
Information Disclosure

For the year ended 31 March 2013

Pursuant to the Electricity Distribution Information Disclosure Determination 2012

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Company Name **Aurora Energy Limited**
 For Year Ended **31 March 2013**

SCHEDULE 1: ANALYTICAL RATIOS

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

sch ref

1(i): Expenditure metrics

	Expenditure per GWh energy delivered to ICPs (\$/GWh)	Expenditure per average no. of ICPs (\$/ICP)	Expenditure per MW maximum coincident system demand (\$/MW)	Expenditure per km circuit length (\$/km)	Expenditure per MVA of capacity from EDB- owned distribution transformers (\$/MVA)
Operational expenditure	14,925	224	95,032	5,706	39,162
Network	7,229	108	46,030	2,764	18,968
Non-network	7,696	115	49,002	2,942	20,193
Expenditure on assets	14,125	212	89,940	5,401	37,063
Network	14,125	212	89,940	5,401	37,063
Non-network	-	-	-	-	-

1(ii): Revenue metrics

	Revenue per GWh energy delivered to ICPs (\$/GWh)	Revenue per average no. of ICPs (\$/ICP)
Total consumer line charge revenue	67,439	1,011
Standard consumer line charge revenue	67,439	1,011
Non-standard consumer line charge revenue	-	-

1(iii): Service intensity measures

Demand density	51	Maximum coincident system demand per km circuit length (for supply) (kW/km)
Volume density	225	Total energy delivered to ICPs per km circuit length (for supply) (MWh/km)
Connection point density	15	Average number of ICPs per km circuit length (for supply) (ICPs/km)
Energy intensity	14,993	Total energy delivered to ICPs per Average number of ICPs (kWh/ICP)

1(iv): Composition of regulatory income

	(\$000)	% of revenue
Operational expenditure	18,641	21.21%
Pass-through and recoverable costs	31,387	35.71%
Total depreciation	11,268	12.82%
Total revaluation	2,734	3.11%
Regulatory tax allowance	7,371	8.39%
Regulatory profit/loss	21,970	24.99%
Total regulatory income	87,903	

1(v): Reliability

	Interruptions per 100 circuit km
Interruption rate	21.52

Company Name	Aurora Energy Limited
For Year Ended	31 March 2013

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

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

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

sch ref

		CY-2	CY-1	Current Year CY
		31 Mar 11	31 Mar 12	31 Mar 13
		%	%	%
7	2(i): Return on Investment			
8				
9	Post tax WACC			
10	ROI—comparable to a post tax WACC			6.22%
11				
12	Mid-point estimate of post tax WACC	6.87%	6.40%	5.85%
13	25th percentile estimate	6.15%	5.68%	5.13%
14	75th percentile estimate	7.60%	7.11%	6.56%
15				
16				
17	Vanilla WACC			
18	ROI—comparable to a vanilla WACC			6.99%
19				
20	Mid-point estimate of vanilla WACC	7.82%	7.22%	6.62%
21	25th percentile estimate	7.09%	6.51%	5.91%
22	75th percentile estimate	8.54%	7.94%	7.34%
23				
24	2(ii): Information Supporting the ROI			
25				
26	Total opening RAB value	318,263		
27	plus Opening deferred tax	(1,755)		
28	Opening RIV		316,508	
29				
30	Operating surplus / (deficit)	37,875		
31	less Regulatory tax allowance	7,371		
32	less Assets commissioned	12,695		
33	plus Asset disposals	-		
34	Notional net cash flows		17,809	
35				
36	Total closing RAB value	322,424		
37	less Adjustment resulting from asset allocation	(0)		
38	less Lost and found assets adjustment	-		
39	plus Closing deferred tax	(2,199)		
40	Closing RIV		320,225	
41				
42	ROI—comparable to a vanilla WACC		0.07	
43				
44	Leverage (%)		44%	
45	Cost of debt assumption (%)		6.31%	
46	Corporate tax rate (%)		28%	
47				
48	ROI—comparable to a post tax WACC		0.06	

Company Name **Aurora Energy Limited**For Year Ended **31 March 2013****SCHEDULE 2: REPORT ON RETURN ON INVESTMENT**

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

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sch ref

2(iii): Information Supporting the Monthly ROI**Cash flows**

(\$000)

	Total regulatory income	Expenses	Tax payments	Assets commissioned	Asset disposals	Notional net cash flows
April						-
May						-
June						-
July						-
August						-
September						-
October						-
November						-
December						-
January						-
February						-
March						-
Total	-	-	-	-	-	-

	Opening / closing RAB	Adjustment resulting from asset allocation	Lost and found assets adjustment	Opening / closing deferred tax	Revenue related working capital	Total
Monthly ROI - opening RIV	318,263			(1,755)		316,508
Monthly ROI -closing RIV	322,424	(0)	-	(2,199)	-	320,225
Monthly ROI -closing RIV less term credit spread differential allowance						320,225
Monthly ROI—comparable to a vanilla WACC						0.01
Monthly ROI—comparable to a post-tax WACC						0.00

2(iv): Year-End ROI Rates for Comparison Purposes

Year-end ROI—comparable to a vanilla WACC	0.07
Year-end ROI—comparable to a post-tax WACC	0.06

* 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.

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

Company Name **Aurora Energy Limited**
 For Year Ended **31 March 2012**

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 3(i), 3(iv) and 3(v) and must provide explanatory comment on their regulatory profit in Schedule 14 (Mandatory Explanatory Notes).

Non-exempt EDBs must also complete sections 3(ii) and 3(iii).

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

sch ref

		(\$000)	
		CY-1	CY
		31 March 2012	31 March 2012
57	3(iii): Incremental Rolling Incentive Scheme		
58			
59			
60	Allowed controllable opex		
61	Actual controllable opex		
62			
63	Incremental change in year		
64			
65			
66	CY-5 31 Mar 08		
67	CY-4 31 Mar 09		
68	CY-3 31 Mar 10		
69	CY-2 31 Mar 11		
70	CY-1 31 Mar 12		
71	Net incremental rolling incentive scheme		
72			
73	Net recoverable costs allowed under incremental rolling incentive scheme		
74	3(iv): Merger and Acquisition Expenditure		
75	Merger and acquisition expenses		N/A
76			
77	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)		
78	3(v): Other Disclosures		
79	Self-insurance allowance		

Company Name **Aurora Energy Limited**
 For Year Ended **31 March 2013**

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 3(i), 3(iv) and 3(v) and must provide explanatory comment on their regulatory profit in Schedule 14 (Mandatory Explanatory Notes).

Non-exempt EDBs must also complete sections 3(ii) and 3(iii).

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

sch ref

7	3(i): Regulatory Profit		(\$000)
8	Income		
9	Line charge revenue	84,995	
10	plus Gains / (losses) on asset disposals	(81)	
11	plus Other regulated income (other than gains / (losses) on asset disposals)	2,989	
12			
13	Total regulatory income	87,903	
14	Expenses		
15	less Operational expenditure	18,641	
17	less Pass-through and recoverable costs	31,387	
18			
19	Operating surplus / (deficit)	37,875	
20			
21	less Total depreciation	11,268	
22			
23	plus Total revaluation	2,734	
24			
25	Regulatory profit / (loss) before tax & term credit spread differential allowance	29,341	
26			
27	less Term credit spread differential allowance	-	
28			
29	Regulatory profit / (loss) before tax	29,341	
30			
31	less Regulatory tax allowance	7,371	
32			
33	Regulatory profit / (loss)	21,970	
34			
35	3(ii): Pass-Through and Recoverable Costs		(\$000)
36	Pass-through costs		
37	Rates	655	
38	Commerce Act levies	109	
	Electricity Authority levies	200	
40	Other specified pass-through costs	2,033	
41	Recoverable costs		
42	Net recoverable costs allowed under incremental rolling incentive scheme	-	
43	Non-exempt EDB electricity lines service charge payable to Transpower	20,772	
44	Transpower new investment contract charges	-	
45	System operator services	-	
46	Avoided transmission charge	7,618	
47	Input Methodology claw-back	-	
48	Recoverable customised price-quality path costs	-	
49	Pass-through and recoverable costs	31,387	

Company Name **Aurora Energy Limited**
 For Year Ended **31 March 2013**

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 3(i), 3(iv) and 3(v) and must provide explanatory comment on their regulatory profit in Schedule 14 (Mandatory Explanatory Notes).

Non-exempt EDBs must also complete sections 3(ii) and 3(iii).

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

sch ref

		(\$000)	
		CY-1	CY
		31 March 2012	31 March 2013
57	3(iii): Incremental Rolling Incentive Scheme		
58			
59			
60	Allowed controllable opex		
61	Actual controllable opex		
62			
63	Incremental change in year		
64			
65			
66	CY-5 31 Mar 08		
67	CY-4 31 Mar 09		
68	CY-3 31 Mar 10		
69	CY-2 31 Mar 11		
70	CY-1 31 Mar 12		
71	Net incremental rolling incentive scheme		
72			
73	Net recoverable costs allowed under incremental rolling incentive scheme		
74	3(iv): Merger and Acquisition Expenditure		
75	Merger and acquisition expenses		N/A
76			
77	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)		
78	3(v): Other Disclosures		
79	Self-insurance allowance		

Company Name	Aurora Energy Limited
For Year Ended	31 March 2013

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

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

sch ref

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

	RAB CY-4 (\$000)	RAB CY-3 (\$000)	RAB CY-2 (\$000)	RAB CY-1 (\$000)	RAB CY (\$000)
Total opening RAB value	285,613	285,613	294,086	312,945	318,263
less Total depreciation		10,135	10,288	11,001	11,268
plus Total revaluations		5,845	13,136	4,915	2,734
plus Assets commissioned		12,763	16,217	11,973	12,695
less Asset disposals		-	206	569	-
plus Lost and found assets adjustment		-	-		-
plus Adjustment resulting from asset allocation		-	-		(0)
Total closing RAB value	285,613	294,086	312,945	318,263	322,424

4(ii): Unallocated Regulatory Asset Base

	Unallocated RAB *		RAB	
	(\$000)	(\$000)	(\$000)	(\$000)
Total opening RAB value		318,263		318,263
less Total depreciation		11,268		11,268
plus Total revaluations		2,734		2,734
plus Assets commissioned (other than below)	1,068		1,068	
Assets acquired from a regulated supplier	-		-	
Assets acquired from a related party	11,627		11,627	
Assets commissioned		12,695		12,695
less Asset disposals (other than below)	-		-	
Asset disposals to a regulated supplier	-		-	
Asset disposals to a related party	-		-	
Asset disposals		-		-
plus Lost and found assets adjustment		-		-
plus Adjustment resulting from asset allocation				(0)
Total closing RAB value		322,424		322,424

* 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 non-regulated services. The RAB value represents the value of these assets after applying this cost allocation. Neither value includes works under construction.

Company Name **Aurora Energy Limited**
 For Year Ended **31 March 2013**

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

This schedule requires information on the calculation of the Regulatory Asset Base (RAB) value to the end of this disclosure year. This informs the ROI calculation in Schedule 2.

EDBs must provide explanatory comment on the value of their RAB in Schedule 14 (Mandatory Explanatory Notes). This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

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

CPI _t	1,174
CPI _t ⁻⁴	1,164
Revaluation rate (%)	0.86%

	Unallocated RAB *		RAB	
	(\$000)	(\$000)	(\$000)	(\$000)
Total opening RAB value	318,263		318,263	
less Opening RAB value of fully depreciated, disposed and lost assets				
Total opening RAB value subject to revaluation	318,263		318,263	
Total revaluations		2,734		2,734

4(iv): Roll Forward of Works Under Construction

	Unallocated works under construction		Allocated works under construction	
		7,699		7,699
plus Capital expenditure	14,600		14,599	
less Assets commissioned	12,695		12,695	
plus Adjustment resulting from asset allocation			-	
Works under construction - current disclosure year		9,604		9,603
Highest rate of capitalised finance applied				

Company Name	Aurora Energy Limited
For Year Ended	31 March 2013

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

This schedule requires information on the calculation of the Regulatory Asset Base (RAB) value to the end of this disclosure year. This informs the ROI calculation in Schedule 2.

EDBs must provide explanatory comment on the value of their RAB in Schedule 14 (Mandatory Explanatory Notes). This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

4(v): Regulatory Depreciation

Depreciation - standard
 Depreciation - no standard life assets
 Depreciation - modified life assets
 Depreciation - alternative depreciation in accordance with CPP
Total depreciation

Unallocated RAB *		RAB	
(\$000)	(\$000)	(\$000)	(\$000)
11,268		11,268	
-		-	
-		-	
-		-	
	11,268		11,268

4(vi): Disclosure of Changes to Depreciation Profiles

(\$000 unless otherwise specified)

Asset or assets with changes to depreciation*

* include additional rows if needed

Reason for non-standard depreciation (text entry)

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

4(vii): Disclosure by Asset Category

(\$000 unless otherwise specified)

	Subtransmission lines	Subtransmission cables	Zone substations	Distribution and LV lines	Distribution and LV cables	Distribution substations and transformers	Distribution switchgear	Other network assets	Non-network assets	Total
Total opening RAB value	14,354	7,782	50,677	44,193	126,619	51,426	20,006	3,206	-	318,263
<i>less</i> Total depreciation	541	319	1,919	2,077	3,650	1,638	931	193	-	11,268
<i>plus</i> Total revaluations	123	67	435	379	1,088	442	172	28	-	2,734
<i>plus</i> Assets commissioned	105	87	3,107	3,372	3,244	1,449	691	640	-	12,695
<i>less</i> Asset disposals	-	-	-	-	-	-	-	-	-	-
<i>plus</i> Lost and found assets adjustment	-	-	-	-	-	-	-	-	-	-
<i>plus</i> Adjustment resulting from asset allocation	-	-	-	-	-	-	-	-	-	-
<i>plus</i> Asset category transfers	-	-	-	-	-	-	-	-	-	-
Total closing RAB value	14,041	7,617	52,300	45,867	127,301	51,679	19,938	3,681	-	322,424
Asset Life										
Weighted average remaining asset life	26.6	24.4	25.0	21.3	34.7	31.4	21.5	12.8	-	(years)
Weighted average expected total asset life	67.5	49.2	40.2	45.8	48.3	50.0	35.8	17.1	-	(years)

Company Name	Aurora Energy Limited
For Year Ended	31 March 2013

SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

This schedule requires information on the calculation of the regulatory tax allowance. This information is used to calculate regulatory profit/loss in Schedule 3 (regulatory profit). EDBs must provide explanatory commentary on the information disclosed in this schedule, in Schedule 14 (Mandatory Explanatory Notes).

