Defective equipment	0.23	13.5
50	Cause unknown	0.57	45.4

51

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

53

		SAIFI	SAIDI
54	**Main equipment involved**		
55	Subtransmission lines	–	–
56	Subtransmission cables	–	–
57	Subtransmission other	–	–
58	Distribution lines (excluding LV)	0.24	86.5
69	Distribution cables (excluding LV)	0.06	28.5
60	Distribution other (excluding LV)	0.24	78.7

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

62

		SAIFI	SAIDI
63	**Main equipment involved**		
64	Subtransmission lines	0.17	13.9
65	Subtransmission cables	–	–
66	Subtransmission other	–	–
67	Distribution lines (excluding LV)	1.32	101.4
68	Distribution cables (excluding LV)	0.05	2.9
69	Distribution other (excluding LV)	0.32	19.4

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

		Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
71	**Main equipment involved**			
72	Subtransmission lines	2	79	2.53
73	Subtransmission cables	–	12	–
74	Subtransmission other	–		
75	Distribution lines (excluding LV)	31	288	10.76
76	Distribution cables (excluding LV)	6	278	2.16
77	Distribution other (excluding LV)	21		
78	**Total**	60		

Company Name	Aurora Energy Limited
For Year Ended	31 March 2021

Schedule 14 Mandatory Explanatory Notes

(Guidance Note: This Microsoft Word version of Schedules 14, 14a and 15 is from the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 3 April 2018. Clause references in this template are to that determination)

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.

4. Return on Investment (Schedule 2)

5. 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

The RY21 ROI continues the trend of recent years of being well below the estimate of WACC used to set Aurora Energy's price path. The RY21 ROI is below the 25th percentile of WACC that has been estimated by the Commerce Commission for Information Disclosure purposes. There have been no items reclassified in accordance with clause 2.7.1(2).

Regulatory Profit (Schedule 3)

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

   6.1 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

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

Box 2: Explanatory comment on regulatory profit

Regulatory profit for the year to 31 March 2021 is $9.6m. This represents a $2.3m decrease from the previous year. The decrease was largely related to lower revaluations of $3.9m.

The 'other regulated income' of $0.9m is predominantly income received to reimburse Aurora Energy's operational costs that arise from network damage by the third parties.

Merger and acquisition expenses (3(iv) of Schedule 3)

7. If the EDB incurred merger and acquisitions expenditure during the disclosure year, provide the following information in the box below-

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

   7.2 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 and acquisition costs incurred.

Value of the Regulatory Asset Base (Schedule 4)

8. 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 regulatory asset base (RAB) grew by $49.9m during the year (2020: $42.8m), an increase of $7.1m on the prior year. The main drivers of this were an increase in commissioned assets ($11.8), and found assets ($2.6m), which were partially offset by an increase in depreciation ($3.5m) and lower revaluation gains of $3.9m.

Further information on found assets is contained in Box 1 of Schedule 15.

Regulatory tax allowance: disclosure of permanent differences (5a(i) of Schedule 5a)

9. In the box below, provide descriptions and workings of the material items recorded in the following asterisked categories of 5a(i) of Schedule 5a-

   9.1 Income not included in regulatory profit / (loss) before tax but taxable;

   9.2 Expenditure or loss in regulatory profit / (loss) before tax but not deductible;

   9.3 Income included in regulatory profit / (loss) before tax but not taxable;

   9.4 Expenditure or loss deductible but not in regulatory profit / (loss) before tax.

Box 5: Regulatory tax allowance: permanent differences

The amount of $13,219 relating to 'Expenditure or loss in regulatory profit or (loss) before tax but not deductible' is non-deductible entertainment.

The amount of $1,242,845 relating to 'Expenditure or loss deductible but not in regulatory profit / (loss) before tax' relates to payments for leases that are now classified as right of use (ROU) assets.

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

10. 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)

Temporary timing differences of $1,239,368 recorded in the current disclosure year relate to the tax effect of income spreading over 10 years on customer initiated works ($1,175,817), downward movements in provision for expected credit losses (doubtful debts) ($105,000), and increase in employee entitlements ($168,551).

The deferred tax balance (-$190,000) on found assets of has been included in line 70 "Deferred tax balance relating to assets acquired in the disclosure year".

Further information on found assets is contained in Box 1 of Schedule 15.

Cost allocation (Schedule 5d)

11. 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

Operating costs are all directly attributable to the regulated business with the exception of shared service costs within business support. Shared services costs in RY21 related to information technology were allocated to an unregulated business.

There have been no items reclassified in accordance with clause 2.7.1(2).

Asset allocation (Schedule 5e)

12. 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

Some non-network assets have been allocated to the RAB based on a proxy allocator of employee full-time equivalents. The rationale for the proxy allocated is based on analysis of what the assets were that are shared with a non-regulated business and the key drivers of these assets as determined by management.

In RY21 we identified fibre assets that are used for communication on the Aurora Energy network that had been excluded from the RAB in prior regulatory years. Further information on found assets is contained in Box 1 of Schedule 15.

There have been no items reclassified in accordance with clause 2.7.1(2).

Capital Expenditure for the Disclosure Year (Schedule 6a)

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

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

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

Box 9: Explanation of capital expenditure for the disclosure year

Aurora Energy's Asset Management Plan identifies a program of work consisting of a set of defined projects which are to be undertaken in any regulatory year. These projects are the basis on which the year's disclosed capital expenditure is based. All projects are identified by the capital expenditure classification (renewal, growth and security, reliability, customer connections, asset relocations and non-network). The projects and programmes described in Schedule 6a have been included because they are the projects or programmes within the expenditure category that represent significant portions of expenditure within that category.

Consumer connection capital expenditure, disclosed in 6a(iii), is all connections. Insufficient data is currently captured to align that expenditure with consumer load groups. The listed projects within this schedule are the higher value projects included within the specific reporting categories.

There have been no items reclassified in accordance with clause 2.7.1(2).

Operational Expenditure for the Disclosure Year (Schedule 6b)

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

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

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

14.3 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

For the first year of DPP3, RY21, Aurora invested in its network at levels that exceeded the expenditure allowances for which it was compensated for under the default price-quality path regime. Aurora Energy is committed to extra resourcing to support the ongoing network investment to deliver safe and reliable services to our customers. Significant external costs were also being incurred as Aurora Energy lifted its asset management maturity in advance of a customised price-quality path application that was approved in March 2021.

There have been no material items of atypical expenditure.

There have been no items reclassified in accordance with clause 2.7.1(2).

Variance between forecast and actual expenditure (Schedule 7)

15. 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

Overall, Aurora Energy's total asset expenditure was $7.9m lower than forecast (-11%).

Capital expenditure:

Capital expenditure on consumer connections reflects continuing higher than expected levels of development activity, mainly within the Central Otago subnetwork.

System growth expenditure was lower than forecast largely due to scoping and design delays to the following projects:

- *new capacitors in the Upper Clutha area;*
- *extension of the Cardrona 11kV feeder cable; and*
- *reconfiguration of the Arrowtown zone substation.*

Asset replacement and renewal expenditure variance is largely related to delays to the following project and programme:

- *Berwick to Outram B line upgrade; and*
- *renewal of 6.6/11kV overhead conductor on the Dunedin subnetwork.*

Asset relocations variance was minimal.

Total reliability, safety and environment was higher than forecast due to additional expenditure relating to seismic strengthening of zone substations on the network.

Non-network capex was lower than expected due to a delay in commencing our Asset Management System project.

