Amended proposed Access Arrangement for the Western Power Network

ELECTRICITY NETWORKS CORPORATION

("WESTERN POWER")

ABN 18 540 492 861

Approved by the Economic Regulation Authority

28 February 2019

(as amended by corrigenda of 10 May 2019)

Minor corrections to clause 5.11.3 and 6.5.13 approved by the Economic Regulation Authority on 10 June 2020

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1. Introduction

1.1 Purpose of this document

1.1.1 These amended proposed revisions were approved by the Authority in accordance with the processes and criteria set out in the *Electricity Networks Access Code 2004*, herein referred to as the "Code" on 28 February 2019. Henceforth this document is referred to as the "access arrangement".

1.1.2 This *access arrangement* is an arrangement for *access* to the *Western Power Network* from the date specified in section 1.3.1 of this *access arrangement*. The *Western Power Network* is a *covered network* under the *Code*.

1.2 Definitions and interpretation

1.2.1 In sections 1 to 9 of this *access arrangement*, where a word or phrase is italicised it has the definition given to that word or phrase as described in this *access arrangement* or section 1.3 of the *Code*, unless the context requires otherwise.

1.2.2 In each of the appendices to this *access arrangement*, a separate glossary of terms is provided where appropriate, and the definitions contained in those separate glossaries apply to the relevant appendix, unless the context requires otherwise.

1.2.3 In this *access arrangement*:

> ***"bi-directional service"*** means a *covered service* provided by *Western Power* at a *connection point* under which the *user* may transfer electricity into and out of the *Western Power Network* at the *connection point*.
>
> ***"MSLA"*** means the model service level agreement approved by the *Authority* under the *Metering* Code (which as at the *AA4 effective date* is the version dated March 2006).

1.3 Proposed access arrangement revisions commencement date

1.3.1 This *access arrangement* (as revised) is effective from 1 July 2019 or a later date in accordance with section 4.26 of the *Code*.

1.4 Revisions submission date and target revisions commencement date

1.4.1 Pursuant to section 5.31(a) of the *Code*, the *revisions submission date* for this *access arrangement* is 26 February 2021.

1.4.2 Pursuant to section 5.31(b) of the *Code*, the target *revisions commencement date* for this *access arrangement* is 1 July 2022.

1.5 Composition of this access arrangement

1.5.1 This *access arrangement* comprises this document together with:

a) the *Standard Access Contract*, termed the Electricity Transfer Access Contract attached at Appendix A;

b) the *Applications and Queuing Policy* attached at Appendix B;

c) the *Contributions Policy* attached at Appendix C.1;

d) the Distribution Low Voltage Connection Scheme Methodology attached at Appendix C.2;

e) the *Transfer and Relocation Policy* attached at Appendix D;

f) the details of the *reference services* offered by Western Power attached at Appendix E;

g) the *price lists* attached at Appendix F, which are a schedule of *reference tariffs* in effect for this *access arrangement*; and

h) the *price list information* attached at Appendix F, which explains how Western Power derived the elements of the proposed *price lists*; and demonstrates that the *price lists* comply with the *access arrangement*.

1.6 Relationship to technical rules

1.6.1 The *technical rules* do not form part of this *access arrangement*, although the *technical rules* are relevant in determining Western Power's *target revenue*.

2. Reference services

2.1 Purpose

2.1.1 Pursuant to sections 5.1(a) and 5.2 of the *Code*, this section of the *access arrangement* describes the *reference services* offered by Western Power.

2.2 Reference services

2.2.1 *Reference services* are provided to *users* that meet and continue to meet the eligibility criteria applicable to the *reference service* provided, on the terms and conditions of the Electricity Transfer Access Contract, at the related *service standard benchmarks* and at the related *reference tariff*.

2.2.2 Western Power specifies 17 *reference services* at *exit points*:

Table 1: Reference services at exit points

Reference service	Short name
Anytime Energy (Residential) Exit Service	A1
Anytime Energy (Business) Exit Service	A2
Time of Use Energy (Residential) Exit Service	A3
Time of Use Energy (Business) Exit Service	A4
High Voltage Metered Demand Exit Service	A5
Low Voltage Metered Demand Exit Service	A6
High Voltage Contract Maximum Demand Exit Service	A7
Low Voltage Contract Maximum Demand Exit Service	A8
Streetlighting Exit Service (including streetlight maintenance)	A9
Unmetered Supplies Exit Service	A10
Transmission Exit Service	A11
3 Part Time of Use Energy (Residential) Exit Service	A12
3 Part Time of Use Energy (Business) Exit Service	A13
3 Part Time of Use Demand (Residential) Exit Service	A14
3 Part Time of Use Demand (Business) Exit Service	A15
Multi Part Time of Use Energy (Residential) Exit Service	A16
Multi Part Time of Use Energy (Business) Exit Service	A17

2.2.3 Western Power specifies three *reference services* at *entry points*:

Table 2: Reference services at entry points

Reference service	Short name
Distribution Entry Service	B1
Transmission Entry Service	B2
Entry Service Facilitating a Distributed Generation or Other Non-Network Solution	B3

2.2.4 Western Power specifies 15 *bi-directional services* as *reference service*s at connection points:

Table 3: Reference services at bi-directional points

Reference service name	Short name
Anytime Energy (Residential) Bi-directional Service	C1
Anytime Energy (Business) Bi-directional Service	C2
Time of Use Energy (Residential) Bi-directional Service	C3
Time of Use Energy (Business) Bi-directional Service	C4
High Voltage Metered Demand Bi-directional Service	C5
Low Voltage Metered Demand Bi-directional Service	C6
High Voltage Contract Maximum Demand Bi-directional Service	C7
Low Voltage Contract Maximum Demand Bi-directional Service	C8
3 Part Time of Use Energy (Residential) Bi-directional Service	C9
3 Part Time of Use Energy (Business) Bi-directional Service	C10
3 Part Time of Use Demand (Residential) Bi-directional Service	C11
3 Part Time of Use Demand (Business) Bi-directional Service	C12
Multi Part Time of Use Demand (Residential) Bi-directional Service	C13
Multi Part Time of Use Demand (Business) Bi-directional Service	C14
Bi-directional Service Facilitating a Distributed Generation or Other Non-Network Solution	C15

2.2.5 Western Power specifies ten *services* at a *connection point* as a *reference service* (ancillary).

Table 4: Reference services at connection points (ancillary)

Reference service name	Short name
Supply Abolishment Service	D1
Capacity Allocation Swap (Nominator) (Business) Service	D2
Capacity Allocation Swap (Nominee) (Business) Service	D3
Capacity Allocation Same Connection Point (Nominator) (Business) Service	D4

Reference service name	Short name
Capacity Allocation Same Connection Point (Nominee) (Business) Service	D5
Remote Direct Load Control Service	D6
Remote Load Limitation Service	D7
Remote De-energise Service	D8
Remote Re-energise Service	D9
Streetlight LED Replacement Service	D10

2.2.6 Western Power specifies 16 standard metering services as *reference services*:

Table 5: Standard metering services

Reference service name	Short name
Unidirectional, accumulation, bi-monthly, manual	M1
Unidirectional, accumulation (TOU), bi-monthly, manual	M2
Unidirectional, interval, bi-monthly, manual	M3
Unidirectional, interval, monthly, manual	M4
Unidirectional, interval, bi-monthly, remote	M5
Unidirectional, interval, monthly, remote	M6
Unidirectional, interval, daily, remote	M7
Bidirectional, accumulation, bi-monthly, manual	M8
Bidirectional, accumulation (TOU), bi-monthly, manual	M9
Bidirectional, interval, bi-monthly, manual	M10
Bidirectional, interval, monthly, manual	M11
Bidirectional interval, bi-monthly, remote	M12
Bidirectional, interval, monthly, remote	M13
Bidirectional, interval, daily, remote	M14
Unmetered supply, accumulation, bi-monthly, manual	M15
One off manual interval read	M16

2.2.7 Appendix E of this *access arrangement* provides details of each *reference service*, including:

- a description of the *reference service*;
- the *user* eligibility criteria;
- the applicable *reference tariff*;
- the applicable *standard access contract*; and
- the applicable *service standard benchmark*.

2.3 Payment by users

2.3.1 *Users* are required to pay a *charge* for *reference services* calculated by applying the related *reference tariffs*.

3. Excluded services

3.1 Purpose

3.1.1 This section of the *access arrangement* describes the *excluded services* offered by Western Power.

3.2 Excluded services

3.2.1 There are no *excluded services* at the *revisions commencement date* of this *access arrangement*. In accordance with section 6.35 of the *Code*, Western Power may at any time request the *Authority* to determine under section 6.33 of the *Code* that one or more *services* provided by means of the *Western Power Network* are *excluded services*.

4. Service standard benchmarks

4.1 Purpose

4.1.1 Pursuant to section 5.1(c) of the *Code*, this section provides the *service standard benchmarks* applicable to the *reference services*. *Service standard benchmark*s are not applicable to *non-reference services*.

4.2 Service standard benchmarks for distribution reference services

4.2.1 For the *reference services* A1 to A10, A12 to A17, B1 and B3, C1 to C15 and any applicable ancillary *reference service* D2 to D7, the *service standard benchmarks* are expressed in terms of System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and call centre performance.

4.2.2 In sections 4.2.3 and 4.2.5 **"distribution customer"** means a *consumer* connected to the *distribution system*.

System Average Interruption Duration Index (SAIDI)

4.2.3 SAIDI is applied as follows:

Table 6: Application of SAIDI

	System Average Interruption Duration Index (SAIDI) CBD Urban Rural Short Rural Long
Unit of Measure	Minutes per year.
Definition	Over a 12 month period, the sum of the duration of each sustained (greater than 1 minute) *distribution customer* interruption (in minutes) attributable to the *distribution system* (after exclusions) divided by the number of *distribution customers* served, that is: $\dfrac{\sum \text{Sustained } \textit{distribution customer} \text{ interruption durations}}{\text{Number of } \textit{distribution customers} \text{ served}}$ where: • A CBD feeder is a feeder supplying predominantly commercial, high-rise buildings, supplied by a predominantly underground *distribution system* containing significant interconnection and redundancy when compared to urban areas. • An Urban feeder is a feeder, which is not a CBD feeder with actual maximum demand over the reporting period per total high voltage feeder route length greater than 0.3 MVA/km. • A Rural Short feeder is a feeder which is not a CBD or urban feeder with a total high voltage feeder route length less than 200 km. • A Rural Long feeder is a feeder which is not a CBD or urban feeder with a total high voltage feeder route length greater than 200 km.

	System Average Interruption Duration Index (SAIDI) CBD Urban Rural Short Rural Long
	• The number of *distribution customers* served is determined by averaging the start of month values for the 12 months included in the 12 month period.
Exclusions	One or more of: • For an unplanned interruption on the *distribution system*, a day on which the major event day threshold, applying the “2.5 beta method”, is exceeded. This method excludes events which are more than 2.5 standard deviations greater than the mean of the log normal distribution of five financial years of SAIDI data. The major event day threshold is determined at the end of each financial year for use in the next financial year. The data set comprises daily unplanned SAIDI calculated over the five immediately preceding financial years after exclusions (below) are applied. Where the logarithms of the data set are not normally distributed, the Box-Cox transformation will be applied to reach a better approximation of the normal distribution. • Interruptions shown to be caused by a fault or other event on the *transmission system.* • Interruptions shown to be caused by a fault or other event on a third party system (for instance, without limitation, interruptions caused by an intertrip signal, generator unavailability or a consumer installation). • Planned interruptions caused by scheduled *works.* • *Force majeure* events affecting the *distribution system*.

