Western Australia Electricity Market

Metrology Procedure for Metering Installations

Produced by:
Western Power Corporation
ABN: 38 983 875

4 September 2006

About this document

Author/Custodianship

Author:	Metering Services, Customer Solutions Branch, Asset Management Division
Custodian:	Derek Ball

Distribution list

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Name	Position/title
Metering Services	Metrology Coordinator, Manager of Metering Services, Laboratory Services
Economic Regulation Authority	
Independent Market Operator	
WA Retailers	
Horizon	

Document version history

Version	Date	Change request no.	Amendment
V1 Draft			Initial draft
V2 Draft	26 Apr 06		Updated document template/styles and restructured to be closer match to new draft NEM Metrology Procedures
V3 Draft	18 May 06		Internal review
V4 Issue	22 May 06		Issued to Retailers for comment.
V5 Issue	8 May 06		Incorporates Retailer and internal comments.
V6 Issue	13 June 06		Incorporates additional Retailer and internal comments
V7 Issue	19 June 06		Additional comments
V8 Definitive	23 June 06		Submission to the ERA
V8.1	7 July 06		Addressed Retailer comments, added channel/suffix information, and clarified half hourly processing.
V9 Definitive	14 July 2006		Addressed additional Retailer comments.
V10 Issue	9 Aug 2006		Addressed ERA secretariat comments.
V11 draft	9 Aug 2006		Addressed internal comments
V12 issue	10 Aug 2006		Issue to Retailers/ERA Secretariat for comment
V13 issue	14 Aug 2006		Addressed data buffer overflows
V14 Draft	17 Aug 2006		Addressed status codes
V15 issue	1 Sep 2006		Addressed Secretariat and Retailer comments
V15 Definitive	4 Sep 2006		Submission to ERA

Review and approval

Name	Role	Signature	Date
Derek Ball (Review)	Metrology Coordinator		
Andrew Wood (Authorisation)	Manager of Metering Services		

Contents

1 General

1.1 Introduction

1.1.1 The title of this document is the "*Western Australian Electricity Market Metrology Procedure for Metering Installations*".

1.1.2 The short title of this document is the "*WA Metrology Procedure*".

1.1.3 The *WA Metrology Procedure* is made in accordance with clauses 6.2 and 6.8 of the *Metering Code*.

1.2 Purpose

1.2.1 The purpose of this *Metrology Procedure* is:

a) to provide guidance to the *responsible person* on the correct provision, installation and maintenance of *metering installations* in line with the principles of the *Metering Code*; and

b) to provide guidance to interested third parties, such as metering manufacturers, on the requirements for metering within the Western Australian electricity system.

1.3 Scope

1.3.1 The *Metrology Procedure* provides information on the application of *metering installations* at *connection points*. In particular this *Metrology Procedure* sets out provisions for *metering installations* relating to:

a) the devices and methods that are used by the *Network Operator* to:

i) measure, or determine by means other than a device, electricity produced and consumed at a *metering point*, and

ii) convey the measured or determined information to other devices using *communications links*, and

iii) prepare the information using devices or methods to form *energy data*; and

iv) provide access to the *energy data* from a telecommunications network; and

b) specify the minimum requirements for *meter*s and *metering installation*s, including:

i) *accumulation meters*; and

ii) interfaces that allow *interval energy data* to be downloaded; and

iii) direct connected *meters* for Type 4 to Type 6 *metering installations*; and

iv) *CTs* and *VTs*; and

v) programmable settings under clause 3.10 of the *Metering Code*.

c) specify the procedures for estimating, substituting and validating *energy data* under the *Metering Code*; and

d) be consistent with the approved asset management system required by section 14 of the Act; and

e) define the rights of access to *energy data* in the *metering installation* and

f) define the procedures for the auditing of *metering installations*.

1.3.2 The *Metrology Procedure* applies to the *Code Participant* and the *Network Operator* in relation to a *load* or *generation* at a *connection point*.

1.3.3 The *Metrology Procedure* sets out those obligations and duties that are imposed on the *Network Operator* with regards to *energy data* provision by the *Metering Code* and *Market Rules*.

1.3.4 The *Metrology Procedure* covers the full extent of a *metering installation*, from the *metering point* at one extreme to the boundary of the *telecommunications network* at the other extreme. It includes connection of the *metering installation* to the *telecommunications network*.

{Explanation:

The *connection point* is a logical construction indicating a point of entry or exit to the electricity network and is assigned a unique *NMI*. The *connection point* may be associated with one or more physical *attachment points* providing each *attachment point* operates at the same voltage. Similarly, a single *attachment point* may be associated with multiple *connection points*.

A *metering point* is the point on the *network* at which an *energy data* measurement is taken by a *revenue meter,* or, for type 7 *meter*s, is the point at which a calculated *energy data* figure is deemed to have been measured. Each *connection point* may be associated with multiple *metering points*.

A *metering installation* is designed for each *metering point* for the purpose of measuring energy to a fiscal standard. Each *metering installation* of type 1-6 contains a single *revenue meter* and may also contain a *check meter,* which may be physically distinct from the *revenue meter*. For example, the *metering installation* may physically consist of separate equipment housings each containing separate elements of the *metering installation*. In this case the *metering point* is co-located with the *revenue meter* and the *check meter* would be deemed to measure energy at the same *metering point*. In such circumstances, the design of the *metering installation* would take into account any corrections necessary because of the physical separation of the *check meter* and *revenue meter* and these would be recorded as correction factors.

For example, consider a domestic connection. In a typical house the *attachment point* would usually be a green power dome and the *metering point* would usually be the *meter* box on the side of the house. The *connection point* is the logical point that electricity leaves the network and enters the residence. For practical purposes in this example the *attachment point* and *connection point* are synonymous. However, if the property consisted of an older building that had been subdivided into two separate residences, the situation might be a little different. In this case there might still be a single *attachment point*. However, each residence would be deemed to have its own supply and hence its own *connection point* and NMI. Each residence would have a separate meter box (housing the *metering installation* and hence *metering point*) and associated *revenue meter*.