Operational expenditure:

Service interruptions and emergencies expenditure was lower than forecast predominantly due to a refinement of our internal processes, which has resulted in a more precise allocation of expenditure associated with fault responses to operational and capital expenditure.

Vegetation management expenditure variance was minimal.

Routine and corrective maintenance and inspection expenditure variance is due to a catch up of prior year work and the completion of the RY21 programme.

Information relating to revenues and quantities for the disclosure year

16. In the box below provide-

    16.1 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

16.2 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
<u>Total Revenue:</u> *The total delivery revenue target was $97.374 million (2020 pricing methodology).* *In Schedule 8 (Total Network), we have reported total delivery revenue of $98.409 million. This is a difference of $1.035 million (1.1%) above target. It is generally expected that total billed line charge revenue for an assessment period will be different from target revenue due to variation in connection numbers and energy demand.* *<u>Residential Revenue:</u>* *In this assessment period, the volume of energy delivered to Residential consumers (the only consumer groups with volume-based pricing) increased from the prior year (by 1.8%). Energy delivered to Residential connections for the year ended 31 March 2021 was 629.1GWh compared with 618.3GWh last year.* *The average number of Residential connections increased by 1.2% during the assessment period. The average number of residential connections for the year ended 31 March 2021 was 77,158, compared with 76,232 for the year ended 31 March 2020.* *The average energy use per Residential consumer in this assessment period has increased from 8,110kWh for the year ended 31 March 2020 to 8,153kWh in this assessment period.* *<u>General Revenue:</u>* *The average number of General connections, which are priced predominantly on the basis of demand and capacity, increased from 14,835 in RY20 to 14,926 in this assessment period (0.6%). This increase was smaller than previous years, likely reflecting the impact of the Covid 19 pandemic.* *The distinction between Residential and General connections is explained in section 4 (page 33) of Aurora Energy's Use-of-System Pricing Methodology, available from http://www.auroraenergy.co.nz/disclosures/pricing/pricing-methodologies.*

Network Reliability for the Disclosure Year (Schedule 10)

17. 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

Supplementing the definitions contained in the Electricity Distribution Information Disclosure Determination 2012, the following categorisations are disclosed:

- *Overhead (subtransmission and distribution) includes poles, stay-wires, crossarms, braces, insulators, conductor (including droppers and connectors), binders and ties.*
- *Underground (subtransmission and distribution) includes cable, mounting brackets, terminations and potheads.*
- *Other (subtransmission and distribution) includes HV fuses (including fuse operation), lightning arrestors, transformers, switchgear, switching and control errors.*
- *Faults include unplanned events <1 minute, and events not resulting in loss of supply to a consumer, which would otherwise be excluded from consideration as an interruption. This, in our view, meets the broad definition of "Fault" given in the Determination – "a physical condition that causes a device, component or network element to fail to perform in the required manner".*

Specific commentary on matters relating to Aurora Energy's reliability performance for the disclosure year is contained in Aurora Energy's Annual Compliance Statement (2021), available from https://www.auroraenergy.co.nz/disclosures/price-quality-path/.

Insurance cover

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

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

    18.2 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

Insurance cover has been obtained/is in place for zone substations, both for the buildings and the plant and equipment contained within them. The material damage (including flood, earthquake etc.) cover for the zone substations and associated equipment is on a replacement cost basis. Material Damage Insurance cover has been obtained for some distribution assets including distribution substations, transformers and switches.

Other distribution assets including distribution poles, lines and cables etc. are not currently insured due to the unavailability of commercial policy terms, geographical spread, the lower value of the individual assets and the reduced likelihood of significant loss on any less than region wide event.

Amendments to previously disclosed information

19. 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:

    19.1 a description of each error; and

    19.2 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
There have been no amendments to previously disclosed information.

Company Name	Aurora Energy Limited
For Year Ended	31 March 2021

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: Found Assets

The fibre network was originally constructed from mid-2009 to 2011 in the lead up to the Government's (Crown Fibre Holdings) Ultra-Fast Broadband roll-out initiative. At that time Delta/Aurora Energy submitted an offer to partner with the Government on the deployment of an ultra-fast broadband network in Dunedin, however the bid was ultimately unsuccessful, and the Dunedin area became part of Telecom's nationwide network build.

In recent years the fibre network has continued to serve a relatively small and declining number of external customers, however the more strategic and predominant use of these assets, over the past five years, has been their successful deployment as critical components of our zone substation communications network in Dunedin. The historical network has been leveraged to connect 12 critical zone substations at Halfway Bush, Smith Street, South City, Anderson Bay, St Kilda, Corstorphine, Green Island, Kaikorai Valley, North City, Ward Street, Willowbank and North East Valley, with our Network Operating Centre (control room) in Halsey Street, Dunedin.

This communications platform is now integral to the means by which we operate and manage our electricity network assets in Dunedin.

The network comprises of ducting/high speed broadband fibre and our assessment is that at least 75.5% of the network is utilised for communications between the Dunedin zone sub-station sites.

The fibre network has previously been excluded from RAB until 31 March 2021. The book value at this time was $3.42m and $2.58m was allocated to RAB. The fibre network had a tax book value of $2.52m and $1.90m was added to the regulatory tax asset valuation (RTAV). The deferred tax balance on found assets equated to -$0.19 m (($1.90-2.58) x 28%).

Box 2: Incremental Rolling Incentive Scheme (IRIS)

Aurora Energy is subject to an incremental rolling incentive scheme (IRIS) under price-quality regulation. The IRIS seeks to incentivise EDBs to control expenditure by penalising them if they exceed expenditure allowances, determined by the Commerce Commission, and rewarding them if expenditure is below the allowance.

In the second DPP period, Aurora Energy exceeded its operational expenditure (opex) allowances in several years, as it sought to address a maintenance backlog. This has resulted in a significant IRIS penalty of $18.470 million, which must be paid back to customers in the 2021 pricing year by reducing prices. This adjustment is shown in Schedule 2.

IRIS allowances are a designated recoverable cost in price-quality regulation and are therefore recovered through pass-through prices, rather than distributions prices; however, our pricing methodology does not explicitly allow for allocation of very large incentive amounts. Accordingly, we have had to exercise judgement as to how the penalty is allocated to pricing areas and load groups.

We have decided to allocate the IRIS incentive to pricing areas and load groups in proportion to last year's revenue recoveries in those areas and groups. We consider this is the most equitable way of allocating the incentive – customers who paid greater charges in the past, when Aurora Energy's expenditure allowances were being exceeded, should receive a greater share of the money being returned.

Having allocated to pricing areas and load groups, we then needed to decide, for customer on General pricing plans[1], whether the incentive should be passed through in the Capacity or CPD component of pass-through prices (or both). We decided to pass the incentive to customers through the Capacity component since the CPD price component is avoidable (or able to be reduced) for consumers who can eliminate or reduce their demand during control periods, whereas the Capacity component is not avoidable. This ensures that all customers receive a share of the money being returned.

[1] This consideration is not required for customers on Residential pricing, since there is only one pass-through price component.

