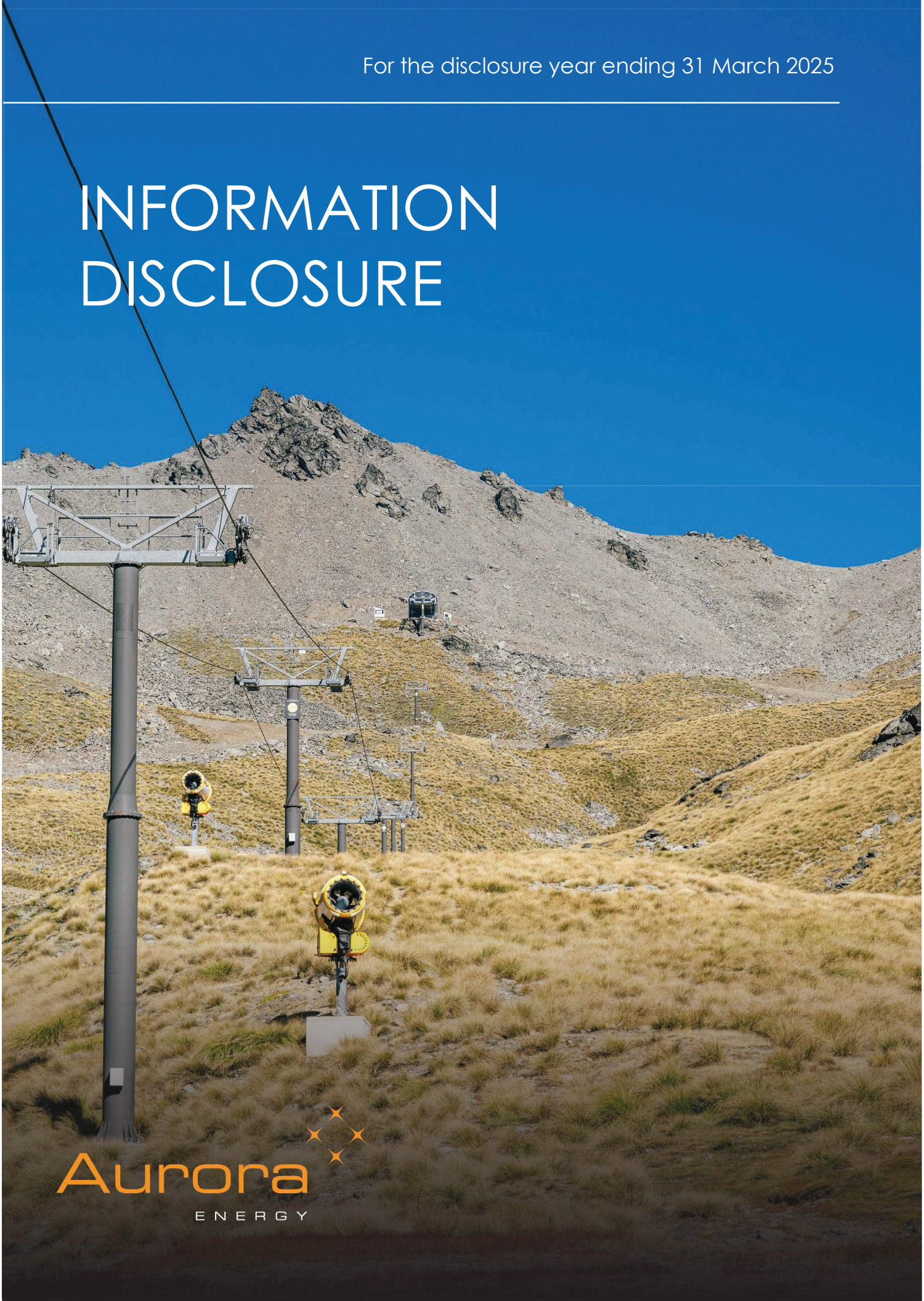
For the disclosure year ending 31 March 2025

INFORMATION DISCLOSURE



Aurora ENERGY

TABLE OF CONTENTS

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**

SCHEDULE 1: ANALYTICAL RATIOS

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

sch ref

1(i): Expenditure metrics

	Expenditure per GWh energy delivered to ICPs ($/GWh)	Expenditure per average no. of ICPs ($/ICP)	Expenditure per MW maximum coincident system demand ($/MW)	Expenditure per km circuit length ($/km)	Expenditure per MVA of capacity from EDB-owned distribution transformers ($/MVA)
Operational expenditure	38,443	563	174,430	8,494	54,262
Network	15,554	228	70,576	3,437	21,955
Non-network	22,888	335	103,854	5,057	32,307
Expenditure on assets	74,183	1,086	336,596	16,391	104,708
Network	72,314	1,058	328,118	15,978	102,071
Non-network	1,868	27	8,478	413	2,637

1(ii): Revenue metrics

	Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
Total consumer line charge revenue	109,958	1,609
Standard consumer line charge revenue	109,781	1,595
Non-standard consumer line charge revenue	133,200	101,004

1(iii): Service intensity measures

Demand density	49	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
Volume density	221	*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	14,633	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*

1(iv): Composition of regulatory income

	($000)	% of revenue
Operational expenditure	54,173	35.09%
Pass-through and recoverable costs excluding financial incentives and wash-ups	29,048	18.81%
Total depreciation	31,778	20.58%
Total revaluations	20,836	13.50%
Regulatory tax allowance	8,541	5.53%
Regulatory profit/(loss) including financial incentives and wash-ups	51,694	33.48%
Total regulatory income	154,397	

1(v): Reliability

Interruption rate	26.14	*Interruptions per 100 circuit km*

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

This schedule requires information on the Return on Investment (ROI) for the EDB relative to the Commerce Commission's estimates of post tax WACC and vanilla WACC. EDBs must calculate their ROI based on a monthly basis if required by clause 2.3.3 of this ID Determination or if they elect to. If an EDB makes this election, information supporting this calculation must be provided in 2(iii).
EDBs must provide explanatory comment on their ROI in Schedule 14 (Mandatory Explanatory Notes).
This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref		CY-2	CY-1	Current Year CY
7	**2(i): Return on Investment**			
8				
9	**ROI – comparable to a post tax WACC**	%	%	%
10	Reflecting all revenue earned	8.19%	7.34%	5.65%
11	Excluding revenue earned from financial incentives	6.87%	5.44%	3.28%
12	Excluding revenue earned from financial incentives and wash-ups	6.96%	5.53%	3.36%
13				
14	**Mid-point estimate of post tax WACC**	4.88%	6.05%	6.18%
15	25th percentile estimate	4.20%	5.37%	5.50%
16	75th percentile estimate	5.56%	6.73%	6.86%
17				
18				
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	8.71%	8.04%	6.37%
21	Excluding revenue earned from financial incentives	7.38%	6.15%	4.00%
22	Excluding revenue earned from financial incentives and wash-ups	7.47%	6.23%	4.08%
23				
24	**WACC rate used to set regulatory price path**	4.57%	4.57%	4.57%
25				
26	**Mid-point estimate of vanilla WACC**	5.39%	6.75%	6.90%
27	25th percentile estimate	4.71%	6.07%	6.22%
28	75th percentile estimate	6.07%	7.43%	7.58%
29				

30	**2(ii): Information Supporting the ROI**		($000)	
31				
32	Total opening RAB value	830,127		
33	*plus* Opening deferred tax	(38,492)		
34	**Opening RIV**		791,635	
35				
36	**Line charge revenue**		154,951	
37				
38	Expenses cash outflow	83,221		
39	*add* Assets commissioned	80,955		
40	*less* Asset disposals	1,976		
41	*add* Tax payments	3,515		
42	*less* Other regulated income	(554)		
43	**Mid-year net cash outflows**		166,268	
44				
45	**Term credit spread differential allowance**		–	
46				
47	Total closing RAB value	898,165		
48	*less* Adjustment resulting from asset allocation	(0)		
49	*less* Lost and found assets adjustment	–		
50	*plus* Closing deferred tax	(43,519)		
51	**Closing RIV**		854,646	
52				
53	**ROI – comparable to a vanilla WACC**			6.37%
54				
55	Leverage (%)			42%
56	Cost of debt assumption (%)			6.12%
57	Corporate tax rate (%)			28%
58				
59	**ROI – comparable to a post tax WACC**			5.65%
60				

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

This schedule requires information on the Return on Investment (ROI) for the EDB relative to the Commerce Commission's estimates of post tax WACC and vanilla WACC. EDBs must calculate their ROI based on a monthly basis if required by clause 2.3.3 of this ID Determination or if they elect to. If an EDB makes this election, information supporting this calculation must be provided in 2(iii).
EDBs must provide explanatory comment on their ROI in Schedule 14 (Mandatory Explanatory Notes).
This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

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 — 3.16%

Year-end ROI – comparable to a post tax WACC — 2.44%

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

2(v): Financial Incentives and Wash-Ups

IRIS incentive adjustment	26,853	
Purchased assets – avoided transmission charge	–	
Innovation and non-traditional solutions recovered amount	–	
Quality incentive adjustment	(582)	
Other CPP financial incentives	–	
Financial incentives		26,272

Impact of financial incentives on ROI — 2.36%

Input methodology claw-back	–	
CPP application recoverable costs	–	
CPP Urgent project allowance		Not Required before DY
Reopener event allowance		Not Required before DY
Wash-up draw down amount		Not Required before DY
Catastrophic event allowance		Not Required after DY20
Capex wash-up adjustment	(831)	Not Required after DY20
Transmission asset wash-up adjustment		Not Required after DY20
2013–15 NPV wash-up allowance		Not Required after DY20
Reconsideration event allowance		Not Required after DY20
Other CPP wash-ups		
Wash-up costs		(831)

Impact of wash-up costs on ROI — –0.07%

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**

SCHEDULE 3: REPORT ON REGULATORY PROFIT

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

sch ref			
7	**3(i): Regulatory Profit**		**($000)**
8		**Income**	
9		Line charge revenue	154,951
10	*plus*	Gains / (losses) on asset disposals	(1,976)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)	1,422
12			
13		**Total regulatory income**	154,397
14		**Expenses**	
15	*less*	Operational expenditure	54,173
16			
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups	29,048
18			
19		**Operating surplus / (deficit)**	71,176
20			
21	*less*	Total depreciation	31,778
22			
23	*plus*	Total revaluations	20,836
24			
25		**Regulatory profit / (loss) before tax**	60,235
26			
27	*less*	Term credit spread differential allowance	–
28			
29	*less*	Regulatory tax allowance	8,541
30			
31		**Regulatory profit/(loss) including financial incentives and wash-ups**	51,694
32			

33	**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**		**($000)**	
34		**Pass through costs**		
35		Electricity lines service charge payable to Transpower	–	Not Required before DY
36		Transpower new investment contract charges	–	Not Required before DY
37		System operator services	–	Not Required before DY
38		Rates	1,699	
39		Commerce Act levies	493	
40		Industry levies	465	
41		CPP or DPP specified pass-through costs	163	
42		**Recoverable costs excluding financial incentives and wash-ups**		
43		Independent engineer costs	–	Not Required before DY
44		FENZ levies	–	Not Required before DY
45		Electricity lines service charge payable to Transpower	25,423	Not Required after DY2
46		Transpower new investment contract charges	775	Not Required after DY2
47		System operator services	–	Not Required after DY2
48		Distributed generation allowance	–	Not Required after DY2
49		Extended reserves allowance	–	
50		Other CPP recoverable costs excluding financial incentives and wash-ups	30	
51		**Pass-through and recoverable costs excluding financial incentives and wash-ups**		29,048
52				

53	**3(iv): Merger and Acquisition Expenditure**		
54			**($000)**
55		Merger and acquisition expenditure	–
56			
57		*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)*	

58	**3(v): Other Disclosures**		
59			**($000)**
60		Self-insurance allowance	–

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**

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

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

sch ref

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

		RAB CY-4 ($000)	RAB CY-3 ($000)	RAB CY-2 ($000)	RAB CY-1 ($000)	RAB CY ($000)
	Total opening RAB value	489,854	539,722	645,301	736,088	830,127
less	**Total depreciation**	20,358	22,502	25,779	29,095	31,778
plus	**Total revaluations**	7,402	37,128	42,563	29,401	20,836
plus	**Assets commissioned**	61,073	93,006	76,873	95,696	80,955
less	**Asset disposals**	830	2,087	2,871	1,962	1,976
plus	**Lost and found assets adjustment**	2,581	–	–	–	–
plus	**Adjustment resulting from asset allocation**	–	34	–	(0)	(0)
	Total closing RAB value	539,722	645,301	736,088	830,127	898,165

4(ii): Unallocated Regulatory Asset Base

			Unallocated RAB * ($000)	Unallocated RAB * ($000)	RAB ($000)	RAB ($000)
	Total opening RAB value			830,999		830,127
less						
	Total depreciation			31,818		31,778
plus						
	Total revaluations			20,858		20,836
plus						
	Assets commissioned (other than below)	Not Required after DY2025	42,689		42,689	
	Assets commissioned out of WUC	Not Required before DY2026	–		–	
	Assets acquired (other than below)	Not Required before DY2026	–		–	
	Assets acquired from a regulated supplier		–		–	
	Assets acquired from a related party		38,266		38,266	
	Assets commissioned			80,955		80,955
less						
	Asset disposals (other than below)		1,976		1,976	
	Asset disposals to a regulated supplier		–		–	
	Asset disposals to a related party		–		–	
	Asset disposals			1,976		1,976
plus	**Lost and found assets adjustment**					
plus	**Adjustment resulting from asset allocation**					(0)
	Total closing RAB value			899,018		898,165

** 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 2025**

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

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

sch ref

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

	CPI_4		1,299
	CPI_4 [4]		1,267
	Revaluation rate (%)		2.53%

		Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
	Total opening RAB value	830,999		830,127	
less	Opening value of fully depreciated, disposed and lost assets	5,134		5,134	
	Total opening RAB value subject to revaluation	825,865		824,994	
	Total revaluations		20,858		20,836

4(iv): Roll Forward of Works Under Construction

			Unallocated works under construction		Allocated works under construction	
	Works under construction—preceding disclosure year	Not Required after DY2025		38,377		38,377
plus	Capital expenditure	Not Required after DY2025	89,034		89,034	
less	Assets commissioned	Not Required after DY2025	80,955		80,955	
plus	Adjustment resulting from asset allocation	Not Required after DY2025				
	Works under construction - current disclosure year	Not Required after DY2025		46,456		46,456

			Unallocated works under construction		Allocated works under construction	
	Works under construction—preceding disclosure year	Not Required before DY2026				
plus	WUC capital expenditure	Not Required before DY2026				
	WUC acquired from a regulated supplier	Not Required before DY2026				
	WUC acquired from a related party	Not Required before DY2026				
	WUC capital expenditure - other	Not Required before DY2026				
	Total WUC capital expenditure	Not Required before DY2026	–		–	
less	WUC capital contributions	Not Required before DY2026				
less	WUC other revenue	Not Required before DY2026				
less	Assets commissioned out of WUC	Not Required before DY2026	–		–	
plus	Adjustment resulting from asset allocation	Not Required before DY2026				
	Works under construction - current disclosure year	Not Required before DY2026		–		–

Highest rate of capitalised finance applied	4.80%

Company Name: **Aurora Energy Limited**

For Year Ended: **31 March 2025**

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

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

sch ref

4(v): Regulatory Depreciation

	Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
Depreciation - standard	29,577		29,577	
Depreciation - no standard life assets	2,241		2,201	
Depreciation - modified life assets	–		–	
Depreciation - alternative depreciation in accordance with CPP	–		–	
Total depreciation		31,818		31,778

4(vi): Disclosure of Changes to Depreciation Profiles

($000 unless otherwise specified)

Asset or assets with changes to depreciation*	Reason for non-standard depreciation (text entry)	Depreciation charge for the period (RAB)	Closing RAB value under 'non-standard' depreciation	Closing RAB value under 'standard' depreciation

** include additional rows if needed*

4(vii): Disclosure by Asset Category

($000 unless otherwise specified)

		Subtransmission lines	Subtransmission cables	Zone substations	Distribution and LV lines	Distribution and LV cables	Distribution substations and transformers	Distribution switchgear	Other network assets	Non-network assets	Total	
	Total opening RAB value	44,492	38,389	136,409	262,592	188,066	85,679	47,091	21,252	6,158	830,127	
less	Total depreciation	1,453	1,051	5,276	7,511	6,247	3,224	2,186	2,758	2,072	31,778	
plus	Total revaluations	1,122	956	3,420	6,613	4,747	2,164	1,165	511	140	20,836	
plus	Assets commissioned	5,336	1,464	10,777	28,480	12,517	7,892	8,089	1,141	5,258	80,955	
less	Asset disposals	71	–	–	807	105	–	992	–	–	1,976	
plus	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–	
plus	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–	–	–	
plus	Asset category transfers	–	(555)	555	–	–	–	–	–	–	(0)	
	Total closing RAB value	49,427	39,202	145,885	289,367	198,978	92,511	53,166	20,146	9,483	898,165	
	Asset Life											
	Weighted average remaining asset life	30.6	36.5	25.9	34.9	30.1	26.6	21.1	7.7	3.0		(years)
	Weighted average expected total asset life	51.0	54.6	51.0	54.6	53.0	49.7	39.7	18.7	8.6		(years)

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**

SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

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

5a(i): Regulatory Tax Allowance

sch ref			($000)		($000)
8		**Regulatory profit / (loss) before tax**			60,235
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	59	*	
12		Amortisation of initial differences in asset values	4,873		
13		Amortisation of revaluations	7,030		
14		**Total**			11,962
15					
16	*less*	Total revaluations	20,836		
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	1,102	*	
20		Notional deductible interest	19,753		
21		**Total**			41,692
22					
23		**Regulatory taxable income**			30,505
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income			30,505
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**			8,541
30					
31	*	Workings to be provided in Schedule 14			

5a(ii): Disclosure of Permanent Differences

32	
33	In Schedule 14, Box 5, provide descriptions and workings of items recorded in the asterisked categories in Schedule 5a(i).