Another example might be a factory that has multiple *attachment points*. The *Retailer* and factory owner may wish to have their aggregate consumption recorded as a single figure. Under these circumstances, providing the *attachment points* operate at the same voltage and the *meter*s are all either accumulation or interval *meter*s but not a combination of both, the *Retailer* may apply to have the multiple *attachment points* treated as a single *connection point* with multiple *metering points*, each with its associated *metering installation*.

Meters in this *Metrology Procedure* are divided into two classes: *revenue meters* and *check meters*. *Revenue meters* are used for fiscal purposes and will meet the accuracy requirements specified below for each *meter* type 1 to 6 as appropriate. *Check meters* are used to validate the correct functioning of the *revenue meter* and may be used to generate *substitute* data if there is a problem with the *revenue meter*. *Check meters* may be of lower precision (up to twice the uncertainty) than the associated *revenue meter* and may be located at a different physical location but will measure *energy data* for the same *metering point*.

A *metering installation* has an end-to-end path that consists of:

- One or more devices to measure the flow of electricity in a power conductor (including a *current transformer* and *voltage transformer* where appropriate, and a *measurement element* usually in the form of a *meter*) and in doing so produces *energy data*; and

- For types 1 to 5 and, optionally, for type 6, a *data logger*, which is a device to record and store (for a limited period) the *energy data* produced by the measurement element in the form of 30-minute energy packets or energy packets in sub-multiples of 30 minutes; and

- A *communications link*, which has the role of connecting the *data logger* to the *telecommunications network*, and in doing so allows *energy data* to be extracted (pushed or pulled) from the *metering installation*.

For a type 1, type 2, type 3 and type 4 *metering installation*, the boundary of the *telecommunications network* is usually at the site of the power conductor, and physically close to the *data logger*. The *data logger* may be within the housing of the measuring element, or a separate device to the measuring element device. That is, a *meter* may contain only a measuring element, or a combined *measuring element* and *data logger*. In either case, for a type 1, type 2, type 3 and type 4 *metering installation*, the *communication link* might consist of only a modem and isolation links for a PSTN connection, or a combined mobile phone and modem for a CDMA, GSM, GPRS or 3G connection. Once connection to the telecommunications network has been made, the *Network Operator* may apply *remote acquisition* techniques to access the *energy data* in the *data logger* on a regular cycle. Note that an option exists for the type 1, type 2, type 3 and type 4 *metering installation*s to extend the *communications link* so that the connection to the *telecommunication network* is made at a location remote from the site of the power conductor. However, the 'extended' *communications link* would need to be a seamless electronic process that permitted the *Network Operator* to obtain *energy data* from the *metering installation* by *remote acquisition*.

For a type 5 *metering installation*, the boundary of the *telecommunications network* would be at a location that is remote to the site of the power conductor, and hence remote from the *data logger*. In this case the *communications link* might consist of:

(a) a manual *meter* read to obtain the *energy data* from the *data logger* (assuming that the *data logger* was within the housing of the *meter*); and,

(b) the manual transfer of the *energy data* from the location of the *meter* to a remote *metering installation database; and*,

(c) the storage of the raw *energy data* within the *metering installation database*; and,

(d) the processing of the *energy data* within the *metering installation database*; and

(e) the storage of the processed *energy data* within that *metering installation database*; and,

(f) the connection of the *metering installation database* to the *telecommunications network*.

Once connection to the *telecommunications network* has been made, the *Network Operator* may apply *remote acquisition* techniques to access the *energy data* in the *metering installation database* on a regular cycle.

For a type 6 *metering installation*, the boundary of the *telecommunications network* would be at a location that is remote to the site of the power conductor. For a type 6 there is no *data logger*. In this case the *communications link* might consist of:

(a) a manual *meter* read to obtain the *energy data* from the *meter; and*,

(b) the manual transfer of the *energy data* from the location of the *meter* to a remote *metering installation database; and*,

(c) the storage of the raw *energy data* within the *metering installation database; and*,

(d) the processing of the *energy data* within the *metering installation database; and*,

(e) the storage of the processed *energy data* within that *metering installation database;* and,

(f) the connection of the *metering installation database* to the *telecommunications network*.

Once connection to the *telecommunications network* has been made, the *Network Operator* may apply *remote acquisition* techniques to access the *energy data* in the *metering installation database* on a regular cycle. Alternatively, a *metering data agent* may be required to transfer the energy data to the *Network Operator's* metering *database* where further processing may be undertaken.

For a type 7 *metering installation*, the boundary of the *telecommunications network* would be at a location that is remote to the site of the power conductor. For type 7 there is no *meter* or *data logger*. In this case the *communications link* might consist of:

(a) a *remote metering installation database*; and,

(b) a *load table* and an *inventory table* within the *metering installation database;* and,

(d) the processing of the *energy data* (using the *load* and *inventory table*) within the *metering installation database;* and,

(e) the storage of the processed *energy data* within that *metering installation database*; and,

(f) the connection of the *metering installation database* to the *telecommunications network*.

Note – It has been agreed that Type 7 meters are out of the scope of this document.

Once connection to the *telecommunications network* has been made, the *Network Operator* may apply *remote acquisition* techniques to access the *energy data* in the *metering installation database* on a regular cycle. Alternatively, a *metering data agent* may be required to transfer the *energy data* to the *Network Operator*'s *metering database* where further processing may be undertaken. }

1.3.5 This *Metrology Procedure* applies to any electricity network for which Western Power is the *Network Operator* or for which Western Power has been appointed *metering data agent*.