Box 3: Disclosure by sub-network

Following feedback received from the Commerce Commission early in 2021, we have revised our approach to sub-network reporting. While our previous disclosures have complied with the Electricity Distribution Information Disclosure Determination 2012 (Determination), it has been noted that there are definitional inconsistencies between the Determination and the Commission's comments in its Information Disclosure for Electricity Distribution Businesses and Gas Pipeline Businesses: Final Reasons Paper (Reasons Paper). Consistent with the additional definitions given in the Reasons Paper, we are now reporting our sub-networks in a manner that aligns to our pricing regions. This means for RY21, we have reported the following sub-networks for schedules 8, 9a, 9b, 9c, 9e and 10:

- *Dunedin;*
- *Central Otago and Wanaka; and*
- *Queenstown.*

The change in subnetwork definition has impacted our Schedule 9a reporting (which requires us to report asset quantities at the start of RY21) both on a total network basis and sub-network basis. Historically, we have reported sub-network information for Dunedin and Central Otago. We therefore do not have opening quantities for the Central Otago & Wanaka and Queenstown sub-networks that correlate to RY20's year-end quantities. For this year's disclosures, we have had to rerun our RY20 data for our sub-networks and for our total network. Despite all reasonable endeavours, at the time of preparing our disclosures each year, we cannot guarantee that all asset additions and removals for the disclosure year have been processed within our GIS system, owing to (1) a need to have a firm cut-off date to *allow preparation of disclosures, (2) GIS workloads and (3) occasional late delivery of completion packages by contractors. This means that in any given regulatory year there will be a small number of asset additions and removals reported that relate to the previous regulatory year. Because we have rerun our RY20 data for the subnetworks, and our total network, the opening figures differ in aggregate from those reported in RY20.*

Box 4: Recording of successive interruptions for the purposes of reliability reporting in Schedule 10

Aurora Energy received an exemption from the Commerce Commission, issued on 17 May 2021, regarding the disclosure and auditing of reliability information within Schedule 10. The information in this box is disclosed in accordance with paragraphs 6 and 7 of that exemption.

Treatment of successive interruptions between disclosure years 2021 and 2020: *We have treated successive interruptions in the same way for the 2021 disclosure year as we did for the 2020 disclosure year.*

Process applied in recognising successive interruptions following an initial outage: *We have recognised any stage of an outage event that interrupts consumers for a second time, or interrupts 'new' consumers as a result of fault finding, as an additional interruption, strictly in line with the definition of "interruption" included in the Electricity Distribution Information Disclosure Determination 2012.*

Box 5: Wash-ups

Aurora Energy calculated a "Wash-up Amount" (as that term is defined in the Electricity Distribution Services Default Price-Quality Path Determination 2020), of ($1.184 million). This amount does not currently fit within the definitions contained within the Electricity Distribution Information Disclosure Determination 2012 and is therefore not reflected within these disclosures.

1 Description of the connection between Aurora Energy and its related parties

Pursuant to clause 2.3.8 of the Electricity Distribution Information Disclosure Determination 2012 (Determination), the following table describes the connection between Aurora Energy and the related parties with which it has had related party transactions during the year ended 31 March 2021.

RELATED PARTY	RELATIONSHIP BETWEEN AURORA AND THE RELATED PARTY	PRINCIPAL ACTIVITIES OF THE RELATED PARTY	TOTAL ANNUAL EXPENDITURE INCURRED BY AURORA ENERGY WITH THE RELATED PARTY
Delta Utility Services Limited (Delta)	Aurora Energy and Delta are related by virtue of the fact that DCHL is the ultimate holding company of both Aurora Energy and Delta. DCHL is the sole shareholder of Delta.	Delta is a multi-utility services contractor providing a range of electrical and other services to local authority and private sector clients. The principal activities of Delta are the management, construction, operation and maintenance of electricity and metering infrastructure assets, and the provision of environmental contracting and related services.	$49,362,000 This expenditure is in relation to operating and capital expenditure incurred by Aurora Energy with Delta.
Dunedin City Holdings Limited (DCHL)	DCHL is the sole shareholder, and ultimate holding company of Aurora Energy.	The principal activity of DCHL is to provide leadership and oversight of its subsidiary and associated companies on behalf of the ultimate shareholder, the DCC. This involves undertaking on-going oversight of subsidiaries' financial and non-financial performance. In carrying out this function the DCHL Board assesses the risks of the activities undertaken by its subsidiaries in the light of the financial sustainability needs of the DCC. Building opportunities for collaborative enterprise and capturing group synergies is an objective of DCHL.	$50,000 This expenditure is in relation to management fees that are paid by each subsidiary company, of which Aurora is one, to DCHL.
Dunedin City Council (DCC)	The DCC is the sole shareholder of DCHL.	The DCC is the territorial authority for the Dunedin area in accordance with the Local Government Act 2002.	$790,000 This expenditure is primarily in relation to local rates that are payable to the DCC.

2 Summary of Aurora Energy's current procurement policy

Pursuant to clause 2.3.10 of the Determination, the following is a summary of Aurora Energy's current policy in respect of the procurement of assets or goods or services from any related party.

2.1 Introduction

Aurora Energy is an electricity distribution business (EDB) which owns and operates electricity distribution networks in Dunedin and Central Otago (including Queenstown Lakes). We own and manage a wide range of assets that are used to transport electricity from the national grid, owned by Transpower, to end-use consumers.

Our role is to ensure the safety and resilience of the network, supplying a reliable electricity service to close to 90,000 homes, farms and businesses throughout the regions we serve.

We are regulated by the Commerce Commission in relation to both the quality of the electricity we supply and the revenue that we are able to generate.

As a result of the regulated constraints within which we operate, it is important for us to ensure that our procurement practices are efficient, controlled and robust. This will result in lower costs to our business, which in turn results in lower costs to consumers in the long term. It will also ensure that we are procuring the right goods and services for our network.

This section 2 summarises briefly the procurement principles that we adopt when procuring goods and services and the procurement methods that we employ.

2.2 Procurement Principles

1. ***Plan and manage for great results:*** we take a strategic approach by considering the long-term benefits, economic impacts and consequences of procurement decisions for Aurora Energy. This means planning procurement requirements in advance, choosing the appropriate procurement method and ensuring we have appropriately skilled and experienced staff to lead procurement activities;
2. ***Be fair to all suppliers:*** we will ensure that all eligible suppliers have a fair opportunity to participate in procurements by encouraging capable suppliers to respond, treating all suppliers equally and making it easy to deal with us;
3. ***Get the right supplier:*** while we will not always choose the lowest price, we will choose the right supplier who can deliver what we need, at a fair price and on time. We need to consider safety on, and reliability of, our network, durability, specialised skills that may be required, availability of resources in the current labour market and the sustainability of suppliers on our network;
4. ***Get the best deal for everyone:*** we will seek the best possible outcome taking into account the total cost of ownership over the whole life of the asset. This means balancing financial and non-financial criteria, balancing risks with benefits, employing robust evaluation processes and working together with suppliers to make ongoing savings and improvements.
5. ***Play by the rules:*** we must ensure that we are transparent, accountable and acting at all times lawfully by being consistent, adhering to best practice, being accurate and unbiased, acting with integrity and good faith and in accordance with the law.

When procuring goods and services, we may not always choose the lowest price, instead we may, having adhered to the above principles, make robust and sound commercial decisions to ensure that we are getting the best commercial outcome.

When determining the appropriate method of procurement it is important to consider the criticality of the goods or services to be supplied and the risks or business impact of non-supply. The identification of low value, low risk goods and services versus high value, highly critical goods or services helps to inform the appropriate procurement method to use.