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

sch ref

7	5a(i): Regulatory Tax Allowance				(\$000)
8	Regulatory profit / (loss) before tax				29,341
9					
10	plus	Income not included in regulatory profit / (loss) before tax but taxable	1,105	*	
11		Expenditure or loss in regulatory profit / (loss) before tax but not deductible	(16)	*	
12		Amortisation of initial differences in asset values	3,809		
13		Amortisation of revaluations	875		
14					5,773
15					
16	less	Income included in regulatory profit / (loss) before tax but not taxable	-	*	
17		Discretionary discounts and consumer rebates	-		
18		Expenditure or loss deductible but not in regulatory profit / (loss) before tax**	-	*	
19		Notional deductible interest	8,788		
20					8,788
21					
22		Regulatory taxable income			26,326
23					
24	less	Utilised tax losses	-		
25		Regulatory net taxable income			26,326
26					
27		Corporate tax rate (%)	28%		
28		Regulatory tax allowance			7,371
29					
30		* Workings to be provided in Schedule 14			
31		** Excluding discretionary discounts and consumer rebates			
32					
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	106,417		
37		Amortisation of initial differences in asset values	3,809		
38		Adjustment for unamortised initial differences in assets acquired	(5,731)		
39		Adjustment for unamortised initial differences in assets disposed	-		
40		Closing unamortised initial differences in asset values			96,878
41					
42		Opening weighted average remaining asset life (years)			28
43	5a(iv): Amortisation of Revaluations				(\$000)
44					
45		Opening Sum of RAB values without revaluations	295,260		
46					
47		Adjusted depreciation	10,393		
48		Total depreciation	11,268		
49		Amortisation of revaluations			875

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

5a(v): Reconciliation of Tax Losses		(\$000)
Opening tax losses	-	
<i>plus</i> Current period tax losses	-	
<i>less</i> Utilised tax losses	-	
Closing tax losses		-
5a(vi): Calculation of Deferred Tax Balance		(\$000)
Opening deferred tax	(1,755)	
<i>plus</i> Tax effect of adjusted depreciation	2,910	
<i>less</i> Tax effect of total tax depreciation	4,206	
<i>plus</i> Tax effect of other temporary differences*	313	
<i>less</i> Tax effect of amortisation of initial differences in asset values	1,066	
<i>plus</i> Deferred tax balance relating to assets acquired in the disclosure year	1,605	
<i>less</i> Deferred tax balance relating to assets disposed in the disclosure year	-	
<i>plus</i> Deferred tax cost allocation adjustment	-	
Closing deferred tax		(2,199)
5a(vii): Disclosure of Temporary Differences		
In Schedule 14, Box 6, provide descriptions and workings of items recorded in the asterisked category in Schedule 5a(vi) (Tax effect of other temporary differences).		
5a(viii): Regulatory Tax Asset Base Roll-Forward		(\$000)
Opening sum of regulatory tax asset values	159,864	
<i>less</i> Tax depreciation	15,020	
<i>plus</i> Regulatory tax asset value of assets commissioned	18,426	
<i>less</i> Regulatory tax asset value of asset disposals	-	
<i>plus</i> Lost and found assets adjustment	-	
<i>plus</i> Other adjustments to the RAB tax value	-	
Closing sum of regulatory tax asset values		163,270

Company Name **Aurora Energy Limited**
 For Year Ended **31 March 2013**

SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

This schedule provides information on the valuation of related party transactions, in accordance with section 2.3.6 and 2.3.7 of the ID determination.

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

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5b(i): Summary—Related Party Transactions

(\$000)

Total regulatory income	50
Operational expenditure	17,656
Capital expenditure	11,627
Market value of asset disposals	-
Other related party transactions	-

5b(ii): Entities Involved in Related Party Transactions

Name of related party	Related party relationship
Delta Utility Services Ltd	Sister Company - Provides Asset Management and Electrical Contracting (Opex and Capex)
Dunedin City Holdings Ltd	Dunedin City Holdings holds 100% of the Shares in Aurora Energy Ltd
Dunedin City Council	Dunedin City Council holds 100% of the shares in Dunedin City Holding Ltd

* include additional rows if needed

5b(iii): Related Party Transactions

Name of related party	Related party transaction type	Description of transaction	Value of transaction (\$000)	Basis for determining value
Delta Utility Services Ltd	Sales	Recovery of Service Failure Payments	50	
				Price Paid as more than 50% of the related parties sales are made to third parties
Dunedin City Council	Opex	Rates Expense	425	
Dunedin City Holdings Ltd	Opex	Management Fee	200	Cost Incurred
				Price paid as more than 50% of the related parties sales are to third parties
Delta Utility Services Ltd	Opex	Service Interruptions and Emergencies in accordance with Asset Management Agreement	3,463	
				Price paid as more than 50% of the related parties sales are to third parties
Delta Utility Services Ltd	Opex	Service Interruptions and Emergencies - repair of equipment damaged by 3rd parties	794	
				Price paid as more than 50% of the related parties sales are to third parties
Delta Utility Services Ltd	Opex	On going Vegetation Management in accordance with Asset Management Agreement	1,253	
				Price paid as more than 50% of the related parties sales are to third parties
Delta Utility Services Ltd	Opex	On going routine inspection and maintenance work in accordance with Asset Management Agreement	2,186	
				Price paid as more than 50% of the related parties sales are to third parties
Delta Utility Services Ltd	Opex	On going asset replacement and renewal work in accordance with Asset Management Agreement	985	
				Price paid as more than 50% of the related parties sales are to third parties

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31	Delta Utility Services Ltd	Opex	Underground conversion costs	346	Price paid as more than 50% of the related parties sales are to third parties
32	Delta Utility Services Ltd	Opex	On going system operation, support and management in accordance with Asset Management Agreement	5,400	Price paid as more than 50% of the related parties sales are to third parties
	Delta Utility Services Ltd	Opex	On going Business support operations in accordance with Asset Management Agreement	2,170	Price paid as more than 50% of the related parties sales are to third parties
33	Delta Utility Services Ltd	Opex	On going general management, administration and accountint services in accordance with Administration Agreement	287	Price paid as more than 50% of the related parties sales are to third parties
34	Delta Utility Services Ltd	Opex	Miscelaneous work associated with processing of easements and ad-hoc advise	106	Price paid as more than 50% of the related parties sales are to third parties
35	Delta Utility Services Ltd	Opex	For lease of CPD metering equipment	41	Price paid as more than 50% of the related parties sales
36	Delta Utility Services Ltd	Capex	Installation of New Network Equipment	7,953	Directly attributable costs plus allowance for indirect overhead
37	Delta Utility Services Ltd	Capex	Installation of New Network Equipment	3,674	In accordance with independant valuations undertaken
* include additional rows if needed					

Company Name **Aurora Energy Limited**
 For Year Ended **31 March 2013**

SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

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

sch ref

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

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	Cost of executing an interest rate swap	Debt issue cost readjustment
* include additional rows if needed						-	-	-	-

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

Gross term credit spread differential

-

Total book value of interest bearing debt

Leverage

44%

Average opening and closing RAB values

Attribution Rate (%)

-

Term credit spread differential allowance

-

Company Name **Aurora Energy Limited**For Year Ended **31 March 2013****SCHEDULE 5d: REPORT ON COST ALLOCATIONS**

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

sch ref

7 5d(i): Operating Cost Allocations

		Value allocated (\$000s)				
	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase (\$000s)	
Service interruptions and emergencies						
Directly attributable		4,259				
Not directly attributable	-	-	-	-		
Total attributable to regulated service		4,259				
Vegetation management						
Directly attributable		1,253				
Not directly attributable	-	-	-	-		
Total attributable to regulated service		1,253				
Routine and corrective maintenance and inspection						
Directly attributable		2,186				
Not directly attributable	-	-	-	-		
Total attributable to regulated service		2,186				
Asset replacement and renewal						
Directly attributable		1,331				
Not directly attributable	-	-	-	-		
Total attributable to regulated service		1,331				
System operations and network support						
Directly attributable		5,400				
Not directly attributable	-	-	-	-		
Total attributable to regulated service		5,400				
Business support						
Directly attributable		4,212				
Not directly attributable	-	-	-	-		
Total attributable to regulated service		4,212				
Operating costs directly attributable		18,641				
Operating costs not directly attributable		-	-	-	-	
Operating expenditure		18,641				

Company Name **Aurora Energy Limited**
 For Year Ended **31 March 2013**

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

5d(ii): Other Cost Allocations

Pass through and recoverable costs

Pass through costs

Directly attributable

2,997

Not directly attributable

-

Total attributable to regulated service

2,997

Recoverable costs

Directly attributable

28,390

Not directly attributable

-

Total attributable to regulated service

28,390

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

(\$000)

CY-1 Current Year (CY)

31 Mar 12 31 Mar 13

Change in cost allocation 1

Cost category

Original allocation

Original allocator or line items

New allocation

New allocator or line items

Difference

-

-

Rationale for change

CY-1 Current Year (CY)

31 Mar 12 31 Mar 13

Change in cost allocation 2

Cost category

Original allocation

Original allocator or line items

New allocation

New allocator or line items

Difference

-

-

Rationale for change

CY-1 Current Year (CY)

31 Mar 12 31 Mar 13

Change in cost allocation 3

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
For Year EndedAurora Energy Limited
31 March 2013**SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS**

This schedule requires information on the allocation of asset values. This information supports the calculation of the RAB value in Schedule 4.

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

sch ref

5e(i): Regulated Service Asset Values

	Value allocated (\$000s) Electricity distribution services
Subtransmission lines	
Directly attributable	14,041
Not directly attributable	-
Total attributable to regulated service	14,041
Subtransmission cables	
Directly attributable	7,616
Not directly attributable	-
Total attributable to regulated service	7,616
Zone substations	
Directly attributable	52,301
Not directly attributable	-
Total attributable to regulated service	52,301
Distribution and LV lines	
Directly attributable	45,868
Not directly attributable	-
Total attributable to regulated service	45,868
Distribution and LV cables	
Directly attributable	127,301
Not directly attributable	-
Total attributable to regulated service	127,301
Distribution substations and transformers	
Directly attributable	51,679
Not directly attributable	-
Total attributable to regulated service	51,679
Distribution switchgear	
Directly attributable	19,938
Not directly attributable	-
Total attributable to regulated service	19,938
Other network assets	
Directly attributable	3,680
Not directly attributable	-
Total attributable to regulated service	3,680
Non-network assets	
Directly attributable	-
Not directly attributable	-
Total attributable to regulated service	-
Regulated service asset value directly attributable	322,424
Regulated service asset value not directly attributable	-
Total closing RAB value	322,424

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

			CY-1 31 Mar 12	Current Year (CY) 31 Mar 13
Change in asset value allocation 1				
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	-	-
Rationale for change				
Change in asset value allocation 2				
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	-	-
Rationale for change				
Change in asset value allocation 3				
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	-	-
Rationale for change				

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

† include additional rows if needed

Company Name
For Year EndedAurora Energy Limited
31 March 2012**SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS**

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

sch ref

5e(i): Regulated Service Asset Values

	Value allocated (\$000s) Electricity distribution services
Subtransmission lines	
Directly attributable	14,354
Not directly attributable	-
Total attributable to regulated service	14,354
Subtransmission cables	
Directly attributable	7,782
Not directly attributable	-
Total attributable to regulated service	7,782
Zone substations	
Directly attributable	50,677
Not directly attributable	-
Total attributable to regulated service	50,677
Distribution and LV lines	
Directly attributable	44,193
Not directly attributable	-
Total attributable to regulated service	44,193
Distribution and LV cables	
Directly attributable	126,619
Not directly attributable	-
Total attributable to regulated service	126,619
Distribution substations and transformers	
Directly attributable	51,426
Not directly attributable	-
Total attributable to regulated service	51,426
Distribution switchgear	
Directly attributable	20,006
Not directly attributable	-
Total attributable to regulated service	20,006
Other network assets	
Directly attributable	3,206
Not directly attributable	-
Total attributable to regulated service	3,206
Non-network assets	
Directly attributable	-
Not directly attributable	-
Total attributable to regulated service	-
Regulated service asset value directly attributable	318,263
Regulated service asset value not directly attributable	-
Total closing RAB value	318,263

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

			CY-1 31 Mar 12	Current Year (CY) 31 Mar 13
Change in asset value allocation 1				
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	-	-
Rationale for change				
Change in asset value allocation 2				
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	-	-
Rationale for change				
Change in asset value allocation 3				
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	-	-
Rationale for change				

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

Company Name
For Year EndedAurora Energy Limited
31 March 2011**SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS**

This schedule requires information on the allocation of asset values. This information supports the calculation of the RAB value in Schedule 4.

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

sch ref

5e(i): Regulated Service Asset Values

	Value allocated (\$000s) Electricity distribution services
Subtransmission lines	
Directly attributable	14,566
Not directly attributable	-
Total attributable to regulated service	14,566
Subtransmission cables	
Directly attributable	7,927
Not directly attributable	-
Total attributable to regulated service	7,927
Zone substations	
Directly attributable	46,201
Not directly attributable	-
Total attributable to regulated service	46,201
Distribution and LV lines	
Directly attributable	44,789
Not directly attributable	-
Total attributable to regulated service	44,789
Distribution and LV cables	
Directly attributable	125,613
Not directly attributable	-
Total attributable to regulated service	125,613
Distribution substations and transformers	
Directly attributable	51,219
Not directly attributable	-
Total attributable to regulated service	51,219
Distribution switchgear	
Directly attributable	19,988
Not directly attributable	-
Total attributable to regulated service	19,988
Other network assets	
Directly attributable	2,641
Not directly attributable	-
Total attributable to regulated service	2,641
Non-network assets	
Directly attributable	-
Not directly attributable	-
Total attributable to regulated service	-
Regulated service asset value directly attributable	312,944
Regulated service asset value not directly attributable	-
Total closing RAB value	312,944

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

			CY-1 31 Mar 12	Current Year (CY) 31 Mar 13
Change in asset value allocation 1				
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	-	-
Rationale for change				
Change in asset value allocation 2				
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	-	-
Rationale for change				
Change in asset value allocation 3				
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	-	-
Rationale for change				

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

† include additional rows if needed

Company Name
For Year EndedAurora Energy Limited
31 March 2010**SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS**

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

sch ref

7 5e(i): Regulated Service Asset Values

	Value allocated (\$000s) Electricity distribution services
Subtransmission lines	
Directly attributable	10,723
Not directly attributable	-
Total attributable to regulated service	10,723
Subtransmission cables	
Directly attributable	7,874
Not directly attributable	-
Total attributable to regulated service	7,874
Zone substations	
Directly attributable	38,669
Not directly attributable	-
Total attributable to regulated service	38,669
Distribution and LV lines	
Directly attributable	44,457
Not directly attributable	-
Total attributable to regulated service	44,457
Distribution and LV cables	
Directly attributable	120,828
Not directly attributable	-
Total attributable to regulated service	120,828
Distribution substations and transformers	
Directly attributable	49,178
Not directly attributable	-
Total attributable to regulated service	49,178
Distribution switchgear	
Directly attributable	19,471
Not directly attributable	-
Total attributable to regulated service	19,471
Other network assets	
Directly attributable	2,886
Not directly attributable	-
Total attributable to regulated service	2,886
Non-network assets	
Directly attributable	-
Not directly attributable	-
Total attributable to regulated service	-
Regulated service asset value directly attributable	294,086
Regulated service asset value not directly attributable	-
Total closing RAB value	294,086

57 5e(ii): Changes in Asset Allocations* †

			CY-1 31 Mar 12	Current Year (CY) 31 Mar 13
Change in asset value allocation 1				
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	-	-
Rationale for change				
Change in asset value allocation 2				
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	-	-
Rationale for change				
Change in asset value allocation 3				
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	-	-
Rationale for change				

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

Company Name **Aurora Energy Limited**
 For Year Ended **31 March 2013**

SCHEDULE 5h: REPORT ON TRANSITIONAL FINANCIAL INFORMATION

This schedule requires information on:

- the calculation of the initial RAB value for the EDB, as of 31 March 2009;
- how the initial RAB value has been rolled forward to 31 March 2011;
- a summary of revaluations,
- the value of works under construction, and
- regulatory tax.