5a(iii): Amortisation of Initial Difference in Asset Values

			($000)	($000)
34				
35				
36		Opening unamortised initial differences in asset values	62,916	
37	*less*	Amortisation of initial differences in asset values	4,873	
38	*plus*	Adjustment for unamortised initial differences in assets acquired	–	
39	*less*	Adjustment for unamortised initial differences in assets disposed	321	
40		Closing unamortised initial differences in asset values		57,722
41				
42		Opening weighted average remaining useful life of relevant assets (years)		13
43				

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**

SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

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

sch ref					
44	**5a(iv): Amortisation of Revaluations**				**($000)**
45					
46		Opening sum of RAB values without revaluations		682,628	
47					
48		Adjusted depreciation		24,748	
49		Total depreciation		31,778	
50		Amortisation of revaluations			7,030
51					
52	**5a(v): Reconciliation of Tax Losses**				**($000)**
53					
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)**
59					
60		**Opening deferred tax**		(38,492)	
61					
62	*plus*	Tax effect of adjusted depreciation		6,929	
63					
64	*less*	Tax effect of tax depreciation		13,394	
65					
66	*plus*	Tax effect of other temporary differences*		2,569	
67					
68	*less*	Tax effect of amortisation of initial differences in asset values		1,365	
69					
70	*plus*	Deferred tax balance relating to assets acquired in the disclosure year		–	
71					
72	*less*	Deferred tax balance relating to assets disposed in the disclosure year		(232)	
73					
74	*plus*	Deferred tax cost allocation adjustment		0	
75					
76		**Closing deferred tax**			(43,519)
77					
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).*			
80					
81	**5a(viii): Regulatory Tax Asset Base Roll-Forward**				
82					**($000)**
83		**Opening sum of regulatory tax asset values**		516,935	
84	*less*	Tax depreciation		47,834	
85	*plus*	Regulatory tax asset value of assets commissioned		93,542	
86	*less*	Regulatory tax asset value of asset disposals		1,146	
87	*plus*	Lost and found assets adjustment		–	
88	*plus*	Adjustment resulting from asset allocation		–	
89	*plus*	Other adjustments to the RAB tax value		–	
90		**Closing sum of regulatory tax asset values**			561,497

Company Name	**Aurora Energy Limited**
For Year Ended	

SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

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

sch ref

5b(i): Summary—Related Party Transactions

	($000)	($000)
Total regulatory income		–
Market value of asset disposals		–
Service interruptions and emergencies	3,873	
Vegetation management	2,671	
Routine and corrective maintenance and inspection	10,365	
Asset replacement and renewal (opex)	–	
Network opex		16,908
Business support	3,221	
System operations and network support	108	
Non-network solutions provided by a related party or third party	–	
Operational expenditure		20,237
Consumer connection	5,717	
System growth	2,254	
Asset replacement and renewal (capex)	28,386	
Asset relocations	2,800	
Quality of supply	238	
Legislative and regulatory	–	
Other reliability, safety and environment	–	
Expenditure on non-network assets		158
Expenditure on assets		39,553
Cost of financing		1,440
Value of capital contributions		3,936
Value of vested assets		–
Capital Expenditure		37,057
Total expenditure		57,294
Other related party transactions		1,460

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

Name of related party	Nature of opex or capex service provided	Total value of transactions ($000)
Delta Utility Services Ltd	Service interruptions and emergencies	3,873
Delta Utility Services Ltd	Vegetation management	2,671
Delta Utility Services Ltd	Routine and corrective maintenance and inspection	10,365
Delta Utility Services Ltd	System operations and network support	108
Delta Utility Services Ltd	Business support	344
Dunedin City Council	Business support	60
Dunedin Venues Management Ltd	Business support	1
Aurora Energy Limited - Directors Fees	Business support	299
Personnel	Business support	2,517
Delta Utility Services Ltd	Consumer connection	5,717
Delta Utility Services Ltd	System growth	2,254
Delta Utility Services Ltd	Asset replacement and renewal (capex)	28,386
Delta Utility Services Ltd	Asset relocations	2,800
Delta Utility Services Ltd	Quality of supply	238
Delta Utility Services Ltd	Expenditure on non-network assets	158
Total value of related party transactions		59,790

** include additional rows if needed*

Company Name	Aurora Energy Limited
For Year Ended	31 March 2025

SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

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

sch ref

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

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
** include additional rows if needed*						–	–	–

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

Gross term credit spread differential		–
Total book value of interest bearing debt		
Leverage	42%	
Average opening and closing RAB values		
Attribution Rate (%)		–
Term credit spread differential allowance		–

Company Name: Aurora Energy Limited
For Year Ended:

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

5d(i): Operating Cost Allocations

	Value allocated ($000s)				
	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
Service interruptions and emergencies					
Directly attributable		3,992			
Not directly attributable		–		–	
Total attributable to regulated service		3,992			
Vegetation management					
Directly attributable		4,434			
Not directly attributable		–		–	
Total attributable to regulated service		4,434			
Routine and corrective maintenance and inspection					
Directly attributable		13,493			
Not directly attributable		–		–	
Total attributable to regulated service		13,493			
Asset replacement and renewal					
Directly attributable		–			
Not directly attributable		–		–	
Total attributable to regulated service		–			
Non-network solutions provided by a related party or third party					
Directly attributable		50			
Not directly attributable		–		–	
Total attributable to regulated service		50			
System operations and network support					
Directly attributable		17,374			
Not directly attributable		–		–	
Total attributable to regulated service		17,374			
Business support					
Directly attributable		14,830			
Not directly attributable		–		–	
Total attributable to regulated service		14,830			
Operating costs directly attributable		54,173			
Operating costs not directly attributable	–	–	–	–	–
Operational expenditure		54,173			

Company Name	**Aurora Energy Limited**
For Year Ended	

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

5d(ii): Other Cost Allocations

	($000)
Pass through and recoverable costs	
Pass through costs	
Directly attributable	2,820
Not directly attributable	–
Total attributable to regulated service	2,820
Recoverable costs	
Directly attributable	26,228
Not directly attributable	–
Total attributable to regulated service	26,228

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

Change in cost allocation 1

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

Rationale for change

Change in cost allocation 2

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

Rationale for change

Change in cost allocation 3

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

Rationale for change

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

† include additional rows if needed

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

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

sch ref

5e(i): Regulated Service Asset Values

	Value allocated ($000s) Electricity distribution services
Subtransmission lines	
Directly attributable	49,427
Not directly attributable	–
Total attributable to regulated service	49,427
Subtransmission cables	
Directly attributable	39,202
Not directly attributable	–
Total attributable to regulated service	39,202
Zone substations	
Directly attributable	145,885
Not directly attributable	–
Total attributable to regulated service	145,885
Distribution and LV lines	
Directly attributable	289,367
Not directly attributable	–
Total attributable to regulated service	289,367
Distribution and LV cables	
Directly attributable	198,978
Not directly attributable	–
Total attributable to regulated service	198,978
Distribution substations and transformers	
Directly attributable	92,511
Not directly attributable	–
Total attributable to regulated service	92,511
Distribution switchgear	
Directly attributable	53,166
Not directly attributable	–
Total attributable to regulated service	53,166
Other network assets	
Directly attributable	17,504
Not directly attributable	2,642
Total attributable to regulated service	20,146
Non-network assets	
Directly attributable	9,483
Not directly attributable	–
Total attributable to regulated service	9,483
Regulated service asset value directly attributable	895,523
Regulated service asset value not directly attributable	2,642
Total closing RAB value	898,165

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

Change in asset value allocation 1

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

Change in asset value allocation 2

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

Change in asset value allocation 3

			($000) CY-1	Current Year (CY)
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 compone*
† include additional rows if needed

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**

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

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

sch ref

6a(i): Expenditure on Assets

			($000)	($000)
8		Consumer connection		18,812
9		System growth		10,687
10		Asset replacement and renewal		63,554
11		Asset relocations		7,853
12		Reliability, safety and environment:		
13		Quality of supply	424	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	573	
16		**Total reliability, safety and environment**		997
17		**Expenditure on network assets**		101,904
18		Expenditure on non-network assets		2,633
19				
20		**Expenditure on assets**		104,537
21	*plus*	Cost of financing		1,440
22	*less*	Value of capital contributions		16,943
23	*plus*	Value of vested assets		–
24				
25		**Capital expenditure**		89,034

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	–

6a(iii): Consumer Connection

	*Consumer types defined by EDB**	($000)	($000)
33	All consumers	18,812	
34			
35			
36			
37			

** include additional rows if needed*

39		**Consumer connection expenditure**	18,812
40			
41	*less*	Capital contributions funding consumer connection expenditure	13,001
42		**Consumer connection less capital contributions**	5,811

6a(iv): System Growth and Asset Replacement and Renewal

		System Growth ($000)	Asset Replacement and Renewal ($000)
46	Subtransmission	2,008	498
47	Zone substations	6,777	11,934
48	Distribution and LV lines	28	30,768
49	Distribution and LV cables	99	6,481
50	Distribution substations and transformers	1,526	3,061
51	Distribution switchgear	8	10,676
52	Other network assets	240	136
53	**System growth and asset replacement and renewal expenditure**	10,687	63,554
54 *less*	Capital contributions funding system growth and asset replacement and renewal	50	–
55	**System growth and asset replacement and renewal less capital contributions**	10,636	63,554

6a(v): Asset Relocations

	*Project or programme**	($000)	($000)
59	Kā Huanui a Tāhuna - NZ Upgrade Programme, Queenstown Package	2,838	
60	Parkins Bay - Glendhu Bay Connection	974	
61	The Views Queenstown 33kV OH to UG Relocation	723	
62	Portobello Road Widening	643	
63	Dalefield 33kV Line Undergrounding	486	

** include additional rows if needed*

65		All other projects or programmes - asset relocations	2,190	
66		**Asset relocations expenditure**		7,853
67	*less*	Capital contributions funding asset relocations	3,878	
68		**Asset relocations less capital contributions**		3,976

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**

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

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

sch ref

6a(vi): Quality of Supply

	*Project or programme**	($000)	($000)
	Camp Hill 2MVA Generator	207	
	Pisa Mooring Network Upgrade	79	
	Remote Area Early Fault Detection	76	
	** include additional rows if needed*		
	All other projects programmes - quality of supply	63	
	Quality of supply expenditure		424
less	Capital contributions funding quality of supply	–	
	Quality of supply less capital contributions		424

6a(vii): Legislative and Regulatory

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

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

	*Project or programme**	($000)	($000)
	Frankton Ripple Injection Plant Upgrade	563	
	** include additional rows if needed*		
	All other projects or programmes - other reliability, safety and environment	10	
	Other reliability, safety and environment expenditure		573
less	Capital contributions funding other reliability, safety and environment	14	
	Other reliability, safety and environment less capital contributions		559

6a(ix): Non-Network Assets

Routine expenditure

	*Project or programme**	($000)	($000)
	ROU asset additions	857	
	Computer devices	113	
	** include additional rows if needed*		
	All other projects or programmes - routine expenditure	76	
	Routine expenditure		1,046

Atypical expenditure

	*Project or programme**	($000)	($000)
	Asset Management System	1,115	
	Enterprise Technology & Infrastructure	90	
	** include additional rows if needed*		
	All other projects or programmes - atypical expenditure	381	
	Atypical expenditure		1,587
	Expenditure on non-network assets		2,633

			Company Name	**Aurora Energy Limited**
			For Year Ended	**31 March 2025**

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

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

sch ref					
7	**6b(i): Operational Expenditure** *Required for DY2025 only*			**($000)**	**($000)**
8	Service interruptions and emergencies			3,992	
9	Vegetation management			4,434	
10	Routine and corrective maintenance and inspection			13,493	
11	Asset replacement and renewal			–	
12	**Network opex**				21,919
13	Non-network solutions provided by a related party or third party	*Required for DY2025 only*		50	
14	System operations and network support			17,374	
15	Business support			14,830	
16	**Non-network opex**				32,254
17					
18	**Operational expenditure**				54,173
19	**6b(i): Operational Expenditure** *Not Required before DY2026*			**($000)**	**($000)**
20	Service interruptions and emergencies:				
21	Vegetation-related				
22	Other				
23	**Total service interruptions and emergencies**			–	
24	Vegetation management:				
25	Assessment and notification costs				
26	Felling or trimming vegetation - in-zone				
27	Felling or trimming vegetation - out-of-zone				
28	Other				
29	**Total vegetation management**			–	
30					

		Company Name	**Aurora Energy Limited**
		For Year Ended	**31 March 2025**

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

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

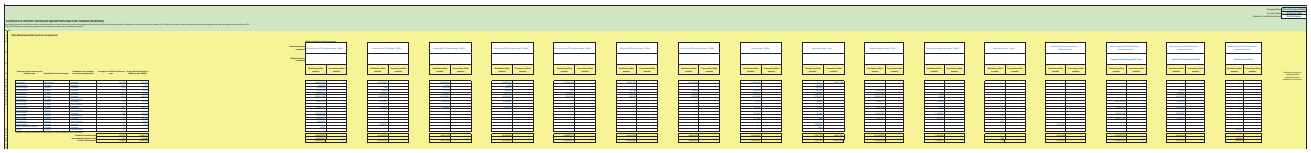
sch ref			
31	Routine and corrective maintenance and inspection:		
32	Asset replacement and renewal		
33	**Network opex**		–
34	Non-network solutions provided by a related party or third party		
35	System operations and network support		
36	Business support		
37	**Non-network opex**		–
38			
39	**Operational expenditure**		–
40	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
41	Energy efficiency and demand side management, reduction of energy losses		–
42	Direct billing*		–
43	Research and development		–
44	Insurance		785
45	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

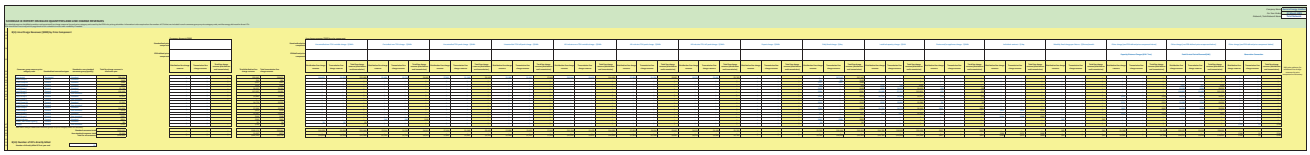
Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**

