



TasNetworks transmission determination 1 July 2015 - 30 June 2019

April 2015

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Shortened forms

Shortened form	Extended form
AER	Australian Energy Regulator
AR	Annual revenue
CESS	Capital expenditure sharing scheme
EBSS	Efficiency benefit sharing scheme
MAR	Maximum allowed revenue
NER	National Electricity Rules
NSP	Network service provider
NTSC	Negotiated transmission service criteria
opex	operating expenditure
PTRM	Post tax revenue model
RAB	Regulatory asset base
STPIS	Service target performance incentive scheme
TNSP	Transmission network service provider

Summary

The Australian Energy Regulator (AER) must make a transmission determination for each transmission network service provider (TNSP) in accordance with chapter 6A of the National Electricity Rules (NER).¹

This document is our transmission determination for TasNetworks for the regulatory control period 1 July 2015 to 30 June 2019. Our reasons are included in the AER's final decision on TasNetworks' transmission determination (April 2015) which is to be read in conjunction with this document.

Our transmission determination for TasNetworks consists of:²

- A revenue determination in respect of the provision by TasNetworks of prescribed transmission services (section 1)
- A determination relating to TasNetworks' negotiating framework (section 2)
- A determination that specifies the negotiated transmission service criteria (NTSC) that apply to TasNetworks (section 3)
- A determination that specifies the pricing methodology that applies to TasNetworks (section 4)
- A determination that specifies pass through events that will apply to this determination in addition to those specified in the NER (section 5).

¹ NER, clause 6A.2.1.

² NER, clause 6A.2.2; 6A.7.3(a1).

1 Revenue

We are required to calculate the amount of revenue that TasNetworks requires each year of the regulatory control period in accordance with a building block approach.³ This is referred to as the *annual building block revenue requirement*. The annual building block revenue is then used to calculate the expected *maximum allowed revenue* (MAR) for each year of the 2015–19 regulatory control period. The annual MAR that TasNetworks may earn from providing prescribed transmission services is subject to adjustments to account for factors such as inflation, approved pass through costs and annual performance rewards or penalties.

Our revenue determination specifies the following matters:⁴

- The amount of the estimated total revenue cap for the regulatory control period or the method of calculating that amount.
- The annual building block revenue requirement for each regulatory year of the regulatory control period.
- The amount of the MAR for each regulatory year of the regulatory control period or the method of calculating that amount.
- The regulatory asset base (RAB) as at the commencement of the regulatory control period.
- Appropriate methodology for the indexation of the RAB.
- The values that are to be attributed to the performance incentive scheme parameters for the purposes of the application to TasNetworks of the service target performance incentive scheme (STPIS) that applies in respect of the regulatory control period.
- The values that are to be attributed to the efficiency benefit sharing scheme parameters for the purposes of the application to TasNetworks of the efficiency benefit sharing scheme (EBSS) that applies in respect of the regulatory control period
- How any capital expenditure sharing scheme (CESS) or small-scale incentive scheme is to apply to TasNetworks
- The commencement and length of the regulatory control period.
- Whether depreciation for establishing the regulatory asset base as at the commencement of the following regulatory control period is to be based on actual or forecast capital expenditure.

³ NER, clause 6A.5.4.

⁴ NER, clause 6A.4.2

1.1 Method for calculating estimated total revenue cap

We determine an estimated total MAR of \$693.9 million (\$ nominal) for TasNetworks for the 2015–19 regulatory control period (or \$880.8 million for the 2014–19 period, including the 2014–15 transitional year) as shown in Table 1. The estimated total MAR is also known as the total revenue cap. It is the sum of the expected MAR for each regulatory year.⁵

Table 1 AER's final determination on TasNetworks' annual expected maximum allowed revenue (\$ million, nominal)

	2014–15	2015–16	2016–17	2017–18	2018–19	Total 2014–19	Total 2015–19
Annual expected MAR (smoothed)	186.9	172.6	173.2	173.8	174.3	880.8	693.9
X factor (%)	n/a	9.81% ^a	2.00% ^b	2.00% ^b	2.00% ^b	n/a	n/a

Source: AER analysis.