EDBs must complete this schedule in relation to the year ending 31 March 2012, and at that time must provide explanatory comment in Schedule 14b (Explanatory Notes on Transitional Financial Information) on the tax effect of temporary differences disclosed in part 5h(vii) of this schedule.

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

sch ref

Regulatory Asset Base Value

5h(i): Establishment of Initial Regulatory Asset Base Value

		Unallocated Initial RAB (\$000)	(\$000)
2009 disclosed assets - 'Total Regulatory Asset Base Value (Excluding FDC)' as of 31 March 2009			277,953
2009 modified asset values (adjusted for results of asset adjustment process)			286,257
Adjustment to reinstate 2009 modified asset values to unallocated amounts			-
Unallocated 2009 modified asset values			286,257
less (to the extent included in row 13)			
Assets not used to supply electricity distribution services			
Easement land			
Non-qualifying intangible assets			
Works under construction		7,475	
Unallocated asset values excluded from unallocated 2009 modified asset values			7,475
plus FDC allowance of 2.45% (Network assets)			6,831
Unallocated initial RAB values			285,613

5h(ii): Roll forward of Unallocated Regulatory Asset Base Value - 2010, 2011 and 2012

	2010 (\$000)	2010 (\$000)	2011 (\$000)	2011 (\$000)	2012 (\$000)	2012 (\$000)
Total opening RAB value		285,613		294,086		312,945
less						
Total depreciation		10,135		10,288		11,001
plus						
Total revaluations		5,845		13,136		4,915
plus						
Assets commissioned (other than below)	4,687		3,041		2,384	
Assets acquired from a regulated supplier	-		-		-	
Assets acquired from a related party	8,076		13,176		9,589	
Assets commissioned		12,763		16,217		11,973
less						
Asset disposals (other than below)			206		569	
Assets disposed of to a regulated supplier	-		-		-	
Assets disposed of to a related party	-		-		-	
Asset disposals		-		206		569
plus						
Lost and found assets adjustment		-		-		-
Total closing RAB value		294,086		312,945		318,263

5h(iii): Calculation of Revaluation Rate and Indexed Revaluation

(\$000 unless otherwise specified)

	2010	2011	2012
CPI at CPI reference date—preceding disclosure year	1,075	1,097	1,146
CPI at CPI reference date—current disclosure year	1,097	1,146	1,164
Revaluation rate (%)	2.05%	4.47%	1.57%
Total opening RAB value	285,613	294,086	312,945
less Opening RAB value of fully depreciated, disposed and lost assets			-
Total opening RAB value subject to revaluation	285,613	294,086	312,945
Total revaluations		5,845	13,136
			4,915

5h(iv): Works Under Construction

	Unallocated works under construction	Allocated works under construction
Works under construction—year ended 2009	7,475	7,475
plus Capital expenditure—year ended 2010	13,657	13,657
less Assets commissioned—year ended 2010	12,763	12,763
plus Adjustment resulting from asset allocation—year ended 2010		
Works under construction—year ended 2010		8,369
plus Capital expenditure—year ended 2011	17,277	17,277
less Assets commissioned—year ended 2011	16,217	16,217
plus Adjustment resulting from asset allocation—year ended 2011		
Works under construction—year ended 2011		9,429
plus Capital expenditure—year ended 2012	10,242	10,242
less Assets commissioned—year ended 2012	11,972	11,972
plus Adjustment resulting from asset allocation—year ended 2012		
Works under construction—year ended 2012		7,699

Company Name	Aurora Energy Limited
For Year Ended	31 March 2013

SCHEDULE 5h: REPORT ON TRANSITIONAL FINANCIAL INFORMATION

This schedule requires information on:

- the calculation of the initial RAB value for the EDB, as of 31 March 2009;
- how the initial RAB value has been rolled forward to 31 March 2011;
- a summary of revaluations,
- the value of works under construction, and
- regulatory tax.

EDBs must complete this schedule in relation to the year ending 31 March 2012, and at that time must provide explanatory comment in Schedule 14b (Explanatory Notes on Transitional Financial Information) on the tax effect of temporary differences disclosed in part 5h(vii) of this schedule.

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

sch ref

5h(v): Initial Difference in Asset Values and Amortisation

(\$000)

	2010	2011	2012
Sum of initial RAB values	285,613		
Sum of regulatory tax asset values	146,031		
Sum of initial differences in asset values	139,582		
Opening unamortised initial differences in asset values	139,582	126,540	116,939
less Amortisation of initial difference in asset values	5,001	4,468	4,151
Adjustment for unamortised initial differences in assets acquired	(8,041)	(5,016)	(6,271)
Adjustment for unamortised initial differences in assets disposed	-	(117)	(99)
Closing unamortised initial differences in asset values	126,540	116,939	106,417
Opening weighted average remaining asset life (years)	28	28	28

5h(vi): Reconciliation of Tax Losses (EDB Business)

	2010	2011	2012
Opening tax losses		-	-
plus Current period tax losses	-	-	-
less Utilised tax losses	-	-	-
Closing tax losses	-	-	-

5h(vii): Calculation of Deferred Tax Balance

	2010	2011	2012
Opening deferred tax		(207)	(1,223)
plus Tax effect of adjusted depreciation	3,040	3,024	2,888
plus Tax effect of total tax depreciation	(4,131)	(4,294)	(4,169)
plus Tax effect of other temporary differences *	(28)	125	185
less Tax effect of amortisation of initial differences in asset values	1,500	1,340	1,162
plus Deferred tax balance relating to assets acquired in the disclosure year	2,412	1,505	1,756
less Deferred tax balance relating to assets disposed in the disclosure year	-	35	30
plus Deferred tax cost allocation adjustment	-	-	-
Closing deferred tax	(207)	(1,223)	(1,755)

5h(viii): Disclosure of Temporary Differences

In Schedule 14, provide descriptions and workings of items recorded in the asterisked category in Schedule 5h(vii) (Tax effect of other temporary differences).

5h(ix): Regulatory Tax Asset Base Roll-Forward

(\$000)

	2010	2011	2012
Sum of unallocated initial RAB values	285,613		
Sum of adjusted tax values	146,031		
Sum of tax asset values	146,031		
Result of asset allocation ratio	1		
Opening Sum of regulatory tax asset values	146,031	153,066	159,864
less Regulatory tax depreciation	13,769	14,314	14,890
plus Regulatory tax asset value of assets commissioned	20,804	21,234	18,244
less Regulatory tax asset value of asset disposals	-	122	104
plus Lost and found assets adjustment	-	-	-
plus Other adjustments to the RAB tax value	-	-	-
Closing sum of regulatory tax asset values	153,066	159,864	163,114

Company Name

Aurora Energy Limited

For Year Ended

31 March 2013

SCHEDULE 5i: REPORT ON INITIAL RAB ADJUSTMENT

Under clause 2.2.1 of the IM determination an EDB may undertake an asset adjustment process in setting their initial RAB.

If the EDB has adjusted its RAB in accordance with clause 2.2.1 of the IM determination, it must complete this schedule when disclosing information relating to the year ending 31 March 2012.

sch ref

7 Summary of Engineer's Valuation Adjustments (at time asset enters regulatory asset register)

	2004 *	2005	2006	2007	2008	2009
	(\$000)	(\$000)	(\$000)	(\$000)	(\$000)	(\$000)
Asset adjustment process - adjustments						
Include load control relays						
Correct asset register errors for 2004 ODV assets						
Distribution Transformers with missing data	43,218					
Distribution substations missed from 2004 ODV	461,270					
Double counting of sub pole fuses in 2004 ODV	(3,158,856)					
Removal of 12/24MVA tx from NEX Sub	(362,182)					
Correction of Dunedin cable insulation type	499,125					
Additional HV cable due to late data entry	3,742,512					
Additional LV cable due to late data entry	3,182,595					
Additional Distribution swgr due to late entry	135,990					
Additional Distribution tx due to late entry	496,659					
	5,040,331					
Correct asset register errors for 2005 – 2009 assets						
Remove Assets installed in 2004 but included in 2005 & 2006 Additions	(3,040,165)					
Remove Assets installed in 2004 but included in 2005 & 2006 Additions		(38,620)				
Remove adjustments to 2004 ODV made in later Disclosures	(4,874,784)					
Remove adjustments to 2004 ODV made in later Disclosures		3,158,856				
Remove adjustments to 2004 ODV made in later Disclosures					(3,340,920)	
Re-apply an existing multiplier to 2004 ODV assets						
Extend application of rocky ground multiplier	2,719,149					
Additional traffic management	1,040,403					
[Insert details of asset or similar asset type]						
	3,759,552					
Re-apply a modified multiplier to 2004 ODV assets						
[Insert details of asset or similar asset type]						
[Insert details of asset or similar asset type]						
[Insert details of asset or similar asset type]						
	-					
Re-apply optimisation or EV tests to 2004 ODV assets						
Remove optimisation of Ward Street 33KV cables	247,191					
[Insert details of asset or similar asset type]						
[Insert details of asset or similar asset type]						
	247,191					
Total value of adjustments by disclosure year	9,047,074	(7,914,949)	3,120,236	-	(3,340,920)	-

* Includes assets which first entered the regulatory asset register in a disclosure year prior to 2004.

Company Name

Aurora Energy Limited

For Year Ended

31 March 2013

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

This schedule requires a breakdown of capital expenditure on assets incurred in the disclosure year, including any assets in respect of which capital contributions are received, but excluding assets that are vested assets. Information on expenditure on assets must be provided on an accounting accruals basis and must exclude finance costs. EDBs must provide explanatory comment on their expenditure on assets in Schedule 14 (Explanatory Notes to Templates).

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

sch ref

7	6a(i): Expenditure on Assets		(\$000)	(\$000)
8	Consumer connection			6,671
9	System growth			2,152
10	Asset replacement and renewal			6,374
11	Asset relocations			459
12	Reliability, safety and environment:			
13	Quality of supply	725		
14	Legislative and regulatory	-		
15	Other reliability, safety and environment	1,261		
16	Total reliability, safety and environment			1,986
17	Expenditure on network assets			17,642
18	Non-network assets			-
19				
20	Expenditure on assets			17,642
21	plus Cost of financing			
22	less Value of capital contributions			3,043
23	plus Value of vested assets			-
24				
25	Capital expenditure			14,599
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			714
29	Research and development			-
30	6a(iii): Consumer Connection			
31	Consumer types defined by EDB*		(\$000)	(\$000)
32	[EDB consumer type]		6,671	
33	[EDB consumer type]			
34	[EDB consumer type]			
35	[EDB consumer type]			
36	[EDB consumer type]			
37	* include additional rows if needed			
38	Consumer connection expenditure			6,671
39				
40	less Capital contributions funding consumer connection expenditure	2,765		
41	Consumer connection less capital contributions			3,906
42	6a(iv): System Growth and Asset Replacement and Renewal			
43			System Growth	Asset Replacement and Renewal
44			(\$000)	(\$000)
45	Subtransmission	54		542
46	Zone substations	1,099		1,830
47	Distribution and LV lines	152		2,391
48	Distribution and LV cables	457		958
49	Distribution substations and transformers	204		281
50	Distribution switchgear	163		264
51	Other network assets	23		108
52	System growth and asset replacement and renewal expenditure	2,152		6,374
53	less Capital contributions funding system growth and asset replacement and renewal	19		-
54	System growth and asset replacement and renewal less capital contributions	2,133		6,374
55				
56	6a(v): Asset Relocations			
57	Project or programme*		(\$000)	(\$000)
58	CFR 6094 - QLDC Arthurs Point realignment		78	
59	CFR 6149 Malaghans road line deviation stage 11		29	
60	CFR 6217 Malaghans road line deviation stage 5 relocations		26	
61	[Description of material project or programme]			
62	[Description of material project or programme]			
63	* include additional rows if needed			
64	All other asset relocations projects or programmes	326		
65	Asset relocations expenditure			459
66	less Capital contributions funding asset relocations	259		
67	Asset relocations less capital contributions			200

Company Name

Aurora Energy Limited

For Year Ended

31 March 2013

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

This schedule requires a breakdown of capital expenditure on assets incurred in the disclosure year, including any assets in respect of which capital contributions are received, but excluding assets that are vested assets. Information on expenditure on assets must be provided on an accounting accruals basis and must exclude finance costs. EDBs must provide explanatory comment on their expenditure on assets in Schedule 14 (Explanatory Notes to Templates).

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

sch ref

6a(vi): Quality of Supply

Project or programme*

CFR 6167 33kv Kawarau River Crossing

Roxburgh

CFR 6397 - New Feed into Cromwell Business Area

CFR 6185 NEV Substation 33KV CB Upgrade

[Description of material project or programme]

* include additional rows if needed

All other quality of supply projects or programmes

Quality of supply expenditure

less Capital contributions funding quality of supply

Quality of supply less capital contributions

(\$000)

(\$000)

141

63

55

50

416

725

-

725

6a(vii): Legislative and Regulatory

Project or programme*

[Description of material project or programme]

[Description of material project or programme]

[Description of material project or programme]

[Description of material project or programme]

[Description of material project or programme]

* include additional rows if needed

All other legislative and regulatory projects or programmes

Legislative and regulatory expenditure

less Capital contributions funding legislative and regulatory

Legislative and regulatory less capital contributions

(\$000)

(\$000)

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

Project or programme*

CFR 5794 Port Chalmers Feeder

CFR 6347 Parry Street - Underground Low LV span

CFR 5985 - Pole replacement

CFR 6239 - Relocate poles to road reserve

CFR 6025 - reoistioning of poles due to land slippage

* include additional rows if needed

All other reliability, safety and environment projects or programmes

Other reliability, safety and environment expenditure

less Capital contributions funding other reliability, safety and environment

Other reliability, safety and environment less capital contributions

(\$000)

(\$000)

220

56

56

43

59

827

1,261

-

1,261

6a(ix): Non-Network Assets**Routine expenditure**

Project or programme*

[Description of material project or programme]

[Description of material project or programme]

[Description of material project or programme]

[Description of material project or programme]

[Description of material project or programme]

* include additional rows if needed

All other routine expenditure projects or programmes

Routine expenditure**Atypical expenditure**

Project or programme*

[Description of material project or programme]

[Description of material project or programme]

[Description of material project or programme]

[Description of material project or programme]

[Description of material project or programme]

* include additional rows if needed

All other atypical expenditure projects or programmes

Atypical expenditure**Non-network assets expenditure**

(\$000)

(\$000)

-

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-

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-

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(\$000)

(\$000)

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Company Name **Aurora Energy Limited**For Year Ended **31 March 2013****SCHEDULE 6b: REPORT ON OPERATIONAL EXPENDITURE FOR THE DISCLOSURE YEAR**

This schedule requires a breakdown of operating 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 operating expenditure and assets replaced or renewed as part of asset replacement and renewal operational expenditure, and additional information on insurance.