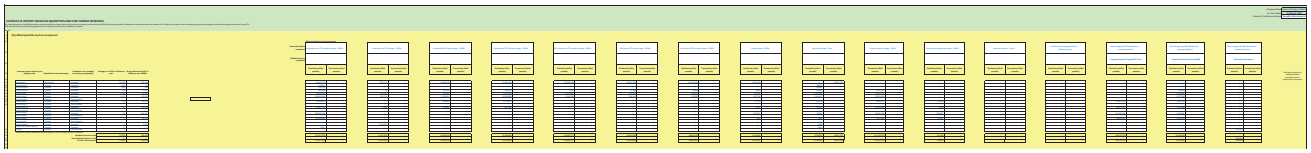
SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

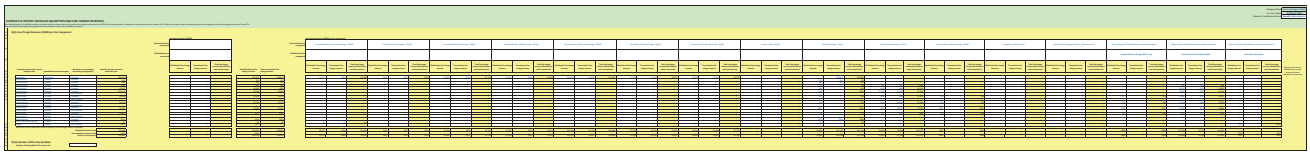
This schedule compares actual revenue and expenditure to the previous forecasts that were made for the disclosure year. Accordingly, this schedule requires the forecast revenue and expenditure information from previous disclosures to be inserted.
EDBs must provide explanatory comment on the variance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

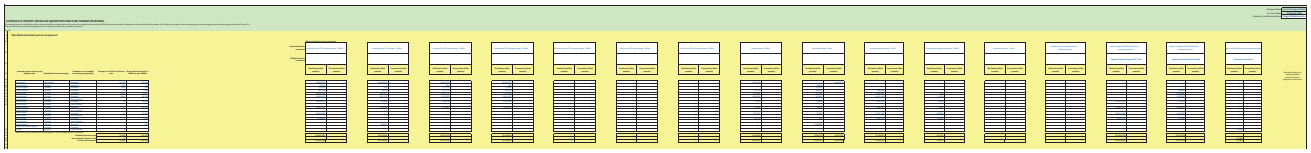
sch ref				
7	**7(i): Revenue**	**Target ($000) [1]**	**Actual ($000)**	**% variance**
8	Line charge revenue	157,980	154,951	(2%)
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	20,717	18,812	(9%)
11	System growth	11,087	10,687	(4%)
12	Asset replacement and renewal	58,107	63,554	9%
13	Asset relocations	2,218	7,853	254%
14	Reliability, safety and environment:			
15	Quality of supply	542	424	(22%)
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	–	573	–
18	**Total reliability, safety and environment**	542	997	84%
19	**Expenditure on network assets**	92,672	101,904	10%
20	Expenditure on non-network assets	5,753	2,633	(54%)
21	Expenditure on assets	98,425	104,537	6%
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	3,738	3,992	7%
24	Vegetation management	4,023	4,434	10%
25	Routine and corrective maintenance and inspection	13,824	13,493	(2%)
26	Asset replacement and renewal	–	–	–
27	**Network opex**	21,585	21,919	2%
28	Non-network solutions provided by a related party or third party	182	50	(73%)
29	System operations and network support	19,044	17,374	(9%)
30	Business support	15,908	14,830	(7%)
31	**Non-network opex**	35,134	32,254	(8%)
32	**Operational expenditure**	56,719	54,173	(4%)
33	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
34	Energy efficiency and demand side management, reduction of energy losses	–	–	–
35	Overhead to underground conversion	–	–	–
36	Research and development	–	–	–
37				
38	**7(v): Subcomponents of Operational Expenditure (where known)**			
39	Energy efficiency and demand side management, reduction of energy losses	–	–	–
40	Direct billing	–	–	–
41	Research and development	–	–	–
42	Insurance	–	785	–
43				
44	*1 From the nominal dollar target revenue for the disclosure year disclosed under clause 2.4.3(3) of this determination*			
45	*2 From the CY+1 nominal dollar expenditure forecasts disclosed in accordance with clause 2.6.6 for the forecast period starting at the beginning of the disclosure year (the second to last disclosure of Schedules 11a and 11b)*			

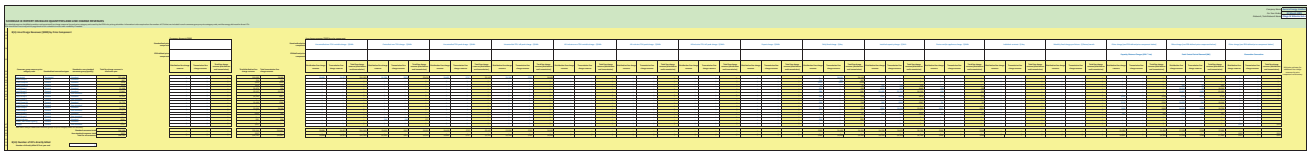


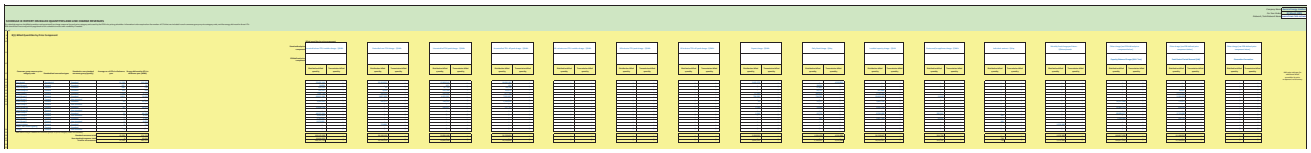


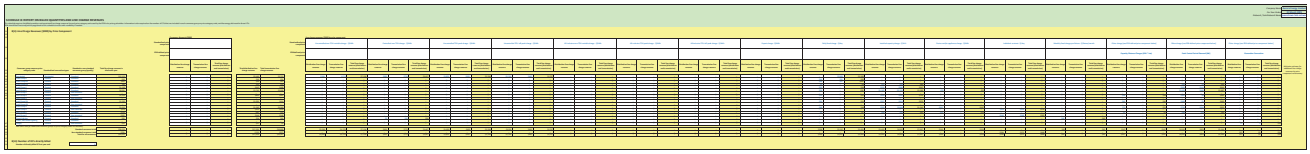












Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
Network / Sub-network Name	**Total Network**

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

9a: Asset Register

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.	31,635	32,403	768	4
10	All	Overhead Line	Wood poles	No.	22,043	21,295	(748)	4
11	All	Overhead Line	Other pole types	No.			–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	522	520	(2)	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km			–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	46	51	5	3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	25	25	0	3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	16	16	0	3
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	11	11	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.	36	37	1	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.	15	15	–	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.			–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	264	265	1	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.	58	54	(4)	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	335	327	(8)	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	24	21	(3)	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	69	69	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2,278	2,271	(7)	4
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km			–	N/A
37	HV	Distribution Line	SWER conductor	km	5	5	(0)	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	804	843	39	3
39	HV	Distribution Cable	Distribution UG PILC	km	410	407	(3)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	5	5	0	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	61	58	(3)	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	3	3	–	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	7,333	7,391	58	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	445	389	(56)	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	986	1,050	64	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	4,005	4,010	5	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	3,370	3,424	54	4
48	HV	Distribution Transformer	Voltage regulators	No.	38	41	3	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	335	323	(12)	4
50	LV	LV Line	LV OH Conductor	km	1,025	1,022	(3)	4
51	LV	LV Cable	LV UG Cable	km	1,164	1,207	43	4
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	1,078	1,086	8	4
53	LV	Connections	OH/UG consumer service connections	No.	97,123	98,470	1,347	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	729	788	59	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	10	8	(2)	4
58	All	Load Control	Relays	No	2,305	1,487	(818)	2
59	All	Civils	Cable Tunnels	km			–	N/A

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
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

9a: Asset Register

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.	18,817	19,096	279	4
10	All	Overhead Line	Wood poles	No.	10,364	10,108	(256)	4
11	All	Overhead Line	Other pole types	No.			–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	143	143	0	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km			–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	15	15	0	3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	25	25	0	3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	16	16	0	3
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	11	11	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.	21	22	1	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.			–	N/A
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.			–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.			–	N/A
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.			–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	103	103	–	4
29	HV	Zone substation switchgear	33kV RMU	No.			–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	3	3	–	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	19	19	–	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	244	229	(15)	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	1		(1)	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	34	34	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	724	722	(2)	4
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km			–	N/A
37	HV	Distribution Line	SWER conductor	km	5	5	(0)	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	57	61	3	3
39	HV	Distribution Cable	Distribution UG PILC	km	271	270	(1)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	5	5	0	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	15	15	–	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	3	3	–	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	2,873	2,897	24	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	243	208	(35)	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	424	442	18	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	1,670	1,678	8	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	1,005	1,023	18	4
48	HV	Distribution Transformer	Voltage regulators	No.	2	2	–	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	335	323	(12)	4
50	LV	LV Line	LV OH Conductor	km	807	804	(3)	4
51	LV	LV Cable	LV UG Cable	km	318	327	9	4
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	683	688	5	4
53	LV	Connections	OH/UG consumer service connections	No.	57,797	58,140	343	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	509	500	(9)	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	7	5	(2)	4
58	All	Load Control	Relays	No	1,123	652	(471)	2
59	All	Civils	Cable Tunnels	km			–	N/A

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
Network / Sub-network Name	**Central Otago & Wānaka Sub-network**

SCHEDULE 9a: ASSET REGISTER

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

sch ref

9a: Asset Register

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.	10,855	11,212	357	4
10	All	Overhead Line	Wood poles	No.	8,992	8,650	(342)	4
11	All	Overhead Line	Other pole types	No.			–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	309	309	0	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km			–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	9	9	(0)	3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km			–	N/A
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km			–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	0	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.	10	10	–	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.	15	15	–	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.			–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	104	105	1	4
29	HV	Zone substation switchgear	33kV RMU	No.	1	1	–	4
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.			–	N/A
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	26	23	(3)	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	51	58	7	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	13	10	(3)	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	21	21	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1,273	1,269	(3)	4
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km			–	N/A
37	HV	Distribution Line	SWER conductor	km			–	N/A
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	531	556	25	3
39	HV	Distribution Cable	Distribution UG PILC	km	58	58	(1)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km			–	N/A
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	28	28	–	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.			–	N/A
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	3,448	3,478	30	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	85	73	(12)	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	293	329	36	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	1,868	1,869	1	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	1,511	1,536	25	4
48	HV	Distribution Transformer	Voltage regulators	No.	28	31	3	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.			–	N/A
50	LV	LV Line	LV OH Conductor	km	174	174	(0)	4
51	LV	LV Cable	LV UG Cable	km	525	552	27	4
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	252	255	3	4
53	LV	Connections	OH/UG consumer service connections	No.	23,986	24,654	668	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	138	180	42	4
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot			–	N/A
56	All	Capacitor Banks	Capacitors including controls	No			–	N/A
57	All	Load Control	Centralised plant	Lot	2	2	–	4
58	All	Load Control	Relays	No	710	517	(193)	2
59	All	Civils	Cable Tunnels	km			–	N/A

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
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

9a: Asset Register

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.	1,963	2,095	132	4
10	All	Overhead Line	Wood poles	No.	2,687	2,537	(150)	4
11	All	Overhead Line	Other pole types	No.			–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	69	67	(2)	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km			–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	22	27	5	3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km			–	N/A
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km			–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km			–	N/A
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km			–	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km			–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km			–	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km			–	N/A
22	HV	Subtransmission Cable	Subtransmission submarine cable	km			–	N/A
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	5	5	–	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.			–	N/A
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.			–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.			–	N/A
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.			–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	57	57	–	4
29	HV	Zone substation switchgear	33kV RMU	No.			–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	6	6	–	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	13	12	(1)	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	11	1	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	14	14	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	282	280	(2)	4
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km			–	N/A
37	HV	Distribution Line	SWER conductor	km			–	N/A
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	216	226	10	3
39	HV	Distribution Cable	Distribution UG PILC	km	81	79	(2)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km			–	N/A
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	18	15	(3)	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.			–	N/A
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1,012	1,016	4	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	117	108	(9)	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	269	279	10	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	467	463	(4)	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	854	865	11	4
48	HV	Distribution Transformer	Voltage regulators	No.	8	8	–	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.			–	N/A
50	LV	LV Line	LV OH Conductor	km	44	44	(0)	4
51	LV	LV Cable	LV UG Cable	km	321	329	7	4
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	143	143	(0)	4
53	LV	Connections	OH/UG consumer service connections	No.	15,340	15,676	336	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	82	108	26	4
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot			–	N/A
56	All	Capacitor Banks	Capacitors including controls	No			–	N/A
57	All	Load Control	Centralised plant	Lot	1	1	–	4
58	All	Load Control	Relays	No	472	318	(154)	2
59	All	Civils	Cable Tunnels	km			–	N/A

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
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

9b: Asset Age Profile

8 — **Disclosure Year (year ended)**

Number of assets at disclosure year end by installation date

9	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	No. with age unknown	Items at end of year	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.		17	1,429	5,863	4,200	2,825	1,608	95	69	120	148	124	61	99	165	158	155	112	129	344	533	445	728	664	960	2,237	1,492	1,086	1,311	1,712	1,415	1,347	770	2	32,403		4
11	All	Overhead Line	Wood poles	No.	577	577	1,146	4,400	3,435	2,854	2,639	279	214	215	345	277	283	230	279	281	267	350	339	241	140	90	103	95	133	633	196	141	140	148	96	82	70		21,295		4
12	All	Overhead Line	Other pole types	No.																																		–		N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	58		61	119	73	35	123	0		1			0		6		1	6	11		0	0	3	2		1	1	0	1	12	1	1	2		535		4
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km																																		–		N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km					0	1	6				0	1	1	0	0	2	1	0	0	1	4		1	0	3	10			0	1	2	10	5		51		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			1	1		37		4
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				1		15		4
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.																																		–		N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.			40	15	29	25	22	1			2	3	1			1	17	2	3	2	1	27	9	9	4	2	19	1	3	13	8	3	2	1	265		4
30	HV	Zone substation switchgear	33kV RMU	No.																													1					1		4
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.							6																				3							9		4
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.					5	7	10			1	1		1		3	4	1	2		3	2	3				1	1		2	4	2	1		54		4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.			31	20	62	24	26				11	17		10		8		19	20	12	2	10	6	6		1	16		2	1	3	16	5		327		4
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.					2		2	1			4	2	1	4						1							1						1		21		4
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.			4	8	12	8	6			1	3	1	1			1		2	3	1	2	1	1	2			2	1	2	1	1	3	4		69		4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1	39	138	542	374	345	325	12	11	14	7	10	29	9	12	7	9	12	13	6	8	7	15	22	10	13	11	27	29	80	47	35	51		2,271		4
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km																																		–		N/A
38	HV	Distribution Line	SWER conductor	km			0	0	0	0	0																								4			5		4
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km				0	4	10	62	12	23	25	29	54	31	38	51	36	21	15	14	9	10	29	40	40	27	30	35	28	40	36	29	27	41		843		3
40	HV	Distribution Cable	Distribution UG PILC	km	0	8	34	47	68	71	63	6	6	9	13	6	9	11	15	5	8	9	6	5	3	4	1	1	0	–	0	–	–	–	0	0	–		407		3
41	HV	Distribution Cable	Distribution Submarine Cable	km		1																													3			5		4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionaliser	No.						1	1					2	3		2	5	9	1	1		2			6	1	3		1	8	5	2	3	2	58		4
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.					2														1															3		4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	2	7	54	377	382	501	865	114	99	114	125	148	118	135	110	116	123	134	137	90	119	114	161	159	120	220	275	278	350	480	530	449	384	1	7,393		4
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.				40	23	50	43	7	3	17	17	16	17	17	30	16	24	20	11	9	15	2	1	1	1	2	2	1				1	1	2	389		3
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.				1	35	57	104	8	16	14	36	10	24	23	17	19	24	15	20	21	12	17	16	33	37	28	55	60	64	64	60	68	92		1,060		3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.			3	23	176	280	622	801	103	82	95	104	93	75	69	64	68	71	56	53	52	75	60	78	63	39	86	89	108	145	146	162	128	134		4,010		4
48	HV	Distribution Transformer	Ground Mounted Transformer	No.				31	142	166	612	58	92	93	114	143	171	158	142	117	121	55	79	60	64	85	97	102	87	94	112	96	112	98	97	115	110	1	3,426		4
49	HV	Distribution Transformer	Voltage regulators	No.					1										3		4	2					2						3	2	7	8	9		41		4
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.				1	95	93	108	7	2	4	1		2	1	1				1			1	1					1		1	2	2		323		4
51	LV	LV Line	LV OH Conductor	km	51	40	101	228	208	157	171	5	4	3	4	5	3	3	2	2	2	3	2	1	2	2	2	1	1	1	1	2	2	1	5	7	1		1,022		4
52	LV	LV Cable	LV UG Cable	km	0	0	1	22	41	159	156	19	21	25	41	48	51	44	47	40	36	22	14	20	15	20	23	28	31	32	41	40	31	35	35	35	32		1,307		4
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	19	15	35	139	151	241	287	7	7	8	9	10	10	7	10	11	9	9	7	10	7	7	4	12	8	11	9	8	5	4	12	9	3	0	1,086		4
54	LV	Connections	OH/UG consumer service connections	No.	13,058	2,713	6,769	8,605	7,072	4,454	21,654	1,010	952	1,201	1,372	1,563	1,567	1,737	1,520	1,645	1,213	1,085	993	877	1,015	1,104	1,209	1,247	1,648	1,491	1,520	1,402	1,556	1,336	1,307	1,194	1,347		98,470		4
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.			96	46	60	27	73			6	17	25	4	24	4	7	8	46	5	25	9	22	7	17	3	12	41	17	61	31	34	51	5	0	598		4
56	All	SCADA and communications	SCADA and communications equipment operating as a single sys	Lot								–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–		1		4
57	All	Capacitor Banks	Capacitors including controls	No																				3														3		4
58	All	Load Control	Controlled plant	Lot				1	1												1	1	3				1											8		4
59	All	Load Control	Relays	No.	3	5	18	67	90	158	288	16	29	36	59	73	80	68	76	32	31	16	15	17	19	21	13	25	17	30	26	29	31	17	29	37	18		1,487		2
60	All	Civils	Cable Tunnels	km																																		–		N/A