4.2.4 The *service standard benchmarks* expressed in terms of SAIDI for the *reference services* A1 to A10, A12 to A17, B1 and B3, C1 to C15 and any applicable ancillary *reference service* D2 to D7 for each year of this *access arrangement period* are shown in the following table:

Table 7: SAIDI service standard benchmarks for reference services A1 to A10, A12 to A17, B1 and B3, C1 to C15 and any applicable ancillary reference service D2 to D7

SAIDI	For the financial year ending 30 June 2018	For the financial year ending 30 June 2019 and each financial year thereafter
CBD	39.9	33.7
Urban	183.0	130.6
Rural Short	227.8	215.4
Rural Long	724.8	848.3

System Average Interruption Frequency Index (SAIFI)

4.2.5 SAIFI is applied as follows:

Table 8: Application of SAIFI

	System Average Interruption Frequency Index (SAIFI) **CBD** **Urban** **Rural Short** **Rural Long**
Unit of Measure	Sustained interruptions per year.
Definition	Over a 12 month period, the number of sustained (greater than 1 minute) *distribution customer* interruptions (number) attributable to the *distribution system* (after exclusions) divided by the number of distribution customers served, that is: Number of sustained *distribution customer* interruptions Number of *distribution customers* served where: • A CBD feeder is a feeder supplying predominantly commercial, high-rise buildings, supplied by a predominantly underground *distribution system* containing significant interconnection and redundancy when compared to urban areas. • An Urban feeder is a feeder, which is not a CBD feeder, with actual maximum demand over the reporting period per total high voltage feeder route length greater than 0.3 MVA/km. • A Rural Short feeder is a feeder which is not a CBD or urban feeder with a total high voltage feeder route length less than 200 km. • A Rural Long feeder is a feeder which is not a CBD or urban feeder with a total high voltage feeder route length greater than 200 km. • The number of *distribution customers* served is determined by averaging the start of month values for the 12 months included in the 12 month period.
Exclusions	One or more of: • For unplanned interruptions on the *distribution system,* a day on which the major event day threshold, applying the “2.5 beta method”, is exceeded. This method excludes events which are more than 2.5 standard deviations greater than the mean of the log normal distribution of five financial years of SAIDI data. The major event day threshold is determined at the end of each financial year for use in the next financial year. The data set comprises daily unplanned SAIDI calculated over the five immediately preceding financial years after exclusions (below) are applied. Where the logarithms of the data set are not normally distributed, the Box-Cox transformation will be applied to reach a better approximation of the normal distribution. • Interruptions shown to be caused by a fault or other event on the *transmission system.*

	System Average Interruption Frequency Index (SAIFI) CBD Urban Rural Short Rural Long
	• Interruptions shown to be caused by a fault or other event on a third party system (for instance, without limitation interruptions caused by an intertrip signal, generator unavailability or a consumer installation). • Planned interruptions caused by scheduled *works*. • *Force majeure* events affecting the *distribution system.*

4.2.6 The *service standard benchmarks* expressed in terms of SAIFI for the *reference services* A1 to A10, A12 to A17, B1 and B3, C1 to C15 and any applicable ancillary *reference service* D2 to D7 for each year of this *access arrangement period* are shown in the following table:

Table 9: SAIFI service standard benchmarks for reference services A1 to A10, A12 to A17, B1 and B3, C1 to C15 and any applicable ancillary reference service D2 to D7

SAIFI	For the financial year ending 30 June 2018	For the financial year ending 30 June 2019 and each financial year thereafter
CBD	0.26	0.21
Urban	2.12	1.27
Rural Short	2.61	2.34
Rural Long	4.51	5.70

4.2.7 For the purpose of this *access arrangement*, the definitions of CBD, Urban, Rural Short and Rural Long feeder classifications are consistent with those applied by the Steering Committee on National Regulatory Reporting Requirements.

Call centre performance

4.2.8 Call centre performance is applied as follows:

Table 10: Application of call centre performance

	Call centre performance
Unit of Measure	Percentage of calls per year.
Definition	Over a 12 month period, in relation to interruptions and life threatening emergencies, percentage of calls responded to in 30 seconds or less (after exclusions), that is: $\frac{\text{Number of fault calls responded to in 30 seconds or less}}{\text{Total Number of fault calls}}$ where:

	Call centre performance
	(a) "Fault calls responded to in 30 seconds or less" is: (i) unless paragraph (a)(ii) applies, where the caller's postcode is automatically determined or when a valid postcode is entered by the caller, the number of fault calls where a recorded message commences within 30 seconds from that determination or entry; or (ii) where the call is placed in the queue to be responded to by a human operator, the number of fault calls where the human operator commences to speak with the caller within 30 seconds of that placement. (b) A "fault call" is a telephone call from a caller entering the fault line or life threatening emergency line. (c) A call may be placed in a queue to be responded to by a human operator when the caller: (i) chooses to hold (when invited to do so) at the end of the recorded message; (ii) chooses to hold (when invited to do so) rather than enter a postcode when prompted to do so; or (iii) enters an invalid postcode. (d) For a call to be counted as being responded to under paragraph (a), the caller must receive from the recorded message or the human operator information regarding power interruptions in their area and related restoration information (e) A call where the interactive message service fails to automatically determine the caller's postcode or invite the entry of a postcode, as a result of which the service of providing information regarding power interruptions in their area and related restoration information does not commence, will be counted as a fault call not responded to in 30 seconds or less.
Exclusions	One or more of: • Calls abandoned by a caller in 4 seconds or less of their postcode being automatically determined or when a valid postcode is entered by the caller. • Calls abandoned by a caller in 30 seconds or less of the call being placed in the queue to be responded to by a human operator. • All telephone calls received on a major event day which is excluded from SAIDI and SAIFI. • A fact or circumstance beyond the control of Western Power affecting the ability to receive calls to the extent that Western Power could not contract on reasonable terms to provide for the continuity of service.

4.2.9 The *service standard benchmarks* expressed in terms of call centre performance for the *reference services* A1 to A10, A12 to A17, B1 and B3, C1 to C15 and any applicable ancillary *reference service* D2 to D7 for each year of this *access arrangement period* are shown in the following table:

Table 11: Call centre service standard benchmarks for reference services A1 to A10, A12 to A17, B1 and B3, C1 to C15 and any applicable ancillary reference service D2 to D7

	For the financial year ending 30 June 2018	For the financial year ending 30 June 2019 and each financial year thereafter
Call centre performance	77.5%	86.8%

4.3 Service standard benchmarks for transmission reference services

4.3.1 For the *reference services* A11 and B2 and any applicable ancillary *reference service* D2 to D7, the *service standard benchmarks* are expressed in terms of circuit availability, loss of supply event frequency and average outage duration.

Circuit availability

4.3.2 Circuit availability is applied as follows:

Table 12: Application of circuit availability

	Circuit availability
Unit of Measure	Percentage of hours per year.
Definition	Over a 12 month period, the actual hours transmission circuits are available divided by the total possible hours available for transmission circuits (after exclusions), that is: $$\frac{\text{Number of hours transmission circuits are available} \times 100}{\text{Total possible hours available for transmission circuits}}$$ where: • A "transmission circuit" is an arrangement of primary transmission elements on the *transmission system* that is overhead lines, underground cables, and bulk transmission power transformers used to transport electricity.
Exclusions	One or more of: • Interruptions affecting the *transmission system* shown to be caused by a fault or other event on a third party system (for instance, without limitation interruptions caused by an intertrip signal, generator unavailability or a consumer installation). • *Force majeure* events affecting the *transmission system*. • Hours exceeding 14 days for planned interruptions for major construction *work*.

4.3.3 The *service standard benchmarks* expressed in terms of circuit availability for the *reference services* A11 and B2 and any applicable ancillary *reference service* D2 to D7 for each year of this *access arrangement period* are shown in the following table:

Table 13: Circuit availability service standard benchmarks for reference services A11 and B2 and any applicable ancillary reference service D2 to D7

	For the financial year ending 30 June 2018	For the financial year ending 30 June 2019 and each financial year thereafter
Circuit availability	97.7%	97.8%

Loss of supply event frequency

4.3.4 Loss of supply event frequency is applied as follows:

Table 14: Application of loss of supply event frequency

	Loss of supply event frequency >0.1 and ≤1.0 system minutes interrupted >1.0 system minutes interrupted
Unit of Measure	Number of events per year.
Definition	Over a 12 month period, the frequency of Unplanned customer outage events where loss of supply: • exceeds 0.1 system minutes interrupted and less than or equal to 1.0 system minutes interrupted; or • exceeds 1.0 system minutes interrupted. System minutes are calculated for each supply interruption by the “load integration method” using the following formula, that is: $\frac{\sum (\text{MWh unsupplied x } 60)}{\text{System Peak MW}}$ where: • “Unplanned customer outages” relates to unplanned customer outages occurring on all parts of the regulated *transmission system*. • “MWh unsupplied” is the energy not supplied as determined by using Western Power metering and PI server database. This data is used to estimate the profile of the load over the period of the interruption by reference to historical load data. • Period of the interruption starts when a loss of supply occurs and ends when Western Power offers supply restoration to the customer. • For the financial year ending 30 June 2018, “System Peak MW” is the maximum peak demand recorded for the South West Interconnected System for the previous financial year. • For the financial year ending 30 June 2019 and each financial year thereafter, “System Peak MW” is the maximum peak demand recorded for the South West Interconnected System for the previous financial year, excluding the coincident demand for those customers receiving a *non-reference service* where the impact of an Unplanned customer outage event is excluded for the purpose of this measure.

	Loss of supply event frequency **>0.1 and ≤1.0 system minutes interrupted** **>1.0 system minutes interrupted**
Exclusions	One or more of: • Planned interruptions. • Momentary interruptions (less than one minute). • Unregulated transmission assets. • Interruptions affecting the *transmission system* shown to be caused by a fault or other event on a third party system (for instance, without limitation interruptions caused by an intertrip signal, generator unavailability or a consumer installation). • *Force majeure* events affecting the *transmission system*.

4.3.5 The *service standard benchmarks* expressed in terms of loss of supply event frequency for the *reference services* A11 and B2 and any applicable ancillary *reference service* D2 to D7 for each year of this *access arrangement period* are shown in the following table:

Table 15: Loss of supply event frequency service standard benchmarks for reference services A11 and B2 and any applicable ancillary reference service D2 to D7

Loss of supply event frequency	For the financial year ending 30 June 2018	For the financial year ending 30 June 2019 and each financial year thereafter
> 0.1 and ≤1.0 system minutes interrupted	33	26
> 1.0 system minutes interrupted	4	7

Average outage duration

4.3.6 Average outage duration is applied as follows:

Table 16: Application of average outage duration

	Average outage duration
Unit of Measure	Minutes per year.
Definition	Over a 12 month period, the sum of the duration (in minutes) of all Unplanned outages divided by the total Number of events on regulated transmission circuits (after exclusions), that is: $\frac{\sum \text{Duration (in minutes) of all Unplanned outages}}{\text{Total Number of events}}$ where: • “Unplanned outages” relates to interruptions occurring on all parts of the regulated *transmission system*. • “Number of events” includes all forced and fault interruptions whether or not loss of supply occurs. • A “transmission circuit” is an arrangement of primary transmission elements on the *transmission system* that is overhead lines, underground cables, and bulk transmission power transformers used to transport electricity.

	Average outage duration
Exclusions	One or more of: • Planned interruptions. • Momentary interruptions (less than one minute). • Unregulated transmission assets. • Reactive compensation plant. • Interruptions affecting the *transmission system* shown to be caused by a fault or other event on a third party system (for instance, without limitation interruptions caused by an intertrip signal, generator unavailability or a consumer installation). • *Force majeure* events affecting the *transmission system*. • The impact of each event is capped at 14 days.

4.3.7 The *service standard benchmarks* expressed in terms of average outage duration for the *reference services* A11 and B2 and any applicable ancillary *reference service* D2 to D7 for each year of this *access arrangement period* is shown in the following table:

Table 17: Average outage duration service standard benchmarks for reference services A11 and B2 and any applicable ancillary reference service D2 to D7

	For the financial year ending 30 June 2018	For the financial year ending 30 June 2019 and each financial year thereafter
Average outage duration	886	1,234

4.4 Service standard benchmarks for street lighting reference services

4.4.1 For the *reference service* A9, the *service standard benchmarks* are expressed in terms of street lighting repair time.