2.3 Procurement methods

We employ the following procurement methods in the course of our business:

- ***direct procurement***: in certain circumstances it will be appropriate to procure goods and services directly from one supplier, for example where the goods and services are low in both value and risk, or where the goods and services are both high in value and risk. This may also be an appropriate method of procurement where the circumstances are unforeseen and an urgent response is required;
- ***written quotations:*** this is appropriate where the good or service being procured is lower in value, but higher in risk;
- ***tender:*** where the good or service being procured is high in both value and risk, a formal tender process (either open or selective) may be conducted). It may be necessary for tender participants to be approved by Aurora Energy to work on our distribution network, and to design and construct additions to the network. Please contact us to become an "*Aurora Authorised Contractor*";
- ***panel arrangement:*** for certain works, we have a panel arrangement in place with several contractors who operate on our distribution network. We adopt this approach to ensure that we are able to deliver our works programme and have the capacity and capabilities on our network to do so;
- ***All-of-Government contract:*** Aurora Energy is a party to several All-of-Government contracts and benefits from the bulk-purchasing power associated with those contracts; and
- ***Group purchasing:*** Aurora Energy is a subsidiary of Dunedin City Holdings Limited and in certain situations has the ability to use the bulk-purchasing power associated with that group.

The following table provides a representative example of the procurement methods that we employ in relation to each category of expenditure.

TYPE OF EXPENDITURE	PROCUREMENT METHODS
OPERATING EXPENDITURE	
Non-network operating expenditure: • business support • system operations and network support	• Direct procurement – low value, low risk • Written quotes • All-of-Government • Group purchasing
Network operating expenditure: • routine and corrective maintenance and inspection • vegetation management • asset replacement and renewal • service interruptions and emergencies	• Panel arrangement • Direct procurement
CAPITAL EXPENDITURE	
Customer initiated works	• Customer-led (a customer or developer may use their own designer and builder provided that they are an Aurora Authorised Contractor).
Network and non-network capital expenditure: • system growth • reliability, safety and environment • asset replacement and renewal • asset relocations • non-system fixed assets (ie IT systems, asset management systems, office buildings and furniture, motor vehicles).	• Panel arrangement • Direct procurement • Tender • All-of-Government

3 Application of procurement policy

Pursuant to clause 2.3.12 of the Determination, the following illustrates Aurora Energy's application of its current policy in respect of the procurement of assets or goods or services from a related party.

3.1 Description of application of Aurora Energy's current procurement policy for the procurement of assets or goods or services from a related party in practice

Historically, Delta undertook both asset management and service provider roles on behalf of Aurora Energy, the asset owner. Following an independent review in early 2017, our shareholder, DCHL, sought formal separation of the two businesses. From 1 July 2017, Aurora Energy became a standalone regulated asset owner and manager, with accountability for providing electricity distribution services.

The separation reinforces that Aurora Energy has a clear responsibility to seek the best available services from the market on behalf of its customers. In order to achieve this, we have introduced contestable performance-based service delivery arrangements with two additional field service providers - Unison Contracting based in Dunedin, and Connetics based in Central Otago. Our new contracts with Unison and Connetics took effect from 1 April 2019. Unison Contracting and Connetics appointment as contractors on our network sees them carrying out renewal, maintenance and development work.

This new arrangement between the three contractors has been consolidated in the field services agreement (FSA) that we have entered with each contractor. Each FSA has an initial term of three years, which provides us with an opportunity on a regular basis to refresh and test our contractual relationship.

Given our specialised needs as an electricity distributor, while we acknowledge that it is important that we are clear about our needs, we need to choose suppliers who can deliver what we need, at a fair price and on time. We need to consider the safety of both consumers and contractors on our network, our ability to provide a reliable supply of electricity to consumers on the network, specialised skills that are required to deliver the work we require, the availability of resources in the current labour market and the sustainability of specialist skill sets within our network and the viability of incumbent service providers.

Traditionally Delta has delivered a large portion of our network operational and capital expenditure works. The skills required to operate on, and knowledge of, our network that it has gained over years, together with the fact that there has traditionally not been any other service provider on the network means that Delta remains, at this point in time, the contractor on our network that is best placed to perform certain types of work, for example first response and fault repair and vegetation management. However, with Unison and Connetics having now established themselves as additional service providers, we need to continue to monitor the application of our procurement policies to ensure that our procurement practices remain efficient. We also need to ensure that those practices are providing the means and incentives for Unison and Connetics to offer alternative solutions and further embed themselves as long-term contractors on our network and to be able to offer Aurora Energy alternative solutions to works delivery. We also understand the need to provide Unison and Connetics with sufficient work to ensure their viability on our network.

In addition to our FSA arrangements, we also operate an external tender market into which works are submitted each year and approved contractors (in addition to our FSA partners) are invited to tender. Delta, plus the other FSA providers and other approved contractors participate in this external tender market.

We also have established an Engineering Services Consultancy Panel to provide specific electricity design services for asset replacement and renewal, and growth projects. The panel consists of engineering consulting and design companies, including Delta and Connetics.

Together with the other approved contractors on our network, Delta provides customer connection services at market value rates. Under our new customer initiated works model, customers or developers are able to choose their own designer and builder from a panel of approved contractors operating on our network.

Internally, staff responsibilities and purchasing controls are managed by delegated financial authorities and claim verification procedures. Our procurement activities are also overseen by the Audit and Risk Committee of the Board.

Our procurement policy details the methods that we use to procure goods and services from any party, whether they be related or not, and those methods are contained in the summary at section 2 above.

3.2 Policies or procedures that require or have the effect of requiring a consumer to purchase assets or goods or services from a related party

Aurora does not have policies or procedures that require a consumer to purchase goods or services from a related party. Aurora has a selection of approved contractors operating on the network, from which customers can choose from.

3.3 Representative example transactions from the year ended 31 March of how the current policy for the procurement of assets or goods or services from a related party is applied in practice, including separate representative example transactions where Aurora Energy has applied the policy significantly differently between expenditure categories

EXPENDITURE CATEGORY	REPRESENTATIVE EXAMPLE	PROCUREMENT METHOD	HOW AND WHEN ARM'S LENGTH TERMS LAST TESTED
Operating expenditure			
Service interruptions and emergencies	Response to a fault that was caused by a broken power pole	Services were procured through the negotiated FSA	The terms upon which services are provided, and the rates at which services are charged, were tested in 2018 during the development of the three FSAs.
Vegetation management	Liaison and cutting on specified feeders	Services were procured through the negotiated FSA	The terms upon which services are provided, and the rates at which services are charged, were tested in 2018 during the development of the three FSAs.
Routine and corrective maintenance and inspection	Inspection of a ring main unit	Services were procured through the negotiated FSA	The terms upon which services are provided, and the rates at which services are charged, were tested in 2018 during the development of the three FSAs.
System operations and network support	Provision of logistic services, including provision of storage facilities	Services were procured through the negotiated FSA	The terms upon which services are provided, and the rates at which services are charged, were tested in 2018 during the development of the three FSAs.
Business support	Rental of office premises	Direct procurement	Market lease rates were tested on 29 March 2018 when an independent valuation report was obtained.
Capital expenditure			
Asset replacement and renewal	Replacement of conductor and poles	Services were procured through the negotiated FSA	The terms upon which services are provided, and the rates at which services are charged, were tested in 2018 during the development of the three FSAs.

EXPENDITURE CATEGORY	REPRESENTATIVE EXAMPLE	PROCUREMENT METHOD	HOW AND WHEN ARM'S LENGTH TERMS LAST TESTED
	Upgrade of overhead sub-transmission poles and conductor	Tender	The terms were last tested on 27 November 2020.
Asset relocations	Replacement of overhead network with underground cables	Direct procurement	The terms upon which services are provided, and the rates at which services are charged, were evaluated against prices charged by the contractor, and other contractors, for similar works. The terms were last tested on 24 September 2020.
Reliability, safety and environment	Installation of voltage regulators	Services were procured through the negotiated FSA	The terms upon which services are provided, and the rates at which services are charged, were tested in 2018 during the development of the three FSAs.
Non-network assets	Modification of container at training facility	Direct procurement	Not tested.