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
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

9b: Asset Age Profile

8		Disclosure Year (year ended)			Number of assets at disclosure year end by installation date																														
9	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	No. with age unknown	Items at end of year	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.		3	1,353	5,518	2,700	1,918	742	21	11	41	53	23	16	22	28	19	16	25	27	79	153	169	311	292	529	1,042	885	612	557	607	526	493	308	1	19,096		4
11	All	Overhead Line	Wood poles	No.	577	557	1,076	2,011	898	1,113	1,445	167	151	115	111	87	110	100	108	139	129	89	80	101	62	36	21	19	37	487	106	62	42	20	22	35	24		10,108		4
12	All	Overhead Line	Other pole types	No.																																			–		N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	48		51	27	3		2																					11					143		4
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		0	0	1				15		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				1			22		4
25	HV	Zone substation Buildings	Zone substations 110kV+	No.																																			–		N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.																																			–		N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.																																			–		N/A
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.																																			–		N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.			27	14	4		9												2	2		27	1		4		2		2	9				103		4
30	HV	Zone substation switchgear	33kV RMU	No.																																			–		N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.																											3								3		4
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.					4					1					3	4				3	2									2				19		4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.				31	20	63	17	13				17			9				11	17							16			1		15			228		4
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.																																			–		4
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.			3	7	10	2	2									1			2		2					2			1		2			34		4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0	12	73	223	130	66	63	5	4	8	3	4	5	5	2	5	5	4	1	1	0	2	2	0	0	1	0	14	9	34	14	16	20		722		4
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km																																			–		N/A
38	HV	Distribution Line	SWER conductor	km			0	0	0	0																									4			5		4
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km				0	0	0	4	1	1	2	2	2	3	3	3	1	1	0	2	1	1	1	1	2	4	2	2	4	3	5	2	4	3	61		3
40	HV	Distribution Cable	Distribution UG PILC	km	0	8	34	47	68	48	29	2	1	1	1	1	2	3	1	1	3	3	6	3	3	3	1	1	0	0	0		0	0	0		0		275		3
41	HV	Distribution Cable	Distribution Submarine Cable	km		1																												3					5		4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionaliser	No.															2		3		1					4		1		1	1	1			1	15		4
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.					2														1															3		4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1	7	32	316	266	269	364	15	12	19	27	35	29	50	33	21	21	21	20	16	25	33	36	45	41	67	77	135	134	223	181	189	137		2,897		4
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.				40	23	50	30	5		9	4	6		3	2	3	6	1	6	4	10	1				1	1	1				1	1		208		3
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.				1	35	55	89	6	6	3	7	4	11	5	3	1	9	6	11	8	9	8	8	8	14	4	12	14	27	27	20	22	29		442		3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.				2	125	166	215	184	29	25	25	39	27	29	33	24	18	16	16	13	17	19	15	25	16	18	28	24	38	41	66	53	52	70		1,678		4
48	HV	Distribution Transformer	Ground Mounted Transformer	No.					32	130	124	190	15	10	15	21	13	21	36	19	11	20	15	19	19	16	19	20	24	25	28	16	32	30	12	23	33	35		1,023		4
49	HV	Distribution Transformer	Voltage regulators	No.						1																								1					2		4
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.				1	95	91	108	7	2	4	1		2	1	1				1			1	1						1		1	2	2		323		4
51	LV	LV Line	LV OH Conductor	km	48	25	64	167	167	139	147	4	3	2	3	4	3	2	2	1	1	2	2	0	2	1	1	0	1	0	1	1	1	1	3	5	0		804		4
52	LV	LV Cable	LV UG Cable	km	0	0	1	22	42	34	35	4	3	4	5	8	8	13	11	7	8	8	4	8	7	8	7	7	8	8	7	8	8	9	7	8	5		327		4
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	12	6	18	114	135	105	218	3	3	2	4	3	4	2	3	3	4	6	4	6	4	3	2	5	4	2	1	1	1	1	5	4	1	1	688		4
54	LV	Connections	OH/UG consumer service connections	No.	13,058	2,713	6,769	8,601	7,064	4,449	4,828	311	283	245	358	485	433	528	505	538	360	428	369	378	364	378	413	364	443	426	451	424	464	426	460	444	343		58,140		4
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.				96	46	54	3	46				22		13	3	2	2	30	1			16		8	2	3	29	14	42	26	20	22		1	500		4
56	All	SCADA and communications	SCADA and communications equipment operating as a single sys	Lot																				–	–	–	–	–	–	–	1		–	–	–	–	–		1		4
57	All	Capacitor Banks	Capacitors including controls	No																				3															3		4
58	All	Load Control	Controlled plant	Lot				1	1														3															5		4
59	All	Load Control	Relays	No.	2	5	13	65	86	77	157	3		4	8	4	9	7	18	7	10	9	8	6	9	8	8	10	13	15	8	13	22	6	18	16	8		652		2
60	All	Civils	Cable Tunnels	km																																			–		N/A

Company Name: Aurora Energy Limited
For Year Ended: 31 March 2025
Network / Sub-network Name: Central Otago & Wānaka Sub-network

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

9b: Asset Age Profile

8		Disclosure Year (year ended)			Number of assets at disclosure year end by installation date																														
9	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	No. with age unknown	Items at end of year	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.		14	78	314	1,298	669	679	63	45	68	78	88	37	70	121	112	125	83	74	213	370	250	373	327	382	997	511	418	676	878	710	726	339		11,212		4
11	All	Overhead Line	Wood poles	No.		16	69	2,077	1,966	1,200	807	83	45	79	208	148	146	100	143	97	98	215	218	106	50	51	71	68	81	117	61	61	75	96	45	16	42		8,630		4
12	All	Overhead Line	Other pole types	No.																																		–		N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	9		8	67	57	34	101	0		1					4			6	11			0	2	2		1	1	0	1	1	1	0		309		4
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	0	0			8		3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km																																		–		N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km																																		–		N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km							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						1			10		4
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					1		15		4
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.																																		–		N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.			13	1		21	11	1			2	3					2		1		1		8	8		16	1	1	2	8	2	2	1	105		4
30	HV	Zone substation switchgear	33kV RMU	No.																												1						1		4
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.																																		–		N/A
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.					7	4				1			1				1				3				1			2	1	2			23		4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.					7						11				1	8			3		2	3	6	6		1			2		3	1	5	58		4
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.						1	1				4	2													1					1				10		4
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.				1		2	1			1	3	1							1			1	1	2					2		1	1	2	21		4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1	27	61	272	241	191	182	5	5	5	7	6	24	1	6	0	3	5	11	2	8	6	12	22	4	11	10	13	20	44	28	14	28	1,269		4
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km																																		–		N/A
38	HV	Distribution Line	SWER conductor	km																																		–		N/A
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km				0	4	8	21	2	13	13	20	34	17	22	35	17	15	10	8	6	9	28	34	32	15	23	22	18	28	22	22	17	27	516		3
40	HV	Distribution Cable	Distribution UG PILC	km	0				0	12	15	1	3	3	3	3	5	2	6	1	0	2	0	1	0	0									0	0		58		3
41	HV	Distribution Cable	Distribution Submarine Cable	km																																		–		N/A
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionaliser	No.						1	1				2	1				5	4	1			1		1	1	2			1	3	2	1	1		28		4
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.																																		–		N/A
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1		23	52	97	183	349	66	57	59	76	87	64	65	54	79	78	87	96	54	82	77	114	99	65	128	167	118	176	210	276	205	134	1	3,478		4
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.							6	1		7	4	2	6	1	13	2	11	7	2	4	3			1	1		1						1	73		3
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.						1	15	1	4	7	9	2	8	4	6	6	3	5	5	6	2	6	4	12	8	15	24	30	25	24	26	32	19	329		3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.		3	28	43	107	165	302	45	45	50	54	52	37	32	33	42	39	25	34	31	46	42	45	39	18	49	56	62	95	69	88	56	52	1,869		4
48	HV	Distribution Transformer	Ground Mounted Transformer	No.					6	28	115	18	46	44	56	73	90	89	80	59	67	27	28	28	37	57	71	53	43	54	61	47	57	55	55	57	55	1,535		4
49	HV	Distribution Transformer	Voltage regulators	No.																	2	2					2						2	2	4	8	9	31		4
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.																																		–		N/A
51	LV	LV Line	LV OH Conductor	km	3	14	30	49	29	17	18	1	1	0	1	1	1	1	1	0	1	1	0	0	0	0	0	0	0	0	1	1	0	1	2	0	176		4
52	LV	LV Cable	LV UG Cable	km					1	71	64	5	8	13	17	22	29	21	17	22	15	11	6	7	5	9	11	16	17	18	27	22	15	19	22	20	21	552		4
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	3	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	6	2	3	4	5	2	1	259		4
54	LV	Connections	OH/UG consumer service connections	No.				3	5	4	10,022	340	321	488	568	606	587	590	582	698	541	365	343	270	347	417	506	610	757	697	673	650	640	609	581	538	668		24,654		4
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.					9	13	4			4	16	3	1	11	1	5	3	5	4	10	7		7	8	1	10	11		13	4	13	11	4	4	140		4
56	All	SCADA and communications	SCADA and communications equipment operating as a single sys	Lot																																		–		N/A
57	All	Capacitor Banks	Capacitors including controls	No.																																		–		N/A
58	All	Load Control	Centralised plant	Lot																	1							1										2		4
59	All	Load Control	Relays	No.	1		5	2	4	46	68	8	13	21	21	43	42	39	36	20	19	6	5	6	7	12	5	9	3	10	12	9	4	8	8	17	8		517		2
60	All	Civils	Cable Tunnels	km																																		–		N/A

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
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

9b: Asset Age Profile

8		Disclosure Year (year ended)			Number of assets at disclosure year end by installation date																															
9	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	No. with age unknown	Items at end of year	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.				28	202	207	187	11	13	10	17	13	8	7	16	27	14	4	28	52	10	26	44	25	49	198	96	56	78	226	178	128	137		2,095		4
11	All	Overhead Line	Wood poles	No.		4	1	313	691	541	386	39	23	21	26	42	27	30	28	45	40	46	41	34	28	3	11	8	15	29	28	18	23	32	29	31	4		2,537		4
12	All	Overhead Line	Other pole types	No.																																			–		N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km			2	26	13	1	13						0		2		1				0		1							0	0	0	2		67		4
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km																																			–		N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km					0		5						1	0	0	0	2	0		0	1						1			0	0	10	5		27		3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km																																			–		N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km																																			–		N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km																																			–		N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km																																			–		N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km																																			–		N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km																																			–		N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km																																			–		N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km																																			–		N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.					1	1	2											1																	5		4
25	HV	Zone substation Buildings	Zone substations 110kV+	No.																																			–		N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.																																			–		N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.																																			–		N/A
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.																																			–		N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.					25	4	2						1				1	15	2					1		2	1			2		1		57		4
30	HV	Zone substation switchgear	33kV RMU	No.																																			–		N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.							6																												6		4
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.					1		6											2								1				1		1			12		4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.							13											8		12		7													40		4
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.					2		1						1	4						1							1					1			11		4
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.				1	1	2	3						1					2		1								1					2		14		4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0	0	5	48	13	88	80	2	2	1	1	0	0	3	4	2	1	3	1	3	0		1	0	5	1	0	0	1	2	5	5	3		280		4
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km																																			–		N/A
38	HV	Distribution Line	SWER conductor	km																																			–		N/A
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km						2	22	4	9	9	7	18	12	12	14	15	5	4	4	2	1	1	5	6	8	5	11	6	8	9	6	8	11		225		3
40	HV	Distribution Cable	Distribution UG PILC	km					0	12	19	3	2	5	9	1	2	5	8	3	5	4	0	0	0	0		0	0										75		3
41	HV	Distribution Cable	Distribution Submarine Cable	km																																			–		N/A
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionaliser	No.													2				2			1				1					6	1		2			15		4
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.																																			–		N/A
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.				9	19	49	152	33	30	36	22	26	25	20	23	16	24	26	21	20	12	4	11	15	14	25	31	25	40	47	73	55	113		1,016		4
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.							7	1	3	1	9	8	11	13	15	11	7	12	3	1	2	1	1			1					1				108		3
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.						1	20	1	6	4	20	4	5	14	8	11	12	4	4	7	1	3	4	13	14	9	19	16	14	13	14	14	24		270		3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.			3	8	17	43	115	27	27	20	11	14	9	4	7	8	16	15	6	4	10	3	8	8	3	9	9	8	9	11	21	20	12		463		4
48	HV	Distribution Transformer	Ground Mounted Transformer	No.				6	14	107	25	16	34	37	57	60	53	43	47	34	13	32	13	11	9	6	24	19	12	35	17	25	31	19	25	20	1		865		4
49	HV	Distribution Transformer	Voltage regulators	No.														3			2													3					8		4
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.																																			–		N/A
51	LV	LV Line	LV OH Conductor	km		1	8	13	12	2	6	0	0	1	0	0	0	–		0	0		0	0	0	0	0	0		0		0			0	0	0		44		4
52	LV	LV Cable	LV UG Cable	km				0	1	51	51	10	10	8	18	18	13	10	18	11	13	3	5	5	3	3	4	6	6	6	7	10	7	6	6	7	6		320		4
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km			4	5	5	50	34	2	2	1	2	5	2	1	4	1	0	1	1	1	1	0		4	1	4	4	1	1	1	3	1	0		143		4
54	LV	Connections	OH/UG consumer service connections	No.				1	3	1	6,198	359	348	468	446	472	547	619	433	409	312	292	281	220	304	309	290	273	448	372	396	328	443	301	257	212	336		15,676		4
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.						11	23			2	1		3	1			2	11		15	1	6		1			1	3	6	1	1	18	1	1	108		4
56	All	SCADA and communications	SCADA and communications equipment operating as a single sys	Lot								–		–						–	–			–					–				–	–	–	–	–		1		N/A
57	All	Capacitor Banks	Capacitors including controls	No.																																			–		N/A
58	All	Load Control	Centralised plant	Lot																		1																	1		4
59	All	Load Control	Relays	No.						33	63	5	16	11	30	26	29	22	22	5	2	1	2	5	3	1		6	1	5	6	7	5	3	3	4	2		318		2
60	All	Civils	Cable Tunnels	km																																			–		N/A

