Network Tasman Limited

Default Price-Quality Path

Annual Compliance Statement

1 April 2022 – 31 March 2023 Assessment Period

28 July 2023

Contents

1. Introduction

Network Tasman Limited is subject to price-quality regulation under Part 4 of the Commerce Act 1986. The Commerce Commission has set a Default Price-Quality Path (DPP) which applies to Network Tasman Limited from 1 April 2020.

This annual compliance statement is published in accordance with clause 11.4 of the 2020 DPP Determination, and applies to the third assessment period, commencing 1 April 2022 and ending 31 March 2023.

2. Date prepared

This statement was prepared on 28 July 2023

3. Wash-up amount

3.1 Statement of compliance

As demonstrated in Table 1 in Section 3.2, and consistent with clause 8.6 of the 2020 DPP Determination Network Tasman Limited has complied with the wash-up amount calculation for the third assessment period.

3.2 Wash-up amount calculation

Table 1

Wash-up amount RY23		
Term	Description	Value ($000)
Actual allowable revenue (AAR)	*Sum of actual net allowable revenue, actual pass-through and recoverable costs + revenue wash-up draw down amount*	45,638
Actual revenue (AR)	*Sum of actual revenue from prices plus other regulated income*	39,668
Revenue foregone (RV)	*Actual net allowable revenue x (revenue reduction percentage - 20%) when revenue reduction percentage is greater than 20%, otherwise nil*	0
Wash-up amount	*AAR - AR - RV*	**5,971**

Further information supporting actual allowable revenue is included in Section 3.2.1.

Further information supporting actual revenue is included in Section 3.2.2.

Further information supporting revenue foregone is included in Section 3.3.3.

3.2.1 Actual allowable revenue

Table 2 below shows the actual allowable revenue for the assessment period consistent with Schedule 1.6 of the 2020 DPP Determination.

Table 2

Actual allowable revenue RY23		
Term	Description	Value ($000)
Actual net allowable revenue (ANAR)	*Actual net allowable revenue for the second assessment period x (1 + CPI) x (1−x)*	29,830
Actual pass-through costs	*Sum of all pass-through costs that were incurred or approved by the Commission in the assessment period*	410
Actual recoverable costs	*Sum of all recoverable costs that were incurred or approved by the Commission in the assessment period*	13,801
Revenue wash-up draw down amount	*Closing wash-up account balance for the second assessment period*	1,597
Total actual allowable revenue (AAR)	*actual net allowable revenue + actual pass-through costs and recoverable costs + revenue wash-up draw down amount*	**45,638**

Further information supporting actual pass-through costs, revenue wash-up draw down amount and actual recoverable costs is included in Appendix A.

3.2.2 Actual revenue

Table 3 below shows actual revenue for the assessment period consistent with clause 4.2 of the 2020 DPP Determination.

Table 3

Actual revenue RY23		
Term	Description	Value ($000)
Actual revenue from prices	*Actual prices between 1 April 2022 and 31 March 2023 multiplied by actual quantities for the assessment period*	39,668
Other regulated income	*Other income associated with supply of electricity distribution services*	-
Total actual revenue (AR)	*Sum of actual revenue from prices plus other regulated income*	**39,668**

Further information supporting actual revenue from prices is included in Appendix B.

3.2.3 Revenue foregone

Table 4 below shows the revenue foregone consistent with clause 4.2 of the 2020 DPP Determination.

Table 4

Revenue foregone RY23		
Term	Description	Value ($000)
Forecast revenue from prices	*Forecast revenue from prices for the third assessment period*	39,603
Revenue reduction percentage (RRP)	*1 - (actual revenue from prices / forecast revenue from prices)*	-0.2%
Actual net allowable revenue (ANAR)	*Actual net allowable revenue for the second assessment period x (1 + CPI) x (1−x)*	29,830
Revenue foregone (RV)	*Actual net allowable revenue x (RRP- 20%) when RRP is greater than 20%, otherwise nil*	**0**

Table 4b

Calculation of ANAR

Year	Month	CPI Index
2021	Mar	1068
	Jun	1082
	Sep	1106
	Dec	1122
2022	Mar	1142
	Jun	1161
	Sep	1186
	Dec	1203
2023	Mar	1218

Term	Description	Value ($000)
ANARprevious		27,853
1+CPI*t*		1.07098
X		0
Actual net allowable revenue (ANAR)	Actual net allowable revenue for the second assessment period x (1 + CPI) x (1−x)	**29,830**

4. Quality standards

4.1 Statement of compliance with planned interruptions quality standards

Network Tasman Limited is subject to a planned accumulated SAIDI limit and a planned accumulated SAIFI limit which are assessed for the DPP regulatory period as stated in clause 9.2 of the 2020 DPP Determination.

Table 5 and Table 6 below show the planned accumulated SAIDI and SAIFI limits for Network Tasman Limited for the DPP regulatory period and the planned SAIDI and SAIFI assessed values for the first to the third assessment period.

