Orion New Zealand Limited

Electricity Distribution Services
Default Price-Quality Path Determination 2015

Annual Compliance statement

For the year ending 31 March 2020

Issued 18 June 2020

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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 200,000 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 36% 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 In 2013, to recognise the impact of the Canterbury earthquakes on our costs and supply quality, Orion applied for a customised price-quality path. In response, and after wider consultation, the Commerce Commission issued a customised price path determination (the CPP determination) that applied to Orion for the five year period from 1 April 2014 to 31 March 2019.

5 Following the period covered by the CPP determination, Orion returned to the default price path (the DPP determination) applying to the wider group of distribution businesses. The DPP determination applied for a 5 year regulatory period ending on 31 March 2020.

6 This statement has been prepared to demonstrate our compliance, or otherwise, with the requirements in the final year of the regulatory period covered by the DPP determination. Specifically, this compliance statement covers the information requirements detailed in clause 11 of the DPP determination for the year ended 31 March 2020.

COMPLIANCE STATEMENTS

Price path statement

7 This year we **complied with** the price path set out in clause 8 of the DPP determination, with notional revenue falling $50.9k below our allowable notional revenue of $167,602.6k.

Quality standard statement

8 This year we **complied with** the quality standards set out in clause 9 of the DPP determination. The DPP determination requires that we must either comply with the reliability assessment in the current assessment period, or have complied with the reliability assessment in each of the two preceding assessment periods, and we have complied on the basis of the first of these two assessments.

9 Our prior reliability results were:

9.1 Duration of interruptions (SAIDI):

	FY20	FY19	FY18
SAIDI result	67.26	73.96	79.05
SAIDI limit	73.40	73.40	82.40
	Comply	Exceeded	Comply

9.2 Frequency of interruptions (SAIFI):

	FY20	FY19	FY18
SAIFI result	0.66	0.79	1.00
SAIFI limit	0.87	0.87	1.02
	Comply	Comply	Comply

Price structure statement

10 We restructured aspects of our pricing during the assessment period. With effect from 1 April 2019, we further adjusted the minimum elective range for moving up to the major customer category from 200kVA to 150kVA, and we managed the transition of a group of connections that benefitted from a change in category.

11 As a result, several of our chargeable quantities that are referenced from two years prior do not relate to our current prices. In respect of affected connections, based on observed and measured metrics, we have deducted the contribution made to the general connection category chargeable quantities from two years prior, and instead added the amount these connections would have made to the major customer category chargeable quantities had they been in that category two years prior.

12 This approach is consistent with our approach in previous compliance statements, and is additional to the adjustments established in last year's compliance statement. That is, there are now two price restructures accommodated within the application of the two-year lagged quantities.

Transfer of assets with Transpower

13 During the assessment period we have not received a transfer of transmission assets from Transpower, nor transferred system fixed assets to Transpower. The DPP determination requires that we state all transfers of this type - prior to the assessment period we have received transmission assets via purchase or partial purchase of assets at grid exit points (and associated high voltage lines) as follows:

Description of assets acquired	**Date purchased**	**Amount paid** ($000)
Papanui grid exit point assets and 66kV supply lines	1/8/2012	4,238.1
Springston grid exit point assets and 66kV supply lines	31/3/2014	5,201.2
Bromley grid exit point assets (partial purchase)	1/4/2014	8,726.6
Addington and Middleton grid exit point assets and 66kV supply lines	1/4/2015	8,983.2
Hororata and Islington grid exit point assets (partial purchase)	3/4/2018	524.7
Total		**27,673.8**

Transaction statements

14 During the assessment period, we:

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

14.2 have not been involved in a Major Transaction.

15 This statement was certified by directors of Orion New Zealand Ltd on 18 June 2020.

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

PRICE PATH SUPPORTING INFORMATION

17 Clause 8.3 of the DPP determination requires that notional revenue (*NR*) must not exceed allowable notional revenue (*ANR*) for the assessment period, as expressed by the following condition:

$$NR \leq ANR$$

Notional revenue

18 Using the definitions provided in clause 8.5, notional revenue is evaluated as:

$$NR = \sum_{i} DP_{i,t} Q_{i,t-2}$$

where *t* denotes the year in which the assessment period ends, that is 2020;

i denotes each Distribution Price;

DPi,t is the i[th] Distribution Price during any part of the Assessment Period; and

Qi,t-2 is the Quantity for the Assessment Period ending two years prior corresponding to the i^{th} Distribution Price.

19 The distribution price is the portion of our total delivery price excluding the parts relating to pass-through and recoverable costs. These individual elements of our price are derived in our published pricing methodology and the schedule showing each part from that methodology is included in appendix A of this compliance statement.

20 This expression is evaluated as $167,551.7k in the worksheet on page 10 titled notional revenue worksheet.

Allowable notional revenue

21 Allowable notional revenue is defined in clause 8.4 and schedule 3B of the DPP determination (using a specific approach for Orion) as:

$$ANR_{2020} = E \times \left(\sum_{i} P_{i,2019} Q_{i,2018} - (K_{2019} + V_{2019}) + (ANR_{2019} - NR_{2019}) \right)$$

$$\times (1 + \Delta CPI_{2020})(1 - X)$$

where *i* denotes each Distribution Price;

E is the 2014-2019 clawback exclusion ratio determined for Orion and specified in the DPP determination as

$E = \frac{638.3-34.8}{638.3}$ = 0.94548

$\sum_i P_{i,2019} Q_{i,2018}$ is the sum of each (i[th]) price during any part of the assessment period ending in 2019, multiplied by the corresponding quantity for 2018. This expression is evaluated as $256,772.5k in the worksheet on page 11 titled *prior notional revenue worksheet*,

$K_{2019} + V_{2019}$ is the sum of all pass-through and recoverable costs for the assessment period ending in 2019. This was evaluated as $5,015.3k and

$77,174.3k respectively in our previous Customised Price Path Compliance Statement. The components making up these amounts are also shown alongside the current year's figures in the tables on page 12 and 13 of this compliance statement,

$ANR_{2019} - NR_{2019}$ is the difference between allowable notional revenue and notional revenue for the assessment period ending in 2019. This was evaluated as $18.2k in our previous Customised Price Path Compliance Statement,

ΔCPI_{2020} is the derived change in CPI to be applied for the current assessment period:

$$= \frac{CPI_{Dec,2017}+CPI_{Mar,2018}+CPI_{Jun,2018}+CPI_{Sep,2018}}{CPI_{Dec,2016}+CPI_{Mar,2017}+CPI_{Jun,2017}+CPI_{Sep,2017}} - 1$$

$$= \frac{1006+1011+1015+1024}{990+1000+1000+1005} - 1$$

$$= 1.527\%$$

1-X is the rate of change specified in schedule 2 of the DPP determination as 0% (ie 1-X = 1)

22 For the purpose of this calculation, Price is the total delivery price (inclusive of pass through and recoverable costs). These prices are provided in our published pricing schedule and included in Appendix A of this compliance statement.

$$\therefore ANR_{2020} = 0.94548 \times (\$256{,}772.5\text{k} - \$5{,}015.3\text{k} - \$77{,}174.3\text{k} + \$18.2\text{k})(1.01527)(1)$$

$$= \$167{,}602.6\text{k}$$

23 Substituting the values calculated above in the price path condition gives:

$$NR \leq ANR$$

$$\$167{,}551.7\text{k} \leq \$167{,}602.6\text{k}$$

24 Our notional revenue is $50.9k less than our allowable notional revenue and, as the condition is satisfied, we comply with the price requirement specified in clause 8.3 of the DPP determination.

Restructuring of prices

25 We restructured an aspect of our prices from the start of the assessment period, on 1 April 19. While not a major change, the new prices are not directly aligned with the quantities that were applied two years ago, and referenced for use in the calculation of notional revenue.

