Orion New Zealand Limited

Electricity Distribution Services
Default Price-Quality Path Determination 2020

Annual compliance statement

For the year ending 31 March 2022

Issued 30 August 2022

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INTRODUCTION

1 Orion New Zealand Limited (Orion) owns and operates the electricity distribution network in central Canterbury between the Waimakariri and Rakaia rivers, and from the Canterbury coast to Arthur's Pass. Our network covers 8,000 square kilometres of diverse geography, including Christchurch city, Banks Peninsula, farming communities and high-country regions. We receive electricity from Transpower's national grid at seven separate locations and we distribute this electricity to more than 215,000 homes and businesses.

2 We charge electricity retailers on a wholesale basis for this delivery service. Retailers, in turn, include this cost in their retail electricity prices - our delivery charges, including Transpower's charges, typically amount to around 34% of a household's electricity bill.

3 As a natural monopoly service provider, we are subject to government regulation under the Commerce Act 1986. Pursuant to the requirements of this Act, the Commerce Commission has set a regulatory framework that includes information disclosure regulations, default price-quality paths (DPP) and the option for distribution businesses to apply for a customised price-quality path (CPP).

4 Orion is subject to the Electricity Distribution Services Default Price-Quality Path Determination 2020 (the Determination) set by the Commerce Commission and applying for the five-year regulatory period from 1 April 2020 to 31 March 2025.

5 The Determination requires us to issue an "annual compliance statement" within 5 months after the end of each assessment period, as well as an "annual price-setting compliance statement" prior to the start of each assessment period to demonstrate compliance, or otherwise, with the requirements of the Determination.

6 This annual compliance statement covers information requirements detailed in clause 11 of the Determination in relation to the wash-up amount calculation, quality standards and quality incentives compliance and transactions for the year ended 31 March 2022, the second assessment period of the five-year regulatory period (the assessment period).

COMPLIANCE STATEMENTS

Wash-up amount calculation statement

7 This year we **complied with** the requirements to calculate the wash-up amount set out in clause 8.6 of the Determination for the assessment period. The wash-up amount for the assessment period is $1,926.1k which will be applied as a revenue increase when setting our prices for FY24.

Quality standard statement

8 This year we **complied with** the quality standards set out in clause 9 of the Determination for the assessment period.

9 For planned interruptions, the compliance test is carried out at the end of the 5th assessment period based on accumulated results. The contribution from the current assessment period and accumulated results for the regulatory period is:

9.1 Duration of planned interruptions (SAIDI):

	FY22	FY21	Accumulated (2 of 5 years)	Limit (at end of 5 years)
Planned SAIDI	24.91	28.87	53.78	198.40

9.2 Frequency of planned interruptions (SAIFI):

	FY22	FY21	Accumulated (2 of 5 years)	Limit (at end of 5 years)
Planned SAIFI	0.0744	0.0933	0.1678	0.7481

10 For unplanned interruptions, a compliance test is carried out at each assessment period. Our reliability results for unplanned interruptions for the assessment period were:

10.1 Duration of unplanned interruptions (SAIDI):

	FY22
Unplanned SAIDI assessed value	42.90
Unplanned SAIDI limit	84.71
	Comply

10.2 Frequency of unplanned interruptions (SAIFI):

	FY22
Unplanned SAIFI assessed value	0.6016
Unplanned SAIFI limit	1.0336
	Comply

11 In terms of extreme events, Orion has complied with the standards as we have not had an extreme event in the assessment period.

12 The quality incentive adjustment has been determined as $610,279 which will be applied as a revenue increase when setting our prices for FY24.

Transaction statement

13 During the assessment period, we:

13.1 have not been involved in an amalgamation or merger, and

13.2 have not been involved in a major transaction or transfer.

14 This statement was prepared and certified by directors of Orion New Zealand Ltd on 30 August 2022.

15 Full details supporting the statements above are included in this compliance statement.

WASH-UP AMOUNT CALCULATION SUPPORTING INFORMATION

16 Clause 8.6 and schedule 1.6 of the Determination require that the wash-up amount is calculated in accordance with the following formula for each assessment period:

AAR - AR - RV

where

AAR is the actual allowable revenue;

AR is the actual revenue; and

RV is the revenue foregone.

17 The calculation of each of these components is set out below.

Actual allowable revenue (AAR)

18 For the second assessment period of the DPP regulatory period, the actual allowable revenue (AAR) is calculated in accordance with the formula below as defined in schedule 1.6 (2)(b) of the Determination:

AAR = ANAR + APRC

where

ANAR is the actual net allowable revenue; and

APRC is the actual pass-through costs and recoverable costs.

19 **Actual net allowable revenue (ANAR)** is defined in schedule 1.6(3) of the Determination as the amount calculated using the following formula:

$ANAR_{previous} * (1 + \Delta CPI_t) * (1 - X)$

Where

$ANAR_{previous}$ is the actual net allowable revenue of the previous assessment period, which is stated in schedule 1.1 of the Determination as $158,498k for the first assessment period;

X is the annual rate of change as specified in Schedule 1.2 of the Determination, which is 0% for the DPP regulatory period; and

ΔCPI is the derived change in CPI to be applied for the assessment period, calculated as:

$$\Delta CPI = \frac{CPI_{Jun,t-1} + CPI_{Sep,t-1} + CPI_{Dec,t-1} + CPI_{Mar,t}}{CPI_{Jun,t-2} + CPI_{Sep,t-2} + CPI_{Dec,t-2} + CPI_{Mar,t-1}} - 1$$

where

$CPI_{q,t-n}$ is the CPI for the quarter year ending *q* in the 12-month period *n* years prior to year *t*; and

t is the year in which the assessment ends.

Substituting the CPI figure[1] for each quarter into the formula, ΔCPI_{2022} for the assessment period is:

$$\Delta CPI_{2022} = \frac{CPI_{Jun,2021} + CPI_{Sep,2021} + CPI_{Dec,\ 2021} + CPI_{Mar,\ 2022}}{CPI_{Jun,2020} + CPI_{Sep,2020} + CPI_{Dec,2020} + CPI_{Mar,2021}} - 1$$

$$= \frac{1082 + 1106 + 1122 + 1142}{1047 + 1054 + 1059 + 1068} - 1$$

$$= 5.30\%$$

20 Therefore, actual net allowable revenue for the assessment period ($ANAR_{2022}$) for Orion is

$$ANAR_{2022} = ANAR_{2021} * (1 + \Delta CPI_{2022}) * (1 - X)$$

$$= 158{,}498k * (1 + 5.30\%) * (1 - 0\%)$$

$$= \$166{,}895.2k$$

21 **Actual pass-through costs and recoverable costs (APRC)** is defined in clause 4.2 of the Determination as the sum of all pass-through costs and recoverable costs that were incurred or, in the case of drawn down amounts from the innovation project allowance, approved by the Commission in the assessment period, excluding any recoverable costs that is a revenue wash-up draw down amount.

22 The following table sets out individual components that we have included in the calculation of actual pass-through and recoverable costs. It shows the amounts for the assessment period, the amounts we forecasted for the assessment period when setting prices, and actual amounts for the prior period:

Pass-through and recoverable costs	**IM reference[2]**	**FY22 actual** $000	**FY22 forecast** $000	**FY21 actual** $000
Transpower charges				
Connection	3.1.3(1)(b)	3,995.8	4,117.0	3,771.5
Interconnection	3.1.3(1)(b)	57,479.1	57,479.1	56,930.6
New investment	3.1.3(1)(c)	975.2	975.2	1,646.4
		62,450.1	62,571.3	62,348.5
Avoided transmission charges				
Addington/Middleton connection charges avoided (final allowance was claimed in FY21)	3.1.3(1)(e)	0	0	2,798.0
Hororata and Islington charges avoided (third assessment period following the assessment period in which the purchase occurred)	3.1.3(1)(e)	309.9	309.9	309.9
		309.9	309.9	3,108.0
Incentives				
IRIS incentive adjustment	3.1.3(1)(a)	0	0	0

[1] The consumer price index stipulated for each quarter in the 'All Groups Index SE9A' as published by Statistics New Zealand
[2] Clause reference to the Electricity Distribution Services Input Methodologies Determination 2012 [2012] NZCC 26

		FY22 actual $000	FY22 forecast $000	FY21 actual $000
Other recoverable costs				
Capex wash-up adjustment[3]	3.1.3(1)(p)	733.2	733.2	NA
FENZ levy	3.1.3(1)(w)	119.3	113.7	110.5
Pass-through costs				
Local authority rates on system fixed assets	3.1.2(2)(a)	4,586.9	4,296.8	4,321.3
Commerce Commission Levies	3.1.2(2)(b)(i)	559.9	364.3	356.7
Electricity Authority Levies	3.1.2(2)(b)(ii)	643.9	651.1	649.7
Utilities Disputes Levies	3.1.2(2)(b)(iii)	122.6	119.6	119.6
		5,913.3	5,431.7	5,447.3
Total pass-through and recoverable costs		**69,525.9**	**69,159.8**	**71,014.2**

23 **Variances from forecasts** that are shown in the table above are normal and expected, because forecasts, by their very nature, are predictions or estimates. In many cases there is no concise reason for the variation other than to observe that the result was different.

24 The following table shows recoverable costs and pass-through costs from above where the actual result varied by more than 2% from the forecast amount for FY22, and provides an explanation of each variance.