Street lighting repair time

4.4.2 Street lighting repair time is applied as follows:

Table 18: Application of street lighting repair time

	Street lighting repair time Metropolitan area Regional area
Unit of Measure	Average number of *business days.*
Definition	Over a 12 month period, average number of *business days* to repair faulty streetlights is the sum of the number of *business days* to repair each faulty streetlight divided by the number of faulty streetlights repaired (after exclusions). $$\frac{\sum \text{Number of } \textit{business days} \text{ to repair each faulty streetlight}}{\text{Number of faulty streetlights repaired}}$$ where:

	Street lighting repair time Metropolitan area Regional area
	• In calculating the number of *business days* to repair a faulty streetlight, the first *business day* is: – where a faulty streetlight is detected by, or reported to, Western Power on a *business day*, the next *business day; or* – where a faulty streetlight is detected by, or reported to, Western Power on a day that is not a *business day*, the second *business day* after that day. • In calculating the number of *business days* to repair a faulty streetlight, the *business day* a fault is repaired is included (subject to the next point) even if the repair is effected part way through that *business day*. • In calculating the number of *business days* to repair a faulty streetlight: – where a faulty streetlight is detected by, or reported to, Western Power on a *business day* and the repair is effected on that *business day*, that *business day* is included as zero; – where a faulty streetlight is detected by, or reported to, Western Power on a day that is not a *business day* and the repair is effected on the next *business day*, that *business day* is included as zero. • A "faulty streetlight" is defined by a recorded fault report. • Metropolitan area means the areas of the State defined in Part 1.5 of the *Code of Conduct for the Supply of Electricity to Small Use Customers 2018*. • Regional area means all areas in the *Western Power Network* other than the metropolitan area. Note: • If a given streetlight is the subject of more than one fault report for the same fault, then only one fault report is recorded. • If a given streetlight is the subject of multiple fault reports that relate to different faults then one report relating to each distinct fault is recorded.
Exclusions	• *Force majeure* events. • Streetlights for which Western Power is not responsible for streetlight maintenance.

4.4.3 The *service standard benchmarks* for the *reference service* A9 for each year of this *access arrangement period* are set out in the following table:

Table 19: Street lighting repair time service standard benchmark for reference service A9

Region	For each financial year ending 30 June
Metropolitan area	5 *business days*
Regional area	9 *business days*

4.4.4 For the *reference service* D10 the *service standard benchmark* is the LED replacement, requested by the *user,* will be completed as soon as reasonably practicable in accordance with *good electricity industry practice*.

4.5 Service standard benchmark for supply abolishment reference service

4.5.1 For the *reference service* D1, the *service standard benchmark* is expressed in terms of response time.

Supply abolishment response time

4.5.2 Supply abolishment response time is applied as follows:

Table 20: Application of supply abolishment response time

	Supply abolishment (whole current meter) response time
Unit of Measure	Average number of *business days.*
Definition	Over a 12 month period, average number of *business days* to abolish supply is the sum of the number of *business days* to abolish supply for all supply abolishment requests, divided by the number of supply abolishment requests made (after exclusions). $$\frac{\sum \text{Number of } \textit{business days} \text{ to abolish supply for all supply abolishment requests}}{\text{Number of supply abolishment requests}}$$ where: • In calculating the number of *business days* to abolish supply, the first *business day* is: – where a supply abolishment request is made by a *user* to Western Power before 3:00 PM on a *business day*, the next *business day*; or – where a supply abolishment request is made by a *user* to Western Power on a day that is not a *business day*, or after 3:00 PM on a *business day*, the second *business day* after that day. • In calculating the number of *business days* to abolish supply: – the *business day* supply is abolished is included (subject to the next point) even if the abolishment is performed part way through that *business day*; and – where a supply abolishment request is made by a *user* to Western Power on a *business day* and the abolishment is performed on that *business day*, that *business day* is counted as zero; or – where a supply abolishment request is made by a *user* to Western Power on a day that is not a *business day,* or after 3:00 PM on a *business day,* and the abolishment is performed on the next *business day*, that *business day* is counted as zero. • A "supply abolishment request" is defined as an electricity transfer application for a supply abolishment in accordance with the *Applications and Queuing Policy* containing all information that Western Power, as a *reasonable and prudent person*, requires to abolish supply. • "Abolish supply" is defined as the time when the permanent disconnection of supply and the removal of the *meter* is completed.

	Supply abolishment (whole current meter) response time
Exclusions	• Supply abolishment requests that: – are cancelled or are requested to be deferred; – relate to non-whole current meters or non-standard technical configurations, site access issues or safety issues;[1] – require external approvals or actions beyond the control of Western Power as a *reasonable and prudent person*; or • A fact or circumstance beyond the control of Western Power as a *reasonable and prudent person* affecting the ability to abolish supply. • *Force majeure* events affecting the ability to abolish supply.

4.5.3 The *service standard benchmarks* for the *reference service* D1 for each year of this *access arrangement period* are set out in the following table:

Table 21: Supply abolishment response time service standard benchmark for reference service D1

	For each financial year ending 30 June
Supply abolishment response time	15 *business days*

4.6 Service standard benchmarks for remote de-energise and remote re-energise reference services

4.6.1 For the *reference service* D8 and D9, the *service standard benchmarks* are expressed in terms of response time.

4.6.2 These *service standard benchmarks* only come into effect once the remote de-energise and remote re-energise *reference services* are provided to one or more *users*.

Remote de-energise response time

4.6.3 Remote de-energise response time is applied as follows:

Table 22: Application of remote de-energise response time

	Remote de-energise response time
Unit of Measure	Average number of *business days.*
Definition	• Over a 12 month period, average number of *business days* to remotely de-energise is the sum of the number of *business days* to remotely de-energise a *meter* for all remote de-energise requests, divided by the number of remote de-energise requests made (after exclusions). $$\frac{\sum \text{Number of } \textit{business days} \text{ to remotely de-energise for all remote de-energise requests}}{\text{Number of remote de-energise requests}}$$ where:

[1] In such instances, the supply abolishment will be carried out as soon as reasonably practicable in accordance with *good electricity industry practice*.

	Remote de-energise response time
	• In calculating the number of *business days* to remotely de-energise, the first *business day* is: – where a remote de-energise request is made by a *user* to Western Power before 12 noon on a *business day*, the next *business day*; or – where a remote de-energise request is made by a *user* to Western Power on a day that is not a *business day*, or after 12 noon on a *business day*, the second *business day* after that day. • Fridays and the *business days* occurring before a *public holiday* are not calculated as *business days* in relation to this measure. • In calculating the number of *business days* to remotely de-energise: – the *business day* the remote de-energise is performed is included, even if the remote de-energise is performed part way through that *business day*; and – where a remote de-energise request is made by a *user* to Western Power on a *business day* and the remote de-energise is performed on that *business day*, that *business day* is counted as zero; or – where a remote de-energise request is made by a *user* to Western Power on a day that is not a *business day*, or after 12 noon on a *business day*, and the remote de-energise is performed on the next *business day*, that *business day* is counted as zero. • A “remote de-energise” is defined as the time when supply voltage is removed from all outgoing circuits from the *meter* on a non-permanent basis by a command sent to a *meter* from a remote locality.
Exclusions	• Remote de-energise requests that are cancelled or are requested to be deferred. • Remote de-energisation requests received on a *business day* in relation to this measure, where the total number of de-energisation requests exceeds the maximum operational capacity of the infrastructure supporting the remote de-energisation requests. • A fact or circumstance beyond the control of Western Power as a *reasonable and prudent person* affecting the ability to remote de-energise. • *Force majeure* events affecting the remote de-energise service.

4.6.4 The *service standard benchmark* for the *reference service* D8 for each year of this *access arrangement period* is set out in the following table:

Table 23: Remote de-energise response time service standard benchmark for reference service D8

	For each financial year ending 30 June
Remote de-energise response time	1 *business day*

Remote re-energise response time

4.6.5 Remote re-energise response time is applied as follows:

Table 24: Application of remote re-energise response time

	Remote re-energise response time
Unit of Measure	Average number of *business days.*
Definition	Over a 12 month period, average number of *business days* to remotely re-energise is the sum of the number of *business days* to remotely re-arm a previously de-energised *meter* for all remote re-energise requests, divided by the number of remote re-energise requests made (after exclusions). $$\frac{\sum \text{Number of } \textit{business days} \text{ to remotely re-arm for all remote re-energise requests}}{\text{Number of remote re-energise requests}}$$ where: • In calculating the number of *business days* to remotely re-energise, the first *business day* is: – where a remote re-energise request is made by a *user* to Western Power before 12 noon on a *business day*, the next *business day*; or – where a remote re-energise request is made by a *user* to Western Power on a day that is not a *business day*, or after 12 noon on a *business day*, the second *business day* after that day. • In calculating the number of *business days* to remotely re-energise: – the *business day* the remote re-energise is performed is included, even if the remote re-energise is performed part way through that *business day*; and – where a remote re-energise request is made by a *user* to Western Power on a *business day* and the remote re-energise is performed on that *business day*, that *business day* is counted as zero; or – where a remote re-energise request is made by a user to Western Power on a day that is not a *business day*, or after 12 noon on a *business day*, and the remote re-energise is performed on the next *business day*, that *business day* is counted as zero. • A "remote re-energise" is defined as the time when a previously de-energised *meter* is re-armed by a command sent to that *meter* from a remote locality.
Exclusions	• Remote re-energise requests that are cancelled or are requested to be deferred. • Remote re-energisation requests received on a *business day* in relation to this measure, where the total number of re-energisation requests exceeds the maximum operational capacity of the infrastructure supporting the remote re-energisation requests. • A fact or circumstance beyond the control of Western Power as a *reasonable and prudent person* affecting the ability to remote re-energise. • *Force majeure* events affecting the remote re-energise service.

4.6.6 The *service standard benchmark* for the *reference service* D9 for each year of this *access arrangement period* is set out in the following table:

Table 25: Remote re-energise response time service standard benchmark for reference service D9

	For each financial year ending 30 June
Remote re-energise response time	1 *business day*

4.7 Exclusions

4.7.1 In each of the *service standard benchmarks* there is a definition of the measure and stated exclusions. Each exclusion is a circumstance in relation to which, when it occurs, the resulting units are not included in the measure. For example, for SAIDI, when a *force majeure* event occurs the duration of the related interruption in minutes is not included in the calculation of the measure.

4.7.2 Whether or not particular circumstances meet the criteria to be an exclusion, such that the resulting units are not included in the measure, may be considered by the *Authority* when it *publishes* Western Power's actual *service standard* performance against the *service standard benchmarks* under section 11.2 of the *Code.* Where the *Authority* accepts an exclusion in such a report, it will be an exclusion for the purposes of the application of this *access arrangement* and the *Code*.

4.7.3 Where Western Power has applied a Box-Cox transformation method to the daily unplanned SAIDI data set to determine the major event day threshold, in the *service standard performance report* provided for the financial year in which the major event day threshold is used, Western Power must:

a) Demonstrate that the natural logarithm of the data set of each unplanned SAIDI value is not normally distributed.

b) Provide the calculations that demonstrate the application of the Box-Cox transformation method to the unplanned SAIDI values.

c) Provide the data set resulting from applying the Box-Cox transformation method.

d) Demonstrate that the resulting data set is normally distributed or that the normality of the data set is improved.

5. Price control

5.1 Overview of price control

5.1.1 In this *access arrangement*:

*"**non-revenue target services**"* means the following services:

a) *non-reference services* provided by Western Power by means of the *Western Power Network* other than *non-reference services* that are provided as *revenue target services*;

b) *reference services* described as *reference services* (ancillary) in Appendix E; and

c) *reference service* (metering) M16 as set out in Appendix E.

*"**revenue target services**"* means the following *covered services* provided by Western Power by means of the *Western Power Network*:

a) *connection service*;

b) *exit service*;

c) *entry service*;

d) bi-directional service;

e) *reference services* (metering) M1 to M15 as set out in Appendix E; and

f) streetlight maintenance.

5.1.2 In accordance with sections 6.1 and 6.2(c) of the *Code*:

a) a *price control* will apply to *revenue target services* that is set by reference to Western Power's *approved total costs*;

b) subject to paragraph (c), charges for *non-revenue target services* will be:

i. any applicable lodgement fees payable under the *Applications and Queuing Policy;*

ii. a charge set out in the Price List for, *reference service* (metering) M16;

and if not provided for in the above instruments, then the charges will be;

iii. negotiated in good faith;

iv. consistent with the *Code objective*; and

v. reasonable; and

c) charges for *access applications* will be consistent with the *Applications and Queuing Policy* and charges for extended metering services (within the meaning of the *MSLA*) will be consistent with the *MSLA* and clause 6.6(1)(e) of the *Electricity Industry (Metering) Code 2012*.

5.1.3 Separate revenue targets will apply in respect of the *revenue target services* provided by means of the *transmission system* and the *distribution system*. The establishment of each revenue target has been made by reference to Western Power's *approved total costs* for *revenue target services for each of* the *transmission system* and the *distribution system*.

5.1.4 The calculation of Western Power's *approved total costs* for *revenue target services* has been undertaken in accordance with the building block method for each of the *transmission system* and the *distribution system*, as contained in the revenue model.