26 The restructuring represents the second step in one of two changes that were introduced a year earlier. On 1 April 2018 we widened the elective range where customers could choose which pricing category applied and we pro-actively shifted customers that would benefit from that election. On 1 April 2019 we applied the planned second step of that change, extending the eligibility range further, and proactively shifting the second tranche of customers that benefit from the change.

27 To establish both allowable notional revenue and comparable notional revenue for the purpose of the compliance test it is necessary to establish chargeable quantities for the new structure at a level equivalent to that which would have applied had the new structure been in place in FY18:

27.1 For the allowable notional revenue calculation (which is based on prices applying in FY19), this entails making an adjustment in respect of the 1 April 2018 changes.

27.2 For the notional revenue calculation (based on prices applying in FY20) this entails making an adjustment in respect of both the 1 April 2018 and 1 April 2019 changes.

28 To calculate the chargeable quantities we established the connections that would have been recategorised if we had applied the same criteria in FY18, identifying 35 connections that would have been recategorised as a result of the 1 April 2018 changes, and 47 connections that would have been recategorised as a result of the 1 April 2019 changes.

29 In all cases the new price structure uses chargeable quantity metrics that were already used in charging, or are available to be measured. So quantities that reasonably relate to the new restructured prices are easily quantified.

30 The following table sets out each new restructured price, the basis for establishing the quantity, and the quantity itself.

Restructure	Description of change	Basis for quantity
Applied a minimum 300 kVA metered maximum demand	From 1 April 2018 for major customers we applied a minimum 300kVA chargeable metered maximum demand (prior to this no minimum had applied). This has the effect of increasing our revenue and an adjustment to our base quantities is needed to capture this in the calculation of notional revenue.	For the notional revenue calculation we recalculated our FY18 chargeable quantities to include the application of the minimum 300kVA charge
Adjusted the criteria for categorisation as a major customer	From 1 April 2018 we adjusted the minimum elective range for moving to the major customer category from 250kVA to 200kVA), and we proactively shifted connections that clearly benefited. From 1 April 2019 we further adjusted the minimum elective range for moving to the major customer category from 200kVA to 150kVA), and we proactively	For each customer notionally shifted, we established their contribution to FY18 general connection quantities and deducted this from our notional revenue and allowable notional revenue calculations (as appropriate). We then established what their FY18 quantities would have been had they been in the major customer category, and added these to our base quantities for the notional revenue calculation.

	shifted connections that clearly benefited.

31 The combined impact of the restructuring resulted in the following adjustments to the FY18 quantities used in our calculations:

	FY18 quantity adjustment for allowable notional revenue and notional revenue	**Additional FY18 quantity adjustment for notional revenue**
Relevant restructuring	**1 April 2018 changes**	**1 April 2019 changes**
Deduction from general connection quantities		
Fixed charge	-35.0 cons	-47.0 cons
Peak charge (peak period demand)	-4,956.3 kW	-5,111.9 kW
Weekdays volume charge (Mon to Fri, 7am - 9pm)	-16,980 MWh	-17,876 MWh
Nights & weekends volume charge (Sat & Sun)	-15,745 MWh	-17,549 MWh
Addition to major customer quantities		
Fixed charge	+35.00 cons	+47.00 cons
Extra switches	+1.00 switches	
11kV Underground cabling	+0.90 km	
Transformer capacity	+20,150.00 kVA	+18,100.00 kVA
Peak charge (control period demand)	+5,055.26 kVA	+5,096.81 kVA
Nominated maximum demand	+9,527.90 kVA	+13,860.37 kVA
Metered maximum demand	+13,005.22 kVA	+13,860.37 kVA

Notional revenue worksheet

$$\sum_i DP_{i,t}Q_{i,t-2}$$

Components (i)	FY2020 Distribution Prices		FY2018 Quantities (adjusted for restructure 1 & 2)	Days applicable	Price x Quantity
Days in quantity year				365	
Streetlighting, general and irrigation connections					($000)
Streetlighting fixed charge	0.1084	$/con/day	47,884.7 cons	365 days	1,894.6
General fixed charge	0.0523	$/con/day	194,351.0 cons	365 days	3,710.1
Streetlighting and general connections Peak charge (peak period demand)	0.2842	$/kW/day	471,425 kW	365 days	48,902.3
Streetlighting, general and irrigation connections volume charge					
Weekdays (Mon to Fri, 7am - 9pm)	0.06042	$/kWh	1,106,503 MWh		66,854.9
Nights & weekends (Sat & Sun)	0.01501	$/kWh	1,267,770 MWh		19,029.2
General connections					
Low power factor charge	0.1500	$/kVAr/day	0 kVAr	365 days	-
Irrigation connections					
Capacity charge	0.3671	$/kW/day	76,140 kW	182 days	5,087.1
Power factor correction rebate	(0.1755)	$/kVAr/day	24,831 kVAr	182 days	(793.1)
Interruptibility rebate	(0.0439)	$/kW/day	47,457 kW	182 days	(379.2)
Major customer connections and embedded networks					
Fixed charge	10.0000	$/con/day	464.70 cons	365 days	1,696.2
Extra switches	3.6700	$/switch/day	110.40 switches	365 days	147.9
11k Metering equipment	4.4500	$/con/day	52.10 cons	365 days	84.6
11kV Underground cabling	3.2900	$/km/day	5.10 km	365 days	6.1
11kV Overhead lines	2.0700	$/km/day	3.20 km	365 days	2.4
Transformer capacity	0.0138	$/kVA/day	302,624.70 kVA	365 days	1,524.3
Peak charge (control period demand)	0.2641	$/kVA/day	109,174.37 kVA	365 days	10,525.5
Nominated maximum demand	0.0916	$/kVA/day	238,858.17 kVA	365 days	7,986.0
Metered maximum demand	0.0000	$/kVA/day	220,643.29 kVA	365 days	-
Large capacity connections					
Customer 1]					
Distribution services					
Ops, maint & admin (dedicated assets)	7.909	$/kVA/year	12,000.0 kVA	365 days	94.9
Ops, maint & admin (shared assets)	21.588	$/kVA/year	9,655.3 kVA	365 days	208.4
Asset charge (dedicated assets)	9.298	$/kVA/year	12,000.0 kVA	365 days	111.6
Asset charge (shared assets)	27.933	$/kVA/year	9,655.3 kVA	365 days	269.7
Customer 2					
Distribution services					
Ops, maint & admin (dedicated assets)	6.081	$/kVA/year	13,000.0 kVA	365 days	79.1
Ops, maint & admin (shared assets)	9.842	$/kVA/year	11,908.8 kVA	365 days	117.2
Asset charge (dedicated assets)	13.305	$/kVA/year	13,000.0 kVA	365 days	173.0
Asset charge (shared assets)	22.069	$/kVA/year	11,908.8 kVA	365 days	262.8
Export and generation credits					
Real power component	(0.0897)	$/kW/day	1,567.0 kW	365 days	(51.3)
Reactive power component	(0.0295)	$/kVAr/day	292.2 kVAr	365 days	(3.1)
Generation credits	0.0000	$/kWh	83,158 kWh		-
Miscellaneous					
Monthly invoice charge	30.00	$/invoice	356.00 inv/yr		10.7
Failure to pay notice	50.00	$/notice	0.00 notices		-
Default and termination notice	100.00	$/notice	0.00 notices		-
Total Notional Revenue (NR_{2020})					**167,551.7**

Notes:

1. The irrigation capacity charge and rebates are applied from 1 October to 31 March only.
2. All prices and charges exclude GST.