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
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

9c: Overhead Lines and Underground Cables

	Overhead (km)	Underground (km)	Total circuit length (km)
Circuit length by operating voltage (at year end)			
> 66kV			–
50kV & 66kV	127	3	129
33kV	393	101	494
SWER (all SWER voltages)	5		5
22kV (other than SWER)			–
6.6kV to 11kV (inclusive—other than SWER)	2,271	1,250	3,521
Low voltage (< 1kV)	1,022	1,207	2,229
Total circuit length (for supply)	3,818	2,560	6,378
Dedicated street lighting circuit length (km)	529	557	1,086
Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			50

	Circuit length (km)	(% of total overhead length)
Overhead circuit length by terrain (at year end)		
Urban	1,151	30%
Rural	2,580	68%
Remote only	–	–
Rugged only	87	2%
Remote and rugged		–
Unallocated overhead lines		–
Total overhead length	3,818	100%

	Circuit length (km)	(% of total circuit length)	
Length of circuit within 10km of coastline or geothermal areas (where known)	1,462	23%	

	Circuit length (km)	(% of total overhead length)	
Overhead circuit requiring vegetation management	3,818	100%	*Not required after DY2025*

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

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

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

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
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

9c: Overhead Lines and Underground Cables

	Overhead (km)	Underground (km)	Total circuit length (km)
Circuit length by operating voltage (at year end)			
> 66kV			–
50kV & 66kV			–
33kV	143	67	210
SWER (all SWER voltages)	5		5
22kV (other than SWER)			–
6.6kV to 11kV (inclusive—other than SWER)	722	331	1,053
Low voltage (< 1kV)	804	327	1,131
Total circuit length (for supply)	1,675	725	2,399
Dedicated street lighting circuit length (km)	457	231	688
Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			3

Overhead circuit length by terrain (at year end)	Circuit length (km)	(% of total overhead length)
Urban	963	58%
Rural	703	42%
Remote only		–
Rugged only	9	1%
Remote and rugged		–
Unallocated overhead lines		–
Total overhead length	1,675	100%

	Circuit length (km)	(% of total circuit length)
Length of circuit within 10km of coastline or geothermal areas (where known)	1,462	61%

	Circuit length (km)	(% of total overhead length)	
Overhead circuit requiring vegetation management	1,675	100%	*Not required after DY2025*

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

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

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

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
Network / Sub-network Name	**Central Otago & Wānaka Sub-network**

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref

9c: Overhead Lines and Underground Cables

	Overhead (km)	Underground (km)	Total circuit length (km)
Circuit length by operating voltage (at year end)			
> 66kV			–
50kV & 66kV	127	3	129
33kV	182	7	189
SWER (all SWER voltages)			–
22kV (other than SWER)			–
6.6kV to 11kV (inclusive—other than SWER)	1,269	614	1,883
Low voltage (< 1kV)	174	552	726
Total circuit length (for supply)	1,752	1,175	2,927
Dedicated street lighting circuit length (km)	57	198	255
Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			27

Overhead circuit length by terrain (at year end)	Circuit length (km)	(% of total overhead length)
Urban	126	7%
Rural	1,572	90%
Remote only		–
Rugged only	55	3%
Remote and rugged		–
Unallocated overhead lines		–
Total overhead length	1,752	100%

	Circuit length (km)	(% of total circuit length)
Length of circuit within 10km of coastline or geothermal areas (where known)		–

	Circuit length (km)	(% of total overhead length)	
Overhead circuit requiring vegetation management	1,752	100%	*Not required after DY2025*

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

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

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

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
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

9c: Overhead Lines and Underground Cables

	Overhead (km)	Underground (km)	Total circuit length (km)
Circuit length by operating voltage (at year end)			
> 66kV			–
50kV & 66kV			–
33kV	67	27	94
SWER (all SWER voltages)			–
22kV (other than SWER)			–
6.6kV to 11kV (inclusive—other than SWER)	280	305	585
Low voltage (< 1kV)	44	329	372
Total circuit length (for supply)	391	661	1,051
Dedicated street lighting circuit length (km)	15	128	143
Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			20

	Circuit length (km)	(% of total overhead length)
Overhead circuit length by terrain (at year end)		
Urban	63	16%
Rural	305	78%
Remote only		–
Rugged only	22	6%
Remote and rugged		–
Unallocated overhead lines		–
Total overhead length	391	100%

	Circuit length (km)	(% of total circuit length)
Length of circuit within 10km of coastline or geothermal areas (where known)	0	0%

	Circuit length (km)	(% of total overhead length)	
Overhead circuit requiring vegetation management	391	100%	*Not required after DY2025*

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

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

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

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**

SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

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

sch ref	Location *	Average number of ICPs in disclosure year	Line charge revenue ($000)
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			

** 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 2025**
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

9e(i): Consumer Connections and Decommissionings

Number of ICPs connected during year by consumer type

*Consumer types defined by EDB**	Number of connections (ICPs)
Residential	1,746
Load Group 0	8
Load Group 0A	(106)
Load Group 1A	18
Load Group 1	(8)
Load Group 2	369
Load Group 3	16
Load Group 3A	16
Load Group 4	11
Load Group 5	(1)
Street Lighting	–
Distributed Unmetered Load (excl. Street Lighting)	–

** include additional rows if needed*

Connections total 2,069

Number of ICPs decommissioned during year by consumer type

*Consumer types defined by EDB**	Number of decommissionings
Residential	110
Load Group 0	8
Load Group 0A	36
Load Group 1A	26
Load Group 1	25
Load Group 2	39
Load Group 3	–
Load Group 3A	2
Load Group 4	–
Load Group 5	–
Street Lighting	–
Distributed Unmetered Load (excl. Street Lighting)	–

** include additional rows if needed*

Decommissionings total 246

Distributed generation

Number of connections made in year	708	**connections**
Capacity of distributed generation installed in year	6	**MVA**

9e(ii): System Demand

		Demand at time of maximum coincident demand (MW)	
Maximum coincident system demand			
	GXP demand	285	
plus	Distributed generation output at HV and above	26	
	Maximum coincident system demand	311	
less	Net transfers to (from) other EDBs at HV and above	–	
	Demand on system for supply to consumers' connection points	311	

		Energy (GWh)	
Electricity volumes carried			
	Electricity supplied from GXPs	1,172	
less	Electricity exports to GXPs	34	
plus	Electricity supplied from distributed generation	350	
less	Net electricity supplied to (from) other EDBs	7	
	Electricity entering system for supply to consumers' connection points	1,481	
less	Total energy delivered to ICPs	1,409	
	Electricity losses (loss ratio)	72	4.8%
	Load factor	0.54	

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
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).

9e(iii): Transformer Capacity

	(MVA)
Distribution transformer capacity (EDB owned)	998
Distribution transformer capacity (Non-EDB owned)	43
Total distribution transformer capacity	1,041

	(MVA)
Zone substation transformer capacity (EDB owned)	1,113
Zone substation transformer capacity (Non-EDB owned)	–
Total zone substation transformer capacity	1,113

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
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

9e(i): Consumer Connections and Decommissionings

Number of ICPs connected during year by consumer type

*Consumer types defined by EDB**	Number of connections (ICPs)
Residential	476
Load Group 0	4
Load Group 0A	(26)
Load Group 1A	(8)
Load Group 1	(24)
Load Group 2	14
Load Group 3	2
Load Group 3A	4
Load Group 4	6
Load Group 5	(1)
Street Lighting	–
Distributed Unmetered Load (excl. Street Lighting)	–

** include additional rows if needed*

Connections total 447

Number of ICPs decommissioned during year by consumer type

*Consumer types defined by EDB**	Number of decommissionings
Residential	62
Load Group 0	1
Load Group 0A	16
Load Group 1A	15
Load Group 1	13
Load Group 2	20
Load Group 3	–
Load Group 3A	2
Load Group 4	–
Load Group 5	–
Street Lighting	–
Distributed Unmetered Load (excl. Street Lighting)	–

** include additional rows if needed*

Decommissionings total 129

Distributed generation

Number of connections made in year	186	**connections**
Capacity of distributed generation installed in year	1.30	**MVA**

9e(ii): System Demand

		Demand at time of maximum coincident demand (MW)	
	Maximum coincident system demand		
	GXP demand	128	
plus	Distributed generation output at HV and above	53	
	Maximum coincident system demand	181	
less	Net transfers to (from) other EDBs at HV and above	–	
	Demand on system for supply to consumers' connection points	181	

		Energy (GWh)	
	Electricity volumes carried		
	Electricity supplied from GXPs	663	
less	Electricity exports to GXPs	0	
plus	Electricity supplied from distributed generation	169	
less	Net electricity supplied to (from) other EDBs	–	
	Electricity entering system for supply to consumers' connection points	832	
less	Total energy delivered to ICPs	789	
	Electricity losses (loss ratio)	42	5.1%

Load factor 0.52

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
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).

9e(iii): Transformer Capacity

	(MVA)
Distribution transformer capacity (EDB owned)	496
Distribution transformer capacity (Non-EDB owned)	26
Total distribution transformer capacity	522

	(MVA)
Zone substation transformer capacity (EDB owned)	604
Zone substation transformer capacity (Non-EDB owned)	–
Total zone substation transformer capacity	604

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
Network / Sub-network Name	**Central Otago & Wānaka 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

9e(i): Consumer Connections and Decommissionings

Number of ICPs connected during year by consumer type

*Consumer types defined by EDB**	Number of connections (ICPs)
Residential	938
Load Group 0	3
Load Group 0A	(56)
Load Group 1A	17
Load Group 1	23
Load Group 2	155
Load Group 3	8
Load Group 3A	9
Load Group 4	1
Load Group 5	–
Street Lighting	–
Distributed Unmetered Load (excl. Street Lighting)	–

** include additional rows if needed*

Connections total 1,098

Number of ICPs decommissioned during year by consumer type

*Consumer types defined by EDB**	Number of decommissionings
Residential	25
Load Group 0	4
Load Group 0A	10
Load Group 1A	6
Load Group 1	9
Load Group 2	10
Load Group 3	–
Load Group 3A	–
Load Group 4	–
Load Group 5	–
Street Lighting	–
Distributed Unmetered Load (excl. Street Lighting)	–

** include additional rows if needed*

Decommissionings total 64

Distributed generation

Number of connections made in year	389	**connections**
Capacity of distributed generation installed in year	3.73	**MVA**

9e(ii): System Demand

		Demand at time of maximum coincident demand (MW)	
	Maximum coincident system demand		
	GXP demand	49	
plus	Distributed generation output at HV and above	22	
	Maximum coincident system demand	71	
less	Net transfers to (from) other EDBs at HV and above	–	
	Demand on system for supply to consumers' connection points	71	

		Energy (GWh)	
	Electricity volumes carried		
	Electricity supplied from GXPs	228	
less	Electricity exports to GXPs	34	
plus	Electricity supplied from distributed generation	165	
less	Net electricity supplied to (from) other EDBs	7	
	Electricity entering system for supply to consumers' connection points	352	
less	Total energy delivered to ICPs	334	
	Electricity losses (loss ratio)	18	5.0%

Load factor 0.57

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
Network / Sub-network Name	**Central Otago & Wānaka 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).

9e(iii): Transformer Capacity

	(MVA)
Distribution transformer capacity (EDB owned)	317
Distribution transformer capacity (Non-EDB owned)	15
Total distribution transformer capacity	331

	(MVA)
Zone substation transformer capacity (EDB owned)	334
Zone substation transformer capacity (Non-EDB owned)	–
Total zone substation transformer capacity	334

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
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

9e(i): Consumer Connections and Decommissionings

Number of ICPs connected during year by consumer type

	*Consumer types defined by EDB**	**Number of connections (ICPs)**
	Residential	332
	Load Group 0	1
	Load Group 0A	(24)
	Load Group 1A	9
	Load Group 1	(7)
	Load Group 2	200
	Load Group 3	6
	Load Group 3A	3
	Load Group 4	4
	Load Group 5	–
	Street Lighting	–
	Distributed Unmetered Load (excl. Street Lighting)	–
	** include additional rows if needed*	
	Connections total	524

Number of ICPs decommissioned during year by consumer type

	*Consumer types defined by EDB**	**Number of decommissionings**
	Residential	23
	Load Group 0	3
	Load Group 0A	10
	Load Group 1A	5
	Load Group 1	3
	Load Group 2	9
	Load Group 3	–
	Load Group 3A	–
	Load Group 4	–
	Load Group 5	–
	Street Lighting	–
	Distributed Unmetered Load (excl. Street Lighting)	–
	** include additional rows if needed*	
	Decommissionings total	53

Distributed generation

Number of connections made in year	133	**connections**
Capacity of distributed generation installed in year	1.46	**MVA**

9e(ii): System Demand

		Demand at time of maximum coincident demand (MW)	
	Maximum coincident system demand		
	GXP demand	68	
plus	Distributed generation output at HV and above	1	
	Maximum coincident system demand	69	
less	Net transfers to (from) other EDBs at HV and above	–	
	Demand on system for supply to consumers' connection points	69	

		Energy (GWh)	
	Electricity volumes carried		
	Electricity supplied from GXPs	281	
less	Electricity exports to GXPs	–	
plus	Electricity supplied from distributed generation	16	
less	Net electricity supplied to (from) other EDBs	–	
	Electricity entering system for supply to consumers' connection points	297	
less	Total energy delivered to ICPs	285	
	Electricity losses (loss ratio)	12	3.9%
	Load factor	0.49	

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
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).