5.1.5 Despite section 1.3.1 of this *access arrangement*, the *price control* and all incentive and cost recovery mechanisms described in this *access arrangement* operate from 1 July 2017, and therefore references to *access arrangement period* should be interpreted accordingly.

5.2 Capital base value

5.2.1 The tables below show the derivation of the *capital base* value as at 30 June 2017.

Table 26: Derivation of Transmission Initial Capital Base (net) ($ million real as at 30 June 2017)

Financial year ending:	30 June 2013	30 June 2014	30 June 2015	30 June 2016	30 June 2017
Opening capital base value	2,816.7	2,927.7	3,161.6	3,197.5	3,135.5
less depreciation	94.0	103.4	114.1	121.3	129.4
less accelerated depreciation	-	-	-	-	-
plus new facilities investment (net of capital contributions and asset disposals)	204.9	337.4	149.9	59.3	102.6
Closing capital base value	2,927.7	3,161.6	3,197.5	3,135.5	3,108.6

Table 27: Derivation of Distribution Initial Capital Base (net) ($ million real as at 30 June 2017)

Financial year ending:	30 June 2013	30 June 2014	30 June 2015	30 June 2016	30 June 2017
Opening capital base value	4,248.7	4,708.5	5,142.9	5,494.3	5,723.1
less depreciation	214.0	236.2	261.9	266.5	281.5
less accelerated depreciation	3.8	0.5	-	-	-
plus new facilities investment (net of capital contributions and asset disposals)	677.6	671.1	613.3	495.2	356.8
Closing capital base value	4,708.5	5,142.9	5,494.3	5,723.1	5,798.4

5.3 Depreciation

5.3.1 Pursuant to section 6.70 of the *Code*, the *price control* set out in this *access arrangement* provides for the depreciation of the *network assets* that comprise the *capital base*. References to depreciation in this *access arrangement* relate solely to regulatory depreciation for the purposes of calculating the *target revenue*, and do not relate to the calculation of depreciation for accounting or taxation purposes.

5.3.2 The depreciation provision contained in the *target revenue* for each year of this *access arrangement period* is calculated using:

a) the straight line depreciation method;

b) the existing weighted average lives for each of the *transmission system* and *distribution system* that comprise the *capital base* value as at 30 June 2017; and

c) for *new facilities investment* forecast for this *access arrangement period* the weighted average lives for each of the *transmission system* and *distribution system* based on the asset lives for each group of *network assets* as set out in the following tables:

Table 28: Transmission asset groupings and economic lives for depreciation purposes

Asset group	Economic Life (years) for depreciation purposes
Transmission transformers	50 years
Transmission reactors	50 years
Transmission capacitors	40 years
Transmission circuit breakers	50 years
Transmission lines – steel towers	60 years
Transmission lines - wood poles	45 years
Transmission cables	55 years
Transmission metering	40 years
Transmission SCADA and communications	11 years
Transmission IT	6 years
Transmission other, non-network assets	27 years

Table 29: Distribution asset groupings and economic lives for depreciation purposes

Asset group	Economic Life (years) for depreciation purposes
Distribution lines - wood poles	41 years
Distribution underground cables	60 years
Distribution transformers	35 years
Distribution switchgear	35 years
Street lighting	20 years
Distribution meters and services	15 years
Distribution IT	6 years
Distribution SCADA & communications	10.16 years
Distribution other, non-network assets	27 years

5.3.3 Western Power is not proposing any accelerated depreciation in this *access arrangement period* in relation to *network assets* for the *transmission system*.

5.3.4 In respect of *network assets* for the *distribution system*, Western Power will apply accelerated depreciation in respect of those *network assets* that will be decommissioned as a result of the State Underground Power Program undertaken by Western Power on behalf of the Western Australian government as set out in the following table:

Table 30: Distribution accelerated depreciation by asset class ($ million real as at 30 June 2017)

	30 June 2018	30 June 2019	30 June 2020	30 June 2021	30 June 2022
Underground Cables	3.63	4.84	3.25	-	-
Transformers	-	-	-	-	-
Switchgear	0.46	1.48	0.76	-	-
Street lighting	0.28	0.57	0.36	-	-
Meters and Services	-	-	-	-	-
IT	-	-	-	-	-
SCADA & Communications	-	-	-	-	-
Other Distribution Non-Network	-	-	-	-	-
Distribution Land & Easements	-	-	-	-	-

5.3.5 The depreciation of the opening *capital base* at the commencement of the next *access arrangement period* will be the forecast depreciation contained in the *target revenue* for the *access arrangement period.*

5.4 Weighted average cost of capital

5.4.1 Pursuant to section 6.64 of the *Code* the *weighted average cost of capital* for the for the financial year ending 30 June 2018 and 30 June 2019 is 5.87% nominal post tax, derived using the following formula:

$$\boldsymbol{WACC_{Nom}} = \boldsymbol{r_e} \times \frac{\boldsymbol{E}}{\boldsymbol{E+D}} + \boldsymbol{r_d} \times \frac{\mathrm{D}}{\boldsymbol{E+D}}$$

where:

r_e is the cost of equity, being 6.57%

r_d is the cost of debt, being 5.29% for the financial years ended 30 June 2018 and 5.29% for the financial year ended 30 June 2019

E is the proportion of equity used to finance regulated assets by a benchmark electricity network service provider (45%)

D is the proportion of debt used to finance regulated assets by a benchmark electricity network service providers (55%)

5.4.2 The cost of debt (r_d) in section 5.4.1 will be updated annually to give effect to the annual update of the trailing average debt risk premium (“**DRP”**). The annual update of the cost of debt will give rise to an annual update of *the weighted average cost of capital*. The update of the *DRP,* cost of debt and *weighted average cost of capital* will apply to the financial years ending 30 June 2020, 30 June 2021 and 30 June 2022.

5.4.3 The updated *DRP* and resulting updated *weighted average cost of capital* will be reflected in the update of the *price list* in accordance with sections 6.4.2 and 6.4.3.

Trailing average cost of debt variation

5.4.4 The annual update of the trailing average *DRP* in each relevant financial year of this *access arrangement period* is to be calculated by applying the following formula:

$$TA\ DRP_0 = \frac{\sum_{t=0}^{-9} DRP_t}{10}$$

where

TA DRP_0 is the equally weighted trailing average of the DRP to apply in the following year as the annual update of the estimate used in the current year; and

DRP_t is the DRP estimated for each of the 10 regulatory years

t = 0, -1, -2…. , -9.

DRP_t refers to the DRP estimated in each year = 0, -1, -2…. , -9, which are either:

5.4.5 The forward looking DRP estimators for the financial years ending 30 June 2020, 30 June 2021 and 30 June 2022 estimated during the 20 *business day* averaging period, using the *Authority's* bond yield method of automatic formulas as described in section 5.4.13 below ("**Bond Yield Approach"**); or

5.4.6 The published DRP_t, estimates, derived as follows:

- financial year 2008/09: $DRP_{2008/09}$: 5.483 per cent;
- financial year 2009/10: $DRP_{2009/10}$: 2.355 per cent;
- financial year 2010/11: $DRP_{2010/11}$: 1.895 per cent;
- financial year 2011/12: $DRP_{2011/12}$: 2.842 per cent;
- financial year 2012/13: $DRP_{2012/13}$: 2.768 per cent;
- financial year 2013/14: $DRP_{2013/14}$: 2.634 per cent;
- financial year 2014/15: $DRP_{2014/15}$: 1.640 per cent;
- financial year 2015/16: $DRP_{2015/16}$: 2.352 per cent;
- financial year 2016/17: $DRP_{2016/17}$: 1.656 per cent;
- financial year 2017/18: $DRP_{2017/18}$: 1.241 per cent.

5.4.7 The trailing average *DRP* estimate for the financial year ending 30 June 2018 (TA DRP_{2018}) is 2.487%.

5.4.8 The trailing average *DRP* estimate for the financial year ending 30 June 2019 (TA DRP_{2019}) is 2.487%, being the average derived from $DRP_{2008/09}$ to $DRP_{2017/18}$ listed in section 5.4.6 above.

5.4.9 The first annual update of the *DRP* will apply for the financial year ending 30 June 2020. All annual updates of the *DRP* are to be determined consistent with the *Bond Yield Approach*.

5.4.10 The *Authority* required that Western Power nominate an averaging period for the purposes of determining the *DRP* for each of the financial years ending 30 June 2020, 30 June 2021 and 30 June 2022. The averaging periods are a nominated 20 *business days* (based on NSW public holidays) during the period 1 January to 30 April in the financial year prior to the relevant financial year. The nominated 20 *business day* averaging period does not need to be identical in each year.

5.4.11 The forward looking estimates of the *DRP* for each financial year ending 30 June 2020, 30 June 2021 and 30 June 2022, will be estimated using the *Bond Yield Approach*. Resulting estimates of the *DRP* will be included in the calculation of the trailing average *DRP* in accordance with the formula in section 5.4.4 above.

5.4.12 The following method of automatic formulas applies where the *Authority's Bond Yield Approach* is used for updating the estimates of the *DRP*, and will remain unchanged for the duration of this *access arrangement period*, and hence will apply for the estimates made for DRP_{2020}, as well as for the estimates DRP_{2021} and DRP_{2022}.

5.4.13 The *Authority's Bond Yield Approach* consists of the following six processes:

a) Determining the Benchmark Sample

Identifying a sample of bonds based on the benchmark sample selection criteria. This will comprise a 'cross section' of bonds.

b) Collecting Data

Collecting data for those bonds over the averaging period in question, for example 20 trading days. This represents 'time series' data related to each bond.

c) Converting Yields to Australian Dollar Equivalents

Converting yields for bonds denominated in foreign currencies into Australian dollar ("**AUD**") equivalents so that all yields are expressed as an *AUD* equivalent.

d) Averaging Yields over the Averaging Period

Calculating an average *AUD* equivalent bond yield for each bond in the cross section across the averaging period. For example, where a 20 trading day averaging period applies, each bond will have a single 20 day 'average yield' calculated.

e) Estimating 'Curves'

Estimating three yield curves based on different methodologies and using the average yield for each bond; its remaining term to maturity; and *AUD* face value.

f) Calculating the *DRP*

Calculating the *DRP* by subtracting the average of the 10 year *AUD* interest rate swap rate from the 10 year cost of debt estimate, with the latter calculated as the average of the three estimated yield curves at the ten year tenor.

5.4.14 Each process is comprised of a series of automatic formulas that will be used for the annual updates of the *DRP*. Further details of the automatic update approach are set out in the *Authority's approval* of this *access arrangement*.

5.5 Deferred revenue from the second and third access arrangement period

5.5.1 Western Power deferred the recovery of some transmission and distribution revenue from the second *access arrangement period* to the third or subsequent *access arrangement periods*.

5.5.2 The tables below show the derivation of the *deferred revenue* value as at 30 June 2017 to be recovered so that Western Power is financially neutral compared to a situation where revenue deferral had not occurred.

Table 31: Derivation of transmission system deferred revenue ($ million real as at 30 June 2017)

Financial year ending:	30 June 2013	30 June 2014	30 June 2015	30 June 2016	30 June 2017
Opening deferred revenue value	96.7	95.9	95.2	94.4	93.6
less principal recovered	0.7	0.7	0.8	0.8	0.8
Closing deferred revenue value	95.9	95.2	94.4	93.6	92.8

Table 32: Derivation of distribution system deferred revenue ($ million real as at 30 June 2017)

Financial year ending:	30 June 2013	30 June 2014	30 June 2015	30 June 2016	30 June 2017
Opening deferred revenue value	726.1	718.5	710.6	702.3	693.9
less principal recovered	7.6	7.9	8.2	8.5	8.8
Closing deferred revenue value	718.5	710.6	702.3	693.9	685.0

5.5.3 Western Power will recover the *deferred revenue* amounts detailed in section 5.5.2 of this *access arrangement* as a real annuity amount over:

a) a 50 year period for the *transmission system deferred revenue* commencing 1 July 2012; and

b) a 42 year period for the *distribution system deferred revenue* commencing 1 July 2012.

5.5.4 The interest rate applicable for the calculation of the real annuity during this *access arrangement period* is the *weighted average cost of capital* for the *Western Power Network* as set out in section 5.4.1 of this *access arrangement*.