Table 5

Planned interruptions quality standard - SAIDI	
Sum of planned SAIDI assessed values ≤ Planned accumulated SAIDI limit	
Planned accumulated SAIDI limit	1,129.14
Planned SAIDI assessed value for the first assessment period	116.01
Planned SAIDI assessed value for the second assessment period	66.13
Planned SAIDI assessed value for the third assessment period	154.01
Sum of planned SAIDI assessed values	336.15
Compliance result	**Compliant**

Table 6

Planned interruptions quality standard - SAIFI	
Sum of planned SAIFI assessed values ≤ Planned accumulated SAIFI limit	
Planned accumulated SAIFI limit	4.9021
Planned SAIFI assessed value for the first assessment period	0.3317
Planned SAIFI assessed value for the second assessment period	0.2054
Planned SAIFI assessed value for the Third assessment period	0.5561
Sum of planned SAIFI assessed values	1.0932
Compliance result	**Compliant**

Further information supporting planned SAIDI and SAIFI assessed values is included in Section 4.1.1.

4.1.1 Planned SAIDI and SAIFI assessed values

Table 7 and Table 8 below show Network Tasman Limited's planned SAIDI and SAIFI assessed values for the assessment period.

Table 7

Planned SAIDI assessed value RY23		
Term	Description	Value
Class B non-notified interruptions		154.01
Class B notified interruptions falling outside window		0
$SAIDI_B$	*Sum of Class B non-notified interruptions*	154.01
Class B notified interruptions falling inside window		0
Class B intended interruptions cancelled without notice		0
Class B intended interruptions cancelled with notice		0
$SAIDI_N$	*Sum of Class B notified interruptions*	0
Planned SAIDI assessed value	$SAIDI_B + (SAIDI_N/2)$	**154.01**

Table 8

Planned SAIFI assessed value RY23		
Term	Description	Value
Planned SAIFI assessed value	*Sum of Class B interruptions commencing within the assessment period*	0.5561

4.2 Statement of compliance with unplanned interruptions quality standards

As demonstrated in Table 9 and Table 10 below, and consistent with clause 9.7 of the 2020 DPP Determination, Network Tasman Limited has complied with the unplanned interruptions quality standard.

Table 9

Unplanned interruptions quality standard RY23 - SAIDI		
Unplanned SAIDI assessed value ≤ Unplanned SAIDI limit		
Unplanned SAIDI limit		101.03
Unplanned SAIDI assessed value	*Sum of normalised SAIDI values for Class C interruptions commencing within the assessment period*	72.01
Compliance result		**Compliant**

Table 10

Unplanned interruptions quality standard RY23 - SAIFI		
Unplanned SAIFI assessed value ≤ Unplanned SAIFI limit		
Unplanned SAIFI limit		1.1956
Unplanned SAIFI assessed value	*Sum of normalised SAIFI values for Class C interruptions commencing within the assessment period*	0.7351
Compliance result		**Compliant**

Information about policies, procedures and calculations for measuring planned and unplanned interruptions during the assessment period is in Appendix C.

4.2.1 Major events

Network Tasman Limited had four major events during the assessment period. One affected the SAIFI only, the other three both SAIFI and SAIDI.

SAIDI major events. The applicable SAIDI unplanned boundary value of 7.22 is used in the normalisation calculation.

Table 11

Unplanned SAIDI major events RY23			
Start	End	Pre-normalised unplanned SAIDI	Normalised unplanned SAIDI
11-Jul-2022 11:30 AM	13-Jul-2022 04:00 AM	7.3269	0.6032
16-Aug-2022 06:00 PM	20-Aug-2022 11:00 PM	31.5662	1.3176
11-Mar-2023 04:00 PM	13-Mar-2023 03:00 PM	12.4298	0.3008

SAIFI major events. The applicable SAIFI unplanned boundary value of 0. 0688 is used in the normalisation calculation.

Table 12

Unplanned SAIFI major events RY23			
Start	End	Pre-normalised unplanned SAIFI	Normalised unplanned SAIFI
31-May-2022 01:00 AM	01-Jun-2022 10:30 PM	0.0707	0.0047
11-Jul-2022 08:00 AM	13-Jul-2022 07:00 AM	0.1194	0.0058
16-Aug-2022 06:00 PM	18-Aug-2022 05:00 PM	0.0894	0.0014
11-Mar-2023 04:00 PM	13-Mar-2023 03:00 PM	0.1695	0.0029

Further information of each major event is in Appendix D

4.3 Statement of compliance with extreme event standard

As demonstrated in Table 13 below, and consistent with clause 9.9 of the 2020 DPP Determination Network Tasman Limited has complied with the extreme event standard.

