Information Disclosure

For the Year Ended 31 March 2026

EDB Information Disclosure Requirements
Information Templates

Schedules 1–10
excluding 5f–5h

Company Name	Counties Energy Limited
Disclosure Date	26 August 2026
Disclosure Year (year ended)	31 March 2026

Templates for Schedules 1–10 excluding 5f–5h
Prepared 2 June 2026

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Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2026**

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.

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	39,364	532	188,270	7,237	55,536
Network	13,711	185	65,574	2,521	19,343
Non-network	25,654	346	122,695	4,717	36,192
Expenditure on assets	83,814	1,132	400,858	15,410	118,245
Network	73,356	991	350,844	13,487	103,492
Non-network	10,457	141	50,014	1,923	14,753

1(ii): Revenue metrics

	Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
Total consumer line charge revenue	131,625	1,777
Standard consumer line charge revenue	143,463	1,688
Non-standard consumer line charge revenue	51,579	497,923

1(iii): Service intensity measures

Demand density	38	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
Volume density	184	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
Connection point density	14	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
Energy intensity	13,503	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*

1(iv): Composition of regulatory income

	($000)	% of revenue
Operational expenditure	26,546	29.90%
Pass-through and recoverable costs excluding financial incentives and wash-ups	15,914	17.92%
Total depreciation	22,857	25.74%
Total revaluations	16,499	18.58%
Regulatory tax allowance	5,248	5.91%
Regulatory profit/(loss) including financial incentives and wash-ups	34,728	39.11%
Total regulatory income	88,794	

1(v): Reliability

Interruption rate	25.22	*Interruptions per 100 circuit km*

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2026**

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					
7	**2(i): Return on Investment**		**CY-2**	**CY-1**	**Current Year CY**
8					
9	**ROI – comparable to a post tax WACC**		**%**	**%**	**%**
10		Reflecting all revenue earned	5.91%	5.34%	6.13%
11		Excluding revenue earned from financial incentives	5.91%	5.34%	6.13%
12		Excluding revenue earned from financial incentives and wash-ups	5.91%	5.34%	6.13%
13					
14		**Mid-point estimate of post tax WACC**	6.05%	6.18%	5.90%
15		25th percentile estimate	5.37%	5.50%	5.17%
16		75th percentile estimate	6.73%	6.86%	6.62%
17					
18					
19	**ROI – comparable to a vanilla WACC**				
20		Reflecting all revenue earned	6.61%	6.06%	6.77%
21		Excluding revenue earned from financial incentives	6.61%	6.06%	6.77%
22		Excluding revenue earned from financial incentives and wash-ups	6.61%	6.06%	6.77%
23					
24		**WACC rate used to set regulatory price path**			
25					
26		**Mid-point estimate of vanilla WACC**	6.75%	6.90%	6.53%
27		25th percentile estimate	6.07%	6.22%	5.81%
28		75th percentile estimate	7.43%	7.58%	7.26%
29					
30	**2(ii): Information Supporting the ROI**			**($000)**	
31					
32		Total opening RAB value	541,698		
33	*plus*	Opening deferred tax	(30,113)		
34	**Opening RIV**			511,585	
35					
36	**Line charge revenue**			88,764	
37					
38		Expenses cash outflow	42,460		
39	*add*	Assets commissioned	31,815		
40	*less*	Asset disposals	339		
41	*add*	Tax payments	794		
42	*less*	Other regulated income	30		
43	**Mid-year net cash outflows**			74,700	
44					
45	**Term credit spread differential allowance**			–	
46					
47		Total closing RAB value	566,816		
48	*less*	Adjustment resulting from asset allocation	0		
49	*less*	Lost and found assets adjustment	–		
50	*plus*	Closing deferred tax	(34,567)		
51	**Closing RIV**			532,249	
52					
53	**ROI – comparable to a vanilla WACC**				6.77%
54					
55		Leverage (%)			41%
56		Cost of debt assumption (%)			5.56%
57		Corporate tax rate (%)			28%
58					
59	**ROI – comparable to a post tax WACC**				6.13%
60					

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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).

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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	6.58%
Year-end ROI – comparable to a post tax WACC	5.95%

** 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		
Purchased assets – avoided transmission charge		
Innovation and non-traditional solutions recovered amount		
Quality incentive adjustment		
Other CPP financial incentives		
Financial incentives		–
Impact of financial incentives on ROI		–
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
Other CPP wash-ups		
Wash-up costs		–
Impact of wash-up costs on ROI		–

Company Name	**Counties Energy Limited**
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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	88,764
10	*plus*	Gains / (losses) on asset disposals	(120)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)	150
12			
13		**Total regulatory income**	88,794
14		**Expenses**	
15	*less*	Operational expenditure	26,546
16			
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups	15,914
18			
19		**Operating surplus / (deficit)**	46,334
20			
21	*less*	Total depreciation	22,857
22			
23	*plus*	Total revaluations	16,499
24			
25		**Regulatory profit / (loss) before tax**	39,976
26			
27	*less*	Term credit spread differential allowance	–
28			
29	*less*	Regulatory tax allowance	5,248
30			
31		**Regulatory profit/(loss) including financial incentives and wash-ups**	34,728
32			

sch ref				
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	14,138	Not Required before D\	
36	Transpower new investment contract charges	224	Not Required before D\	
37	System operator services	–	Not Required before D\	
38	Rates	1,098		
39	Commerce Act levies	164		
40	Industry levies	213		
41	CPP or DPP specified pass-through costs	–		
42	**Recoverable costs excluding financial incentives and wash-ups**			
43	Independent engineer costs	–	Not Required before D\	
44	FENZ levies	77	Not Required before D\	
45	Extended reserves allowance	–		
46	Other CPP recoverable costs excluding financial incentives and wash-ups	–		
47	**Pass-through and recoverable costs excluding financial incentives and wash-ups**			15,914
48				

sch ref		
49	**3(iv): Merger and Acquisition Expenditure**	
50		**($000)**
51	Merger and acquisition expenditure	–
52		
53	*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)*	
54	**3(v): Other Disclosures**	
55		**($000)**
56	Self-insurance allowance	–

SCHEDULE 3a: REPORT ON INCREMENTAL ROLLING INCENTIVE SCHEME

This schedule requires information on the calculation of IRIS incentive amounts. All non-exempt EDBs must complete this section.

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.

Please note; only the white cells should be filled in (i.e. F7 - J7, F10 - J12, F15 - J17). Forecast values should be filled in for all years, actual values should be filled in for all years where known.

Section	Row	Context	Category1	Category2	RY1	RY2	RY3	RY4	RY5	Total over / (under) spend
3a: Incremental Rolling Incentive Scheme	7		**Current Year**	**Current Year**	CY-2	CY-1	CY	CY+1	CY+2	

Section	Row	Context	Category1	Category2	RY1 ($000)	RY2 ($000)	RY3 ($000)	RY4 ($000)	RY5 ($000)	Total over / (under) spend
3a: Incremental Rolling Incentive Scheme	10		Opex incentive amounts	Forecast opex						
3a: Incremental Rolling Incentive Scheme	11		Opex incentive amounts	Actual opex						
3a: Incremental Rolling Incentive Scheme	12	+	Opex incentive amounts	Plus lease payments						
3a: Incremental Rolling Incentive Scheme	13		Opex incentive amounts	Actual opex for IRIS	-	-	-	-	-	
3a: Incremental Rolling Incentive Scheme	14		Opex incentive amounts	Expenditure variance to opex allowance	-	-	-	-	-	-
3a: Incremental Rolling Incentive Scheme	15		Capex incentive amounts	Forecast aggregate value of commissioned assets						
3a: Incremental Rolling Incentive Scheme	16		Capex incentive amounts	Actual commissioned assets						
3a: Incremental Rolling Incentive Scheme	17	-	Capex incentive amounts	Less right-of-use assets						
3a: Incremental Rolling Incentive Scheme	18		Capex incentive amounts	Actual commissioned assets for IRIS	-	-	-	-	-	
3a: Incremental Rolling Incentive Scheme	19		Capex incentive amounts	Expenditure variance to commissioned assets allowance	-	-	-	-	-	-

Company Name	**Counties Energy Limited**
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SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

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

sch ref

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

	RAB CY-4 ($000)	RAB CY-3 ($000)	RAB CY-2 ($000)	RAB CY-1 ($000)	RAB CY ($000)
Total opening RAB value	330,036	374,478	427,054	505,781	541,698
less **Total depreciation**	12,097	13,441	15,843	17,933	22,857
plus **Total revaluations**	22,796	24,806	17,102	12,735	16,499
plus **Assets commissioned**	33,968	41,748	78,227	41,939	31,815
less **Asset disposals**	225	537	759	824	339
plus **Lost and found assets adjustment**	–	–	–	–	–
plus **Adjustment resulting from asset allocation**	–	–	(0)	0	0
Total closing RAB value	374,478	427,054	505,781	541,698	566,816

4(ii): Unallocated Regulatory Asset Base

		Unallocated RAB * ($000)	Unallocated RAB * ($000)	RAB ($000)	RAB ($000)
Total opening RAB value			543,441		541,698
less					
Total depreciation			23,135		22,857
plus					
Total revaluations			16,553		16,499
plus					
Assets commissioned out of WUC	Not Required before DY2026	24,798		24,798	
Assets acquired (other than below)	Not Required before DY2026	7,250		7,017	
Assets acquired from a regulated supplier					
Assets acquired from a related party					
Assets commissioned			32,048		31,815
less					
Asset disposals (other than below)		346		339	
Asset disposals to a regulated supplier					
Asset disposals to a related party					
Asset disposals			346		339
plus **Lost and found assets adjustment**			–		–
plus **Adjustment resulting from asset allocation**					0
Total closing RAB value			568,561		566,816

** 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	**Counties Energy Limited**
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SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