5.5.5 The amounts that will be added to the *target revenue* for the *transmission system* and *distribution system* and recovered during this *access arrangement period* are detailed in the table below.

Table 33: Amount to be added to the target revenue due to the recovery of deferred revenue ($ million real as at 30 June 2017)

Financial year ending:	30 June 2018	30 June 2019	30 June 2020	30 June 2021	30 June 2022
Transmission system	4.4	4.4	4.4	4.4	4.4
Distribution system	35.6	35.6	35.6	35.6	35.6

5.6 Transmission system price control – period of application

Despite section 1.3.1 of this *access arrangement* the *transmission system price control* commences on 1 July 2017. This *price control* applies annually on a financial year basis for the duration of the *access arrangement period*.

5.7 Transmission system price control for revenue target services – years ending 30 June 2018 and 30 June 2019

5.7.1 The *transmission system price control* for *revenue target services* is used to determine the maximum transmission revenue target (MTR_t) for Western Power's *transmission system* for each financial year t, where t is financial years ending 30 June 2018 and 30 June 2019.

5.7.2 For the financial years ending 30 June 2018 and 2019, MTR_t is determined as follows:

$$\mathbf{MTR_t} = TR_t + TK_t + TAA3_t$$

where:

$\mathbf{TR_t}$ is the dollar amount for the financial year t calculated from the dollar amounts (expressed in 30 June 2017 prices) set out in Table 34. For the avoidance of doubt, the dollar amounts set out in the table below include the amounts due to the recovery of *deferred revenue* detailed in section 5.5.5 of this *access arrangement* for the *transmission system*. Note that the values in the table will be updated, and these values will be reported in the *price list information* for the financial years ending 30 June 2021 and 30 June 2022, as a result of the annual updates to *weighted average cost of capital* specified in section 5.4.

$\mathbf{TK_{2017/18}}$ = \$1.226M real as at 30 June 2017

$\mathbf{TK_{2018/19}}$ = \$0

$\mathbf{TAA3_t}$ is a positive or negative amount for the financial year t calculated to correct for any errors in the amounts included in the calculation of TR_t to give effect to the following adjustments (if applicable) arising from the operation of the previous *access arrangement*:

- Adjusting *target revenue* for unforeseen events;
- Adjusting *target revenue* for technical rule changes;
- *Investment adjustment mechanism*;
- *Gain sharing mechanism*;
- *Service standards adjustment mechanism*; and
- D factor scheme.

$TAA3_t$ must take account of inflation, the time value of money and estimates (if any) of the above adjustments that have been included in the calculation of TR_t in this section 5.7.2 of this *access arrangement*. Western Power will provide model outputs to the *Authority* to demonstrate that the above adjustments have been made in accordance with the previous *access arrangement*.

5.8 Transmission system price control for revenue target services – years ending 30 June 2020, 30 June 2021 and 30 June 2022

5.8.1 The *transmission system price control* for *revenue target services* is used to determine the transmission revenue target (TTR_t) for Western Power's *transmission system* for each financial year t, where t is financial years ending 30 June 2020, 30 June 2021 and 30 June 2022.

5.8.2 For the financial years ending 30 June 2020, 30 June 2021 and 30 June 2022, TTR_t is determined as follows:

$$\mathbf{TTR_t} = TR_t + TAA3_t$$

where:

$\mathbf{TR_t}$ is as defined in section 5.7.2.

$\mathbf{TAA3_t}$ is as defined in section 5.7.2.

Table 34: Transmission revenue target service revenues to be used for calculating TRt ($ million real as at 30 June 2017)

Financial year ending:	30 June 2018	30 June 2019	30 June 2020	30 June 2021	30 June 2022
TR_t	280.7	282.1	340.0	407.7	486.9

For the purpose of calculating TR_t, TK_t and therefore MTR_t and TTR_t, in each financial year *CPI* adjustments will be effected by using published *CPI* data relating to the most recent December quarter compared to the December quarter in the previous year, with the exception of the financial year ending 30 June 2020 pricing year which will use the most recent September quarter compared to the September quarter in the previous year for the *CPI* to apply to financial year ending 30 June 2020 only.

5.8.3 Notwithstanding section 5.8.2 for the financial year ending 30 June 2021, TTR_t will also include an additional term TK' as follows:

$$\mathbf{TK'} = (AMTR_{2018/19} – FMTR_{2018/19}) * (1 + WACC_{2018/19}) * (1 + WACC_{2019/20})$$

where:

$\mathbf{AMTR_{2018/19}}$ is the actual transmission revenue received in 2018/19.

$\mathbf{FMTR_{2018/19}}$ = $291.711M nominal

$\mathbf{WACC_{2018/19}}$ is as defined in section 5.4.

$\mathbf{WACC_{2019/20}}$ is as defined in section 5.4.

5.9 Distribution system price control – period of application

5.9.1 Despite section 1.3.1 of this *access arrangement* the *distribution system price control* commences on 1 July 2017. This *price control* applies annually on a financial year basis for the duration of the *access arrangement period*.

5.10 Distribution system price control for revenue target services – years ending 30 June 2018 and 30 June 2019

5.10.1 The *distribution system* price control for revenue target services is used to determine the maximum distribution revenue target (MDR_t) for Western Power's *distribution system* for each financial year t, where t is financial year ending 30 June 2018 and 30 June 2019.

5.10.2 For the financial years ending 30 June 2018 and 30 June 2019, MDR_t is defined as follows:

$$\mathbf{MDR_t} = DR_t + DK_t + TEC_t + DAA3_t$$

where:

DR_t is the dollar amount for the financial year t calculated from the dollar amounts (expressed in 30 June 2017 prices) set out in Table 35. For the avoidance of doubt, the dollar amounts set out in the table below include the amounts due to the recovery of *deferred revenue* detailed in section 5.5.5 for the *distribution system*. Note that the values in the table will be updated, and these values will be reported in the *price list information* for the financial years ending 30 June 2021 and 30 June 2022, as a result of the annual updates to *weighted average cost of capital* specified in section 5.4.

Table 35: Distribution revenue target service revenues to be used for calculating DRt ($ million real as at 30 June 2017)

Financial year ending:	30 June 2018	30 June 2019	30 June 2020	30 June 2021	30 June 2022
DR_t	991.5	987.3	974.7	927.3	876.5

$DK_{2017/18}$ = $36.407M real as at 30 June 2017

$DK_{2008/19}$ = $0

TEC_t is any cost incurred by the *distribution system* for the financial year t as a result of the tariff equalisation contribution in accordance with section 6.37A of the *Code*.

$DAA3_t$ is a positive or negative amount for the financial year t calculated to correct for any errors in the amounts included in the calculation of DR_t to give effect to the following adjustments (if applicable) arising from the operation of the previous *access arrangement*:

- Adjusting *target revenue* for unforeseen events;
- Adjusting *target revenue* for technical rule changes;
- *Investment adjustment mechanism*;
- *Gain sharing mechanism;*
- *Service standards adjustment mechanism*; and
- D factor scheme.

$DAA3_t$ must take account of inflation, the time value of money and estimates (if any) of the above adjustments that have been included in the calculation of DR_t in this section 5.10.2. Western Power will provide model outputs to the *Authority* to demonstrate that the above adjustments have been made in accordance with the previous *access arrangement*.

5.11 Distribution system price control for revenue target services – years ending 30 June 2020, 30 June 2021 and 30 June 2022

5.11.1 The *distribution system price control* for *revenue target services* is used to determine the distribution revenue target (TDR_t) for Western Power's *distribution system* for each financial year t, where t is financial year ending 30 June 2020, 30 June 2021 and 30 June 2022.

5.11.2 For the financial years ending 30 June 2020, 30 June 2021 and 30 June 2022, TDR_t is determined as follows:

$$\mathbf{TDR_t} = DR_t + TEC_t + DAA3_t + DTEC_t$$

where:

$\mathbf{DR_t}$ is as defined in section 5.10.2.

$\mathbf{TEC_t}$ is as defined in section 5.10.2.

$\mathbf{DAA3_t}$ is as defined in section 5.10.2.

$\mathbf{DTEC_t}$ is an adjustment for any shortfall or over-recovery of actual *distribution system revenue* compared to TEC_t in preceding years and is calculated in accordance with section 5.11.3 of this access arrangement.

For the purpose of calculating DR_t, DK_t and therefore MDR_t and TDR_t, in each financial year *CPI* adjustments will be effected by using published *CPI* data relating to the most recent December quarter compared to the December quarter in the previous year, with the exception of the financial year ending 30 June 2020 pricing year which will use the most recent September quarter compared to the September quarter in the previous year for the *CPI* to apply to financial year ending 30 June 2020 only.

5.11.3 For the financial year ending on 30 June 2020 to 30 June 2022:

$$\mathbf{DTEC_t} = (FTEC_{t-2} - ATEC_{t-2}) * (1 + WACC_t) * (1 + WACC_{t-1}) + (TEC_{t-1} - FTEC_{t-1}) * (1 + WACC_t)$$

where:

$\mathbf{ATEC_t}$ is the actual tariff equalisation contribution revenue received in financial year t.

$\mathbf{FTEC_t}$ is the forecast of tariff equalisation contribution revenue to be received in financial year t.

$\mathbf{TEC_t}$ is the amount of tariff equalisation contribution to be recovered in a financial year t as gazetted.

$\mathbf{WACC_t}$ is the *weighted average cost of capital* in year t-1 for the *Western Power Network* as detailed in section 5.4 of this *access arrangement*, on a post-tax real basis.

5.11.4 Notwithstanding clause 5.11.2 for the financial year ending 30 June 2021, TDR_t will also include an additional term DK' as follows:

$$\mathbf{DK'} = (AMDR_{2018/19} – FMDR_{2018/19}) * (1 + WACC_{2018/19}) * (1 + WACC_{2019/20})$$

where:

$\mathbf{AMDR_{2018/19}}$ is the actual revenue received in 2018/19

$\mathbf{FMDR_{2018/19}}$ = $1,218.981M nominal

$\mathbf{WACC_{2018/19}}$ is as defined in section 5.4

$\mathbf{WACC_{2019/20}}$ is as defined in section 5.4

6. Pricing methods, price lists and price information

6.1 Purpose

6.1.1 Pursuant to section 5.1(e) and chapter 7 of the *Code*, this section describes the *pricing methods* applied by Western Power.

6.2 Network pricing objectives

6.2.1 Western Power's *pricing methods* are designed to achieve the objectives set out in sections 7.3 and 7.4 of the *Code*.

6.2.2 In accordance with the objectives set out in sections 7.3 and 7.4 of the *Code*, Western Power's *pricing methods* seek to recover the costs of providing *reference services* from *users* in a manner that is simple, practical and equitable.

6.3 Overview of pricing methods

6.3.1 *Reference tariffs* are derived from an analysis of the cost of *reference service* provision which entails:

a) identifying the costs of providing *revenue target services*;

b) determining the expected *non-reference service* revenue within the costs of providing *revenue target services*;

c) deducting the expected *non-reference service* revenue from the costs of providing *revenue target services* to determine the costs of providing *reference services*;

d) allocating the costs of providing *reference services* to particular *reference service* customer groups;

e) translating the costs of serving particular *reference service* customer groups to the costs of providing *reference tariffs*; and

f) determining a structure of *reference tariffs* in a manner that reflects the underlying cost structure, in accordance with section 7.6 of the *Code*.

6.3.2 The costs relating to *reference services* A1 to A10, A12 to A17 and C1 to C15 are allocated so that these costs can determine the relevant *reference tariff* in a cost reflective manner.

6.3.3 *Reference tariffs* for *reference services* A11, B1 to B3 are location-specific and are published for each electrical node.

6.4 Price list and price list information

6.4.1 The *price lists* in respect of the pricing year ending on 30 June 2018 and the *pricing year* ending on the day before the effective date under section 1.3.1 of this *access arrangement* (30 June 2019) are attached at Appendix F.1 and F.3 respectively. In respect of these *pricing years*, these are the current *price lists* for the purposes of section 5.1(f) of the *Code*. The respective *price list information* for these *price lists* are attached at Appendix F.2 and F.4.

6.4.2 The *price list* in respect of the *pricing year* commencing on the date in section 1.3.1 of this *access arrangement* (1 July 2019) and ending on 30 June 2020 is attached at Appendix F.5. The *price list information* for this *price list* is attached at Appendix F.6.