4 Map of anticipated network expenditure and network constraints

Pursuant to clauses 2.3.13 to 2.3.16 of the Determination, the following tables and associated maps provide detail on Aurora Energy's 10 largest operational and capital expenditure projects in the AMP planning period.

4.1 Top 10 operational and capital expenditure projects

The following tables and corresponding maps identify our largest anticipated operational and expenditure projects on our network in the AMP planning period. The legends contained on the maps of our subnetworks correspond to the project number in each table.

4.1.1 Operational expenditure projects

In relation to operational expenditure, we have four main programmes of work that affect the whole of our network:

- preventive maintenance;
- reactive maintenance;
- vegetation management; and
- corrective maintenance.

We have included details of each of these programmes in the table below and have identified, for preventive and corrective maintenance, those sub-programmes that sit within each of those that contribute to our ten largest operational expenditure programmes.

DESCRIPTION OF THE PROJECT (INCLUDING ANY POSSIBLE FUTURE NETWORK OR EQUIPMENT CONSTRAINT THAT THE PROJECT ADDRESSES)		LIKELY TIMING OF THE PROJECT	LIKELY VALUE OF THE PROJECT	LOCATION OF THE PROJECT	CONTRACTUAL STATUS
Operational expenditure					
1.	**Preventive Maintenance** This programme encompasses routine maintenance activities including testing, inspections, condition assessments and servicing. We have incorporated high level and lower level programmes (where possible) into the top 10 list to show visibility of high value works of similar type. We have identified our likely spend over the AMP planning period at a high programme level, while	RY22-31	$60.9 million	Total network	This programme of works is covered by three FSAs, each of which have a three year term from 1 April 2019 to 31 March 2022. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers.

DESCRIPTION OF THE PROJECT (INCLUDING ANY POSSIBLE FUTURE NETWORK OR EQUIPMENT CONSTRAINT THAT THE PROJECT ADDRESSES)		LIKELY TIMING OF THE PROJECT	LIKELY VALUE OF THE PROJECT	LOCATION OF THE PROJECT	CONTRACTUAL STATUS
	each lower level programme reflects how that expenditure is allocated in RY22.				
1a.	**Pole Inspections** This programme of works encompasses the preventive inspection of poles on the Aurora Energy network.	RY22	$1.8 million	Total network	This programme of works is covered by three FSAs, each of which have a three year term from 1 April 2019 to 31 March 2022. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers.
1b.	**RMU Preventive Maintenance** This programme of works encompasses the carrying out of preventive maintenance on Aurora Energy's RMUs.	RY22	$1.0 million	Total network	This programme of works is covered by three FSAs, each of which have a three year term from 1 April 2019 to 31 March 2022. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers.
1c.	**Zone Substation Preventive Maintenance** This programme of works encompasses the carrying out of preventive maintenance in Aurora Energy's zone substations.	RY22	$0.8 million	Total network	This programme of works is covered by three FSAs, each of which have a three year term from 1 April 2019 to 31 March 2022. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers.
1d.	**Overhead Conductor Inspections** This programme of works encompasses the carrying out of preventive inspections on Aurora Energy's overhead conductors.	RY22	$0.5 million	Total network	This programme of works is covered by three FSAs, each of which have a three year term from 1 April 2019 to 31 March 2022. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers.
1e.	**Distribution Transformer Inspections**	RY22	$0.4 million	Total network	This programme of works is covered by three FSAs, each of which have a

DESCRIPTION OF THE PROJECT (INCLUDING ANY POSSIBLE FUTURE NETWORK OR EQUIPMENT CONSTRAINT THAT THE PROJECT ADDRESSES)		LIKELY TIMING OF THE PROJECT	LIKELY VALUE OF THE PROJECT	LOCATION OF THE PROJECT	CONTRACTUAL STATUS
	This programme of works encompasses the carrying out of preventive inspections on Aurora Energy's distribution transformers.				three year term from 1 April 2019 to 31 March 2022. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers.
1f.	**LV Enclosure Inspections** This programme of works encompasses the carrying out of preventive inspections on Aurora Energy's LV enclosures.	RY22	$0.2 million	Total network	This programme of works is covered by three FSAs, each of which have a three year term from 1 April 2019 to 31 March 2022. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers.
2.	**Reactive Maintenance** Expenditure related to unplanned interruptions to the supply of electricity through the Aurora Energy network and emergency events where a fault has occurred, require response by field-based contractors on our network.	RY22-31	RY22-31: $43.8 million RY22: $4.7 million	Total network	This programme of works is covered by three FSAs, each of which have a three year term from 1 April 2019 to 31 March 2022. One of the FSAs is with Delta, a related party. Under the FSAs, this programme of works is primarily contracted to a related party, Delta, however two other contractors on our network, to whom we are not related, are contracted to provide additional resource for service interruptions and emergencies.
3.	**Vegetation Management** Our vegetation management programme includes identification, inspection and assessment of vegetation growing near Aurora Energy's network, notification and liaison with customers and the carrying out of preliminary and physical works.	RY22-31	RY22-31: $38.9 million RY22: $5.1 million	Total network	This programme of works is covered by three FSAs, each of which have a three year term from 1 April 2019 to 31 March 2022. One of the FSAs is with Delta, a related party. Under the FSAs, this programme of works is contracted exclusively to Delta.

DESCRIPTION OF THE PROJECT (INCLUDING ANY POSSIBLE FUTURE NETWORK OR EQUIPMENT CONSTRAINT THAT THE PROJECT ADDRESSES)		LIKELY TIMING OF THE PROJECT	LIKELY VALUE OF THE PROJECT	LOCATION OF THE PROJECT	CONTRACTUAL STATUS
4.	**Corrective Maintenance** Primarily involves remediating defects, by replacing components or minor assets, or undertaking repairs. Corrective work may be identified during preventive maintenance or fault response. Programmes 4a and 4b below are encompassed within this category of expenditure.	RY22-31	RY22-31: $27.6 million RY22: $3.8 million	Total network	This programme of works is covered by three FSAs, each of which have a three year term from 1 April 2019 to 31 March 2022. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers.
4a.	**Pole Straightening** This programme of work encompasses the straightening of leaning poles that are otherwise in good health and don't require replacement.	RY22	RY21: $0.2 million	Total network	This programme of works is covered by three FSAs, each of which have a three year term from 1 April 2019 to 31 March 2022. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers.
4b.	**Possum and Cable Guard Retrofit Programme** This programme of work encompasses the retrofitting of possum guards and cable guards on the Aurora network.	RY22-26	RY22-26: $1.8 million RY22: $0.3 million	Total network	This programme of works is covered by three FSAs, each of which have a three year term from 1 April 2019 to 31 March 2022. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers.

4.1.2 Capital expenditure projects

In relation to capital expenditure, we have identified our largest programmes of work. These affect the whole of our network, however, we have identified, where relevant, the largest projects that form a part of that programme, which can be easily identified as affecting a specific part of the network.