Cost category	**Variance** $000	%	**Explanation**
Transpower Connection charges	(121.2)	-2.9%	Transpower connection charges for Islington GXP lower than forecast
Local authority rates	290.1	+6.8%	Normal variation from the amount forecast
Commerce Commission levies	195.6	+53.7%	The levies were higher than the prior year which we based our forecast on
FENZ Levy	5.7	+5.0%	Normal variation from the amount forecast
Utilities Disputes levies	3.1	+2.6%	Normal variation from the amount forecast

25 Therefore, the **actual allowable revenue (AAR)** for the assessment period is:

AAR = ANAR + APRC

= 166,895.2k + 69,525.9k

= $236,421.1k

[3] Amount disclosed in Appendix D of Orion's annual price-setting compliance statement for prices applying from 1 April 2021 https://www.oriongroup.co.nz/assets/Company/Corporate-publications/AnnualPriceSettingComplianceFY22.pdf

Actual revenue (AR)

26 The actual revenue (AR) is defined as actual revenue from prices plus other regulated income.

27 **Actual revenue from prices** is calculated as the sum of each price multiplied by each corresponding actual quantity. For the current assessment period, our actual revenue from prices was $230,403.6k.

28 The schedule of prices that we set for the assessment period (as published on our website) is included in Appendix A, and the worksheet showing the calculation of actual revenue from prices is included in Appendix C.

29 **Other regulated income** for Orion for the assessment period was $4,091.4k. The following table sets out individual components that we have included in the other regulated income.

Other regulated income	FY22 Actual $000
Rent	2,378.0
Network usage	192.0
Network damage	882.0
Other sundry revenue	737.3
Gain (loss) on asset disposals	(97.8)
Total	**4,091.4**

30 Therefore, actual revenue (AR) for the assessment period was:

$\$230{,}403.6\text{k} + \$4{,}091.4\text{k} = \$234{,}495.0\text{k}$

Revenue foregone (RV)

31 Revenue forgone (RV) is defined in clause 4.2 of the Determination as:

31.1 Nil, if the revenue reduction percentage is not greater than 20%;

31.2 ANAR x (revenue reduction percentage - 20%), if the revenue reduction percentage is greater than 20%.

32 The formula to calculate the revenue reduction percentage is:

1 – (actual revenue from prices ÷ forecast revenue from prices)

33 For the assessment period, our actual revenue from prices was $230,403.6k as calculated in Appendix C. Forecast revenue from prices was $227,606.3k, as disclosed in clause 16 of our annual price-setting compliance statement for prices applying from 1 April 2021, and shown in Appendix B.

34 Substituting these values into the revenue reduction percentage formula gives:

1 – ($230,403.6k ÷ $227,606.3k) = -1.2%

35 Therefore, revenue forgone (RV) for Orion is nil for the assessment period, as the revenue reduction percentage is not greater than 20%.

Wash-up amount calculation

36 Substituting the values calculated above for actual allowable revenue (AAR), actual revenue (AR) and revenue forgone (RV), the wash-up amount is:

AAR — AR — RV

= $236,421.1k — $234,495.0k — $0

= $1,926.1k

Summary of contributing factors

37 The wash-up amount equates to actual allowable revenue being 0.81% higher than actual revenue. At a high level, the main factors contributing to this variation are shown in the table below.

Factor	$000	%
Rapid increase of CPI resulting in actual net allowable revenue being higher than forecast net allowable revenue set for Orion for setting prices	5,306.2	2.24%
Actual chargeable quantities were greater than forecast	(2,797.3)	-1.18%
Other regulated income was higher than forecast[4]	(1,049.4)	-0.44%
Pass-through and recoverable costs were higher than forecast	366.1	0.15%
Other variation	100.5	0.04%
Total	**1,926.1**	**0.81%**

4 The Determination does not require us to include a forecast of other regulated income when calculating compliant prices. However, Orion elected to allow for other regulated income when setting prices, so the variation against this forecast contributes to the wash-up amount.

QUALITY STANDARDS AND QUALITY INCENTIVES SUPPORTING INFORMATION

38 The Determination sets out quality standards that assess reliability results against a set of reliability limits set specifically for Orion.

39 To comply, Orion must demonstrate that it has met:

39.1 the planned reliability limits for planned interruptions for the DPP regulatory period;

39.2 the annual unplanned reliability limits for unplanned interruptions for the assessment period; and

39.3 the extreme event standard for the assessment period.

40 Two measures of reliability are assessed:

40.1 SAIDI, or system average interruption duration index, which reflects the average number of minutes a customer is off in a year, and

40.2 SAIFI, or system average interruption frequency index, which reflects the average number of interruptions a customer has in a year.

41 The Determination also sets out quality incentives (rewards and penalties) based on reliability results.

42 The following section describes our policies and procedures for capturing and recording outage information, and this is followed by a summary of the calculation of our reliability results.

Recording reliability information

43 Orion uses “PowerOn” as its network management system. PowerOn is the front-end package that presents Scada data to our network controllers in a sensible format. Information comes into PowerOn via SCADA or our Call Taker application, that logs customer calls relating to disruptions in electricity supply.

44 For planned outages and network faults, our network controllers follow sequential operating orders to carry out switching and configuration changes on the network to bypass affected assets and to facilitate planned or remedial work. At each point during these operating orders PowerOn shows and records the number of connections affected, together with switching points and switching times. Switching is either carried out remotely from the control room via SCADA or by our operators and contractors in the field. Switching information from the field comes into PowerOn via a mobile app (called PEEK).

45 Power is often restored in stages, and PowerOn automatically determines how many customers are affected by each stage and records details separately for each restoration stage. Where successive interruptions occur (including where a group of customers may be turned off to allow another area to be restored) the outage times are recorded separately for each group affected. Successive interruptions are recorded against the same incident when they occur during the restoration period, or are recorded as a separate incident when they occur after the initial incident has been fully restored. Customers who form part of a planned interruption but were not notified are separated out under a different incident and are record as unplanned.

46 PowerOn consists of two major modules, these being the NMS (Network management System) and the OMS (Outage Management System). The NMS manages the work packages and actual operation of equipment (events, alarms, switching, trends, equipment status). The OMS reports the impact of outages (customers affected, duration, causes etc) and allows for SAIDI/SAIFI and web-based external reporting, as well as the creation of notification lists and management of planned outages.

47 The information stored in PowerOn's OMS is used to create an 'Outage statistics' report for unplanned outages and a 'Planned outage statistics' report for planned outages. The information in both reports is used for our end of year disclosure reporting.

48 For each outage the following details are recorded in the outage statistics report:

48.1 interruption type (planned or unplanned, originating on Orion's network or on Transpower's network);

48.2 district substation affected;

48.3 feeder affected;

48.4 asset type affected;

48.5 cause of interruption;

48.6 time/date off for each loss of supply stage;

48.7 time/date for each restoration stage;

48.8 for planned outages, the notification window;

48.9 number of consumers affected in each stage; and

48.10 explanatory notes.

49 Interruptions not originating in our network are also captured in this report. An example of the report can be seen below:

Outage Statistics between 1-Apr-2021 and 9-Apr-2021

Excluding incidents affecting no customers

Run on 31-May-2022

Outage Statistics for Date Range

Date	Incident #	Job #	Type	Stages	Off	On	Mins Off	# Ints	Cust Mins	Planned	Description
01-Apr-21	4	4					114	264	4991		
	INCD-288994-B	F-24706-B	Orion Fault HV		01/04/21 08:31:18	01/04/21 08:43:30	12.2	118	1440	0	Hororata ZS - HK13/23 , CB 112 - Hororata
			Stage No:	1	01/04/21 08:31:18	01/04/21 08:43:30	12.2	118	1440		
	INCD-289003-B	F-25288-B	Orion Fault HV		01/04/21 10:30:51	01/04/21 10:59:19	28.5	51	1196	0	Wrights Rd - SE7/72, ABI
			Stage No:	1	01/04/21 10:34:37	01/04/21 10:55:33	20.9	34	712		
			Stage No:	2	01/04/21 10:30:51	01/04/21 10:59:19	28.5	17	484		

Zone	Voltage	Substation	Feeder	Controller Comments	Tripped Device	Cause Group	Cause Type	Planned Reason	Cause Comments	Work Type	Failed Asset	Failure Mode
Hororata	11kV	Hororata - HK13/23	Unit 112			Defective equipment	Condition Deterioration		ABI HO16/1 cable ties installed	11kV OH Emergency Maint	HV Line	OH Insulator
					Hororata ZS - HK13/23 , CB 112 - Hororata							
Greendale	11kV	Greendale - SE2/66	Unit 111			Defective equipment	Condition Deterioration		ABI SE3/14 cable ties installed	11kV OH Emergency Maint	HV Line	OH Insulator
					Hororata Dunsandel Rd - SE3/58, ABI							
					Wrights Rd - SE7/72, ABI							

50 The planned outage statistics report shows a similar level of detail as the outage statistics report but has additional fields to show that we have carried out correct requirements to receive the planned outage incentive. For example:

Planned Outage Statistics between 29-Mar-2021 and 31-Mar-2021

Run on 31-May-2022

Planned Outage Statistics for Date Range

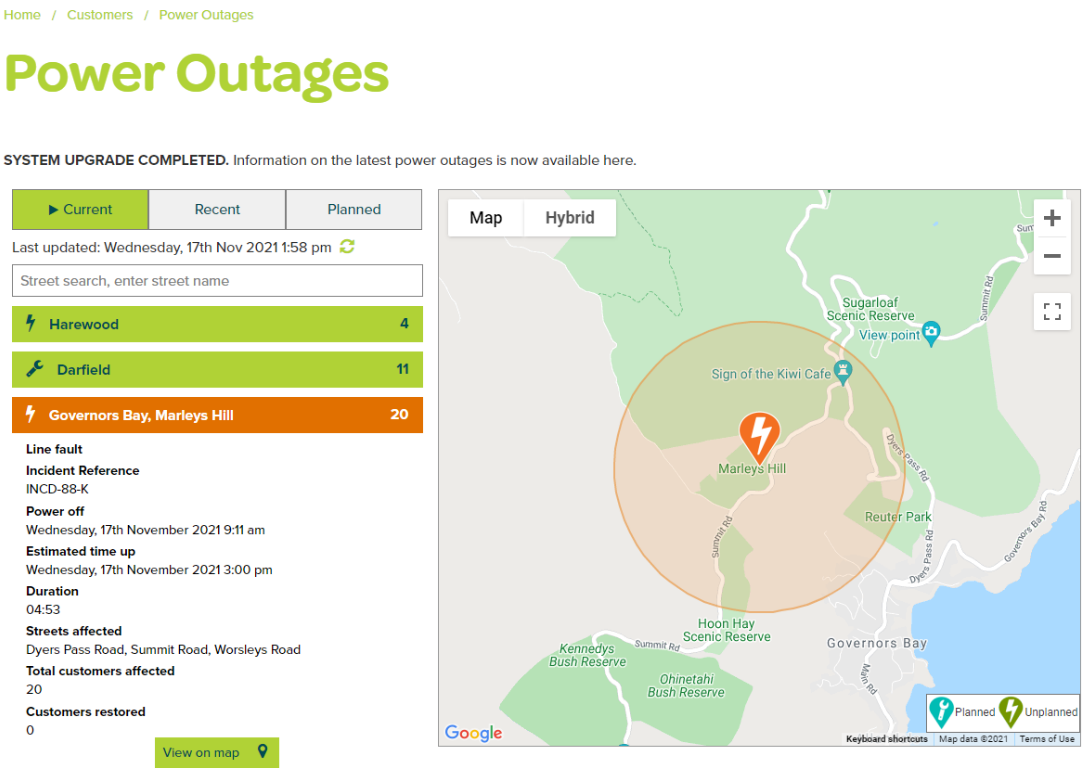
Date	Incident No	Job No	Type	Stages	Opt In	Notification Date	Notification Duration	Alt Day	Alt Date Notified	Cancelled >24hrs	Cancelled <24hrs	Notified Of Cancellation	Notified Off	Notified On
⊟29-Mar-21	1	1												
	⊟INCD-51920-C	J-30668-C	Orion Planned HV											
			Stage No:	1	True	10/03/21	12	False		False	False		29/03/21 08:30:00	29/03/21 14:00:00

Alt Notified Off	Alt Notified On	Actual Off	Actual On	Mins Within Window	Mins Outside Window	Mins Within Alt Window	Mins Outside Alt Window	Alt Notified Mins	Cancelled Mins	Additional Mins (2 hour rule)	# Ints	# Notified	SADIn Raw	SADIn Raw Half
											4			
		29/03/21 08:30:42	29/03/21 13:40:00								4	4	1,240	620
		29/03/21 08:30:42	29/03/21 13:40:00	310	0	0	0	0	0		4	4	1,240	620

SADIb	Pre Deweighted Cust Mins	Cust Mins	⊞Description	Tripped Device	⊞Cause Group	Failure Comments	Report #
		620					
0	1,240	620	Dawsons Rd - R16/16, Transformer Unit T1 - Dawsons Rd - R16/16				FREP-18011-C
0	1,240	620		Maddisons Rd - R16/36, ABI			

51 The results in the outage statistics reports are checked for accuracy by our network control centre, with results reviewed against operating orders. At the end of each month, following checks and validation, a final report for the month is checked by the control centre manager.

52 Planned and unplanned outages are reported on our website providing a live display of outages together with a map showing their location, for example:



53 Finally, to establish our system-average reporting measures, the total number of connected consumers on the network is obtained from our connections database. We maintain details of all our network connections on this database, and we regularly undertake reconciliations with the Electricity Authority Registry.

Planned interruptions quality standard

54 For planned interruptions (called Class B interruptions), the reliability standard is assessed at the end of the 5th assessment period of the DPP regulatory period based on accumulated results. The planned accumulated SAIDI and SAIFI limits set for Orion for the DPP regulatory period are set out in Schedule 3.1 (1) in the Determination as:

Planned accumulated SAIDI limit for the DPP regulatory period	Planned accumulated SAIFI limit for the DPP regulatory period
198.40	0.7481

Planned SAIDI assessed value

55 The assessment of planned SAIDI includes an incentive that de-weights the assessment of planned interruptions where we have met a set of notification obligations, referred to as "notified interruptions" ($SAIDI_N$).

56 $SAIDI_N$ provides the opportunity to de-weight planned outages by halving the minutes where we have met notification and information requirements. The de-weighting does not apply to any proportion of an outage that falls outside the notified window. There is also a penalty applied when outages are more than two hours shorter than the notified window, and when the outages are cancelled with less than 24 hours' notice.

57 The overall planned SAIDI assessed values ($SAIDI_{planned, assessed}$) is the sum of results for these notified interruptions together with the results for other planned interruptions. This is set out in the Determination in schedule 3.1 (2) as:

$$SAIDI_{planned, assessed} = SAIDI_B + \frac{SAIDI_N}{2}$$

Where

$SAIDI_B$ is the sum of:

the SAIDI value for any class B interruptions that are not Class B notified interruptions; and

the SAIDI value attributable to the period of minutes that falls outside the specified notified interruption window or alternate day, for any Class B notified interruptions that have occurred partially or wholly outside their notified interruption window or alternate day.

$SAIDI_N$ is the sum of:

the SAIDI values attributable to any minutes that fall within the specified notified interruption window or alternate day of any Class B notified interruptions, where the SAIDI value is the greater of that calculated based on:

- the duration of minutes accumulated for each ICP; and
- the period of the notified interruption window minus two hours;

the 'intended SAIDI values' of any intended interruptions cancelled without 24 hours' notice, where the intended SAIDI value is the greater of that calculated based on:

- the duration of the minutes accumulated for each ICP which will be nil; and

- the period of the notified interruption window minus two hours; and

the intended SAIDI values of any intended interruption cancelled with at least 24 hours' notice, where the intended SAIDI value for each of those is nil.

58 In situations where we have not met the notification or information requirements for a notified outage, the outage is still included within the calculation of $SAIDI_N$, but we have not applied the de-weighting.

59 The following table sets out individual components that we have included in the calculation of $SAIDI_{planned, assessed}$ for the current assessment period:

Duration of Interruptions

		Contributing Outages	Minutes
Minutes lost attributed to $SAIDI_B$			
(a)	Class B interruptions that are not notified interruptions	514	5,292,141
(b)	The period of minutes that falls outside the specified notified window or alternate day for any Class B notified interruptions	7	3,334
			5,295,475
Minutes lost attributed to $SAIDI_N$			
(a)	Class B notified interruptions fall within the specified notified window or alternate day	10	27,942
	Short duration interruptions (the extend to which the interruption is more than two hours shorter than notified)	2	164
(b)	Intended interruptions cancelled without notice	1	60
(c)	Contribution from intended interruption cancelled with notice	0	Nil
			28,166
Average number of customers (ICPs)			213,669

SAIDI values

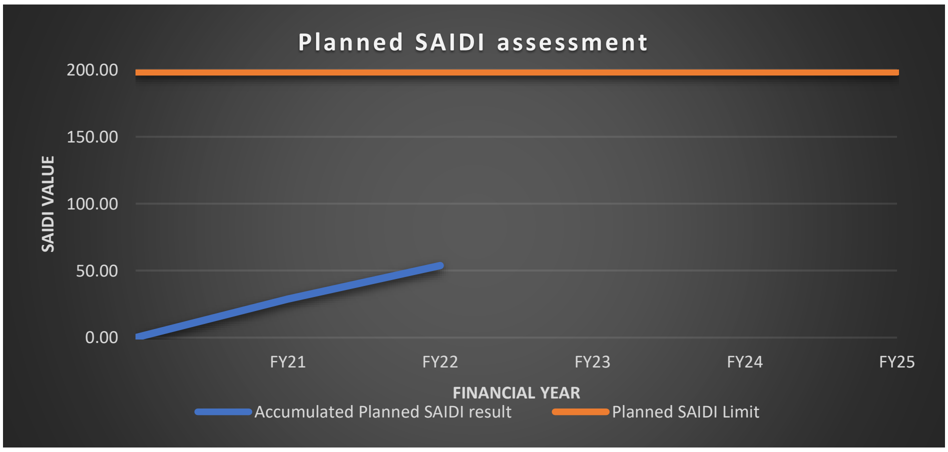
$SAIDI_B$	24.78
$SAIDI_N$ /2	0.13

60 Substituting the above $SAIDI_B$ and $SAIDI_N$ values into the formula for calculating $SAIDI_{planned, assessed}$ gives:

$$\begin{aligned} SAIDI_{planned, assessed} &= SAIDI_B + \frac{SAIDI_N}{2} \\ &= 24.78 + 0.13 \\ &= 24.91 \end{aligned}$$

