Access Arrangement

(marked up)

Revised proposed access arrangement

14 June 2018

Important note – Amendments that were made as part of Western Power's original proposal are shown as purple and green, amendments that are made as part of this revised proposal are shown as blue.

Access arrangement for the period
1 July 2017 to 30 June 2022

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~~Proposed~~Revised proposed revisions to the Access Arrangement for the Western Power Network

ELECTRICITY NETWORKS CORPORATION
("WESTERN POWER")

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~~2 October 2017~~

14 June 2018

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1 Introduction

1.1 Purpose of this document

1.1.1 These *revised* ~~amended~~ *proposed revisions* are lodged by Western Power on 2 ~~October 2012~~2017 ~~for~~14 June 2018 for *review* and *approval* 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***". 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*:

"AMI Meter" has the meaning given to it in the model service level agreement most recently approved by the *Authority* under the Electricity Industry (Metering Code) 2012.

"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 ~~amended~~revised) is effective from 1 ~~July~~November~~February 2013~~ 2018 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 ~~31 December 2016.~~~~1 March~~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 ~~2017~~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)~~c) ~~the distribution headworks methodology attached at Appendix 0~~;

~~e)~~d) the distribution low voltage connection headworks scheme methodology attached at Appendix ~~A.1;~~ C.2;

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

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

~~h)~~g) the *price* ~~*list*~~*lists* attached at Appendix ~~F.1~~F, which ~~is~~are a schedule of *reference tariffs* in effect for this *access arrangement*; and

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

1.6 Relationship to technical rules and access arrangement information

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*.

1.6.2 Western Power's amended *access arrangement information* ~~is submitted on~~dated ~~2017~~14 June 2018 is submitted alongside this *access arrangement* in accordance with section 4.4 of the *Code*. The ~~amended~~ amended *access arrangement information* is to be read in conjunction with the revised *access arrangement information* that was submitted on 2 October 2017. The amended *access arrangement information* and the revised *access arrangement information* do not form part of this *access arrangement*.

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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 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.~~

~~"**AMI Meter**" has the meaning given to it in the model service level agreement most recently approved by the Authority under the Electricity Industry (Metering Code) 2012.~~

~~"**AMI metering installation**" means a metering installation with an AMI Meter (other than a compliance meter).~~

~~"**compliance meter**" means an AMI Meter that has been installed under Schedule 3, clause 3.2 (Meter Upgrade) of the model service level agreement most recently approved by the Authority under the Electricity Industry (Metering Code) 2012.~~

~~"**compliance metering installation**" means a metering installation with a compliance meter.~~

~~"**metering installation**" has the meaning given to it in the Electricity Industry (Metering Code) 2012.~~

~~2.2.2~~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*.

~~2.2.3~~2.2.2 Western Power specifies 11 *reference services* at *exit points*~~ and *bi-directional points*~~:

Table 1: Reference services at exit points ~~and *bi-directional points*~~

Reference service	Short name
Anytime Energy (Residential) Exit Service	A1
Anytime Energy (Business) Exit Service	A2

Reference service	Short name
Time of Use Energy (Residential) Exit Service	A3
Time of Use Energy (Business) Exit Service	A4
High Voltage Metered Demand Exit ~~Exit~~ Service	A5
Low Voltage Metered Demand Exit ~~Exit~~ Service	A6
High Voltage Contract Maximum Demand Exit ~~Exit~~ Service	A7
Low Voltage Contract Maximum Demand Exit ~~Exit~~ Service	A8
Streetlighting Exit Service (including streetlight maintenance)	A9
Unm~~M~~etered Supplies Exit Service	A10
Transmission Exit Service	A11

~~2.2.4~~2.2.3 Western Power specifies two *reference services* at *entry points*:

Table 2: Reference services at entry points

Reference service	Short name
Distribution Entry Service	B1
Transmission Entry Service	B2

~~2.2.5~~2.2.4 Western Power specifies ~~four~~ eight *bi-directional services* as *reference services* at connection points:

Table 3: Reference services at ~~B~~bi-directional points ~~services that are reference services~~

Reference service name	Short name
Anytime Energy (Residential) Bi-~~D~~directional Service	C1
Anytime Energy (Business) Bi-~~D~~directional Service	C2
Time Of Use Energy (Residential) Bi-~~D~~directional Service	C3
Time Of Use Energy (Business) Bi-~~D~~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

2.2.5 Western Power specifies ~~four~~two services at an exit point or a bi-directional point with an AMI meter or an interval metering ~~installation or a compliance metering installation~~ as reference services.

Table 4: Reference Services at an exit point or a bi-directional point with an AMI meter or an interval meter~~with an AMI metering installation or a compliance metering installation~~

Reference service name	Short name
~~Time of Use Energy (Residential) AMI Service~~3 Part Time of Use Energy (Residential) Service	D1
~~Time of Use Energy (Business) AMI Service~~3 Part Time of Use Energy (Business) Service	D2
~~Time of Use Demand (Residential) AMI Service~~	~~D3~~
~~Time of Use Demand (Business) AMI Service~~	~~D4~~

2.2.6 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 benchmarks* 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, B1 ~~and~~, C1 to C~~4~~8 and D1 ~~to~~and D~~4~~2, 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 ~~clauses~~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 5: 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: $$\frac{\sum \text{Sustained } \textit{distribution customer} \text{ interruption durations}}{\text{Number of } \textit{distribution customers} \text{ served}}$$ 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.

	System Average Interruption Duration Index (SAIDI) CBD Urban Rural Short Rural Long
	• 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 an unplanned interruption on the *distribution system*, a day on which the major event day threshold, ~~determined in accordance with IEEE1366-2003 definitions~~ 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, B1~~ and~~, C1 to C48 and D1 ~~to~~and D42 for each year of this *access arrangement period* are shown in the following table:

Table 6: SAIDI service standard benchmarks for reference services A1 to A10, B1~~ and~~, C1 to C48 and D1 ~~to~~and D42

SAIDI	For ~~each~~the financial year ending 30 June 2018	For each financial year ending 30 June thereafter
CBD	39.9	37.2
Urban	183.0	134.7

SAIDI	For ~~each~~the financial year ending 30 June 2018	For each financial year ending 30 June thereafter
Rural Short	227.8	226.3
Rural Long	724.8	902.9

System Average Interruption Frequency Index (SAIFI)

4.2.5 SAIFI is applied as follows:

Table 7: Application of SAIFI

	System Average Interruption Frequency Index (SAIFI) CBD Urban Rural Short Rural Long
Unit of Measure	~~Interruptions~~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, ~~determined in accordance with IEEE1366-2003 definitions~~ 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

	System Average Interruption Frequency Index (SAIFI) CBD Urban Rural Short Rural Long
	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.*

4.2.6 The *service standard benchmarks* expressed in terms of SAIFI for the *reference services* A1 to A10, B1 ~~and~~, C1 to C48 and D1 ~~to~~and D42 for each year of this *access arrangement period* are~~is~~ shown in the following table:

Table 8: SAIFI service standard benchmarks for reference services A1 to A10, B1 ~~and~~, C1 to C48 and D1 ~~to~~and D42

SAIFI	For ~~each~~the financial year ending 30 June 2018	For each financial year ending 30 June thereafter
CBD	0.26	0.23
Urban	2.12	1.33
Rural Short	2.61	2.38
Rural Long	4.51	5.90

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 (SCNRRR).

Call centre performance

4.2.8 Call centre performance is applied as follows:

Table 9: Application of call centre performance

	Call centre performance
Unit of Measure	Percentage of calls per year.

	Call centre performance
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: $\dfrac{\text{Number of fault calls responded to in 30 seconds or less}}{\text{Total Number of fault calls}}$ where: (a) "Number of 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; (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, B1 ~~and~~, C1 to C48 and D1 ~~to~~and D42 for each year of this *access arrangement period* are~~is~~ shown in the following table:

Table 10: Call centre performance service standard benchmarks for reference services A1 to A10, B1 ~~and~~, C1 to C48 and D1 ~~to~~and D42

	For ~~each~~the financial year ending 30 June 2018	For each financial year ending 30 June thereafter
Call centre performance	77.5%	85.3%

4.3 Service standard benchmarks for transmission reference services

4.3.1 For the *reference services* A11 and B2, the *service standard benchmarks* are expressed in terms of circuit availability, system minutes interrupted, ~~system minutes interrupted,~~ loss of supply event frequency and average outage duration.

Circuit availability

4.3.2 Circuit availability is applied as follows:

Table 11: 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: • Zone substation power transformers. • 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*.

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4.3.3 The *service standard benchmarks* expressed in terms of circuit availability for the *reference services* A11 and B2 for each year of this *access arrangement period* are~~is~~ shown in the following table:

Table 12: Circuit availability service standard benchmarks for reference services A11 and B2

	For ~~each~~the financial year ending 30 June 2018	For each financial year ending 30 June thereafter
Circuit availability	97.7%	97.6%

System minutes interrupted

4.3.4 System minutes interrupted is applied as follows:

Table 13: Application of system minutes interrupted

	System minutes interrupted Meshed Radial
Unit of Measure	Minutes per year.
Definition	Over a 12 month period: • System minutes interrupted Meshed is the summation of MW (in minutes) of Unserved energy at substations which are connected to the Meshed transmission network divided by the System Peak MW; and • System minutes interrupted Radial is the summation of MW (in minutes) of Unserved energy at substations which are connected to the Radial transmission network divided by the System Peak MW, that is, for both Meshed and Radial transmission network separately: ∑ MW (in minutes) of Unserved Energy System Peak MW where: • "Unserved energy" relates to outages on transmission circuits (including all overhead lines, underground cables, power transformers, reactive compensation circuits and transmission zone substation equipment) for unplanned events including extreme events, but not including the events defined as exclusions. • "System Peak MW" is the maximum peak demand recorded on the SWIS for the previous financial year.
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 system minutes interrupted for the *reference services* A11 and B2 for each year of this *access arrangement period* are shown in the following table:

Table 14: System minutes interrupted service standard benchmarks for reference services A11 and B2

System minutes interrupted	For the financial year ending 30 June	For each financial year ending 30 June thereafter
Meshed	12.5	17.3
Radial	5.0	9.4

Loss of supply event frequency

~~4.3.4~~4.3.6 Loss of supply event frequency is applied as follows:

Table 15: 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: $\frac{\sum(\text{MWh unsupplied} \times 60)}{\text{System Peak MW}}$ 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. • "System Peak MW" is the maximum peak demand recorded on the South West Interconnected System for the previous financial year.
Exclusions	One or more of: • Planned interruptions. • Momentary interruptions (less than one minute). • Unregulated transmission assets.