- (a) Applying the X factor for 2015–16 and the actual CPI of 1.72 per cent in accordance with the annual revenue adjustment formula set out in section 1.3 of this transmission determination, the MAR for 2015–16 is \$171.5 million.
- (b) The X factor will be revised to reflect the annual return on debt update.

We determine the annual expected MAR by using the X factors to smooth the annual building block revenue requirement as set out below.

1.2 Annual building block revenue requirement

We determine the annual building block revenue requirement for TasNetworks as shown in Table 2.

⁵ NER, clause 6A.5.3.

Table 2 AER's final determination on TasNetworks' annual building block revenue requirement (\$ million, nominal)

	2014–15	2015–16	2016–17	2017–18	2018–19	Total
Return on capital	91.4	92.0	94.9	96.9	98.4	473.6
Regulatory depreciation	19.4	22.9	26.3	26.2	27.4	122.3
Operating expenditure	45.1	45.5	46.8	48.2	48.8	234.4
Efficiency benefit sharing scheme (carryover amounts)	12.5	8.8	7.2	4.5	0	33.0
Net tax allowance	3.6	3.9	4.2	4.2	4.6	20.4
Annual building block revenue requirement (unsmoothed)	172.0	173.0	179.5	180.0	179.2	883.7

Source: AER analysis.

1.3 Method for calculating maximum allowed revenue

We use a forecast inflation rate in our post-tax revenue model (PTRM) to calculate the expected MAR (as shown in Table 1) in nominal dollar terms. Therefore, the calculation of the actual annual MAR will require an adjustment for actual inflation. The MAR is also subject to adjustments for updating the return on debt annually, revenue increment or decrement determined in accordance with the STPIS, and any approved pass through amounts. This section sets out the method of this annual adjustment process.

We determine that the method for calculating TasNetworks' MAR for each year of the 2014–19 period will be the sum of its allowed revenue (AR) for that year and adjustments arising from the STPIS and any approved pass through amounts.

We determine AR of \$186.9 million for TasNetworks for 2014–15. TasNetworks then applies an annual adjustment to determine its AR for each subsequent year of the 2014–19 period, based on the previous year's AR and using the CPI–X methodology. That is, the subsequent year's AR is determined by adjusting the previous year's AR for actual inflation and the X factor determined after the annual return on debt update:

$$AR_t = AR_{t-1} \times (1 + \Delta CPI) \times (1 - X_t)$$

where:

AR = the allowed revenue

t = time period/financial year (for t = 2, (2015–16), 3 (2016–17), 4 (2017–18), 5 (2018–19))

ΔCPI = the annual percentage change in the Australian Bureau of Statistics' (ABS) consumer price index (CPI) all groups, weighted average of eight capital cities from December in year $t - 2$ to December in year $t - 1$ ⁶

X = the smoothing factor determined in accordance with the PTRM as approved in the AER's final decision, and annually revised for the return on debt update in accordance with the formula specified in the AER's draft decision return on debt appendix of attachment 3 calculated for the relevant year.

The MAR is determined annually in accordance with the NER by adding to (or deducting from) the AR:

- the service target performance incentive scheme revenue increment (or revenue decrement)⁷
- any approved pass through amounts.⁸

Table 3 sets out the timing of the annual calculation of the AR and performance incentive:

$\text{MAR}_t = (\text{allowed revenue}) + (\text{performance incentive}) + (\text{pass through})$

$$= \text{AR}_t + \left(\frac{(\text{AR}_{t-1} + \text{AR}_{t-2})}{2} \times S_{ct} \right) + P_t$$

where:

MAR = the maximum allowed revenue

AR = the allowed revenue

S = the revenue increment or decrement determined in accordance with the STPIS

P = the pass through amount (positive or negative) that the AER has determined in accordance with clauses 6A.7.2 and 6A.7.3 of the NER