61 Therefore, the contribution from the current assessment period and accumulated results for the regulatory period is:

	FY22	FY21	Accumulated (2 of 5 years)	Limit (at end of 5 years)
Planned SAIDI	24.91	28.87	53.78	198.40



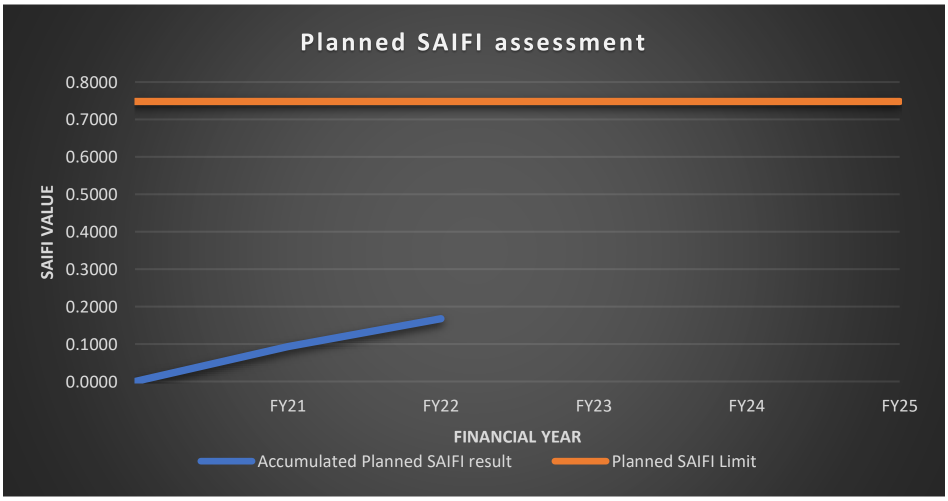
Planned SAIFI assessed value

62 The assessment of planned SAIFI does not include an incentive adjustment. The planned SAIFI assessed value ($SAIFI_{planned, assessed}$) for planned interruptions for each assessment period is simply calculated as the sum of the SAIFI values for Class B interruptions, as follows:

Frequency of Interruption	FY22
Class B interruptions	15,903
Average number of customers	213,669
$SAIFI_{planned, assessed}$	**0.0744**

63 The contribution from the current assessment period and accumulated result for the regulatory period are:

	FY22	FY21	Accumulated (2 of 5 years)	Limit (at end of 5 years)
Planned SAIFI	0.0744	0.0933	0.1678	0.7481



Unplanned interruptions quality standard

64 For unplanned interruptions (called Class C interruptions), the reliability standard is assessed annually for SAIDI and SAIFI. The unplanned SAIDI and SAIFI limits, and SAIDI and SAIFI unplanned boundary values for Orion for each assessment period are set out in schedule 3.2 of the Determination as:

Unplanned SAIDI limit	Unplanned SAIFI limit	SAIDI unplanned boundary value	SAIFI unplanned boundary value
84.71	1.0336	7.60	0.0668

Unplanned SAIDI and SAIFI assessed values

65 The total duration and number of outages for Class C interruptions is accumulated to calculate the unplanned SAIDI and SAIFI indices. The results prior to normalising the data for major events were:

65.1 Duration of interruptions:

	FY22
Unplanned minutes lost (Class C)	11,314,608
Average number of customers	213,669
Unplanned SAIDI	52.95

65.2 Frequency of interruptions:

	FY22
Unplanned outages (Class C)	128,542
Average number of customers	213,669
Unplanned SAIFI	0.6016

Normalising the reliability results for major events

66 The Determination provides for the normalisation of reliability results to mitigate the impact of major events and provide a view of underlying network reliability.

67 The assessment dataset for unplanned interruptions is normalised by adjusting the results for major events. SAIDI and SAIFI major events are triggered independently, and their definitions are given in clause 4.2 of the Determination. For any 24-hour period that starts on the hour or half past the hour:

67.1 a SAIDI major event is triggered when the sum of SAIDI values over that 24-hour period for unplanned interruptions exceeds the SAIDI unplanned boundary value; and

67.2 a SAIFI major event is triggered when the sum of SAIFI values over that 24-hour period for unplanned interruptions exceeds the SAIFI unplanned boundary value.

68 When a SAIDI or SAIFI major event is identified, the raw SAIDI or SAIFI value for each half-hour period within the major event is capped at $1/48^{th}$ of their respective unplanned boundary value.

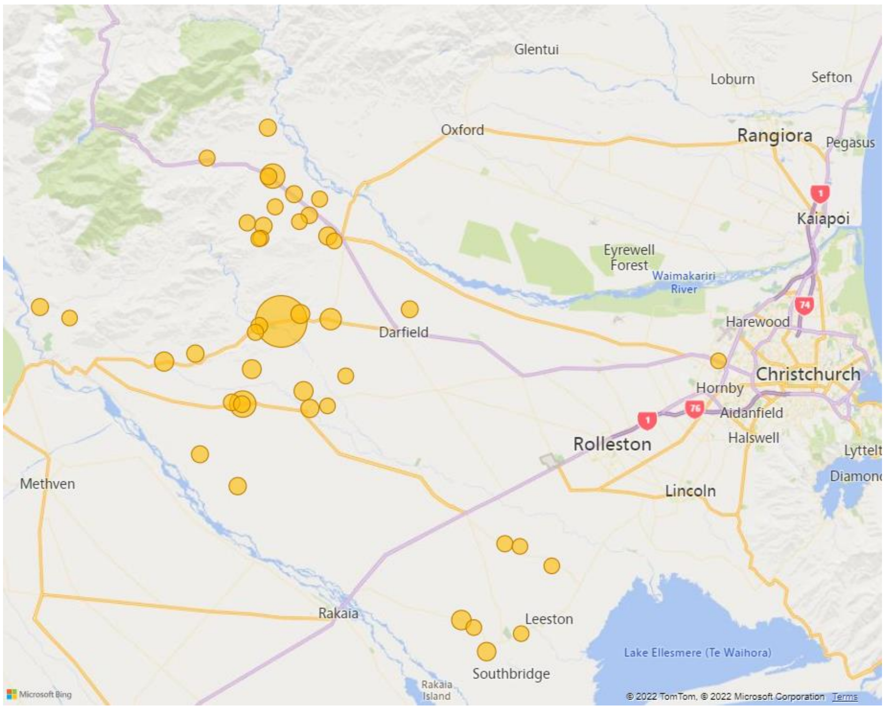
69 For the assessment period, we identified one extended SAIDI major event as a result of a severe windstorm on 10 September 2021. We had no SAIFI major events this year.

70 We defined the SAIDI major event as an "extended major event" as it lasted longer than 24 hours. In accordance to the Commission's final decision reasons paper, the Commission allows major events to last longer than 24 hours as long as the major event criteria is met[5]. The SAIDI major event covers a 46-hour period from 9 September 2021 to 11 September 2021.

71 Below is information relating to the extended SAIDI major event in accordance with clause 11.6(g) of the Determination. Supporting information for normalising the half-hourly SAIDI values during the major event is included in Appendix F.

<table>
<tr><td>Start date and time:</td><td>9/9/2021 05:30 am</td><td>SAIDI value before replacements:</td><td>11.87</td></tr>
<tr><td>End date and time:</td><td>11/9/2021 03:30 am</td><td>Replaced SADI value:</td><td>1.81</td></tr>
<tr><td>Location:</td><td colspan="3">Various locations across Orion's operating zones including Annat, Kimberly, Brookside and Moffett St. Annat, Brookside, Coleridge, Greendale, Hororata, Killinchy, Kimberley, Moffett St operating zone.

Below is a map showing where the interruptions were. Detailed locations are included in Appendix F.


</td></tr>
<tr><td>Main equipment involved:</td><td colspan="3">HV lines across the network</td></tr>
<tr><td>Cause of the event:</td><td colspan="3">Adverse weather - a sustained period of extreme winds brought trees down on our lines and in some cases the damage was extensive.</td></tr>
<tr><td colspan="4">Orion's response:

Severe winds across the South Island caused more than 50 power outages across Orion's network and more than 4,000 customers were without power.</td></tr>
</table>

[5] https://comcom.govt.nz/__data/assets/pdf_file/0020/191810/Default-price-quality-paths-for-electricity-distribution-businesses-from-1-April-2020-Final-decision-Reasons-paper-27-November-2019.PDF, Section K69-K72, p.391

As winds reached dangerous levels, Orion withdrew its field crews from the area. After the high winds receded, and emergency services provided access, Orion despatched around 12 crews to undertake repairs to its damaged lines, working in with emergency services and on-the-ground tree clearing specialists. Co-ordination of crews was undertaken by our subsidiary Connetics' Project Management Office, in conjunction Orion's Control Room and Customer Support teams.

The battery of crews deployed included Orion's own emergency response operators who are on permanent standby to restore service after outages; crews from its subsidiary Connetics and additional contractors' crews who were brought in from other areas to assist. At the height of the repair effort, Orion estimates it had more than 35 crew members assessing the damage and restoring power.

Trees falling on power lines were the main cause of the outages.

Orion took a triage approach to prioritising repairs:

1. Safety issues dealt with first
2. High voltage sub-transmission lines – 33kV
3. Essential services dependent on power – water supplies
4. Townships with a significant number of residents

Mitigation factors that may have prevented or minimised the SAIDI major event, and proposed steps to mitigate the risk of future similar event:

Orion has an extensive tree management programme and regular communications to urban and rural landowners reminding them of their obligations under the tree regulations.