9e(iii): Transformer Capacity

	(MVA)
Distribution transformer capacity (EDB owned)	186
Distribution transformer capacity (Non-EDB owned)	2
Total distribution transformer capacity	188

	(MVA)
Zone substation transformer capacity (EDB owned)	175
Zone substation transformer capacity (Non-EDB owned)	–
Total zone substation transformer capacity	175

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

8 **10(i): Interruptions**

		Number of interruptions
9	**Interruptions by class**	
10	Class A (planned interruptions by Transpower)	–
11	Class B (planned interruptions on the network)	1,020
12	Class C (unplanned interruptions on the network)	641
13	Class D (unplanned interruptions by Transpower)	3
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**	1,667

		≤3Hrs	>3hrs
21	**Interruption restoration**		
22	Class C interruptions restored within	475	166

		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	165.3
27	Class C (unplanned interruptions on the network)	1.25	92.0
28	Class D (unplanned interruptions by Transpower)	0.03	2.4
29	Class E (unplanned interruptions of EDB owned generation)	–	–
30	Class F (unplanned interruptions of generation owned by others)	0.00	0.0
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	0.1
34	**Total**	1.84	259.7

		SAIFI	SAIDI
36	**Transitional SAIFI and SAIDI (previous method)**		
37	Class B (planned interruptions on the network)		
38	Class C (unplanned interruptions on the network)		

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
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 this 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	0.00	0.01
Vegetation	0.15	13.00
Adverse weather	–	–
Adverse environment	0.02	3.13
Third party interference	0.12	6.73
Wildlife	0.02	2.14
Human error	0.19	6.73
Defective equipment	0.48	42.09
Other cause	–	–
Unknown	0.27	18.19

Breakdown of third party interference	SAIFI	SAIDI
Dig-in	0.01	0.37
Overhead contact	0.03	2.33
Vandalism	0.00	0.14
Vehicle damage	0.09	3.89
Other	–	–

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

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.00	0.35
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.40	121.75
Distribution cables (excluding LV)	0.11	31.64
Distribution other (excluding LV)	0.05	11.5

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.16	12.28
Subtransmission cables	0.02	0.69
Subtransmission other	0.04	1.54
Distribution lines (excluding LV)	0.60	53.28
Distribution cables (excluding LV)	0.20	15.36
Distribution other (excluding LV)	0.23	8.87

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	15	522	2.87
Subtransmission cables	1	89	1.12
Subtransmission other	5		
Distribution lines (excluding LV)	175	2,285	7.66
Distribution cables (excluding LV)	38	1,195	3.18
Distribution other (excluding LV)	150		
Total	384		

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

10(vi): Worst-performing feeders (unplanned)

SAIDI

Rank	Feeder name	Unplanned SAIDI values	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1	CB168	12.34	26	Defective equipment	169	1122	
2	CB2006	8.34	28	Defective equipment	130	1125	
3	CB656	7.24	53	Defective equipment	257	688	
4	CB2423	3.58	12	Defective equipment	126	390	
5	CB480	3.34	28	Vegetation	114	412	
6	PC3	2.99	8	Defective equipment	62	529	
7	CB2755	2.79	4	Wildlife	60	913	
8	CB5310	2.50	3	Human error	5	220	
9	CB2758	2.04	6	Defective equipment	52	1180	
10	CB167	2.04	7	Human error	23	905	
11	CB821	2.03	8	Human error	103	778	
12	CB832	1.90	7	Human error	121	1425	
13	CB838	1.60	4	Defective equipment	18	544	
14	CB2752	1.48	10	Third-party Interference	156	1523	
15	CB7632	1.42	17	Defective equipment	122	633	
16	CB6576	1.41	14	Wildlife	99	221	
17	CB5309	1.31	5	Human error	11	370	
18	CB4635	1.26	4	Vegetation	35	224	
19	WS4	1.22	5	Adverse Environment	15	304	
20	ET2	1.21	7	Vegetation	44	593	
21	CB7652	1.15	6	Human error	52	547	
22	CB2084	1.11	21	Cause Unknown	78	150	
23	CB169	1.11	14	Defective equipment	91	303	
24	CB190	1.09	3	Human error	25	657	

[1] *Extend table as necessary to disclose all worst-performing feeders*

SAIFI

Rank	Feeder name	Unplanned SAIFI values	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1	CB168	0.1079	26	Defective equipment	169	1122	
2	CB2006	0.0861	28	Defective equipment	130	1125	
3	CB656	0.0590	53	Defective equipment	257	688	
4	CB480	0.0428	28	Vegetation	114	412	
5	CB2755	0.0382	4	Wildlife	60	913	
6	CB2423	0.0377	12	Defective equipment	126	390	
7	CB2758	0.0325	6	Defective equipment	52	1180	
8	CB190	0.0319	3	Human error	25	657	
9	CB5309	0.0285	5	Human error	11	370	
10	CB5310	0.0284	3	Human error	5	220	
11	CB7784	0.0277	6	Human error	119	1600	
12	CB7652	0.0276	6	Human error	52	547	
13	CB821	0.0260	8	Human error	103	778	
14	CB4637	0.0256	6	Vegetation	21	483	
15	CB2757	0.0252	1	Human error	51	1203	
16	CB167	0.0209	7	Human error	23	905	
17	CB838	0.0205	4	Defective equipment	18	544	
18	CB2752	0.0196	10	Third-party Interference	156	1523	
19	PC3	0.0191	8	Defective equipment	62	529	
20	CB7782	0.0186	11	Human error	100	1109	
21	CB7632	0.0183	17	Defective equipment	122	633	
22	CB5730	0.0181	8	Defective equipment	18	883	
23	GI2	0.0178	8	Defective equipment	10	215	
24	ET9	0.0172	5	Third-party Interference	42	1541	

[1] *Extend table as necessary to disclose all worst-performing feeders*

Customer Impact

Rank	Feeder name	Customer Impact Ratio	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1	CB710	1691.00	1	Defective equipment	1	1	
2	CB2084	1147.51	21	Cause Unknown	78	150	
3	CB2423	565.86	12	Defective equipment	126	390	
4	CB5272	540.91	1	Human error	3	77	
5	CB656	481.41	53	Defective equipment	257	688	
6	HSB33	369.33	9	Cause Unknown	0	6	
7	CB480	350.76	28	Vegetation	114	412	
8	CB4633	348.04	7	Defective equipment	25	55	
9	CB6576	343.02	14	Wildlife	99	221	
10	CB168	328.58	26	Defective equipment	169	1122	
11	CB4639	267.18	8	Defective equipment	35	122	
12	CB4635	263.62	4	Vegetation	35	224	
13	CB5309	243.42	5	Human error	11	370	
14	OT1	233.03	8	Defective equipment	26	110	
15	CB7830	227.86	9	Defective equipment	12	80	
16	CB167	216.41	7	Human error	23	905	
17	CB7783	199.00	3	Human error	0	1	
18	GI4	194.48	3	Third-party Interference	5	23	
19	CB199	190.03	3	Defective equipment	8	36	
20	CB2006	188.27	28	Defective equipment	130	1125	
21	GI2	175.11	8	Defective equipment	10	215	
22	CB192	172.04	6	Defective equipment	29	107	
23	CB2881	169.93	2	Wildlife	18	28	
24	SC1	156.80	1	Defective equipment	3	68	

[1] *Extend table as necessary to disclose all worst-performing feeders*

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

10(i): Interruptions

	Interruptions by class	Number of interruptions
10	Class A (planned interruptions by Transpower)	–
11	Class B (planned interruptions on the network)	409
12	Class C (unplanned interruptions on the network)	196
13	Class D (unplanned interruptions by Transpower)	2
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**	607

	Interruption restoration	≤3Hrs	>3hrs
22	Class C interruptions restored within	145	51

	SAIFI and SAIDI by class	SAIFI	SAIDI
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.43	123.9
27	Class C (unplanned interruptions on the network)	0.40	25.9
28	Class D (unplanned interruptions by Transpower)	0.00	0.0
29	Class E (unplanned interruptions of EDB owned generation)	–	–
30	Class F (unplanned interruptions of generation owned by others)	–	–
31	Class G (unplanned interruptions caused by another disclosing entity)	–	–
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	–	–
34	**Total**	0.84	149.8

	Transitional SAIFI and SAIDI (previous method)	SAIFI	SAIDI
37	Class B (planned interruptions on the network)		
38	Class C (unplanned interruptions on the network)		

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
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 this 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	0.00	0.01
Vegetation	0.09	8.18
Adverse weather	–	–
Adverse environment	0.01	0.53
Third party interference	0.05	4.12
Wildlife	0.00	0.74
Human error	0.04	0.58
Defective equipment	0.19	9.98
Other cause	–	–
Unknown	0.02	1.77

Breakdown of third party interference	SAIFI	SAIDI
Dig-in	0.00	0.05
Overhead contact	0.01	1.09
Vandalism	0.00	0.24
Vehicle damage	0.04	2.74
Other	–	–

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

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	–	–
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.32	89.67
Distribution cables (excluding LV)	0.07	22.18
Distribution other (excluding LV)	0.05	12.04

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	–	–
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.21	17.85
Distribution cables (excluding LV)	0.09	5.43
Distribution other (excluding LV)	0.10	2.62

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	–	144	–
Subtransmission cables	–	66	–
Subtransmission other	–		
Distribution lines (excluding LV)	43	730	5.89
Distribution cables (excluding LV)	18	332	5.42
Distribution other (excluding LV)	51		
Total	112		

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

10(vi): Worst-performing feeders (unplanned)

SAIDI

Rank	Feeder name	Unplanned SAIDI values	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1	PC3	5.04	8	Defective equipment	62	529	
2	WS4	2.06	5	Adverse Environment	15	304	
3	ET2	2.04	7	Vegetation	44	593	
4	OT3	1.73	10	Defective equipment	55	230	
5	HB13	1.57	2	Vegetation	22	672	
6	OT2	1.12	5	Human error	40	313	
7	GI10	1.09	6	Third-party Interference	29	703	
8	HB1	1.03	4	Human error	31	649	
9	CO7	0.99	5	Defective equipment	25	485	
10	GI2	0.95	8	Defective equipment	10	215	
11	OT1	0.79	8	Defective equipment	26	110	
12	CO11	0.75	1	Defective equipment	11	440	
13	PC4	0.72	8	Adverse Environment	54	783	
14	ET3	0.54	6	Defective equipment	65	783	
15	WB11	0.53	5	Defective equipment	3	188	
16	AB7	0.47	1	Cause Unknown	31	694	

† *Extend table as necessary to disclose all worst-performing feeders*

SAIFI

Rank	Feeder name	Unplanned SAIFI values	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1	PC3	0.0322	8	Defective equipment	62	529	
2	GI2	0.0301	8	Defective equipment	10	215	
3	ET9	0.0290	5	Third-party Interference	42	1541	
4	GI10	0.0265	6	Third-party Interference	29	703	
5	HB13	0.0236	2	Vegetation	22	672	
6	ET2	0.0203	7	Vegetation	44	593	
7	OT3	0.0196	10	Defective equipment	55	230	
8	CO11	0.0182	1	Defective equipment	11	440	
9	OT2	0.0175	5	Human error	40	313	
10	PC4	0.0147	8	Adverse Environment	54	783	
11	PC7	0.0137	2	Defective equipment	45	765	
12	GI3	0.0137	3	Human error	27	773	
13	WB11	0.0132	5	Defective equipment	3	188	
14	HB1	0.0126	4	Human error	31	649	
15	WS4	0.0110	5	Adverse Environment	15	304	
16	CO9	0.0107	1	Defective equipment	11	597	

† *Extend table as necessary to disclose all worst-performing feeders*

Customer Impact

Rank	Feeder name	Customer Impact Ratio	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1	HSB33	369.33	9	Cause Unknown	0	6	
2	OT1	233.03	8	Defective equipment	26	110	
3	GI4	194.48	3	Third-party Interference	5	23	
4	GI2	175.11	8	Defective equipment	10	215	
5	SC1	156.80	1	Defective equipment	3	68	
6	OT3	128.25	10	Defective equipment	55	230	
7	OT2	125.22	5	Human error	40	313	
8	WB11	119.83	5	Defective equipment	3	188	
9	CO7	112.90	5	Defective equipment	25	485	
10	PC3	89.95	8	Defective equipment	62	529	
11	WS8	70.38	2	Adverse Environment	8	242	
12	ET2	70.34	7	Vegetation	44	593	
13	GI10	65.16	6	Third-party Interference	29	703	
14	SC4	42.38	2	Defective equipment	4	135	
15	ET3	39.68	6	Defective equipment	65	783	
16	AB7	38.64	1	Cause Unknown	31	694	

† *Extend table as necessary to disclose all worst-performing feeders*

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
Network / Sub-network Name	**Central Otago & Wānaka Sub-network**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

8 **10(i): Interruptions**

9	**Interruptions by class**	**Number of interruptions**
10	Class A (planned interruptions by Transpower)	–
11	Class B (planned interruptions on the network)	396
12	Class C (unplanned interruptions on the network)	333
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**	732

21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	244	89

24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.77	241.86
27	Class C (unplanned interruptions on the network)	2.99	253.99
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	0.00
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	0.21
34	**Total**	3.76	496.1

36	**Transitional SAIFI and SAIDI (previous method)**	**SAIFI**	**SAIDI**
37	Class B (planned interruptions on the network)		
38	Class C (unplanned interruptions on the network)		

39

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
Network / Sub-network Name	**Central Otago & Wānaka Sub-network**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

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

Cause	SAIFI	SAIDI
Lightning	0.00	0.01
Vegetation	0.35	27.62
Adverse weather	–	–
Adverse environment	0.07	11.20
Third party interference	0.09	12.89
Wildlife	0.08	6.59
Human error	0.35	11.58
Defective equipment	1.23	128.31
Other cause	–	–
Unknown	0.81	55.79

Breakdown of third party interference	SAIFI	SAIDI
Dig-in	0.00	0.03
Overhead contact	0.05	6.69
Vandalism	–	–
Vehicle damage	0.04	6.17
Other	–	–

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

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.00	1.05
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.54	185.00
Distribution cables (excluding LV)	0.17	41.15
Distribution other (excluding LV)	0.05	14.66

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.60	45.94
Subtransmission cables	0.10	2.76
Subtransmission other	0.11	5.88
Distribution lines (excluding LV)	1.38	148.69
Distribution cables (excluding LV)	0.42	32.57
Distribution other (excluding LV)	0.38	18.15

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	14	309	4.53
Subtransmission cables	1	10	10.00
Subtransmission other	4		
Distribution lines (excluding LV)	106	1,271	8.34
Distribution cables (excluding LV)	10	573	1.75
Distribution other (excluding LV)	73		
Total	208		

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
Network / Sub-network Name	**Central Otago & Wānaka Sub-network**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

10(vi): Worst-performing feeders (unplanned)

SAIDI

Rank	Feeder name	Unplanned SAIDI values	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1	CB168	49.52	26	Defective equipment	169	1122	
2	CB2006	33.46	28	Defective equipment	130	1125	
3	CB656	29.07	53	Defective equipment	257	688	
4	CB2423	14.35	12	Defective equipment	126	390	
5	CB480	13.41	28	Vegetation	114	412	

† *Extend table as necessary to disclose all worst-performing feeders*

SAIFI

Rank	Feeder name	Unplanned SAIFI values	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1	CB168	0.43	26	Defective equipment	169	1122	
2	CB2006	0.35	28	Defective equipment	130	1125	
3	CB656	0.24	53	Defective equipment	257	688	
4	CB480	0.17	28	Vegetation	114	412	
5	CB2755	0.15	4	Wildlife	60	913	

† *Extend table as necessary to disclose all worst-performing feeders*

Customer Impact

Rank	Feeder name	Customer Impact Ratio	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1	CB2084	1147.51	21	Cause Unknown	78	150	
2	CB2423	565.86	12	Defective equipment	126	390	
3	CB656	481.41	53	Defective equipment	257	688	
4	HSB33	369.33	9	Cause Unknown	0	6	
5	CB480	350.76	28	Vegetation	114	412	

† *Extend table as necessary to disclose all worst-performing feeders*

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

8 **10(i): Interruptions**

		Number of interruptions
9	**Interruptions by class**	
10	Class A (planned interruptions by Transpower)	–
11	Class B (planned interruptions on the network)	215
12	Class C (unplanned interruptions on the network)	112
13	Class D (unplanned interruptions by Transpower)	1
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**	328

		≤3Hrs	>3hrs
21	**Interruption restoration**		
22	Class C interruptions restored within	86	26

		SAIFI	SAIDI
24	**SAIFI and SAIDI by class**		
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.66	199.89
27	Class C (unplanned interruptions on the network)	1.68	84.65
28	Class D (unplanned interruptions by Transpower)	0.20	14.91
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**	2.55	299.4

		SAIFI	SAIDI
36	**Transitional SAIFI and SAIDI (previous method)**		
37	Class B (planned interruptions on the network)		
38	Class C (unplanned interruptions on the network)		

39

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
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 this 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	–	–
Vegetation	0.06	8.04
Adverse weather	–	–
Adverse environment	0.01	0.14
Third party interference	0.42	6.83
Wildlife	0.01	0.35
Human error	0.47	22.19
Defective equipment	0.37	26.56
Other cause	–	–
Unknown	0.34	20.53

Breakdown of third party interference	SAIFI	SAIDI
Dig-in	0.03	2.11
Overhead contact	0.05	0.10
Vandalism	–	–
Vehicle damage	0.34	4.62
Other	–	–

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

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.00	0.53
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.45	142.40
Distribution cables (excluding LV)	0.18	52.16
Distribution other (excluding LV)	0.03	4.78

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.07	5.24
Subtransmission cables	–	–
Subtransmission other	0.08	0.48
Distribution lines (excluding LV)	0.81	35.74
Distribution cables (excluding LV)	0.26	25.48
Distribution other (excluding LV)	0.47	17.71

10(v): Fault Rate

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2025**
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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

10(vi): Worst-performing feeders (unplanned)

SAIDI

Rank	Feeder name	Unplanned SAIDI values	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1	CB5310	15.80	3	Human error	5	220	
2	CB7632	8.96	17	Defective equipment	122	633	
3	CB5309	8.31	5	Human error	11	370	
4	CB7652	7.25	6	Human error	52	547	

† *Extend table as necessary to disclose all worst-performing feeders*

SAIFI

Rank	Feeder name	Unplanned SAIFI values	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1	CB5309	0.18	5	Human error	11	370	
2	CB5310	0.18	3	Human error	5	220	
3	CB7784	0.18	6	Human error	119	1600	
4	CB7652	0.17	6	Human error	52	547	

† *Extend table as necessary to disclose all worst-performing feeders*

Customer Impact

Rank	Feeder name	Customer Impact Ratio	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1	CB710	1691.00	1	Defective equipment	1	1	
2	CB5272	540.91	1	Human error	3	77	
3	CB5309	243.42	5	Human error	11	370	
4	CB7830	227.86	9	Defective equipment	12	80	

† *Extend table as necessary to disclose all worst-performing feeders*

Company Name	Aurora Energy Limited
For Year Ended	31 March 2025

Schedule 14 Mandatory Explanatory Notes

1. This schedule requires EDBs to provide explanatory notes to information provided in accordance with clauses 2.3.1, 2.4.21, 2.4.22, and subclauses 2.5.1(1)(f),and 2.5.2(1)(e).