Prior notional revenue worksheet

$$ANR_{2020} = E \times \left(\sum_i P_{i,2019}\, Q_{i,2018} - (K_{2019} + V_{2019}) + (ANR_{2019} - NR_{2019}) \right) \times (1 + \Delta CPI_{2020}) \times (1 - X)$$

Components (i)	FY2019 Delivery Prices		FY2018 Quantities (adjusted for restructure 1)	Days applicable	Price x Quantity
Days in quantity year				365	
Streetlighting, general and irrigation connections					($000)
Streetlighting fixed charge	0.1211	$/con/day	47,884.7 cons	365 days	2,116.6
General fixed charge	0.0000	$/con/day	194,398.0 cons	365 days	-
Streetlighting and general connections Peak charge (peak period demand)	0.5181	$/kW/day	476,536 kW	365 days	90,116.1
Streetlighting, general and irrigation connections volume charge					
Weekdays (Mon to Fri, 7am - 9pm)	0.09316	$/kWh	1,124,379 MWh		104,747.1
Nights & weekends (Sat & Sun)	0.01193	$/kWh	1,285,319 MWh		15,333.9
General connections Low power factor charge	0.2000	$/kVAr/day	0 kVAr	365 days	-
Irrigation connections					
Capacity charge	0.4350	$/kW/day	76,140 kW	182 days	6,028.0
Power factor correction rebate	(0.1793)	$/kVAr/day	24,831 kVAr	182 days	(810.3)
Interruptibility rebate	(0.0448)	$/kW/day	47,457 kW	182 days	(386.9)
Major customer connections and embedded networks					
Fixed charge	7.5000	$/con/day	417.70 cons	365 days	1,143.5
Extra switches	3.6100	$/switch/day	110.40 switches	365 days	145.5
11k Metering equipment	4.3700	$/con/day	52.10 cons	365 days	83.1
11kV Underground cabling	3.2300	$/km/day	5.10 km	365 days	6.0
11kV Overhead lines	2.0300	$/km/day	3.20 km	365 days	2.4
Transformer capacity	0.0135	$/kVA/day	284,524.70 kVA	365 days	1,402.0
Peak charge (control period demand)	0.4730	$/kVA/day	104,077.56 kVA	365 days	17,968.5
Nominated maximum demand	0.1102	$/kVA/day	224,997.80 kVA	365 days	9,050.1
Metered maximum demand	0.0862	$/kVA/day	206,782.92 kVA	365 days	6,506.0
Large capacity connections					
Customer 1					
Distribution services					
Ops, maint & admin (dedicated assets)	5.51	$/kVA/year	12,000.0 kVA	365 days	66.1
Ops, maint & admin (shared assets)	21.75	$/kVA/year	9,655.3 kVA	365 days	210.0
Asset charge (dedicated assets)	7.97	$/kVA/year	12,000.0 kVA	365 days	95.6
Asset charge (shared assets)	32.78	$/kVA/year	9,655.3 kVA	365 days	316.5
Transmission services					
Interconnection charge (winter)	69.60	$/kVA/year	2,733.0 kVA	365 days	190.2
Interconnection charge (summer)	55.74	$/kVA/year	8,072.1 kVA	365 days	449.9
Connection charge	6.99	$/kVA/year	8,072.1 kVA	365 days	56.4
Customer 2					
Distribution services					
Ops, maint & admin (dedicated assets)	5.90	$/kVA/year	13,000.0 kVA	365 days	76.7
Ops, maint & admin (shared assets)	10.10	$/kVA/year	11,908.8 kVA	365 days	120.3
Asset charge (dedicated assets)	13.71	$/kVA/year	13,000.0 kVA	365 days	178.2
Asset charge (shared assets)	23.47	$/kVA/year	11,908.8 kVA	365 days	279.5
Transmission services					
Interconnection charge (winter)	67.92	$/kVA/year	1,346.2 kVA	365 days	91.4
Interconnection charge (summer)	54.39	$/kVA/year	9,782.8 kVA	365 days	532.1
Connection charge	1.59	$/kVA/year	9,782.8 kVA	365 days	15.6
Customer investment contract charge	54.46	$/kVA/year	13,000.0 kVA	365 days	708.0
Export and generation (distribution part only)					
Real power component	(0.0844)	$/kW/day	1,567.0 kW	365 days	(48.3)
Reactive power component	(0.0277)	$/kVAr/day	292.2 kVAr	365 days	(3.0)
Generation credits	(0.30)	$/kWh	83,158 kWh		(24.9)
Miscellaneous					
Monthly invoice charge	30.00	$/invoice	356.00 inv/yr		10.7
Failure to pay notice	0.00	$/notice	0.00 notices		-
Default and termination notice	0.00	$/notice	0.00 notices		-
Total prior notional revenue					**256,772.5**

Notes:

1. The irrigation capacity charge and rebates are applied from 1 October to 31 March only.
2. All prices and charges are shown GST exclusive.

Pass through costs and recoverable costs

32 Pass through costs and recoverable costs are specifically recognised in the DPP determination so that changes in the amounts can be directly reflected in prices, and to allow any under or over recovery to be carried forward using a pass through account balance.

33 Recoverable costs include transmission charges (including charges payable to Transpower and avoided transmission charges), system operator charges and regulatory incentives. Prior to FY20 it also included costs associated with payments to embedded generators for support that reduced transmission costs. From FY20 the Electricity Authority prevented us from recognising this savings, and this cost reduced to nil.

34 The following table of recoverable costs shows the recoverable cost amounts for the assessment period, the amounts we forecast for the assessment period when setting prices, and actual amounts for the prior period:

Recoverable costs	IM reference[1]	**FY20 actual** $000	**FY20 forecast** $000	**FY19 actual** $000
Transpower and System Operator charges				
Connection	3.1.3(1)(b)	4,452.4	4,452.4	4,331.3
Interconnection	3.1.3(1)(b)	52,705.7	52,705.7	65,836.0
New investment	3.1.3(1)(c)	2,052.9	2,052.9	2,209.7
System Operator charges	3.1.3(1)(d)	nil	nil	nil
		59,211.0	59,211.0	72,377.0
Avoided transmission charges				
Addington/Middleton connection charges avoided (fourth assessment period following the assessment period in which the purchase occurred)	3.1.3(1)(e)	2,779.3	2,958.3	2,941.7
Bromley connection charges avoided (fifth assessment period following the assessment period in which the purchase occurred)	3.1.3(1)(e)	986.9	nil	985.2
Hororata and Islington charges avoided (first assessment period following the assessment period in which the purchase occurred)	3.1.3(1)(e)	304.0	304.0	308.2
		4,070.3	3,262.3	4,235.1
Transmission part of distributed generation payments				
Export credits	3.1.3(1)(f)	nil	nil	106.9
Generation credits	3.1.3(1)(f)	nil	nil	15.4
		nil	nil	122.3

[1] Clause reference to the Electricity Distribution Services Input Methodologies Determination 2012 [2012] NZCC 26

CPP costs[2]				
CPP application fee	3.1.3(1)(h)	N/A	N/A	5.0
CPP assessment fee	3.1.3(1)(i)	N/A	N/A	317.8
CPP verifier fee	3.1.3(1)(j)	N/A	N/A	51.5
CPP auditor's fee	3.1.3(1)(k)	N/A	N/A	61.7
CPP engineer's fee	3.1.3(1)(l)	N/A	N/A	3.9
		N/A	N/A	439.9
Regulatory incentives				
Incremental rolling incentive scheme allowance (in relation to operational expenditure – see appendix B)	3.1.3(1)(a) & 3.3.2(2)	4,032.9	4,034.1	N/A
Quality Incentive Adjustment (this is specified as nil for Orion[3])	1.1.4(2)[4]	Nil	Nil	N/A
Total recoverable costs		**67,314.1**	**66,507.4**	**77,174.3**

35 Pass-through costs include rates payable to territorial local authorities, Electricity Authority levies, Commerce Act levies and Utilities Disputes scheme charges.