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

sch ref

		(\$000)	(\$000)
7	6b(i): Operational Expenditure		
8	Service interruptions and emergencies	4,259	
9	Vegetation management	1,253	
10	Routine and corrective maintenance and inspection	2,186	
11	Asset replacement and renewal	1,331	
12	Network opex		9,029
13	System operations and network support	5,400	
14	Business support	4,212	
15	Non-network opex		9,612
16			
17	Operational expenditure		18,641
18	6b(ii): Subcomponents of Operational Expenditure (where known)		
19	Energy efficiency and demand side management, reduction of energy losses		N/A
20	Direct billing*		N/A
21	Research and development		N/A
22	Insurance		192
23	* Direct billing expenditure by suppliers that directly bill the majority of their consumers		

Company Name

Aurora Energy Limited

For Year Ended

31 March 2013

SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

This schedule compares actual revenue and expenditure to the previous forecasts that were made for the disclosure year. Accordingly, this schedule requires the forecast revenue and expenditure information from previous disclosures to be inserted.

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

sch ref

7	7(i): Revenue	Target (\$000) ¹	Actual (\$000)	% variance
8	Line charge revenue	83,982	84,229	0%
9	7(ii): Expenditure on Assets	Forecast (\$000) ²	Actual (\$000)	% variance
10	Consumer connection	5,351	6,671	25%
11	System growth	477	2,152	351%
12	Asset replacement and renewal	9,422	6,374	(32%)
13	Asset relocations	2,258	459	(80%)
14	Reliability, safety and environment:			
15	Quality of supply	410	725	77%
16	Legislative and regulatory	-	-	-
17	Other reliability, safety and environment	157	1,261	703%
18	Total reliability, safety and environment	567	1,986	250%
19	Expenditure on network assets	18,075	17,642	(2%)
20	Non-network capex	-	-	-
21	Expenditure on assets	18,075	17,642	(2%)
22	7(iii): Operational Expenditure			
23	Service interruptions and emergencies	3,941	4,259	8%
24	Vegetation management	1,280	1,253	(2%)
25	Routine and corrective maintenance and inspection	3,200	2,186	(32%)
26	Asset replacement and renewal	1,162	1,331	15%
27	Network opex	9,583	9,029	(6%)
28	System operations and network support	585	5,400	823%
29	Business support	315	4,212	1,237%
30	Non-network opex	900	9,612	968%
31	Operational expenditure	10,483	18,641	78%
32	7(iv): Subcomponents of Expenditure on Assets (where known)			
33	Energy efficiency and demand side management, reduction of energy losses	-	-	-
34	Overhead to underground conversion	714	-	-
35	Research and development	-	-	-
36				
37	7(v): Subcomponents of Operational Expenditure (where known)			
38	Energy efficiency and demand side management, reduction of energy losses	N/A	-	-
39	Direct billing	N/A	-	-
40	Research and development	N/A	-	-
41	Insurance	192	-	-
42				

1 From the nominal dollar target revenue for the disclosure year disclosed under clause 2.4.3(3) of the Determination

2 From the nominal dollar expenditure forecast and disclosed in the second to last AMP as the year CY+1 forecast

Company Name	Aurora Energy Limited
For Year Ended	31 March 2012
Network / Sub-Network Name	Total Business

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

8(i): Billed Quantities by Price Component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)
Standard domestic	Standard domestic	Standard	69,405	585,032
Load Group 0	Non-standard domestic / non domestic	Standard	331	13
Load Group 0A	Non-standard domestic / non domestic	Standard	340	344
Load Group 1A	Non-standard domestic / non domestic	Standard	722	2,302
Load Group 1	Non-standard domestic / non domestic	Standard	5,671	42,242
Load Group 2	Non-standard domestic / non domestic	Standard	5,701	332,194
Load Group 3	Non-standard domestic / non domestic	Standard	202	73,998
Load Group 3A	Non-standard domestic / non domestic	Standard	180	97,444
Load Group 4	Non-standard domestic / non domestic	Standard	108	87,181
Load Group 5	Non-standard domestic / non domestic	Standard	8	5,503
Street Lighting	Non-standard domestic / non domestic	Standard	8	10,166
Add extra rows for additional consumer groups or price category codes as necessary				
Standard consumer totals			82,656	1,236,619
Non-standard consumer totals			-	-
Total for all consumers			82,656	1,236,619

Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)

Billed quantities by price component

Item	Fixed (Distribution)		Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease, Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Distribution)
	LS	Lamp	kWh	kVA	kVA x km	kW	kVA	LS	kWh	kVA	kW
Total	69,405		585,031.879						585,031.879		
	331							331			
	340							340			
	722			5,779		681			5,779	681	
	5,671			85,066		13,745			85,066	13,745	
	5,701			286,090		44,774			286,090	44,774	
	202			37,266	557,048	9,000			37,266	9,000	
	160			49,520	566,475	14,077			49,520	14,077	
	108			81,327	935,201	25,461	81,327		81,327	25,461	
	8			35,135	304,845	9,659	35,125		35,135	9,659	
	8	6,170	10,166,038						10,166,038		
	82,656	6,170	595,197,917	580,183	2,363,569	117,397	116,452	671	595,197,917	580,183	117,397
	82,656	6,170	595,197,917	580,183	2,363,569	117,397	116,452	671	595,197,917	580,183	117,397

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

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

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone (if applicable)
Standard Domestic	Standard domestic	Standard	\$42,089	
Load Group 0	Non-standard domestic / non domestic	Standard	\$64	
Load Group 0A	Non-standard domestic / non domestic	Standard	\$137	
Load Group 1A	Non-standard domestic / non domestic	Standard	\$255	
Load Group 1	Non-standard domestic / non domestic	Standard	\$4,109	
Load Group 2	Non-standard domestic / non domestic	Standard	\$13,695	
Load Group 3	Non-standard domestic / non domestic	Standard	\$2,786	
Load Group 3A	Non-standard domestic / non domestic	Standard	\$3,723	
Load Group 4	Non-standard domestic / non domestic	Standard	\$5,742	
Load Group 5	Non-standard domestic / non domestic	Standard	\$1,661	
Street Lighting	Non-standard domestic / non domestic	Standard	\$558	
Add extra rows for additional consumer groups or price category codes as necessary				
Standard consumer totals			\$75,690	
Non-standard consumer totals			-	
Total for all consumers			\$75,690	-

Total distribution line charge revenue	Total transmission line charge revenue (if available)	Rate (eg, \$/day, \$/kWh, etc.)
\$30,872	\$12,089	
\$45	\$19	
\$92	\$45	
\$8		
\$177	\$78	
\$2,736	\$1,373	
\$9,940	\$3,755	
\$1,995	\$791	
\$2,487	\$1,236	
\$3,541	\$2,201	
\$773	\$888	
\$425	\$133	
\$53,083	\$22,607	
-	-	
\$53,083	\$22,607	

Line charge revenues by price component

Price Component	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease, Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Distribution)	
	\$ / annum	\$ / lamp	\$ / kWh	\$ / kVA	\$ / kVA x km	\$ / kW	\$ / kVA	\$ / annum	\$ / kWh	\$ / kVA	\$ / kW
	\$3,772		\$27,100					\$12,089			
	\$45							\$19			
	\$92							\$45			
	\$8			\$101		\$68			\$24	\$55	
	\$62			\$1,346		\$1,328			\$269	\$1,104	
	\$117			\$5,539		\$4,299	(\$15)		\$201	\$3,554	
	\$85			\$1,124	\$180	\$642	(\$30)		\$86	\$705	
	\$96			\$1,371	\$179	\$896	(\$27)		\$132	\$1,105	
	\$111			\$1,185	\$293	\$1,394	\$599		\$201	\$2,000	
	\$8			\$284	\$86	\$281	\$105		\$124	\$764	
	\$238	\$84	\$103					\$86	\$47		
	\$4,604	\$84	\$27,203	\$10,950	\$737	\$8,919	\$586	\$150	\$12,135	\$1,036	\$9,286
	\$4,604	\$84	\$27,203	\$10,950	\$737	\$8,919	\$586	\$150	\$12,135	\$1,036	\$9,286

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

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end

Check ☒ OK

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.

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Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)

Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)

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

Price component

Total distribution	Total transmission line charge	Rate (eg, \$/day,
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Add extra columns
for additional line
charge revenues
by price
component as
necessary

Number of directly billed ICPs at year end	
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Company Name	Aurora Energy Limited
For Year Ended	31 March 2013
Network / Sub-Network Name	Total Business

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 ICs that are included in each consumer group or price category code, and the energy delivered to these ICs.

sch ref

8(i): Billed Quantities by Price Component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICs in disclosure year	Energy delivered to ICs in disclosure year (MWh)
Standard domestic	Standard domestic	Standard	69,852	605,167
Load Group 0	Non-standard domestic / non domestic	Standard	338	703
Load Group 0A	Non-standard domestic / non domestic	Standard	394	1,411
Load Group 1A	Non-standard domestic / non domestic	Standard	752	2,812
Load Group 1	Non-standard domestic / non domestic	Standard	5,651	44,050
Load Group 2	Non-standard domestic / non domestic	Standard	5,833	235,516
Load Group 3	Non-standard domestic / non domestic	Standard	200	46,938
Load Group 3A	Non-standard domestic / non domestic	Standard	156	80,850
Load Group 4	Non-standard domestic / non domestic	Standard	110	161,769
Load Group 5	Non-standard domestic / non domestic	Standard	9	67,395
Street Lighting	Non-standard domestic / non domestic	Standard	10	2,848
Add extra rows for additional consumer groups or price category codes as necessary				
Standard consumer totals			83,305	1,248,959
Non-standard consumer totals				
Total for all consumers			83,305	1,248,959

Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)

Billed quantities by price component

Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease, Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Distribution)
LS	Lamp	kWh	kVA	kVA x km	kW	kVA	LS	kWh	kVA	kW
69,852		188,839,962						188,839,962		
338							338			
394							394			
752			6,015		716				6,015	716
5,651		84,706			13,564			84,706		13,564
5,833		291,418			44,803			291,418		44,803
200		37,113		575,640	8,868			37,113		8,868
156		48,337		546,836	13,578			48,337		13,578
110		81,688		807,773	25,789	81,688		81,688		25,789
9		37,373		299,788	9,884	37,373		37,373		9,884
2	6,325	2,848,228					2	2,848,228		
83,297	6,325	191,688,190	586,710	2,330,037	117,232	115,061	734	191,688,190	586,710	117,232
83,297	6,325	191,688,190	586,710	2,330,037	117,232	115,061	734	191,688,190	586,710	117,232

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

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

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone (if applicable)
Standard domestic	Standard domestic	Standard	\$47,798	
Load Group 0	Non-standard domestic / non domestic	Standard	\$72	
Load Group 0A	Non-standard domestic / non domestic	Standard	\$176	
Load Group 1A	Non-standard domestic / non domestic	Standard	\$299	
Load Group 1	Non-standard domestic / non domestic	Standard	\$4,563	
Load Group 2	Non-standard domestic / non domestic	Standard	\$15,209	
Load Group 3	Non-standard domestic / non domestic	Standard	\$3,043	
Load Group 3A	Non-standard domestic / non domestic	Standard	\$3,982	
Load Group 4	Non-standard domestic / non domestic	Standard	\$6,565	
Load Group 5	Non-standard domestic / non domestic	Standard	\$2,025	
Street Lighting	Non-standard domestic / non domestic	Standard	\$596	
Add extra rows for additional consumer groups or price category codes as necessary				
Standard consumer totals			\$84,229	
Non-standard consumer totals				
Total for all consumers			\$84,229	

Total distribution line charge revenue

\$32,627	\$15,171
\$49	\$24
\$113	\$63
\$196	\$102
\$2,878	\$1,686
\$10,564	\$4,545
\$2,059	\$980
\$2,478	\$1,504
\$3,737	\$2,829
\$830	\$1,195
\$432	\$163

Total transmission line charge revenue (if available)

\$55,963	\$28,265
\$55,963	\$28,265

Rate (eg, \$/day, \$/kWh, etc.)