	Loss of supply event frequency >0.1 and ≤1.0 system minutes interrupted >1.0 system minutes interrupted
	• 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~~4.3.7 The *service standard benchmarks* expressed in terms of loss of supply event frequency for the *reference services* A11 and B2 for each year of this *access arrangement period* ~~i~~are~~s~~ shown in the following table:

Table 16: Loss of supply event frequency service standard benchmarks for reference services A11 and B2

Loss of supply event frequency	For ~~each~~the financial year ending 30 June 2018	For each financial year ending 30 June thereafter
> 0.1 system minutes interrupted and ≤1.0 system minutes interrupted	33	27
> 1.0 system minutes interrupted	4	~~4~~6

Average outage duration

~~4.3.6~~4.3.8 Average outage duration is applied as follows:

Table 17: Application of average outage duration

	Average outage duration
Unit of Measure	Minutes per year.
Definition	Over a 12 month period, the accumulative actual duration (in minutes) of Unplanned outages divided by the total Number of events on regulated transmission circuits (after exclusions), that is: $$\frac{\text{Aggregate duration (in minutes) of all Unplanned outages}}{\text{Total Number of events}}$$ 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.
Exclusions	One or more of:

	Average outage duration
	• Planned interruptions. • Momentary interruptions (less than one minute). • Unregulated transmission assets. • Zone substation power transformers and 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~~4.3.9 The *service standard benchmarks* expressed in terms of average outage duration for the *reference services* A11 and B2 for each year of this *access arrangement period* is shown in the following table:

Table 18: Average outage duration service standard benchmarks for reference services A11 and B2

	For ~~each~~the financial year ending 30 June 2018	For each financial year ending 30 June thereafter
Average outage duration	886	1,333

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 19: 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). $$\frac{\sum \text{Number of } \textit{business days} \text{ to repair each faulty streetlight}}{\text{Number of faulty streetlights repaired}}$$

	Street lighting repair time **Metropolitan area** **Regional area**
	where: • In calculating the number of *business days* to repair a faulty streetlight, the first *business day* is: o where a faulty streetlight is detected by, or reported to, Western Power on a *business day*, the next *business day*; or o 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: o 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 o 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. • The period of a *business day* is the time period from one midnight to the following midnight. • 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 2008. • 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 20: Street lighting repair time service standard benchmark for reference service A9

Region	For each financial year ending 30 June
Metropolitan area	5 days

Region	For each financial year ending 30 June
Regional area	9 days

4.5 Exclusions

4.5.1 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.

4.5.2 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*.

4.5.3 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 cap services" means *non-reference services* provided by Western Power by means of the *Western Power Network* other than *non-reference services* that are provided as *revenue cap services*.

"revenue cap 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* ~~(within the meaning of section 2.2.1 of this *access arrangement*)~~; ~~and~~

e) the metering *services* provided ancillary to the *services* in paragraphs (a) to (d) that are defined as standard metering services in the *MSLA*~~model service level agreement most recent Model Service Level Agreement~~recently ~~approved by the *Authority* under the Electricity Industry (Metering Code 2005) 2012~~; and

f) streetlight maintenance.

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

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

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

i. negotiated in good faith;

ii. consistent with the *Code objective*; and

iii. reasonable.

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*.

5.1.3 Separate revenue caps will apply in respect of the *revenue cap services* provided by means of the *transmission system* and the *distribution system*. The establishment of each revenue cap has been made by reference to Western Power's *approved total costs* for *revenue cap 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 cap 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 ~~2012~~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 ~~2012~~2017.

Table 21: Derivation of Transmission Initial Capital Base (net) ($ million real as at 30 June 2017)

Financial year ending:	30 June ~~2009~~2013	30 June ~~2010~~2014	30 June ~~2011~~2015	30 June ~~2012~~2016	30 June 2017
Opening capital base value	2,816.7	2,942.828.6 319.7	3,1632,435.13,177.6	3,199.233,215.4	3,138.0 ~~3,156.0~~
less depreciation	94.0	~~-74~~103.4	~~-79.5~~114.1	~~-90.0~~121.3	129.4
less accelerated depreciation	-	~~0.0~~-	~~0.0~~-	~~0.0~~-	-
plus new facilities investment (net of capital contributions and asset disposals)	205.8 ~~220.1~~	338.0 ~~338189.7~~	150.0 ~~151149.3~~	60.1 ~~61133.2~~	105.2 ~~105.2~~
~~plus investment from prior periods~~Closing capital base value	2,928.6 ~~2,942.8~~	3,163.2 ~~33,177.6~~	3,199.233,215.4	3,138.06.53,156.0	3,113.8 ~~3,131.8~~

Table 22: Derivation of Distribution Initial Capital Base (net) ($ million real as at 30 June ~~2012~~2017)

Financial year ending:	30 June ~~2009~~2013	30 June ~~2010~~2014	30 June ~~2011~~2015	30 June ~~2012~~2016	30 June 2017
Opening capital base value	4,248.7	4,707.844,709.9	5,142.33,276.5,144.4	5,504.453,538.15,506.4	5,746.2 ~~5,752.6~~
less depreciation	214.0	-152.7236.2	~~-166.0~~261.9	-183.6266.5	281.5
less accelerated depreciation	3.8	~~-4.1~~0.5	-~~4.1~~	-~~3.9~~	-
plus new facilities investment (net of capital contributions and asset disposals)	676.9 ~~679.0~~	671.2 ~~671430.3~~	624.0 ~~624431.7~~	508.4 ~~512502.9~~	362.3 ~~363.8~~
~~plus investment from prior periods~~Closing capital base value	4,707.8 ~~4,709.9~~	5,142.350.05,144.4	5,504.450.05,506.4	5,746.250.05,752.6	5,827.1 ~~5,834.9~~

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~~5.2.2 The *capital base* value as at 30 June 2012 reflects a forecast of *new facilities investment* for the year ending 30 June 2012 (2011/12) and a forecast of inflation of 1.25% for the year ending 30 June 2012. To ensure that Western Power is remunerated only for actual *new facilities investment* that is undertaken in the year ending 30 June 2012 and actual inflation, the opening *capital base* at the commencement of the next *access arrangement period* will be adjusted and the *target revenue* in the next *access arrangement period* will be adjusted as follows:~~

~~a) the *capital base* value at the commencement of the next *access arrangement period* will be adjusted (in real terms) for any difference between the actual *new facilities investment* and the forecast of *new facilities investment* for the 2011/12 year that was used to establish the opening *capital base* value at 30 June 2012 (the 2011/12 new facilities investment forecast error);~~

~~b) the *capital base* value at the commencement of the next *access arrangement period* will also be adjusted for any difference between the actual inflation (using the *CPI*) and the forecast inflation for the 2011/12 year that was used to establish the opening *capital base* value at 30 June 2012 (the 2011/12 inflation forecast error); and~~

~~c) an adjustment to the *target revenue* in the next *access arrangement period* will be made to compensate Western Power (or *users*) for the revenue foregone (or additional revenue recovered) by Western Power over this *access arrangement period* in respect of the 2011/12 new facilities investment forecast error and the 2011/12 inflation forecast error.~~

~~5.2.3 For the avoidance of doubt:~~

~~d) under the arrangements set out in section 5.2.2 of this *access arrangement* the *target revenue* for this *access arrangement period* will not be adjusted for the 2011/12 new facilities investment forecast error or the 2011/12 inflation forecast error;~~

~~e) the intended effect of the arrangements set out in section 5.2.2 of this *access arrangement* is to hold Western Power and *users* financially neutral in the event that there is a 2011/12 new facilities investment forecast error or 2011/12 inflation forecast error by taking account of:~~

~~i. the effects of actual inflation; and~~

~~ii. the time value of money as reflected by Western Power's *weighted average cost of capital* for the *Western Power Network*~~

~~and~~

~~adjustments made pursuant to section 5.2.2 of this *access arrangement* will have the effect of ensuring that the total revenue recovered by Western Power over this *access arrangement period* and subsequent *access arrangement periods* will be equivalent in present value terms to the amount that would be recovered if there were no 2011/12 new facilities investment forecast errors and no 2011/12 inflation forecast error.~~

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 ~~2012~~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 23: 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	16.85 years

Table 24: Distribution asset groupings and economic lives for depreciation purposes

Asset group	Economic Life (years) for depreciation purposes
Distribution lines - wood poles	41 years
~~Distribution lines - steel poles~~	~~50 years~~
Distribution underground cables	60 years

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Asset group	Economic Life (years) for depreciation purposes
Distribution transformers	35 years
Distribution switchgear	35 years
Street lighting	20 years
Distribution meters and services	~~25~~15 years
Distribution IT	6 years
Distribution SCADA & communications	10.16 years
Distribution other, non-network assets	10.16 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*~~. or the *distribution 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 25: 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	-	-	-	-	-

~~5.3.3~~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 this *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 *Western Power Network* ~~is 3.60% real post-tax.~~$WACC_{Nom}$ for the financial year ending 30 June 2018 is 6.~~09~~12% nominal post tax and for the financial year ending 30 June 2019 is 6.~~09%~~[1]12% nominal post-tax, derived using the following formula:

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

Where:

r_e is the cost of equity, being ~~7.24~~6.99%

r_d is the cost of debt, being 5.~~32~~42% for the financial years ended 30 June 2018 and 5.~~32~~42% 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 (~~40~~45%)

D is the proportion of debt used to finance regulated assets by a benchmark electricity network service providers (~~60~~55%)