Table 113

Extreme event standard RY23	
Unplanned SAIDI value ≤ 120 minutes, and customer interruption minutes ≤ six million during any 24-hour period, excluding unplanned interruptions from major external factors	
Number of extreme events	Compliance result
Nil	Compliant

4.4 Quality Incentive Adjustment

Table 14 below shows Network Tasman Limited's quality incentive adjustment for the assessment period.

Table 14

Quality Incentive Adjustment RY23		
Term	Description	Value ($000)
SAIDI planned adjustment	$(SAIDI_{planned, target} - SAIDI_{planned, assessed}) \times 0.5 \times IR$	(246)
SAIDI unplanned adjustment	$(SAIDI_{unplanned, target} - SAIDI_{unplanned, assessed}) \times IR$	16
Total adjustment	*SAIDI planned adjustment + SAIDI unplanned adjustment*	(231)
Revenue at risk	*0.02 * ANAR*	596.609
Total penalty/reward		(231)
67th percentile estimate of post-tax WACC		4.23%
Quality incentive adjustment		**(251)**

Table 15 below shows Network Tasman Limited's quality incentive adjustment inputs consistent with Schedule 4 of the 2020 DPP Determination.

Table 15

Quality Incentive Adjustment Inputs RY23					
Term	Units	Value	Term	Units	Value
SAIDI planned interruption cap	minutes	225.83	SAIDI unplanned interruption cap	minutes	101.03
SAIDI planned interruption collar	minutes	0	SAIDI unplanned interruption collar	minutes	0
SAIDI planned interruption target	minutes	75.28	SAIDI unplanned interruption target	minutes	74.49
Planned SAIDI assessed value	minutes	154.01	Unplanned SAIDI assessed value	minutes	72.01
Incentive rate	$	6,260			
Actual net allowable revenue (ANAR)	$000	29,830			
SAIDI planned interruption target	minutes	75.28	SAIDI unplanned interruption target	minutes	74
Minimum of the planned SAIDI cap and assessed value	minutes	154.01	Minimum of the unplanned SAIDI cap and assessed value	minutes	72
Planned SAIDI subject to incentive	minutes	(79)	Unplanned SAIDI subject to incentive	minutes	2
Adjustment (IR x 0.5)	$	3,130	Adjustment (IR)	$	6,260
SAIDI planned adjustment	$000	(246)	SAIDI unplanned adjustment	$000	16

5. Transactions

Network Tasman Limited has not entered into any agreements with another EDB or Transpower for an amalgamation, merger, major transaction or transfer in the assessment period.

6. Director's certification

A Director's certificate in the form set out in Schedule 7 of the 2020 DPP Determination is included as Appendix E.

7. Assurance report

An assurance report meeting the requirements of Schedule 8 of the 2020 DPP Determination is included in Appendix F.

Appendix A – Pass-through and recoverable costs

Pass-through costs

Table 126

Actual pass-through costs RY23	
Actual pass-through costs	Actual ($000)
Rates on system fixed assets	173
Commerce Act levies	85
Electricity Authority levies	125
Utilities Disputes levies	26
Total actual pass-through costs	**410**

Recoverable costs

Table 137

Actual recoverable costs RY23	
Actual recoverable costs	Actual ($000)
IRIS incentive adjustment	395
Transmission charges	10,893
New investment contract charges	1,113
System operator services charges	0
Avoided transmission charges	1,825
Distributed generation allowance	0
Claw-back	0
Catastrophic event allowance	0
Extended reserves allowance	0
Quality incentive adjustment	(251)
Capex wash-up adjustment	(219)
Reconsideration event allowance	0
Quality standard variation engineers fee	0
Urgent project allowance	0
Fire and Emergency NZ levies	45
Innovation project allowance	0
Total actual recoverable costs	**13,801**

Revenue wash-up draw down amount

Table 18 to 20 show the calculation of the Revenue wash-up draw down amount.

Table 18

Revenue wash-up draw down amount RY23	
The revenue wash-up draw down amount for the third assessment period = closing wash-up balance for the second assessment period. The closing wash-up balance for the second assessment period = (Wash-up amount for the first assessment period - voluntary undercharging amount foregone for the first assessment period) x (1 + 67th percentile estimate of post-tax WACC)2	
Term	Value ($000)
Wash-up amount for the first assessment period	1,470
Voluntary undercharging amount foregone for the first assessment period	0
(1 + 67th percentile estimate of post-tax WACC)^2	1.09
Revenue wash-up draw down amount for the third assessment period	**1,597**

Table 19

Voluntary undercharging amount foregone RY21	
Voluntary undercharging amount foregone for RY21 = nil if the forecast revenue from prices for the first assessment period is greater than the voluntary undercharging revenue floor for the first assessment period; otherwise voluntary undercharging revenue floor for the first assessment period - forecast revenue from prices for the first assessment period	
Term	Value ($000)
Forecast revenue from prices for the first assessment period	38,147
Voluntary undercharging revenue floor for the first assessment period	36,325
Voluntary undercharging amount foregone for the first assessment period	**0**