Line charge revenues by price component

Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease, Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Distribution)
\$ / annum	\$ / lamp	\$ / kWh	\$ / kVA	\$ / kVA x km	\$ / kW	\$ / kVA	\$ / annum	\$ / kWh	\$ / kVA	\$ / kW
\$3,796		\$28,832						\$15,171		
\$49								\$24		
\$113								\$63		
\$9			\$110		\$78				\$33	\$69
\$64			\$1,387		\$1,427				\$373	\$1,313
\$125		\$5,828			\$4,617	(73)		\$268		\$4,277
\$80		\$1,090	\$301	\$683	(54)			\$147		\$837
\$67			\$1,307	\$184	\$931	(\$11)		\$218		\$1,286
\$118			\$1,238	\$301	\$1,545	\$555		\$384		\$2,444
\$9			\$272	\$86	\$346	\$117		\$254		\$941
\$241	\$85	\$106					\$115	\$48		
\$4,680	\$85	\$28,938	\$11,211	\$772	\$9,628	\$649	\$202	\$15,219	\$1,677	\$11,167
\$4,680	\$85	\$28,938	\$11,211	\$772	\$9,628	\$649	\$202	\$15,219	\$1,677	\$11,167

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

8(iii): Number of ICs directly billed

Number of directly billed ICs at year end

Check ☒ OK

Company Name	Aurora Energy Limited
For Year Ended	31 March 2013
Network / Sub-Network Name	Central Otago

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

8(i): Billed Quantities by Price Component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)
Standard domestic	Standard domestic	Standard	22,898	187,948
Load Group 0	Non-standard domestic / non domestic	Standard	211	281
Load Group 0A	Non-standard domestic / non domestic	Standard	283	1,199
Load Group 1A	Non-standard domestic / non domestic	Standard	362	1,332
Load Group 1	Non-standard domestic / non domestic	Standard	2,574	19,496
Load Group 2	Non-standard domestic / non domestic	Standard	2,816	186,363
Load Group 3	Non-standard domestic / non domestic	Standard	100	16,321
Load Group 3A	Non-standard domestic / non domestic	Standard	65	28,551
Load Group 4	Non-standard domestic / non domestic	Standard	36	45,376
Load Group 5	Non-standard domestic / non domestic	Standard	1	4,888
Street Lighting	Non-standard domestic / non domestic	Standard	8	2,848
Add extra rows for additional consumer groups or price category codes as necessary				
Standard consumer totals			29,354	414,803
Non-standard consumer totals			-	-
Total for all consumers			29,354	414,803

Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)

Billed quantities by price component

ent	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease, Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Distribution)
d.	LS	Lamp	kWh	kVA	kVA x km	kW	kVA	LS	kWh	kVA	kW
	22,898		187,948,419						187,948,419		
	211							211			
	283							283			
	362			2,897		329				2,897	329
	2,574			38,609		5,837				38,609	5,837
	2,816			140,203		19,419				140,203	19,419
	100			17,443	467,790	3,147				17,443	3,147
	65			19,943	385,916	4,454				19,943	4,454
	36			24,508	585,624	8,432	24,508			24,508	8,432
	1			5,200	64,896	920	5,200			5,200	920
		6,248	2,848,228						2,848,228		
	29,346	6,248	190,796,647	248,803	1,504,226	42,538	29,708	494	190,796,647	248,803	42,538
	29,346	6,248	190,796,647	248,803	1,504,226	42,538	29,708	494	190,796,647	248,803	42,538

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

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

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone (if applicable)
Standard Domestic	Standard domestic	Standard	\$21,468	
Load Group 0	Non-standard domestic / non domestic	Standard	\$50	
Load Group 0A	Non-standard domestic / non domestic	Standard	\$135	
Load Group 1A	Non-standard domestic / non domestic	Standard	\$167	
Load Group 1	Non-standard domestic / non domestic	Standard	\$2,419	
Load Group 2	Non-standard domestic / non domestic	Standard	\$8,186	
Load Group 3	Non-standard domestic / non domestic	Standard	\$1,603	
Load Group 3A	Non-standard domestic / non domestic	Standard	\$1,855	
Load Group 4	Non-standard domestic / non domestic	Standard	\$2,640	
Load Group 5	Non-standard domestic / non domestic	Standard	\$238	
Street Lighting	Non-standard domestic / non domestic	Standard	\$238	
Add extra rows for additional consumer groups or price category codes as necessary				
Standard consumer totals			\$39,060	
Non-standard consumer totals			-	
Total for all consumers			\$39,060	-

Total distribution line charge revenue	Total transmission line charge revenue (if available)	Rate (eg, \$/day, \$/kWh, etc.)
\$16,171	\$5,298	
\$35	\$14	
\$89	\$46	
\$123	\$44	
\$1,735	\$685	
\$6,294	\$1,892	
\$1,245	\$358	
\$1,338	\$518	
\$4,720	\$900	
\$123	\$175	
\$190	\$48	
\$29,063	\$9,997	
\$29,063	\$9,997	

Line charge revenues by price component

net	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease, Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Distribution)
	\$ / annum	\$ / lamp	\$ / kWh	\$ / kVA	\$ / kVA x km	\$ / kW	\$ / kVA	\$ / annum	\$ / kWh	\$ / kVA	\$ / kW
	\$1,247		\$14,924						\$5,298		
	\$35							\$14			
	\$89							\$46			
	\$5			\$71		\$48				\$12	\$12
	\$33			\$879		\$822				\$121	\$563
	\$66			\$3,605		\$2,629	(\$7)			\$80	\$1,812
	\$50			\$604	\$172	\$423	(\$3)			\$65	\$293
	\$32			\$658	\$140	\$517	(\$9)			\$101	\$417
	\$44			\$575	\$214	\$792	\$156			\$127	\$792
	\$1			\$46	\$23	\$54				\$88	\$87
		\$85	\$105						\$48		
	1,603	85	15,029	6,437	549	5,225	137	60	5,345	995	3,996
	1,603	85	15,029	6,437	549	5,225	137	60	5,345	995	3,996

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

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end

Check ☒ OK

Company Name **Aurora Energy Limited**For Year Ended **31 March 2013**Network / Sub-network Name **Total Business****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

					Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy 1-4
8	Voltage	Asset category	Asset class	Units				
9	All	Overhead Line	Concrete poles / steel structure	No.	19,929	20,383	454	4
10	All	Overhead Line	Wood poles	No.	33,769	33,325	(444)	4
11	All	Overhead Line	Other pole types	No.	74	54	(20)	4
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	513	513	0	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	15	16	0	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	25	25	-	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	41	41	-	4
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	12	12	(0)	4
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	27	27	-	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	3	3	-	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	193	194	1	4
29	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	6	6	-	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	48	48	-	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	328	328	-	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	30	32	2	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	64	66	2	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2,329	2,328	(1)	4
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-
37	HV	Distribution Line	SWER conductor	km	9	9	-	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	412	422	9	4
39	HV	Distribution Cable	Distribution UG PILC	km	365	366	1	4
40	HV	Distribution Cable	Distribution Submarine Cable	km	1	1	-	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	40	43	3	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	18	12	(6)	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	6,204	6,308	104	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	434	448	14	4
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	1,021	1,035	14	4
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	4,187	4,188	1	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	2,430	2,461	31	4
48	HV	Distribution Transformer	Voltage regulators	No.	35	37	2	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	2,393	2,461	68	4
50	LV	LV Line	LV OH Conductor	km	1,050	1,048	(1)	3
51	LV	LV Cable	LV UG Cable	km	749	762	13	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	212	206	(6)	3
53	LV	Connections	OH/UG consumer service connections	No.	84,150	84,875	725	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	433	429	(4)	4
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	95	95	-	4
56	All	Capacitor Banks	Capacitors including controls	No	3	3	-	4
57	All	Load Control	Centralised plant	Lot	6	6	-	4
58	All	Load Control	Relays	No	2,172	2,193	21	4
59	All	Civils	Cable Tunnels	km	-	-	-	-

Company Name **Aurora Energy Limited**For Year Ended **31 March 2013**Network / Sub-network Name **Dunedin****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

				Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy 1-4
8	Voltage	Asset category	Asset class					
9	All	Overhead Line	Concrete poles / steel structure	No.	13,765	13,872	107	4
10	All	Overhead Line	Wood poles	No.	15,408	15,291	(117)	4
11	All	Overhead Line	Other pole types	No.	38	19	(19)	4
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	144	144	-	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	0	0	-	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	25	25	-	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	41	41	-	4
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	11	11	-	4
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	18	18	-	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	-
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	71	71	-	4
29	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	20	20	-	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	260	260	-	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	2	2	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	34	35	1	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	733	732	(1)	4
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-
37	HV	Distribution Line	SWER conductor	km	9	9	-	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	26	26	0	4
39	HV	Distribution Cable	Distribution UG PILC	km	235	237	2	4
40	HV	Distribution Cable	Distribution Submarine Cable	km	1	1	-	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	10	11	1	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	18	12	(6)	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	2,506	2,525	19	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	276	286	10	4
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	590	598	8	4
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	1,701	1,704	3	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	871	876	5	4
48	HV	Distribution Transformer	Voltage regulators	No.	13	13	-	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	861	876	15	4
50	LV	LV Line	LV OH Conductor	km	823	823	(0)	3
51	LV	LV Cable	LV UG Cable	km	214	219	6	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	137	139	1	3
53	LV	Connections	OH/UG consumer service connections	No.	54,333	54,557	224	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	298	294	(4)	4
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	38	38	-	4
56	All	Capacitor Banks	Capacitors including controls	No	3	3	-	4
57	All	Load Control	Centralised plant	Lot	3	3	-	4
58	All	Load Control	Relays	No	1,108	1,115	7	4
59	All	Civils	Cable Tunnels	km	-	-	-	-

Company Name **Aurora Energy Limited**For Year Ended **31 March 2013**Network / Sub-network Name **Central Otago****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

					Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy 1-4
8	Voltage	Asset category	Asset class	Units				
9	All	Overhead Line	Concrete poles / steel structure	No.	6,164	6,511	347	4
10	All	Overhead Line	Wood poles	No.	18,361	18,034	(327)	4
11	All	Overhead Line	Other pole types	No.	36	35	(1)	4
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	369	369	0	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	15	15	0	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	1	0	(0)	4
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	9	9	-	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	3	3	-	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	122	123	1	4
29	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	6	6	-	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	28	28	-	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	68	68	-	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	30	30	-	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	30	31	1	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1,596	1,596	(0)	4
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-
37	HV	Distribution Line	SWER conductor	km	-	-	-	-
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	386	395	9	4
39	HV	Distribution Cable	Distribution UG PILC	km	130	129	(1)	4
40	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	-
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	29	31	2	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	-	-
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	3,698	3,783	85	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	158	162	4	4
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	429	435	6	4
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	2,486	2,484	(2)	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	1,554	1,580	26	4
48	HV	Distribution Transformer	Voltage regulators	No.	22	24	2	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	1,527	1,580	53	4
50	LV	LV Line	LV OH Conductor	km	226	225	(1)	3
51	LV	LV Cable	LV UG Cable	km	530	537	7	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	74	66	(8)	3
53	LV	Connections	OH/UG consumer service connections	No.	29,740	30,237	497	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	135	135	-	4
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	57	57	-	4
56	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	-
57	All	Load Control	Centralised plant	Lot	3	3	-	4
58	All	Load Control	Relays	No.	1,059	1,073	14	4
59	All	Civils	Cable Tunnels	km	-	-	-	-

ch ref

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.

Disclosure Year (year ended)			31 March 2013		Number of assets at disclosure year end by installation date																				No. with Age unknown	Total assets at year end	No. with default dates	Data accuracy (1-4)
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				
All	Overhead Line	Concrete poles / steel structure	No.	-	32	1,718	6,225	4,850	3,236	1,861	94	117	206	139	81	119	191	173	217	107	143	231	541	102	-	-	-	20,383
All	Overhead Line	Wood poles	No.	1,346	1,606	2,985	9,677	6,180	3,973	3,388	341	236	409	458	314	279	334	294	325	331	342	341	149	17	-	-	-	33,325
All	Overhead Line	Other pole types	No.	-	1	-	16	6	5	8	-	-	-	-	1	2	1	2	1	1	-	-	7	2	-	-	-	54
HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	71	3	74	108	76	27	128	-	-	-	-	-	-	1	6	-	-	4	4	11	0	-	-	-	513
HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	-	-	-	7	-	-	-	-	0	1	1	0	1	2	1	0	1	1	-	-	-	16
HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-	23	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25
HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	6	31	3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	41
HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	8	-	0	0	2	0	-	0	0	1	-	-	0	-	-	-	-	0	-	-	-	-	12
HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	1	5	3	7	5	4	-	-	-	-	-	-	-	-	-	-	1	-	1	-	-	-	-	27
HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	3
HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	53	27	5	25	24	-	-	-	6	1	2	-	26	17	2	3	2	1	-	-	-	-	194
HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6
HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	3	5	5	4	8	7	-	-	1	-	-	-	1	1	2	5	3	1	-	2	-	-	-	48
HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	32	46	97	80	7	32	-	11	17	-	1	-	9	9	-	2	16	20	12	-	-	-	-	-	328
HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	6	9	1	1	3	-	-	1	-	2	5	-	-	-	-	1	3	2	3	3	-	-	-	32
HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	7	15	15	6	6	5	-	2	1	4	1	-	-	-	-	1	2	3	3	3	-	-	-	3
HV	Distribution Line	Distribution OH Open Wire Conductor	km	78	145	335	431	427	402	344	12	12	14	11	30	12	12	7	11	14	4	16	4	4	-	-	-	2,328
HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HV	Distribution Line	SWER conductor	km	-	-	6	2	0	1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9
HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	-	0	5	11	68	21	23	31	46	32	27	56	32	15	19	12	11	8	3	-	-	-	422
HV	Distribution Cable	Distribution UG PILC	km	0	7	30	46	60	68	60	8	7	11	5	9	10	13	4	6	7	5	4	3	1	-	-	-	366
HV	Distribution Cable	Distribution Submarine Cable	km	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1
HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	-	-	-	-	1	3	1	-	-	-	4	3	3	6	5	6	7	1	-	3	-	-	-	43
HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	6	-	-	2	-	1	-	-	-	-	-	-	2	-	-	-	-	-	1	-	-	-	-	12
HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1	39	126	794	722	955	1,424	157	169	172	220	163	173	176	166	165	168	221	151	124	22	-	-	-	6,308
HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	7	71	43	39	75	11	13	11	9	9	26	22	17	11	18	22	27	16	1	-	-	-	448
HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	-	-	4	95	185	276	28	34	72	30	52	36	27	37	38	32	30	38	15	6	-	-	-	1,035
HV	Distribution Transformer	Pole Mounted Transformer	No.	68	84	344	931	605	563	813	54	58	139	67	55	54	60	54	58	43	25	50	51	3	-	-	-	4,188
HV	Distribution Transformer	Ground Mounted Transformer	No.	-	-	35	177	286	183	307	70	112	142	158	197	137	189	161	95	67	54	42	44	5	-	-	-	2,461
HV	Distribution Transformer	Voltage regulators	No.	-	-	-	-	3	6	4	2	-	-	-	3	3	1	2	4	5	-	-	2	-	-	-	-	37
HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	3	73	173	211	402	80	100	133	145	190	160	189	147	131	91	76	68	69	20	-	-	-	2,461
LV	LV Line	LV OH Conductor	km	56	42	108	263	211	171	153	5	2	5	4	4	3	3	2	2	3	2	1	2	0	-	7	-	1,048
LV	LV Cable	LV UG Cable	km	-	-	2	23	40	157	137	20	21	33	42	49	47	43	43	28	26	13	20	15	2	-	-	-	762
LV	LV Street lighting	LV OH/UG Streetlight circuit	km	4	3	3	8	8	8	27	97	2	2	2	5	4	6	5	8	1	7	4	4	7	-	-	-	206
LV	Connections	OH/UG consumer service connections	No.	13,086	3,706	6,998	8,756	7,053	4,587	23,048	1,006	1,213	1,431	1,485	1,662	1,701	1,610	1,738	1,363	1,086	1,130	936	1,183	117	-	-	-	84,875
All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	41	46	80	96	3	30	35	-	-	1	30	5	16	2	11	5	11	25	6	14	2	-	-	429
All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	-	-	19	-	-	-	6	10	5	9	1	5	1	5	9	2	6	12	5	-	-	-	95
All	Capacitor Banks	Capacitors including controls	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	3
All	Load Control	Centralised plant	Lot	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	1	-	1	3	-	-	-	-	6
All	Load Control	Relays	No.	1	1	12	182	263	263	496	51	48	62	95	157	119	142	109	57	56	31	21	25	2	-	-	-	2,193
All	Civils	Cable Tunnels	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Company Name
For Year Ended
Network / Sub-network Name