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sch ref

sch ref							
52							
53	**4(iii): Calculation of Revaluation Rate and Revaluation of Assets**						
54							
55		CPI_4					1,339
56		CPI_4^{-4}					1,299
57		Revaluation rate (%)					3.08%
58							
59				**Unallocated RAB ***		**RAB**	
60				**($000)**	**($000)**	**($000)**	**($000)**
61		Total opening RAB value		543,441		541,698	
62	*less*	Opening value of fully depreciated, disposed and lost assets		5,894		5,894	
63							
64		Total opening RAB value subject to revaluation		537,547		535,804	
65		**Total revaluations**			16,553		16,499
66							
67	**4(iv): Roll Forward of Works Under Construction**						
68				**Unallocated works under construction**		**Allocated works under construction**	
69		**Works under construction—preceding disclosure year**	Not Required before DY2026		4,719		4,719
70	*plus*	WUC capital expenditure	Not Required before DY2026				
71		WUC acquired from a regulated supplier	Not Required before DY2026				
72		WUC acquired from a related party	Not Required before DY2026				
73		WUC capital expenditure - other	Not Required before DY2026	49,556		49,556	
74		Total WUC capital expenditure	Not Required before DY2026	49,556		49,556	
75	*less*	WUC capital contributions	Not Required before DY2026	20,266		20,266	
76	*less*	WUC other revenue	Not Required before DY2026				
77	*less*	Assets commissioned out of WUC	Not Required before DY2026	24,798		24,798	
78	*plus*	Adjustment resulting from asset allocation	Not Required before DY2026				
79		**Works under construction - current disclosure year**	Not Required before DY2026		9,211		9,211
80							
81		Highest rate of capitalised finance applied					4.55%
82							

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

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sch ref

83 **4(v): Regulatory Depreciation**

sch ref		Unallocated RAB *		RAB	
85		($000)	($000)	($000)	($000)
86	Depreciation - standard	14,507		14,507	
87	Depreciation - no standard life assets	8,628		8,350	
88	Depreciation - modified life assets				
89	Depreciation - alternative depreciation in accordance with CPP				
90	**Total depreciation**		23,135		22,857

92 **4(vi): Disclosure of Changes to Depreciation Profiles**

($000 unless otherwise specified)

sch ref	Asset or assets with changes to depreciation*	Reason for non-standard depreciation (text entry)	Depreciation charge for the period (RAB)	Closing RAB value under 'non-standard' depreciation	Closing RAB value under 'standard' depreciation
94					
95					
96					
97					
98					
99					
100					
101					

102 ** include additional rows if needed*

103 **4(vii): Disclosure by Asset Category**

104 ($000 unless otherwise specified)

sch ref			Subtransmission lines	Subtransmission cables	Zone substations	Distribution and LV lines	Distribution and LV cables	Distribution substations and transformers	Distribution switchgear	Other network assets	Non-network assets	Total
106		**Total opening RAB value**	23,314	220	86,416	196,266	73,300	49,170	36,039	8,022	68,951	541,698
107	*less*	Total depreciation	661	10	2,339	4,860	2,289	2,033	1,365	870	8,430	22,857
108	*plus*	Total revaluations	718	7	2,661	6,039	2,256	1,511	1,109	243	1,955	16,499
109	*plus*	Assets commissioned	–	–	1,334	12,182	6,376	3,226	282	1,398	7,017	31,815
110	*less*	Asset disposals				146	27	93			73	339
111	*plus*	Lost and found assets adjustment										–
112	*plus*	Adjustment resulting from asset allocation										–
113	*plus*	Asset category transfers	(848)			848						–
114		**Total closing RAB value**	22,523	217	88,072	210,329	79,616	51,781	36,065	8,793	69,420	566,816
116		**Asset Life**										
117		Weighted average remaining asset life	43.5	20.3	37.6	46.9	39.1	29.9	28.8	8.3	19.4	(years)
118		Weighted average expected total asset life	59.2	45.0	44.4	59.2	52.1	45.0	35.5	13.6	22.9	(years)

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SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

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

sch ref					
7		**5a(i): Regulatory Tax Allowance**		**($000)**	
8		**Regulatory profit / (loss) before tax**		39,976	
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	(137)		*
12		Amortisation of initial differences in asset values	2,663		
13		Amortisation of revaluations	4,091		
14		**Total**		6,617	
15					
16	*less*	Total revaluations	16,499		
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			*
20		Notional deductible interest	11,351		
21		**Total**		27,850	
22					
23		**Regulatory taxable income**		18,743	
24					
25	*less*	Utilised tax losses			
26		Regulatory net taxable income		18,743	
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**		5,248	
30					
31	*	Workings to be provided in Schedule 14			
32		**5a(ii): Disclosure of Permanent Differences**			
33		In Schedule 14, Box 5, provide descriptions and workings of items recorded in the asterisked categories in Schedule 5a(i).			
34		**5a(iii): Amortisation of Initial Difference in Asset Values**		**($000)**	
35					
36		Opening unamortised initial differences in asset values	55,923		
37	*less*	Amortisation of initial differences in asset values	2,663		
38	*plus*	Adjustment for unamortised initial differences in assets acquired			
39	*less*	Adjustment for unamortised initial differences in assets disposed			
40		Closing unamortised initial differences in asset values		53,260	
41					
42		Opening weighted average remaining useful life of relevant assets (years)		21	
43					

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SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

This schedule requires information on the calculation of the regulatory tax allowance. This information is used to calculate regulatory profit/loss in Schedule 3 (regulatory profit). EDBs must provide explanatory commentary on the information disclosed in this schedule, in Schedule 14 (Mandatory Explanatory Notes).
This information is part of audited disclosure information (as defined in section 1.4 of 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	440,578	
47				
48		Adjusted depreciation	18,766	
49		Total depreciation	22,857	
50		Amortisation of revaluations		4,091
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**	(30,113)	
61				
62	*plus*	Tax effect of adjusted depreciation	5,254	
63				
64	*less*	Tax effect of tax depreciation	8,961	
65				
66	*plus*	Tax effect of other temporary differences*	(31)	
67				
68	*less*	Tax effect of amortisation of initial differences in asset values	746	
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	(30)	
73				
74	*plus*	Deferred tax cost allocation adjustment	(0)	
75				
76		**Closing deferred tax**		(34,567)
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**	276,195	
84	*less*	Tax depreciation	32,004	
85	*plus*	Regulatory tax asset value of assets commissioned	31,815	
86	*less*	Regulatory tax asset value of asset disposals	233	
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**		275,773

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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			
7	**5b(i): Summary—Related Party Transactions**	**($000)**	**($000)**
8	**Total regulatory income**		18
9			
10	**Market value of asset disposals**		
11			
12	Service interruptions and emergencies	–	
13	Vegetation management	–	
14	Routine and corrective maintenance and inspection	–	
15	Asset replacement and renewal (opex)	–	
16	**Network opex**		–
17	Business support	488	
18	System operations and network support	–	
19	Non-network solutions provided by a related party or third party	–	
20	**Operational expenditure**		488
21	Consumer connection	–	
22	System growth	–	
23	Asset replacement and renewal (capex)	–	
24	Asset relocations	–	
25	Quality of supply	–	
26	Legislative and regulatory	–	
27	Other reliability, safety and environment	–	
28	**Expenditure on non-network assets**		–
29	**Expenditure on assets**		–
30	Cost of financing		
31	Value of capital contributions		
32	Value of vested assets		
33	**Capital Expenditure**		–
34	**Total expenditure**		488
35			
36	**Other related party transactions**		

37	**5b(iii): Total Opex and Capex Related Party Transactions**		
38	**Name of related party**	**Nature of opex or capex service provided**	**Total value of transactions ($000)**
39	Director Fees	Business support	488
40			
41			
42			
43			
44			
45			
46			
47			
48			
49			
50			
51			
52			
53			
54	Total value of related party transactions		488
55	** include additional rows if needed*		

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2026**

SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

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

sch ref

7

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

9

sch ref	Issuing party	Issue date	Pricing date	Original tenor (in years)	Coupon rate (%)	Book value at issue date (NZD)	Book value at date of financial statements (NZD)	Term Credit Spread Difference	Debt issue cost readjustment
11	Counties Energy Limited does not have any qualifying debt								
12									
13									
14									
15									
16	*Total*						–	–	–

17

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

19

sch ref			
20	**Gross term credit spread differential**		–
21			
22	Total book value of interest bearing debt		
23	Leverage	41%	
24	Average opening and closing RAB values		
25	**Attribution Rate (%)**		–
26			
27	**Term credit spread differential allowance**		–

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2026**

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						
7	**5d(i): Operating Cost Allocations**					
8			**Value allocated ($000s)**			
9		**Arm's length deduction**	**Electricity distribution services**	**Non-electricity distribution services**	**Total**	**OVABAA allocation increase ($000s)**
10	**Service interruptions and emergencies**					
11	Directly attributable		3,521			
12	Not directly attributable				–	
13	**Total attributable to regulated service**		3,521			
14	**Vegetation management**					
15	Directly attributable		3,121			
16	Not directly attributable				–	
17	**Total attributable to regulated service**		3,121			
18	**Routine and corrective maintenance and inspection**					
19	Directly attributable		1,734			
20	Not directly attributable				–	
21	**Total attributable to regulated service**		1,734			
22	**Asset replacement and renewal**					
23	Directly attributable		870			
24	Not directly attributable				–	
25	**Total attributable to regulated service**		870			
26	**Non-network solutions provided by a related party or third party**					
27	Directly attributable		–			
28	Not directly attributable				–	
29	**Total attributable to regulated service**		–			
30	**System operations and network support**					
31	Directly attributable		3,763			
32	Not directly attributable				–	
33	**Total attributable to regulated service**		3,763			
34	**Business support**					
35	Directly attributable		749			
36	Not directly attributable		12,788	1,857	14,645	
37	**Total attributable to regulated service**		13,537			
38						
39	**Operating costs directly attributable**		13,758			
40	**Operating costs not directly attributable**	–	12,788	1,857	14,645	–
41	**Operational expenditure**		26,546			
42						