DESCRIPTION OF THE PROJECT (INCLUDING ANY POSSIBLE FUTURE NETWORK OR EQUIPMENT CONSTRAINT THAT THE PROJECT ADDRESSES)		LIKELY TIMING OF THE PROJECT	LIKELY VALUE OF THE PROJECT	LOCATION OF THE PROJECT	CONTRACTUAL STATUS
Capital expenditure					
1.	**Pole Replacement** This is an ongoing programme of work to replace poles on a condition basis. The replacements involve entire pole assemblies (with crossarms) and may include replacement of pole mounted equipment such as distribution transformers if these are also assessed as being at end of life.	RY22-31	$80.2 million	Total network	This programme of works is covered by three FSAs, each of which have a three year term from 1 April 2019 to 31 March 2022. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers.
2.	**Zone Substation Renewals** This is a programme of renewal projects that we plan to undertake at specific zone substations due to assets that have been identified as being in poor condition and having reached end-of-life. Items 6a through 6d describe the four most significant of these renewal projects.	RY22-31	$76.7 million	Specific zone substations located across the network	Currently not indicated for supply by a related party.
2a.	**Andersons Bay Substation Rebuild** The equipment contained in the Andersons Bay substation is near-end-of-life and requires renewal. The optimum solution is for the substation to be rebuilt on the existing site.	RY22	$5.3 million	Andersons Bay, Dunedin	Currently not indicated for supply by a related party.
2b.	**Mosgiel Transformer Replacement and 33 kV Outdoor-Indoor Conversion** The equipment contained in the Mosgiel substation is near-end-of-life and requires renewal. This project involves replacing the power transformers and replacing the 33 kV outdoor switchyard with a new switchroom building to house a new 33 kV switchboard.	RY26-27	$7.5 million	Mosgiel, Dunedin	Currently not indicated for supply by a related party.
2c.	**Green Island Substation Rebuild** The equipment contained in the Green Island substation is near-end-of-life and requires renewal.	RY23-24	$6.2 million	Green Island, Dunedin	Currently not indicated for supply by a related party.

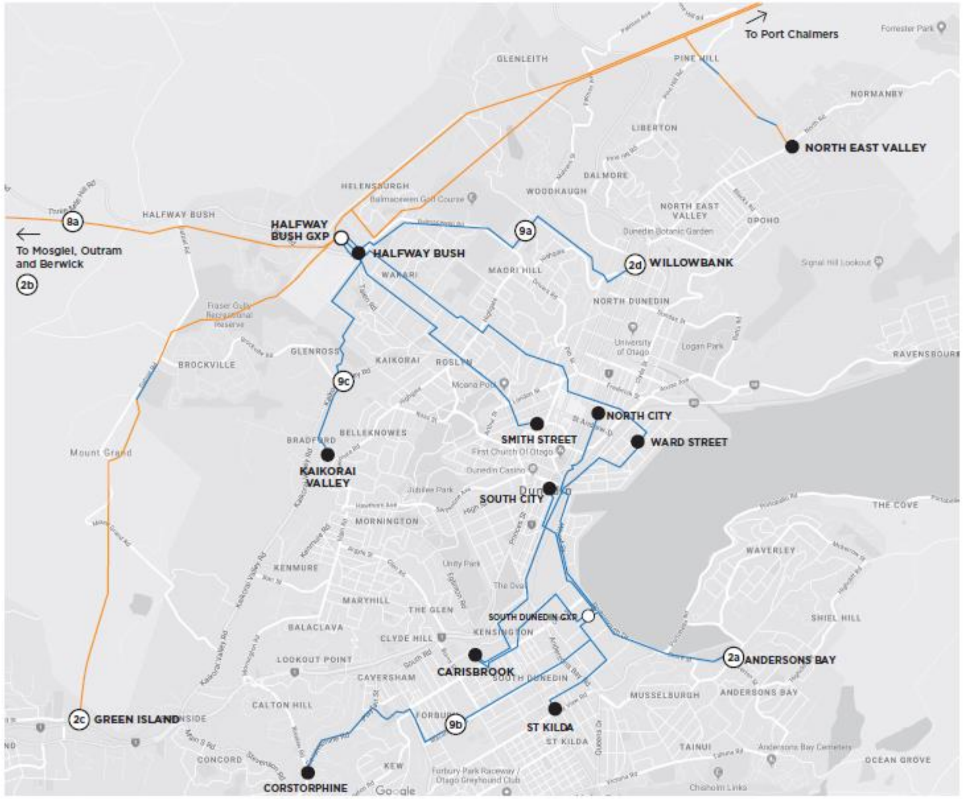
DESCRIPTION OF THE PROJECT (INCLUDING ANY POSSIBLE FUTURE NETWORK OR EQUIPMENT CONSTRAINT THAT THE PROJECT ADDRESSES)		LIKELY TIMING OF THE PROJECT	LIKELY VALUE OF THE PROJECT	LOCATION OF THE PROJECT	CONTRACTUAL STATUS
	The optimum solution is for the substation to be rebuilt on the existing site.				
2d.	**Willowbank Substation Renewal** The equipment contained in the Willowbank substation is near-end-of-life and requires renewal. The optimum solution involves the replacement of the 6.6 kV switchboard and the power transformers.	RY27-28	$5.9 million	Willowbank, Dunedin	Currently not indicated for supply by a related party.
3.	**Crossarm Replacement** This is an ongoing programme of work to replace crossarms on a condition basis.	RY22-31	$63.2 million	Total network	This programme of works is covered by three FSAs, each of which have a three year term from 1 April 2019 to 31 March 2022. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers.
4.	**Distribution Conductor Replacement** This is an ongoing programme of work to replace distribution conductor that has reached end-of-life.	RY22-31	$55.8 million	Total network	This programme of works will likely be provided by a mix of FSAs, each of which have a three year term from 1 April 2019 to 31 March 2022, and competitive tender. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
5.	**Pole Mounted Distribution Transformer Replacement** This is an ongoing programme of work to replace distribution transformers that have reached end-of-life. It includes pole mount to ground mount conversions of large two pole substations, which are not seismically qualified.	RY22-31	$33.1 million	Total network	This programme of works is covered by three FSAs, each of which have a three year term from 1 April 2019 to 31 March 2022. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers.

DESCRIPTION OF THE PROJECT (INCLUDING ANY POSSIBLE FUTURE NETWORK OR EQUIPMENT CONSTRAINT THAT THE PROJECT ADDRESSES)		LIKELY TIMING OF THE PROJECT	LIKELY VALUE OF THE PROJECT	LOCATION OF THE PROJECT	CONTRACTUAL STATUS
6.	**LV Conductor Replacement** This is an ongoing programme of work to replace LV conductor that has reached end-of-life.	RY22-31	$34.5 million	Total network	This programme of works is covered by three FSAs, each of which have a three year term from 1 April 2019 to 31 March 2022. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers.
7.	**Ground Mounted Switchgear Replacements** This is an ongoing programme of work to replace ground mounted switchgear that has reached end-of-life.	RY22-31	$24.1 million	Total network	This programme of works is covered by three FSAs, each of which have a three year term from 1 April 2019 to 31 March 2022. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers.
8.	**Subtransmission Conductor Replacement** This is an ongoing programme of work to replace subtransmission conductor that has reached end-of-life. The programme includes one significant renewal project that is described below in Item 12a.	RY22-31	$11.9 million	Total network	This programme of works will likely be provided by a mix of FSAs, each of which have a three year term from 1 April 2019 to 31 March 2022, and competitive tender. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
8a.	**Halfway Bush to Waipori 33kV Line Replacement** This project sees the rebuild of the three Waipori subtransmission overhead pole line circuits from Halfway Bush to Berwick with two higher capacity circuits, which started in RY21. Timing for later stages will depend on condition profiles of poles on these circuits compared to poles in other areas of the network.	RY22-24	$8.2 million	Halfway Bush, Dunedin to Berwick	First stage of project (replacement of B Line) commenced in RY21 with Delta, a related party, after a competitive procurement process. Future stages (replacement of A Line and deconstruction of C Line) are currently not indicated for supply by a related party.