⁶ In the transmission determination for TasNetworks' 2009–14 regulatory control period, the CPI required for the annual MAR adjustment process reflects the March quarter CPI, which is typically published by the ABS in late April each year. For this transmission determination we require TasNetworks to use the December quarter of the previous calendar year CPI for the annual MAR adjustment for its next regulatory control period. December quarter CPI is typically released by the ABS towards the end of January of the following year. As the same set of CPI will be used for the RAB roll forward at the next reset for TasNetworks in 2019, this change will allow us to update the actual CPI for RAB roll forward purposes well before the publication date of the AER's final decision at the next reset. We note that there will be an overlapping issue of the March quarter CPI when the transition to the December quarter CPI occurs (this will be in the year 2014–15 for the TNSP). This is because the CPI for March quarter 2014 will be reflected in both 2013–14 and 2014–15. However, we consider this is only a transitional issue and does not have a material impact on the revenue to be recovered by the TNSP.

⁷ NER, clauses 6A.7.4.

⁸ NER, clauses 6A.7.2 and 6A.7.3.

t = time period/financial year (for $t = 2$ (2015–16), 3 (2016–17), 4 (2017–18), 5 (2018–19))

ct = time period/calendar year (for $t = 2$ (2014), 3 (2015), 4 (2016), 5 (2017)).

Under the NER, a TNSP may also adjust the MAR for under or over recovery amounts.⁹ That is, the revenue amounts recovered higher or lower than the approved MAR for each year would be included in the subsequent year's MAR. In the case of an under-recovery, the amount would be added to the future year's MAR. In the case of an over-recovery, the amount would be subtracted from the future year's MAR.

Table 3 Timing of the calculation of allowed revenues and the performance incentive for TasNetworks

t	Allowed revenue (financial year)	ct	Performance incentive (calendar year)
2	1 July 2015–30 June 2016	2	1 January 2014–31 December 2014
3	1 July 2016–30 June 2017	3	1 January 2015–31 December 2015
4	1 July 2017–30 June 2018	4	1 January 2016–31 December 2016
5	1 July 2018–30 June 2019	5	1 January 2017–31 December 2017

Note: The performance incentive for 1 January 2013–31 December 2013 is to be applied to the AR determined for 2014–15 (the placeholder determination).

1.4 Regulatory asset base

We determine an opening RAB value of \$1443.8 million as at the commencement of the 2015–19 regulatory control period for TasNetworks. This is based on an opening RAB value of \$1410.3 million as at 1 July 2014.

1.5 Method for indexation of the regulatory asset base

We determine that the method for indexing TasNetworks' RAB for each year of the 2014–19 period will be the same as that used to escalate its AR for that relevant year—that is, to apply the annual percentage change in the published ABS CPI all groups, weighted average of eight capital cities.¹⁰ For TasNetworks, this will be the December quarter CPI. This method will be used as part of the roll forward of TasNetworks' opening RAB for the purposes of the AER's transmission revenue determination for the regulatory control period commencing on 1 July 2019.

⁹ NER, clauses 6A.23.3(c)(2)(iii) and 6A.24.4(c).

¹⁰ ABS, *Catalogue number 6401.0, Consumer price index*, Australia.

1.6 Performance incentive scheme parameters

The AER has determined the values for the performance targets, caps, collars and weightings for each of the parameters for the service component of the service target performance incentive scheme (STPIS) applicable to TasNetworks for the 2015–19 regulatory control period.¹¹ These are shown in Table 4.