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2026**

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

Pass through and recoverable costs	($000)
Pass through costs	
Directly attributable	15,719
Not directly attributable	118
Total attributable to regulated service	15,837
Recoverable costs	
Directly attributable	77
Not directly attributable	–
Total attributable to regulated service	77

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

Change in cost allocation 1			CY-1 ($000)	Current Year (CY) ($000)
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			CY-1 ($000)	Current Year (CY) ($000)
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			CY-1 ($000)	Current Year (CY) ($000)
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	**Counties Energy Limited**
For Year Ended	**31 March 2026**

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	22,523
Not directly attributable	–
Total attributable to regulated service	22,523
Subtransmission cables	
Directly attributable	217
Not directly attributable	–
Total attributable to regulated service	217
Zone substations	
Directly attributable	88,072
Not directly attributable	–
Total attributable to regulated service	88,072
Distribution and LV lines	
Directly attributable	210,329
Not directly attributable	–
Total attributable to regulated service	210,329
Distribution and LV cables	
Directly attributable	79,616
Not directly attributable	–
Total attributable to regulated service	79,616
Distribution substations and transformers	
Directly attributable	51,781
Not directly attributable	–
Total attributable to regulated service	51,781
Distribution switchgear	
Directly attributable	36,065
Not directly attributable	–
Total attributable to regulated service	36,065
Other network assets	
Directly attributable	8,793
Not directly attributable	–
Total attributable to regulated service	8,793
Non-network assets	
Directly attributable	56,437
Not directly attributable	12,983
Total attributable to regulated service	69,420
Regulated service asset value directly attributable	553,833
Regulated service asset value not directly attributable	12,983
Total closing RAB value	566,816

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

			($000)	
Change in asset value allocation 1			**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				

			($000)	
Change in asset value allocation 2			**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				

			($000)	
Change in asset value allocation 3			**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	**Counties Energy Limited**
For Year Ended	**31 March 2026**

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				
7		**6a(i): Expenditure on Assets**	**($000)**	**($000)**
8		Consumer connection		14,683
9		System growth		574
10		Asset replacement and renewal		24,910
11		Asset relocations		5,294
12		Reliability, safety and environment:		
13		Quality of supply	3,292	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	716	
16		**Total reliability, safety and environment**		4,008
17		**Expenditure on network assets**		49,469
18		Expenditure on non-network assets		7,052
19				
20		**Expenditure on assets**		56,521
21	*plus*	Cost of financing		87
22	*less*	Value of capital contributions		20,266
23	*plus*	Value of vested assets		–
24				
25		**Capital expenditure**		36,342
26		**6a(ii): Subcomponents of Expenditure on Assets (where known)**		**($000)**
27		Energy efficiency and demand side management, reduction of energy losses		
28		Overhead to underground conversion		1,754
29		Research and development		
31		**6a(iii): Consumer Connection**		
32		*Consumer types defined by EDB**	**($000)**	**($000)**
33		Urban Residential	8,076	
34		Urban Commercial	2,202	
35		Rural Residential	2,937	
36		Rural Commercial	1,468	
37				
38		** include additional rows if needed*		
39		**Consumer connection expenditure**		14,683
40				
41	*less*	Capital contributions funding consumer connection expenditure	12,187	
42		**Consumer connection less capital contributions**		2,496
43		**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset Replacement and**
44			**System Growth**	**Renewal**
45			**($000)**	**($000)**
46		Subtransmission	422	1,932
47		Zone substations	109	5,929
48		Distribution and LV lines	7	10,480
49		Distribution and LV cables	36	3,020
50		Distribution substations and transformers	–	2,482
51		Distribution switchgear	–	883
52		Other network assets	–	184
53		**System growth and asset replacement and renewal expenditure**	574	24,910
54	*less*	Capital contributions funding system growth and asset replacement and renewal	2,479	
55		**System growth and asset replacement and renewal less capital contributions**	(1,905)	24,910
56				
57		**6a(v): Asset Relocations**		
58		*Project or programme**	**($000)**	**($000)**
59		Various relocations (largely reimbursed by customers)	5,294	
60				
61				
62				
63				
64		** include additional rows if needed*		
65		All other projects or programmes - asset relocations		
66		**Asset relocations expenditure**		5,294
67	*less*	Capital contributions funding asset relocations	5,600	
68		**Asset relocations less capital contributions**		(306)

Company Name: **Counties Energy Limited**

For Year Ended: **31 March 2026**

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				
69				
70	**6a(vi): Quality of Supply**			
71		*Project or programme**	**($000)**	**($000)**
72		Reliability Programme	3,292	
73				
74				
75				
76				
77		** include additional rows if needed*		
78		All other projects programmes - quality of supply		
79		**Quality of supply expenditure**		3,292
80	*less*	Capital contributions funding quality of supply		
81		**Quality of supply less capital contributions**		3,292
82	**6a(vii): Legislative and Regulatory**			
83		*Project or programme**	**($000)**	**($000)**
84				
85				
86				
87				
88				
89		** include additional rows if needed*		
90		All other projects or programmes - legislative and regulatory		
91		**Legislative and regulatory expenditure**		–
92	*less*	Capital contributions funding legislative and regulatory		
93		**Legislative and regulatory less capital contributions**		–
94	**6a(viii): Other Reliability, Safety and Environment**			
95		*Project or programme**	**($000)**	**($000)**
96		Other reliability projects	716	
97				
98				
99				
100				
101		** include additional rows if needed*		
102		All other projects or programmes - other reliability, safety and environment		
103		**Other reliability, safety and environment expenditure**		716
104	*less*	Capital contributions funding other reliability, safety and environment		
105		**Other reliability, safety and environment less capital contributions**		716
106				
107	**6a(ix): Non-Network Assets**			
108		**Routine expenditure**		
109		*Project or programme**	**($000)**	**($000)**
110		IT equipment and software	5,298	
111		Land & buildings	706	
112		Vehicles	280	
113		Other plant & equipment	768	
114				
115		** include additional rows if needed*		
116		All other projects or programmes - routine expenditure		
117		**Routine expenditure**		7,052
118		**Atypical expenditure**		
119		*Project or programme**	**($000)**	**($000)**
120				
121				
122				
123				
124				
125		** include additional rows if needed*		
126		All other projects or programmes - atypical expenditure		
127		**Atypical expenditure**		–
128				
129		**Expenditure on non-network assets**		7,052

Company Name	Counties Energy Limited
For Year Ended	31 March 2026

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** *Not Required before DY2026*	**($000)**	**($000)**
8	Service interruptions and emergencies:		
9	Vegetation-related	221	
10	Other	3,300	
11	**Total service interruptions and emergencies**	3,521	
12	Vegetation management:		
13	Assessment and notification costs	236	
14	Felling or trimming vegetation - in-zone	2,039	
15	Felling or trimming vegetation - out-of-zone	248	
16	Other	598	
17	**Total vegetation management**	3,121	
18			
19	Routine and corrective maintenance and inspection:	1,734	
20	Asset replacement and renewal	870	
21	**Network opex**		9,246
22	Non-network solutions provided by a related party or third party	–	
23	System operations and network support	3,763	
24	Business support	13,537	
25	**Non-network opex**		17,300
26			
27	**Operational expenditure**		26,546
28	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
29	Energy efficiency and demand side management, reduction of energy losses		
30	Direct billing*		
31	Research and development		
32	Insurance		749
33	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2026**

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	87,720	88,764	1%
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	11,000	14,683	33%
11	System growth	1,426	574	(60%)
12	Asset replacement and renewal	24,060	24,910	4%
13	Asset relocations	384	5,294	1,279%
14	Reliability, safety and environment:			
15	Quality of supply	6,794	3,292	(52%)
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	473	716	51%
18	**Total reliability, safety and environment**	7,267	4,008	(45%)
19	**Expenditure on network assets**	44,137	49,469	12%
20	Expenditure on non-network assets	9,955	7,052	(29%)
21	Expenditure on assets	54,092	56,521	4%
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	3,313	3,521	6%
24	Vegetation management	3,219	3,121	(3%)
25	Routine and corrective maintenance and inspection	2,576	1,734	(33%)
26	Asset replacement and renewal	852	870	2%
27	**Network opex**	9,960	9,246	(7%)
28	Non-network solutions provided by a related party or third party		–	–
29	System operations and network support	4,234	3,763	(11%)
30	Business support	15,221	13,537	(11%)
31	**Non-network opex**	19,456	17,300	(11%)
32	**Operational expenditure**	29,416	26,546	(10%)
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	–	1,754	–
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	825	749	(9%)
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)*			

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the EDB in its pricing schedules. Information is also required on the number of ICPs that are included in each consumer group or price category code, and the energy delivered to these ICPs.
EDBs should feel free to adjust the page break of this schedule to assist with readibility if needed.