6.4.3 In accordance with section 8.1 of the *Code* this *access arrangement* requires Western Power to submit a proposed *price list*, together with *price list information*, to the *Authority* for approval at least 45 *business days* before the start of the *pricing year* ending 30 June 2021 and 30 June 2022.

6.4.4 The *pricing years* for the *access arrangement period* are defined in the table below:

Table 36: Pricing years for this access arrangement period

Pricing year	Start date	End date
1	1 July 2017	30 June 2018
2	1 July 2018	The day before the effective date under section 1.3.1 of this access arrangement (30 June 2019)
3	Effective date under section 1.3.1 of this access arrangement (1 July 2019)	30 June 2020
4	1 July 2020	30 June 2021
5	1 July 2021	30 June 2022

6.4.5 For the purposes of the p*rice list* and p*rice list information* in the financial years ending 30 June 2020, 30 June 2021 and 30 June 2022, Western Power will use the customer information in the table below to determine prices:

Table 37: Customer numbers and energy volumes

Customer segment	Sub-segment	Tariffs	2019/20		2020/21		2021/22	
			Customer numbers	Energy volumes, GWh	Customer numbers	Energy volumes, GWh	Customer numbers	Energy volumes, GWh
Residential	Without PV	RT1, RT3, RT17, RT19, RT21	810,777	4,088	810,556	3,996	810,672	3,911
	With PV	RT13, RT15	254,837	1,103	275,034	1,080	294,895	1,054
Unmetered supply		RT10	16,493	40	16,641	41	16,789	43
Small businesses	Without PV	RT2, RT4, RT18, RT20, RT22	81,740	1,759	80,886	1,654	80,008	1,554
	With PV	RT14, RT16	2,250	284	2,420	345	2,590	406
Medium businesses	Low voltage business	RT6	3,967	2,037	3,998	1,964	4,029	1,948
	High voltage business	RT5	296	758	300	803	303	835
Large businesses	Low voltage business	RT8	58	186	58	181	58	176
	High voltage business	RT7	291	3,109	293	3,068	295	3,012
CMD		TR1		695 MW		695 MW		695 MW
DSOC		TR2		5,405 MW		5,405 MW		5,405 MW
Maximum kVA		RT5 RT6 RT7 RT8		140,172 545,642 960,969 87,784		140,172 545,642 960,969 87,784		140,172 545,642 960,969 87,784
Streetlights		RT9	288,415	141	296,223	143	304,058	146

6.5 Pricing methods

6.5.1 This section of the *access arrangement* explains how the *pricing methods* comply with sections 7.3 and 7.4 of the *Code*. In accordance with the *Code* requirements, the *price list information* provided as Appendix F.6 to the *access arrangement* explains the *pricing methods* that underpinned the development of *reference tariffs* for this *access arrangement period*.

Recovery of forward-looking efficient costs of providing reference services

6.5.2 In accordance with section 7.3(a) of the *Code*, *reference tariffs* are designed to recover the forward-looking efficient costs of providing *reference services*. Further information is provided in the *price list information*, Appendix F.6 to the *access arrangement*.

6.5.3 Western Power, as a *reasonable and prudent person*, will set the *reference tariffs* in the *price list* so that the forecast *transmission system* revenue for *revenue target services* for year t recovers MTR or TTR as applicable and the forecast *distribution system* revenue for *revenue target services* for year t recovers MDR or TDR as applicable.

6.5.4 *Non-revenue target services* revenue is recovered on a fee-for-service basis.

6.5.5 *Capital contributions* are charged in accordance with Western Power's *contributions policy*. In general terms, such *contributions* seek to recover in net present value terms any shortfall between the expected revenue from *reference tariffs* and the costs of connection.

Reference tariffs should be between the incremental and the stand-alone cost of service provision

6.5.6 In accordance with section 7.3(b) of the *Code*, *reference tariffs* are set to at least recover the *incremental cost of service provision*, but to be less than the *stand-alone cost of service provision*. Further information is provided in the *price list information*, Appendix F.6 to the *access arrangement*.

Charges paid by different users of a reference service

6.5.7 In accordance with section 7.4(a) of the *Code*, the *charges* paid by different *users* of a *reference serv*ice differ only to the extent necessary to reflect differences in the *average cost of service provision* to the *users*.

6.5.8 Each of the *reference tariffs* takes into account the metering information available for each *reference service*, and therefore contains components that vary with usage or demand. In addition *reference tariffs* for *reference services* A5, A6, A7, A8, C5, C6, C7, C8, A11, B1 and B2 vary with location. Within the requirements of section 7.4(a) and 7.7 of the *Code*, these components reflect the differences in the average cost of different *users* of the same *reference service*. Further information is provided in the *price list information*, Appendix F.6 to the *access arrangement*.

Reasonable requirements of users

6.5.9 In accordance with section 7.4(b) of the *Code*, the structure of *reference tariffs* has been set to reasonably accommodate the requirements of *users* collectively.

Structure of tariffs should enable a user to predict likely annual changes

6.5.10 In accordance with section 7.4(c) of the *Code*, *users* can predict the likely annual changes in *reference tariffs*. All *reference tariffs* are specified until the financial year ending 30 June 2020. For the remainder of this *access arrangement period* rebalancing of *reference tariffs* is constrained by the imposition of side constraints on annual revenue movements. In addition, the *revenue targets* have been smoothed across this *access arrangement period* to facilitate smooth price movements.

Avoidance of price shock

6.5.11 *The transmission system and distribution system target revenue* for *revenue target services* has each been smoothed across this *access arrangement period* so that price movements will be smoothed from year to year.

6.5.12 In accordance with section 7.4(d) of the *Code*, rebalancing of *reference tariffs* is constrained by the imposition of side constraints on annual revenue movements.

6.5.13 To constrain *tariff* rebalancing the maximum change in revenue for each *reference tariff* when the *price list* is updated is:

For financial years ending on 30 June 2020 to 30 June 2022:

$$\frac{\sum_{y=1}^{n} p_t^{xy} q_t^{xy}}{\sum_{y=1}^{n} p_{t-1}^{xy} q_t^{xy}} \leq (1+CPI_t)(1-X_t)+A'_t+0.02$$

where:

a given reference *tariff* x , has up to n tariff components, and where:

t	is the financial year in which the *reference tariffs* as varied will apply;
$t-1$	is the financial year immediately preceding financial year t;
p_{t-1}^{xy}	is the price being charged in the financial year $t-1$ for component y of a given *reference tariff* x ;
p_t^{xy}	is the proposed price for component y of a given *reference tariff* x in financial year t;
q_t^{xy}	is the quantity of component y of a given *reference tariff* x that is forecast to be sold in financial year t;
CPI_t	is the percentage increase in the *CPI* data relating to the most recent December quarter compared to the December quarter in the previous year;

X_t is the annual percentage change in the sum of DR_t and TR_t is initially determined to be:

Table 38: X_t

Financial year ending:	30 June 2019	30 June 2020	30 June 2021	30 June 2022
X_t	0.23%	-3.57%	-1.54%	-2.14%

A'_t is the annual correction factor in financial year t determined as follows:

$$A'_t = \frac{(DAA3_t + TAA3_t + \triangle TEC_t + DTEC_t)}{(DR'_t + TR'_t)}$$

DK_t is as defined in section 5.10.2 of the *access arrangement*;

$DAA3_t$ is as defined in section 5.10.2 of the *access arrangement*;

ΔTEC_t is the difference in the cost incurred by the *distribution system* between the financial years t-1 and t as a result of the tariff equalisation contribution in accordance with section 6.37A of the *Code*;

$DTEC_t$ is the revenue correction factor for the tariff equalisation contribution as defined in section 5.11.3 of the *access arrangement;*

DR'_t is DR_t (as set out in section 5.10.2 of the *access arrangement*), converted to nominal dollars;

TR'_t is TR_t (as set out in section 5.7.2 of the *access arrangement*), converted to nominal dollars.

For the financial year 2020/21, the numerator of A’t must include DK’ and TK’ as defined in sections 5.8.3 and 5.11.4.

6.5.14 The values for X_t in Table 38 will be updated and these values will be reported in the *price list information* for the financial years ending 30 June 2021 and 30 June 2022, as a result of the annual updates to *weighted average costs of capital* specified in section 5.4. Note that the update for the financial year ending 30 June 2021 will update the *weighted average cost of capital* for 30 June 2020 and 30 June 2021.

Tariff components

6.5.15 In accordance with section 7.6 of the *Code*, *reference tariffs* have been designed so that the *incremental cost of service provision* is to be recovered by *tariff* components that vary with usage, and the costs in excess of the *incremental cost of service provision* are to be recovered through *tariff* components that do not vary with usage. Further information is provided in the *price list information*, Appendix F.6 to the *access arrangement*.

6.6 Policy on prudent discounting

6.6.1 In accordance with section 7.9 of the *Code*, Western Power may discriminate between *users* in its pricing of *services* to the extent that it is necessary to do so to aid economic efficiency, by:

a) entering into an agreement with a *user* to apply a *discount* to the *equivalent tariff* to be paid by the *user* for a *covered service*; and

b) then, recovering the amount of the *discount* from other *users* of *reference services* through *reference tariffs*.

6.6.2 In exercising its discretion with regard to prudent discounting, Western Power will have regard to the pricing objectives in sections 7.3 and 7.4 of the *Code*.

6.6.3 Western Power may offer a prudent discount if the existing *user* or *applicant* seeking *access* to the *Western Power Network* is able to demonstrate that another supply option will provide a comparable *service* at a lower price than that offered by Western Power's *reference services* and *reference tariffs*.

6.6.4 The existing *user* or *applicant* must provide Western Power with sufficient details of the cost of the other option to enable Western Power to calculate the annualised cost of the other option.

6.6.5 Western Power's discounted price offer will be set to reflect the higher of:

a) the cost of the other option; or

b) the *incremental cost of service provision*.

6.7 Policy on discounts for distributed generation

6.7.1 In accordance with section 7.10 of the *Code*, Western Power will provide, through *reference services* B3 and C15, to *users* who *connect distributed generating plant* and other non-network solutions behind the *connection* point which provide benefits to the *Western Power Network that* defer its *capital-related costs* or *non-capital costs* which benefits arise as a result of the *entry point* or *bi-directional point* being located in a particular part of the *Western Power Network* a discount as described and calculated under the *Price List*.

7. Adjustments to target revenue in the next access arrangement period

7.1 Adjusting target revenue for unforeseen events

7.1.1 If a *force majeure* event occurs which results in Western Power incurring unrecovered costs (within the meaning of the *Code*) during this *access arrangement period* then Western Power will, as part of its *proposed revisions* for the next *access arrangement period*, provide a report to the *Authority* setting out:

a) a description of the nature of the *force majeure* event;

b) a description of the insurance cover that Western Power had in place at the time of the *force majeure* event;

c) the unrecovered costs borne, or an estimate of the unrecovered costs likely to be borne, by Western Power during the *access arrangement period* as a result of the occurrence of the *force majeure* event; and

d) a demonstration that the amount to be added to the *target revenue* for the next *access arrangement period* in respect of those unrecovered costs does not exceed the costs which would have been (or, in the case of estimated costs, would be) borne by a *service provider efficiently minimising costs*.

7.1.2 Pursuant to sections 6.6 to 6.8 of the *Code*, an amount will be added to the *target revenue* for the next *access arrangement period* in respect of the unrecovered costs relating to a *force majeure* event which occurred in this *access arrangement period*.

7.1.3 The addition to *target revenue* in the next *access arrangement period* must leave Western Power financially neutral given the timing of when Western Power incurred any unrecovered costs by taking account of:

a) the effects of inflation; and

b) the time value of money as reflected by Western Power's *weighted average cost of capital* for the *Western Power Network* as determined in section 5.4.

7.2 Adjusting target revenue for technical rule changes

7.2.1 If the *technical rules* are amended during this *access arrangement period*, Western Power will, as part of its *proposed revisions* for the next *access arrangement period*, provide a report to the *Authority* setting out:

a) a description of the nature and timing of the impact of the *technical rule* change on Western Power's *non-capital costs* and *new facilities investment* for this *access arrangement period*; and

b) the costs (or cost savings) incurred, or an estimate of the costs (or cost savings) likely to be incurred, by Western Power as a result of that *technical rule* change.

7.2.2 Pursuant to sections 6.9 to 6.12 of the *Code*, if the *technical rule* change leads to a cost increase, an amount will be added to the *target revenue* for the next *access arrangement period*.