5.4.2 The cost of debt (r_d) in section 0~~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 ended ~~30 June 2019,~~ 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 year of this *access arrangement period* is to be calculated by applying the following formula:

~~[1] This figure (and the related figure for cost of debt (r_d)) is a 'placeholder' and will be updated as part of the *approval* of the proposed *access arrangement* by the *Authority*.~~

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

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 estimates in each year = 0, -1, -2.... , -9, which are either:

5.4.5 ~~t~~The forward looking DRP estimators for the financial year ended 30 June 2020, 30 June 2021 or 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 5.4.14 ~~5.4.27~~ below ("**Bond Yield Approach**"); or

5.4.6 ~~t~~The published *DRP*$_t$, estimates, derived as follows:

- ~~calendar~~financial year 2008/09: DRP$_{2008/09}$: 5.525~~: 3.76~~ per cent ~~(derived from the Reserve Bank of Australia 10 year credit spread to swap interpolated daily data)~~;
- ~~calendar~~ financial year 2009/10: DRP$_{2009/10}$: ~~4.62~~2.509 per cent;
- ~~calendar~~ financial year 2010/11: DRP$_{2010/11}$: 2.~~13~~005 per cent;
- ~~calendar~~ financial year 2011/12: DRP$_{2011/12}$: 3.000~~: 2.38~~ per cent;
- ~~calendar~~ financial year 2012/13: DRP$_{2012/13}$: ~~3~~2.988~~: 3.17~~ per cent;
- ~~calendar~~ financial year 2013/14: DRP$_{2013/14}$: 3.0~~4~~16 per cent;
- ~~calendar~~ financial year 2014/15: DRP$_{2014/15}$: 1.770~~: 2.25~~ per cent;
- ~~calendar~~ financial year 2015/16: DRP$_{2015/16}$: 2.~~07~~420 per cent;
- ~~calendar~~ financial year 2016/17: DRP$_{2016/17}$: 1.656~~: 2.56~~ per cent ~~(derived from the Reserve Bank of Australia 10 year credit spread to swap for the period up to 31 May 2016 and the Authority's Bond Yield Approach thereafter)~~;
- ~~calendar~~ financial year 2017/18: DRP$_{2017/18}$: 1.~~95~~241 per cent ~~(applying the Authority's Bond Yield Approach for the period 1 January 2017 to 30 June 2017)~~;

~~calendar year 2018: DRP$_{2018}$: to be calculated prior to the *approval* of this *access arrangement*~~.

5.4.7 The trailing average *DRP* estimate for the financial year ending 30 June 2018 (TA DRP$_{2018}$), will be 2.~~79~~613%~~, being the average derived from DRP$_{2008}$ to DRP$_{2017}$ listed in section 5.4.4 above~~.

5.4.8 The trailing average *DRP* estimate for the financial year ending 30 June 2019 (TA DRP_{2019}) will be 2.613%, being the average derived from $DRP_{2008/09}$ to $DRP_{2017/18}$ listed in section 5.4.6 above~~the average derived from~~ ~~DRP_{2009} to DRP_{2018} listed 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 pruposes 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 ~~eastern states~~NSW public holidays) during the period 1 September to 31 January 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 ~~5.4.6~~5.4.4 above.

5.4.12 The next *DRP* estimate that will be made will be based on the nominated 20 days falling in the period 1 September 2019 to 31 January 2020 (for DRP_{2020}). That next *DRP* estimate will be incorporated in the trailing average DRP_{2020} (that is, TA DRP_{2020}), and the updated *weighted average cost of capital*, which will then apply in the financial year 2020 by way of the *price list* update in section ~~6.4.3~~6.4.3.

5.4.13 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}.

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

Determining the Benchmark Sample

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

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.

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.

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.

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.

Calculating the DRP

Calculating the *DRP* by subtracting the average of the 10 year AUD interest rate swap (IRS) 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.

5.4.15 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*~~.~~ ("**initial deferred revenue**").

~~5.5.2 The tables below show the derivation of the *deferred revenue* value as at 30 June 2012 to be recovered so that Western Power is financially neutral compared to a situation where *revenue* deferral had not occurred.~~

5.5.2 This *access arrangement* will defer additional transmission revenue from the fourth *access arrangement period* to subsequent *access arrangement periods* (**"additional transmission deferred revenue"**). The table below shows the *additional transmission deferred revenue*

Table 26: Derivation of Additional transmission ~~system~~ ~~initial~~deferred revenue ($ million real as at 30 June ~~2012~~2017)

Financial year ending:	30 June ~~2009~~2018	30 June ~~2010~~2019	30 June ~~2011~~2020	30 June ~~2012~~2021	30 June 2022
~~Opening~~Additional deferred revenue ~~value~~	55.566.4	52.85469.654.4	24.14475.244.5	21.03881.238.4	10.730.4
~~plus time value of money~~		~~5.6~~	~~6.0~~	~~6.5~~	
~~Closing deferred revenue value~~	~~69.6~~	~~75.2~~	~~81.2~~	~~87.7~~	

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

Table 27: Derivation of ~~distribution~~transmission system initial deferred revenue ($ million real as at 30 June ~~2012~~2017)

Financial year ending:	30 June ~~2009~~2013	30 June ~~2010~~2014	30 June ~~2011~~2015	30 June ~~2012~~2016	30 June 2017
Opening deferred revenue value	96.7	~~523.1~~95.9	~~564.8~~95.2	~~609.9~~94.4	93.6
~~plus time value of money~~ less principal recovered	0.7	~~41~~0.7	~~45.1~~0.8	~~48.7~~0.8	0.8
Closing deferred revenue value	~~523.1~~95.9	~~564.8~~95.2	~~609.9~~94.4	~~658~~93.6	92.8

Table 28: Derivation of distribution system initial 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~~5.5.4 Western Power will recover the *initial deferred revenue* amounts detailed in section 5.5.3 of this *access arrangement* as a real annuity amount over:

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

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

~~5.5.4~~5.5.5 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*.~~,~~

~~Notwithstanding section 5.5.4, Western Power will further recover *distribution system initial deferred revenue* in this *access arrangement period* equal to the *additional transmission deferred revenue*.~~

~~5.5.5~~5.5.6 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 29: Amount to be added to the target revenue due to the recovery of initial ~~deferred revenue and additional transmission~~ deferred revenue ($ million real as at 30 June ~~2012~~2017)

Financial year ending:	30 June ~~2013~~2018	30 June ~~2014~~2019	30 June ~~2015~~2020	30 June ~~2016~~2021	30 June ~~2017~~2022
Transmission system	4.6~~44.8~~	4.6~~44.8~~	4.6~~44.8~~	4.6~~44.8~~	4.6~~44.8~~
Distribution system	36.8 ~~30.7~~ ~~104.1~~	36.8 ~~30.7~~ ~~92.1~~	36.8 ~~30.7~~ ~~82.2~~	36.8 ~~30.7~~ ~~76.1~~	36.8 ~~30.7~~ ~~68.2~~

~~The deferred revenue value as at 30 June 2012 reflects a forecast of inflation of 1.25% for the year ending 30 June 2012. To ensure that Western Power is remunerated only for actual inflation, the *target revenue* in the next *access arrangement period* will be adjusted to compensate Western Power (or *users*) for the revenue foregone (or additional revenue recovered) by Western Power over this *access arrangement period* in respect of the 2011/12 inflation forecast error.~~

5.6 Transmission system revenue cap for revenue cap services

5.6.1 The *transmission system* revenue cap for *revenue cap services* is used to determine the maximum transmission *revenue cap service* revenue (MTR_t) for Western Power's *transmission system* for each financial year t.

5.6.2 The operation of the correction factor, TK_t, as described in sections 5.6.7 and 5.6.8 of this *access arrangement* will ensure that the MTR in financial year t is adjusted for any shortfall or over-recovery of actual transmission *revenue cap service* revenue compared to the MTR in preceding years.

5.6.3 For the purposes of this *transmission system* revenue cap for *revenue cap services*, Western Power's actual *transmission system* revenue in financial year t is transmission revenue earned in relation to the provision of *revenue cap services* in financial year t, subject to section 5.6.4 of this *access arrangement*. Where a *revenue cap service* is provided jointly by Western Power's *transmission system* and *distribution system*, the revenue earned must be allocated between the systems in a fair and reasonable manner.

5.6.4 Revenue received by Western Power for *excluded services*, *non-revenue cap services* and *capital contributions* will not be treated as actual revenue for the purposes of this *transmission system* revenue cap for *revenue cap services*.

5.6.5 Despite section 1.3.1 of this *access arrangement* the *transmission system* revenue cap for *revenue cap services* commences on 1 July ~~2012~~2017. This revenue cap applies annually on a financial year basis for the duration of this *access arrangement*.

5.6.6 For this *access arrangement period*, the maximum transmission *revenue cap service* revenue MTR_t is determined as follows:

$$MTR_t = TR_t + TAA3_t \cancel{TAA2_t} + TK_t$$

where:

TR_t is the dollar amount for the financial year t calculated from the dollar amounts (expressed in 30 June ~~2012~~2017 prices) set out in the table below. For the avoidance of doubt, the dollar amounts set out in the table below include the amounts due to the recovery of *initial deferred revenue* detailed in section 5.5.6 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 2020, 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 30: Transmission revenue cap service revenues to be used for calculating TR_t ($ million real as at 30 June ~~2012~~2017)

Financial year ending:	30 June ~~2013~~2018	30 June ~~2014~~2019	30 June ~~2015~~2020	30 June ~~2016~~2021	30 June ~~2017~~2022
TR_t	283.0 ~~287387.3~~	302.7 ~~312328.1~~	348.6 ~~337321.4~~	384.0 ~~362290.6~~	421.4 ~~387262.8~~

~~$TAA2_t$~~$TAA3_t$ 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.

~~$TAA2_t$~~$TAA3_t$ 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 5.6.6 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*.

TK_t is the correction factor calculated in accordance with sections 5.6.7 and 5.6.8 of this *access arrangement*. For the purpose of calculating TR_t, TK_t and therefore MTR_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.