8(i): Billed Quantities by Price Component

Consumer group name or price category code	Standardised connection types	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)
Business	Commercial	Standard	6,680	127,438
Standard Domestic	Residential	Standard	23,337	213,759
Low User Domestic	Residential	Standard	19,715	109,540
Time Of Use	Commercial	Standard	189	135,229
Streetlights	Commercial	Standard	10	1,518
Major Customer A	Commercial	Non-standard	4	31,056
Major Customer B	Commercial	Non-standard	2	15,280
Major Customer C	Commercial	Non-standard	1	27,520
Major Customer D	Commercial	Non-standard	2	13,026
	[Select one]	[Select one]		
Add extra rows for additional consumer groups or price category codes as necessary				
		Standard consumer totals	49,931	587,484
		Non-standard consumer totals	9	86,882
		Total for all consumers	49,940	674,366

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

Consumer group name or price category code	Standardised connection types	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Consumer discounts ($000) Standardised price component: Consumer discount - $/kWh EDB defined price component: $/Unit			Total distribution line charge revenue	Total transmission line charge revenue
				Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)		
Business	Commercial	Standard	$18,882	$2,646		$2,646	$18,800	$2,728
Standard Domestic	Residential	Standard	$32,356	$4,402		$4,402	$31,709	$5,049
Low User Domestic	Residential	Standard	$18,041	$2,522		$2,522	$17,760	$2,803
Time Of Use	Commercial	Standard	$13,756	$1,763		$1,763	$13,618	$1,901
Streetlights	Commercial	Standard	$1,247	$123		$123	$1,117	$253
Major Customer A	Commercial	Non-standard	$1,510	$85		$85	$714	$881
Major Customer B	Commercial	Non-standard	$684	$70		$70	$463	$291
Major Customer C	Commercial	Non-standard	$1,704	$100		$100	$232	$1,572
Major Customer D	Commercial	Non-standard	$583	$70		$70	$462	$191
	[Select one]	[Select one]	–			–	–	–
Add extra rows for additional consumer groups or price category codes as necessary								
		Standard consumer totals	$84,282	$11,455	–	$11,455	$83,003	$12,734
		Non-standard consumer totals	$4,481	$325	–	$325	$1,871	$2,935
		Total for all consumers	$88,764	$11,780	–	$11,780	$84,874	$15,670

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	9

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the EDB in its pricing schedules. Information is also required on the number of ICPs that are included in each consumer group or price category code, and the energy delivered to these ICPs.
EDBs should feel free to adjust the page break of this schedule to assist with readibility if needed.

sch ref

Billed quantities by price component - kWh 000s

Standardised price component	Daily fixed charge - $/day		Uncontrolled non-TOU variable charge - $/kWh		Uncontrolled non-TOU variable charge - $/kWh		Controlled non-TOU charge - $/kWh		Uncontrolled non-TOU variable charge - $/kWh	
EDB defined price component	**Daily Price**		**Peak**		**Offpeak**		**Controlled**		**Uncontrolled**	
	Distribution billed quantity	**Transmission billed quantity**	**Distribution billed quantity**	**Transmission billed quantity**	**Distribution billed quantity**	**Transmission billed quantity**	**Distribution billed quantity**	**Transmission billed quantity**	**Distribution billed quantity**	**Transmission billed quantity**
	2,505,187	2,505,187	8,793		21,012		5,347		90,625	
	8,419,544	8,419,544	16,903		41,956		44,214		114,350	
	7,243,190	7,243,190	9,131		23,054		24,697		48,342	
	–	–								
	18,167,921	18,167,921	34,826	–	86,022	–	74,258	–	253,317	–
	–	–	–	–	–	–	–	–	–	–
	18,167,921	18,167,921	34,826	–	86,022	–	74,258	–	253,317	–

Line charge revenues ($000) by price component

Standardised price component	Daily fixed charge - $/day			Uncontrolled non-TOU variable charge - $/kWh			Uncontrolled non-TOU variable charge - $/kWh			Controlled non-TOU charge - $/kWh			Uncontrolled non-TOU variable charge - $/kWh		
EDB defined price component	**Daily Price**			**Peak**			**Offpeak**			**Controlled**			**Uncontrolled**		
	Distribution line charge revenue	**Transmission line charge revenue**	**Total line charge revenue (distribution and transmission)**	**Distribution line charge revenue**	**Transmission line charge revenue**	**Total line charge revenue (distribution and transmission)**	**Distribution line charge revenue**	**Transmission line charge revenue**	**Total line charge revenue (distribution and transmission)**	**Distribution line charge revenue**	**Transmission line charge revenue**	**Total line charge revenue (distribution and transmission)**	**Distribution line charge revenue**	**Transmission line charge revenue**	**Total line charge revenue (distribution and transmission)**
	$4,783	$2,728	$7,511	$2,814		$2,814	$420		$420	$599		$599	$10,150		$10,150
	$12,069	$5,049	$17,118	$5,916		$5,916	$1,091		$1,091	$332		$332	$12,258		$12,258
	$2,573	$2,803	$5,376	$3,716		$3,716	$1,913		$1,913	$1,593		$1,593	$7,933		$7,933
			–			–			–			–			–
			–			–			–			–			–
			–			–			–			–			–
			–			–			–			–			–
			–			–			–			–			–
			–			–			–			–			–
			–			–			–			–			–
	$19,425	$10,580	$30,005	$12,446	–	$12,446	$3,425	–	$3,425	$2,524	–	$2,524	$30,341	–	$30,341
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	$19,425	$10,580	$30,005	$12,446	–	$12,446	$3,425	–	$3,425	$2,524	–	$2,524	$30,341	–	$30,341

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the EDB in its pricing schedules. Information is also required on the number of ICPs that are included in each consumer group or price category code, and the energy delivered to these ICPs.
EDBs should feel free to adjust the page break of this schedule to assist with readibility if needed.

sch ref

Standardised price component	Export charge - $/kWh		Power factor charge - $/kVA		AMD charge - $/kVA		Seasonal charge - $/kWh		Seasonal charge - $/kWh	
EDB defined price component	**Export/DG**		**Power Factor**		**Demand**		**Summer Night**		**Summer Peak**	
	Distribution billed quantity	**Transmission billed quantity**	**Distribution billed quantity**	**Transmission billed quantity**	**Distribution billed quantity**	**Transmission billed quantity**	**Distribution billed quantity**	**Transmission billed quantity**	**Distribution billed quantity**	**Transmission billed quantity**
	1,506		366							
	4,233		–							
	3,048		–							
			6,570		456		17,809		28,466	
			1,669							
	8,787	–	6,936	–	456	–	17,809	–	28,466	–
	–	–	1,669	–	–	–	–	–	–	–
	8,787	–	8,605	–	456	–	17,809	–	28,466	–

Standardised price component	Export charge - $/kWh			Power factor charge - $/kVA			AMD charge - $/kVA			Seasonal charge - $/kWh			Seasonal charge - $/kWh		
EDB defined price component	**Export/DG**			**Power Factor**			**Demand**			**Summer Night**			**Summer Peak**		
	Distribution line charge revenue	**Transmission line charge revenue**	**Total line charge revenue (distribution and transmission)**	**Distribution line charge revenue**	**Transmission line charge revenue**	**Total line charge revenue (distribution and transmission)**	**Distribution line charge revenue**	**Transmission line charge revenue**	**Total line charge revenue (distribution and transmission)**	**Distribution line charge revenue**	**Transmission line charge revenue**	**Total line charge revenue (distribution and transmission)**	**Distribution line charge revenue**	**Transmission line charge revenue**	**Total line charge revenue (distribution and transmission)**
	$16		$16	$19		$19			–			–			–
	$44		$44	–		–			–			–			–
	$31		$31	–		–			–			–			–
			–	$414		$414	$5,366		$5,366	$226		$226	$857		$857
			–	–		–			–			–			–
			–	$95		$95			–			–			–
			–	–		–			–			–			–
			–	–		–			–			–			–
			–	–		–			–			–			–
			–			–			–			–			–
	$91	–	$91	$432	–	$432	$5,366	–	$5,366	$226	–	$226	$857	–	$857
	–	–	–	$95	–	$95	–	–	–	–	–	–	–	–	–
	$91	–	$91	$527	–	$527	$5,366	–	$5,366	$226	–	$226	$857	–	$857

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the EDB in its pricing schedules. Information is also required on the number of ICPs that are included in each consumer group or price category code, and the energy delivered to these ICPs.
EDBs should feel free to adjust the page break of this schedule to assist with readibility if needed.

sch ref

Standardised price component	Seasonal charge - $/kWh		Seasonal charge - $/kWh		Seasonal charge - $/kWh		Seasonal charge - $/kWh		AMD charge - $/kVA	
EDB defined price component	Summer Offpeak		Winter Night		Winter Peak		Winter Offpeak		Excess Demand	
	Distribution billed quantity	Transmission billed quantity	Distribution billed quantity	Transmission billed quantity	Distribution billed quantity	Transmission billed quantity	Distribution billed quantity	Transmission billed quantity	Distribution billed quantity	Transmission billed quantity
	32,372		12,997		20,648		22,935			
	32,372	–	12,997	–	20,648	–	22,935	–	–	–
	–	–	–	–	–	–	–	–	–	–
	32,372	–	12,997	–	20,648	–	22,935	–	–	–

Standardised price component	Seasonal charge - $/kWh			Seasonal charge - $/kWh			Seasonal charge - $/kWh			Seasonal charge - $/kWh			AMD charge - $/kVA		
EDB defined price component	Summer Offpeak			Winter Night			Winter Peak			Winter Offpeak			Excess Demand		
	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)
			–			–			–			–			–
			–			–			–			–			–
			–			–			–			–			–
	$411		$411	$214		$214	$2,147		$2,147	$378		$378			–
			–			–			–			–			–
			–			–			–			–			–
			–			–			–			–			–
			–			–			–			–			–
			–			–			–			–			–
			–			–			–			–			–
	$411	–	$411	$214	–	$214	$2,147	–	$2,147	$378	–	$378	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	$411	–	$411	$214	–	$214	$2,147	–	$2,147	$378	–	$378	–	–	–

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the EDB in its pricing schedules. Information is also required on the number of ICPs that are included in each consumer group or price category code, and the energy delivered to these ICPs.
EDBs should feel free to adjust the page break of this schedule to assist with readibility if needed.