1.4 Referenced Material

1.4.1 The document has been produced with reference to the following publications

WP DMS Ref.	Acronym	Document
2728031	"*Metering Code*", "*Code*"	Electricity Industry *Metering Code* 2005, Published in the Western Australian Government Gazette on 23 Dec 2005, No. 243.
2326074	"*Service Level Agreement*", "*SLA*"	Model Service Level Agreement, approved 30 March 2006 version.
2428349	"*Communication Rules*"	*Metering Code* Communication Rules, approved 16 February 2006 version.

1.5 Definitions

1.5.1 Words shown in *italics* have the meaning specified in section 4.

1.6 Interpretation

1.6.1 If a provision of this *Metrology Procedure* is inconsistent with the *Metering Code*, the *Metering Code* prevails to the extent of the inconsistency.

1.6.2 For the purpose of clarification, to the extent that this *Metrology Procedure* and the National Measurement Act are inconsistent, the National Measurement Act is to prevail.

1.6.3 Where aspects of this *Metrology Procedure* are found to be unclear, the *Network Operator* will issue guidelines and procedures that clarify those aspects.

1.6.4 Unless the contrary intention is apparent:

1. The Interpretation Act 1984 applies to the interpretation of this *Metrology Procedure*.
2. A reference in this *Metrology Procedure* to a document or a provision of a document includes an amendment or supplement to, or replacement of or novation of, the document or provision.
3. A reference in this *Metrology Procedure* to a person includes the person's executors, administrators, successors, and substitutes and permitted assigns.
4. Where italic typeface has been applied to some words and expressions in this *Metrology Procedure*, it is solely to indicate that those words or expressions may be defined in clause 4, *Definitions*, or elsewhere, and in interpreting this *Metrology Procedure* the fact that italic typeface has or has not been applied to a word or expression is to be disregarded.
5. Where information in this *Metrology Procedure* is set out in braces (namely "{" and "}"), whether or not preceded by the expression "Note", "Outline" or "Example", the information:
    i. is provided for information only and does not form part of this *Metrology Procedure*; and
    ii. is to be disregarded in interpreting this *Metrology Procedure*; and
    iii. might not reflect amendments to this *Metrology Procedure* or other documents or written laws.
6. "Including" and similar expressions are not words of limitation in this *Metrology Procedure*.
7. Meaning of 'publish.' If the *Network Operator* is required to "publish" a thing, the *Network Operator* must:
    i. place the thing upon an internet website under the *Network Operator*'s control; and,
    ii. send an electronic notice to each *Code Participant* advising the *Code Participant* that the thing has been placed on the internet website.

1.7 Commencement

1.7.1 The date of publication of the *Metrology Procedure* is ten days following approval by the *Authority*.

1.7.2 This *Metrology Procedure* comes into operation three months after the date of publication.

1.8 Metering Installation Components

1.8.1 The components of a *metering installation* covered by this *Metrology Procedure* are:

a) One or more *metering points;* and,

b) The *instrument transformers;* and,

c) The *measurement element;* and,

d) The *data logger;* and,

e) The *communications link;* and,

f) The associated wiring, connectors, fuses, mounting boards and housings.

1.8.2 This document also addresses the following associated services:

a) *Meter data services* within the *communications link.*

b) Testing and inspection.

c) Management, maintenance and auditing.

1.8.3 The primary components, their characteristics and associated service requirements have been itemised in the Schedules for the purpose of allowing the *Network Operator* to exercise discretion in a transparent manner, or to provide the information required by the *Metering Code* or *Market Rules.*

1.8.4 The information contained in the Schedules is largely a replication of the requirements in the *Metering Code* and Market Rules with practical clarification by the *Network Operator* where necessary.

2 Responsibility for Meter Provision

2.1 Network Operator is Responsible for Meter Provision

2.1.1 The *Network Operator* is responsible for the design, provision, installation and maintenance of *metering installations*.

2.1.2 A physical *metering installation* shall be provided for all *connection points* of type 1 to 6.

2.2 Enhanced Technology Features

2.2.1 Where reasonably requested by a *Code Participant*, the *Network Operator* will provide *metering installations* with *enhanced technology* features.

2.2.2 *Metering installations* with *enhanced technology* features will only be used where they meet or exceed the standards required of the un-enhanced type 1-6 *metering installation* that would otherwise be used at the *connection point* under consideration.

2.2.3 Where a *meter* includes enhanced features more normally associated with a *meter* of a more advanced type, the normal provisions of the standard type of *meter* apply for all aspects other than the enhanced feature.

{For example, addition of communications capability to a type five *meter* does not mean that the *meter* should thereafter be treated as being of type 4. Rather it will continue to be treated as a type 5 *meter* in every respect except communications. }

2.2.4 Notwithstanding clause 2.2.3, a *meter* will be reported as a different type within the *metering database* where this is necessary to support the *enhanced technology feature*.

{For example, an interval capable type 6 *meter* has the accuracy and other requirements of a type 6 *meter* under this *Metrology Procedure* for metrology (in the dictionary sense) purposes. When used as an *accumulation meter* this makes no difference. However if the *meter* is reprogrammed to become an *interval meter* then to properly support and disseminate the interval *energy data* it may need to be processed and reported as a type 5 *meter* within the Western Power metering systems. From a *Retailer* perspective it can be treated as a type 5 *meter* but the difference may be significant if a *meter test* is requested.