Table 20

Voluntary undercharging revenue floor RY21	
Voluntary undercharging revenue floor for RY21 = lesser of: (a) forecast allowable revenue for assessment period one x voluntary undercharging threshold; and (b) (1 + limit on annual percentage increase in forecast revenue from prices) x forecast revenue from prices for assessment period zero	
Term	Value ($000)
Forecast allowable revenue for the first assessment period	40,362
Voluntary undercharging threshold	90%
Forecast revenue from prices for assessment period zero	N/A
Limit on annual percentage increase in forecast revenue from prices	10%
Voluntary undercharging revenue floor for the first assessment period	**36,325**

Appendix B – Prices and quantities

Table 21 shows the actual prices and quantities for actual revenue from prices for the third assessment period.

Table 21

Actual revenue from prices RY23				
Price Code	Unit	Unit price	Actual quantity	Actual revenue ($000)
0S	$/day	0.000	0	0
0STL	$/W/day	0.00121	432,391	191
0STL	$/W/day	0.00119	0	0
0STL	$/W/day	0.00121	0	0
0UNM	$/day	0.550	72	14
0UNM	$/day	0.533	0	0
0UNM	$/day	0.545	0	0
1GL	$/day	1.000	3,795	1,385
1GLANY	$/kWh	0.025	(36,342)	(1)
1GLANY	$/kWh	0.022	18,239,363	392
1GLDAY	$/kWh	0.027	1,119,299	30
1GLDAY	$/kWh	0.030	(7,219)	(0)
1GLGEN	$/kWh	0.000	0	0
1GLNIT	$/kWh	0.004	567,257	2
1GLNIT	$/kWh	0.005	(6,077)	(0)
1GLWSR	$/kWh	0.006	1,684,343	10
1GLWSR	$/kWh	0.008	(3,955)	(0)
1RL	$/day	0.300	18,915	2,071
1RL	$/day	0.150	(4)	(0)
1RL	$/day	0.300	9	1
1RLANY	$/kWh	0.073	(136,552)	(10)
1RLANY	$/kWh	0.053	73,483,470	3,924
1RLDAY	$/kWh	0.058	2,433,741	142
1RLDAY	$/kWh	0.080	(321,691)	(26)
1RLGEN	$/kWh	0.000	0	0
1RLNIT	$/kWh	0.036	2,217,715	80
1RLNIT	$/kWh	0.013	(172,968)	(2)
1RLWSR	$/kWh	0.036	27,258,251	976
1RLWSR	$/kWh	0.020	(30,401)	(1)
1RS	$/day	1.000	16,379	5,978
1RSANY	$/kWh	0.025	(428,791)	(11)
1RSANY	$/kWh	0.022	105,973,923	2,278
1RSDAY	$/kWh	0.027	3,188,637	84
1RSDAY	$/kWh	0.030	498	0
1RSGEN	$/kWh	0.000	0	0
Actual revenue from prices RY23				

Price Code	Unit	Unit price	Actual quantity	Actual revenue ($000)
1RSNIT	$/kWh	0.005	(484,975)	(3)
1RSNIT	$/kWh	0.004	2,755,662	12
1RSWSR	$/kWh	0.006	33,452,903	204
1RSWSR	$/kWh	0.008	32,868	0
2	$/kVA/day	0.094	22	1
2	$/kVA/day	0.095	130,037	4,509
2	$/kVA/day	0.094	(22)	(1)
2ANY	$/kWh	0.034	(2,326)	(0)
2ANY	$/kWh	0.029	69,108,632	2,032
2DAY	$/kWh	0.034	3,742,496	127
2DAY	$/kWh	0.039	(10,686)	(0)
2DAY	$/kWh	0.034	16,250,899	553
2GEN	$/kWh	0.000	0	0
2HANY	$/kWh	0.189	13,265	3
2HANY	$/kWh	0.262	390	0
2HLFC	$/day	0.150	0	0
2HLFC	$/day	0.300	5	1
2HWSR	$/kWh	0.176	4,833	1
2HWSR	$/kWh	0.170	51	0
2LANY	$/kWh	0.132	2,320	0
2LANY	$/kWh	0.102	375,865	38
2LDAY	$/kWh	0.150	(64)	(0)
2LDAY	$/kWh	0.107	48,843	5
2LGEN	$/kWh	0.000	0	0
2LLFC	$/day	0.150	19	1
2LLFC	$/day	0.300	222	24
2LNIT	$/kWh	0.051	49	0
2LNIT	$/kWh	0.085	23,124	2
2LWSR	$/kWh	0.089	57,360	5
2LWSR	$/kWh	0.057	311	0
2NIT	$/kWh	0.012	(24,593)	(0)
2NIT	$/kWh	0.012	8,326,836	99
2WSR	$/kWh	0.016	(16,762)	(0)
2WSR	$/kWh	0.016	3,021,552	49
3.3GEN	$/kWh	0.000	0	0
3.4GEN	$/kWh	0.000	0	0
6.1	$/ICP	1,570,136.400	1	1,570
6.2	$/ICP	510,614.700	1	511
AnyDem31	$/kVA/day	0.131	2,296	109
AnyDem33	$/kVA/day	0.150	2,450	134
AnyDem34	$/kVA/day	0.158	49,573	2,852
AnyDem34	$/kVA/day	0.154	57	3
AnyDem35	$/kVA/day	0.150	3,094	169