sch ref

Standardised price component	Installed capacity charge - $/kVA		Monthly fixed charge - $/month		Monthly fixed charge - $/month		onthly fixed charge per fixture - $/fixture/mor		Daily fixed charge - $/day	
EDB defined price component	**Connection Capacity Price**		**Transformer Monthly Price**		**Transformer Capacity Price**		**Unmetered Distributed Streetlights**		**Metered Lighting - Daily Price**	
	Distribution billed quantity	**Transmission billed quantity**	**Distribution billed quantity**	**Transmission billed quantity**	**Distribution billed quantity**	**Transmission billed quantity**	**Distribution billed quantity**	**Transmission billed quantity**	**Distribution billed quantity**	**Transmission billed quantity**
	2,168		1,936		1,985					
							132	132		
	2,168	–	1,936	–	1,985	–	132	132	–	–
	–	–	–	–	–	–	–	–	–	–
	2,168	–	1,936	–	1,985	–	132	132	–	–

Standardised price component	Installed capacity charge - $/kVA			Monthly fixed charge - $/month			Monthly fixed charge - $/month			Monthly fixed charge per fixture - $/fixture/month			Daily fixed charge - $/day		
EDB defined price component	**Connection Capacity Price**			**Transformer Monthly Price**			**Transformer Capacity Price**			**Unmetered Distributed Streetlights**			**Metered Lighting - Daily Price**		
	Distribution line charge revenue	**Transmission line charge revenue**	**Total line charge revenue (distribution and transmission)**	**Distribution line charge revenue**	**Transmission line charge revenue**	**Total line charge revenue (distribution and transmission)**	**Distribution line charge revenue**	**Transmission line charge revenue**	**Total line charge revenue (distribution and transmission)**	**Distribution line charge revenue**	**Transmission line charge revenue**	**Total line charge revenue (distribution and transmission)**	**Distribution line charge revenue**	**Transmission line charge revenue**	**Total line charge revenue (distribution and transmission)**
			–			–			–			–			–
			–			–			–			–			–
			–			–			–			–			–
	$3,073	$1,901	$4,974	$243		$243	$287		$287			–			–
			–			–			–	$1,117	$253	$1,370			–
			–			–			–			–			–
			–			–			–			–			–
			–			–			–			–			–
			–			–			–			–			–
			–			–			–			–			–
	$3,073	$1,901	$4,974	$243	–	$243	$287	–	$287	$1,117	$253	$1,370	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	$3,073	$1,901	$4,974	$243	–	$243	$287	–	$287	$1,117	$253	$1,370	–	–	–

Counties Energy Limited	
31 March 2026	
COUP	

	Uncontrolled non-TOU variable charge - $/kWh		Other charge [see EDB defined price component below]	
Standardised price component	Uncontrolled non-TOU variable charge - $/kWh		Other charge [see EDB defined price component below]	
EDB defined price component	Metered Lighting - kWh		Annual Contract	
	Distribution billed quantity	**Transmission billed quantity**	**Distribution billed quantity**	**Transmission billed quantity**
	1,518			
			13,500	19,225
			9,375	5,904
			3,545	23,975
			9,216	3,810
	1,518	–	–	–
	–	–	35,637	52,913
	1,518	–	35,637	52,913

Standardised price component	Uncontrolled non-TOU variable charge - $/kWh			Other charge [see EDB defined price component below]		
EDB defined price component	Metered Lighting - kWh			Annual Contract		
	Distribution line charge revenue	**Transmission line charge revenue**	**Total line charge revenue (distribution and transmission)**	**Distribution line charge revenue**	**Transmission line charge revenue**	**Total line charge revenue (distribution and transmission)**
			–			–
			–			–
			–			–
			–			–
			–			–
			–	$619	$881	$1,500
			–	$463	$291	$754
			–	$232	$1,572	$1,804
			–	$462	$191	$653
			–			–
	–	–	–	–	–	–
	–	–	–	$1,776	$2,935	$4,711
	–	–	–	$1,776	$2,935	$4,711

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2026**
Network / Sub-network Name	

SCHEDULE 9a: ASSET REGISTER

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

sch ref

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.	25,860	25,871	11	3
10	All	Overhead Line	Wood poles	No.	1,717	1,642	(75)	3
11	All	Overhead Line	Other pole types	No.	59	64	5	3
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	56	55	(1)	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	66	66	0	4
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	1	1	0	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	N/A
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	N/A
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	0	0	–	4
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.	4	4	–	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	5	5	–	4
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	5	5	–	4
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	18	18	–	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	18	19	1	4
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	N/A
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	9	9	–	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	98	98	–	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	N/A
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	17	17	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1,500	1,505	4	3
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	–	–	–	N/A
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	331	342	11	3
39	HV	Distribution Cable	Distribution UG PILC	km	7	6	(1)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	3	2	(1)	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	42	43	1	3
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	N/A
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	5,356	5,395	39	3
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	N/A
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	485	513	28	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	3,196	3,204	8	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	1,087	1,113	26	3
48	HV	Distribution Transformer	Voltage regulators	No.	15	15	–	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	1,075	1,117	42	3
50	LV	LV Line	LV OH Conductor	km	676	666	(10)	2
51	LV	LV Cable	LV UG Cable	km	965	992	27	2
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	37	36	(2)	2
53	LV	Connections	OH/UG consumer service connections	No.	49,457	19,906	(29,551)	2
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	186	183	(3)	3
55	All	SCADA and communications	SCADA and communications equipment operating as a single syster	Lot	1	1	–	4
56	All	Capacitor Banks	Capacitors including controls	No	17	17	–	3
57	All	Load Control	Centralised plant	Lot	6	6	–	4
58	All	Load Control	Relays	No	2,932	–	(2,932)	3
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

			Company Name	Counties Energy Limited
			For Year Ended	31 March 2026
			Network / Sub-network Name	

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

9b: Asset Age Profile

8 Disclosure Year (year ended)

Number of assets at disclosure year end by installation date

sch ref	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.	13	17	112	1,461	2,678	5,098	5,941	224	688	331	258	333	291	387	311	367	500	309	312	247	139	228	130	118	1,147	517	272	371	518	486	799	548	600	100	–	–	20	25,871		3
11	All	Overhead Line	Wood poles	No.	–	1	4	31	85	83	474	26	12	10	1	4	4	6	4	4	11	7	4	4	3	6	6	4	699	129	4	–	4	1	4	1	–	–	–	–	6	1,642		3
12	All	Overhead Line	Other pole types	No.	–	–	2	15	4	–	1	–	–	–	–	–	–	–	1	–	–	–	–	–	–	4	–	–	18	1	–	–	–	–	–	–	1	16	–	–	1	64		3
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	–	22	12	7	–	–	–	–	–	14	–	–	–	–	–	–	0	–	–	–	–	–	1	–	–	–	–	–	0	–	–	–	–	–	–	55		4
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	0	18	–	6	–	–	–	0	20	–	–	–	–	–	–	–	10	5	–	–	–	2	–	–	–	0	4	0	–	–	–	–	66		4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	–	0	–	–	–	–	–	0	–	–	0	–	–	–	0	–	–	–	–	–	–	–	0	0	–	–	–	–	–	–	–	–	–	1		4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0	–	–	–	–	–	–	–	–	–	–	0		4
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.	–	–	–	3	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	4		4
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	1	–	–	–	–	–	–	1	–	–	0	–	–	–	–	1	–	–	–	–	1	–	–	1	–	–	–	–	–	–	–	5		4
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	5	–	–	–	–	–	–	–	–	–	–	5		4
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	9	6	–	–	–	–	–	–	–	3	–	–	–	–	–	–	18		4
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	–	9	–	1	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	1	–	–	–	7	–	–	–	–	–	–	–	–	19		4
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4	–	1	–	–	2	–	1	1	–	–	–	–	–	–	–	–	–	9		4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	3	–	11	12	–	–	–	–	–	–	11	–	–	–	–	–	–	–	22	–	–	–	–	26	–	–	13	–	–	–	–	–	–	–	98		4
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	–	2	1	1	2	–	–	–	–	–	1	1	–	–	–	–	–	–	–	2	–	–	–	–	2	–	4	1	–	–	–	–	–	–	–	17		4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	14	41	70	203	220	277	260	19	18	28	18	9	11	25	13	9	27	18	15	11	9	9	8	9	15	30	5	22	23	11	18	25	11	0	–	–	3	1,505		3
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
38	HV	Distribution Line	SWER conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	0	0	0	0	24	4	6	2	2	7	7	15	10	2	9	11	8	9	8	14	14	9	10	12	22	27	32	26	21	14	8	1	–	–	5	342		3
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	0	–	2	4	–	–	–	0	–	–	0	0	–	–	–	–	–	–	0	–	0	–	–	–	–	–	–	–	0	–	–	–	–	–	6		3
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	0	–	–	–	–	1	–	–	–	–	–	0	0	–	–	–	–	–	–	–	0	2		4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionaliser	No.	–	–	–	–	–	1	2	2	–	–	–	–	–	–	3	–	–	–	–	–	7	1	–	–	–	6	2	4	1	1	7	2	4	–	–	–	–	43		3
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	–	–	12	38	134	346	910	173	140	97	95	100	132	50	118	70	91	219	208	174	249	151	153	134	121	180	137	81	113	152	303	198	197	27	–	–	92	5,395		3
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	–	1	3	4	3	3	–	5	3	–	4	8	5	9	6	10	13	2	3	4	5	25	32	46	60	51	61	53	52	36	3	–	–	3	513		3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	–	11	12	69	179	416	51	78	56	66	78	87	38	75	32	45	160	179	146	207	121	123	101	71	116	71	43	70	98	181	90	111	14	–	–	9	3,204		3
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	–	1	2	10	118	25	19	16	23	19	25	27	24	28	15	35	40	28	54	46	42	38	60	58	52	43	60	57	52	48	32	4	–	–	12	1,113		3
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	–	–	1	1	–	–	–	8	3	–	–	–	–	–	–	–	–	–	15		3
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	3	2	8	116	25	19	16	23	19	26	28	24	28	15	35	40	28	54	48	42	38	60	57	54	43	64	57	52	47	31	4	–	–	11	1,117		3
51	LV	LV Line	LV OH Conductor	km	–	0	1	2	3	3	35	6	4	6	3	2	3	2	1	2	5	1	4	2	3	2	1	0	2	2	2	0	5	2	2	4	3	0	–	–	554	666		2
52	LV	LV Cable	LV UG Cable	km	–	–	1	1	9	3	116	24	19	21	16	15	34	43	24	15	7	20	12	20	18	38	26	34	43	46	36	38	39	45	39	26	24	2	–	–	136	992		2
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	–	–	–	–	0	0	1	–	–	–	–	–	–	1	–	0	2	0	3	3	6	3	–	5	–	3	–	2	3	1	0	–	–	–	2	36		2
54	LV	Connections	OH/UG consumer service connections	No.	–	–	3	73	617	188	770	298	262	330	255	251	455	544	367	248	203	395	298	333	265	440	615	528	817	916	714	842	955	1,327	1,155	822	924	140	–	–	3,556	19,906		2
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	8	–	9	2	–	–	–	–	–	–	–	4	–	–	–	4	2	–	17	4	–	14	–	26	26	7	–	17	9	24	10	–	–	–	183		3
56	All	SCADA and communications	SCADA and communications equipment operating as a single syst	Lot	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	1		4
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	11	–	–	–	–	–	–	3	1	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	1	–	–	–	–	17		3
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	1	1	–	–	–	–	–	–	1	–	–	–	–	–	–	–	1	–	–	–	–	–	1	–	–	1	–	–	–	–	–	–	6		4
59	All	Load Control	Relays	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		3
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–										–	–		N/A