36 The following table of pass through costs shows the pass through amounts for the assessment period, the amounts we forecast for the assessment period when setting prices, and actual amounts for the prior period:

Pass through costs	IM reference[5]	**FY20 actual** $000	**FY20 forecast** $000	**FY19 actual** $000
Local authority rates	3.1.2(2)(a)	4,111.7	3,994.0	3,894.9
Commerce Commission levies	3.1.2(2)(b)(i)	515.9	520.0	422.9
Electricity Authority levies	3.1.2(2)(b)(ii)	565.8	600.0	588.1
Utilities Disputes charges	3.1.2(2)(b)(iii)	112.8	110.0	109.4
Total pass through costs		**5,306.2**	**5,224.0**	**5,015.3**

37 Clause 11.4(i) of the DPP determination requires that we provide the amount of pass-through costs that were used to set pass-through prices. The FY20 forecast amounts in the recoverable costs and pass through costs tables above were the amounts used for this purpose, as shown in our published pricing methodology.

2 CPP costs were recognised as a recoverable cost under Orion's customised price path, and these amounts are taken from our FY19 compliance statement.

3 Schedule 5B of the DPP determination sets out the calculation of the quality incentive adjustment and clauses 6(b) and 8(b) specify that in relation to Orion for FY20 the revenue at risk is nil, and therefore the adjustment is nil.

4 This term does not appear to be defined in the version of the Input Methodologies that is referenced by the DPP determination (version NZCC 26), however it is defined in more recent versions.

5 Clause reference to the Electricity Distribution Services Input Methodologies Determination 2012 NZCC 26

Variances from forecasts

38 Clause 11.4(j) of the DPP determination requires that we provide an explanation as to the cause of any differences between the amounts used to set pass-through prices and the actual amounts. Such variances 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.

39 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 FY20, and provides an explanation of each variance.

Cost category	**Variance**		**Explanation**
	$000	%	
Avoided transmission charges	808.0	+24.7%	When setting prices the amounts were calculated using the prior method for this purpose, and this was subsequently updated to the method required in the DPP determination
Local authority rates	117.7	+2.9%	Normal variation from the amount forecast
Electricity Authority levies	-34.2	-5.7%	Normal variation from the amount forecast
Utilities Disputes charges	2.8	+2.5%	Normal variation from the amount forecast

Recovery of pass-through costs

40 Pass through costs are recovered via the application of pass-through prices which form a part of our overall delivery prices. The parts of the total price relating to pass through costs are derived and stated in our published pricing methodology for FY20. The resulting schedule of prices from this methodology is included in appendix A to this compliance statement, showing pass through prices.

41 The following table provides the information required in Clause 11.4(f) of the DPP determination, showing the actual chargeable quantities for FY20, the units of measure associated with numeric data, the pass through prices and the calculation of pass through revenue.

Pass through Revenue (PTR)

$\sum_i PTP_{i,t}Q_{i,t}$

Components (i)	FY2020 Pass Through Prices: Transmission Price	FY2020 Pass Through Prices: Incentives and Recoveries Price	FY2020 Pass Through Prices: Rates and Levies Price	Units	FY2020 Actual Quantities (as at 21 April 2020)	Days applicable	FY2020 Actual Pass Through Revenue: Transmission Revenue	FY2020 Actual Pass Through Revenue: Incentives and Recoveries Revenue	FY2020 Actual Pass Through Revenue: Rates and Levies Revenue	Total Forecast Pass Through Revenue
Days in price/quantity year						366 days	($000)	($000)	($000)	**($000)**
Streetlighting, general and irrigation connections										
Streetlighting fixed charge	(0.0038)	0.0038	0.0049	$/con/day	49,470.2 cons	366 days	(68.8)	68.8	88.7	**88.7**
General fixed charge	0.0000	0.0426	0.0551	$/con/day	201,017.4 cons	366 days	-	3,134.2	4,053.8	**7,188.0**
Streetlighting and general connections										
Peak charge (peak period demand)	0.1450	0.0000	0.0000	$/kW/day	471,158 kW	366 days	25,004.4	-	-	**25,004.4**
Streetlighting, general and irrigation connections volume charge										
Weekdays (Mon to Fri, 7am - 9pm)	0.01517	0.00000	0.00000	$/kWh	1,136,591 MWh		17,242.1	-	-	**17,242.1**
Nights & weekends (Sat & Sun)	0.00297	0.00000	0.00000	$/kWh	1,316,909 MWh		3,911.2	-	-	**3,911.2**
General connections										
Low power factor charge	0.0500	0.0000	0.0000	$/kVAr/day	0 kVAr	366 days	-	-	-	-
Irrigation connections										
Capacity charge	0.0630	0.0172	0.0223	$/kW/day	77,139 kW	183 days	889.3	242.8	314.8	**1,446.9**
Power factor correction rebate	0.0000	0.0000	0.0000	$/kVAr/day	25,429 kVAr	183 days	-	-	-	-
Interruptibility rebate	0.0000	0.0000	0.0000	$/kW/day	49,885 kW	183 days	-	-	-	-
Major customer connections and embedded networks										
Fixed charge	0.0000	0.0000	0.0000	$/con/day	485.85 cons	366 days	-	-	-	-
Extra switches	0.0000	0.0000	0.0000	$/switch/day	103.29 switches	366 days	-	-	-	-
11k Metering equipment	0.0000	0.0000	0.0000	$/con/day	41.91 cons	366 days	-	-	-	-
11kV Underground cabling	0.0000	0.0000	0.0000	$/km/day	7.30 km	366 days	-	-	-	-
11kV Overhead lines	0.0000	0.0000	0.0000	$/km/day	3.00 km	366 days	-	-	-	-
Transformer capacity	0.0000	0.0000	0.0000	$/kVA/day	327,781.36 kVA	366 days	-	-	-	-
Peak charge (control period demand)	0.1507	0.0000	0.0000	$/kVA/day	108,144.63 kVA	366 days	5,964.8	-	-	**5,964.8**
Nominated maximum demand	0.0090	0.0056	0.0073	$/kVA/day	258,547.44 kVA	366 days	851.7	529.9	690.8	**2,072.4**
Metered maximum demand	0.0713	0.0000	0.0000	$/kVA/day	227,302.74 kVA	366 days	5,931.6	-	-	**5,931.6**
Large capacity connections										
Distribution services										
Ops, maint & admin (dedicated assets)	0.000	0.441	0.000	$/kVA/year	19,000.0 kVA		-	8.4	-	**8.4**
Ops, maint & admin (shared assets)	0.000	1.202	0.000	$/kVA/year	18,400.0 kVA		-	22.1	-	**22.1**
Asset charge (dedicated assets)	0.000	0.000	0.582	$/kVA/year	19,000.0 kVA		-	-	11.1	**11.1**
Asset charge (shared assets)	0.000	0.000	1.587	$/kVA/year	18,400.0 kVA		-	-	29.2	**29.2**
Ops, maint & admin (dedicated assets)	0.000	0.339	0.000	$/kVA/year	16,000.0 kVA		-	5.4	-	**5.4**
Ops, maint & admin (shared assets)	0.000	0.548	0.000	$/kVA/year	14,270.0 kVA		-	7.8	-	**7.8**
Asset charge (dedicated assets)	0.000	0.000	0.645	$/kVA/year	16,000.0 kVA		-	-	10.3	**10.3**
Asset charge (shared assets)	0.000	0.000	0.501	$/kVA/year	14,270.0 kVA		-	-	7.1	**7.1**
Transmission services										
Interconnection charge (winter)	54.290	0.000	0.000	$/kVA/year	6,044.7 kVA		328.2	-	-	**328.2**
Interconnection charge (summer)	44.840	0.000	0.000	$/kVA/year	10,541.2 kVA		472.7	-	-	**472.7**
Connection charge	5.600	0.000	0.000	$/kVA/year	10,541.2 kVA		59.0	-	-	**59.0**
Interconnection charge (winter)	52.980	0.000	0.000	$/kVA/year	1,601.9 kVA		84.9	-	-	**84.9**
Interconnection charge (summer)	43.800	0.000	0.000	$/kVA/year	11,078.2 kVA		485.2	-	-	**485.2**
Connection charge	1.290	0.000	0.000	$/kVA/year	11,078.2 kVA		14.3	-	-	**14.3**
Customer investment contract charge	52.430	0.000	0.000	$/kVA/year	16,000.0 kVA		838.9	-	-	**838.9**
Pass through Revenue (PTR_{2020})							**62,009.5**	**4,019.4**	**5,205.9**	**71,234.8**

42 Clause 11.4(f) of the DPP determination also requires pass through prices and quantities for the preceding assessment period. Orion did not set separate pass through prices for the prior assessment period because the CPP determination that applied to Orion during that assessment period did not have a separate assessment.