Thus,

Meter type	Treated as
Basic accumulation *meter*	Type 6
Interval capable *meter* read as accumulation	Type 6
Interval capable read as accumulation with communications	Type 6
Interval capable read as interval	Types 1-5 depending on other features
Interval capable with communications	Types 1-4 depending on annual consumption}

2.2.5 If the *metering installation* includes a *data logger* then:

a) The *metering installation* must include facilities for the on-site storage of *energy data* for a period of at least:

i) 100 calendar days from the time of the last successful read of the *meter*, for meters with one data stream; or

ii) 50 calendar days from the time of the last successful read of the *meter,* for meters with two data streams; or

iii) 35 calendar days from the time of the last successful read of the *meter,* for meters with three data streams; or

iv) 27 calendar days from the time of the last successful read of the *meter* for meters with four data streams.

b) The scheduled meter reading frequency for a meter will be set in accordance with the relevant service level agreement at a level that the *Network Operator* believes will minimise the opportunity for lost data due to *data logger overflow*.

c) Should a *data logger overflow* occur then data will be substituted in accordance with the substitution rules for that class of *metering installation* as defined in section 3.4.

d) If a *meter* or group of *meters* experiences more than two *data logger overflows* within a twelve month period, the *Network Operator* and relevant *Retailer* must agree a suitable method of managing this problem.

{Note – a data logger overflow should be a very rare event. The intention is that if a regular overflow occurs the parties will agree a suitable method of avoiding data loss while the underlying issue is addressed. For example, if a meter were experiencing regular communications problems and it was not possible to always read the meter before energy data were lost, the network operator may agree to read the meter more frequently, at no charge to the Retailer, while the remote communications to the meter are upgraded. However if the data loss was a one-off, or very low probability, event no action would be necessary since it would not be cost effective to do so}

e) The *Retailer* may request that an individual meter be read at a greater frequency, in line with the relevant *service level agreement*.

{Note –in practice the meters available can store 220 days of data on a half-hourly basis shared across data streams. In WA, the meters log data on fifteen-minute intervals and this is then aggregated within the metering database to 30 minute trading intervals. Thus 220 "days" of data could correspond to:

- *36 days in each of three data streams, (e.g. kWh, KVARrh, kVAh) or*
- *55 days in each of two data streams (e.g. hWh, kVARh) or*
- *110 days for a single data stream (e.g. kWh)*
- *27.5 days for a combined import export meter with both active and reactive energy data streams.*

These are due to the limitations and physical characteristics of the standard meters supplied from metering companies. To increase the number of days of storage requires an enhanced meter at significant extra cost – this would be handled under the enhanced metering provisions of the code.

Note that an export meter with both KwH and KVARh datastreams in 15 minute intervals can buffer more than 50 days of data which is more than adequate to cope with a monthly reading cycle. Similarly, with active, reactive and apparent energy datastreams 35 days of data can be buffered. This should be adequate to ensure that the meter can be reached if communications fail. The clauses as worded allow for negotiated SLAs with other reading frequencies.}

2.2.6 Where a *metering installation* includes a *data logger* and no remote reading facility exists, or where remote communications has not been possible, then a manual visit will be scheduled prior to the end of the periods allowed for in 2.2.5.

{Note – the intention here is that if communications fail then someone will manually attend site to take a reading prior to the data being lost. Thus the timing is set to maximum time between scheduled reads plus the period necessary to ensure someone can attend site. This is left to the discretion of the network operator given the unqualified requirement to attend site prior to this period expiring. Where the number of data streams being recorded mean that the time between reads has to be less than a monthly reading cycle will permit there is now an obligation to read the meter at a more frequent interval as permitted/allowed for in the relevant SLA. Thus if a Retailer wishes to receive more than the basic consumption data they will need to accept a more frequent reading schedule – however this still allows for monthly reads with just active and reactive energy.}

2.2.7 A *Network Operator* providing one or more *metering installations* with *enhanced technology* features must:

a) be licensed to use and access the metering software applicable to all devices being installed; and

b) be able to program the devices and set para*meter*s, including 'read only' and 'write' passwords.

2.2.8 Where signals are provided from the *metering installation* for the *user* or the *user's* customer use:

a) the *Network Operator* must ensure that the signals are isolated by relays or electronic buffers to prevent accidental or malicious damage to the *meter*; and

b) the *Network Operator* must provide the user or the *user's* customer with sufficient details of the signal specification to enable the *user* or the *user's* customer to comply with clause 2.2.8(c); and

c) customer must ensure that a device to be connected to the signal output is compatible with the signal.

2.2.9 If *metering installations* with *enhanced technology* are introduced to the *network* this *Metrology Procedure* will be amended if necessary to cater for other features of these *metering installations*.

2.3 Prepayment Meters

2.3.1 Where *prepayment meters* are installed:

a) they will be treated where reasonably possible as Type 6 accumulation *meter*s; and

b) they will be operated and maintained in accordance with good electricity practice.

2.3.2 Despite clause 2.3.1, a dispute or difference arising in connection with a *prepayment meter* will be handled under the provisions of clause 3.12, Disputes.

2.3.3 If *prepayment meters* that cannot be treated as Type 6 accumulation *meter*s are introduced to the *network* this *Metrology Procedure* will be amended where necessary to cater for other features of these *meter*s.

2.4 Metering Installation Components – Meter Provision

2.4.1 The requirements in this clause are applicable to types 1 – 4, type 5 and type 6 *metering installations*.

2.4.2 The *Network Operator* must ensure that the components, characteristics and requirements for *meter* provision for type 1 – 4, type 5 and type 6 *metering installations* are as shown in Schedules 1, 2 and 3 respectively.

2.4.3 Schedule 1 details the minimum requirements for *meter* provision for the type 1 – 4 *metering installations*, Schedule 2 details the minimum requirements for type 5 *metering installations* and Schedule 3 details the minimum requirements for type 6 *metering installations*.

2.4.4 Notwithstanding 2.4.2 and 2.4.3, *metering installations* which have been installed, or which are held in stock for the *Network Operator*, prior to the effective date of the initial *Metrology Procedure* and which do not meet the requirements in Schedules 1, 2 or 3 will be used at the discretion of the *Network Operator* but must be used in accordance with section 3.14 of the *Metering Code*.

2.4.5 The choice of *metering installation* type will be based on the historic or anticipated annual consumption and peak load at the *connection point*, as agreed with the *Retailer*, and on the need for *interval energy data* and communications.