We have a proactive programme in place to trim trees within the corridor stated in the tree regulations. We also consult with landowners with trees that pose a risk to our assets but are outside the trim corridor. We run a two-year cyclic safety line clearance program across our entire high voltage network and a four-year cyclic safety line clearance program across our low voltage urban network.

During the past 12 months we have refocussed our tree management programme on the most problematic areas, and this is expected to further reduce outages from trees in the future.

In addition to our tree management programme, we have instituted projects to replace aging high voltage lines switches with remoted controlled switches which allow us to more quickly isolate affected areas and reduce the number of customers without power. In addition, as part of our ongoing maintenance programme, Orion is upgrading key line assets in areas more vulnerable to power outages, such as Diamond Harbour, to reduce the impact of extremely high winds.

Given the impact of trees on lines, and the lack of clarity and difficulty in enforcing the current regulations, Orion supports MBIE's review of The Electricity (Hazards from Trees) Regulations 2003.

72 Applying the normalisation adjustments to our calculated SAIDI and SAFI results provides a result that is compared to the respective limits, as follows:

72.1 Duration of interruptions:

	FY22
Unplanned SAIDI	52.95
less normalisation adjustments for major events	10.06
SAIDI $_{\text{unplanned, assessed}}$	**42.90**
Annual unplanned SAIDI Limit	84.71
Annual reliability result	Comply

72.2 Frequency of interruptions:

	FY22
Unplanned SAIFI	0.6016
less normalisation adjustments for major events	0.0000
SAIFI $_{\text{unplanned, assessed}}$	**0.6016**
Annual unplanned SAIFI Limit	1.0336
Annual reliability result	Comply

73 This year we have met our compliance obligation for the unplanned interruption reliability assessment with both the unplanned SAIDI and SAIFI assessed values below their respective annual limits.

Extreme event quality standard

74 The extreme event standard limits for unplanned interruptions (excluding any unplanned interruption that is the result of major external factors) for the DPP regulatory period are set out in schedule 3.3 of the Determination. They are:

74.1 a SAIDI value of 120 minutes, whereby the extreme event standard limit will be exceeded if, during any period of 24 hours (starting on the hour or half past the hour), the SAIDI value of all unplanned interruptions that start during that 24-hour period, in aggregate, is above 120 minutes; and

74.2 a total of six million customer interruption minutes, whereby the extreme event standard limit will be exceeded if, during any period of 24 hours (starting on the hour or half past the hour), the total duration of customer interruption minutes resulting from all unplanned interruptions that start during that 24-hour period, in aggregate, is more than six million customer interruption minutes.

75 This year we have complied with the extreme event standards as we have not had any 24-hour period that exceeded the above limits for unplanned interruptions.

Quality incentive adjustment

76 The Determination sets out a quality incentive adjustment based on reliability results and a specific approach for calculating the adjustment is given in Schedule 4 of the Determination.

77 Calculation of this revenue-linked quality incentive is applied to unplanned and planned SAIDI only, SAIFI is excluded. It is also capped at 2% of the actual net allowable revenue.

78 The first step is to calculate the lessor of:

78.1 $\left(SAIDI_{unplanned,\ target} - SAIDI_{unplanned,\ assessed}\right) \times IR +$

$\left(SAIDI_{planned,\ target} - SAIDI_{planned,\ assessed}\right) \times 0.5 \times IR$; and

78.2 $0.02 \times ANAR$

where

$SAIDI_{unplanned,\ target}$ is the SAIDI unplanned interruption target set for Orion in schedule 4 of the Determination;

$SAIDI_{unplanned,\ assessed}$ is the SAIDI unplanned assessed value calculated in accordance with schedule 3.2 of the Determination, and when it is greater than the SAIDI unplanned interruption cap set for Orion in schedule 4 of the Determination, it equals to the SAIDI unplanned interruption cap;

$SAIDI_{planned,\ target}$ is the SAIDI planned interruption target set for Orion in schedule 4 of the Determination;

$SAIDI_{planned,\ assessed}$ is the SAIDI planned assessed value calculated in accordance with schedule 3.1 of the Determination, and when it is greater than the SAIDI planned interruption cap set for Orion in schedule 4 of the Determination, it equals to the SAIDI planned interruption cap;

IR is the incentive rate set for Orion in schedule 4 of the Determination; and

ANAR is the actual net allowable revenue for the assessment period which is calculated in clause 20 as $166,895.2k.

79 The second step is to adjust the calculated amount from above for the time-value for money by multiplying with the following formula:

$(1 + \text{67th percentile estimate of post-tax WACC})^2$

where

67th percentile estimate of post-tax WACC is 4.23% as defined in clause 4.2 of the Determination.

80 The following table outlines the unplanned and planned SAIDI collars, targets, caps and the incentive rate set for Orion in schedule 4 of the Determination:

	Value
SAIDI unplanned interruption collar (SAIDI $_{\text{unplanned, collar}}$)	0
SAIDI unplanned interruption target (SAIDI $_{\text{unplanned, target}}$)	66.47
SAIDI unplanned interruption cap (SAIDI $_{\text{unplanned, cap}}$)	84.71
SAIDI planned interruption collar (SAIDI $_{\text{planned, collar}}$)	0
SAIDI planned interruption target (SAIDI $_{\text{planned, target}}$)	13.23
SAIDI planned interruption cap (SAIDI $_{\text{planned, cap}}$)	39.68
Incentive Rate (IR)	$31,686

81 The SAIDI unplanned and planned assessed value calculated in accordance to schedule 3.2 and schedule 3.1 of the Determination are:

	Calculated	Capped
SAIDI unplanned assessed value (SAIDI $_{\text{unplanned, assessed}}$)	42.90	42.90
SAIDI planned assessed value (SAIDI $_{\text{planned, assessed}}$)	24.91	24.91

82 Substituting these values into the formulas gives:

82.1 $\left(\text{SAIDI}_{\text{unplanned, target}} - \text{SAIDI}_{\text{unplanned, assessed}}\right) \times \text{IR} +$

$\left(\text{SAIDI}_{\text{planned, target}} - \text{SAIDI}_{\text{planned, assessed}}\right) \times 0.5 \times \text{IR}$

$= (66.47 - 42.90) \times \$31{,}686 + (13.23 - 24.91) \times 0.5 \times \$31{,}686$

$= \$561{,}750$

and

82.2 $0.02 \times \text{ANAR}$

$= 0.02 \times \$166{,}895.2\text{k}$

$= \$3{,}337.9\text{k}$

82.3 The lessor of the above calculated amounts is $561,750, therefore the quality incentive adjustment is:

$\$561{,}750 \times (1 + 4.23\%)^2$

$= \$610{,}279$

TRANSACTIONS

83 Clause 10.1 of the Determination requires us to notify the Commission of any amalgamation, merger, major transaction or transfer.

84 Clause 10.2 of the Determination requires us to adjust the forecast net allowable revenue and wash-up amount, SAIDI and SAIFI limits, boundary values, caps and targets, and incentive rate following a transfer of consumers.

85 Orion has not been involved in any amalgamation, merger, major transaction or transfer during the assessment period. Therefore, there were no adjustments made to the measures mentioned above.

APPENDIX A – DELIVERY AND EXPORT PRICE SCHEDULES

Electricity delivery price schedule for Orion NZ Ltd

(applicable from 1 April 2021)

This schedule lists the wholesale prices that Orion uses to charge electricity retailers and directly contracted customers for the electricity delivery service in Orion's network area. This delivery service includes the transmission and distribution of electricity to homes and businesses, but does not include the cost of the electricity itself. Please refer to your electricity retailer for details of retail electricity prices.

All prices exclude GST	Price Category Code[3]	Price Component Code[3]	Delivery Price	Unit of measure
Streetlighting connections	LIG			
Fixed charge		STFXD	0.0954	$/con/day
Peak charge (peak period demand)		GENPK	0.3995	$/kW/day
Volume charge				
Weekdays (Mon to Fri, 7am to 9pm)		VOLWD	0.06755	$/kWh
Nights & weekends (Sat & Sun)		VOLNW	0.01844	$/kWh
General connections	GEN			
Fixed charge		GENFXD	0.1500	$/con/day
Peak charge (peak period demand)		GENPK	0.3995	$/kW/day
Volume charge				
Weekdays (Mon to Fri, 7am to 9pm)		VOLWD	0.06755	$/kWh
Nights & weekends (Sat & Sun)		VOLNW	0.01844	$/kWh
Low power factor charge		LOWPF	0.2000	$/kVAr/day
Irrigation connections	IRR			
Capacity charge		ICCAP	0.4383	$/kW/day*
Volume charge				
Weekdays (Mon to Fri, 7am to 9pm)		VOLWD	0.06755	$/kWh
Nights & weekends (Sat & Sun)		VOLNW	0.01844	$/kWh
Rebates				
Power factor correction rebate		ICPFC	(0.1618)	$/kVAr/day*
Interruptibility rebate		ICIRR	(0.0405)	$/kW/day*
* applied from 1 October to 31 March only				
Major customer and embedded network connections	MCC			
Fixed charge		MCFXD	10.0000	$/con/day
Fixed charge (additional connections)		MCFXDA	5.0000	$/con/day
Extra switches		EQESW	3.3300	$/switch/day
11kV Metering equipment		EQMET	4.3400	$/con/day
11kV Underground cabling		EQUGC	3.4000	$/km/day
11kV Overhead lines		EQOHL	2.1400	$/km/day
Transformer capacity		EQTFC	0.0119	$/kVA/day
Peak charge (control period demand)		MCCPD	0.3757	$/kVA/day
Nominated maximum demand		MCNMD	0.1034	$/kVA/day
Metered maximum demand		MCMMD	0.0769	$/kVA/day
Large capacity connections	LCC			
Individually assessed prices advised and charged directly to the customers				
Miscellaneous				
Monthly invoice and contract charge to retailers and directly contracted customers		INVFXD	30.00	$/invoice
Failure to pay notice		INVFTP	50.00	$/notice
Default and termination notice		INVDAT	100.00	$/notice

Notes

1. Full details on how we apply these prices are included in our *Pricing Policy* document, available on our website.
2. Peak and volume prices for streetlighting, general connections and irrigation connections are applied to peak loadings and volumes derived from measurements taken at grid exit points, and it is appropriate to allow for normal network losses when assessing the contribution individual connections make to these charges. All other prices in this schedule are applied against measurements or ratings taken at the connection.
3. The applicable price category code is recorded against each connection ICP on the Electricity Authority's registry, and the price component code is used in our mandatory 'electricity information exchange protocol' files.