Aurora Energy Limited
31 March 2013
Dunedin

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

Disclosure Year (year ended)			31 March 2013		Number of assets at disclosure year end by installation date																				No. with Age unknown	Total assets at year end	No. with default dates	Data accuracy (1-4)
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				
All	Overhead Line	Concrete poles / steel structure	No.	-	13	1,627	5,781	2,951	2,165	812	21	13	79	31	11	32	33	23	17	11	30	46	152	24	-			
All	Overhead Line	Wood poles	No.	1,346	1,565	2,783	3,593	1,275	1,362	1,790	196	127	119	124	92	125	132	116	170	104	89	113	60	10	-			
All	Overhead Line	Other pole types	No.	-	1	-	12	3	1	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-			
HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	62	-	62	14	3	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	0	0	-	-	-			
HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-	22	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	6	31	3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	8	-	0	0	1	0	-	0	0	1	-	-	0	-	-	-	0	-	-	-			
HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
HV	Zone substation Buildings	Zone substations up to 66kV	No.	0	1	5	3	6	2	1	0	0	0	0	0	0	0	0	0	0	-	0	0	-	-			
HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	0	-	39	22	2	-	6	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-			
HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	3	-	2	4	-	-	-	-	-	-	-	-	1	2	5	-	-	-	-	-	-			
HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	0	32	46	37	78	-	13	0	0	-	17	-	9	-	0	-	11	17	-	-	-	-			
HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-			
HV	Zone Substation Transformer	Zone Substation Transformers	No.	0	0	-	6	10	10	2	2	0	0	-	-	-	0	0	0	-	1	-	2	-	-			
HV	Distribution Line	Distribution OH Open Wire Conductor	km	2	35	123	251	139	68	64	5	4	6	5	6	5	1	4	6	5	1	2	0	-	-			
HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
HV	Distribution Line	SWER conductor	km	-	-	6	2	0	1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	-	0	-	0	4	2	2	1	3	2	3	2	2	1	1	1	1	1	0	-			
HV	Distribution Cable	Distribution UG PILC	km	0	7	30	46	60	42	24	2	1	1	1	2	3	1	1	2	2	4	3	2	1	-			
HV	Distribution Cable	Distribution Submarine Cable	km	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	-	-	-	-	-	-	1	-	-	-	-	-	1	4	-	-	3	1	-	1	-			
HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	0	6	-	-	2	-	1	0	0	-	-	-	-	2	-	-	0	-	-	1	-	-			
HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	-	23	77	631	467	447	499	14	19	27	42	30	50	44	29	22	34	17	22	29	2	-			
HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	0	-	7	71	43	39	40	5	7	4	7	3	5	1	3	4	8	21	5	12	1	-			
HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	0	-	-	4	89	167	186	14	6	16	8	22	14	6	4	14	12	14	12	4	6	-			
HV	Distribution Transformer	Pole Mounted Transformer	No.	4	14	130	629	282	195	202	6	21	37	20	19	30	31	12	12	19	8	21	11	1	-			
HV	Distribution Transformer	Ground Mounted Transformer	No.	-	-	33	165	234	119	108	3	12	18	21	19	24	18	15	19	21	21	14	10	2	-			
HV	Distribution Transformer	Voltage regulators	No.	-	-	-	-	3	4	4	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
HV	Distribution Substations	Ground Mounted Substation Housing	No.	0	0	-	3	73	157	161	219	11	17	22	19	18	31	29	13	19	22	19	20	19	4			
LV	LV Line	LV OH Conductor	km	53	25	68	191	168	149	133	4	2	3	4	3	3	2	1	1	2	2	0	2	0	-			
LV	LV Cable	LV UG Cable	km	-	-	2	23	39	35	32	3	4	4	6	7	13	9	9	5	8	4	8	6	1	-			
LV	LV Street lighting	LV OH/UG Streetlight circuit	km	4	2	3	8	7	8	83	0	0	0	1	1	1	1	1	2	4	2	2	6	0	-			
LV	Connections	OH/UG consumer service connections	No.	13,086	3,706	6,998	8,750	7,047	4,582	4,816	293	271	369	433	503	501	524	558	407	396	463	369	405	80	-			
All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	0	41	46	39	84	-	14	0	0	0	1	17	-	11	1	2	5	11	17	1	2	2			
All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	0	0	0	0	0	19	0	0	0	2	-	1	1	-	1	-	-	-	1	1	9	3			
All	Capacitor Banks	Capacitors including controls	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-			
All	Load Control	Centralised plant	Lot	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-			
All	Load Control	Relays	No.	1	1	12	178	244	208	313	15	9	14	9	14	15	16	10	9	18	13	7	7	2	-			
All	Civils	Cable Tunnels	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			

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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.

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Company Name

Aurora Energy Limited

For Year Ended

31 March 2013

Network / Sub-network Name

Total Business

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref

		Overhead (km)	Underground (km)	Total circuit length (km)
9				
10	Circuit length by operating voltage (at year end)			
11	> 66kV	-	-	-
12	50kV & 66kV	108	1	109
13	33kV	404	93	497
14	SWER (all SWER voltages)	9	-	9
15	22kV (other than SWER)	-	-	-
16	6.6kV to 11kV (inclusive—other than SWER)	2,328	789	3,117
17	Low voltage (< 1kV)	1,048	762	1,810
18	Total circuit length (for supply)	3,898	1,645	5,543
19				
20	Dedicated street lighting circuit length (km)	40	166	206
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			-
22				
23	Overhead circuit length by terrain (at year end)			
24	Urban	1,463	38%	
25	Rural	2,331	60%	
26	Remote only	-	-	
27	Rugged only	-	-	
28	Remote and rugged	104	3%	
29	Unallocated overhead lines	-	-	
30	Total overhead length	3,898	100%	
31				
32				
33	Length of circuit within 10km of coastline or geothermal areas (where known)	1,948	35%	
34				
35	Overhead circuit requiring vegetation management	157	4%	

Company Name

Aurora Energy Limited

For Year Ended

31 March 2013

Network / Sub-network Name

Dunedin

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref

		Overhead (km)	Underground (km)	Total circuit length (km)
9				
10	Circuit length by operating voltage (at year end)			
11	> 66kV	-	-	-
12	50kV & 66kV	-	-	-
13	33kV	144	78	222
14	SWER (all SWER voltages)	9	-	9
15	22kV (other than SWER)	-	-	-
16	6.6kV to 11kV (inclusive—other than SWER)	732	264	996
17	Low voltage (< 1kV)	823	219	1,042
18	Total circuit length (for supply)	1,708	561	2,269
19				
20	Dedicated street lighting circuit length (km)	37	101	139
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			-
22				
23	Overhead circuit length by terrain (at year end)			
24	Urban	1,181	69%	
25	Rural	513	30%	
26	Remote only	-	-	
27	Rugged only	-	-	
28	Remote and rugged	14	1%	
29	Unallocated overhead lines	-	-	
30	Total overhead length	1,708	100%	
31				
32				
33	Length of circuit within 10km of coastline or geothermal areas (where known)	1,948	86%	
34				
35	Overhead circuit requiring vegetation management	78	5%	

Company Name

Aurora Energy Limited

For Year Ended

31 March 2013

Network / Sub-network Name

Central Otago

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref

		Overhead (km)	Underground (km)	Total circuit length (km)
9				
10	Circuit length by operating voltage (at year end)			
11	> 66kV	-	-	-
12	50kV & 66kV	108	1	109
13	33kV	261	15	275
14	SWER (all SWER voltages)	-	-	-
15	22kV (other than SWER)	-	-	-
16	6.6kV to 11kV (inclusive—other than SWER)	1,596	524	2,119
17	Low voltage (< 1kV)	225	537	762
18	Total circuit length (for supply)	2,190	1,077	3,267
19				
20	Dedicated street lighting circuit length (km)	2	64	66
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			-
22				
23	Overhead circuit length by terrain (at year end)			
24	Urban	282	13%	
25	Rural	1,818	83%	
26	Remote only	-	-	
27	Rugged only	-	-	
28	Remote and rugged	90	4%	
29	Unallocated overhead lines	-	-	
30	Total overhead length	2,190	100%	
31				
32				
33	Length of circuit within 10km of coastline or geothermal areas (where known)	-	-	
34				
35	Overhead circuit requiring vegetation management	79	4%	

Company Name	Aurora Energy Limited
For Year Ended	31 March 2013

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 *	Number of ICPs served	Line charge revenue (\$000)
9	Heritage Park Subdivision, Te Anau	89	60
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26	* Extend embedded distribution networks table as necessary to disclose each embedded network owned by the EDB which is embedded in another EDB’s network or in another embedded network		

Company Name

Aurora Energy Limited

For Year Ended

31 March 2013

Network / Sub-network Name

Total Business

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref

9e(i): Consumer Connections

Number of ICPs connected in year by consumer type

Consumer types defined by EDB*

Standard domestic (8 and 15kVA variable)

Load group 0 (1 kVA un-metered)

Load group 0A (2 kVA un-metered)

Load group 1A (8 kVA, plus standard domestic 8 kVA)

Load group 1 (15 kVA, plus standard domestic 15 kVA)

Load group 2 (16 - 149 kVA)

Load group 3 (150 - 249 kVA)

Load group 3A (250 - 499 kVA)

Load group 4 (500 - 2,499 kVA)

Load group 5 (2,500+ kVA)

Street lighting

* include additional rows if needed

Connections total

Number of
connections (ICPs)

523

9

63

37

(21)

137

(4)

(2)

6

-

-

748

Distributed generation

Number of connections made in year

54

connections

Capacity of distributed generation installed in year

1,419

MVA

9e(ii): System Demand**Maximum coincident system demand**

GXP demand

231

plus Distributed generation output at HV and above

53

Maximum coincident system demand

284

less Net transfers to (from) other EDBs at HV and above

(0)

Demand on system for supply to consumers' connection points

284

Demand at time
of maximum
coincident
demand (MW)**Electricity volumes carried**

Electricity supplied from GXPs

1,058

less Electricity exports to GXPs

44

plus Electricity supplied from distributed generation

315

less Net electricity supplied to (from) other EDBs

(1)

Electricity entering system for supply to consumers' connection points

1,330

less Total energy delivered to ICPs

1,255

Electricity losses (loss ratio)

75

5.6%

Load factor

53%

Energy (GWh) Energy (GWh)

9e(iii): Transformer Capacity

Distribution transformer capacity (EDB owned)

824

Distribution transformer capacity (Non-EDB owned)

70

Total distribution transformer capacity

894

Zone substation transformer capacity

897

(MVA)

Company Name

Aurora Energy Limited

For Year Ended

31 March 2013

Network / Sub-network Name

Dunedin

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref

9e(i): Consumer Connections

Number of ICPs connected in year by consumer type

Consumer types defined by EDB*

Standard domestic (8 and 15kVA variable)

Load group 0 (1 kVA un-metered)

Load group 0A (2 kVA un-metered)

Load group 1A (8 kVA, plus standard domestic 8 kVA)

Load group 1 (15 kVA, plus standard domestic 15 kVA)

Load group 2 (16 - 149 kVA)

Load group 3 (150 - 249 kVA)

Load group 3A (250 - 499 kVA)

Load group 4 (500 - 2,499 kVA)

Load group 5 (2,500+ kVA)

Street lighting

* include additional rows if needed

Connections total

Number of
connections (ICPs)

152

1

12

14

(50)

40

(2)

(3)

5

-

-

169

Distributed generation

Number of connections made in year

5

connections

Capacity of distributed generation installed in year

1.173

MVA

9e(ii): System Demand**Maximum coincident system demand**

GXP demand

145

plus Distributed generation output at HV and above

52

Maximum coincident system demand

196

less Net transfers to (from) other EDBs at HV and above

-

Demand on system for supply to consumers' connection points

196

Electricity volumes carried

Electricity supplied from GXPs

740

less Electricity exports to GXPs

2

plus Electricity supplied from distributed generation

148

less Net electricity supplied to (from) other EDBs

-

Electricity entering system for supply to consumers' connection points

886

less Total energy delivered to ICPs

841

Electricity losses (loss ratio)

45

5.1%

Load factor

52%

9e(iii): Transformer Capacity

Distribution transformer capacity (EDB owned)

476

Distribution transformer capacity (Non-EDB owned)

49

Total distribution transformer capacity

525

Zone substation transformer capacity

610

Company Name **Aurora Energy Limited**For Year Ended **31 March 2013**Network / Sub-network Name **Central Otago****SCHEDULE 9e: REPORT ON NETWORK DEMAND**

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

sch ref

9e(i): Consumer Connections

Number of ICPs connected in year by consumer type

Consumer types defined by EDB*

Standard domestic (8 and 15kVA variable)

Load group 0 (1 kVA un-metered)

Load group 0A (2 kVA un-metered)

Load group 1A (8 kVA, plus standard domestic 8 kVA)

Load group 1 (15 kVA, plus standard domestic 15 kVA)

Load group 2 (16 - 149 kVA)

Load group 3 (150 - 249 kVA)

Load group 3A (250 - 499 kVA)

Load group 4 (500 - 2,499 kVA)

Load group 5 (2,500+ kVA)

Street lighting

* include additional rows if needed

Connections total

Number of
connections (ICPs)

361

8

53

23

29

97

(2)

1

1

-

-

571

Distributed generation

Number of connections made in year

49

connections

Capacity of distributed generation installed in year

0.247

MVA

9e(ii): System Demand**Maximum coincident system demand**

GXP demand

76

plus Distributed generation output at HV and above

24

Maximum coincident system demand

100

less Net transfers to (from) other EDBs at HV and above

-

Demand on system for supply to consumers' connection points

100

Electricity volumes carried

Electricity supplied from GXPs

319

less Electricity exports to GXPs

42

plus Electricity supplied from distributed generation

167

less Net electricity supplied to (from) other EDBs

-

Electricity entering system for supply to consumers' connection points

443

less Total energy delivered to ICPs

414

Electricity losses (loss ratio)

29

6.6%

Load factor

51%

9e(iii): Transformer Capacity

Distribution transformer capacity (EDB owned)

348

Distribution transformer capacity (Non-EDB owned)

21

Total distribution transformer capacity

369

Zone substation transformer capacity

287

Company Name **Aurora Energy Limited**For Year Ended **31 March 2013**Network / Sub-network Name **Total Business****SCHEDULE 10: REPORT ON NETWORK RELIABILITY**