{Note: it is anticipated that routine discussion will not be required. I.e. that the *Retailer* will indicate to Metering Services the circumstances under which they need to be consulted about the *metering installation*.}

2.4.6 An increase in annual or peak consumption that, in the opinion of the *Network Operator*, places the *connection point* into a higher type will result in a meter upgrade. Where annual consumption has decreased with time no meter change will result.

2.4.7 Where a *metering installation* includes a type 5 *meter* that is read as an *accumulation meter*, the *meter* will not be replaced by or, reconfigured to, an interval-read *meter* without the agreement of the *Retailer,* except:

a) Where another *Retailer* has requested an interval survey, at which point it will be necessary to permanently convert the *meter* to an interval-read *meter*; or

2.4.8 Where the connection point is due to transfer to another *Retailer*, under which circumstances it may be necessary to replace or reprogram the *meter* to interval-read a few days prior to the formal transfer.

{Note: this is intended to address a number of historical *meter*s that are currently read as accumulation *meter*s but which might have been supplied with interval *meter*s if the current rules and processes had applied in the past. If it is necessary to replace such a *meter* it is important to the *Retailer*s that this replacement does not unexpectedly change the type of data they receive. }

2.5 Metrology Procedure Defines Minimum Rather Than Maximum Requirements

2.5.1 It should be noted that this document presents the minimum requirements and does not preclude a *meter* supplier, *Network Operator* or metering *data agent* from deploying products or developing processes that exceed or complement the requirements defined in this section, providing that such features are compatible with the requirements of the *Metrology Procedure*. For example, the deployment of *meter*s with *enhanced technology* features or the future provision of *interval meter*s for *connection points* with low annual consumption.

2.6 Removal of Meters

2.6.1 From the commencement of this *Metrology Procedure*, the *Network Operator* must ensure that a type 1- 4 or type 5 *metering installations* are not replaced by a type 6 *metering installation,* unless agreed by all the relevant *Code Participants*.

2.7 Testing and Inspection of Meters

2.7.1 The *Network Operator* must ensure that *metering installations* are tested and inspected in accordance with Schedules 1, 2 and 3.

2.7.2 Clauses 2.7.3 to 2.7.11 (inclusive) are to be regarded as the asset management strategy guidelines for the whole-current (direct connected) *meters* for the purpose of section 6.8(d) of the *Code*.

2.7.3 The *meter management plan* referred to in clause 2.7.2 must include, as a minimum, the requirements the Australian Standard ‘AS1284 Part 13: In-service compliance testing’.

2.7.4 The *Network Operator* must ensure that a *meter management plan* is established and maintained for the testing and inspection requirements of whole-current (direct connected) *meters*.

2.7.5 For the purposes of the *meter management plan*, the whole-current (direct connected) *meters* must be divided into *testing classes*.

2.7.6 Where historical *meter* records permit, the *testing classes* referred to in clause 2.7.5 should consist of *meters* of the same year of manufacture and common design.

2.7.7 The *Network Operator* must ensure that a sampling plan is established and maintained in accordance with the *meter management plan* to ensure that each *testing class* of whole-current (direct connected) *meter*, and associated *data logger* (where the *data logger* is located at the *metering point*) for type 5 *metering installations*, is tested at least once in the first fifteen (15) years following manufacture and at least once in each subsequent five (5) year period.

2.7.8 For those whole-current (direct connected) *meters* for which new or amended pattern approval has been received from the National Measurement Institute, or for which new or amended type testing has been undertaken by a National Association of Testing Authorities (NATA) accredited laboratory or overseas equivalent approved by the National Measurement Institute, the *Network Operator* must ensure that the sampling plan ensures that this *testing class* of *meter* is tested at least once in the first three (3) years following receipt of the new or amended pattern approval, or the new or amended type test certificate.

2.7.9 If the results from a sampling test carried out in accordance with a sampling plan described in clauses 2.7.7 and 2.7.8 demonstrate that the *testing class* of *meters* being sampled fails to meet the requirements of the sampling plan, then the *Network Operator* must ensure that all *meters* in that *testing class* are replaced or recalibrated within a reasonable period of time.

2.7.10 When determining the planned schedule for the replacement or recalibration of a *testing class* of *meter* in accordance with 2.7.9, the *Network Operator*, will consult with the affected *Code Participants*.

2.7.11 The *meter management plan* must include, but need not be limited to:

a) Records relating to *meter testing classes* and age of manufacture;

b) *Meter* test records for each *meter testing class*;

c) *Meter* test plan for each *meter testing class* based on *meter* quantity (sample size) and *meter* age;

d) Frequency of test;

e) Records of *meter* failures per *meter testing class*;

f) Planned replacement strategy based on age and/or performance;

g) Location of each *meter*; and

h) Meter registration number.

2.8 Installation of Meter

2.8.1 The *Network Operator* must ensure that when each *meter* and associated *data logger* (where the *data logger* is located at the *metering point*) is installed, it is checked to ensure that it:

a) Complies with the relevant requirements of Schedules 1-3, respectively subject to clause 2.4.4;

b) Has the optical port, communications port, and/or visual display located so that the optical port, communications port, and/or visual display can be readily accessed for meter reading.

2.8.2 Notwithstanding clause 2.8.1, *meter*s procured to a specification that conforms to Schedules 1-3, and which is usually held as a standard stock item by the *Network Operator*, can be assumed to meet the requirements of Schedules 1-3 without further testing.

3 Responsibility for Energy Data Services

3.1 Overview

3.1.1 *Energy data services* cover all aspects of retrieving, storing and disseminating the *energy data* readings recorded by the *meter*.

3.2 Metering Installation Components – Energy Data Services

3.2.1 The *Network Operator* must ensure that the components, characteristics and requirements for *energy data services* for all *metering installations* are:

a) for *metering installations* of types 1-5, as described in Schedule 4 – Components of a Type 1-5 Metering Installation – Energy Data Services; and,

b) for *metering installations* of types 6, as described in Schedule 5 – Components of a Type 6 Metering Installation – Energy Data Services.