Pass through Balance

43 Clauses 11.4(f) and (k) of the DPP determination require a calculation of the Pass-through balance and a reconciliation with the pass-through balance for the prior period. This is shown in the table below.

		($000)
Pass-through balance at end of prior assessment period		Nil
Allowance in pass through prices for any prior under or over recovery of pass-through costs		Nil
Actual pass through costs for the current assessment period		
Recoverable costs	67,314.1	
Pass-through costs	5,306.2	
Total		72,620.3
less Pass through revenue		71,234.8
gives Pass through balance (under recovery of pass-through costs)		1,385.5

Revenue excluded from the price path assessment

44 **Other revenue** - We directly charge customers for very few other services, and make extensive use of external contractors rather than maintaining contracting staff in-house. Customers requiring electrical work are generally referred to their own electrical contractor, or to a number of Orion approved contractors for major work. Customers then pay the contractor directly. We provide other services without charge (such as decommissioning of connections).

45 The sundry revenue we do receive is from services including rentals from Vodafone cabling, advertising, leasing, limited field service activities and upper South Island load coordination services. The Commerce Commission has deducted this sundry revenue in establishing our maximum allowable revenue (MAR) figure. Consistent with this, we have not included this revenue in our notional revenue calculation which is compared against allowable notional revenue (which is derived from the initial MAR).

46 **Capital contributions** - Assets vested in Orion by customers in the form of capital contributions are taken at nil value, are not added to our regulatory asset base and are therefore excluded from this price path assessment.

47 Consistent with this exclusion, revenue from cash capital contributions, which is taken to offset the asset value in our regulatory asset base, is also excluded from this price path assessment.

QUALITY STANDARD SUPPORTING INFORMATION

48 The DPP determination sets out a quality standard that considers reliability results against a reliability limit set specifically for Orion.

49 To comply, Orion must demonstrate that it has either met the reliability limits in the assessment period, or has met the reliability limits in the two preceding extant assessment periods.

50 Two measures of reliability are assessed:

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

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

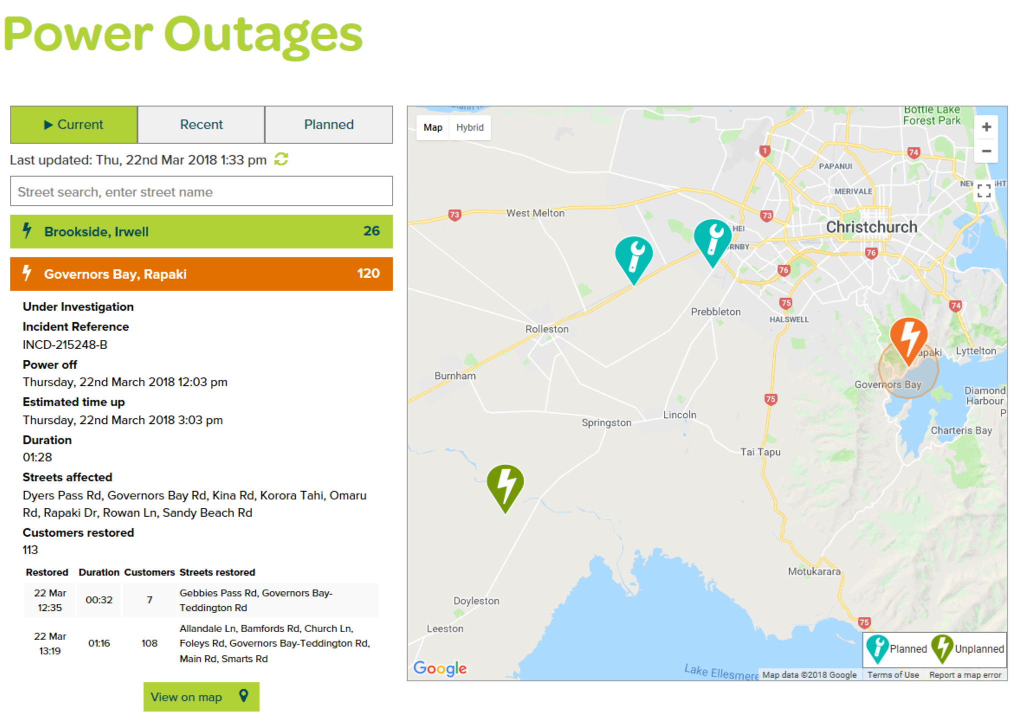
51 The following section describes our policies and procedures for recording outage information, and this is followed by a summary of the calculation of our reliability results.

Recording reliability information

52 Orion operates an outage management system as part of its “PowerOn” SCADA network management system. The system maintains a live connectivity model of our high voltage network which includes information on customer connection points, and where each connection point is fed from.

53 For planned outages and following network faults, our network controllers follow sequential operating orders to carry out switching and configuration changes on the network to bypass affected assets and facilitate planned or remedial work. At each point during these operating orders PowerOn shows the number of connections affected, together with switching points and switching times.

54 Initially, both planned and unplanned outages are reported on our website providing a live display of outages together with a map showing their location, for example:



55 Our network management system, PowerOn, automatically collates a record of outage results within the system. Power is often restored in stages, and PowerOn automatically assesses 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 as part of 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.

56 To provide an example, the outage entry shown above was collated in the PowerOn system and recorded as follows:

Outage Statistics between 22-Mar-2018 and 10-Apr-2018

Excluding incidents affecting no customers

Run on 9-Apr-2018

Outage Statistics for Date Range

Date	Incident #	Job #	Type	Stages	Off	On	Mins Off	# Ints	Cust Mins	Planned	⊟ Description
⊟ 22-Mar-18	11	5					1822	2524	59216		
	⊟ INCD-215248-B	F-20896-B	Orion Fault HV		22/03/18 12:03:43	22/03/18 16:59:00	295.3	418	39980	0	Teddington ZS - HA8/38 , CB 111 - Governors Bay
			Stage No:	1	22/03/18 12:03:43	22/03/18 12:35:00	31.3	6	188		
			Stage No:	2	22/03/18 12:03:43	22/03/18 13:14:00	70.3	107	7520		
			Stage No:	3	22/03/18 12:03:43	22/03/18 14:04:00	120.3	46	5533		
			Stage No:	4	22/03/18 12:03:43	22/03/18 14:24:00	140.3	26	3647		
			Stage No:	5	22/03/18 14:26:06	22/03/18 14:41:57	15.8	159	2520		
			Stage No:	6	22/03/18 15:59:00	22/03/18 16:55:00	56.0	46	2576		
			Stage No:	7	22/03/18 14:28:00	22/03/18 16:55:00	147.0	26	3822		
			Stage No:	8	22/03/18 12:03:43	22/03/18 16:59:00	295.3	48	14174		

…

Zone	Voltage	Substation	Feeder	Controller Comments	Tripped Device	⊟ Cause Group	Cause Type	Planned Reason	Cause Comments	Work Type	Failed Asset	Failure Mode
Teddington	11kV	Teddington - HA8/38	Unit 111			Asset Failure	Condition Deterioration		Insulator on ByPass ABI HA3/19.	11kV OH Emergency Maint	HV Line	OH Insulator
					Teddington ZS - HA8/38 , CB 111 - Governors Bay							
					Teddington ZS - HA8/38 , CB 111 - Governors Bay							
					Teddington ZS - HA8/38 , CB 111 - Governors Bay							
					Teddington ZS - HA8/38 , CB 111 - Governors Bay							
					Teddington ZS - HA8/38 , CB 111 - Governors Bay							
					Main Rd - HA3/8, ABI							
					Governors Bay Rd - HA3/19							
					Teddington ZS - HA8/38 , CB 111 - Governors Bay							

57 Note that the website screenshot was taken part way through the outage. During restoration work, additional connections were affected and recorded as separate stages to the outage. This is an example of successive interruptions that occurred during restoration.