Actual revenue from prices RY23

Price Code	Unit	Unit price	Actual quantity	Actual revenue ($000)
CB	$/ICP	1,711,567.900	1	1,712
CBGEN	$/kWh	0.000	0	0
Energy	$/kWh	0.000	0	0
Energy	$/kWh	0.000	0	0
HLF	$/kVA/day	0.402	2,783	409
HLFANY	$/kWh	0.008	42,176	0
HLFANY	$/kWh	0.007	3,777,700	25
HLFDAY	$/kWh	0.008	2,757,484	21
HLFDAY	$/kWh	0.009	(1,561)	(0)
HLFGEN	$/kWh	0.000	0	0
HLFNIT	$/kWh	0.009	(236)	(0)
HLFNIT	$/kWh	0.002	1,082,181	2
HLFWSR	$/kWh	0.001	59,492	0
HLFWSR	$/kWh	0.002	(1,706)	(0)
kVAr	$/kVAr/day	0.296	124	13
MAT	$/ICP	87,819.180	1	88
MATANY	$/kWh	0.000	0	0
MATGEN	$/kWh	0.000	0	0
NEL	$/Connection	1,731,703.000	0	1,732
SD31	$/kWh	0.003	3,489,900	12
SD33	$/kWh	0.010	3,888,238	40
SD34	$/kWh	0.009	20,526	0
SD34	$/kWh	0.010	53,780,769	549
SD35	$/kWh	0.007	4,642,410	32
SN31	$/kWh	0.002	1,428,556	2
SN33	$/kWh	0.006	1,789,607	10
SN34	$/kWh	0.005	10,680	0
SN34	$/kWh	0.006	19,723,382	110
SN35	$/kWh	0.004	2,117,307	9
WD31	$/kWh	0.006	2,527,792	15
WD33	$/kWh	0.026	2,236,100	59
WD34	$/kWh	0.026	43,001,150	1,131
WD35	$/kWh	0.022	3,525,262	79
WinDem	$/kW/day	0.276	24,362	2,455
WinDem	$/kW/day	0.281	19	2
WN31	$/kWh	0.002	985,819	2
WN33	$/kWh	0.006	938,991	5
WN34	$/kWh	0.006	15,905,648	89
WN35	$/kWh	0.004	1,623,358	7
Actual revenue from prices RY23				

Price Code	Unit	Unit price	Actual quantity	Actual revenue ($000)
Recoverable Costs billed to Direct Customers				
EA Levy	$/MWh	0.1464	218,705	32
Utility Rates	$/Month	69.27	24	2
Connection Fee				
0	Connection Fee	125	0	0.0
1	Connection Fee	250	804	201.0
2	Connection Fee	325	34	11.1
3	Connection Fee	400	10	4.0
Solar Connections				
Solar Pt 1A	<10kW	100	442	44.2
Solar Pt 2		500	33	16.5
Solar Pt 1	<10 kW	200	2	0.4
Network Development Levy (aggregated)				
1c	per ICP	3,250	0	0.0
1	$/kVA-km	142	1002	142.3
2	$/kVA-km	335	165	55.3
3.4	$/kVA-km	1,662	14	23.3
SubDivision	$/kVA-km		0	0.0
Generator Fees				
Network Fee 1	Network Fee pa	684	1	0.684
Network Fee 2	Network Fee pa	600	1	0.600
Network Fee 3	Network Fee pa	360	1	0.360
Onekaka 33 Trnfr	Transformer Charge pa	5280	1	5.280
Total actual revenue from prices				**39,668**

Appendix C – Policies and procedures for measuring planned and unplanned interruptions

For the purposes of compiling annual SAIDI and SAIFI data:

1) A high voltage outage on the distribution network is defined as an event resulting in loss of supply to any number of consumers for a duration of more than one minute
2) Only those outages resulting in de-energisation of a high voltage feeder or conductor (6.6kV and above on NTL's network) are included in SAIDI & SAIFI statistics. Outages stemming from low voltage (400V) equipment are excluded.
3) Both planned (Class B) and unplanned (Class C) events are included within high voltage outage statistics
4) All high voltage outages are managed through Network Tasman's control room by a qualified NTL System Operator
5) The Faults and Maintenance Contract between NTL and its faults contractor, Delta, obligates both parties to manage all outage events centrally through the System Operator located in NTL's control room.
6) All HV fault switching operations are recorded by the System Operator in the Control Room Log at the time the activity takes place. This provides a detailed record of the switching events for future reference and record keeping.