5.6.7 For the financial year ending on 30 June ~~2013~~2018:

~~$TK_{2012/13} = (FTR_{2010/11} - ATR_{2010/11}$~~ $TK_{2017/18} = (FTR_{2015/16} - ATR_{2015/16})$ * (1+ ~~7.98~~3.60%) * (1+ ~~$WACC_{post\text{-}tax\ real}) + (MTR_{2011/12} - FTR_{2011/12}$~~ $WACC_{2017/18}) + (MTR_{2016/17} - FTR_{2016/17})$ * (1+ ~~$WACC_{post\text{-}tax\ real}$~~ $WACC_{2017/18}$)

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For financial years ending on 30 June ~~2014~~2019 to 30 June ~~2017~~2022:

$$TK_t = (FTR_{t-2} - ATR_{t-2}) * (1+\cancel{WACC_{post\ tax\ real})^{2}}-WACC_t)*(1+WACC_{t-1}) + (MTR_{t-1} - FTR_{t-1}) * (1+\cancel{WACC_{post\ tax\ real}}WACC_t)$$

where:

~~$FTR_{2010/11}$~~$FTR_{2015/16}$ is $~~355.6~~328.8 million (real as at 30 June ~~2012~~2017)

~~$ATR_{2010/11}$~~$ATR_{2015/16}$ is $~~356.1~~324.3 million (real as at 30 June ~~2012~~2017)

~~$MTR_{2011/12}$~~$MTR_{2016/17}$ is $~~414~~263.1 million (real as at 30 June ~~2012~~2017)

~~$FTR_{2011/12}$~~$FTR_{2016/17}$ is $~~387.9~~293.6 million (real as at 30 June ~~2012~~2017)

FTR_{t-2} is the forecast transmission *revenue cap services* revenue in the financial year t-2 as calculated in the financial year t-2.

ATR_{t-2} is the actual transmission *revenue cap services* revenue in the financial year t-2 as defined in accordance with section 5.6.3 of this *access arrangement*.

MTR_{t-1} is the maximum *revenue cap services* revenue for Western Power's *transmission system* in the financial year t-1.

FTR_{t-1} is the forecast transmission *revenue cap services* revenue in the financial year t-1.

~~**$WACC_{post\ tax\ real}$**~~ **$WACC_{2017/18}$** is 4.~~38~~21% real post tax

$WACC_{2018/19}$ is 4.~~38%[2]~~21% real post tax

$WACC_t$ is the *weighted average cost of capital* in year t for the *Western Power Network* as detailed in section ~~5.4.1~~5.4 of this *access arrangement*, on a post-tax real basis.

$WACC_{t-1}$ 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.

This formula reflects that the annual tariff-setting process for financial year t typically takes place before the end of financial year t-1. Therefore, TK_t will need to be estimated in the first instance, and then recalculated in the subsequent financial year when ATR_{t-2} is known.

5.6.8 The correction factor, TK_t, will also apply:

a) in the first year of the next *access arrangement period* to adjust for any difference between maximum transmission *revenue cap services* revenue and forecast transmission *revenue cap services* revenue, in relation to the financial year ending on 30 June ~~2017~~2022 and for any difference between forecast transmission *revenue cap services* revenue and actual transmission *revenue cap services* revenue, in relation to the financial year ending on 30 June ~~2016~~2021; and

b) in the second year of the next *access arrangement period* to adjust for any difference between forecast transmission *revenue cap services* revenue and

~~[2] This figure is a 'placeholder' will be updated as part of the *approval* of the proposed *access arrangement* by the *Authority*.~~

actual transmission *revenue cap services* revenue, in relation to the financial year ending on 30 June ~~2017~~2022.

5.7 Distribution system revenue cap for revenue cap services

5.7.1 The *distribution system* revenue cap for *revenue cap services* is used to determine the maximum distribution *revenue cap service* revenue (MDR_t) for Western Power's *distribution system* for each financial year t.

5.7.2 The operation of the correction factor, DK_t, as described in sections 5.7.7 and 5.7.8 of this *access arrangement* will ensure that the MDR in financial year t is adjusted for any shortfall or over-recovery of actual distribution *revenue cap service* revenue compared to the MDR in preceding years.

5.7.3 For the purposes of this *distribution system* revenue cap, Western Power's actual *distribution system* revenue in financial year t is distribution revenue earned in relation to the provision of *revenue cap services* in financial year t, subject to section 5.7.4 of this *access arrangement*. Where a *revenue cap service* is provided jointly by Western Power's *transmission system* and *distribution system*, the revenue earned must be allocated between the systems in a fair and reasonable manner.

5.7.4 Revenue received by Western Power for *excluded services*, *non-revenue cap services* and *capital contributions* will not be treated as actual revenue for the purposes of this *distribution system* revenue cap for *revenue cap services*.

5.7.5 Despite section 1.3.1 of this *access arrangement* the *distribution system* revenue cap for *revenue cap services* commences on 1 July ~~2012~~2017. This revenue cap applies annually on a financial year basis for the duration of this *access arrangement*.

5.7.6 For this *access arrangement period*, the maximum regulated distribution revenue MDR_t is determined as follows:

$$MDR_t = DR_t + TEC_t + \cancel{DAA2_t} DAA3_t + DK_t$$

where:

DR_t is the dollar amount for the financial year t calculated from the dollar amounts (expressed in 30 June ~~2012~~2017 prices) set out in the table below. For the avoidance of doubt, the dollar amounts set out in the table below include the amounts due to the recovery of *initial deferred revenue* ~~and *additional transmission deferred revenue*~~ detailed in section 5.5.6 of this *access arrangement* 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 2020, 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 31: Distribution revenue cap service revenues to be used for calculating DR_t ($ million real as at 30 June 201~~2~~7)

Financial year ending:	30 June ~~2013~~2018	30 June ~~2014~~2019	30 June ~~2015~~2020	30 June ~~2016~~2021	30 June ~~2017~~2022
DR_t	993.0 ~~685~~ ~~1,000.7~~	1,001.4 ~~684.8~~ ~~1,059.3~~	1,050.8 ~~816.7~~ ~~1,091.5~~	1,051.2 ~~932.9~~ ~~1,108.5~~	1,046.2 ~~1,120018.0~~

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*.

~~**$DAA2_t$**~~**$DAA3_t$** 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.

~~$DAA2_t$~~$DAA3_t$ 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 5.7.6 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*.

DK_t is the correction factor calculated in accordance with sections 5.7.7 and 5.7.8 of this *access arrangement*.

For the purpose of calculating DR_t, DK_t and therefore MDR_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.

5.7.7 For the financial year ending on 30 June ~~2013~~2018:

$$\cancel{DK_{2012/13} = (FDR_{2010/11} - ADR_{2010/11}}DK_{2017/18} = (FDR_{2015/16} - ADR_{2015/16}) * (1+\cancel{7.98}3.60\%) * (1+\cancel{WACC_{post\text{-}tax\ real}) + (MDR_{2011/12} - FDR_{2011/12}}WACC_{2017/18}) + (MDR_{2016/17} - FDR_{2016/17}) * (1+\cancel{WACC_{post\text{-}tax\ real}}WACC_{2017/18})$$

For financial years ending on 30 June ~~2014~~2019 to 30 June ~~2017~~2022:

$$DK_t = (FDR_{t-2} - ADR_{t-2}) * (1+\cancel{WACC_{post\text{-}tax\ real})^2}WACC_t)*(1+WACC_{t-1}) + (MDR_{t-1} - FDR_{t-1}) * (1+\cancel{WACC_{post\text{-}tax\ real}}WACC_t)$$

~~**$FDR_{2010/11}$**~~where:

$FDR_{2015/16}$ is $~~729.9~~1,191.1 million (real as at 30 June ~~2012~~2017)

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~~**$ADR_{2010/11}$**~~**$ADR_{2015/16}$** is $~~733.3~~1,173.6 million (real as at 30 June ~~2012~~2017)

~~**$MDR_{2011/12}$**~~**$MDR_{2016/17}$** is $~~855.9~~1,120.2 million (real as at 30 June ~~2012~~2017)

~~**$FDR_{2011/12}$**~~**$FDR_{2016/17}$** is $~~804.8~~1,218.0 million (real as at 30 June ~~2012~~2017)

FDR_{t-2} is the forecast distribution *revenue cap services* revenue in the financial year t-2 as calculated in the financial year t-2.

ADR_{t-2} is the actual *revenue cap service* distribution revenue in the financial year t-2 as defined in accordance with section 5.7.3 of this *access arrangement*.

MDR_{t-1} is the maximum *revenue cap service* revenue for Western Power's *distribution system* in the financial year t-1.

FDR_{t-1} is the forecast distribution *revenue cap services* revenue in the financial year t-1.

~~**$WACC_{post\text{-}tax\ real}$**~~ **$WACC_{2017/18}$** is 4.~~38~~21% real post tax.

$WACC_{2018/19}$ is 4.~~38%[3]~~21% real post tax.

$WACC_t$ is the *weighted average cost of capital* for year t for the *Western Power Network* as detailed in section ~~5.4.1~~5.4 of this *access arrangement* on a post-tax real basis.

$WACC_{t-1}$ 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.

This formula reflects that the annual tariff-setting process for financial year t typically takes place before the end of financial year t-1. Therefore, DK_t will need to be estimated in the first instance, and then recalculated in the subsequent financial year when ADR_{t-2} is known.

5.7.8 The correction factor, DK_t, will also apply:

a) in the first year of the next *access arrangement period* to adjust for any difference between maximum distribution *revenue cap services* revenue and forecast distribution *revenue cap services* revenue, in relation to the financial year ending on 30 June ~~2017~~2022 and for any difference between forecast distribution *revenue cap services* revenue and actual distribution *revenue cap services* revenue, in relation to the financial year ending on 30 June ~~2016~~2021; and

b) in the second year of the next *access arrangement period* to adjust for any difference between forecast distribution *revenue cap services* revenue and actual distribution *revenue cap services* revenue, in relation to the financial year ending on 30 June ~~2017~~2022.