3.2.2 The Schedules referenced in clause 3.2.1 detail the minimum requirements for *energy data services* for *metering installations*.

3.3 Meter Reading For Metering Installations

3.3.1 The *Network Operator* will ensure that for *metering installations* of types 1-4*, interval energy data* will be collected on a monthly basis, or, by agreement with the relevant *Retailer*, daily.

3.3.2 The *Network Operator* will ensure that for *metering installations* of types 5, *interval energy data* will be collected on a monthly basis.

3.3.3 The *Network Operator* will ensure that for *metering installations* of types 6, *energy data* will be collected on a monthly or bi-monthly basis, as agreed between the *Network Operator* and *Retailer* at the time of installation.

3.3.4 Notwithstanding 3.3.1 and 3.3.2, the *Network Operator* may choose for operational or other reasons to disseminate the *energy data* for *metering installation* types 1-5 more frequently. Under these circumstances the published meter reading schedule and substitution and other deadlines will not be affected.

3.3.5 Where the *Network Operator* chooses to gather and issue *energy data* more frequently than the published Schedule, the *Retailer* will only be charged for reading in accordance with the agreed and published meter reading schedule.

{Note: the *Network Operator* may choose for internal reasons to collect and issue data weekly for monthly read meters, as is common practice at present.

Also, if reading weekly still only obliged to send data monthly – deadlines apply to the published monthly schedule.}

3.3.6 Where a type 6 *meter* is capable of recording both interval and accumulated *energy data*, it will be treated as an *accumulation meter*, unless otherwise agreed between the *Network Operator* and *Retailer*.

3.3.7 When a *Retailer* has requested that an interval-capable type 6 *meter* be treated as an *interval meter*, then the *meter* cannot revert to being read as an *accumulation meter* in the future.

3.3.8 The *Network Operator* and *Retailer* can agree other reading frequencies for specific *meters* or classes of *meters*, as documented in a *service level agreement*.

3.3.9 For the purposes of clauses 3.3.1, 3.3.2 and 3.3.3, the meter reading cycle for a *metering installation* commences from the most recent meter reading prior to, or in conjunction with, the end-use customer transferring to a new *Retailer*.

3.3.10 The *Network Operator* must ensure that *energy data* is collected from a *meter* or *meter*/ associated *data logger* and this *energy data* is transferred to the relevant *metering database*, no later than two (2) business days after the scheduled reading date for that *metering installation*, or within the time frame specified in the applicable *service level agreement*.

{E.g. if the scheduled read date is a Friday on a normal working week then the data must be in the metering database by 23:59:59 on the following Tuesday (Two business days later).}

3.3.11 Where *energy data* is collected from a *meter* or *meter*/associated *data logger* by a *user* this data must be provided to the *Network Operator* no more than two (2) business days after collecting or receiving the data, or within the period specified in the applicable *service level agreement*.

3.3.12 The *Network Operator* must ensure that a schedule is developed and maintained to determine the scheduled reading dates for each *metering installation* in accordance with the applicable *service level agreement*. Not withstanding the provisions of the applicable *service level agreement*, the maximum interval between attempts to read each *meter* will be one calendar year.

3.3.13 The meter reading schedule for each calendar year for all network *connection points* will be published no later than the last day of the month of October preceding the start of the year under consideration.

{For example, the meter reading schedule for the year falling from 1st January 2008 to 31st December 2008 will be published on the Western Power website no later than 23:59 on 31st October 2007}

3.3.14 The *Network Operator* will accept requests for special meter reads in accordance with the provisions of the *Communication Rules* and will respond to valid requests within the response times specified in the applicable *service level agreement*.

3.3.15 The *Network Operator* must in all other respects arrange for any special meter reads, final meter reads or estimated reads to be undertaken in accordance with any relevant transfer rules or jurisdictional instruments which relate to meter reading.

3.3.16 Where *energy data* for *metering installations* of type 1-5 is gathered at a frequency greater than a *trading interval* it will be aggregated into *trading intervals*.

3.3.17 Where a *check meter* is installed which is of the same precision as the *revenue meter* then the *Network Operator* will calculate and pass to market the average of the check and revenue meter reading for active and reactive channels to be used for billing and settlement purposes.

{Note default channels are given in the appendices – the Network operator will send out check revenue and average}

3.4 Validation And Substitution/Estimation of Energy Data

3.4.1 The *Network Operator* must ensure that *energy data* collected for a *metering installation* of types 1 to 5 in accordance with clause 3.3 is validated in accordance with the validation rules in Schedule 6 – *Metering Installation* Types 1-5 – Validation .

3.4.2 The *Network Operator* must ensure that *energy data* collected for a *metering installation* of type 6 in accordance with clause 3.3 is validated in accordance with the validation rules in Schedule 8 – Metering Installation Type 6 – Validation, Substitution and Estimation.

3.4.3 Where a *Code Participant* requests validation of data under clause 5.20 of the *Code*, the *Network Operator* will repeat the applicable tests specified in clauses 3.4.1 or 3.4.2.

3.4.4 Where the *energy data* fails the validation tests under clauses 3.4.1or 3.4.2, or 3.4.3 the *Network Operator* will:

a) manually correct the reading if the correct reading can be determined; or

b) re-read the *meter* if no correction has been possible and the meter can be re-read prior to the applicable deadline for the dissemination of *energy data*; or

c) substitute the reading where neither manual correction or a re-read is possible.