58 The results in the above outage statistics report 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 signed off by the control centre manager.

59 For each outage the following details are recorded:

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

59.2 district substation affected;

59.3 feeder affected;

59.4 asset type affected;

59.5 cause of interruption;

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

59.7 time/date for each restoration stage;

59.8 number of consumers affected in each stage; and

59.9 explanatory notes.

60 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.

System fixed assets transferred from Transpower

61 Clause 11.5(d) of the DPP determination requires us to provide any recalculations of SAIDI and SAIFI limits, boundary values, caps and collars following a major transaction or transfer of assets from Transpower. Orion has acquired assets from Transpower in prior assessment periods, but a Transmission Asset Wash-up Adjustment has not been specified by the Commission (in terms of clause 10.6 of the DPP determination) and we have not carried out any recalculations in respect of these asset transfers. These metrics are used in the calculation of the quality incentive adjustment, and this adjustment is specifically set to nil for Orion, so any recalculation could not affect this result.

Reliability limits

62 The reliability limits are given in table 4A.1 of schedule 4A of the DPP determination, and table 2 of Schedule 3 of the prior CPP determination, as:

	FY20	**FY19**	**FY18**
$SAIDI_{LIMIT}$	73.4	73.4	82.4
$SAIFI_{LIMIT}$	0.87	0.87	1.02

Assessed values

63 The total duration and number of outages is accumulated to calculate the SAIDI and SAIFI indices. The results (prior to normalising the data for extreme events) were:

63.1 Duration of interruptions:

	FY20	**FY19**	**FY18**
Unplanned minutes lost (class C)	9,399,958	11,180,031	12,931,922
Planned minutes lost (class B)	4,567,361	4,244,670	2,869,551
	13,967,319	15,424,701	15,801,473
Average number of customers	206,000	202,956	199,838
SAIDI			
Unplanned	45.63	55.09	64.71
Planned	22.17	20.91	14.36
Total	**67.80**	**76.00**	**79.07**

63.2 Frequency of interruptions:

	FY20	FY19	FY18
Unplanned outages (class C)	122,593	145,968	185,663
Planned outages (class B)	13,785	14,121	13,321
	136,378	160,089	198,984
Average number of customers	206,000	202,956	199,838
SAIFI			
Unplanned	0.60	0.72	0.93
Planned	0.07	0.07	0.07
Total	**0.66**	**0.79**	**1.00**

Normalising the reliability results

64 The DPP and CPP determinations provide for the normalisation of reliability results to mitigate the impact of extreme events and provide a view of underlying network reliability. In the current assessment period we identified one day that met the definition of a major event day (MED) when the daily SAIDI exceeded the 4.4 minute boundary value given in the DPP determination. Major event days for prior assessment periods (as identified in prior compliance statements) use different boundary values and are triggered only when the SAIDI boundary value is exceeded.

65 The assessment dataset is normalised by adjusting the results on major event days, replacing the daily SAIDI with the applicable SAIDI boundary value and the daily SAIFI with the applicable SAIFI boundary value. The normalisation changes for prior and the current assessment period are:

Major event day adjustments

Date	Daily SAIDI adjustment	Daily SAIFI adjustment	Cause
FY18			
22 January 2018	5.02 reduced to 5.0	0.062 unchanged	This was caused by a number of smaller events coinciding, the main contributors being: • Two 33kV cable joint faults feeding Hornby zone substation that occurred at the same time as planned work by Transpower, which delayed restoration, and • A 33kV cable termination fault in the feed to Sockburn zone substation.
FY19			
23 January 2019	6.44 reduced to 4.4	0.041 unchanged	A severe evening storm with rain and winds gusting up to 140km/h struck Canterbury caused multiple outages from trees, some of which took more than a day to repair, and also transient faults where no fault could be identified.
FY20 (current assessment period)			
29 April 2019	4.94 reduced to 4.4	0.029 unchanged	A short but severe southerly storm hit the Selwyn and Banks Peninsula regions around mid-afternoon. Winds in excess of 110km per hour and torrential rain caused widespread outages across the network, mainly associated with fallen trees and vegetation. We deployed our emergency response crews and power was mostly restored by early evening.

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

66.1 Duration of interruptions:

	FY20	FY19	FY18
SAIDI result	67.80	76.00	79.07
less normalisation adjustments	(0.54)	(2.04)	(0.02)
Normalised SAIDI*	**67.26**	**73.96**	**79.05**
Annual SAIDI Limit (from above)	73.40	73.40	82.40
Annual reliability result	Comply	Exceeded	Comply

66.2 Frequency of interruptions:

	FY20	FY19	FY18
SAIFI result	0.66	0.79	1.00
less normalisation adjustments	0.00	0.00	0.00
Normalised SAIFI*	**0.66**	**0.79**	**1.00**
Annual SAIFI Limit (from above)	0.87	0.87	1.02
Annual reliability result	Comply	Comply	Comply

67 Clause 9.1 of the DPP determination requires that we either:

67.1 comply with the annual reliability requirement for the assessment period (FY20), or

67.2 have complied with the annual reliability requirement in both the preceding two extant assessment periods (FY18 and FY19).

68 This year we have met our compliance obligation by satisfying the first of the two requirements.

QUALITY INCENTIVE ADJUSTMENT

69 The DPP determination sets out a quality incentive adjustment and a specific approach for calculating the adjustment is given in Schedule 5B of the DPP determination. For Orion, the revenue at risk (REV_{risk}) term is set to nil, so the result of all calculations is nil, and the quality incentive adjustment is nil.

TRANSACTIONS

Major transactions and amalgamations

70 We have not been a party to any major transactions during the assessment period that would meet the thresholds in clause 10.1 of the DPP determination.

71 We have not completed an amalgamation or merger during the assessment period in terms of clause 10.3 of the DPP determination.

72 We have not purchased system fixed assets from Transpower during the assessment period, nor has the Commission specified a Transmission Asset Wash-up Adjustment under clause 10.6 of the DPP determination.

APPENDIX A – DELIVERY AND EXPORT PRICE SCHEDULES

Electricity delivery price schedule for Orion NZ Ltd

(applicable from 1 April 2019)

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. The components of the total delivery price are shown in order to meet information disclosure and price path compliance requirements.