~~[3] This figure is a 'placeholder' will be updated as part of the *approval* of the proposed *access arrangement* by the *Authority*.~~

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~~s~~ 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 cap services*;

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

c) deducting the expected *non-reference service* revenue from the costs of providing *revenue cap 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~~ and~~, C1 to C48 and D1 ~~to~~and D42 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 and B2 are location-specific and are published for each electrical node.

6.4 Price list and price list information

6.4.1 The price list in respect of the pricing year ending on 30 June ~~2013~~2018 and the pricing year ending on the day before the date in section 1.3.1 of this *access arragenemt* is attached at Appendix ~~0.~~F.1. In respect of the *pricing year* ending on 30 June 2018 and the pricing year ending on the day before the date in section 1.3.1 of this *access arrangement*, this is the current *price list* for the purposes of section 5.1(f) of the *Code*. The price list information for this price list is attached at Appendix ~~0.~~F.2.

6.4.2 The *price list* ~~is to be updated~~ in ~~accordance with Chapter 8~~respect of the ~~Code. The~~ *pricing* ~~*years*~~*year* commencing on the date in section 1.3.1 of this *access arrangement* and ending on 30 June 2019 is attached at Appendix F.3. The *price list information* for this ~~*access arrangement* period are defined in the table below:~~*price list* is attached at Appendix F.4.

~~1.1.1 Table 30: Pricing years for this access arrangement period~~

~~1.1.1 Pricing year~~	~~1.1.1 Start date~~	~~1.1.1 End date~~
~~1~~	~~Effective date under section 1.3.1 of this *access arrangement*~~	~~30 June 2013~~
~~2~~	~~1 July 2013~~	~~30 June 2014~~
~~3~~	~~1 July 2014~~	~~30 June 2015~~
~~4~~	~~1 July 2015~~	~~30 June 2016~~
~~5~~	~~1 July 2016~~	~~30 June 2017~~

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 2020 and each *pricing year* ~~(except~~thereafter.

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

Table 32: 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
3	Effective date under section 1.3.1 of this access arrangement	30 June 2019
4	1 July 2019	30 June 2020
5	1 July 2020	30 June 2021
6	1 July 2021	30 June 2022

~~the first *pricing year*).~~

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 ~~0~~F.4 to this *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 ~~0~~F.4 to this *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 cap services* for year t does not exceed MTR_t and the forecast *distribution system* revenue for *revenue cap services* for year t does not exceed MDR_t.

6.5.4 *Non-revenue cap 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~~)(i) and (ii~~) 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.2~~ F.4 to this *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.2~~ F.4 to this *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. This has been achieved by developing the *reference tariffs* through a consultative process that involved Government and industry stakeholders.

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 ~~for~~until the ~~first~~financial year ~~of the *access arrangement*~~ending 30 June 2019. 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 caps 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* revenue caps for *revenue cap services* have 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 *reference tariff* rebalancing the maximum change in *reference tariff* revenue for the *transmission system* from each *reference tariff* when the *price list* is updated is:

~~For the financial year ending on 30 June 2013:~~

$$\frac{\sum_{y=1}^{n} p_{2012/13}^{xy} q_{2012/13}^{xy}}{\sum_{y=1}^{n} p_{2011/12}^{xy} q_{2012/13}^{xy}} \cancel{\leq (1+CPI_{2012/13})(1-TX_{2012/13})+B'_{2012/13}+0.02}$$

For financial years ending on 30 June ~~2014~~2019 to 30 June ~~2020~~~~2017~~2020:

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

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} $\cancel{p_{2011/12}^{xy}}$ $\cancel{p_{t-1}^{xy}}$ is the price being charged in the financial year ~~ending on 30 June 2012~~ $t-1$ for component y of a given *reference tariff* x;

p_t^{xy} $\cancel{p_{2012/13}^{xy}}$ $\cancel{p_t^{xy}}$ is the ~~average of the~~proposed price ~~being charged between 1 July 2012 – 31 January 2013 and the price charged between 1 February 2013 – 30 June 2013~~ for component y of a given *reference tariff* x $\cancel{x}$ $\cancel{x}$ in financial year t;

q_t^{xy} $\cancel{q_{2012/13}^{xy}}$ $\cancel{q_t^{xy}}$ is the quantity of component y of a given *reference tariff* x that is forecast to be sold in financial year t ~~ending on 30 June 2013;~~ $\cancel{t}$;

~~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;~~

~~$CPI_{2012/13}$ is 2.25%;~~

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;

~~$TX_{2012/13}$ is 6.7%;~~

TX_t is the annual percentage change in TR_t and is initially determined to be:

Table 33: TXt

~~Financial year ending:~~	~~30 June 2014~~	~~30 June 2015~~	~~30 June 2016~~	~~30 June 2017~~
~~TX~~$_t$	~~15.3%~~	~~2.0%~~	~~9.6%~~	~~9.6%~~

~~$B'_{2012/13}$ is 6.8%;~~

Financial year ending:	30 June 2019	30 June 2020	30 June 2021	30 June 2022
TX$_t$	-6.95%~~-8.47%~~	-15.15%~~-8.01%~~	-10.17%~~-7.45%~~	-9.73%~~-7.03%~~

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

$$B'_t = \frac{TK_t + TAA3_t}{TR'_t}$$

TK_t is as defined in section 5.6.6 of this *access arrangement*;

$TAA3_t$ is as defined in section 5.6.6 of this *access arrangement*;

TR'_t is TR_t (as set out in section 5.6.6 of this *access arrangement*), converted to nominal dollars.

6.5.14 The values for TX$_t$ in table **Error! Reference source not found.** will be updated, and these values will be reported in the *price list information* for the financial years ending 30 June 2020, 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.

~~6.5.14~~6.5.15 To constrain *tariff* rebalancing the maximum change in *reference tariff* revenue for the *distribution system* from each *reference tariff* when the *price list* is updated is:

~~For the financial year ending on 30 June 2013:~~

$$\cancel{\frac{\sum_{y=1}^{n} p_{2012/13}^{xy} q_{2012/13}^{xy}}{\sum_{y=1}^{n} p_{2011/12}^{xy} q_{2012/13}^{xy}} \leq (1+CPI_{2012/13})(1-DX_{2012/13}) + A'_{2012/13} + 0.02}$$

For financial years ending on 30 June ~~2014~~2019 to 30 June ~~2017~~2022:

$$\frac{\sum_{y=1}^{n} p_{t}^{xy} q_{t}^{xy}}{\sum_{y=1}^{n} p_{t-1}^{xy} q_{t}^{xy}} \leq (1+CPI_{t})(1-DX_{t}) + A'_{t} + 0.02$$

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} $\cancel{p_{2011/12}^{xy}}$ ~~is the price being charged in the financial year ending on 30 June 2012 for component~~ $\cancel{y}$ ~~of a given *reference tariff*~~ $\cancel{x}$~~;~~

$\cancel{p_{2012/13}^{xy}}$ ~~is the average of the price being charged between 1 July 2012 – 31 January 2013 and the price charged between 1 February 2013 – 30 June 2013 for component~~ $\cancel{y}$ ~~of a given *reference tariff*~~ $\cancel{x}$~~;~~

$\cancel{p_{t-1}^{xy}}$ ~~is the price being charged in the financial year~~ $\cancel{t-1}$ ~~for component~~ $\cancel{y}$ ~~of a given *reference tariff*~~ $\cancel{x}$~~;~~

$\cancel{p_{t}^{xy}}$ ~~is the proposed price for component~~ $\cancel{y}$ ~~of a given *reference tariff*~~ $\cancel{x}$ ~~in financial year~~ $\cancel{t}$~~;~~

$\cancel{q_{2012/13}^{xy}}$ 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 ~~ending on 30 June 2013;~~ ~~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;

~~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;~~

~~$CPI_{2012/13}$ is 2.25%;~~

~~$DX_{2012/13}$ is 1.9%~~

DX_t is the annual percentage change in DR_t and is initially determined to be:

Table 34: DXt

Financial year ending:	30 June ~~2014~~2019	30 June ~~2015~~2020	30 June ~~2016~~2021	30 June ~~2017~~2022
DX_t	-0.84% ~~-51.9~~5.86%	-4.93% ~~-31.2~~3.04%	-0.04% ~~3-~~ 1.55%	0.48% ~~8-~~ 1.05%

~~$A'_{2012/13}$ is 3.3%;~~

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

$$A'_t = \frac{DK_t + DAA3_t + \Delta TEC_t}{DR'_t}$$

DK_t is as defined in section 5.7.6 of this *access arrangement*;

$DAA3_t$ is as defined in section 5.7.6 of this *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*;

DR'_t is DR_t (as set out in section 5.7.6 of this access arrangement), converted to nominal dollars.

The values for DX_t in

6.5.16 Table 34 will be updated and these values will be reported in the *price list information* for the financial years ending 30 June 2020, 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.

Tariff components

~~6.5.15~~6.5.17 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.2~~.F.4 to this *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 offer to a *user* who *connects distributed generating plant* to the *Western Power Network*, a share of any reductions in either or both of Western Power's *capital-related costs* or *non-capital costs* which arise as a result of the *entry point* for *distributed generating plant* being located in a particular part of the *Western Power Network* 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*.

6.7.2 The amount of the total *discount* available under section 6.7.1 of this *access arrangement* will be determined by Western Power as the forecast *capital-related costs* and *non-capital costs* that would be incurred if the *distributed generating plant* were not to *connect* minus the forecast *capital-related costs* and *non-capital costs* that would be incurred if the *distributed generating plant* were to *connect*. The cost analysis will be conducted over a period of at least 10 years, depending on the availability and accuracy of data. A *discount* will only be payable if the amount calculated in accordance with this section 6.7.2 of this *access arrangement* is greater than zero.

6.7.3 The *discount* calculated in accordance with section 6.7.2 of this *access arrangement* will be calculated in present value terms and, using the *weighted average cost of capital* for the *Western Power Network* as set out in section 5.4.1 of this *access arrangement*, converted to an equivalent annualised *discount* for a defined period of time, as agreed by the parties. Nothing in this calculation prevents the *discount* exceeding 100% of the equivalent tariff.