Table 4 AER's final decision on TasNetworks' parameter values and weightings for the service component of the STPIS

Parameter	Collar	Target	Cap	Weighting (% of MAR)
Average circuit outage rate				
Line outage – fault	64.59%	31.17%	13.39%	0.2
Transformer outage – fault	17.28%	11.60%	7.03%	0.2
Reactive plant – fault	9.99%	3.33%	0.17%	0.1
Line outage – forced outage	17.62%	9.99%	2.67%	0.0
Transformer outage – forced outage	4.37%	2.82%	1.28%	0.0
Reactive plant – forced outage	32.82%	14.00%	1.07%	0.0
Loss of supply event frequency				
>0.1 system minutes	11	10	8	0.15
>1.0 system minutes	5	3	0	0.15
Average outage duration				
Average outage duration	169.76	111.52	63.99	0.2
Proper operation of equipment				
Failure of protection system	14	9	5	0.0
Material failure of SCADA	25	8	0	0.0
Incorrect operational isolation of primary or secondary equipment	8	4	1	0.0

Sources: TasNetworks, *Revenue proposal regulatory control period 1 July 2014 – 30 June 2019*, p. 123; TasNetworks, *Further changes to TasNetworks (TasNetworks) Reset RIN templates*, 17 July 2014; AER analysis.

TasNetworks' market impact parameter performance targets that will apply within the 2015–19 regulatory control period will be published annually as part of our service standards compliance reporting process.

¹¹ AER, *Final – Service target performance incentive scheme*, September 2014.

The AER has determined that the priority projects and improvement targets shown in Table 5 will apply to TasNetworks during the 2015–19 regulatory control period.

Table 5 AER’s final decision on TasNetworks’ network capability priority projects (\$ 000s, 2013–14)

Ranking	Project	Description	Improvement target	Capex	Opex	Total
1	All transmission lines that are currently controlled through AEMO’s generation dispatch	Fifteen Minutes Transient Rating for Transmission Lines	<p>a) An additional line capacity of 5 to 20 % can be achieved depending upon the conductor properties, transmission line construction (stringing) and the ambient conditions.</p> <p>b) The scheme is found to provide an additional capacity of 10 to 20 % levels during low wind conditions. This will provide boost to transmission capacity during adverse high temperature and low wind conditions.</p> <p>c) The scheme requires no additional control mechanisms to regulate the line flow and can use AEMO’s existing generation dispatch engine to reduce the overload.</p> <p>d) The same computation methodology can be extended to provide two minute dynamic ratings that are required for future NCSPS schemes.</p>	40	0	40
2	Knights Road Substation	Dynamic rating of Knights Road Substation supply transformers	<p>Defer need to expend substantial capital to augment transformers for several years until station load exceeds dynamic rating.</p> <p>Ratings of transformers are made using weighted ambient of 20degC. Possibility of using DRMCC at sites such as Knights Road, where load is over firm name plate rating, and utilise actual winter peak ambient (about 10DegC) which would increase load rating of transformers.</p>	150	16	166
3	██████████ Substation ¹²	Dynamic rating of substation supply transformers	Enable a customer to continue plant production for longer time in the event of loss of a transformer. ¹³	180	20	200
4	Farrell-Que-Savage River-Hampshire, Farrell-Rosebery-	Installation of new line fault	Reduced fault outage restoration times for customers supplied from the 110	230	19	249

12 Substation location may reveal confidential customer information. This information is included in confidential appendix A to this determination.

13 Confidential information regarding TasNetworks’ customer’s information is included in confidential appendix A to this determination.