All prices exclude GST	Price breakdown: Transmission	Incentives and Recoveries	Rates and Levies	Net Distribution	Delivery Price (total)	Unit of measure
Streetlighting connections		*approx 49,513 connections*				
Fixed charge	(0.0038)	0.0038	0.0049	0.1084	**0.1133**	$/con/day
Peak charge (peak period demand)	0.1450			0.2842	**0.4292**	$/kW/day
Volume charge						
Weekdays (Mon to Fri, 7am to 9pm)	0.01517			0.06042	**0.07559**	$/kWh
Nights & weekends (Sat & Sun)	0.00297			0.01501	**0.01798**	$/kWh
General connections		*approx 201,095 connections*				
Fixed charge		0.0426	0.0551	0.0523	**0.1500**	$/con/day
Peak charge (peak period demand)	0.1450			0.2842	**0.4292**	$/kW/day
Volume charge						
Weekdays (Mon to Fri, 7am to 9pm)	0.01517			0.06042	**0.07559**	$/kWh
Nights & weekends (Sat & Sun)	0.00297			0.01501	**0.01798**	$/kWh
Low power factor charge	0.0500			0.1500	**0.2000**	$/kVAr/day
Irrigation connections		*approx 1,066 connections*				
Capacity charge	0.0630	0.0172	0.0223	0.3671	**0.4696**	$/kW/day*
Volume charge						
Weekdays (Mon to Fri, 7am to 9pm)	0.01517			0.06042	**0.07559**	$/kWh
Nights & weekends (Sat & Sun)	0.00297			0.01501	**0.01798**	$/kWh
Rebates						
Power factor correction rebate				(0.1755)	**(0.1755)**	$/kVAr/day*
Interruptibility rebate				(0.0439)	**(0.0439)**	$/kW/day*
* applied from 1 October to 31 March only						
Major customer and embedded network connections		*approx 487 connections*				
Fixed charge				10.0000	**10.0000**	$/con/day
Extra switches				3.6700	**3.6700**	$/switch/day
11kV Metering equipment				4.4500	**4.4500**	$/con/day
11kV Underground cabling				3.2900	**3.2900**	$/km/day
11kV Overhead lines				2.0700	**2.0700**	$/km/day
Transformer capacity				0.0138	**0.0138**	$/kVA/day
Peak charge (control period demand)	0.1507			0.2641	**0.4148**	$/kVA/day
Nominated maximum demand	0.0090	0.0056	0.0073	0.0916	**0.1135**	$/kVA/day
Metered maximum demand	0.0713				**0.0713**	$/kVA/day
Large capacity connections		*15 connections*				
Individually assessed prices advised and charged directly to the customers						
Miscellaneous						
Monthly invoice and contract charge to retailers and directly contracted customers				30.00	**30.00**	$/invoice
Failure to pay notice				50.00	**50.00**	$/notice
Default and termination notice				100.00	**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

Electricity delivery price schedule for Orion NZ Ltd

(applicable from 1 April 2018 to 31 March 2019)

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 Component Code[3]	Distribution Part	Transmission Part	Delivery Price	Unit of measure
Streetlighting connections		*approx 48,876 connections*			
Fixed charge	STFXD	0.1254	(0.0043)	0.1211	$/con/day
Peak charge (peak period demand)	GENPK	0.3288	0.1893	0.5181	$/kW/day
Volume charge					
Weekdays (Mon to Fri, 7am to 9pm)	VOLWD	0.07347	0.01969	0.09316	$/kWh
Nights & weekends (Sat & Sun)	VOLNW	0.00896	0.00297	0.01193	$/kWh
General connections		*approx 197,429 connections*			
Peak charge (peak period demand)	GENPK	0.3288	0.1893	0.5181	$/kW/day
Volume charge					
Weekdays (Mon to Fri, 7am to 9pm)	VOLWD	0.07347	0.01969	0.09316	$/kWh
Nights & weekends (Sat & Sun)	VOLNW	0.00896	0.00297	0.01193	$/kWh
Low power factor charge	LOWPF	0.1500	0.0500	0.2000	$/kVAr/day
Irrigation connections		*approx 1,047 connections*			
Capacity charge	ICCAP	0.3759	0.0591	0.4350	$/kW/day*
Volume charge					
Weekdays (Mon to Fri, 7am to 9pm)	VOLWD	0.07347	0.01969	0.09316	$/kWh
Nights & weekends (Sat & Sun)	VOLNW	0.00896	0.00297	0.01193	$/kWh
Rebates					
Power factor correction rebate	ICPFC	(0.1793)		(0.1793)	$/kVAr/day*
Interruptibility rebate	ICIRR	(0.0448)		(0.0448)	$/kW/day*
* applied from 1 October to 31 March only					
Major customer and embedded network connections		*approx 437 connections*			
Fixed charge	MCFXD	7.5000		7.5000	$/con/day
Extra switches	EQESW	3.6100		3.6100	$/switch/day
11kV Metering equipment	EQMET	4.3700		4.3700	$/con/day
11kV Underground cabling	EQUGC	3.2300		3.2300	$/km/day
11kV Overhead lines	EQOHL	2.0300		2.0300	$/km/day
Transformer capacity	EQTFC	0.0135		0.0135	$/kVA/day
Peak charge (control period demand)	MCCPD	0.2939	0.1791	0.4730	$/kVA/day
Nominated maximum demand	MCNMD	0.0994	0.0108	0.1102	$/kVA/day
Metered maximum demand	MCMMD		0.0862	0.0862	$/kVA/day
Large capacity connections		*12 connections*			
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		30.00	$/invoice

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 price component code is used in our mandatory 'electricity information exchange protocol' files.

Delivery prices

(applicable from 1 April 2017 to 31 March 2018)

Orion

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.

	Price Component Code[3]	Delivery Price	All prices exclude GST
Streetlighting connections		*approx 48,266 connections*	
Fixed charge	STFXD	0.1129	$/con/day
Peak charge (peak period demand)	GENPK	0.5310	$/kW/day
Volume charge			
Weekdays (Mon to Fri, 7am to 9pm)	VOLWD	0.08773	$/kWh
Nights & weekends (Sat & Sun)	VOLNW	0.01125	$/kWh
General connections		*approx 198,087 connections*	
Peak charge (peak period demand)	GENPK	0.5310	$/kW/day
Volume charge			
Weekdays (Mon to Fri, 7am to 9pm)	VOLWD	0.08773	$/kWh
Nights & weekends (Sat & Sun)	VOLNW	0.01125	$/kWh
Low power factor charge	LOWPF	0.2000	$/kVAr/day
Irrigation connections		*approx 1,102 connections*	
Capacity charge	ICCAP	0.4197	$/kW/day*
Volume charge			
Weekdays (Mon to Fri, 7am to 9pm)	VOLWD	0.08773	$/kWh
Nights & weekends (Sat & Sun)	VOLNW	0.01125	$/kWh
Rebates			
Power factor correction rebate	ICPFC	(0.1793)	$/kVAr/day*
Interruptibility rebate	ICIRR	(0.0448)	$/kW/day*
* applied from 1 October to 31 March only			
Major customer and embedded network connections		*approx 404 connections*	
Fixed charge	MCFXD	1.8900	$/con/day
Extra switches	EQESW	3.5400	$/switch/day
11kV Metering equipment	EQMET	4.2900	$/con/day
11kV Underground cabling	EQUGC	3.1700	$/km/day
11kV Overhead lines	EQOHL	2.0000	$/km/day
Transformer capacity	EQTFC	0.0133	$/kVA/day
Peak charge (control period demand)	MCCPD	0.4857	$/kVA/day
Nominated maximum demand	MCNMD	0.1049	$/kVA/day
Metered maximum demand	MCMMD	0.0848	$/kVA/day
Large capacity connections		*12 connections*	
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

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 price component code is used in our mandatory 'electricity information exchange protocol' files.

Export credit schedule for Orion NZ Ltd

(applicable from 1 April 2019)

Orion

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	0.00370	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	0.26260	EXPPP	$/kWh
30 - 750kW Control period credits[4]				
- real power, plus	Chargeable control period	0.0897	EXPCP1	$/kW/day
- reactive power[5]		0.0295	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.

Export and generation credit schedule for Orion NZ Ltd

(applicable from 1 April 2018 to 31 March 2019)

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 further details refer to our *Export and Generation Credits Policy* document, available on our website.