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2026**
Network / Sub-network Name	

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref

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

10

sch ref		Overhead (km)	Underground (km)	Total circuit length (km)
11	**Circuit length by operating voltage (at year end)**			
12	> 66kV	66	0	66
13	50kV & 66kV	–	–	–
14	33kV	55	1	57
15	SWER (all SWER voltages)	–	–	–
16	22kV (other than SWER)	619	289	908
17	6.6kV to 11kV (inclusive—other than SWER)	886	94	980
18	Low voltage (< 1kV)	666	992	1,657
19	**Total circuit length (for supply)**	2,292	1,376	3,668
20				
21	Dedicated street lighting circuit length (km)	0	36	36
22	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			2
23				

sch ref		Circuit length (km)	(% of total overhead length)
24	**Overhead circuit length by terrain (at year end)**		
25	Urban	152	7%
26	Rural	2,075	91%
27	Remote only	–	–
28	Rugged only	65	3%
29	Remote and rugged	–	–
30	Unallocated overhead lines	–	–
31	**Total overhead length**	2,292	100%
32			

sch ref		Circuit length (km)	(% of total circuit length)
33			
34	Length of circuit within 10km of coastline or geothermal areas (where known)	1,674	46%
35			

sch ref		Total newly identified throughout the disclosure year	Total remaining at high risk at the disclosure year-end	
36				
37	Number of overhead circuit sites at high risk from vegetation damage	521	174	*Not required before DY2026*
38				

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

sch ref	Category of overhead circuit site	Number of overhead circuit sites at high risk from vegetation damage at disclosure year-end	Number of overhead circuit sites involving critical assets at disclosure year-end	
40				
41	Private Landowner - First/Free Cut	71	15	*Not required before DY2026*
42	Private Landowner - Chargeable Cut	6	–	*Not required before DY2026*
43	Private Landowner - No Interest	47	9	*Not required before DY2026*
44	Auckland Council - First/Free Cut	8	3	*Not required before DY2026*
45	Auckland Council - Chargeable Cut	2	–	*Not required before DY2026*
46	Auckland Council - No Interest	18	2	*Not required before DY2026*
	Waikato Council - First/Free Cut	4	1	
	Waikato Council - Chargeable Cut	–	–	
	Waikato Council - No Interest	15	2	
	Hauraki Council - First/Free Cut	3	–	
	Hauraki Council - Chargeable Cut	–	–	
	Hauraki Council - No Interest	–	–	
47	**Total number of sites**	174	32	*Not required before DY2026*

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

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2026**

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			
8	**Location ***	**Average number of ICPs in disclosure year**	**Line charge revenue ($000)**
9	Counties Energy has no embedded networks		
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			

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

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2026**
Network / Sub-network Name	

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref				
8	**9e(i): Consumer Connections and Decommissionings**			
9	*Number of ICPs connected during year by consumer type*			
10	*Consumer types defined by EDB**		**Number of connections (ICPs)**	
11	Urban Residential		228	
12	Urban Commercial		614	
13	Rural Residential		86	
14	Rural Commercial		292	
15				
16	**Connections total**		1,220	
17	** include additional rows if needed*			
18				
19	*Number of ICPs decommissioned during year by consumer type*			
20	*Consumer types defined by EDB**		**Number of decommissionings**	
21	Urban Residential		99	
22	Urban Commercial		76	
23	Rural Residential		96	
24	Rural Commercial		82	
25				
26	**Decommissionings total**		353	
27	** include additional rows if needed*			
28				
29	**Distributed generation**			
30	Number of connections made in year		228	**connections**
31	Capacity of distributed generation installed in year		4.20	**MVA**
32				
33	**9e(ii): System Demand**			
34				
35			**Demand at time of maximum coincident demand (MW)**	
36	**Maximum coincident system demand**			
37	GXP demand		133	
38	Distributed generation output at HV and above	*plus*	8	
39	**Maximum coincident system demand**		141	
40	Net transfers to (from) other EDBs at HV and above	*less*		
41	**Demand on system for supply to consumers' connection points**		141	
42	**Electricity volumes carried**		**Energy (GWh)**	
43	Electricity supplied from GXPs		638	
44	Electricity exports to GXPs	*less*		
45	Electricity supplied from distributed generation	*plus*	70	
46	Net electricity supplied to (from) other EDBs	*less*		
47	**Electricity entering system for supply to consumers' connection points**		708	
48	Total energy delivered to ICPs	*less*	674	
49	**Electricity losses (loss ratio)**		34	4.8%
50				
51	**Load factor**		0.57	
52	**9e(iii): Transformer Capacity**			
53			**(MVA)**	
54	Distribution transformer capacity (EDB owned)		478	
55	Distribution transformer capacity (Non-EDB owned)		85	
56	**Total distribution transformer capacity**		563	
57				
58			**(MVA)**	
59	Zone substation transformer capacity (EDB owned)		575	
60	Zone substation transformer capacity (Non-EDB owned)			
61	**Total zone substation transformer capacity**		575	

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2026**
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

This schedule requires a summary of the key measures of network reliability (interruptions, SAIDI, SAIFI and fault rate) for the disclosure year. EDBs must provide explanatory comment on their network reliability for the disclosure year in Schedule 14 (Explanatory notes to templates). The SAIFI and SAIDI information is part of audited disclosure information (as defined in section 1.4 of 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)	450	
12	Class C (unplanned interruptions on the network)	398	
13	Class D (unplanned interruptions by Transpower)	–	
14	Class E (unplanned interruptions of EDB owned generation)	–	
15	Class F (unplanned interruptions of generation owned by others)	–	
16	Class G (unplanned interruptions caused by another disclosing entity)	–	
17	Class H (planned interruptions caused by another disclosing entity)	–	
18	Class I (interruptions caused by parties not included above)	77	
19	**Total**	925	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	165	233
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)		
26	Class B (planned interruptions on the network)	0.61	190.9
27	Class C (unplanned interruptions on the network)	2.26	155.2
28	Class D (unplanned interruptions by Transpower)		
29	Class E (unplanned interruptions of EDB owned generation)		
30	Class F (unplanned interruptions of generation owned by others)		
31	Class G (unplanned interruptions caused by another disclosing entity)		
32	Class H (planned interruptions caused by another disclosing entity)		
33	Class I (interruptions caused by parties not included above)	0.10	12.2
34	**Total**	2.97	358.3
35			
36	**Transitional SAIFI and SAIDI (previous method)**	**SAIFI**	**SAIDI**
37	Class B (planned interruptions on the network)	N/A	N/A
38	Class C (unplanned interruptions on the network)	2.03	155.2
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	**Counties Energy Limited**
For Year Ended	**31 March 2026**
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

This schedule requires a summary of the key measures of network reliability (interruptions, SAIDI, SAIFI and fault rate) for the disclosure year. EDBs must provide explanatory comment on their network reliability for the disclosure year in Schedule 14 (Explanatory notes to templates). The SAIFI and SAIDI information is part of audited disclosure information (as defined in section 1.4 of 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	0.04	2.3
Vegetation	0.52	48.1
Adverse weather		
Adverse environment		
Third party interference	0.28	20.9
Wildlife	0.05	1.3
Human error	0.14	0.9
Defective equipment	0.86	65.8
Other cause		
Unknown	0.38	15.9

Breakdown of third party interference	SAIFI	SAIDI
Dig-in	0.04	2.3
Overhead contact	0.03	1.7
Vandalism	0.00	0.0
Vehicle damage	0.21	16.9
Other	0.00	0.0

Breakdown of vegetation interruptions (vegetation cause)	SAIFI	SAIDI	
In-zone	0.08	10.3	*Not required before DY2026*
Out-of-zone	0.44	37.8	*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)	0.41	148.9
Distribution cables (excluding LV)	0.03	11.6
Distribution other (excluding LV)	0.17	30.4

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.07	2.6
Subtransmission cables		
Subtransmission other		
Distribution lines (excluding LV)	1.98	144.8
Distribution cables (excluding LV)	0.05	3.6
Distribution other (excluding LV)	0.15	4.3

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	13	122	10.68
Subtransmission cables		1	–
Subtransmission other			
Distribution lines (excluding LV)	375	1,505	24.92
Distribution cables (excluding LV)	6	383	1.57
Distribution other (excluding LV)	18		
Total	412		