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

sch ref

10(i): Interruptions**Interruptions by class****Number of interruptions**

Class A (planned interruptions by Transpower)
Class B (planned interruptions on the network)
Class C (unplanned interruptions on the network)
Class D (unplanned interruptions by Transpower)
Class E (unplanned interruptions of EDB owned generation)
Class F (unplanned interruptions of generation owned by others)
Class G (unplanned interruptions caused by another disclosing entity)
Class H (planned interruptions caused by another disclosing entity)
Class I (interruptions caused by parties not included above)
Total

346
357
703

Interruption restoration**≤3Hrs >3hrs**

Class C interruptions restored within

286	71
-----	----

SAIFI and SAIDI by class**SAIFI SAIDI**

Class A (planned interruptions by Transpower)
Class B (planned interruptions on the network)
Class C (unplanned interruptions on the network)
Class D (unplanned interruptions by Transpower)
Class E (unplanned interruptions of EDB owned generation)
Class F (unplanned interruptions of generation owned by others)
Class G (unplanned interruptions caused by another disclosing entity)
Class H (planned interruptions caused by another disclosing entity)
Class I (interruptions caused by parties not included above)
Total

0.12	21.8
0.93	53.8
1.05	75.6

Normalised SAIFI and SAIDI**Normalised SAIFI Normalised SAIDI**

Classes B & C (interruptions on the network)

1.05	75.6
------	------

Quality path normalised reliability limit**SAIFI reliability limit SAIDI reliability limit**

SAIFI and SAIDI limits applicable to disclosure year*

1.67	98.3
------	------

* not applicable to exempt EDBs

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

Lightning
Vegetation
Adverse weather
Adverse environment
Third party interference
Wildlife
Human error
Defective equipment
Cause unknown

0.01	0.39
0.13	15.39
0.02	4.68
0.03	2.18
0.09	6.26
0.02	1.47
0.14	3.28
0.15	11.17
0.35	9.01

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)
Distribution cables (excluding LV)
Distribution other (excluding LV)

-	-
-	0.04
-	-
0.09	19.31
0.01	0.44
0.01	2.01

10(iv): Class C Interruptions and Duration by Main Equipment Involved**Main equipment involved****SAIFI SAIDI**

Subtransmission lines
Subtransmission cables
Subtransmission other
Distribution lines (excluding LV)
Distribution cables (excluding LV)
Distribution other (excluding LV)

0.10	4.70
-	-
0.12	1.76
0.49	36.50
0.08	5.72
0.13	5.12

10(v): Fault Rate**Main equipment involved**

	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	33	512	6.45
Subtransmission cables		94	-
Subtransmission other	6		
Distribution lines (excluding LV)	278	2,337	11.90
Distribution cables (excluding LV)	20	789	2.53
Distribution other (excluding LV)	141		
Total	478		

Company Name

Aurora Energy Limited

For Year Ended

31 March 2013

Network / Sub-network Name

Dunedin

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

10(i): Interruptions**Interruptions by class****Number of interruptions**

Class A (planned interruptions by Transpower)
 Class B (planned interruptions on the network)
 Class C (unplanned interruptions on the network)
 Class D (unplanned interruptions by Transpower)
 Class E (unplanned interruptions of EDB owned generation)
 Class F (unplanned interruptions of generation owned by others)
 Class G (unplanned interruptions caused by another disclosing entity)
 Class H (planned interruptions caused by another disclosing entity)
 Class I (interruptions caused by parties not included above)

48
135
183

Total**Interruption restoration**

≤3Hrs

>3hrs

Class C interruptions restored within

113	22
-----	----

SAIFI and SAIDI by class

SAIFI

SAIDI

Class A (planned interruptions by Transpower)
 Class B (planned interruptions on the network)
 Class C (unplanned interruptions on the network)
 Class D (unplanned interruptions by Transpower)
 Class E (unplanned interruptions of EDB owned generation)
 Class F (unplanned interruptions of generation owned by others)
 Class G (unplanned interruptions caused by another disclosing entity)
 Class H (planned interruptions caused by another disclosing entity)
 Class I (interruptions caused by parties not included above)

0.03	1.84
0.82	31.67
0.85	33.5

Total**Normalised SAIFI and SAIDI**

Normalised SAIFI

Normalised SAIDI

Classes B & C (interruptions on the network)

0.85	33.5
------	------

Quality path normalised reliability limit

SAIFI reliability limit

SAIDI reliability limit

SAIFI and SAIDI limits applicable to disclosure year*

* not applicable to exempt EDBs

1.67	98.3
------	------

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

SAIFI

SAIDI

Lightning
 Vegetation
 Adverse weather
 Adverse environment
 Third party interference
 Wildlife
 Human error
 Defective equipment
 Cause unknown

0.01	0.05
0.07	4.69
-	0.84
-	0.09
0.07	6.33
0.03	1.95
0.11	2.91
0.16	9.72
0.38	5.14

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)
 Distribution cables (excluding LV)
 Distribution other (excluding LV)

-	-
-	-
-	-
0.02	1.24
-	0.07
0.01	0.53

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

SAIFI

SAIDI

Subtransmission lines
 Subtransmission cables
 Subtransmission other
 Distribution lines (excluding LV)
 Distribution cables (excluding LV)
 Distribution other (excluding LV)

0.11	2.21
-	-
0.19	2.66
0.37	19.35
0.08	4.52
0.08	2.93

10(v): Fault Rate**Main equipment involved**

Number of Faults

Circuit length (km)

Fault rate (faults per 100km)

Subtransmission lines
 Subtransmission cables
 Subtransmission other
 Distribution lines (excluding LV)
 Distribution cables (excluding LV)
 Distribution other (excluding LV)

16	144
-	79
5	
60	741
14	315
60	
155	

11.11
-
8.10
4.44

Total

Company Name **Aurora Energy Limited**For Year Ended **31 March 2013**Network / Sub-network Name **Central Otago****SCHEDULE 10: REPORT ON NETWORK RELIABILITY**

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

sch ref

10(i): Interruptions**Interruptions by class****Number of interruptions**

Class A (planned interruptions by Transpower)
Class B (planned interruptions on the network)
Class C (unplanned interruptions on the network)
Class D (unplanned interruptions by Transpower)
Class E (unplanned interruptions of EDB owned generation)
Class F (unplanned interruptions of generation owned by others)
Class G (unplanned interruptions caused by another disclosing entity)
Class H (planned interruptions caused by another disclosing entity)
Class I (interruptions caused by parties not included above)
Total

298
222
520

Interruption restoration**≤3Hrs >3hrs**

Class C interruptions restored within

173	49
-----	----

SAIFI and SAIDI by class**SAIFI SAIDI**

Class A (planned interruptions by Transpower)
Class B (planned interruptions on the network)
Class C (unplanned interruptions on the network)
Class D (unplanned interruptions by Transpower)
Class E (unplanned interruptions of EDB owned generation)
Class F (unplanned interruptions of generation owned by others)
Class G (unplanned interruptions caused by another disclosing entity)
Class H (planned interruptions caused by another disclosing entity)
Class I (interruptions caused by parties not included above)
Total

0.28	58.53
1.12	94.60
1.40	153.1

Normalised SAIFI and SAIDI

Normalised SAIFI	Normalised SAIDI
1.40	153.1

Quality path normalised reliability limit

SAIFI reliability limit	SAIDI reliability limit
1.67	98.3

SAIFI and SAIDI limits applicable to disclosure year*

* not applicable to exempt EDBs

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

Lightning
Vegetation
Adverse weather
Adverse environment
Third party interference
Wildlife
Human error
Defective equipment
Cause unknown

-	1.02
0.23	35.09
0.06	11.75
0.08	6.03
0.12	6.14
0.01	0.60
0.19	3.98
0.14	13.86
0.30	16.13

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)
Distribution cables (excluding LV)
Distribution other (excluding LV)

-	-
-	0.12
-	-
0.23	52.53
0.02	1.14
0.03	4.74

10(iv): Class C Interruptions and Duration by Main Equipment Involved**Main equipment involved****SAIFI SAIDI**

Subtransmission lines
Subtransmission cables
Subtransmission other
Distribution lines (excluding LV)
Distribution cables (excluding LV)
Distribution other (excluding LV)

0.08	9.29
-	-
0.01	0.13
0.73	68.08
0.09	7.95
0.21	9.15

10(v): Fault Rate**Main equipment involved**

	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	17	369	4.61
Subtransmission cables	-	16	-
Subtransmission other	1		
Distribution lines (excluding LV)	218	1,596	13.66
Distribution cables (excluding LV)	6	537	1.12
Distribution other (excluding LV)	81		
Total	323		

Company Name	Aurora Energy Limited
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For Year Ended	31 March 2013
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Schedule 14 Mandatory Explanatory Notes

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012)

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 2.5.2.
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 12 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 clause 2.7.1(2).

Box 1: Explanatory comment on return on investment

ROI is between the mid-point and 75th percentile estimate of WACC. There have been no items reclassified in accordance with clause 2.7.1(2).

Regulatory Profit (Schedule 3)

5. In the box below, comment on regulatory profit for the disclosure year as disclosed in Schedule 3. This comment must include-
 - 5.1 a description of material items included in 'other regulatory line income' other than gains and losses on asset sales, as disclosed in 3(i) of Schedule 3
 - 5.2 information on reclassified items in accordance with clause 2.7.1(2).

Box 2: Explanatory comment on regulatory profit

Included in 'other regulatory line income' are the following (all figures in \$000's):

- Transmission Rental Rebate Received \$1,981
- Transmission Charge Recovered \$ 435
- Accident Damage Recoveries \$ 396
- Miscellaneous / other income \$ 177

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

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

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

- 6.1 information on reclassified items in accordance with clause 2.7.1(2)
- 6.2 any other commentary on the benefits of the merger and acquisition expenditure to the EDB.

Box 3: Explanatory comment on merger and acquisition expenditure

There were no merger and acquisition costs incurred.

Value of the Regulatory Asset Base (Schedule 4)

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

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

The amounts disclosed in the regulatory asset base calculations as assets commissioned have been reduced by the amount of customer contributions received and have been adjusted in respect of acquisitions sourced from Delta Utility Services Ltd (a related party).

Related party transactions have been recorded either at:

- Directly attributable cost plus allowance for indirect / overhead expenses incurred by Delta or
- At valuation – in accordance with an independent valuation process undertaken in respect of specific larger projects.

The impact of these adjustments are as follows (\$000):

	<u>2011</u>	<u>2012</u>	<u>2013</u>
Original cost (and regulatory tax value)	21,234	18,244	18,426
Less offset customer contributions	(4,620)	(3,820)	(3,043)
Less margin on related party capex	(1,205)	(1,848)	(1,835)
Less cost of asset subject to valuation	(5,667)	(3,135)	(4,526)
Plus assets included at valuation	6,475	2,531	3,674
	-----	-----	-----
Value RAB assets commissioned	16,217	11,973	12,695

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

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

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

- 8.1 income not included in regulatory profit / (loss) before tax but taxable;
- 8.2 expenditure or loss in regulatory profit / (loss) before tax but not deductible;
- 8.3 income included in regulatory profit / (loss) before tax but not taxable;
- 8.4 expenditure or loss deductible but not in regulatory profit / (loss) before tax.

Box 5: Regulatory tax allowance: permanent differences

The figure shown in 'Income not included in regulatory profit / (loss) before tax but taxable' is an adjustment in respect of \$1,105,000 of customer contribution that is assessable for income tax purposes in that year.

The figure 'Expenditure or loss in regulatory profit or (loss) before tax but not deductible' relates to \$16,000 of doubtful debts.

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

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

Box 6: Temporary differences / Tax effect of other temporary differences (current disclosure year)
 The \$313,000 shown in the line 'Tax effect of other temporary differences' is (\$000):

Value of customer contributions as above	\$1,105
Plus doubtful debts as above	\$16

Sub-total of differences	\$1,089
Tax effect at 28%	\$313

Related party transactions: disclosure of related party transactions (Schedule 5b)

10. In the box below, provide descriptions of related party transactions beyond those disclosed on schedule 5b including identification and descriptions as to the nature of directly attributable costs disclosed under clause 2.3.6(1)(b).

Box 7: Related party transactions

Over 50% of of sales of goods and service by Aurora's sibling company, Delta Utility Services Limited, are to third parties and third parties may purchase the same or similar goods and services provided to Aurora on substantially the same terms and conditions, including price. Accordingly, related party transactions disclosed in schedule 5b are valued in accordance with clause 2.3.6(1)(c).

Cost allocation (Schedule 5d)

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

Box 8: Cost allocation

Operating costs along with pass through and recoverable costs are all directly attributable to the regulated business.

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

Asset allocation (Schedule 5e)

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

Box 9: Commentary on asset allocation

All assets acquired are all directly attributable to the regulated business.

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

Capital Expenditure for the Disclosure Year (Schedule 6a)

13. In the box below, comment on capital expenditure for the disclosure year, as disclosed in Schedule 6a. This comment must include-
- 13.1 a description of the materiality threshold applied to identify material projects and programmes described in Schedule 6a;
 - 13.2 information on reclassified items in accordance with clause 2.7.1(2),

Box 10: Explanation of capital expenditure for the disclosure year

Consumer connection capital expenditure disclosed in 6a(iii) is all connections. Insufficient data is currently captured to align that expenditure with consumer load groups. No specific materiality threshold has been applied to the specific reporting of 'asset relocations', 'quality of supply', 'other reliability, safety and environment'. The listed projects are the highvalue projects comprising the category. Further system work is required in the capture and reporting of project categorisation. Improved disclosure is expected for the 2014 period.

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

Operational Expenditure for the Disclosure Year (Schedule 6b)

14. In the box below, comment on operational expenditure for the disclosure year, as disclosed in Schedule 6b. This comment must include-
- 14.1 commentary on assets replaced or renewed with asset replacement and renewal operating expenditure, as reported in 6b(i) of Schedule 6b;
 - 14.2 information on reclassified items in accordance with clause 2.7.1(2);
 - 14.3 commentary on any material atypical expenditure included in operational expenditure disclosed in Schedule 6b, a including the value of the expenditure the purpose of the expenditure, and the operational expenditure categories the expenditure relates to.

Box 11: Explanation of operational expenditure for the disclosure year

Expenditure on asset replacement and renewal is relatively minor in nature, generally, applying to asset components and designed to ensure the asset achieves its service life. Typically, such expenditure includes replacement and/or renewal of insulators, fuse links, service and link pillar components, cable terminations, equipment earth grids, transformer and switchgear components, including painting.

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

There are no items of of operationsal expenditure that have been identified as atypical.

Variance between forecast and actual expenditure (Schedule 7)

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

Box 12: Explanatory comment on variance in actual to forecast expenditure

It should be noted that format for disclosing expenditure, in the second to last AMP, was not prescribed, owing to the fact that a different disclosure regime existed at that time. Accordingly, the target figures have been taken from Aurora's last disclosed AMP as the year CY forecast.