Export credit pricing

(excluding GST)

Orion provides credits for electricity exported on to Orion's network during specified periods. The prices for these credits are:

Generator rated output	Period applied	Price Component Code[3]	Credit Price	Unit of measure
0 - 30kW generation[2]				
Anytime credits (without PV), or	Anytime	EXPA	0.00920	$/kWh
Anytime credits (with PV)	(24 hours, 7 days)	EXPAPV	0.00030	$/kWh
0 - 30kW generation[2]				
Peak period credits (with or without PV)	Chargeable peak period	EXPPP	0.64290	$/kWh
30 - 750kW Control period credits[4]				
- real power, plus	Chargeable control period	EXPCP1	0.2202	$/kW/day
- reactive power[5]		EXPCP2	0.0277	$/kVAr/day
above 750kW	*Individually assessed prices provided on application*			

Notes for export credit pricing

1. Full details covering generation and metering requirements and application of prices are included in our *Export and Generation Credits Policy* document, available on Orion's 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 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 14 connections are approved for export credits.

Generation credit pricing (closed)

(excluding GST)

The generation credits arrangement is closed and is not available to any new generation. For existing participating generation we signal "generation periods" and provide a credit that reflects generation support provided at times when the export credit (above) is not available. These credits are based on the generated volume, regardless of whether this results in export from the connection.

Generator rated output	Period applied	Price Component Code[3]	Credit Price	Unit of measure
All participating generation (not available to any further generation)	Orion's ripple signalled generation period	GEN1	0.50000	$/kWh

Notes for generation credit pricing

1. Full details covering generation and metering requirements and application of prices are included in our *Export and Generation Credits Policy* document, available on Orion's website.
2. These prices apply for the current group of approved generation during our ripple signalled generation period. The total duration of generation periods is likely to vary significantly from year to year. In some years there may be no generation periods.
3. The price component code is used in our mandatory 'electricity information exchange protocol' files.
4. Approximately 9 connections are approved for generation credits.

Export and generation credits

(applicable from 1 April 2017 to 31 March 2018)

Orion

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 further details refer to our *Export and Generation Credits Policy* document, available on our website.

Export credit pricing

Orion provides credits for electricity exported on to Orion's network during specified periods. The prices for these credits are:

Generator rated output	Period applied	Price Component Code[3]	Credit Price	All prices exclude GST
0 - 30kW generation[2]				
Anytime credits (without PV), or	Anytime	EXPA	0.00930	$/kWh
Anytime credits (with PV)	(24 hours, 7 days)	EXPAPV	0.00030	$/kWh
0 - 30kW generation[2]				
Peak period credits (with or without PV)	Chargeable peak period	EXPPP	0.64860	$/kWh
30 - 750kW Control period credits[4]				
- real power, plus	Chargeable control period	EXPCP1	0.2221	$/kW/day
- reactive power[5]		EXPCP2	0.0298	$/kVAr/day
above 750kW	*Individually assessed prices provided on application*			

Notes for export credit pricing

1. Full details covering generation and metering requirements and application of prices are included in our *Export and Generation Credits Policy* document, available on Orion's 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 times the daily credit price.
5. Credit quantities 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 18 connections are approved for export credits.

Generation credit pricing (closed)

The generation credits arrangement is closed and is not available to any new generation. For existing participating generation we signal "generation periods" and provide a credit that reflects generation support provided at times when the export credit (above) is not available. These credits are based on the generated volume, regardless of whether this results in export from the connection.

Generator rated output	Period applied	Price Component Code[3]	Credit Price	All prices exclude GST
All participating generation (not available to any further generation)	Orion's ripple signalled generation period	GEN1	0.50000	$/kWh

Notes for generation credit pricing

1. Full details covering generation and metering requirements and application of prices are included in our *Export and Generation Credits Policy* document, available on Orion's website.
2. These prices apply for the current group of approved generation during our ripple signalled generation period. The total duration of generation periods is likely to vary significantly from year to year. In some years there may be no generation periods.
3. The price component code is used in our mandatory 'electricity information exchange protocol' files.
4. Approximately 16 connections are approved for generation credits.

APPENDIX B – CALCULATION OF INCREMENTAL ROLLING INCENTIVE

Orion default price path FY2020

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	1045	1066	1088	1109	1132	1154
CPIQ2		979	983	1000	1015	1032	1051	1073	1094	1116	1138	1161
CPIQ3		982	986	1005	1024	1039	1059	1080	1102	1124	1146	1169
CPIQ4		977	990	1006	1025	1040	1061	1082	1104	1126	1149	1172
Inflation rate			0.64%	1.85%	1.60%	1.53%	1.90%	2.02%	2.00%	2.00%	2.00%	2.00%
						RBNZ Forecast ->		2% Forecast ->				
Opex subject to IRIS												
Allowed opex	$000	54,908.5	58,104.3	57,926.1	57,997.4	58,854.0	NA					
(CPP Determination schedule 7)												
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							(4,702.1)					
Incremental gains/(losses) carried forward												
Year 1	$000		4,106.6	4,182.7	4,249.5	4,314.5	4,396.5					
2	$000			(1,685.9)	(1,712.8)	(1,739.1)	(1,772.1)	(1,808.0)				
3	$000				(238.9)	(242.6)	(247.2)	(252.2)	(257.2)			
4	$000					1,624.8	1,655.7	1,689.2	1,723.0	1,757.4		
5	$000						0.0	0.0	0.0	0.0	0.0	
6	$000							(4,797.3)	(4,893.3)	(4,991.1)	(5,090.9)	(5,192.8)
Net balance							4,032.9	(5,168.3)	(3,427.5)	(3,233.7)	(5,090.9)	(5,192.8)
IRIS amount - Net balances treated as Recoverable cost							4,032.9	0.0	0.0	0.0	0.0	0.0

DIRECTORS' CERTIFICATE
FOR COMPLIANCE STATEMENT

We, Deborah Jane Taylor and Bruce Donald Gemmell, 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 Ltd, and related information, prepared for the purposes of the Electricity Distribution Services Default Price-Quality Path Determination 2015 are true and accurate

Deborah Jane Taylor

Bruce Donald Gemmell

18 June 2020

AUDIT NEW ZEALAND
Mana Arotake Aotearoa

Independent Auditor's Report

To the Directors of Orion New Zealand Limited and to the Commerce Commission

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 provide an opinion, on his behalf, on whether the Company's Compliance Statement for the year ended on 31 March 2020 on pages 3 to 22 complies, in all material respects, with the Electricity Distribution Services Default Price-Quality Path Determination 2015 (the Determination).

Directors' responsibilities

The Directors of the Company are responsible for the preparation of the Compliance Statement in accordance with the Determination, and for such internal control as the Directors determine is necessary to enable the preparation of a Compliance Statement that is free from material misstatement.

Auditor's responsibility

Our responsibility is to express an opinion on whether the Compliance Statement 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 (Revised): *Assurance Engagements on Compliance* issued by the Assurance Standards 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 Compliance Statement 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 Compliance Statement. The procedures selected depend on the auditor's judgement, including the assessment of the risks of material misstatement of the Compliance Statement, 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 Compliance Statement 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.

In relation to the price path and quality standards set out in clauses 8 and 9 of the Determination respectively, our audit included examination, on a test basis, of evidence relevant to the amounts and disclosures contained on pages 3 to 22 of the Compliance Statement.

Our audit also included assessment of the significant estimates and judgements, if any, made by the Company in the preparation of the Compliance Statement.

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

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 Compliance Statement 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 Compliance Statement nor do we guarantee complete accuracy of the Compliance Statement. Also we did not evaluate the security and controls over the electronic publication of the Compliance Statement.

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 auditor requirements specified in the Determination.

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 business, this engagement, the audit of the Company's disclosure information prepared under the Electricity Distribution Information Disclosure Determination 2012, and the annual audit of the Company's financial statements, we have no relationship with or interests in the Company.

Opinion

In our opinion:

- the Compliance Statement of Orion New Zealand Limited for the year ended on 31 March 2020, has been prepared, in all material respects, in accordance with the Determination;
- the information used in the preparation of the Compliance Statement has been properly extracted from the Company's accounting and other records, sourced from its financial and non-financial systems; and
- proper records to enable the complete and accurate compilation of the Compliance Statement have been kept.

Our audit was completed on 18 June 2020 and our opinion is expressed as at that date.

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