2. This schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.1. Information provided in boxes 1 to 11 of this schedule is part of the audited disclosure information, and so is subject to the assurance requirements specified in section 2.8.

3. Schedule 15 (Voluntary Explanatory Notes to Schedules) provides for EDBs to give additional explanation of disclosed information should they elect to do so.

Return on Investment (Schedule 2)

4. In the box below, comment on return on investment as disclosed in Schedule 2. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

Box 1: Explanatory comment on return on investment-

The company's reported RY25 ROI (reflecting all revenue earned) exceeded the vanilla WACC rate used to set the regulatory price path for the current year. Reported RY25 ROI comparable to vanilla WACC is below the Commission's mid-point estimate, but between the 25th and 75th percentiles. Significant drivers of the reported RY25 ROI figures again included the RAB revaluation, and allowable revenue from financial incentives.

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.

The opex IRIS incentive for RY25 is a positive adjustment of $28.434 mil that relates to operational expenditure allowances from the previous regulatory control period. The capex IRIS incentive for RY25 is a penalty of $1.581 mil for overspending capital expenditure allowances in the previous regulatory control period. These incentives were included in the company's calculation of allowable revenue when setting prices for RY25.

IRIS allowances are a designated recoverable cost in price-quality regulation and are therefore recovered through pass-through prices, rather than distribution prices. Consistent with our Pricing Methodology we have allocated the IRIS incentive to pricing areas and customer 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 incentives.

No items have been reclassified in accordance with clause 2.7.1(2)

Regulatory Profit (Schedule 3)

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

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

    5.2 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 2025 is $60.2 mil before tax. This is $7.1 mil lower than the previous year. The movement comprised of higher regulatory income (+$11.6 mil), higher operational expenditure (-$6.2 mil) higher pass-through and recoverable costs (-$1.2 mil), higher depreciation (-$2.7 mil), and lower revaluations (-$8.6 mil) for the year.

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

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

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

    6.2 any other commentary on the benefits of the merger and acquisition expenditure to the EDB.

Box 3: Explanatory comment on merger and acquisition expenditure

There were no merger and acquisition costs incurred.

Value of the Regulatory Asset Base (Schedule 4)

7. In the box below, comment on the value of the regulatory asset base (rolled forward) in Schedule 4. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

Box 4: Explanatory comment on the value of the regulatory asset based (rolled forward)

The Regulatory Asset Base (RAB) increased by $68.0 mil during the year (2024: $94.0 mil). Commissioned asset values were $14.7 mil lower than in the previous year, revaluations declined by $8.6 mil and depreciation charges increased by $2.7 mil for the year.

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

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

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

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

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

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

Box 5: Regulatory tax allowance: permanent differences

The amount of $58,665 relating to 'Expenditure or loss in regulatory profit or (loss) before tax but not deductible' is non-deductible entertainment. The amount of $1,102,303 relating to 'Expenditure or loss deductible but not in regulatory profit / (loss) before tax' relates to payments for leases that are classified as Right of Use (ROU) assets.

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

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

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

Temporary timing differences of $2,569,309 recorded in the current disclosure year relate to the tax effect of income spreading over 10 years of customer-initiated works (+$2,209,472), upward movement in provision for expected credit losses (+$29,400) and increase in employee entitlements (+$330,437).

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

Cost allocation (Schedule 5d)

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

Box 7: Cost allocation

All opex is 100% directly attributable to the regulated business.

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

Asset allocation (Schedule 5e)

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

Box 8: Commentary on asset allocation

Other network assets include a fibre network that comprises of ducting / high speed broadband fibre utilised for communications between the Dunedin zone sub-station sites.

Fibre network assets have been allocated to the RAB based on a proxy allocator of network fibre length. The rationale for the proxy allocator is based on analysis of what the assets were that are shared with non-regulated businesses and the key drivers of these assets as determined by management.

On the above assessment we have determined that for RY25, 75.5% of the network is utilised for communications between the Dunedin zone sub-station sites (RY24: 75.5%).

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

Capital Expenditure for the Disclosure Year (Schedule 6a)

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

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

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

Box 9: Explanation of capital expenditure for the disclosure year

Aurora's Asset Management Plan contains the 10-year expenditure forecasts relating to capital projects and programmes of work to be undertaken in each regulatory year. The projects and programmes are grouped by the regulatory expenditure categories of consumer connection, system growth, asset replacement and renewal, asset relocations, reliability, safety and environment and non-network capex.

Consumer connection capital expenditure, disclosed in 6a(iii), is inclusive of all customer load group 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.

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

Operational Expenditure for the Disclosure Year (Schedule 6b)

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

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

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

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

Box 10: Explanation of operational expenditure for the disclosure year

RY25 OPEX was $54,173 mil, this was $2.546 mil lower than the RY25 target.

RY25 network maintenance was $21.919 mil, $0.334 mil above target of $21.585 mil.

RY25 non-network opex was $2.880 mil below target at $32.254 mil. Components of the underspend included:

- Non-network solutions provided by a third party was circa $0.13 mil below target partly due to the third party going into liquidation in late 2024.
- SONS expenditure was circa $1.67 mil below target inclusive of underspends in network evolution, and IT expenditure.
- Business support expenditure was circa $1.08 mil below target inclusive of underspends in people costs, and administration and governance.

Variance between forecast and actual expenditure (Schedule 7)

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

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

Overall, Aurora's total expenditure on assets of $104.537 mil was $6.112 mil (6.2%) higher than forecast.

Consumer connection expenditure was impacted by a slight decline in total actual customer driven capex (-$0.4 mil) from the prior year. The RY25 forecast assumed a $1.5 mil uplift.

System growth expenditure was within 4% of forecast for the year.

Asset replacement and renewal expenditure was higher than forecast due to the delivery of a greater quantity of projects than initially anticipated.

Total reliability, safety, and environment expenditure was higher than forecast due to the addition of a Frankton Ripple Plant injection project. This project was not included in the original forecast but was required to be performed due to changes made to the transmission network.

Non-network capex was lower than expected largely due to lower than expected new leases recognised under IFRS 16 as right-of-use assets, and a few small IT capex projects being either deferred or cancelled.

Service interruptions and emergency expenditure was higher than expected. This is partly attributable to a higher volume of smaller, under $2,000, network faults.

Routine and corrective maintenance expenditure was within 2% of forecast for the year.

Vegetation management expenditure was higher than expected partly due to risk assessments identifying the need for additional clearance of fall-zone trees on sub-transmission circuits.

Information relating to revenues and quantities for the disclosure year

15. In the box below provide-

    15.1 a comparison of the target revenue disclosed before the start of the disclosure year, in accordance with clause 2.4.1 and subclause 2.4.3(3) to total billed line charge revenue for the disclosure year, as disclosed in Schedule 8; and

    15.2 explanatory comment on reasons for any material differences between target revenue and total billed line charge revenue.

Box 12: Explanatory comment relating to revenue for the disclosure year-

Total Revenue:

The forecast revenue from line charges was $157,980 million (Annual Price-Setting Compliance Statement – 1 April 2024).

In Schedule 8 (Total Network), we have reported total line charge revenue of $154,951 million. This is a difference of $3,029 million (1.9%) below 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.

Residential Revenue:

In this assessment period, the volume of energy delivered to Residential consumers (the only consumer groups with volume-based pricing) decreased from the prior year (by 3.5%). Energy delivered to Residential connections for the year ended 31 March 2025 was 652.3 GWh compared with 675.9 GWh 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 2025 was 80,678, compared with 79,726 for the previous year.

The average energy use per Residential consumer in this assessment period has decreased by 4.6% from 8,478 kWh for the year ended 31 March 2024 to 8,085 kWh in this assessment period.

General Revenue:

The average number of General connections, which are priced predominantly on the basis of demand and capacity, increased from 15,503 in RY24 to 15,612 in this assessment period (0.7%).

The distinction between Residential and General connections is explained in section 5 of Aurora Energy's Use-of-System Pricing Methodology, available from https://www.auroraenergy.co.nz/disclosures/pricing-methodologies

Network Reliability for the Disclosure Year (Schedule 10)

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

Box 13: Commentary on network reliability for the disclosure year

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 (2025), available from https://www.auroraenergy.co.nz/disclosures/price-quality-path/

Insurance cover

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

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

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

Box 14: Explanation of insurance cover

Insurance cover is in place for zone substation 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 other distribution assets e.g. distribution transformers and switches.

Distribution line assets including distribution poles, lines and cables etc. are not currently insured due to the unavailability of commercial policy terms.

Amendments to previously disclosed information

18. In the box below, provide information about amendments to previously disclosed information disclosed in accordance with clause 2.12.1 in the last 7 years, including:

    18.1 a description of each error; and

    18.2 for each error, reference to the web address where the disclosure made in accordance with clause 2.12.1 is publicly disclosed.

Box 15: Disclosure of amendment to previously disclosed information

There have been no material errors in previously disclosed information requiring amendment.

RELATED PARTIES TRANSACTIONS

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 2025.

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 as DCHL is the ultimate holding company of 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.	$56,913,000 This expenditure is in relation to operating and capital expenditure incurred by Aurora Energy with Delta.
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.	$1,520,000 This expenditure is primarily in relation to local rates that are payable to the DCC.
Dunedin Venues Management Limited (DVML)	Aurora Energy and DVML are related by virtue of DCHL being the ultimate holding company of Aurora Energy and DVML. DCHL is the sole shareholder of DVML.	DVML is a specialist venue management organisation.	$1,000 This expenditure is relation to venue hire and refreshments.
Dunedin City Treasury Limited (DCTL)	Aurora Energy and DCTL are related as DCHL is the ultimate holding company of Aurora Energy and DCTL. DCHL is the sole shareholder of DCTL.	DCTL provides funding and financial services to the other entities in the Dunedin City Holdings Limited group.	$1,440,000 This expenditure is in relation to interest payable by Aurora Energy to DCTL that has been capitalised.
Aurora Energy Limited - Directors	Directors of Aurora Energy Limited	Governance of Aurora Energy Limited	$299,000 This expenditure is in relation to Directors Fees
Aurora Energy Limited - Key Management Personnel	Key Management Personnel of Aurora Energy Limited	Business leadership and delivery of strategic goals for Aurora Energy Limited	$2,517,000 This expenditure is in relation to Key Management Personnel remuneration

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 over 97,000 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;
- **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 contractor provided that they are an Aurora Energy Approved Contractor).
Network and non-network capital expenditure: • system growth • reliability, safety and environment • asset replacement and renewal • asset relocations • non-system fixed assets (i.e. 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

3.1.1 Field Services Agreements

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 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 contracts with Unison and Connetics took effect from 1 April 2019, seeing them carry out renewal, maintenance and development work. Each field services agreement (FSA) had an initial term of three years, which provided us with an opportunity on a regular basis to refresh and test our contractual relationship. The FSAs with all providers were renewed during 2021 for a further two years and therefore became five-year agreements, which expired on 31 March 2024.

Subsequently we refreshed the FSAs and appointed field service providers for a new 4-year period from 1 April 2024. This included running a tender process, at the end of which Delta and Unison were re-appointed as field service providers. We also appointed ElectroNet as a Secondary Service Provider in the Central Otago region (to replace Connetics).

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. Since the commencement of the Field Service Agreements in 2019, this was reflected in Delta being the Primary Service Provider. The Primary Service Provider performs the bulk of maintenance activity on the network, including all first response and fault repairs.

We 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 all Service Providers to offer alternative solutions and for Unison and ElectroNet to further embed themselves as long-term contractors on our network. We also understand the need to provide our partners with sufficient work to ensure their viability on our network.

3.1.2 Vegetation Services Agreements

Delta had traditionally performed vegetation management services across the entire Aurora Energy network. However, from 1 April 2022, vegetation management for the Queenstown subnetwork has been procured separately to the FSA under a specific vegetation services agreement (VSA). The term of the VSA is five years and was competitively tendered on the open market in 2021.

Alongside the procurement process for the FSA outlined in section 3.1.1, we ran a procurement process for vegetation management services for the Dunedin subnetwork and Central Otago / Wānaka subnetwork (it excluded the Queenstown subnetwork) in 2023. Asplundh was the successful contractor for the Dunedin subnetwork and replaced Delta. Delta was the successful contractor for the Central Otago / Wānaka subnetwork.

3.1.3 External tender market

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 providers) are invited to tender. Delta, plus the other FSA providers and other approved contractors participate in this external tender market.

3.1.4 Engineering Services Consultancy Panel

We also have established an Engineering Services Consultancy Panel to provide specific electricity design services for asset replacement and renewal projects and growth projects. The panel consists of engineering consulting companies and included Delta until July 2023.

3.1.5 Customer Initiated Works

Together with the other approved contractors on our network, Delta provides customer connection services at market value rates. Under our 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.

3.1.6 Internal controls

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 Energy does not have policies or procedures that require a consumer to purchase goods or services from a related party. Aurora Energy 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 on overhead network	Services were procured through the tendered FSA	The terms upon which services are provided, and the rates at which services are charged, were tested in 2023 during the procurement of the FSAs.
	Liaison of specified feeders in the Queenstown region	Services were procured through the tendered VSA	The terms upon which services are provided, and the rates at which services are charged, were tested in 2021 during the tendering of the VSA.
	Liaison of specified feeders in the Central Otago / Wānaka region	Services were procured through the tendered VSA	The terms upon which services are provided, and the rates at which services are charged, were tested in 2023 during the tendering of the VSA.
Routine and corrective maintenance and inspection	Yearly recloser preventative maintenance – Visual inspection, thermographic testing.	Services were procured through the tendered FSA	The terms upon which services are provided, and the rates at which services are charged, were tested in 2023 during the procurement of the FSAs.
System operations and network support	Provision of logistic services including provision of storage facilities.	Direct procurement	The rates at which services are charged were tested in 2023 during the procurement of the FSAs.
Business support	Rental of office premises	Direct procurement	Market lease rates were tested on 1 April 2022 when an independent valuation report was obtained.

EXPENDITURE CATEGORY	REPRESENTATIVE EXAMPLE	PROCUREMENT METHOD	HOW AND WHEN ARM'S LENGTH TERMS LAST TESTED
Capital expenditure			
System growth	Reinforcement of low voltage network	Services were procured through the tendered FSA	The terms upon which services are provided, and the rates at which services are charged, were tested in 2023 during the procurement of the FSAs.
Asset replacement and renewal	Replacement of poles	Services were procured through the tendered FSA.	The terms upon which services are provided, and the rates at which services are charged, were tested in 2023 during the procurement of the FSAs.
Asset relocations	Relocation of overhead network on third party (Chorus) owned poles	Services were procured through the tendered FSA.	The terms upon which services are provided, and the rates at which services are charged, were tested in 2023 during the procurement of the FSAs.
Reliability, safety and environment	Installation of recloser	Services were procured through the tendered FSA.	The terms upon which services are provided, and the rates at which services are charged, were tested in 2023 during the procurement of the FSAs.
Non-network assets	Procurement of locks for assisting in ensuring the safety of people operating the network	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 programmes and projects

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

4.1.1 Operational expenditure programmes and projects

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

- preventative 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. Note the value of projects is expressed in nominal terms.