{Note –

- *There is always a manual review where validation fails.*
- *an example of where manual correction is appropriate would be the case where a review of a suspect reading reveals that the error is probably due to a transcription error such as the reversal of adjacent digits.*
- *an example of where a re-read may be appropriate is if it is still within the current billing cycle and the meter has remote reading capability or can be easily visited by a meter reader or other* metering *personnel.}*

3.4.5 Where any of the error conditions listed as resulting in substitution in Appendix 1 are encountered, the *energy data* will always be substituted except where the reported status is determined to be spurious by the *Network Operator*. Where a spurious error condition has been detected the *Network Operator* will consult with the *Retailer* over the correct course of action.

3.4.6 Where the *energy data* fails the validation tests under clauses 3.4.1or 3.4.2, or 3.4.3 the *Network Operator* will always review the validation failures to determine the cause of any apparently lost or erroneous *energy data.* Where the *Network Operator* believes the error to be due to a *metering installation* fault:

a) if the meter is believed to be performing outside of its design specification the *meter installation* will be placed under test; or

b) where the *metering installation* is clearly defective, the *metering installation* will be repaired or replaced within the period defined in the applicable *service level agreement* for meter repairs.

3.4.7 Where any alarm is reported by the meter, whether it requires substitution or not, which is not caused by a *metering installation* fault but which can be compensated for by an adjustment to the *metering installation*, the *metering installation* must be reset, reprogrammed or otherwise adjusted as applicable, within the period defined in the applicable *service level agreement* for meter repairs, unless the *Network Operator* is satisfied that the alarm condition will not reoccur.

{For example;

- *If the meter is showing the "Alarm" status the meter will always be reprogrammed or replaced.*

- *If a pulse overflow occurs, the meter will always be reprogrammed or replaced to prevent a future reoccurrence unless the Network Operator is satisfied there is an imminent significant and ongoing load reduction by the consumer (e.g. plant going out of service). In practice for a small spike the meter will be reprogrammed with a new scaling factor; if however the spike is extended the site will be visited for a more detailed analysis- if the CT rating has been exceeded the a CT upgrade will be required. }*

3.4.8 Where data is required for market settlement purposes and a reading is not scheduled for the *meter* prior to the end of the settlement period, the *Network Operator* will estimate the *energy data* for the period under consideration.

3.4.9 For *metering installations* of types 1-5 the *Network Operator* must ensure that the *energy data* is substituted or estimated in accordance with Schedule 7 – Metering Installation Types 1-5 – Accumulation, Substitution and Estimation, where:

a) the network Operator has elected to perform substitution under clause 3.4.4(c); or

b) the network Operator has elected to perform estimation under clause 3.4.8; or

c) there has been a failure of the metering equipment; or,

d) an inspection or test on the metering equipment has established that the measurement uncertainty exceeds the specified standard for that class of *meter;* or,

e) it has not been possible to obtain a reading from the meter.

3.4.10 Where the data substituted or estimated in accordance with 3.4.9 pertains to an *energy data* channel of a meter for which *reactive energy data* is recorded in addition to an *active energy* channel, then both channels must be substituted or estimated as a set to ensure consistency and the availability of correct power factors.

{E.g. if Wh fails validation and is replaced with the Wh value from the previous week then the VARh value should also be replaced with the VARh value corresponding to the substituted Wh value and, where applicable, the VAh either recalculated or substituted to the corresponding VAh.

If only Wh were replaced then the relationship $VAh^2 = VARh^2 + Wh^2$ might not hold and the Power factor could be nonsensical.}

3.4.11 For *metering installations* of type 6 the *Network Operator* must ensure that the *energy data* is substituted or estimated in accordance with Schedule 8 – Metering Installation Type 6 – Validation, Substitution and Estimation, where:

a) the network Operator has elected to perform substitution or estimation under clause 3.4.4(c) or

b) the network Operator has elected to perform estimation under clause 3.4.8; or

c) there has been a failure of the metering equipment; or,

d) an inspection or test on the metering equipment has established that the measurement uncertainty exceeds the specified standard for that class of *meter;* or,

e) it has not been possible to obtain a reading from the meter.

3.4.12 Substituted data will be marked as a final substitute when no further updates are possible. For the avoidance of doubt, it is not necessary to issue a final substitute for any particular reading.

{Note. In practice this means only when it is no longer physically possible to read the meter – e.g. meter is faulty. Other than that it is always conceivable that the data will be revised and so the vast majority of energy data will never have a final status set.

3.4.13 Where it is necessary to substitute a meter reading because of an inability to access the meter, a reason code will be supplied in accordance with the NEM12 and NEM13 meter data file format specification.

3.5 Calculation of Energy Data For Type 7 Metering Installations

3.5.1 The *Retailers* and the *Network Operator* have agreed that type 7 consumption calculations will continue to be made by the methods and systems in place as of June 2006 for the foreseeable future. The method of substitution under this agreement is thus treated as type 74 under the *Metering Code* and this *Metrology Procedure*.

3.5.2 The *metering installation* and *metering database* associated with each type 7 *meter* are therefore the systems in use as of June 2006, or as agreed between those *Retailers* with customers at type 7 *metering installations* and the *Network Operator*.

3.6 Data Storage

3.6.1 The *Network Operator* must provide a metering *database* containing *energy data* in respect of each types 1-6 *metering installations*, in accordance with the requirements,:

a) for *metering installations* of types 1-5, as described in Schedule 4 – Components of a Type 1-5 Metering Installation – Energy Data Services; and,

b) for *metering installations* of types 6, as described in Schedule 5 – Components of a Type 6 Metering Installation – Energy Data Services..

3.6.2 For the avoidance of doubt, the *energy data* for a type 5 or type 6 *metering installation* is the data collected from the *meter* or associated *data logger* in accordance with clause 3.3 subject to clause 3.4, and/or the data that is estimated in accordance with clause 3.4.8.

3.6.3 The rights of access to the data held within the *metering database* are set out in clauses 4.8 and 7.6 of the *Code* and in clause 3.7.1 of this *Metrology Procedure*.

3.7 Information

3.7.1 The *Network Operator* must provide access to *energy data* to a C*ode Participant* for each *connection point* at which the *Code Participant* supplies, generates or purchases electricity.