Ranking	Project	Description	Improvement target	Capex	Opex	Total
	Queenstown, Norwood-Scottsdale-Derby and Lindisfarne-Sorell-Triabunna 110 kV transmission circuits	indicators	kV transmission circuits listed above.			
5	All transmission circuits whose flow is controlled by AEMO constraint equations	Review and optimisation of Operational Margins for TasNetworks limit equations	The deliverable from this project will be the submission of an updated TasNetworks' operational margins paper to AEMO for implementation.	0	35	35
6	Palmerston-Avoca and Knights Road-Huon River-Kermantie 110kV transmission circuits	Line fault indicator (LFI) remote communications	Reduced fault outage durations for customers supplied from Avoca, St Marys, Kermantie and Huon River substations	60	0	60
7	Basslink Tasmania-Victoria interconnector	George Town automatic voltage control scheme (GTAVCS) 2.0	Improved, automated voltage control at George Town 220 kV bus at times of low fault level and Basslink export levels 300 MW or higher.	480	0	480
8	All 220/110kV network transformers	Dynamic rating of all 220/110 kV network transformers	Dynamic ratings (and life expectancy) of network transformers will be continuously monitored and reported.	900	58	958
9	Sheffield – Devonport transmission circuit	Substandard spans verification and rectification	Completion of LIDAR survey for circuits of interest. Rectification of substandard clearances. Increase in line design temperature where possible.	279	0	279
10	Sheffield-George Town 220 kV transmission line	Replace disconnectors, CT and bay conductor to achieve line rating increase and reduce market constraints	Replace present limiting terminal equipment at Sheffield Substation on the SH-GT 1 and 2 220 kV transmission circuits to increase their circuit terminal ratings to 2000A to reduce market constraints.	1,120	0	1120
11	Weather stations at Creek Road, Chapel Street, Devonport, Trevallyn, Hadspen, Sheffield, and Farrell substations	Weather station telemetry renewal	Relocation and/or upgrade of weather station assets at seven sites.	1050	0	1050
12	Liapootah-Waddamana-Palmerston No 1, Liapootah-Cluny-Repulse-Chapel Street No 1, Liapootah-Chapel Street No 2 and George Town-	Upgrade of dead end fittings on selected transmission lines	Increased power transfer capability.	840	0	840

Ranking	Project	Description	Improvement target	Capex	Opex	Total
	Comalco No 4 & 5 220 kV transmission circuits. Hadspen-Norwood No 1 & 2 110 kV transmission circuits.					
13	Palmerston-Avoca transmission circuit	Substandard spans verification and rectification	Completion of LIDAR survey for circuits of interest. Rectification of substandard clearances. Increase in line design temperature where possible.	926	0	926
14	Castle Forbes Bay Tee Switching Station	Castle Forbes Bay Tee Switching Station disconnecter upgrade	<p>Reduce the number of planned outages unnecessarily affecting customers supplied from Kermandie Substation. It is estimated that this could prevent at least one planned outage per year from impacting on customers supplied from Kermandie Substation.</p> <p>Reduce the duration of unplanned outages for customers supplied from Kermandie and Huon River substations, where the cause of the outage is on the Huon River Spur. In the event of wind borne debris causing a sustained fault outage on the Huon River Spur, it is reasonable to expect that the supply restoration time for customers supplied from Kermandie Substation could be reduced by up to 90 minutes.</p>	250	0	250
15	Sheffield-Farrell 1 & 2, Farrell-Reece 1 & 2, Farrell-John Butters 220kV and Farrell-Rosebery-Queenstown 110 kV transmission circuits	Transmission line surge diverter installation and tower footing earthing improvements	Reduced unplanned outage frequency due to lightning.	550	0	550
16	Savage River Spur transmission circuit	Substandard spans verification and rectification	Completion of LIDAR survey for circuits of interest. Rectification of substandard clearances. Increase in line design temperature where possible.	1,389	0	1,389
17	Knights Road-Kermandie transmission circuit	Increase transmission line design temperature by removing substandard clearance on selected spans	Collection of substandard line clearance data to facilitate rerating of surveyed transmission lines	291	0	291
18	Palmerston-Hadspen No 1 & 2, Palmerston-Sheffield and Sheffield-Burnie No 1	Installation of modern fault location functionality	Fault location relay capability on the identified transmission circuits	120	14	134

Ranking	Project	Description	Improvement target	Capex	Opex	Total
	220 kV transmission circuits	for more accurate fault location on the identified transmission circuits				
19	Chapel St Substation	Install a second 110 kV bus coupler dead tank circuit breaker in series with the existing bus coupler circuit breaker	No interruption of supply caused by failure of a single 110 kV bus coupler circuit breaker	450	0	450
Total				9,305	162	9,467

Source: TasNetworks, *Appendix 1 – Network capability incentive parameter action plan*, 2 June 2014. AEMO, *AEMO endorsement of TasNetworks Network Capability Incentive Parameter Action Plan (NCIPAP) for 1 July 2014 – 30 June 2019*, 4 February 2014. TasNetworks, *NCIPAP Overview Sheet – Low spans breakdown*, 31 July 2014, TasNetworks, *Transmission Service Standards Compliance Review*, 30 January 2015.