DESCRIPTION OF THE PROJECT (INCLUDING ANY POSSIBLE FUTURE NETWORK OR EQUIPMENT CONSTRAINT THAT THE PROJECT ADDRESSES)		LIKELY TIMING OF THE PROJECT	LIKELY VALUE OF THE PROJECT	LOCATION OF THE PROJECT	CONTRACTUAL STATUS
9.	**Subtransmission Cable Replacements** This is a programme involving the renewal of specific subtransmission cables on our Dunedin network that are in poor condition and have reached end-of-life. Items 13a, 13b and 13c below describe three of the most significant projects.	RY22-31	$20.3 million	Dunedin	Currently not indicated for supply by a related party.
9a.	**Willowbank Cable Replacement and Switchboard** This project involves the installation of a 33 kV switchboard at the Willowbank Substation and the replacement of the existing Halfway Bush to Willowbank gas filled, PILC, underground, 33 kV cables. It forms a part of our plan to gradually transition to a meshed sub-transmission network in the Dunedin CBD.	RY27-28	$7.8 million	Willowbank, Dunedin	Currently not indicated for supply by a related party.
9b.	**Corstorphine Cable Replacement** This project involves the replacement of the existing oil filled, PILC, 33 kV underground cables that run between the South Dunedin GXP and the Corstophine zone substation.	RY25-26	$7.3 million	Corstorphine, Dunedin	Currently not indicated for supply by a related party.
9c.	**Kaikorai Valley Cable Replacement** This project involves the replacement of the existing PILC, 33 kV underground cables that run between the Halfway Bush GXP and the Kaikorai zone substation.	RY23-24	$5.1 million	Kaikorai Valley, Dunedin	Currently not indicated for supply by a related party.
10	**Protection Relay Replacement** This is an ongoing programme of work to replace protection relays that have reached end-of-life.	RY22-31	$14.5 million	Total network	Currently not indicated for supply by a related party.

4.2 Heatmaps

4.2.1 Dunedin subnetwork



Grid Exit Point — Zone Substation — 33kV overhead line — 33kV underground cable

Operational Expenditure:

1 - 4 Total network

Capital Expenditure:

1 3 - 8 10 Total network

2a Andersons Bay substation rebuild

2b Mosgiel transformer replacement and 33 kV outdoor-indoor conversion

2c Green Island substation rebuild

2d Willowbank substation renewal

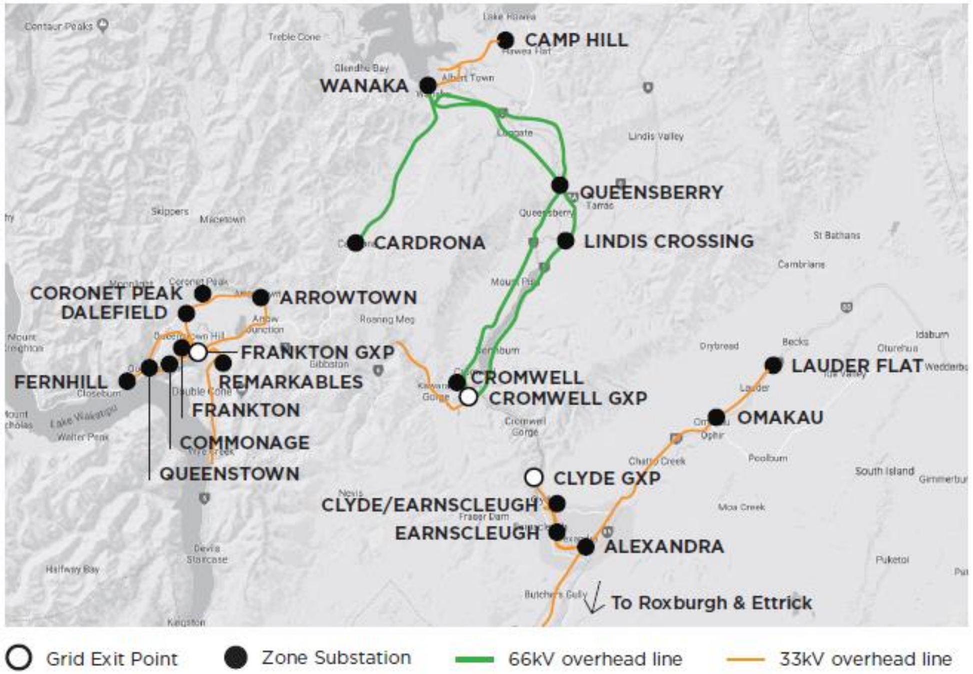
8a Halfway Bush to Waipori 33 kV line replacement

9a Willowbank cable replacement and switchboard

9b Corstorphine cable replacement

9c Kaikorai Valley cable replacement

4.2.2 Central Otago subnetwork



Operational Expenditure:

①-④ Total network

Capital Expenditure:

① ③-⑧ ⑩ Total network

SCHEDULE 18

Certification for Year-end Disclosures

Clause 2.9.2

We, Stephen Richard Thompson and Margaret Patricia Devlin, being directors of Aurora Energy 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 Aurora Energy 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.

Stephen Richard Thompson

Margaret Patricia Devlin

26 August 2021

Independent Assurance Report

To the directors of Aurora Energy Limited and to the Commerce Commission on the disclosure information for the disclosure year ended 31 March 2021 as required by the Electricity Distribution Information Disclosure Determination 2012

Aurora Energy Limited (the company) is required to disclose certain information under the Electricity Distribution Information Disclosure Determination 2012 (the Determination) and to procure an assurance report by an independent auditor in terms of section 2.8.1 of the Determination.

The Auditor-General is the auditor of the company.

The Auditor-General has appointed me, Julian Tan, using the staff and resources of Audit New Zealand, to undertake a reasonable assurance engagement, on his behalf, on whether the information prepared by the company for the disclosure year ended 31 March 2021 (the Disclosure Information) complies, in all material respects, with the Determination.

The Disclosure Information that falls within the scope of the assurance engagement are:

- Schedules 1 to 4, 5a to 5g, 6a and 6b, 7, 10 and 14 (limited to the explanatory notes in boxes 1 to 11) of the Determination.
- Clause 2.3.6 of the Determination and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012 (the IM Determination), in respect of the basis for valuation of related party transactions (the Related Party Transaction Information).

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

Opinion

In our opinion, in all material respects:

- as far as appears from an examination, proper records to enable the complete and accurate compilation of the Disclosure Information have been kept by the company;

- as far as appears from an examination, the information used in the preparation of the Disclosure Information has been properly extracted from the company's accounting and other records sourced from the company's financial and non-financial systems;
- the Disclosure Information complies, in all material respects, with the Determination; and
- the basis for valuation of related party transactions complies with the Determination and the IM Determination.

Basis for opinion

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

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

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 audit, and in forming our opinion. We do not provide a separate opinion on these matters.