Under fault conditions, customers affected by operation of a distribution system high voltage protection device can be divided into:

(a) Those within the core fault area (i.e. who won't have supply restored until the necessary line repairs are completed)
(b) Those outside the immediate fault area (i.e. who can have power restored through co-ordinated switching activity)

To calculate the customer minutes lost under each fault event, each event is approximated as a maximum two step restoration process. This is in keeping with the philosophy of fault restoration that relies on the following sequential process for supply restoration:

(a) Identification, isolation and minimisation of the core fault area.
(b) Restoration, through switching, of supply to areas not immediately within the core fault area
(c) Making repairs and restoration of the core fault area.

The switching and recording process is managed by a NTL System Operator using NTL's Geographical Information System (GIS). To record outage data the operator draws geographical selection polygons around all sections of the high voltage line affected by the fault event. The software is then used to select and identify all the distribution transformers within the fault area. A query is then made into NTL's customer connection database to find and list all customers (ICPs) connected to those transformers affected by the fault event.

This data is then used in the following formula to calculate the total customer minutes for a fault event:

Total No. of customers initially affected **x** (Time Unfaulted Area restored – Time of Initial Interruption)

+

No. of Fault area customers **x** (Time Fault Area restored – Time Unfaulted Area restored)

Planned and unplanned events rely on essentially the same recording process however by nature, planned interruptions can be identified down to a predetermined set of consumers within a known area in advance.

The total customer minutes for a planned interruption are thus calculated using the following formula:

Total No. of customers interrupted **x** (Time Interrupted Area restored – Time of Initial Interruption)

The system operator records details of all outage events in the NTL Outage Database. This is an access database that remains on line in the control room. Each planned or unplanned event forms one record entry into the database. For the avoidance of doubt, an unplanned loss of supply event can, in some circumstances, be followed by restoration of supply and then by a successive interruption as a result of isolating the initial cause or making repairs and completing the permanent restoration of supply to all consumers. Where this occurs, NTL's reported SAIFI records the initial outage and not any subsequent short duration outages required to effect the restoration of supply. NTL's reported SAIDI includes the customer minutes from subsequent short duration outages required to effect the restoration of supply. The Outages Database is subject to NTL's normal electronic file backup and security protocols.

The Outage Database records the following data fields for each event:

- Date
- ID number of the protective device that has operated (allows identification of the HV feeder and area affected)
- Area: (Text description of area affected)
- Description; (Text description of fault cause and type – recorded once known)
- Outage type (Planned Shutdown or Fault)
- Area Class (Urban or Rural)
- Fault Class (Overhead or Underground)
- Fault Voltage (6.6kV, 11kV, 33kV, 66kV)
- Outage Region (Stoke, Motueka, Golden Bay, Kikiwa, Murchison)
- Time of Initial Interruption
- Time Unfaulted Area Restored
- Time Fault area restored
- Customers (ICPs) in Total Area (recorded post event)
- Customers (ICPs) in Fault area (recorded post event)

Unless otherwise stated all data is recorded on line by the NTL System Operator at the time of the event.

The outage database supports the following NTL activities:

1) Queries on an as needed basis by NTL's Network and Operations Managers
2) Summary outage statistics are prepared and provided to NTL's CEO and Board of Directors on a monthly basis and are compared against expected values.
3) Annual outage statistics are prepared and independently audited for regulatory and financial reporting purposes.
4) Summary statistics are recorded on a cumulative basis and are used for comparative analysis and form a key input into NTL's annual Asset Management Planning process.
5) Annual data is also reported against reliability targets in NTL's SCI, Information Disclosure Statements and Annual Financial Statements.
6) The SCI targets are negotiated and agreed annually with the Network Tasman Trust.

Appendix D – SAIDI and SAIFI major events

Four Major events (4 SAIFI and 3 SAIDI) occurred during Assessment Period 3.

1 Adverse weather event 31 May – 01 June 2022

(i) Cause of event: Adverse weather

(ii) Event start time and date:
SAIFI: 31-May-2022 01:00

(iii) Event end date and time:
SAIFI: 01-Jun-2022 22:30

(iv) SAIFI value before and after replacements:

This event consists of 4 individual outages that occurred during this extended major event. The respective SAIFI original and replacement SAIFI values for these outages are as follows:

	Before	Replacement
1	0.012334554	0.001433333
2	0.056476811	0.001433333
3	0.000608536	0.000608536
4	0.001240477	0.001240477

Description of event:

A rain and wind storm affected the 33kV feeder supplying the Mapua zone substation as well as an 11kV feeder supplying the Ruby Bay area, affecting close to 3000 customers in the very early hours of the morning.

(v) Location of the major event:

The Waimea plains / Mapua areas.