Export credit schedule for Orion NZ Ltd

(applicable from 1 April 2021)

This schedule lists the credit prices that we use to credit electricity retailers or directly contracted customers for exports or contributions from their distributed generation. The credits do not represent the purchase of electricity. They are a recognition of the value to Orion in providing its delivery service. Credits are only available for generation approved by Orion and customers must apply in advance.

For exporting generators that were in place prior to 6 December 2016 and approved by the Electricity Authority an additional credit reflecting any actual savings in Transpower charges is available (at the date of issue of this schedule, no exporting generators have been approved by the Electricity Authority). In addition to applying for our distribution credit, exporting customers can approach Transpower (for example, under Transpower's demand response program) for recognition of any transmission benefit, and approach their electricity retailer for recognition of the value of energy exported.

Export credits are based on electricity exported only during specific time periods. Our prices for credits are:

(excluding GST)

Generator rated output	Period applied	Credit prices	Price Component Code[3]	Unit of measure
0 - 30kW generation[2]				
Anytime credits (without PV), or	Anytime	0.00290	EXPA	$/kWh
Anytime credits (with PV)	(24 hours, 7 days)	0.00010	EXPAPV	$/kWh
0 - 30kW generation[2]				
Peak period credits (with or without PV)	Chargeable peak period	0.20560	EXPPP	$/kWh
30 - 750kW Control period credits[4]				
- real power, plus	Chargeable control period	0.0704	EXPCP1	$/kW/day
- reactive power[5]		0.0231	EXPCP2	$/kVAr/day
above 750kW	*Individually assessed prices provided on application*			

Notes for export credit pricing

1. Full details, including metering requirements and how credit prices are applied, are available in our *Export Credits Policy* document available on our website.
2. Small 0 to 30kW generators may elect (in advance) to receive the alternative peak period based credits, subject to the installation of appropriate metering to record peak period export.
3. The price component code is used in our mandatory 'electricity information exchange protocol' files.
4. Control period credits are assessed during control periods and applied as an annual credit at 365/366 times the daily credit price.
5. The credit quantity for reactive power (kVAr) export is limited to 33% of the credit quantity for real power (kW) export in each half hour period, the equivalent of exporting with a 0.95 lagging power factor.
6. Approximately 11 connections are approved for export credits.

APPENDIX B – FORECAST REVENUE FROM PRICES WORKSHEET

	FY2022 Delivery Prices		FY2022 Forecast Quantities	Days applicable	Price x Quantity
Streetlighting, general and irrigation connections					($000)
Streetlighting fixed charge	0.0954	$/con/day	51,113 cons	365 days	1,779.8
General fixed charge	0.1500	$/con/day	208,311 cons	365 days	11,405.0
Streetlighting and general connections	0.3995	$/kW/day	470,219 kW	365 days	68,566.2
Peak charge (peak period demand)					
Streetlighting, general and irrigation connections volume charge					
Weekdays (Mon to Fri, 7am - 9pm)	0.06755	$/kWh	1,140,636 MWh		77,050.0
Nights & weekends (Sat & Sun)	0.01844	$/kWh	1,304,258 MWh		24,050.5
General connections					
Low power factor charge	0.2000	$/kVAr/day	0 kVAr	365 days	-
Irrigation connections					
Capacity charge	0.4383	$/kW/day	76,469 kW	182 days	6,100.0
Power factor correction rebate	(0.1618)	$/kVAr/day	23,778 kVAr	182 days	(700.2)
Interruptibility rebate	(0.0405)	$/kW/day	49,266 kW	182 days	(363.1)
Major customer connections and embedded networks					
Fixed charge	10.0000	$/con/day	409.0 cons	365 days	1,492.9
Fixed charge (additional connections)	5.0000	$/con/day	94.0 cons	365 days	171.6
Extra switches	3.3300	$/switch/day	108.0 switches	365 days	131.3
11k Metering equipment	4.3400	$/con/day	41.0 cons	365 days	64.9
11kV Underground cabling	3.4000	$/km/day	7.3 km	365 days	9.1
11kV Overhead lines	2.1400	$/km/day	3.0 km	365 days	2.3
Transformer capacity	0.0119	$/kVA/day	351,424.0 kVA	365 days	1,526.4
Peak charge (control period demand)	0.3757	$/kVA/day	111,579.0 kVA	365 days	15,300.9
Nominated maximum demand	0.1034	$/kVA/day	276,387.0 kVA	365 days	10,431.1
Metered maximum demand	0.0769	$/kVA/day	231,578.0 kVA	365 days	6,500.0
Large capacity connections					
Distribution services					
Asset charge (dedicated assets)	11.280	$/kVA/year	19,000.0 kVA		214.3
Asset charge (dedicated assets)	14.290	$/kVA/year	16,000.0 kVA		228.6
Asset charge (shared assets)	26.440	$/kVA/year	18,500.0 kVA		489.1
Asset charge (shared assets)	24.690	$/kVA/year	13,300.0 kVA		328.4
Operations, maintenance & administration (dedicated assets)	10.630	$/kVA/year	19,000.0 kVA		202.0
Operations, maintenance & administration (dedicated assets)	6.130	$/kVA/year	16,000.0 kVA		98.1
Operations, maintenance & administration (shared assets)	23.290	$/kVA/year	18,500.0 kVA		430.9
Operations, maintenance & administration (shared assets)	10.600	$/kVA/year	13,300.0 kVA		141.0
Transmission services					
Connection charge	4.840	$/kVA/year	15,730.0 kVA		76.1
Connection charge	1.450	$/kVA/year	11,130.0 kVA		16.1
Customer investment contract charge	12.020	$/kVA/year	16,000.0 kVA		192.3
Interconnection charge (summer)	48.900	$/kVA/year	15,730.0 kVA		769.2
Interconnection charge (summer)	47.740	$/kVA/year	11,130.0 kVA		531.3
Interconnection charge (winter)	57.750	$/kVA/year	4,610.0 kVA		266.2
Interconnection charge (winter)	56.390	$/kVA/year	1,820.0 kVA		102.6
Export credits					
Real power component	(0.0704)	$/kW/day	449.6 kW	365 days	(11.6)
Reactive power component	(0.0231)	$/kVAr/day	117.5 kVAr	365 days	(1.0)
Miscellaneous					
Monthly invoice charge	30.00	$/invoice	432 invoices		13.0
Failure to pay notice	50.00	$/notice	12 invoices		0.6
Default and termination notice	100.00	$/notice	3 invoices		0.3
Forecast Revenue from Prices $_{FY2022}$					**227,606.3**