	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.	**Preventative 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 each lower level programme reflects how that expenditure is allocated in RY26.	RY26—35	$ 84.7 million	Total network	This programme of works is covered by three FSA providers, each of which have a four-year term from 1 April 2024 to 31 March 2028. Delta, a related party, is one of the field service providers. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
1a.	**Overhead Conductor Inspections** This programme of works encompasses the carrying out of preventive inspections on Aurora Energy's overhead conductors.	RY26	$ 2.2 million	Total network	This programme of works is covered by three FSA providers, each of which have a four-year term from 1 April 2024 to 31 March 2028. Delta, a related party, is one of the field service providers. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
1b.	**Zone Substation Preventive Maintenance** This programme of works encompasses the carrying out of preventive maintenance in Aurora Energy's zone substations.	RY26	$ 1.5 million	Total network	This programme of works is covered by three FSA providers, each of which have a four-year term from 1 April 2024 to 31 March 2028. Delta, a related party, is one of the field service 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
					We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
1c.	**RMU Preventive Maintenance** This programme of works encompasses the carrying out of preventive maintenance on Aurora Energy's RMUs.	RY26	$ 1.3 million	Total network	This programme of works is covered by three FSA providers, each of which have a four-year term from 1 April 2024 to 31 March 2028. Delta, a related party, is one of the field service providers. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
1d.	**Ground and pole mounted transformer inspections** This programme of work encompasses the carrying out of preventative inspections on Aurora Energy's mounted transformers.	RY26	$ 0.3 million	Total network	This programme of works is covered by three FSA providers, each of which have a four-year term from 1 April 2024 to 31 March 2028. Delta, a related party, is one of the field service providers. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
2.	**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	RY26-35	$ 49.7 million	Total network	This programme of works is covered by three FSA providers, each of which have a four-year term from 1 April 2024 to 31 March 2028. Delta, a related party, is one of the field service 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
	response. Programmes 2a and 2b below are encompassed within this category of expenditure.				We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
2a.	**Consumer Pole Replacements**	RY26	$4.0 million	Total network	This programme of works is covered by three FSA providers, each of which have a four-year term from 1 April 2024 to 31 March 2028. Delta, a related party, is one of the field service providers. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
2b.	**Possum and Cable Guard Retrofit Programme** This programme of work encompasses the retrofitting of possum guards and cable guards on the Aurora network.	RY24-26	$ 0.2 million	Total network	This programme of works is covered by three FSA providers, each of which have a four-year term from 1 April 2024 to 31 March 2028. Delta, a related party, is one of the field service providers. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
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	RY26-35	$ 56.4 million	Total network	This programme of works is covered by two providers, across three VSAs. Two of the VSAs each have a four-year term, from 1 April 2024 to 31 March 2028, with the Frankton VSA

	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
	and the carrying out of preliminary and physical works.				having a five-year term from 1 April 2022 to 31 March 2027. Two of the three VSAs are with Delta, a related party. We expect the work to be allocated across the two VSA providers.
4.	**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.	RY26-35	$ 52.0 million	Total network	This programme of works is covered by three FSA providers, each of which have a four-year term from 1 April 2024 to 31 March 2028. Delta, a related party, is one of the field service providers. 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.

4.1.2 Capital expenditure programmes and projects

In relation to capital expenditure, we have identified our largest projects and programmes of work. These affect the whole of our network, however, we have identified, where relevant, the largest projects that can be easily identified as affecting a specific part of the network. As with table 4.1.1, the value of projects is expressed in nominal terms.

	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.	RY26-35	$ 160.5 million	Total network	This programme of works is covered by three FSA providers, each of which have a four-year term from 1 April 2024 to 31 March 2028. Delta, a related party, is one of the field service providers. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
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 2a through 2g describe the seven most significant of these renewal projects.	RY26-35	$ 89.3 million	Specific zone substations located across the network	Currently not indicated for supply by a related party.
2a.	**Corstorphine Transformer Renewal** The power transformers at the Corstorphine substation are near end-of-life and require renewal.	RY32-34	$ 12.8 million	Corstorphine, Dunedin	Currently not indicated for supply by a related party
2b.	**East Taieri Substation Renewal**	RY32-33	$ 12.4 million	Mosgiel, 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 equipment contained in the East Taieri substation is near-end-of-life and requires renewal.				
2c.	**Green Island Substation Rebuild** The equipment contained in the Green Island substation is near-end-of-life and requires renewal. The optimum solution is for the substation to be rebuilt on the existing site.	RY23-26	$ 11.2 million	Green Island, Dunedin	The electrical portion of this project was awarded to Delta as the result of a competitive tender process.
2d.	**Mosgiel Substation Renewal**	RY28-30	$10.6million	Mosgiel, Dunedin	Currently not indicated for supply by a related party.
2e	**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	$ 10.3million	Willowbank, Dunedin	Currently not indicated for supply by a related party.
2f.	**Alexandra Substation Renewal** The equipment contained in the Alexandra substation is near-end-of-life and requires renewal. This project involves re-establishing the 11kV and 33kV switchgear in indoor buildings.	RY24-26	$ 9.1 million	Alexandra, Central Otago	This project was awarded to Delta as the result of a competitive tender process.
2g.	**South City Renewal** 11kV Switchboard replacement	RY31-32	$ 6.7 million	South City, Dunedin	Currently not indicated for supply by a related party.
3.	**Distribution Conductor Replacement** This is an ongoing programme of work to replace distribution conductor that has reached end-of-life.	RY26-35	$ 62.9 million	Total network	This programme of works is covered by three FSA providers, each of which have a four-year term from 1 April 2024 to 31 March 2028.

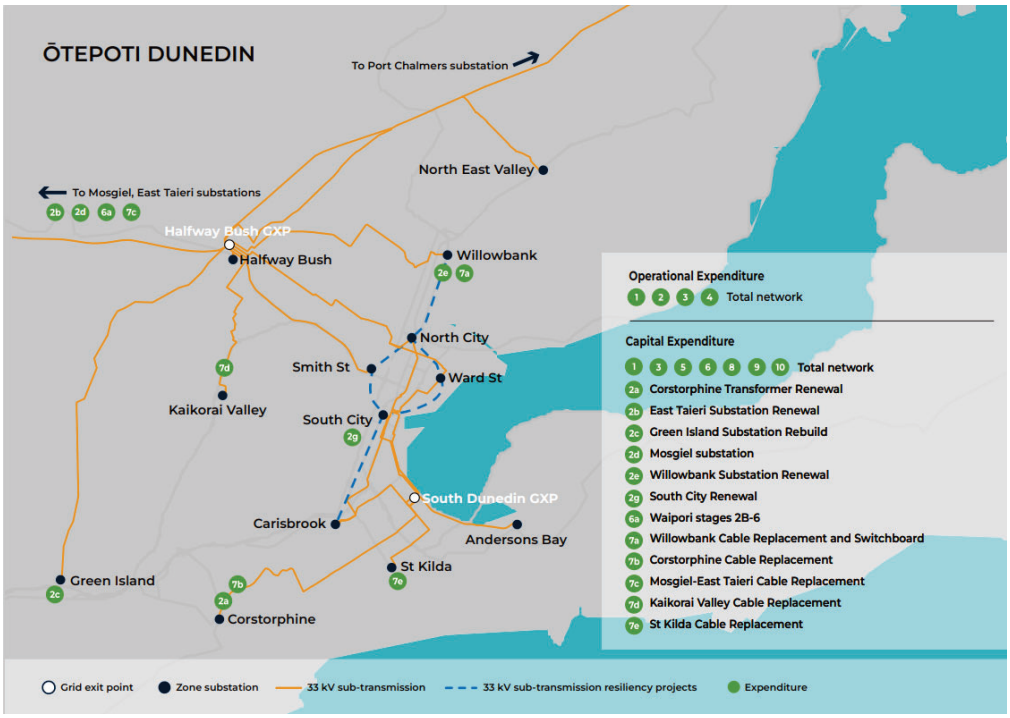
	DESCRIPTION OF THE PROJECT (INCLUDING ANY POSSIBLE FUTURE NETWORK OR EQUIPMENT CONSTRAINT THAT THE PROJECT ADDRESSES)	LIKELY TIMING OF THE PROJECT	LIKELY VALUE OF THE PROJECT	LOCATION OF THE PROJECT	CONTRACTUAL STATUS
					Delta, a related party, is one of the field service providers. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
4.	**New Upper Clutha 66kV Line** This project involves the installation of a new sub-transmission line in the Upper Clutha region.	RY27-31	$ 71.1 million	Central Otago	Currently not indicated for supply by a related party.
5.	**Ground Mounted Switchgear Replacements** This is an ongoing programme of work to replace ground mounted switchgear that has reached end-of-life.	RY26-35	$ 46.8 million	Total network	This programme of works is covered by three FSA providers, each of which have a four-year term from 1 April 2024 to 31 March 2028. Delta, a related party, is one of the field service providers. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
6.	**Subtransmission Conductor Replacement** This is an ongoing programme of work to replace subtransmission conductor that has reached end-of-life.	RY26-35	$ 41.1 Million	Total Network	This programme of works is covered by three FSA providers, each of which have a four-year term from 1 April 2024 to 31 March 2028. Delta, a related party, is one of the field service providers. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.

	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
6a.	**Waipori stages 2B – 6** This project involves conductor renewal on Waipori A, B and C overhead lines.	RY24-32	$ 37.8 Million	Dunedin	Currently not indicated for supply by a related party.
7.	**Subtransmission Cable Replacements** This is a programme involving the renewal of specific subtransmission cables on our Dunedin subnetwork that are in poor condition and have reached end-of-life. Items 7a, 7b, 7c, 7d and 7e below describe five of the most significant projects.	RY25-35	$ 45.6 million	Dunedin	Currently not indicated for supply by a related party.
7a.	**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.	RY27-29	$ 12.8 million	Willowbank, Dunedin	Currently not indicated for supply by a related party.
7b.	**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 Corstorphine zone substation.	Ry29-31	$ 10.1 million	Corstorphine, Dunedin	Currently not indicated for supply by a related party.
7c.	**Mosgiel – East Taieri Cable Replacement**	RY33-35	$8.6 million	Mosgiel, Dunedin	Currently not indicated for supply by a related party.
7d.	**Kaikorai Valley Cable Replacement** This project involves the replacement of the existing PILC, 33 kV underground cables that run	RY25-27	$ 8.4 million	Kaikorai Valley, 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
	between the Halfway Bush GXP and the Kaikorai zone substation.				
7e.	**St. Kilda Cable Replacement**	RY31-33	$5.5 million	St. Kilda, Dunedin	Currently not indicated for supply by a related party.
8.	**Crossarm Replacement** This is an ongoing programme of work to replace crossarms on a condition basis.	RY26-35	$ 25.2 million	Total network	This programme of works is covered by three FSA providers, each of which have a four-year term from 1 April 2024 to 31 March 2028. Delta, a related party, is one of the field service providers. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
9.	**Low voltage Conductor Replacement** This is an ongoing programme of work to replace LV conductor that has reached end-of-life.	RY26-35	$ 19.1 million	Total network	This programme of works is covered by three FSA providers, each of which have a four-year term from 1 April 2024 to 31 March 2028. Delta, a related party, is one of the field service providers. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
10.	**Secondary Systems – Protection Projects**	RY26-35	$18.8 million	Total Network	Currently not indicated for supply by a related party.

4.2 Maps

4.2.1 Dunedin sub-network



4.2.2 Central Otago & Wānaka and Queenstown sub-networks

NETWORK GEOGRAPHIC INFORMATION

Pursuant to clause 2.5.2A of the Electricity Distribution Information Disclosure Determination 2012 as amended, access to the information about each of our zone substations can be found on our website at the following link - https://www.auroraenergy.co.nz/disclosures/information-disclosures

SCHEDULE 18

Certification for Year-end Disclosures

Clause 2.9.2

We, Stephen Richard Thompson and Janice Evelyn Fredric, 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, 2.3.8-2.3.12, 2.4.21, 2.4.22, 2.5.1(a)-(f), 2.5.2, 2.5.2A, 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, 10a 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

Janice Evelyn Fredric

27 August 2025

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 2025 as required by the Electricity Distribution Information Disclosure (amendments related to IM Review 2023) Amendment Determination 2024 [2024] NZCC 31

Aurora Energy Limited (the company) is required to disclose certain information under the Electricity Distribution Information Disclosure (amendments related to IM Review 2023) Amendment Determination 2024 [2024] NZCC 31 (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, Chantelle Gernetzky, 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 2025 (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 (excluding 3a)[1], 5a to 5h, 6a and 6b, 7, 10, and 10a (limited to the SAIDI and SAIFI information) 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 (consolidated 23 April 2024) (the IM Determination), in respect of the basis for valuation of related party transactions (the Related Party Transaction Information).

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;

[1] Schedule 3a requirement applies from 1 April 2025, which is the beginning of disclosure year 2026. As such, the first disclosures will be due in 2026.

- 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 International Standard on Assurance Engagements (New Zealand) 3000 (Revised), *Assurance Engagements Other Than Audits or Reviews of Historical Financial Information ("ISAE (NZ) 3000 (Revised)")*, and the Standard on Assurance Engagements (SAE) 3100 (Revised), *Compliance Engagements ("SAE 3100 (Revised)")*, issued by the New Zealand Auditing and Assurance Standards Board.

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 compliance engagement, 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 $74 million and assets commissioned into the RAB amounted to $81 million, compared to total network operating expenditure of $54 million. The amount of capital expenditure is also significant relative to the RAB opening value of $898 million.	We have obtained an understanding of the compliance requirements relevant to the RAB as set out in the Determination. The procedures we carried out to satisfy ourselves that the capital expenditure and assets commissioned meet the definition under the 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 determine whether the expenditure met

Key assurance matter	How our procedures addressed the key assurance matter
Capital expenditure and assets commissioned into the RAB are a key assurance matter due to the significant judgement by company personnel and the auditor to assess whether the capital expenditure and assets commissioned into the RAB meets the definition set out in the Determination.	the capitalisation criteria in the Determination and capitalised to the appropriate asset category; 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 frequency 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.	We have obtained an understanding of the company's system to record electricity outages, and their duration. This included review of the company's definition of interruptions, planned interruptions, and major event days. Our procedures to assess the adequacy of the company's methods to identify and record electricity outages and their duration included: • reviewing and testing the overall control environment; • performing an assessment of the reliability of the manual and automated processes to record the details of interruptions to supply; • obtaining internal and external information on interruptions to supply to gain assurance that interruptions to supply were recorded. Internal and external information sources included works orders for contractors, media reports, and board minutes; • 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; • checking the SAIDI and SAIFI ratios were correctly calculated in accordance with the Determination and the IM Determination; • obtaining explanations for all significant variances to forecast; and • testing the accuracy of the number of connections to the Electricity Authority's register. 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; and
- 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), 2.2.11(5), and 2.2.11(6) of the IM Determination.

To meet these responsibilities, we planned and performed procedures in accordance with ISAE (NZ) 3000 (Revised) and SAE 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 requirements of Professional and Ethical Standard 1, *International Code of Ethics for Assurance Practitioners (including International Independence Standards) (New Zealand)* (PES 1), issued by the New Zealand Auditing and Assurance Standards Board. PES 1 is founded on the fundamental principles of integrity, objectivity, professional competence and due care, confidentiality and professional behaviour.

We have also complied with the Auditor-General's quality management requirements, which incorporate the requirements of Professional and Ethical Standard *3, Quality Management for Firms that Perform Audits or Reviews of Financial Statements, or Other Assurance or Related Services Engagements* (PES 3), issued by the New Zealand Auditing and Assurance Standards Board. PES 3 requires our firm to design, implement and operate a system of quality management including policies or procedures regarding compliance with ethical requirements, professional standards and applicable legal and regulatory requirements.

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 the Customised Price-Quality Path, the assurance engagement on the Annual Delivery Report, the assurance engagement on the operating leases information and the depreciation of existing assets information, and the annual audit of the company's financial statements and performance information, we have no relationship with, or interests in, the company.

Chantelle Gernetzky
Audit New Zealand
On behalf of the Auditor-General
Christchurch, New Zealand
27 August 2025