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; ~~and~~

c) the unrecovered costs borne, or an estimate of the unrecovered costs likely to be borne, by Western Power during this *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.~~.~~

~~7.1.4 A *force majeure* event includes but is not limited to any costs arising from the introduction of any scheme or mechanism with respect, directly or indirectly, to emissions of greenhouse gases and with respect to any activity including pricing, reduction, cessation, offset and sequestration (including the Carbon Pricing Mechanism announced by the Commonwealth in February 2011), full retail contestability, and the mandated roll-out of Advanced Interval Meters, contestability, and any other government energy reforms, to the extent that such costs were not included in the calculation of *target revenue* for this *access arrangement period* or otherwise addressed through the *trigger event* provisions in section 8 of this *access arrangement*.~~

7.2 Adjusting target revenue for technical rule changes

7.2.1 If ~~amendments to~~ the *technical rules* are ~~are amended~~~~result in a material cost impact~~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 this *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 ~~2012~~2017;

b) arising from the connection of new *load* to the *transmission system* or *distribution system* from 1 July ~~2012~~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 ~~2012;~~

~~d)~~c) ~~undertaken for *augmentation* of the *distribution system* under the rural power improvement program;~~ 2017;

~~e)~~d) undertaken for *augmentation* of the *distribution system* under the state underground power program; and

~~f)~~e) ~~in relation to~~arising from the provision of *metering installations* (within the meaning in the Electricity Industry (Metering Code) 2012) on the *distribution system* ~~wood pole management for the provision of *covered services* from~~ from 1 July ~~2012~~2017.

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 this *access arrangement*.

7.4.2 This *gain sharing mechanism* applies separately to each of:

a) the *transmission system*; and

b) the *distribution system*.

~~7.4.2~~7.4.3 Subject to section 7.4.4 of this *access arrangement*, an *above-benchmark surplus* (within the meaning of the *Code*) is to be calculated for each of the ~~years 2012/13 to 2016/17~~*transmission system* and *distribution system* for each of the financial years ending 30 June 2018 to 30 June 2022 as follows:

~~$ABS_{2012/13} = EIB_{2012/13} - A_{2012/13}$~~

~~$ABS_{2013/14} = (EIB_{2013/14} - A_{2013/14}) - (EIB_{2012/13} - A_{2012/13})$~~

~~$ABS_{2014/15} = (EIB_{2014/15} - A_{2014/15}) - (EIB_{2013/14} - A_{2013/14})$~~

~~$ABS_{2015/16} = (EIB_{2015/16} - A_{2015/16}) - (EIB_{2014/15} - A_{2014/15})$~~

~~$ABS_{2016/17} = (EIB_{2016/17} - A_{2016/17}) - (EIB_{2015/16} - A_{2015/16})$~~

$ABS_{2017/18} = EIB_{2017/18} - A_{2017/18}$

$ABS_{2018/19} = (EIB_{2018/19} - A_{2018/19}) - (EIB_{2017/18} - A_{2017/18})$

$ABS_{2019/20} = (EIB_{2019/20} - A_{2019/20}) - (EIB_{2018/19} - A_{2018/19})$

$ABS_{2020/21} = (EIB_{2020/21} - A_{2020/21}) - (EIB_{2019/20} - A_{2019/20})$

$ABS_{2021/22} = (EIB_{2021/22} - A_{2021/22}) - (EIB_{2020/21} - A_{2020/21})$

where:

ABS_t is the *above-benchmark surplus* in year t;

EIB_t is the *efficiency and innovation benchmark* for financial year t as set out in

Table 35~~,~~ for the *transmission system* and ~~Table 34~~Table 36 for the *distribution system*, adjusted for:

a) any difference between the actual ~~scale~~ relevant network growth escalation factors in each financial year and the forecast ~~scale~~relevant network growth escalation factors and any difference between the actual relevant indirect and corporate cost growth escalation factors in each financial year and the forecast relevant indirect and corporate cost growth escalation factors used to establish the *non-capital costs* component of *approved total costs for* *each of the transmission system and distribution system* for that financial year, in accordance with section 7.4.10 of this *access arrangement*~~. The scale escalation factors are a customer growth rate based on growth in customer numbers and~~

~~a network growth rate based on increases in line length, increases in substation capacity and increases in the number of distribution transformers~~; and

b) the effects of inflation.

Table 35: Efficiency and innovation benchmarks for the transmission system ($M real as at 30 June ~~2012~~2017)

Financial year ending:	30 June ~~2013~~2018	30 June ~~2014~~2019	30 June ~~2015~~2020	30 June ~~2016~~2021	30 June ~~2017~~2022
Transmission network	52.9~~53.0~~	52.9~~52.6~~	53.2~~52.6~~	53.5~~52.5~~	53.5~~52.2~~
Corporate	29.5~~29.2~~	21.6~~21.0~~	21.5~~20.8~~	21.6~~20.8~~	21.7~~20.9~~
Indirect costs	10.0~~10.0~~	8.8~~9.1~~	8.8~~8.2~~	11.1~~9.7~~	11.1~~9.7~~
~~Efficiency~~Transmission efficiency and innovation benchmark - EIB_t	92.3~~444.492.2~~	83.3~~44682.6~~	83.5~~443.081.6~~	86.2~~440.683.0~~	86.4~~452.082.8~~

Table 36: Efficiency and innovation benchmarks for the distribution system ($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
Distribution network	177.0~~177.8~~	178.3~~178.8~~	179.9~~179.9~~	181.4~~181.1~~	182.8~~182.3~~
Corporate	80.7~~79.9~~	59.1~~57.4~~	58.9~~56.9~~	59.2~~57.0~~	59.5~~57.2~~
Indirect costs	30.1~~30.2~~	26.8~~27.9~~	26.8~~25.4~~	33.9~~30.3~~	34.4~~30.6~~
Distribution efficiency and innovation benchmark - EIB_t	287.7~~287.9~~	264.2~~264.1~~	265.6~~262.3~~	274.5~~268.4~~	276.6~~270.1~~

and

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

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

ii. in accordance with any adjustment made under section 7.1 of this *access arrangement*;

iii. in accordance with any adjustment made under section 7.2 of this *access arrangement*;

iv. in relation to superannuation for defined benefits schemes;

v. in relation to *non-revenue cap services*;

vi. in relation to licence fees;

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

~~viii. in relation to network control services~~

~~ix.~~viii. in relation to amounts payable under the Economic Regulation Authority (Electricity Network Access Funding Regulations) 2012.

~~7.4.3~~7.4.4 In any year in which for the *transmission system* an *above-benchmark surplus* is calculated to be a positive value the *above-benchmark surplus* does not exist to the extent that Western Power achieved efficiency gains or innovation in excess of the *efficiency and innovation benchmarks* during this *access arrangement period* by failing to provide transmission *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 this *access arrangement*.

7.4.5 In any year in which for the *distribution system* an *above-benchmark surplus* is calculated to be a positive value the *above-benchmark surplus* does not exist to the extent that Western Power achieved efficiency gains or innovation in excess of the *efficiency and innovation benchmarks* during this *access arrangement period* by failing to provide distribution *reference services* at a *service standard* at least equivalent to the *service standard benchmarks* for those *distribution services* for that year as set out in section 4 of this *access arrangement*.

~~7.4.4~~7.4.6 If in any year in which an *above-benchmark surplus* is calculated to be a positive value for the *transmission system* or the *distribution system* and Western Power fails to provide a relevant *reference service* at a *service standard* at least equivalent to the relevant *service standard benchmark*, Western Power will demonstrate to the Authority how and to what extent there is, or is not, a relationship between that failure and Western Power's achieved relevant efficiency gains or innovation in excess of the *efficiency and innovation benchmarks*, through consideration of:

a) which *service standard benchmark* has 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 that *service standard benchmark* (which may be sub-categories of the cost categories in section 7.4.~~8~~11);

d) after normalising the forecast *non-capital costs* for those categories in section 7.4.6c) used to establish the *non-capital costs* component of *approved total costs* for inflation (using the *CPI*) and ~~scale~~network growth escalation factors and indirect and corporate cost growth escalation factors in a manner that is consistent with 7.4.8, whether there has, or has not, been an underspend in those *non-capital costs* categories; and

e) any other issues that are relevant.

This information will be used to determine the extent, if any, that Western Power achieved relevant efficiency gains or innovation in excess of the *efficiency and innovation benchmarks* during this *access arrangement period* by failing to provide relevant *reference services* at a *service standard* at least equivalent to the relevant *service standard benchmarks*.

7.4.7 Subject to section 7.4.8 of this *access arrangement*, the following amounts $GSMA_t$ will be added to *target revenue* for each of the *transmission system* and the *distribution system* for one or more *access arrangement periods* covering the financial years ~~2017~~ending 30 June 2023 to 30 June 2027:

~~7.4.5~~ $GSMA_{2022/23} = ABS_{2017/18}$ ~~to 2021/22:~~

~~$GSMA_{2017/18} = ABS_{2012/13} + ABS_{2013/14} + ABS_{2014/15} + ABS_{2015/16} + ABS_{2016/17}$~~

~~$GSMA_{2018}$~~ $+ ABS_{2018/19}$ ~~$= ABS_{2013/14} + ABS_{2014/15} + ABS_{2015/16} + ABS_{2016/17}$~~

~~$GSMA_{2019}$~~ $+ ABS_{2019/20}$ ~~$= ABS_{2014/15} + ABS_{2015/16} + ABS_{2016/17}$~~

~~$GSMA_{2020}$~~ $+ ABS_{2020/21}$ ~~$= ABS_{2015/16} + ABS_{2016/17}$~~ $+ ABS_{2021/22}$

~~$GSMA_{2021/22} = ABS_{2016/17}$~~

$$GSMA_{2023/24} = ABS_{2018/19} + ABS_{2019/20} + ABS_{2020/21} + ABS_{2021/22}$$

$$GSMA_{2024/25} = ABS_{2019/20} + ABS_{2020/21} + ABS_{2021/22}$$

$$GSMA_{2025/26} = ABS_{2020/21} + ABS_{2021/22}$$

$$GSMA_{2026/27} = ABS_{2021/22}$$

where:

$GSMA_t$ is the *gain sharing mechanism* adjustment to *target revenue* for each of the *transmission system* and the *distribution system* for year t.