APPENDIX C – ACTUAL REVENUE FROM PRICES WORKSHEET

	FY2022 Delivery prices		FY2022 Actual quantities	Days applicable	Price x quantity
Streetlighting, general and irrigation connections					($000)
Streetlighting fixed charge	0.0954	$/con/day	51,736 cons	365 days	1,801.5
General fixed charge	0.1500	$/con/day	209,685 cons	365 days	11,480.3
Streetlighting and general connections	0.3995	$/kW/day	494,124 kW	365 days	72,051.9
Peak charge (peak period demand)					
Streetlighting, general and irrigation connections volume charge					
Weekdays (Mon to Fri, 7am - 9pm)	0.06755	$/kWh	1,150,338 MWh		77,705.3
Nights & weekends (Sat & Sun)	0.01844	$/kWh	1,291,249 MWh		23,810.6
General connections					
Low power factor charge	0.2000	$/kVAr/day	0 kVAr	365 days	-
Irrigation connections					
Capacity charge	0.4383	$/kW/day	76,375 kW	182 days	6,092.5
Power factor correction rebate	(0.1618)	$/kVAr/day	23,657 kVAr	182 days	(696.6)
Interruptibility rebate	(0.0405)	$/kW/day	48,232 kW	182 days	(355.5)
Major customer connections and embedded networks					
Fixed charge	10.0000	$/con/day	403.4 cons	365 days	1,472.3
Fixed charge (additional connections)	5.0000	$/con/day	101.3 cons	365 days	184.8
Extra switches	3.3300	$/switch/day	109.0 switches	365 days	132.5
11k Metering equipment	4.3400	$/con/day	45.2 cons	365 days	71.5
11kV Underground cabling	3.4000	$/km/day	7.3 km	365 days	9.1
11kV Overhead lines	2.1400	$/km/day	3.0 km	365 days	2.3
Transformer capacity	0.0119	$/kVA/day	344,067.5 kVA	365 days	1,494.5
Peak charge (control period demand)	0.3757	$/kVA/day	107,704.5 kVA	365 days	14,769.6
Nominated maximum demand	0.1034	$/kVA/day	270,240.2 kVA	365 days	10,199.1
Metered maximum demand	0.0769	$/kVA/day	227,807.4 kVA	365 days	6,394.2
Large capacity connections					
Distribution services					
Asset charge (dedicated assets)	11.280	$/kVA/year	19,000.0 kVA	365 days	214.3
Asset charge (dedicated assets)	14.290	$/kVA/year	16,000.0 kVA	365 days	228.6
Asset charge (shared assets)	26.440	$/kVA/year	18,500.0 kVA	365 days	489.1
Asset charge (shared assets)	24.690	$/kVA/year	13,300.0 kVA	365 days	328.4
Operations, maintenance & administration (dedicated assets)	10.630	$/kVA/year	19,000.0 kVA	365 days	202.0
Operations, maintenance & administration (dedicated assets)	6.130	$/kVA/year	16,000.0 kVA	365 days	98.1
Operations, maintenance & administration (shared assets)	23.290	$/kVA/year	18,500.0 kVA	365 days	430.9
Operations, maintenance & administration (shared assets)	10.600	$/kVA/year	13,300.0 kVA	365 days	141.0
Transmission services					
Connection charge	4.840	$/kVA/year	10,461.1 kVA	365 days	50.6
Connection charge	1.450	$/kVA/year	10,400.3 kVA	365 days	15.1
Customer investment contract charge	12.020	$/kVA/year	16,000.0 kVA	365 days	192.3
Interconnection charge (summer)	48.900	$/kVA/year	10,461.1 kVA	365 days	511.5
Interconnection charge (summer)	47.740	$/kVA/year	10,400.3 kVA	365 days	496.5
Interconnection charge (winter)	57.750	$/kVA/year	4,386.6 kVA	365 days	253.3
Interconnection charge (winter)	56.390	$/kVA/year	2,271.0 kVA	365 days	128.1
Export credits					
Real power component	(0.0704)	$/kW/day	380.9 kW	365 days	(9.8)
Reactive power component	(0.0231)	$/kVAr/day	75.0 kVAr	365 days	(0.6)
Miscellaneous					
Monthly invoice charge	30.00	$/invoice	471 invoices		14.1
Failure to pay notice	50.00	$/notice	1 invoices		0.1
Default and termination notice	100.00	$/notice	0 invoices		-
Actual Revenue from Prices $_{FY2022}$					**230,403.6**

APPENDIX D – CALCULATION OF INCREMENTAL ROLLING INCENTIVE

Orion default price path FY2022

Opex IRIS assessment

		CPP regulatory period					6 year period following CPP					
Financial year		FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25
Regulatory year		1	2	3	4	5	1	1	2	3	4	5
Disclosure year ending		31-Mar-15	31-Mar-16	31-Mar-17	31-Mar-18	31-Mar-19	31-Mar-20	31-Mar-21	31-Mar-22	31-Mar-23	31-Mar-24	31-Mar-25
Assessment Period		1st	2nd	3rd	4th	5th	1st	1st	2nd	3rd	4th	5th
CPIQ1		975	979	1000	1011	1026	1052	1068	1142	1192	1222	1246
CPIQ2		979	983	1000	1015	1032	1047	1082	1158	1198	1226	1249
CPIQ3		982	986	1005	1024	1039	1054	1106	1175	1210	1236	1261
CPIQ4		977	990	1006	1025	1044	1059	1122	1184	1214	1240	1265
Inflation rate			0.64%	1.85%	1.60%	1.62%	1.71%	3.94%	6.40%	3.37%	2.27%	1.98%
									RBNZ Forecast ->			2% Forecast ->
Opex subject to IRIS												
Allowed opex (CPP Determination schedule 7)	$000	54,908.5	58,104.3	57,926.1	57,997.4	58,854.0	NA					
Actual disclosed Opex		50,828.0	55,679.0	55,736.0	54,207.0	59,678.0						
Difference	$000	4,080.5	2,425.3	2,190.1	3,790.4	(824.0)						
Incremental change	$000	4,080.5	(1,655.3)	(235.2)	1,600.3	0.0						
Incremental adjustment term							(4,693.5)					
Incremental gains/(losses) carried forward												
Year 1	$000		4,106.6	4,182.7	4,249.5	4,318.3	4,392.3					
2	$000			(1,685.9)	(1,712.8)	(1,740.6)	(1,770.4)	(1,840.2)				
3	$000				(238.9)	(242.8)	(246.9)	(256.7)	(273.1)			
4	$000					1,626.2	1,654.1	1,719.3	1,829.3	1,890.8		
5	$000						0.0	0.0	0.0	0.0	0.0	
6	$000							(4,878.5)	(5,190.5)	(5,365.3)	(5,487.3)	(5,595.6)
Net balance							4,029.1	(5,256.1)	(3,634.4)	(3,474.4)	(5,487.3)	(5,595.6)
IRIS amount - Net balances treated as Recoverable cost							4,029.1	0.0	0.0	0.0	0.0	0.0

APPENDIX F – SAIDI MAJOR EVENT NORMALISATION

Supporting information for normalising the half-hourly SAIDI values for the extended SAIDI major event that took place during the assessment period:

SAIDI Unplanned Boundary	**7.60**
1/48th of the SAIDI Boundary value	**0.16**

Start date and time:	9/9/2021 05:30 am	**SAIDI value before replacements:**	11.87
End date and time:	11/9/2021 03:30 am	**Replaced SADI value:**	1.81
No. of half-hours:	92	**Normalisation:**	10.06

Date and time (half-hour ending)	SAIDI Raw (half-hour)	SAIDI Sum (rolling 24-hour)	SAIDI Major Event	SAIDI assessed value (half-hour)		Interruption locations
9/09/2021 06:00	**0.00**	10.42	Y	-		
9/09/2021 06:30	**0.00**	10.89	Y	-		
9/09/2021 07:00	**0.00**	11.03	Y	-		
9/09/2021 07:30	**0.00**	11.39	Y	-		
9/09/2021 08:00	**0.00**	11.41	Y	**0.00**		Gillanders Road
9/09/2021 08:30	**0.00**	11.40	Y	-		
9/09/2021 09:00	**0.00**	11.40	Y	-		
9/09/2021 09:30	**0.00**	11.40	Y	**0.00**		Newtons Road
9/09/2021 10:00	**0.00**	11.40	Y	-		
9/09/2021 10:30	**0.00**	11.41	Y	-		
9/09/2021 11:00	**0.00**	11.41	Y	-		
9/09/2021 11:30	**0.00**	11.41	Y	-		
9/09/2021 12:00	**0.00**	11.41	Y	-		
9/09/2021 12:30	**0.00**	11.47	Y	-		
9/09/2021 13:00	**0.00**	11.48	Y	-		
9/09/2021 13:30	**0.00**	11.48	Y	-		
9/09/2021 14:00	**0.00**	11.49	Y	-		
9/09/2021 14:30	**0.00**	11.49	Y	-		
9/09/2021 15:00	**0.00**	11.49	Y	-		
9/09/2021 15:30	**0.00**	11.49	Y	-		
9/09/2021 16:00	**0.00**	11.49	Y	-		
9/09/2021 16:30	**0.00**	11.51	Y	-		
9/09/2021 17:00	**0.00**	11.51	Y	-		
9/09/2021 17:30	**0.00**	11.51	Y	-		
9/09/2021 18:00	**0.00**	11.51	Y	-		
9/09/2021 18:30	**0.00**	11.51	Y	-		
9/09/2021 19:00	**0.00**	11.52	Y	-		
9/09/2021 19:30	**0.00**	11.52	Y	-		
9/09/2021 20:00	**0.00**	11.52	Y	-		
9/09/2021 20:30	**0.00**	11.52	Y	-		
9/09/2021 21:00	**0.11**	11.53	Y	**0.11**		Coleridge
9/09/2021 21:30	**0.00**	11.42	Y	-		
9/09/2021 22:00	**0.00**	11.42	Y	-		
9/09/2021 22:30	**0.00**	11.42	Y	-		
9/09/2021 23:00	**0.00**	11.42	Y	-		
9/09/2021 23:30	**0.00**	11.42	Y	-		
10/09/2021 00:00	**0.00**	11.58	Y	-		
10/09/2021 00:30	**0.00**	11.58	Y	-		
10/09/2021 01:00	**0.00**	11.58	Y	-		
10/09/2021 01:30	**0.00**	11.76	Y	-		
10/09/2021 02:00	**0.00**	11.76	Y	-		
10/09/2021 02:30	**0.94**	11.76	Y	**0.16**	Normalised	Rockwood Rd Coleridge Rd Leaches Rd
10/09/2021 03:00	**0.00**	10.82	Y	-		
10/09/2021 03:30	**0.79**	10.82	Y	**0.16**	Normalised	North Rakaia Rd Rakaia Terrace Rd W Coleridge Sharlands Rd East Rakaia Terrace Rd
10/09/2021 04:00	**2.91**	10.02	Y	**0.16**	Normalised	Main Rakaia Rd Leaches Rd