(vi) Main equipment involved:

11kV feeder out of Mapua substation

33kV Mapua feeder between Hope substation and the Appleby Highway

(vii) How we responded to the major event:

The 11kV fault was handled through the normal fault response process, i.e. a patrol of public spaces was carried out before it was re-livened.

The 33kV supply to Mapua was reinstated by switching to an alternative supply route. This allowed supply to be restored to most of the affected customers within 30 minutes.

(viii) Mitigating factors that may have prevented or minimised the major event:

The 11kV fault was due to a tree branch over the lines from a 'fall distance' tree. Fall distance trees such as this are not covered by the Tree Regulations.

No fault was found for the 33kV Mapua feeder fault. The high winds experienced at the time could have blown debris onto the line.

(ix) A description of any steps we propose to take to mitigate the risk of future similar major events:

Our vegetation survey and notification process specifically includes the identification of high-risk fall distance trees and we offer to fell such trees for affected property owners. This policy results in many high-risk trees being removed but the owners of fall distance trees that are not in the 'close distance' growth zone have no obligation to accept our offer to fell such trees. In this case, the tree involved was not considered as being a high-risk tree and the vegetation team will review their assessment of what constitutes high-risk tree.

We recently installed a secondary 33kV supply for the Mapua substation and this allowed us to rapidly restore supply to Mapua during this storm.

2 Major Event 12 July 2022.

(i) Cause of event: Cable fault and a fallen tree that landed on our lines

(ii) & (iii) Event start time and date:
SAIDI: 11-Jul-2022 11:30
SAIFI: 11-Jul-2022 08:00

(iv) & (v) Event end date and time:
SAIDI: 13-Jul-2022 04:00
SAIFI: 13-Jul-2022 07:00

(iv) SAIDI/SAIFI values before and after replacements:

Value	SAIDI		SAIFI	
Changes	**Before**	**Replacement**	**Before**	**Replacement**
1	0.0015213	0.0015213	0.0000234	0.0000234
2	4.0677815	0.1504167	0.0284139	0.0014333
3	0.4184854	0.1504167	0.0697476	0.0014333
4	1.8242033	0.1504167	0.0177646	0.0014333
5	1.0148974	0.1504167	0.0034172	0.0014333

Description of event:

This was combination of four coinciding faults at different sites. Three of the faults were caused by high winds in the region, but one of the faults was not weather related. The faults were:

- A fault caused by a tree falling onto the HV and LV lines
- An 11kV cable fault for which no obvious reason was found
- Two smaller HV faults resulting from windblown debris

The tree fault was found to have been caused by a large tree on a person's private property that fell over during high winds after they had undertaken earthworks near the tree which may have weakened the tree's support system.

The two smaller 11kV faults were a blown lightning arrestor probably caused by electrical storm activity, and blown drop-out fuses, which are likely to have been related to airborne debris or vegetation.

No obvious reason for the 11kV cable fault was found, however the weather at the time of the fault (high winds and rain) extended the repair time.

(v) Location of the major event:

The tree fault occurred on Hill Street in Richmond in a residential area.

The two smaller 11kV faults were in the Mapua and Cable Bay areas.

The 11kV fault was on a stretch of cable that passed under a river and supplied the Kaiteriteri area.

(vi) Main equipment involved:

11kV feeder supplying the northern part of Hill Street area.

11kV line supplying the Cable Bay area.

11kV substation in Mapua area (Seaton Valley Road)

11kV cable supplying the Kaiteriteri area

(vii) How we responded to the major event:

All of the faults were handled via the normal fault response processes.

The 11kV cable fault was being worked on when the rain and wind storm took place affecting the supply the Hill Street.

(viii) Mitigating factors that may have prevented or minimised the major event:

All of the faults were on radial sections of the network and there were no back-feed options available.

(ix) A description of any steps we propose to take to mitigate the risk of future similar major events:

Hill Street fault: Our vegetation survey and notification process specifically includes the identification of high-risk fall distance trees and we offer to fell such trees for affected property owners. This policy results in many high-risk trees being removed but the owners of fall distance trees that are not in the 'close distance' growth zone have no obligation to accept our offer to fell such trees. In this case, the tree involved was not considered as being a high-risk tree and the vegetation team will review their assessment of what constitutes high-risk tree.

Kaiteriteri cable fault: The cable fault was made more difficult to find and repair due to it being located at a river crossing.