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2026**
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

This schedule requires a summary of the key measures of network reliability (interruptions, SAIDI, SAIFI and fault rate) for the disclosure year. EDBs must provide explanatory comment on their network reliability for the disclosure year in Schedule 14 (Explanatory notes to templates). The SAIFI and SAIDI information is part of audited disclosure information (as defined in section 1.4 of 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	Kaiaua	16.17	22	Defective Equipment	102.24 km	1074	94%
2	Te Toro	13.64	38	Defective Equipment	98.25 km	1183	93%
3	Hunua	11.96	22	Defective Equipment	71.97 km	1016	87%
4	Anchor Factory	8.70	13	Third Party Interference	49.70 km	1285	76%
5	Waiuku South	7.55	13	Defective Equipment	57.85 km	799	97%
6	Railway	7.22	7	Defective Equipment	42.72 km	1003	88%

[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	Te Toro	0.287	38	Defective Equipment	98.25 km	1183	93%
2	Kaiaua	0.220	22	Defective Equipment	102.24 km	1074	94%
3	Hunua	0.150	22	Defective Equipment	71.97 km	1016	87%
4	Manukau Heads	0.105	45	Defective Equipment	107.24 km	949	98%
5	Waiau Pa	0.103	11	Defective Equipment	34.04 km	1351	74%
6	Drury	0.087	12	Defective Equipment	38.32 km	1691	51%

[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	Kaiaua	750.37	22	Defective Equipment	102.24 km	1074	94%
2	Drury Hills	600.45	16	Defective Equipment	20.89 km	400	73%
3	Hunua	587.74	22	Defective Equipment	71.97 km	1016	87%
4	Pukekawa	585.60	23	Defective Equipment	47.00 km	434	97%
5	Te Toro	574.16	38	Defective Equipment	98.25 km	1183	93%
6	Waiuku South	471.04	13	Defective Equipment	57.85 km	799	97%

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

Company Name	Counties Energy Limited
For Year Ended	31 March 2026

Schedule 14 Mandatory Explanatory Notes

(Guidance Note: This Microsoft Word version of Schedules 14, 14a and 15 is from the Electricity Distribution Information Disclosure (amendments related to IM Review 2023) Amendment Determination 2024. Clause references in this template are to that determination.

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

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

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

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

Classification is consistent with previous treatment.

ROI comparable to a post tax WACC increased from 5.34% in FY25 to 6.13% in FY26 with the following items of note:

- Revenue increased by 14% in FY26 to $88.8m (FY25 - $78.0m);
- Operational costs decreased from 32% of lines revenue in FY25 to 30% of lines revenue in FY26 (Network Spend – 1% down, Business Support down 1%);
- Revaluations increased from $12.7m in FY25 (2.5% CPI) to $16.5m in FY26 (3.1% CPI); and
- Depreciation increased from $17.9m in FY25 to $22.9m in FY26 reflecting continued high network growth.

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-

6. 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

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

Box 2: Explanatory comment on regulatory profit
Line charge revenue and operational expenditure excludes non-regulated Smart Meters. Other regulated income includes only standard recoveries relating to the regulated business (eg electricity reserve market). There were no changes in classification within regulatory profit this disclosure year.

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

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

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

    9.1 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 mergers or acquisitions during the disclosure year.

Value of the Regulatory Asset Base (Schedule 4)

10. 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)
There were no changes to RAB classifications from the prior year. The revaluation uplift was $16.5m reflecting the CPI of 3.1% in FY26. Commissioned assets in FY26 were $31.8m (FY25 - $41.9m). Assets being disposed of comprise non-system vehicles and IT equipment/software ($73k), transformers sold as scrap ($93k) and network assets damaged by third party incidents ($172k). A loss of $120k was recorded for these disposals. Higher depreciation in FY26 reflects continued high network growth and investment in IT related assets to support the network. An asset category transfer of $848k between Subtransmission lines and Distribution and LV lines was recorded with the re-categorisation on close-out of jobs.

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

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

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

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

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

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

Box 5: Regulatory tax allowance: permanent differences

Items included in permanent differences are the difference between gain/loss on sale of regulatory assets used for the regulatory P&L and the equivalent calculation for tax purposes and permanent differences (eg non-deductible entertainment).

8.1 Income not included in regulatory profit before tax but taxable (Nil).

8.2 Expenditure or loss in regulatory profit before tax but not deductible - accounting vs tax loss on disposal ($105k), entertainment expense ($28k) and other ($4k).

8.3 Income included in regulatory profit before tax but not taxable (Nil).

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

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

12. 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 differences relate to holiday pay provisions, gratuity and sick leave provisions and doubtful debt provisions as they related to the regulated business. The movement in these provisions has been multiplied by the tax rate to calculate the deferred tax figure ($31k).

Cost allocation (Schedule 5d)

13. 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

Cost allocations were calculated using ABAA methodology as per the IM Determination for business support. In particular:

• Property identified space usage as the proxy allocator; and

• Finance, IT and Corporate costs allocated costs using resource as the proxy allocator.

Proxy allocators were used as causal relationships could not be reasonably established. Property costs were allocated as a proportion of space used. IT, Finance and Corporate costs were allocated based on the level of resource allocated to the regulated business.

Asset allocation (Schedule 5e)

14. 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

Asset allocations were calculated using ABAA methodology as per the IM Determination.

In particular:

• Property identified space usage as the proxy allocator where costs could not be directly allocated; and

• Finance, IT and Corporate costs used resource as the proxy allocator.

No items have been reclassified during the disclosure year.

Capital Expenditure for the Disclosure Year (Schedule 6a)

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

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

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

Box 9: Explanation of capital expenditure for the disclosure year

12.1: Consumer types are based on historical AMP descriptions. Treatment for all other categories was to sum the many small projects (>$50k) by significant core drivers.

12.2: Classification is consistent with treatment in prior years.

Operational Expenditure for the Disclosure Year (Schedule 6b)

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

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

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

20. 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
Operational expenditure includes items such as cable and conductor repairs, insulator replacements, transformer and switch repairs, and other work of a non-capital nature. Classification is consistent with previous treatment. There is no atypical expenditure.

Variance between forecast and actual expenditure (Schedule 7)

21. 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

7(i): Line charge revenue finished near to target.

7(ii): Variances above 10% and >$0.5m listed by category:

•Consumer connections were $3.7m (33%) above target due to the continued high number of residential and large commercial connections;

•System growth was $0.9m (60%) below target primarily related to delays on a single large Developer driven project that proceeded slower than initially advised;

• Asset relocations were $4.9m (1,279%) above target due to significant customer asset relocation works;

•Quality of Supply was $3.5m (52%) below target with lower than forecast costs for delivery of the largest associated programme, with some other projects delayed to FY27 due to timing of consenting approvals;

•Expenditure on non-network assets was $2.9m (29%) lower than forecast due to phasing into outlying years.

7(iii): Variances above 10% and >$0.5m listed by category:

•Routine and corrective maintenance was $0.8m (22%) below target due to efficient delivery and to a lesser extent rephasing of non-urgent works; and

•Business support costs were $1.6m (11%) below target due largely to timing for commissioning of Digital projects with subscription and related costs flowing through later than initially estimated.

Information relating to revenues and quantities for the disclosure year

22. In the box below provide-

23. 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

    23.1 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 billed line charge revenue was within 1% of target for the year.

Network Reliability for the Disclosure Year (Schedule 10)

24. 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

Consistent with prior years, Counties Energy has reallocated SAIFI / SAIDI arising from events initiating from privately owned network assets to Class I (0.09 successive SAIFI / 10.21 SAIDI has been reallocated from Class C with the balance in Class I moving from Class B where planned requests on privately owned networks impact more than one ICP).

For schedule 10(vi), the following interpretations of the ID requirements have been applied:

a) 'Unplanned SAIDI', 'Unplanned SAIFI' and 'Customer Impact Ratio' includes class C interruptions only (and does not include other classes such as D, G or I).
b) 'Unplanned Interruptions' has also been assumed to only include class C – which makes the values consistent with the measures reported but is inconsistent with the definition in the ID determination.
c) 'Most Common Cause' has been determined by the modal cause within the list of unplanned interruptions. It is understood this is the requirement but isn't reflective of the measure being reported (e.g. SAIDI, SAIFI or Customer Impact Ratio).
d) Where there are two modal causes (equal counts), the cause with the largest measure (SAIDI/SAIFI/Customer Minutes) has been reported.

Refer to schedule 15 for commentary on "Successive Interruptions".

Insurance cover

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

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

26.1 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
Essential equipment is insured under a materials damage policy that is reviewed annually. The material damage cover is for physical loss or damage including earthquake and natural disaster cover. Other than key substations and essential equipment, the bulk of the Network system is not covered by insurance due to the inability to get sufficient cover from the insurance industry for such assets, at an acceptable cost.

Amendments to previously disclosed information

27. 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:

    27.1 a description of each error; and

28. 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 amendments to previously disclosed information pursuant to clause 2.12.1 disclosed in the last 10 years.

Company Name	Counties Energy Limited
For Year Ended	31 March 2026

Schedule 14a Mandatory Explanatory Notes on Forecast Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure (amendments related to IM Review 2023) Amendment Determination 2024.

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

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

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

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

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts
The difference between nominal and constant prices reflects inflation of 3% per annum.

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

32. In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts
The difference between nominal and constant prices reflects inflation of 3% per annum.

Company Name Counties Energy Limited

For Year Ended 31 March 2025

Schedule 15 Voluntary Explanatory Notes

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure (amendments related to IM Review 2023) Amendment Determination 2024.