7.2.3 Pursuant to sections 6.9 to 6.12 of the *Code*, if the *technical rule* change leads to a cost saving, an amount will be deducted from the *target revenue* for the next *access arrangement period*.

7.2.4 The adjustment to *target revenue* in the next *access arrangement period* must leave Western Power financially neutral given the timing of when Western Power incurred any costs or received cost savings as a result of the *technical rule* change by taking account of:

a) the effects of inflation; and

b) the time value of money as reflected by Western Power's *weighted average cost of capital* for the *Western Power Network* as determined in section 5.4.

7.3 Investment adjustment mechanism

7.3.1 In accordance with sections 6.13 to 6.18 of the *Code*, an *investment adjustment mechanism* applies in relation to this *access arrangement*.

7.3.2 An amount will be added to, or deducted from, the *target revenue* for the next *access arrangement period* in accordance with the *investment adjustment mechanism* set out below.

7.3.3 The *investment adjustment mechanism* will apply separately to each of:

a) *new facilities investment* for the *transmission system*; and

b) *new facilities investment* for the *distribution system*.

7.3.4 The purpose of the *investment adjustment mechanism* is to adjust Western Power's *target revenue* in the next *access arrangement period* in a manner that exactly corrects for the economic loss or gain to Western Power as a result of any *investment difference* in this *access arrangement period* in relation to the categories of *new facilities investment* specified in section 7.3.7 of this *access arrangement*. In order to give effect to this purpose, the *investment adjustment mechanism* must take account of:

a) the effects of inflation;

b) the time value of money as reflected by Western Power's *weighted average cost of capital* for the *Western Power Network* as determined in section 5.4; and

c) the *capital-related costs* due to any *investment difference* in the *access arrangement period*.

7.3.5 Given the requirements of the *investment adjustment mechanism* as described in section 7.3.4 of this *access arrangement*, Western Power's approach to calculating the *capital-related costs* due to any *investment difference* is to calculate the difference in present value terms between:

a) the *target revenue* that would have been calculated for this *access arrangement period* if the *investment difference* had been zero (i.e. there was no forecasting error in relation to the *new facilities investment* categories that are subject to the *investment adjustment mechanism*); and

b) the *target revenue* that actually applied in this *access arrangement period*.

7.3.6 The amount under section 7.3.2 of this *access arrangement* is equal to the present value of the difference calculated under section 7.3.5 of this *access arrangement*.

7.3.7 The categories that are used in calculating the *investment difference* are *new facilities investment*:

a) arising from the connection of new generation capacity to the *transmission system* or *distribution system* from 1 July 2017;

b) arising from the connection of new *load* to the *transmission system* or *distribution system* from 1 July 2017;

c) in relation to all *augmentations* to provide additional capacity to the *transmission system* or *distribution system* for the provision of *covered services* from 1 July 2017; and

d) undertaken for *augmentation* of the *distribution system* under the state underground power program.

7.4 Gain sharing mechanism and efficiency and innovation benchmarks

7.4.1 In accordance with sections 5.25 and 6.20 of the *Code*, a *gain sharing mechanism* and *efficiency and innovation benchmarks* will apply with respect to the *access arrangement*.

7.4.2 An *above-benchmark surplus* (within the meaning of the *Code*) is to be calculated for each of the financial years of the access arrangement period as follows:

$$ABS_{t1} = EIB_{t1} - A_{t1}$$

$$ABS_{t2} = (EIB_{t2} - A_{t2}) - (EIB_{t1} - A_{t1})$$

$$ABS_{t3} = (EIB_{t3} - A_{t3}) - (EIB_{t2} - A_{t2})$$

$$ABS_{t4} = (EIB_{t4} - A_{t4}) - (EIB_{t3} - A_{t3})$$

$$ABS_{t5} = (EIB_{t5} - A_{t5}) - (EIB_{t4} - A_{t4})$$

where:

ABS_t is the *above-benchmark surplus* in year t of the *access arrangement period*;

EIB_t is the *efficiency and innovation benchmark* for financial year t as set out in Table 39, adjusted for:

a) any difference between the actual network growth escalation factors in each financial year and the forecast network growth escalation factors and any difference between the actual indirect cost growth escalation factors in each financial year and the forecast indirect cost growth escalation factors used to establish the *non-capital costs* component of *approved total costs* that financial year, in accordance with section 7.4.8 of the *access arrangement*; and

b) the effects of inflation;

Table 39: Efficiency and innovation benchmarks ($M real as at 30 June 2017)

Financial year ending:	30 June 2018	30 June 2019	30 June 2020	30 June 2021	30 June 2022
Network	230.1	230.4	230.8	231.0	230.9
Corporate	81.2	80.6	80.1	77.1	71.8

Financial year ending:	30 June 2018	30 June 2019	30 June 2020	30 June 2021	30 June 2022
Indirect costs	43.2	39.5	39.2	48.7	48.2
Efficiency and innovation benchmark - EIB_t	**354.6**	**350.5**	**350.1**	**356.8**	**350.8**

and

A_t is the sum of the actual *non-capital costs* incurred by Western Power for the *transmission system* and *distribution system* in year t, excluding any amount of *non-capital costs* incurred by Western Power:

A. in accordance with the D-factor scheme in the *access arrangement* and providing that the expenditure has been approved by the *Authority;*

B. in accordance with any adjustment made under section 7.1*;*

C. in accordance with any adjustment made under section 7.2*;*

D. in relation to superannuation for defined benefits schemes;

E. in relation to *non-revenue target services;*

F. in relation to licence fees;

G. in relation to a levy made under section 14 of the *Energy Safety Act 2006 (WA)* applicable to Western Power; and

H. in relation to amounts payable under the *Economic Regulation Authority (Electricity Network Access Funding Regulations) 2012*.

7.4.3 The gain sharing mechanism amount ($GSMA_{AA}$) for the *access arrangement period* is to be calculated as follows:

$GSMA_{AA} = \sum[GSMA_{1:5}]$

where:

$GSMA_1 = \max(0, ABS_{t1} + ABS_{t2} + ABS_{t3} + ABS_{t4} + ABS_{t5})$

$GSMA_2 = \max(0, ABS_{t2} + ABS_{t3} + ABS_{t4} + ABS_{t5})$

$GSMA_3 = \max(0, ABS_{t3} + ABS_{t4} + ABS_{t5})$

$GSMA_4 = \max(0, ABS_{t4} + ABS_{t5})$

$GSMA_5 = \max(0, ABS_{t5})$

where:

$GSMA_n$ is the total *above-benchmark surplus* for the equivalent year of the *access arrangement period*; and

ABS_t is the *above-benchmark surplus* in year t of the *access arrangement period* calculated in accordance with section 7.4.2.

7.4.4 For year in which Western Power failed to provide *reference services* at a *service standard* at least equivalent to the *service standard benchmarks* for those *reference services* for that year as set out in section 4 of the access arrangement:

a) a determination will be made by the *Authority* of the extent (expressed as a percentage) that Western Power achieved the *above-benchmark surplus* by failing to provide *reference services* at a *service standard* at least equivalent to the *service standard benchmarks* for those *reference services* for that year as set out in section 4; and

b) the percentage determined by the Authority in 7.4.4(a) will be applied as a proportion of the year (the "**SSB Deficiency Proportion**") in accordance with section 7.4.6.

7.4.5 For the purposes of section 7.4.4, for any year in which Western Power fails to provide *reference services* at a *service standard* at least equivalent to the *service standard benchmarks* for those *reference services* for that year as set out in section 4 of the *access arrangement*, Western Power must demonstrate how and to what extent there is, or is not, a relationship between the failure and Western Power's achieved *above-benchmark surplus*, through consideration of:

a) which *service standard benchmarks* have not been met in that year;

b) an analysis of the causes for not meeting the *service standard benchmark* in that year;

c) the categories of *non-capital costs* that impact on the achievement of those *service standard benchmarks* (which may be sub-categories of the cost categories in section 7.4.2);

d) the forecast *non-capital costs* for those categories in section 7.4.5(c) used to establish the *non-capital costs* component of *approved total costs*, after normalising for inflation (using the *CPI*), network growth escalation factors and indirect and corporate cost growth escalation factors; or

e) any other issues that are relevant.

7.4.6 A total *gain sharing mechanism* revenue amount for the *access arrangement* (**GSMR**) will be added to *target revenue* for the next *access arrangement period* calculated as follows:

$$GSMR = GSMA_{AA} - (GSMA_{AA} \times (\sum \text{SSB Deficiency Proportion} / \text{AA Length}))$$

where:

$GSMA_{AA}$ is the total *above-benchmark surplus* for the *access arrangement period* calculated in accordance with section 7.4.3;

SSB Deficiency Proportion is determined under section 7.4.4; and

AA Length is the number of years in the *access arrangement period*.

7.4.7 The *gain sharing mechanism* does not affect the ordinary operation of the *transmission system* and *distribution system* revenue targets (absent the *gain sharing mechanism*), which already provides for Western Power to retain 100% of any efficiency gains achieved during the *access arrangement period*. This characteristic is consistent with section 6.24 of the *Code* which ensures that Western Power can retain all of the *surplus* achieved in the *access arrangement period*.

7.4.8 The adjustment to EIB_t due to any differences between the actual network growth escalation factors in each financial year and the forecast network growth escalation factors and any differences between the actual indirect cost growth escalation factors in each financial year and the forecast indirect cost growth escalation factors used to establish the *non-capital costs* component of *approved total costs* for that financial year will be calculated by:

a) deflating EIB_t for financial year t by using:

i. the network growth escalation factors and indirect cost growth escalation factors assumed for financial year t when setting the forecast *non-capital cost* component of *approved total costs* for that financial year, compounded to that financial year, as set out in Table 40, Table 41 and Table 42; and

b) inflating the value determined under section 7.4.8(a) for financial year t using:

i. the network growth escalation factors recalculated for financial year t using actual data for each network growth escalation factor in each financial year, compounded to that financial year, and following the calculation method set out in Table 40 and Table 41; and

ii. indirect cost growth escalation factors recalculated for financial year t using actual data, compounded to that financial year, following the calculation method set out in Table 42 and section 7.4.9.

7.4.9 When inflating the EIB value determined under section 7.4.8(a) for indirect cost growth escalation factors, the growth factor applied to indirect costs is a weighted average of the *distribution system* and *transmission system* recalculated network growth escalation factors. The weighting is based on the total *distribution system* operating expenditure that attracts indirect costs (as a proportion of total operating expenditure that attracts indirect costs) and the total *transmission system* operating expenditure that attracts indirect costs (as a proportion of total operating expenditure that attracts indirect costs) in accordance with the Cost and Revenue Allocation Methodology and derived from the Regulatory Financial Statements for financial year t.

Table 40: Distribution system forecast network growth escalation assumptions

Network growth factor	Calculation method	Weight	2017/18	2018/19	2019/20	2020/21	2021/22
Customer numbers (a)	Year on year growth	45.8%	1.65%	1.73%	1.69%	1.66%	1.63%
Circuit length (b)	Year on year growth	23.8%	0.91%	0.91%	0.91%	0.91%	0.91%
Ratcheted Maximum Demand (c)	Year on year growth	17.6%	0.00%	0.00%	0.00%	0.00%	0.00%
Energy delivered (d)	Year on year growth	12.8%	-0.37%	-0.20%	-0.20%	-0.71%	-1.10%
Customer and Network growth factor	**Weighted average of a, b, c and d**	**100%**	**0.92%**	**0.98%**	**0.97%**	**0.89%**	**0.82%**

Table 41: Transmission system forecast network growth escalation assumptions

Network growth factor	Calculation method	Weight	2017/18	2018/19	2019/20	2020/21	2021/22
Circuit length (a)	Year on year growth	37.6%	0.32%	0.33%	0.22%	0.33%	0.32%
Ratcheted Maximum Demand (b)	Year on year growth	19.4%	0.00%	0.00%	0.00%	0.00%	0.00%
Energy Delivered (c)	Year on year growth	23.1%	-0.37%	-0.20%	-0.20%	-0.71%	-1.10%
Customer numbers (d)	Year on year growth	19.9%	0.00%	0.00%	2.63%	2.56%	0.00%
Network growth factor	**Weighted average of a, b, c and d**	**100%**	**0.03%**	**0.08%**	**0.56%**	**0.47%**	**-0.13%**

Table 42: Indirect cost forecast growth escalation assumptions

Growth escalation factor	Calculation method	2017/18	2018/19	2019/20	2020/21	2021/22
Indirect	Year on year growth	0.70%	0.76%	0.87%	0.78%	0.59%

7.4.10 For the purposes of section 7.4.8(a) the actual data used for each relevant network growth escalation factor must be independently audited. The audit must be carried out by an independent auditor approved by the *Authority*, with Western Power managing and funding the audit. The scope of the audit will be determined by the *Authority*.