3 Major Event 17 August to 21 August 2022

(i) Cause of event: Storm (Big August Rain Storm Event)

(ii) & (iii) Event start time and date:
SAIDI: 16-Aug-2022 18:00
SAIFI: 16-Aug-2022 18:00

(iv) & (v) Event end date and time:
SAIDI: 20-Aug-2022 23:00
SAIFI: 18-Aug-2022 17:00

(vi) SAIDI/SAIFI value before and after replacements:

Value	SAIDI		SAIFI	
Changes	Before	Replacement	Before	Replacement
1	7.6346912	0.1504167	0.0894080	0.0014333
2	14.4843009	0.1504167		
3	0.1997870	0.1504167		
4	5.0419071	0.1504167		
5	1.5841359	0.1504167		
6	0.1123451	0.1123451		
7	0.3746709	0.1504167		
8	0.3035892	0.1504167		
9	0.0018724	0.0018724		
10	1.8289078	0.1504167		

Description of event:

Heavy and prolonged rain event, flooding, land slips etc.

(vii) Location of the major event:

This event resulted from high rainfalls in the eastern ranges of Tasman which mainly affected Nelson and eastern Nelson areas.

(viii) Main equipment involved:

33kV feeders to Founders, and Wakapuaka zone substations

Various 11kV feeders in the affected areas

(ix) How we responded to the major event:

This was a large event that involved all available fault crew working at some stage during it. The Network Tasman media team was stood up to provide liaison between the control room and the civil defence emergency control centre and the media. The control room was also moved to a 24/7 operation for the main duration of the event.

(x) Mitigating factors that may have prevented or minimised the major event:

The impact of the faults was made worse by access issues caused by swollen rivers and slips making it unsafe for us to send fault crew to the affected parts of the network while the event was unfolding. When the weather cleared we used helicopters to patrol lines and access parts of the network that were cut off due to road closures.

(xi) A description of any steps we propose to take to mitigate the risk of future similar major events:

We have a capital investment project planned to provide an additional 33kV supply from Founders to Wakapuaka substation. This will improve our resilience to events that presently affect the single circuit supply to Wakapuaka substation.

4 Major Event 11 March to 13 March 2023

(i) Cause of event: Coincident faults, high winds

(ii) & (iii) Event start time and date:
SAIDI: 11-Mar-2023 16:00
SAIFI: 11-Mar-2023 16:00

(iv) & (v) Event end date and time:
SAIDI: 13-Mar-2023 15:00
SAIFI: 13-Mar-2023 15:00

(vi) SAIDI/SAIFI value before and after replacements:

Value Changes	SAIDI		SAIFI	
	Before	Replacement	Before	Replacement
1	0.4911119	0.1504167	0.0054534	0.0014333
2	11.9387017	0.1504167	0.1640706	0.0014333

Description of event:

Two series connected 33kV circuit breakers operated at the same time. Under normal circumstances, only one of these CB's should operate to clear a fault, so the situation was unusual and made a diagnosis of the likely location of the fault difficult as well as increasing the length of line which needed to be patrolled.

(vii) Location of the major event:

33kV feeder supplying the Wakefield, Brightwater and Hope areas

(viii) Main equipment involved:

33kV feeder supplying the Wakefield, Brightwater and Hope areas

(ix) How we responded to the major event:

Public spaces along the entire 33kV feeder were patrolled before re-livening was attempted. This happened relatively quickly and supply was restored to most customers within an hour, but the impact was high because of the number of customers affected. An alternative supply route was available for some customers but it was decided to focus on getting the normal supply restored instead of diverting field crew to switching in the alternative route.

(x) Mitigating factors that may have prevented or minimised the major event:

Post-event analysis shows that there were two separate but related faults. The first one was 'cause unknown'. The second fault was caused by line clashing resulting from fault current EMF's upstream of the CB which cleared the fault but then re-closed onto it again. The line clashes caused the main GXP feeder CB to operate. If the upstream lines had not clashed, then the second fault would not have occurred.

(xi) A description of any steps we propose to take to mitigate the risk of future similar major events:

There have been similar faults to the initial one that have not resulted in line clashes, so it's possible that this event was unique in terms of having precisely the right duration and fault current for the upstream lines to move and clash in the way that they did. However, an engineering analysis of the 33kV line that clashed will be undertaken to determine if there are design issues that may have made these lines more likely to clash in this situation.

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APPENDIX E – Directors Certificate

Schedule 7: Form of director's certificate for annual compliance statement

Clause 11.5(d)

We, Michael John McCliskie and Anthony Page Reilly, being directors of Network Tasman Limited certify that, having made all reasonable enquiry, to the best of our knowledge and belief, the attached annual compliance statement of Network Tasman 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.

Michael John McCliskie
Director

Anthony Page Reilly
Director

28 July 2023

Appendix F – Assurance report

Independent Assurance Report

To the directors of Network Tasman Limited on the Annual Compliance Statement for the assessment period ended 31 March 2023 as required by the Electricity Distribution Services Default Price-Quality Path Determination 2020 (consolidated 20 May 2020)

The Auditor-General is the auditor of Network Tasman 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 4 to 35 for the assessment period ended on 31 March 2023 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 2023.

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 (NZ) 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.

- For the 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 2023, 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 4 to 7, and 17 to 24 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 8 to 13, and 25 to 35 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 14 and 15 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
28 July 2023