1. This schedule enables EDBs to provide, should they wish to-

2. additional explanatory comment to reports prepared in accordance with clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1, 2.5.2 and 2.6.6;

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

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

5. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information

Schedule 9a – [54] LV Connections

In previous years, the total number of ICPs was disclosed with no age profile information. This has now updated to report on the LV connection points of which only ground mount/UG "pillar" connections are recorded. This accounts for the large decrease for the current year. The corresponding age profile is disclosed in schedule 9b. This change is consistent with Schedule 12a in the 2026 AMP.

Schedule 9a – [59] Load Control Relays

These are now recognised as being owned by the Metering (MEP) business as part of the revenue meter installation, and not part of our Network equipment. They have therefore been excluded from the schedules.

Schedule 10 - Successive Interruptions:

For FY26, "Successive Interruption" is covered by the updates to schedule 10(i):

- Class B (planned) disclosure in Schedule 10 includes the full impact of "Successive Interruptions". This is consistent with disclosures since FY21 (inclusive), with the enabling change to reporting for planned events having been implemented part way through FY20. Consequently, there are no 'Transitional' numbers reported for Class B.
- Class C (unplanned) disclosure in Schedule 10 (i) is now updated to reflect SAIFI, including successive interruptions within a single outage event. This is inconsistent with reporting prior to FY24, and the calculation as per the prior method is reported as 'Transitional' for Class C. The change in interpretation has resulted in Class C (unplanned) SAIFI result for FY26 increasing by 12.0% from 2.03 to 2.26. There is no change to the SAIDI number.

Schedule 18 Certification for Year-end Disclosures

Clause 2.9.2

We, Keith Watson and Hamish Stevens, being directors of Counties 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 – 2.3.18, 2.4.21, 2.4.22, 2.5.1 (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 Counties Energy Limited's accounting and other records sourced from its financial and non-financial systems, and that sufficient appropriate records have been retained; and

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.

Keith Watson
26 August 2026

Hamish Stevens
26 August 2026

The Audit Office
Te Mana Arotake

Independent Assurance Report

To the directors of Counties Energy Limited and to the Commerce Commission on the disclosure information for the disclosure year ended 31 March 2026 as required by the Electricity Distribution Information Disclosure (Amendments related to IM Review 2023) Amendment Determination 2024 [2024] NZCC 31 (as amended)

Counties 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 (as amended) (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, Matthew White, using the staff and resources of PricewaterhouseCoopers, to undertake a reasonable assurance engagement, on his behalf, on whether the information prepared by the company for the disclosure year ended 31 March 2026 (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, 2, 3, 3a, 4, 5a to 5h, 6a and 6b (except for information required to be disclosed in Schedule 6(b)(i) under the “Vegetation-related” and “Other” sub-categories of the “Service interruptions and emergencies” category, and the “assessment and notification costs”, “Felling or trimming vegetation – in-zone”, “Felling or trimming vegetation – out-of-zone”, and “Other” sub-categories of the “Vegetation management” category), 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.

- The basis for the valuation of related party transactions (the Related Party Transaction Information) in accordance 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 Electricity Distribution Services Input Methodologies Determination 2012 (as amended) (the IM Determination); and the information disclosed under clauses 2.3.8.

Opinion

In our opinion, in all material respects:

- as far as appears from an examination, proper records to enable the complete and accurate compilation of the Disclosure Information have been kept by the company;
- as far as appears from an examination, the information used in the preparation of the Disclosure Information has been properly extracted from the company's accounting and other records, sourced from the company's financial and non-financial systems;
- the Disclosure Information complies, 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
Regulatory Asset Base (RAB): The Regulatory Asset Base (RAB), as set out in Schedule 4, reflects the value of the Company's electricity distribution assets. These are valued using an indexed historic cost methodology prescribed by the Determination. It is a measure which is used widely and is key to measuring the Company's return on investment and therefore important when monitoring financial performance or setting electricity distribution prices. The RAB inputs, as set out in the IM Determination, are similar to those used in the measurement of fixed assets in the financial statements, however, there are a number of different requirements and complexities which require careful consideration. Due to the importance of the RAB within the regulatory regime, the incentives to overstate the RAB value, and complexities within the regulations, we have considered it to be a key area of focus. The Regulatory Asset Base (RAB), as set out in Schedule 4, reflects the value of the Company's electricity distribution assets. These are valued using an indexed historic cost methodology prescribed by the Determination. It is a measure which is used widely and is key to measuring the Company's return on investment and therefore important when monitoring financial performance or setting electricity distribution prices. The RAB inputs, as set out in the IM Determination, are similar to those used in the measurement of fixed assets in the financial statements, however, there are a number of different requirements and complexities which require careful consideration. Due to the importance of the RAB within the regulatory regime, the incentives to overstate the RAB value, and complexities within the regulations, we have considered it to be a key area of focus.	We have obtained an understanding of the compliance requirements relevant to the RAB as set out in the Determination and the IM Determination. Our procedures over the regulatory asset base included the following: **Assets commissioned** • We considered the nature of the assets commissioned during the period, as per the regulatory fixed asset register, to identify any specific cost or asset type exclusions, as set out in the Determination, which are required to be removed from the RAB; • We inspected the assets commissioned during the period, as per the regulatory fixed asset register, to identify any specific cost or asset type exclusions, as set out in the Determination, which are required to be removed from the RAB; • We reconciled the assets commissioned, as per the regulatory fixed asset register, to the asset additions disclosed in the audited annual financial statements and investigated any material reconciling items; and • We tested a sample of assets commissioned during the disclosure period for appropriate asset category classification. **Depreciation** • For assets with no standard asset lives we assessed the reasonableness of the lives used by reference to the accounting depreciation rates used in preparing the financial statements; • We have performed a reasonableness test to ensure regulatory depreciation expense is calculated in line with IM Determination clause 2.2.5 • We compared the standard asset lives by asset category to those set out in the IM Determination. **Revaluation** • We recalculated the revaluation rate set out in the IM Determination using the relevant Consumer Price Index indices taken from the Statistics New Zealand website; and • We tested the mathematical accuracy of the revaluation calculation performed by management.

<table>
<tr><th>Key Assurance Matter</th><th>How our procedures addressed the key assurance matter</th></tr>
<tr><td>
Cost & Asset Allocation:
The Determination relates to information concerning the supply of electricity distribution services. In addition to the regulated supply of electricity, the Company also supplies customers with other unregulated services such as contracting services.
As set out in schedules 5d, 5e, 5f and 5g, costs and asset values that relate to electricity distribution services regulated under the Determination should comprise:
All of the costs directly attributable to the regulated goods or services; and
An allocated portion of the costs that are not directly attributable.
The IM Determination set out rules and processes for allocating costs and assets which are not directly attributable to either regulated or unregulated services. A number of screening tests apply which must be considered when deciding on the appropriate allocation method.
The Company has applied the Accounting-Based Allocation Approach Methodology (ABAA) utilising proxy cost and asset allocators to allocate the asset values and operating costs that are not directly attributable where causal relationships could not be identified.
Given the judgement involved in the application of the cost and asset allocation methodologies we consider it a key assurance matter.
</td><td>
We obtained an understanding of the Company’s cost and asset allocation processes and the methodologies applied.
Our procedures over cost and asset allocation included:
Reconciling the regulated and unregulated financial information to the audited financial statements;
Classification as directly/not directly attributable

Considering the appropriateness of the costs allocated as directly attributable, based on the nature and our understanding of the business to determine the reasonableness of the directly attributable classification;
Testing a sample of transactions to ensure their classification as either directly attributable or not directly attributable costs are appropriate and in line with the Determination;
Inspecting the fixed asset register to identify any asset classes which based on their nature and our understanding of the business could be considered assets directly attributable to a specific business unit;
Testing a sample of assets commissioned to ensure their classification as either directly attributable or not directly attributable are appropriate and in line with the Determination;

Appropriateness of the allocators used for not directly attributable costs and assets

Considering the appropriateness of the cost and asset causal and proxy allocators used in applying the ABAA to not directly attributable costs including inspecting supporting documentation and recalculating proxy allocators;
Understanding why causal relationships could not be identified in allocating some costs or assets and ensuring appropriate disclosure has been included outlining these in Schedule 14;
Recalculating the split between not directly attributable costs and asset values allocated to electricity distribution services and non-electricity distribution services.

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Key Assurance Matter	How our procedures addressed the key assurance matter
SAIDI and SAIFI Reliability Measures SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index) as disclosed in Schedule 10 and 10a are non-financial network reliability measures. These are considered key measures when assessing the performance of the network against the annual targets set. Due to the nature of the unplanned interruptions there are inherent limitations in capturing complete and accurate data for all interruptions. The calculations of the disclosed information are also complex and require careful consideration. Due to the importance of the SAIDI and SAIFI measures within the Disclosure Information, inherent limitations in capturing unplanned interruption data and complexities within the regulations, we have considered the reliability measures to be a key area of focus.	We obtained an understanding of the Company's control environment and processes around capturing, recording and reviewing interruption data. Our procedures over the non-financial network reliability measures included: • Testing a sample of planned and unplanned outages from the interruptions output to supporting documentation including internally generated work orders and notifications to test the duration and cause of the interruption ensuring appropriate classification within the Information Disclosure schedules. • Recalculated a sample of the outage minutes that are calculated by the outage management system; • Assessed completeness of the interruption information by performing a media search for significant events that should result in an interruption being recorded, performing a sequential number check on the interruption information and detailed testing of call records and the GIS database; and • Assessed the accuracy and completeness of the ICPs ('Installation Control Points') affected by an interruption through testing a sample of interruptions to underlying GIS database information.

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) as applicable for audits of public interest entities (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, PricewaterhouseCoopers and its partners and employees may deal with the company and its subsidiaries, 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, and the annual audit of the company’s financial statements and performance information, we have no relationship with, or interests in, the company and its subsidiaries.

Matthew White
PricewaterhouseCoopers
On behalf of the Auditor-General
Hamilton, New Zealand
27 August 2026