1.7 Efficiency benefit sharing scheme (EBSS) parameters

The AER has determined the values for the efficiency benefit sharing scheme (EBSS) parameters that are to apply to TasNetworks in the 2014–19 period, subject to adjustments required by the EBSS. These values are set out in Table 6.

Table 6 AER's decision on TasNetworks' forecast operating expenditure (opex) for the EBSS (\$ million, 2013–14)

	2014-15	2015-16	2016-17	2017-18	2018-19
Forecast opex for EBSS purposes	44.0	43.4	43.6	43.9	43.4
Self insurance	0.7	0.7	0.7	0.7	0.7
Network support costs	-	-	-	-	-
Debt raising costs	0.95	0.95	0.96	0.96	0.96
Forecast opex for EBSS purposes	42.4	41.8	42.0	42.2	41.7

Source: AER analysis.

Note: opex does not include network capability incentive projects

The AER will exclude the following costs from the EBSS:

- debt raising costs
- network support costs
- self-insurance costs

- opex on network capability incentive projects.

In addition to these excluded cost categories we will also:

- adjust forecast opex to add (subtract) any approved revenue increments (decrements) made after the initial regulatory determination. This may include approved pass through amounts.
- adjust actual opex to add capitalised opex that has been excluded from the RAB
- exclude categories of opex not forecast using a single year revealed cost approach for the regulatory control period beginning in 2019 where doing so better achieves the requirements of clause 6A.6.5 of the NER.

When calculating actual opex under the EBSS we will adjust reported actual opex for the 2014–19 period to reverse any movements in provisions.

1.8 Application of the capital expenditure sharing scheme (CESS)

We will apply version 1 of the CESS as set out in the capital expenditure incentives guideline to TasNetworks in the 2015–19 regulatory control period.¹⁴ The guideline provides for the exclusion from the CESS of capex the service provider incurs in delivering a priority project approved under the network capability component of the STPIS.¹⁵

1.9 Commencement and length of the regulatory control period

The regulatory control period will be four years, commencing on 1 July 2015 and ending on 30 June 2019.

1.10 Depreciation for establishing the regulatory asset base as at the commencement of the next regulatory control period

We determine that the forecast depreciation approach (that is, based on forecast capex) will apply to the 2014–19 period and is to be used to establish the RAB at the commencement of the regulatory control period from 1 July 2019 for TasNetworks.

¹⁴ AER, *Capex incentive guideline*, November 2013, pp. 5–9.

¹⁵ AER, *Capex incentive guideline*, November 2013, p. 6.

2 Negotiating framework

Our determination on TasNetworks' negotiating framework accepts in full the framework prepared by TasNetworks.

TasNetworks must comply with its negotiating framework and its NTSC (see section 3 of this determination) when it is negotiating the terms and conditions of access for negotiated transmission services to be provided to a person.¹⁶

TasNetworks' negotiating framework sets out the procedure to be followed during negotiations between TasNetworks and any person who wishes to receive a negotiated transmission service from TasNetworks, as to the terms and conditions of access for provision of the service.¹⁷

The negotiating framework in Attachment A to this determination must be adopted by TasNetworks for the regulatory control period covered by this determination.

¹⁶ NER, clause 6A.9.2(a); 6A.9.3. TasNetworks must also comply with chapters 4, 5 and 6A of the NER.

¹⁷ NER, clause 6A.9.5(a).

3 Negotiated transmission service criteria (NTSC)

Our determination on TasNetworks' NTSC accepts in full the NTSC proposed by TasNetworks.