~~7.4.6~~7.4.8 In any year where the amount of an adjustment to *target revenue* for the *transmission system* or the *distribution system* determined under section 7.4.7 of this *access arrangement* is a negative value, the amount of the adjustment to *target revenue* for the *transmission system* or the *distribution system* respectively in that year is zero.

~~7.4.7~~7.4.9 The *gain sharing mechanism* does not affect the ordinary operation of the transmission system and distribution system revenue caps (absent the *gain sharing mechanism*), which already provides for Western Power to retain 100% of any efficiency gains achieved during this *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 this *access arrangement period*.

~~7.4.8~~7.4.10 The adjustment to EIB_t due to any differences between the actual ~~scale~~relevant network growth escalation factors in each financial year and the forecast ~~scale~~relevant network growth escalation factors and any differences between the actual relevant indirect and corporate cost growth escalation factors in each financial year and the forecast relevant indirect and corporate cost growth escalation factors used to establish the *non-capital costs* component of *approved total costs* for each of the *transmission system* and *distribution system* for that financial year will be calculated by:

a) deflating EIB_t for financial year t by using:

  i. ~~the scale~~the network growth escalation factors and indirect and corporate cost growth escalation factors assumed for financial year t when setting the forecast *non-capital cost* component of *approved total costs* for each of the *transmission system* and *distribution system* for that financial year, compounded to that financial year, as set out in Table 37, Table 38 and Table 39; and

  ~~ii. the applicable scale escalation factor for financial year t determined for each category of expenditure as set out in Table 35; and~~

b) inflating the value determined under section 7.4.10(a) for financial year t using:

  i. the ~~scale~~network growth escalation factors recalculated for financial year t using actual data for each ~~scale escalation driver~~of the *transmission system* and *distribution system* for each relevant network growth escalation factor in each financial year, compounded to that financial year, and following the calculation method set out in Table 37~~,~~ and Table 38; and

ii. ~~the applicable scale~~indirect and corporate cost growth escalation ~~factor~~ factors recalculated for financial year t ~~determined~~ using actual data for each ~~category~~ of the *transmission system* and *distribution system*, compounded to that financial year, following the calculation method set out in Table 39 and section 7.4.11~~7.4.11~~.

7.4.11 When inflating the EIB value determined under section ~~7.4.10a)~~ 7.4.10(a) for indirect and corporate cost growth escalation factors:

a) The growth factor applied to corporate costs is a weighted average of the *distribution system* and *transmission system* recalculated network growth escalation factors. The weighting is based on the total corporate operating expenditure allocated to the *distribution system* (as ~~set out in Table 35.~~a proportion of total corporate operating expenditure) and the total corporate operating expenditure allocated to the *transmission system* (as a proportion of total corporate operating expenditure) in accordance with the Cost and Revenue Allocation Methodology and derived from the Regulatory Financial Statements for financial year t.

b) 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 37: Distribution system forecast network growth escalation assumptions

~~Table 34: Forecast scale escalation assumptionsScale escalation driver~~Network growth factor	Calculation method	~~2011/12~~ Weight	~~2012/13~~ 2017/18	~~2012/14~~ 2018/19	~~2014/15~~ 2019/20	~~2015/16~~ 2020/21	~~2016/17~~ 2021/22
~~Customer numbers factor~~	~~Year on year growth~~	~~2.41%~~	~~2.41%~~	~~2.41%~~	~~2.41%~~	~~2.41%~~	~~2.41%~~
~~Total line length~~Customer numbers (a)	Year on year growth	45.8%~~1.3167.6%~~	1.~~31~~65%	1.~~31~~73%	1.~~31~~69%	1.~~31~~66%	1.~~31~~63%
~~Distribution transformers~~Circuit length (b)	Year on year growth	23.8%~~1.3310.7%~~	~~1.33~~0.91%	~~1.33~~0.91%	~~1.33~~0.91%	~~1.33~~0.91%	~~1.33~~0.91%
~~Zone substation capacity~~Ratcheted Maximum Demand (c)	Year on year growth	17.6%~~3.6521.7%~~	~~3.65~~0.00%	~~3.65~~0.00%	~~3.65~~0.00%	~~3.65~~0.00%	~~3.65~~0.00%

~~Table 34: Forecast scale escalation assumptionsScale escalation driver~~Network growth factor	Calculation method	~~2011/12~~ Weight	~~2012/13~~ 2017/18	~~2012/14~~ 2018/19	~~2014/15~~ 2019/20	~~2015/16~~ 2020/21	~~2016/17~~ 2021/22
Energy delivered (d)	Year on year growth	12.8%	-0.37%	-0.20%	-0.20%	-0.71%	-1.10%
Customer and Network growth factor	**~~Average~~Weighted average of a, b ~~and,~~ -c and d**	**~~2.10~~100 %**	**0.92%~~2.101.21%~~**	**0.98%~~2.101.26%~~**	**0.97%~~2.101.24%~~**	**0.89%~~2.101.22%~~**	**0.82%~~2.101.20%~~**

Table 38: ~~Scale~~Transmission system forecast network growth escalation ~~factor for each category of expenditure~~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%~~28.7%~~	0.32%	0.33%	0.22%	0.33%	0.32%
Ratcheted Maximum Demand (b)	Year on year growth	19.4%~~22.1%~~	0.00%	0.00%	0.00%	0.00%	0.00%
Energy Delivered (c)	Year on year growth	23.1%~~21.4%~~	-0.37%~~0.30%~~	-0.20%~~0.00%~~	-0.20%~~2.89%~~	-0.71%~~2.50%~~	-1.10%~~0.00%~~
~~Weighted entry and exit connection points~~Customer numbers (d)	Year on year growth	19.9%~~27.8%~~	0.00%~~-0.24%~~	0.00%~~-0.73%~~	2.63%~~-0.25%~~	2.56%~~-0.98%~~	0.00%~~0.00%~~
Network growth factor	**Weighted average of a, b, c and d**	**100%**	**0.03%~~0.09%~~**	**0.08%~~-0.11%~~**	**0.56%~~0.62%~~**	**0.47%~~0.35%~~**	**-0.13%~~0.09%~~**

Table 39: Indirect and corporate 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%~~0.93%~~	0.76%~~0.92%~~	0.87%~~1.09%~~	0.78%~~1.01%~~	0.59%~~0.92%~~
Corporate	Year on year growth	0.69%~~0.91%~~	0.74%~~0.90%~~	0.86%~~1.08%~~	0.78%~~0.99%~~	0.57%~~0.91%~~

~~7.4.9~~7.4.12 For the purposes of ~~clause~~section 7.4.10(a)~~(i(i)~~ the actual data used for each ~~scale~~relevant network growth escalation ~~driver~~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*.

~~7.4.10~~

7.5 Service standards adjustment mechanism

7.5.1 In accordance with section 6.30 of the *Code*, a *service standards adjustment mechanism* applies ~~in relation~~ to ~~the financial year ending 30 June 2019 and following financial years ending 30 June of~~ this *access arrangement* ~~(**"SSAM Year"**)~~.

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, ~~system minutes interrupted - radial,~~ loss of supply event frequency and average outage duration as defined in section 4 of this *access arrangement*.

7.5.4 In relation to actual service performance for each financial year ending 30 June 2019 and following financial years ending 30 June (*"**SST Year**"*)~~*year of this access arrangement period*~~~~*SSAM year* for each *SSAM SSB*~~ 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, ~~system minutes interrupted – radial,~~ 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, ~~system minutes interrupted – radial,~~ 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 ~~*SSAM y*~~*SST Year* t;

SST is the SSAM target detailed in section 7.5.11 of this *access arrangement*;

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

SSA_t is the actual service performance in *SST Y~~SSAM y~~ear* 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 of this *access arrangement* to each component of SAIDI and SAIFI.

7.5.6 The rewards and penalties are applied to the performance *SST Y~~SSAM y~~ear* in this *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 system minutes interrupted – radial will be allocated to the performance of the *transmission system*;~~

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

~~f)~~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 Y~~SSAM y~~ear* 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 *~~SSAM y~~SST Year* is capped at 1% of TR_t for that year as ~~defined~~set out in ~~Table [27]~~ **Error! Reference source not found.**. For the avoidance of doubt, for the purposes of this section ~~5.6.6.~~ TR_t in that table will not be updated as a result of the annual updates to *weighted average costs of capital* as determined in section 5.4.

Notwithstanding section 7.5.7 of this *access arrangement*, the sum of the rewards or penalties for the *distribution system* applied to each *SST Y~~SSAM y~~ear* is capped at 5% of DR_t for that year as ~~defined~~set out in ~~Table [28]~~

7.5.9 Table 34. For the avoidance of doubt, for the purposes of this section ~~5.7.6.~~ DR_t in that table will not be updated as a result of the annual updates to *weighted average costs 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 0 of this *access arrangement*).