Date and time (half-hour ending)	SAIDI Raw (half-hour)	SAIDI Sum (rolling 24-hour)	SAIDI Major Event	SAIDI assessed value (half-hour)		Interruption locations
						Downs Rd Windwhistle Rd Springfield West Coast Rd Kowai Rd
10/09/2021 04:30	**0.00**	7.11	Y	-		
10/09/2021 05:00	**0.80**	7.11	Y	**0.16**	Normalised	Hororata Annat ZS Malvern Hills Rd Barrs Rd Bluff Rd
10/09/2021 05:30	**4.86**	6.31	Y	**0.16**	Normalised	Hartnells Rd Leaches Road Malvern Hills Rd Pig Saddle Rd Coaltrack Rd Wairiri Rd Clintons Rd
10/09/2021 06:00	**0.47**	1.45	Y	**0.16**	Normalised	Pig Saddle Rd Russells Flat Wyndale Rd Fergusons Rd
10/09/2021 06:30	**0.14**	0.98	Y	**0.14**		Homebush Rd Kimberley Road
10/09/2021 07:00	**0.37**	0.84	Y	**0.16**	Normalised	Clintons Rd Substation Rd Bankside ZS
10/09/2021 07:30	**0.01**	0.47	Y	**0.01**		Hanmer Road Yaldhurst Road
10/09/2021 08:00	**0.00**	0.46	Y	-		
10/09/2021 08:30	**0.00**	0.47	Y	-		
10/09/2021 09:00	**0.00**	0.50	Y	-		
10/09/2021 09:30	**0.00**	0.50	Y	-		
10/09/2021 10:00	**0.01**	0.50	Y	**0.01**		Watsons Road
10/09/2021 10:30	**0.00**	0.49	Y	-		
10/09/2021 11:00	**0.00**	0.49	Y	**0.00**		Clintons Rd
10/09/2021 11:30	**0.00**	0.49	Y	-		
10/09/2021 12:00	**0.06**	0.49	Y	**0.06**		Sandersons Road
10/09/2021 12:30	**0.00**	0.43	Y	**0.00**		Haldon Road
10/09/2021 13:00	**0.00**	0.42	Y	**0.00**		Clintons Rd
10/09/2021 13:30	**0.01**	0.43	Y	**0.01**		Bealey Rd East
10/09/2021 14:00	**0.00**	0.42	Y	-		
10/09/2021 14:30	**0.00**	0.42	Y	-		
10/09/2021 15:00	**0.00**	0.42	Y	-		
10/09/2021 15:30	**0.00**	0.42	Y	-		
10/09/2021 16:00	**0.02**	0.42	Y	**0.02**		Leaches Road
10/09/2021 16:30	**0.00**	0.40	Y	-		
10/09/2021 17:00	**0.00**	0.41	Y	-		
10/09/2021 17:30	**0.00**	0.41	Y	-		
10/09/2021 18:00	**0.00**	0.41	Y	-		
10/09/2021 18:30	**0.00**	0.41	Y	**0.00**		Feredays Rd
10/09/2021 19:00	**0.00**	0.41	Y	-		
10/09/2021 19:30	**0.00**	0.41	Y	-		
10/09/2021 20:00	**0.00**	0.41	Y	**0.00**		Leaches Rd
10/09/2021 20:30	**0.01**	0.41	Y	**0.01**		Mclaughlins Rd
10/09/2021 21:00	**0.00**	0.40	Y	-		
10/09/2021 21:30	**0.00**	0.40	Y	-		
10/09/2021 22:00	**0.00**	0.40	Y	-		
10/09/2021 22:30	**0.00**	0.40	Y	**0.00**		Russells Flat
10/09/2021 23:00	**0.00**	0.40	Y	-		
10/09/2021 23:30	**0.16**	0.40	Y	**0.16**	Normalised	Clintons Rd
11/09/2021 00:00	**0.00**	0.24	Y	-		
11/09/2021 00:30	**0.00**	0.24	Y	-		
11/09/2021 01:00	**0.17**	0.24	Y	**0.16**	Normalised	Hartnells Rd Leaches Road Downs Rd Hororata

Date and time (half-hour ending)	SAIDI Raw (half-hour)	SAIDI Sum (rolling 24-hour)	SAIDI Major Event	SAIDI assessed value (half-hour)	Interruption locations
					Clintons Rd
11/09/2021 01:30	**0.00**	0.06	Y	-	
11/09/2021 02:00	**0.00**	0.06	Y	-	
11/09/2021 02:30	**0.00**	0.06	Y	-	
11/09/2021 03:00	**0.00**	0.06	Y	-	
11/09/2021 03:30	**0.00**	0.06	Y	-	
Total	**11.87**			**1.81**	

DIRECTORS' CERTIFICATE FOR ANNUAL COMPLIANCE STATEMENT

We, Paul Jason Munro and Michael Earl Sang, being directors of Orion New Zealand Ltd certify that, having made all reasonable enquiry, to the best of our knowledge and belief, the attached annual compliance statement of Orion New Zealand Limited, and related information, prepared for the purposes of the *Electricity Distribution Services Default Price-Quality Path Determination 2020* has been prepared in accordance with all the relevant requirements.

Paul Jason Munro

Michael Earl Sang

30 August 2022

Independent Assurance Report

To the Directors of Orion New Zealand Limited on the Annual Compliance Statement for the assessment period ended 31 March 2022 as required by the Electricity Distribution Services Default Price-Quality Path Determination 2020 (consolidated 20 May 2020)

The Auditor-General is the auditor of Orion New Zealand Limited (the Company). The Auditor-General has appointed me, John Mackey, using the staff and resources of Audit New Zealand, to undertake a reasonable assurance engagement, on his behalf, on whether the Annual Compliance Statement on pages 3 to 22 for the assessment period ended on 31 March 2022 has been prepared, in all material respects, in compliance with the Electricity Distribution Services Default Price-Quality Path Determination 2020 (consolidated 20 May 2020) (the Determination).

Opinion

In our opinion, in all material respects:

- as far as appears from our examination, the information used in the preparation of the Annual Compliance Statement has been properly extracted from the Company's accounting and other records, sourced from its financial and non-financial systems; and
- the Company has complied with clauses 11.5 and 11.6 of the Determination in preparing the Annual Compliance Statement for the assessment period ended 31 March 2022.

Basis for opinion

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

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

Directors' responsibilities

The Directors of the Company are responsible for the:

- preparation of the Annual Compliance Statement under clause 11.4 and in accordance with the requirements in clauses 11.5 and 11.6 of the Determination; and

- identification of risks that may threaten compliance with the clauses identified above and controls which will mitigate those risks and monitor ongoing compliance.

Auditor's responsibilities

Our responsibilities in terms of clause 11.5(e) and schedule 8(1)(b)(vi) and 8(1)(c) of the Determination, are to express an opinion on whether:

- as far as appears from our examination, the information used in the preparation of the Annual Compliance Statement has been properly extracted from the Company's accounting and other records, sourced from its financial and non-financial systems; and
- the Annual Compliance Statement, for the assessment period ended 31 March 2022, has been prepared, in all material respects, in accordance with the requirements in clauses 11.5 and 11.6 of the Determination.

To meet these responsibilities, we planned and performed procedures in accordance with SAE 3100 (Revised), to obtain reasonable assurance about whether the Company has complied, in all material respects, with clauses 11.5 and 11.6 of the Determination.

In relation to the wash-up amount set out in clause 8.6 of the Determination, our procedures included recalculation of the wash-up amount in accordance with schedule 1.6 of the Determination and assessing it against the amounts and disclosures contained on pages 6 to 10 of the Annual Compliance Statement.

In relation to the quality standards in clause 9 of the Determination, our procedures included examination, on a test basis, of evidence relevant to the values and disclosures contained on pages 11 to 20 of the Annual Compliance Statement.

In relation to the quality incentive adjustment set out in schedule 4 of the Determination, our procedures included recalculation of the quality incentive adjustment in accordance with schedule 4 of the Determination and assessing it against the amounts and disclosures contained on pages 21 to 22 of the Annual Compliance Statement.

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

Inherent limitations

Because of the inherent limitations of an assurance engagement, together with the internal control structure, it is possible that fraud, error or non-compliance with clauses 11.5 and 11.6 of the Determination may occur and not be detected. A reasonable assurance engagement throughout the assessment period does not provide assurance on whether compliance with clauses 11.5 and 11.6 of the Determination will continue in the future.

Restricted use

This report has been prepared for use by the Directors of the Company and the Commerce Commission in accordance with clause 11.5 (e) of the Determination and is provided solely for the purpose of establishing whether the compliance requirements have been met. We disclaim any assumption of responsibility for any reliance on this report to any person other than the Directors of the Company and the Commerce Commission, or for any other purpose than that for which it was prepared.

Independence and quality control

We complied with the Auditor-General's:

- independence and other ethical requirements, which incorporate the independence and ethical requirements of Professional and Ethical Standard 1 issued by the New Zealand Auditing and Assurance Standards Board; and
- quality control requirements, which incorporate the quality control requirements of Professional and Ethical Standard 3 (Amended) issued by the New Zealand Auditing and Assurance Standards Board.

The Auditor-General, and his employees, and Audit New Zealand and its employees may deal with the Company on normal terms within the ordinary course of trading activities of the Company. Other than any dealings on normal terms within the ordinary course of trading activities of the Company, this engagement, the assurance engagement on the Information Disclosures and the annual audit of the Company's financial statements and performance information, we have no relationship with, or interests in, the Company.

John Mackey
Audit New Zealand
On behalf of the Auditor-General
Christchurch, New Zealand
30 August 2022