TasNetworks must comply with its negotiating framework (see section 2 of this determination) and its NTSC when it is negotiating the terms and conditions of access for negotiated transmission services to be provided to a person.¹⁸

TasNetworks' NTSC sets out the criteria that are to be applied:¹⁹

- by TasNetworks in negotiating:
 - the terms and conditions of access for negotiated transmission services, including the prices that are to be charged for the provision of those services by TasNetworks for the regulatory control period
 - any access charges which are negotiated by TasNetworks during the regulatory control period
- by a commercial arbitrator in resolving any dispute, between TasNetworks and a person who wishes to receive a negotiated transmission service, in relation to:
 - the terms and conditions of access for the negotiated transmission service, including the price that is to be charged for the provision of that service by TasNetworks
 - any access charges that are to be paid to or by TasNetworks.

The following NTSC will apply to TasNetworks for the regulatory control period covered by this determination.

National Electricity Objective

1. The terms and conditions of access for a negotiated transmission service, including the price that is to be charged for the provision of that service and any access charges, should promote the achievement of the National Electricity Objective.

Criteria for terms and conditions of access

Terms and conditions of access

2. The terms and conditions of access for a negotiated transmission service must be fair, reasonable and consistent with the safe and reliable operation of the power system in accordance with the NER.

¹⁸ NER, clause 6A.9.2(a); 6A.9.3. TasNetworks must also comply with chapters 4, 5 and 6A of the NER.

¹⁹ NER, clause 6A.9.4

3. The terms and conditions of access for negotiated transmission services, particularly any exclusions and limitations of liability and indemnities, must not be unreasonably onerous. Relevant considerations include the allocation of risk between the TNSP and the other party, the price for the negotiated transmission service and the cost to the TNSP of providing the negotiated service.
4. The terms and conditions of access for a negotiated transmission service must take into account the need for the service to be provided in a manner that does not adversely affect the safe and reliable operation of the power system in accordance with the NER.

Price of services

5. The price of a negotiated transmission service must reflect the cost that the TNSP has incurred or incurs in providing that service, and must be determined in accordance with the principles and policies set out in the Cost Allocation Methodology.
6. Subject to criteria 7 and 8, the price for a negotiated transmission service must be at least equal to the avoided cost of providing that service but no more than the cost of providing it on a stand-alone basis.
7. If the negotiated transmission service is a shared transmission service that:
 - (a) exceeds any network performance requirements which it is required to meet under any relevant electricity legislation; or
 - (b) exceeds the network performance requirements set out in schedule 5.1a and 5.1 of the NER
8. then the difference between the price for that service and the price for the shared transmission service which meets network performance requirements must reflect the TNSP's incremental cost of providing that service (as appropriate).
9. For shared transmission services, the difference in price between a negotiated transmission service that does not meet or exceed network performance requirements and a service that meets those requirements should reflect the TNSP's avoided costs. Schedule 5.1a and 5.1 of the NER or any relevant electricity legislation must be considered in determining whether any network service performance requirements have not been met or exceeded.
10. The price for a negotiated transmission service must be the same for all Transmission Network Users. The exception is if there is a material difference in the costs of providing the negotiated transmission service to different Transmission Network Users or classes of Transmission Network Users.
11. The price for a negotiated transmission service must be subject to adjustment over time to the extent that the assets used to provide that service are subsequently used to provide services to another person. In such cases the adjustment must reflect the extent to which the costs of that asset are being recovered through charges to that other person.

12. The price for a negotiated transmission service must be such as to enable the TNSP to recover the efficient costs of complying with all regulatory obligations associated with the provision of the negotiated transmission service.

Criteria for access charges

Access charges

13. Any access charges must be based on the costs reasonably incurred by the TNSP in providing Transmission Network User access. This includes the compensation for forgone revenue referred to in clause 5.4A(h) to (j) of the NER and the costs that are likely to be incurred by a person referred to in clause 5.4A(h) to (j) of the NER (as appropriate).