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

Table 40: SAIDI SSAM targets ~~(for year ending 30 June)~~ and incentive rates ($ real as at 30 June ~~2012~~2017)

	SSAM target (SST_t) for year ending 30 June 2018	SSAM target (SST_t) for each ~~*SSAM*~~ ~~*y*~~*SST Year*	Reward side incentive rate ($ per SAIDI minute)	Penalty side incentive rate ($ per SAIDI minute)
SAIDI - CBD (minutes)	-	~~20.3~~17.8	~~67,817~~26,734	~~67,817~~26,734
SAIDI - Urban (minutes)	-	~~136.6~~108.7	~~529,816~~366,800	~~529,816~~366,800
SAIDI - Rural Short (minutes)	-	~~207.8~~190.4	~~223,472~~114,374	~~223,472~~114,374
SAIDI - Rural Long (minutes)	-	~~582.2~~675.6	~~65,219~~41,958	~~65,219~~41,958

Table 41: SAIFI SSAM targets ~~(for year ending 30 June)~~ and incentive rates ($ real as at 30 June ~~2012~~2017)

	SSAM target (SST_t) for year ending 30 June 2018	SSAM target (SST_t) for each ~~*SSAM*~~ ~~*y*~~*SST Year*	Reward side incentive rate ($ per 0.01 event)	Penalty side incentive rate ($ per 0.01 event)
SAIFI - CBD (events)	-	0.14	~~87,081~~30,114	~~87,081~~30,114
SAIFI - Urban (events)	-	1.~~36~~12	~~548,988~~366,867	~~548,988~~366,867
SAIFI - Rural Short (events)	-	2.~~27~~01	~~222,511~~117,788	~~222,511~~117,788
SAIFI - Rural Long (events)	-	4.~~06~~67	~~101,725~~65,982	~~101,725~~65,982

Table 42: Call centre performance SSAM target ~~(for year ending 30 June)~~ and incentive rate ($ real as at 30 June ~~2012~~2017)

	SSAM target (SST_t) for year ending 30 June 2018	SSAM target (SST_t) for each ~~*SSAM*~~ ~~*y*~~*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)	-	~~87.6~~92.2%	-41,140 ~~-4343,042~~	-9,540 ~~41,08499,807~~

Table 43: Circuit availability SSAM target ~~(for year ending 30 June)~~ and incentive rate ($ real as at 30 June ~~2012~~2017)

	SSAM target (SST_t) for year ending 30 June 2018	SSAM target (SST_t) for each ~~SSAM~~ ~~y~~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.~~1~~5%	-434,953~~-421421,856~~	-193,313~~-187187,492~~

Table 44~~: System minutes interrupted – Radial~~: Loss of supply event frequency SSAM target ~~(for year ending 30 June)~~ and incentive rate ($ real as at 30 June ~~2012~~2017)

-	SSAM target (SST_t) for year ending 30 June 2018	SSAM target (SST_t) for each SSAM year	Reward side incentive rate ($ per ~~minute)~~ event)	Penalty side incentive rate ($ per ~~minute~~event)
~~System~~Loss of supply event frequency >0.1 and ≤1.0 system minutes interrupted ~~- Radial (minutes~~(number of events)	~~1.9~~-	~~105,443~~17	43,495~~172,039~~~~42,186~~	54,369 ~~52,732~~
Loss of supply event frequency >1.0 system minutes interrupted (number of events)	-	~~1~~2	108,738 ~~140,619~~	217,477 ~~421,856~~

Table 45~~: Loss of supply event frequency~~: Average outage duration SSAM target ~~(for year ending 30 June)~~ and incentive rate ($ real as at 30 June ~~2012~~2017)

-	SSAM target (SST_t) for year ending 30 June 2018	SSAM target (SST_t) for each ~~SSAM~~ ~~y~~SST Year	Reward side incentive rate ($ per ~~event)~~minute)	Penalty side incentive rate ($ per ~~event~~minute)
~~Loss of supply event frequency >0.1 system minutes interrupted (number of events)~~		~~24~~	~~36,319~~	~~27,240~~

-	SSAM target (SST_t) for year ending 30 June 2018	SSAM target (SST_t) for each ~~SSAM~~ ~~y~~SST Year	Reward side incentive rate ($ per ~~event)~~minute)	Penalty side incentive rate ($ per ~~event~~minute)
~~Loss of supply event frequency >1.0 system minutes interrupted (number of events)~~Average outage duration (minutes)	-	~~2~~871	1,883~~11,826~~	3,000~~163,437~~2,909

~~Table 42: Average outage duration SSAM target (for year ending 30 June) and incentive rate ($ real as at 30 June 2012)~~

-		~~SSAM target (SST_t)~~	~~Reward side incentive rate ($ per minute)~~	~~Penalty side incentive rate ($ per minute)~~
~~Average outage duration (minutes)~~		~~698~~	~~3,477~~	~~2,495~~

7.6 D factor

7.6.1 In ~~clause~~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 ~~clause~~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*.

(**"D factor incurred costs"**).

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 (**"D factor non-capital costs test"**).

7.6.6 Western Power may at any time during this *access arrangement period* apply to the *Authority* for the *Authority* to determine that a business case contains proposed *non-capital costs* that satisfy the *D factor non-capital costs test*.

7.6.7 If an application is made to the *Authority* under section 7.6.6 the *Authority* must make a determination within 25 Business Days, unless the Authority forms the view that public consultation should be undertaken, in which case the timeframe will be adjusted in accordance with the timeframes described in Appendix 7 of the *Code*, but shall be no longer than 45 business days.

7.6.8 If the *Authority* determines that proposed *non-capital costs* satisfy the *D factor non-capital costs test* (**"approved business case amount"**) then if *D factor incurred costs* are not more than the *approved business case amount* the *Authority* will add the *D factor incurred costs* to Western Power's *target revenue* in the next *access arrangement period*. If the *D factor incurred costs* are more than the *approved business case amount*, the *Authority* will add the *D factor incurred costs* to Western Power's *target revenue* in the next *access arrangement period* and Western Power may seek the further amount be added to *target revenue* for the next *access arrangement period* by demonstrating to the *Authority's* satisfaction that the further amount of *non-capital costs* satisfy the requirements of sections 6.40 and 6.41 of the *Code.*

7.6.9 A determination of an *approved business case amount* does not oblige Western Power to proceed with the project that is the subject of the business case.

7.6.10 If the *Authority* determines that proposed *non-capital costs* do not satisfy the *D factor non-capital costs test* then the *Authority* will provide reasons for that determination to Western Power and Western Power may make an amended application under section ~~7.6.6~~7.6.6.

~~7.6.6~~7.6.11 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~~Initial deferred revenue

7.7.1 For the purposes of ~~clauses~~sections 6.5A to 6.5E of the *Code* an amount must be added to the target revenue for the *distribution system* in the ~~fourth~~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).

~~7.7.1~~ For the purposes of sections 6.5A to 6.5E of the *Code* an amount must be added to the target revenue for the *transmission system* in the fifth *access arrangement period* or subsequent *access arrangement periods* such that the present value (at 30 June ~~2012~~2017) of the total amount added to *target revenue* (taking account of inflation and the time value of money) is equal to $~~520.5~~589.0 million ($ real as at 30 June ~~2012).~~

7.7.2 ~~For the purposes of clauses 6.5A to 6.5E of the *Code* an amount must be added to the target revenue for the *transmission system* in the fourth *access arrangement period* or subsequent *access arrangement periods* such that the present value (at 30 June~~

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~~2012) of the total amount added to *target revenue* (taking account of inflation and the time value of money) is equal to $70.5 million ($ real as at 30 June 2012~~2017).

7.7.3 The timeframe for recovering the deferred revenue amounts in section 7.7.1 will be ~~37~~32 years and in section 7.7.2~~1.1.1~~ will be ~~45~~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 ~~financial~~ 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 A *trigger event* may include without limitation the introduction of any scheme or mechanism with respect, directly or indirectly, to emissions of greenhouse gases and with respect to any activity including pricing, reduction, cessation, offset and sequestration (including the Carbon Pricing Mechanism announced by the Commonwealth in February 2011), full retail contestability, and the mandated roll-out of Advanced Interval Meters, contestability, and any other government energy reforms, to the extent that such costs were not included in the calculation of *target revenue* for this *access arrangement period* or otherwise addressed through the unforeseen event provisions in sections 7.1.1 to 7.1.4 of this *access arrangement*.~~

~~8.1.3~~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 they Balancing~~

9.1 ~~Balancing requirements under~~General

~~Previous versions of the access arrangement shall be in accordance with have referred, in the Supplementary Matters chapter, to balancing requirements, ancillary service, trading and settlement requirements.~~

~~Under the Wholesale Electricity Market Rules these functions are now principally undertaken by the Australian Energy Market Operator (**"AEMO"**).~~

9.1.1 ~~However~~ Western Power will discharge ~~such~~ the obligations it has under ~~in relation to these matters as they are imposed upon Western Power by~~ the Wholesale Electricity Market Rules (WEM Rules) as in force from time to time relating to balancing requirements, ancillary services, trading and settlement requirements ~~and,~~ in accordance with the WEM ~~those r~~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 ~~Wholesale Electricity Market~~ WEM Rules. ~~As at 2 October 2017 this *access arrangement* is prepared by Western Power, the principal role Western Power will have is to provide network information to AEMO to support settlements and balancing~~.

9.1.2 {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 ~~2005~~) 2012 and the ~~*Metering Code Model Service Level Agreement.*~~

~~9.4~~ ~~Ancillary services~~

~~9.4.1~~9.3.1 ~~Requirements for~~~~model service level agreement most recently approved by the~~ ~~treatment of ancillary services~~Authority under the *access arrangement* shall be in ~~accordance with the Wholesale Electricity Market Rules.~~~~Industry (Metering Code)~~ ~~2012~~MSLA.

~~9.5 Stand-by~~

~~9.5.1 Under the Wholesale Electricity Market Rules there is no requirement for stand-by generation.~~

~~9.6 Trading~~

~~9.6.1 Trading requirements under the *access arrangement* shall be in accordance with the Wholesale Electricity Market Rules.~~

~~9.7 Settlement~~

~~9.7.1 Settlement requirements under the *access arrangement* shall be in accordance with the Wholesale Electricity Market Rules.~~

APPENDICES

Appendix A. Electricity transfer access contract

Appendix B. Applications and queuing policy

Appendix C. Contributions policy

C.1 Contributions policy

~~C.2 Distribution headworks methodology~~

~~C.3~~C.2 Distribution low voltage connection ~~headworks~~ scheme methodology

Appendix D. Transfer and relocation policy

Appendix E. Reference services

Appendix F. Reference tariffs

F.1 ~~2012/13~~2017/18 price list

F.2 ~~2012/13~~2017/18 price list information

F.3 2018/19 price list

F.4 2018/19 price list information