7.5 Service standards adjustment mechanism

7.5.1 In accordance with section 6.30 of the *Code*, a *service standards adjustment mechanism* applies to the *access arrangement*.

7.5.2 An amount will be added to, or deducted from, the *target revenue* for each of the *transmission system* and the *distribution system* for the next *access arrangement period* in accordance with the *service standards adjustment mechanism* set out below.

7.5.3 The *service standards adjustment mechanism* will apply to the ***"SSAM SSBs"*** meaning the *service standard benchmarks* for SAIDI, SAIFI, call centre performance, circuit availability, loss of supply event frequency and average outage duration as defined in section 4.

7.5.4 In relation to actual service performance for each of the financial years ending 30 June 2018 and 30 June 2019, and the following financial years ending 30 June ("**SST Year**"*)* a reward (a positive amount) or penalty (a negative amount) will be calculated for each *SSAM SSB* by applying the applicable incentive rate to the relevant Service Standard Difference ("**SSD**"). The *SSD* is calculated as follows*:*

a) if SSA_t < SSB for SAIDI, SAIFI, loss of supply event frequency and average outage duration; or

SSA_t > SSB for call centre performance and circuit availability then

$SSD_t = (SST - SSA_t)$

b) if $SSA_t \geq SSB$ for SAIDI, SAIFI, loss of supply event frequency and average outage duration; or $SSA_t \leq SSB$ for call centre performance and circuit availability then

$$SSD_t = (SST - SSB)$$

where:

SSD_t is the service standard difference in *SST Year* t;

SST is the SSAM target detailed in section 7.5.11;

SSB is the *service standard benchmark* for the *SSAM SSBs* as defined in section 7.5.3; and

SSA_t is the actual service performance in *SST Year* t with respect to the *SSAM SSBs*.

7.5.5 In relation to SAIDI and SAIFI, the rewards or penalties are calculated as the sum of the application of the formulae in section 7.5.4 to each component of SAIDI and SAIFI.

7.5.6 The rewards and penalties are applied to the performance *SST Year* in the *access arrangement period* and:

a) the reward or penalty for circuit availability will be allocated to the performance of the *transmission system*;

b) the reward or penalty for SAIDI and SAIFI will be allocated to the performance of the *distribution system*;

c) the reward or penalty for call centre performance will be allocated to the performance of the *distribution system*;

d) the reward or penalty for loss of supply event frequency will be allocated to the performance of the *transmission system;* and

e) the reward or penalty for average outage duration will be allocated to the performance of the *transmission system*.

7.5.7 The rewards and penalties applied to each *SST Year* as allocated to each of the *transmission system* and *distribution system* are summed for each of the *transmission system* and *distribution system*.

7.5.8 Notwithstanding section 7.5.7 of this *access arrangement*, the sum of the rewards or penalties for the *transmission system* applied to each *SST Year* is capped at 1% of TR_t for that year as set out in Table 34. For the avoidance of doubt, for the purposes of this section TR_t in that table will not be updated as a result of the annual updates to *weighted average cost of capital* as determined in section 5.4.

7.5.9 Notwithstanding section 7.5.7 of this *access arrangement*, the sum of the rewards for the *distribution system* applied to each *SST Year* is capped at 1% of DR_t for that year, and the sum of the penalties for the *distribution system* applied to each *SST Year* is capped at 2.5% as set out in Table 35. For the avoidance of doubt, for the purposes of this section DR_t in that table will not be updated as a result of the annual updates to *weighted average cost of capital* as determined in section 5.4.

7.5.10 The amount that will be added to, or deducted from, the *target revenue* for each of the *transmission system* and the *distribution system* is equal to the present value of the sum of the amounts for each of the *transmission system* and the *distribution system* calculated under section 7.5.7 of this *access arrangement* (as subject to sections 7.5.8 and 7.5.9 of this *access arrangement*).

7.5.11 The SSAM targets and incentive rates for the *SSAM SSBs* are as follows:

Table 43: SAIDI SSAM targets and incentive rates ($ real as at 30 June 2017)

	SSAM target (SST_t) for years ending 30 June 2018 and 30 June 2019	SSAM target (SST_t) for each *SST Year*	Reward side incentive rate ($ per SAIDI minute)	Penalty side incentive rate ($ per SAIDI minute)
SAIDI - CBD (minutes)	-	17.7	30,215	30,215
SAIDI - Urban (minutes)	-	106.8	446,660	446,660
SAIDI - Rural Short (minutes)	-	188.6	143,118	143,118
SAIDI - Rural Long (minutes)	-	677.7	52,503	52,503

Table 44: SAIFI SSAM targets and incentive rates ($ real as at 30 June 2017)

	SSAM target (SST_t) for years ending 30 June 2018 and 30 June 2019	SSAM target (SST_t) for each *SST Year*	Reward side incentive rate ($ per 0.01 event)	Penalty side incentive rate ($ per 0.01 event)
SAIFI - CBD (events)	-	0.12	29,224	29,224
SAIFI - Urban (events)	-	1.09	290,697	290,697
SAIFI - Rural Short (events)	-	1.96	91,819	91,819
SAIFI - Rural Long (events)	-	4.29	55,341	55,341

Table 45: Call centre performance SSAM target and incentive rate ($ real as at 30 June 2017)

	SSAM target (SST_t) for years ending 30 June 2018 and 30 June 2019	SSAM target (SST_t) for each *SST Year*	Reward side incentive rate ($ per 0.1%)	Penalty side incentive rate ($ per 0.1%)
Call centre performance (Percentage of calls responded to within 30 seconds)	-	92.0%	-38,059	-12,442

Table 46: Circuit availability SSAM target and incentive rate ($ real as at 30 June 2017)

	SSAM target (SST_t) for years ending 30 June 2018 and 30 June 2019	SSAM target (SST_t) for each *SST Year*	Reward side incentive rate ($ per 0.1%)	Penalty side incentive rate ($ per 0.1%)
Circuit availability (Percentage of total possible hours available)	-	98.5%	-449,344	-256,768

Table 47: Loss of supply event frequency SSAM target and incentive rate ($ real as at 30 June 2017)

	SSAM target (SST_t) for years ending 30 June 2018 and 30 June 2019	SSAM target (SST_t) for each *SSAM year*	Reward side incentive rate ($ per event)	Penalty side incentive rate ($ per event)
Loss of supply event frequency >0.1 and ≤1.0 system minutes interrupted (number of events)	-	17	89,869	59,912
Loss of supply event frequency >1.0 system minutes interrupted (number of events)	-	3	179,737	134,803

Table 48: Average outage duration SSAM target and incentive rate ($ real as at 30 June 2017)

	SSAM target (SST_t) for years ending 30 June 2018 and 30 June 2019	SSAM target (SST_t) for each *SST Year*	Reward side incentive rate ($ per minute)	Penalty side incentive rate ($ per minute)
Average outage duration (minutes)	-	784	5,661	1,598

7.6 D factor

7.6.1 In section 7.6.3 **"network control service"** means demand-side management or generation solutions (such as *distributed generating plant*) that can be a substitute for *network augmentation*.

7.6.2 This D factor scheme applies separately to each of:

a) *non-capital costs* for the *transmission system*; and

b) *non-capital costs* for the *distribution system*.

7.6.3 In the next *access arrangement period*, the *Authority* will add to Western Power's *target revenue* an amount so that Western Power is financially neutral as a result of:

a) any additional *non-capital costs* incurred by Western Power as a result of deferring a *new facilities investment* project during this *access arrangement period,* net of any amounts previously included in *target revenue* in relation to the deferred *new facilities investment* (other than such amounts included in the calculation of the *capital-related costs* due to any *investment difference* under section 7.3.5); and

b) any additional *non-capital costs* incurred by Western Power in relation to demand management initiatives or *network control services*.

7.6.4 In relation to section 7.6.3(a), the *new facilities investment* project that has been deferred must have been included in the *forecast new facilities investment* for this *access arrangement period*.

7.6.5 In relation to sections 7.6.3(a) and 7.6.3(b), an amount will only be added to *target revenue* for the next *access arrangement period* if there is an approved business case for the relevant expenditure, and this business case is made available to the *Authority*. The business case must demonstrate to the *Authority's* satisfaction that the proposed *non-capital costs* satisfy the requirements of sections 6.40 and 6.41 of the *Code*, as relevant.

7.6.6 In relation to sections 7.6.3(a) and 7.6.3(b), the adjustment to the *target revenue* for the next *access arrangement period* must leave Western Power financially neutral by taking account of:

a) the effects of inflation; and

b) the time value of money as reflected by Western Power's *weighted average cost of capital* for the *Western Power Network* as determined in section 5.4.

7.7 Deferred revenue

7.7.1 For the purposes of sections 6.5A to 6.5E of the *Code* an amount must be added to the target revenue for the *distribution system* in the fifth *access arrangement period* or subsequent *access arrangement periods* such that the present value (at 30 June 2017) of the total amount added to *target revenue* (taking account of inflation and the time value of money) is equal to $408.8 million ($ real as at 30 June 2017).

7.7.2 For the purposes of sections 6.5A to 6.5E of the *Code* an amount must be added to the *target revenue* for the *transmission system* in the fifth *access arrangement period* or subsequent *access arrangement periods* such that the present value (at 30 June 2017) of the total amount added to *target revenue* (taking account of inflation and the time value of money) is equal to $89.0 million ($ real as at 30 June 2017).

7.7.3 The timeframe for recovering the deferred revenue amounts in section 7.7.1 will be 32 years and in section 7.7.2 will be 40 years.

8. Trigger events

8.1.1 Pursuant to section 4.37 of the *Code* a *trigger event* is any significant unforeseen event which has a materially adverse impact on Western Power and which is:

a) outside the control of Western Power; and

b) not something that Western Power, acting in accordance with *good electricity industry practice*, should have been able to prevent or overcome; and

c) so substantial that the advantages of making a variation to this *access arrangement* before the end of this *access arrangement period* outweigh the disadvantages, having regard to the impact of the variation on regulatory certainty.

8.1.2 The *designated date* by which Western Power must submit *proposed revisions* to the *Authority* is 90 *business days* after a *trigger event* has occurred. If the costs associated with the *trigger event* are uncertain at the time of the *designated date*, Western Power's proposed revision to the *Authority* under section 4.37 of the *Code* must incorporate an appropriate mechanism for cost recovery having regard to the *Code objective*.

9. Supplementary matters

9.1 General

9.1.1 Western Power will discharge the obligations it has under the Wholesale Electricity Market Rules ("**WEM Rules**") as in force from time to time relating to balancing requirements, ancillary services, trading and settlement requirements in accordance with the WEM Rules. Western Power will also support the Australian Energy Market Operator ("**AEMO**") in the discharge of its functions, including by providing information to AEMO as required by the WEM Rules.

{Note: Previous versions of the access arrangement have referred, in the Supplementary Matters chapter, to balancing requirements, ancillary service, trading and settlement requirements. Under the WEM Rules, these functions are now principally undertaken by AEMO. This occurred when the System Management functions were transferred from Western Power to AEMO on 1 July 2016. As at 1 July 2016, Western Power's principal role in respect to these functions under the WEM Rules is to provide network information to AEMO to support settlements and balancing.}

9.2 Line losses

9.2.1 Requirements for the treatment of line losses under the *access arrangement* shall be in accordance with the Wholesale Electricity Market Rules.

9.3 Metering

9.3.1 Metering requirements under the *access arrangement* shall be in accordance with the *Electricity Industry (Metering Code) 2012* and the MSLA.

Appendix A: Electricity transfer access contract

Appendix B: Applications and queuing policy

Appendix C: Contributions policy

C.1 Contributions policy

C.2 Distribution low voltage connection scheme methodology

Appendix D: Transfer and relocation policy

Appendix E: Reference services

Appendix F: Reference tariffs

F.1 2017/18 price list

F.2 2017/18 price list information

F.3 2018/19 price list

F.4 2018/19 price list information

F.5 2019/20 price list

F.6 2019/20 price list information