Key assurance matter	**How our procedures addressed the key assurance matter**
Capital expenditure and assets commissioned into the regulatory asset base (the RAB) The RAB, as set out in Schedule 4, reflects the value of the company's electricity distribution assets. During the disclosure year, the company has carried out a large number of individual network system projects that are either operational (network maintenance) or capital (asset replacement or network growth) in nature. Capital expenditure in the current disclosure year totalled $58 million and assets commissioned into the RAB amounted to $61 million, compared to total network operating expenditure of $19 million. The amount of capital expenditure is	We obtained an understanding of the compliance requirements relevant to the RAB as set out in the IM Determination. The procedures we carried out, to satisfy ourselves that the capital expenditure and assets commissioned meet the definition under the IM Determination, included: • assessing the company's capitalisation policy was in line with NZ IAS 16 *Property, Plant and Equipment*; • evaluating the design and implementation of controls over the classification of the network expenditure; • testing a sample of capital expenditure to invoices or other supporting information to

Key assurance matter	How our procedures addressed the key assurance matter
also significant relative to the RAB opening value of $489 million. Capital expenditure and assets commissioned into the RAB are a key assurance matter due to the significant professional judgements used by the auditor to assess whether the capital expenditure and assets commissioned into the RAB meets the definition set out in the IM Determination.	determine whether the expenditure met the capitalisation criteria in the Determination and capitalised to the appropriate asset category at the correct value; and • reconciling the assets commissioned from the regulatory fixed asset register, to the additions disclosed in the audited financial statements and investigated any reconciling items. Having completed these procedures, we have no matters to report.
Valuation of related-party transactions at arms-length The Determination and the IM Determination place a requirement on the company to value related-party procurement transactions at a value not greater than arm's-length. In other words, the value at which a transaction, with the same terms and conditions, would be entered into between a willing seller and a willing buyer who are unrelated and who are acting independently of each other and pursuing their own best interests. In the absence of an active market for related-party transactions, assignment of an objective arm's-length value to a related-party transaction is difficult. This a key assurance matter because it involves considerable judgement by company personnel. In turn, verification of the appropriate assignment of an objective arm's-length valuation to related-party transactions require the exercise of significant professional judgement by the auditor.	We obtained an understanding of the company's approach to identifying and valuing related-party transactions at arm's-length in accordance with the Determination and the IM Determination. The procedures we carried out, to satisfy ourselves that related-party transactions are appropriately valued at a value not greater than arm's-length, included: • testing the completeness of related-parties identified through review of Board minutes, review of Companies Office records, and related-parties identified through detailed testing of transactions and balances in the annual financial statements audit; • reviewing the relevant policies for approval and negotiation of related-party transactions, and testing compliance with those policies; • reviewing and testing the field services agreement with related parties; • benchmarking the charges against quotations from non-related parties; • confirming the material accuracy of related party values disclosed, and compliance of their calculation with the Determination and the IM Determination; and • confirming related party transactions valued at the cost incurred by the related party to underlying records.

Key assurance matter	How our procedures addressed the key assurance matter
	Having carried out these procedures, we are satisfied that related party transactions are valued at arms-length.
Accuracy of the number and duration of electricity outages The company has a combination of manual and automated systems to identify outages and to record the duration of outages. This outage information is used to report the company's Report on Network Reliability in Schedule 10. If this information is inaccurate, then the measures of the reliability of the network could be materially misstated. This is a key assurance matter because information on the number and duration of outages is an important measure of the reliability of electricity supply. Relatively small inaccuracies can have a significant impact on the reliability thresholds against which the company's performance is assessed. There can also be significant consequences if the company breaches the reliability thresholds. The Commerce Commission has issued an Exemption notice which excludes the assurance report from coverage of the information in Schedule 10 of the ID Determination for any issues arising out of the company's recording of SAIDI, SAIFI and number of interruptions due to successive interruptions. We need to ensure that the company meets the criteria for the Exemption to apply, including that it makes the necessary disclosures so the exclusion to the assurance opinion applies.	We obtained an understanding of the company's system to record electricity outages, and their duration. This included a review of the company's definition of interruptions, planned interruptions and major event days. The procedures we carried out to assess the adequacy of the company's methods to identify and record electricity outages and their duration included: • reviewing the overall control environment; • performing an assessment of the reliability of the manual and automated processes to record the details of interruptions to supply; • reviewing internal and external information such as works orders for contractors, media reports and Board minutes on interruptions to supply to gain assurance that interruptions to supply were recorded; • testing a sample of interruptions to supply to source records to conclude on their accuracy of calculation, and the appropriateness of the categorisation of the cause of the interruption and whether it was planned or unplanned, and that the cause of the interruptions is correctly categorised; • checked the SAIDI and SAIFI ratios were correctly calculated in accordance with the Determination and the IM Determination; • obtained explanations for all significant variances to forecast; and • testing the accuracy of the number of connections to the Electricity Authority's register. With respect to the Exemption, we: • obtained and documented our understanding of the company's methods

	by which electricity outages and their duration are recorded where an outage event results in successive interruptions of supply; • compared this to the documented process that the company followed in the previous year; and • identified potential incidences of successive interruptions of supply to ensure that the company's methods, by which electricity outages and their duration are recorded where an outage event results in successive interruptions of supply, were the same for both years. Having carried out these procedures, and assessed the likelihood of reported electricity outages and their duration being materially misstated in the Disclosure Information, we have no matters to report.

Directors' responsibilities

The directors of the company are responsible in accordance with the Determination for:

- the preparation of the Disclosure Information; and
- the Related Party Transaction Information.

The directors of the company are also responsible for the identification of risks that may threaten compliance with the schedules and clauses identified above and controls which will mitigate those risks and monitor ongoing compliance.

Auditor's responsibilities

Our responsibilities in terms of clauses 2.8.1(1)(b)(vi) and (vii), 2.8.1(1)(c) and 2.8.1(1)(d) are to express an opinion on whether:

- As far as appears from an examination, the information used in the preparation of the audited Disclosure Information has been properly extracted from the company's accounting and other records sourced from its financial and non-financial systems.
- As far as appears from an examination, proper records to enable the complete and accurate compilation of the audited Disclosure Information required by the Determination have been kept by the company and, if not, the records not so kept.
- The company complied, in all material respects, with the Determination in preparing the audited Disclosure Information.

- The company’s basis for valuation of related party transactions in the disclosure year has complied, in all material respects, with clause 2.3.6 of the Determination and clauses 2.2.11(1)(g) and 2.2.11(5) of the IM Determination.

To meet these responsibilities, we planned and performed procedures in accordance with SAE (NZ) 3100 (Revised), to obtain reasonable assurance about whether the company has complied, in all material respects, with the Disclosure Information (which includes the Related Party Transaction Information) required to be audited by the Determination.

An assurance engagement to report on the company’s compliance with the Determination involves performing procedures to obtain evidence about the compliance activity and controls implemented to meet the requirements. The procedures selected depend on our judgement, including the identification and assessment of the risks of material non-compliance with the requirements.

Inherent limitations

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

Restricted use

This report has been prepared for use by the directors of the company and the Commerce Commission in accordance with clause 2.8.1(1)(a) of the Determination and is provided solely for the purpose of establishing whether the compliance requirements have been met. We disclaim any assumption of responsibility for any reliance on this report to any person other than the directors of the company and the Commerce Commission, or for any other purpose than that for which it was prepared.

Independence and quality control

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 issued by the New Zealand Auditing and Assurance Standards Board; and

- 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 Audit New Zealand and its employees may deal with the company on normal terms within the ordinary course of trading activities of the company. Other than any dealings on normal terms within the ordinary course of trading activities of the company, this engagement, the assurance engagement on Default Price-Quality Path and the annual audit of the company's financial statements and statement of service performance, we have no relationship with or interests in the company.

Julian Tan
Audit New Zealand
On behalf of the Auditor-General
Dunedin, New Zealand
26 August 2021