4 Pricing methodology

Our determination on TasNetworks' pricing methodology accepts in full TasNetworks' proposed pricing methodology (Attachment B to this transmission determination).

The role of TasNetworks' pricing methodology is to answer the question 'who should pay how much'²⁰ in order for TasNetworks to recover its costs. TasNetworks' pricing methodology provides a 'formula, process or approach'²¹ that when applied:

- allocates the aggregate annual revenue requirement to the categories of prescribed transmission services that a transmission business provides and to the connection points of network users²²
- determines the structure of prices that a transmission business may charge for each category of prescribed transmission services.²³

TasNetworks' pricing methodology relates to prescribed transmission services only.

²⁰ AEMC, *Rule determination: National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No. 22*, 21 December 2006, p. 1.

²¹ NER, 6A.24.1(b).

²² NER, clause 6A.24.1(b)(1).

²³ NER, clause 6A.24.1(b)(2).

5 Pass through events

Under the NER any of the following is a pass through event for this transmission determination:²⁴

- a regulatory change event
- a service standard event
- a tax change event
- an insurance event
- any other event specified in this transmission determination as a pass through event for this determination.

The first four of these pass through events are prescribed by, and defined in, the NER.²⁵

In addition, the following nominated pass through events will apply to TasNetworks for the 2015–19 regulatory control period:²⁶

5.1 Insurance cap event

An insurance cap event occurs if:

1. TasNetworks makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy,
2. TasNetworks incurs costs beyond the relevant policy limit, and
3. the costs beyond the relevant policy limit materially increase the costs to TasNetworks in providing direct control

For this insurance cap event:

4. the relevant policy limit is the greater of:
 - (a) TasNetworks' actual policy limit at the time of the event that gives, or would have given rise to a claim, and
 - (b) the policy limit that is explicitly or implicitly commensurate with the allowance for insurance premiums that is included in the forecast operating expenditure allowance approved in the AER's final decision for the regulatory control period in which the insurance policy is issued.

²⁴ NER, clause 6A.7.3(1a).

²⁵ NER, Chapter 10 Glossary

²⁶ NER, clauses 6A.6.9, 6A.7.3(a1)(5).

5. A relevant insurance policy is an insurance policy held during the 2015-19 regulatory control period or a previous regulatory control period in which TasNetworks was regulated.

Note: for the avoidance of doubt, in assessing an insurance cap event cost pass through application under rule 6A.7.3, the AER will have regard to:

- i. the insurance policy for the event,
- ii. the level of insurance that an efficient and prudent NSP would obtain in respect of the event, and
- iii. the extent to which a prudent provider could reasonably mitigate the impact of the event.

5.2 Terrorism event

A terrorism event is:

An act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear) and which materially increases the costs to TasNetworks in providing direct control services.

Note: In assessing a terrorism event pass through application, the AER will have regard to, amongst other things:

- i. whether TasNetworks has insurance against the event,
- ii. the level of insurance that an efficient and prudent NSP would obtain in respect of the event,
- iii. whether a declaration has been made by a relevant government authority that a terrorism event has occurred, and
- iv. the extent to which a prudent provider could reasonably mitigate the impact of the event.

5.3 Natural disaster event

A natural disaster event is:

Any major fire, flood, earthquake or other natural disaster occurs during the 2015-19 regulatory control period and materially increases the costs to TasNetworks in providing direct control services, provided the fire, flood or other event was not a consequence of the acts or omissions of the service provider

The term 'major' in the above paragraph means an event that is serious and significant. It does not mean material as that term is defined in the Rules (that is 1 per cent of the TNSP's annual revenue requirement for that regulatory year).

Note: In assessing a natural disaster event pass through application, the AER will have regard to, amongst other things:

- i. whether TasNetworks has insurance against the event,
- ii. the level of insurance that an efficient and prudent NSP would obtain in respect of the event,
- iii. whether a relevant government authority has made a declaration that a natural disaster has occurred, and
- iv. the extent to which a prudent NSP could reasonably mitigate the impact of the event.