The variance in 'system growth' is primarily attributable to the Tarras water scheme being deferred, shifting the allocation into the 2013/14 year. The remaining actual spend is mainly attributable to Roxburgh zone substation refurbishment. The variance in 'asset replacement and renewal' expenditure is due to deferral as a consequence of supplier delays (Andersons Bay 33kV cable rejects, requiring re-manufacture), as well as re-appraisal of some transformer-related projects and optimisation of part of the system control, communications and protection programme. "Consumer connection" and 'asset relocation' expenditure is generally externally driven and less controllable than other categories. Additional emphasis was placed on reliability and quality expenditure in the disclosure period. Additional emphasis was placed on reliability and quality of supply projects in the later part of the disclosure years, resulting in an overall increase in "total reliability, safety and environment" expenditure.

Overall maintenance expenditure is down slightly during the disclosure period. Delay in evaluating some inspection work, and associated project planning, translated into an under-spend in 'routine and corrective maintenance and inspection'. This was, in part, offset by additional work required in 'service interruptions and emergencies' and 'asset replacement and renewal'. Non-network opex was materially incorrectly stated in the AMP.

Information relating to revenue and quantities for the disclosure year

16. In the box below provide-

- 16.1 a comparison of the target revenue disclosed before the start of the disclosure year, in accordance with clauses 2.4.1 and 2.4.3(3) to total billed line charge revenue for the disclosure year, as disclosed in Schedule 8; and
- 16.2 explanatory comment on reasons for any material differences between target revenue and total billed line charge revenue.

Box 13: Explanatory comment relating to revenue for the disclosure year

It should be noted that distributors have not been specifically required to state target revenue within pricing methodologies prior to the publication of the methodology for prices commencing 1 April 2013. Nonetheless, Aurora has generally stated its total budgeted delivery revenue in each year, as below. Target revenue is not determined on a sub-network basis.

2012

Total delivery revenue budgeted	\$75.743 million
Reported – Schedule 8 (Total Business)	\$75.690 million
Difference	\$0.053 million below target

2013

Total delivery revenue budgeted	\$83.982 million
Reported – Schedule 8 (Total Business)	\$84.229 million
Difference	\$0.247 million above target

It is generally expected that total billed line charge revenue for an assessment period will be different from target revenue for that same period due to variation in connection numbers and energy demand. This is because prices are derived to ensure that Aurora's allowable notional revenue, as determined under the default price path, is not exceeded. Accordingly, total billed line charge revenue is based on actual quantities during the assessment period whereas allowable notional revenue is derived using quantities that existing two years prior.

Network Reliability for the Disclosure Year (Schedule 10)

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

Box 14: Commentary on network reliability for the disclosure year

In accordance with Information Disclosure definitions:

- Overhead (subtransmission and distribution) includes poles, stay-wires, crossarms, braces, insulators, conductor (including droppers and connectors), binders and ties
- Underground (subtransmission and distribution) includes cable, mounting brackets, terminations and potheads.
- Other (subtransmission and distribution) includes HV fuses (including fuse operation), lighting arrestors, transformers, switchgear, switching and control errors.
- Faults include unplanned events <1 minute, and events not resulting in loss of supply to a consumer, which would otherwise be excluded from consideration as an interruption.

In accordance with issue 231 of the Issues Register for Electricity and Gas Information Disclosure, Aurora declares that it has derived normalised SAIFI and normalised SAIDI values for each sub-network using the normalised assessment dataset for the network (constructed with boundary values calculated using the reference dataset for the network). The reason for selecting this option was to manage the time constraints that would have been exacerbated by deriving, auditing and certifying sub-network specific values. It is expected that Aurora will report sub-network specific values in future disclosures.

Insurance cover

18. In the box below provide details of any insurance cover for the assets used to provide electricity distribution services, including-
 - 18.1 the EDB's approaches and practices in regard to the insurance of assets used to provide electricity distribution services, including the level of insurance;
 - 18.2 in respect of any self insurance, the level of reserves, details of how reserves are managed and invested, and details of any reinsurance.

Box 15: Explanation of insurance cover

Insurance cover has been obtained / in place with respect of zone substations, both for the buildings and the plant and equipment contained within them.

The material damage (including flood, earthquake etc) cover for the zone substations and associated equipment is on a replacement cost basis.

Disbtibution assets including distribution substations, lines and cables etc are not covered due to the geographical spread, the lower value of the individual assets and the reduced likelihood of significant loss on any less than region wide event.

Company Name	<u>Aurora Energy Limited</u>
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For Year Ended	<u>31 March 2013</u>
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Schedule 14b Mandatory Explanatory Notes on Transitional Financial Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012)

1. This Schedule provides for EDBs to provide explanatory notes to the transitional financial information disclosed in accordance with clause 2.12.1.
2. This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.12.1. This information is part of the audited disclosure information, and so is subject to the assurance requirements specified in section 2.8.
3. In the box below provide explanatory comment on the tax effect of other temporary differences for the years ending 31 March 2010, 31 March 2011 and 31 March 2012 (as reported in Schedule 5h(vii)).

Box 1: Commentary on tax effect of other temporary differences (years ended 31 March 2010, 31 March 2011, and 31 March 2012)

'Tax effect of other temporary differences' is shown below (\$000)

	<u>2010</u>	<u>2011</u>	<u>2012</u>
Capital contributions assessable	0	418	800
Deferred tax effect	0	126	224
Doubtfull debt provision	94	4	-138
Deferred tax effect	-28	-1	-39
Net deferred	-28	125	185

4. To the extent that any change in regulatory profit and ROI reported for 2013 (compared to that reported for 2012) is attributable to the change in treatment of related party transactions, provide an explanation of the change in the box below.

Box 2: Change in regulatory profit and ROI due to change in treatment of related party transactions
 As related party transactions for operational expenditure have been valued in accordance with with clause 2.3.6(1)(c), regulatory profit is not affected. Return on investment for the 2012 disclosure year was 8.26% versus 6.22% in 2013. The 2012 value was derived under different rules more closely aligned to GAAP. Aurora has not redetermined the 2012 ROI under the most recent disclosure rules; however analysis of the 2013 ROI has been undertaken, comparing the ROI derived where related party transactions for asset construction / additions are valued at the transaction cost (6.03% post-tax) and ROI derivation in accordance with clause 2.2.11 of the Electricity Distribution Services Input Methodologies Determination 2012 (6.22% post tax).

5. In the box below, comment on asset allocation as disclosed in Schedule 5e. This comment must include information on reclassified items in accordance with clause 2.7.1(2) for disclosure years 2011 and 2012.

Box 3: Commentary on asset allocation
 All assets acquired are directly attributable to the regulated business.
 There have been no items reclassified in accordance with clause 2.7.1(2).

Company Name	<u>Aurora Energy Limited</u>
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For Year Ended	<u>31 March 2013</u>
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Schedule 15 Voluntary Explanatory Notes

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012)

1. This Schedule enable EDBs to provide, should they wish to-
 - 1.1 additional explanatory comment to reports prepared in accordance with clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1, 2.5.2, and 2.6.5;
 - 1.2 information on any substantial changes to information disclosed in relation to a prior disclosure year, as a result of final wash-ups.
2. Information in this Schedule is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.
3. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information

Aurora requested that the Commerce Commission grant an extension of time for completion of the 2013 Information Disclosure submission. The Commerce Commission approved that request and, on 29 July 2013, granted an exemption under clause 2.11.1(1) of the Electricity Distribution Information Disclosure Determination 2012. The exemption granted Aurora a 4 week extension, from the original deadline of Saturday 31 August 2013, to Friday 27 September 2013. A copy of the Commerce Commission's exemption notice, which explains the rationale for the exemption and associated conditions, is posted on the Aurora website at <http://www.auroraenergy.co.nz/content/performancestatements.php>

There is a \$766,000 discrepancy between the total line charge revenue reported in schedule 8, and that recorded in Aurora's financial system. The schedule 8 information has been compiled from Aurora's stand-alone connection management system and may contain some wash-up values recorded in the disclosure period, but attributable to events outside the disclosure period. Line charge revenue derived from Aurora's financial system includes accruals for over/under reporting by retailers, calculated with respect to published loss ratios. The line charge revenue stated in schedule 3 (line 9) and schedule 7 (line 8) has been manually entered and reflects the value stated in Aurora's financial system. In May 2013, Aurora implemented an upgrade of its connection management system, which now integrates with the financial system. It is expected that future discrepancies will be reduced as a result. Similar variances exist for 2012 in the transitional schedule 3 (2012) and transitional schedule 8 (2012).

SCHEDULE 18

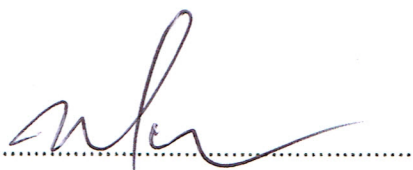
Certification for Year-end Disclosures

Clause 2.9.2 of section 2.9

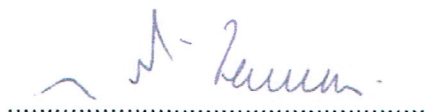
We, Raymond Stuart Polson and Stuart James McLauchlan, directors of Aurora Energy Ltd, certify that, having made all reasonable enquiry, to the best of our knowledge -

- a. the information prepared for the purposes of clauses 2.3.1 and 2.3.2; and clauses 2.4.21 and 2.4.22; clauses 2.5.1 and 2.5.2; and clauses 2.7.1 and 2.7.2 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, 14a and 14b has been properly extracted from the Aurora Energy's accounting and other records sourced from its financial and non-financial systems, and that sufficient appropriate records have been retained [and if not, what records and systems were used]; and
- c. the forecasts in Schedules 11a, 11b, 12a, 12b and 12c are based on objective and reasonable assumptions which both align with Aurora Energy's corporate vision and strategy and are documented in retained records.

In respect of related party costs and revenues recorded in accordance with clauses 2.3.6(1) (when valued in accordance with clause 2.2.11(5)(h)(ii) of the Electricity Distribution Services Input Methodologies Determination 2010), 2.3.6(2)(f) and 2.3.7(2)(b), we certify that, having made all reasonable enquiry, including enquiries of our related parties, we are satisfied that to the best of our knowledge and belief the costs and revenues recorded for related party transactions reasonably reflect the price or prices that would have been paid or received had these transactions been at arm's-length.



Raymond Stuart Polson



Stuart James McLauchlan

24 September 2013

SCHEDULE 19

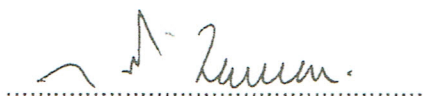
Certification for Transitional Disclosures

Clause 2.9.2 of section 2.9

We, Raymond Stuart Polson and Stuart James McLauchlan, directors of Aurora Energy Ltd, certify that, having made all reasonable enquiry, to the best of our knowledge, the information prepared for the purpose of clauses 2.12.1, 2.12.2, 2.12.3, and 2.12.5 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

A handwritten signature in dark ink, appearing to be 'R. Polson', written over a horizontal dotted line.

Raymond Stuart Polson

A handwritten signature in dark ink, appearing to be 'Stuart James McLauchlan', written over a horizontal dotted line.

Stuart James McLauchlan

24 September 2013

Independent Auditor's Report

To the directors of Aurora Energy Limited and to the Commerce Commission

The Auditor-General is the auditor of Aurora Energy Limited (the company). The Auditor-General has appointed me, Ian Lothian, using the staff and resources of Audit New Zealand, to provide an opinion, on her behalf, on whether Schedules 1 to 4, 5a to 5i, 6a and 6b, 7, Schedule 10 sub-schedules (i) to (iv), the explanatory notes disclosed in boxes 1 to 12 of Schedule 14 and the explanatory comments in Schedule 14b ('the Disclosure Information') for the disclosure year ended 31 March 2013, have been prepared, in all material respects, in accordance with the Electricity Distribution Information Disclosure Determination 2012 (the "Determination").

Directors' responsibility for the Disclosure Information

The directors of the company are responsible for preparation of the Disclosure Information in accordance with the Determination, and for such internal control as the directors determine is necessary to enable the preparation of the Disclosure Information that is free from material misstatement.

Auditor's responsibility for the Disclosure Information

Our responsibility is to express an opinion on whether the Disclosure Information has been prepared, in all material respects, in accordance with the Determination.

Basis of opinion

We conducted our engagement in accordance with the International Standard on Assurance Engagements (New Zealand) 3000: Assurance Engagements Other Than Audits or Reviews of Historical Financial Information issued by the External Reporting Board and the Standard on Assurance Engagements 3100: Compliance Engagements issued by the External Reporting Board.

These standards require that we comply with ethical requirements and plan and perform our audit to provide reasonable assurance (which is also referred to as "audit" assurance) about whether the Disclosure Information has been prepared in all material respects in accordance with the Determination.

An audit involves performing procedures to obtain evidence about the amounts and disclosures in the Disclosure Information. The procedures selected depend on the auditor's judgement, including the assessment of the risks of material misstatement of the Disclosure Information, whether due to fraud or error or non-compliance with the Determination. In making those risk assessments, the auditor considers internal control relevant to the company's preparation of the Disclosure Information in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the company's internal control.

An audit also involves evaluating:

- the appropriateness of assumptions used and whether they have been consistently applied; and
- the reasonableness of the significant judgements made by the directors of the company.

Use of this report

This independent auditor's report has been prepared for the directors of the company and for the Commerce Commission for the purpose of providing those parties with independent audit assurance about whether the Disclosure Information has been prepared, in all material respects, in accordance with the Determination. We disclaim any assumption of responsibility for any reliance on this report to any person other than the directors of the company or the Commerce Commission, or for any other purpose than that for which it was prepared.

Scope and inherent limitations

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

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

The opinion expressed in this independent auditor's report has been formed on the above basis.

Independence

When carrying out the engagement we followed the independence requirements of the Auditor-General, which incorporate the independence requirements of the External Reporting Board. We also complied with the independent auditor requirements specified in clause 1.4.3 of the Determination.

The Auditor-General, and her employees, and Audit New Zealand and its employees may deal with the company on normal terms within the ordinary course of trading activities. Other than any dealings on normal terms within the ordinary course of business, this engagement, the audit of the annual compliance statement and the annual audit of the company's financial statements, we have no relationship with or interests in the company.

Opinion

In our opinion:

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

- the information used in the preparation of the Disclosure Information has been properly extracted from the company's accounting and other records and has been sourced, where appropriate, from the company's financial and non-financial systems; and
- the company has complied with the Determination, in all material respects, in preparing the Disclosure Information.

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



Ian Lothian
Audit New Zealand
On behalf of the Auditor-General
Dunedin, New Zealand
24 September 2013