3.7.2 Where a *communication link* is installed for a *metering installation*, the *Network Operator* will provide a read-only password and connection details to the *Code Participants* who have access under clause 3.7.1

3.7.3 The *Network Operator* must provide access to *energy data* to the *IMO* for settlement and load forecasting purposes.

3.7.4 The *Network Operator* must provide access to *energy data* to the *Authority* for auditing and compliance purposes upon request.

3.7.5 For the purposes of clauses 3.7.1, 3.7.3 and 3.7.4 access to *energy data* must be provided by 11 a.m. on the third business day following the scheduled read date.

3.7.6 The *Network Operator must* ensure that access to the *metering installation* is secured from unauthorised access in line with clause 4.8.4(a) of the *Metering Code* and in line with good electricity and IT industry practice.

3.7.7 The *Network Operator must* ensure that access to the *metering database* is secured from unauthorised access in line with clause 4.8.4(a) of the *Metering Code* and in line with good electricity and IT industry practice.

3.8 Validation of Metering Database

3.8.1 The *Network Operator* must ensure that a sampling plan is established and maintained, in accordance with Australian Standards "AS1199: Sampling Procedures and Tables for Inspection by Attributes" or "AS2490: Sampling Procedures and Charts for Inspection by Variables for Percent Nonconforming" to validate that the data stored in the *metering database* with respect to a type 5 or type 6 *metering installation* is consistent with the data stored in the *meter* or *meter*/associated *data logger* and that validation, substitution and estimation is being performed in accordance with this *Metrology Procedure*.

3.8.2 The validation test must be conducted at a frequency in accordance with the sampling plan described in clause 3.8.1, which must not be less than once every twelve (12) months.

3.8.3 If there is an inconsistency between the data held in a *meter* or *meter*/associated *data logger*, and the data held in the metering *database*, the data in the *meter* or *meter*/associated *data logger* is to be taken as prima facie evidence of the *energy data* for that *metering point.*

3.8.4 If there is an inconsistency in the validation, or the estimated/substituted value held in the *metering database* and the value used for comparison during the test, the value used for comparison is to be taken as prima facie evidence of the *energy data* for that *metering point*.

3.8.5 A validation test must be conducted at a frequency in accordance with the sampling plan described in clause 3.8.4, which must not be less than once every twelve (12) months.

3.8.6 If there is an inconsistency between the data held in the *metering database* and the physical inventory, the physical inventory is to be taken as prima facie evidence of the actual data.

3.8.7 Actions in event of non-compliance with accuracy requirements are set out in:

a) Schedule 1 – Components of Types 1- 4 Metering Installations – Meter Provision, or

b) Schedule 2 – Components of a Type 5 Metering Installation – Meter Provision, or

c) Schedule 3 – Components of a Type 6 Metering Installation – Meter Provision, or

d) Schedule 4 – Components of a Type 1-5 Metering Installation – Energy Data Services, or

e) Schedule 5 – Components of a Type 6 Metering Installation – Energy Data Services.

3.9 Request for testing of the Metering Installation

3.9.1 If requested by a *Code Participant*, the *Network Operator* must conduct a test to determine the consistency of data held in the *metering database* and data held in the *meter* or associated *data logger* of a *metering installation*.

3.9.2 This test should compare all values available in the *meter* or associated *data logger* of the *metering installation* to the equivalent data in the *metering database*.

3.9.3 The *Network Operator* must make available the results of the test described in clause 3.9.1 to the *Code* Participant as soon as practicable.

3.9.4 Where the test undertaken in accordance with clause 3.9.1 determines an inconsistency, the *Network Operator* must pay the costs of, and associated with, that test.

3.9.5 Where the test undertaken in accordance with clause 3.9.1 determines no inconsistency, the *Code Participant* who requested the test under clause 3.9.1 must pay the costs of, and associated with, that test.

3.9.6 Where there is a discrepancy between:

a) *energy data* stored in the *meter* or *meter*/associated *data logger*; and

b) *energy data* stored in the metering *database* in respect of the respective *meter* or *meter*/associated *data logger*, the *energy data* stored in the *meter* or *meter*/associated *data logger* is prima facie evidence of the amount of electricity supplied to that *metering point*.

3.9.7 Where there is a discrepancy between the data held in the *metering database* and the physical inventory, the physical inventory is to be taken as prima facie evidence of the actual data.

3.9.8 If requested by a *Code Participant*, the *Network Operator* must, prior to any test being undertaken in accordance with clause 3.9.1, provide an estimate of the costs of, or associated with, that test.

{Note – the service level agreement dictates the charges associated with performing a test on the meter itself. The clauses in this section deal with different tests – namely, validation of the data in the database against the meter – that are not covered by the standard fees and which will be costed on a case by case basis.}

3.10 Request for testing of the energy data processing

3.10.1 If requested by a *Code Participant*, the *Network Operator* must conduct a test to determine the correct processing and storage of *energy data* for a *metering installation*.

3.10.2 This test shall ensure that:

a) The validation tests have been performed in agreement with this *Metrology Procedure*; and

b) That metering statuses are reported in agreement with this *Metrology Procedure*; and

c) That aggregation of quarter-hourly data to half-hourly data has been performed in agreement with this *Metrology Procedure*; and

d) That substitution and/or estimation has been performed in agreement with this *Metrology Procedure*.

3.10.3 The *Network Operator* must make available the results of the test described in clause 3.10.1 to the *Code Participant* as soon as practicable.

3.10.4 Where the test undertaken in accordance with clause 3.10.1 determines an inconsistency, the *Network Operator* must pay the costs of, and associated with, that test.

3.10.5 Where the test undertaken in accordance with clause 3.10.1 determines no inconsistency, the *Code Participant* who requested the test under clause 3.10.1 must pay the costs of, and associated with, that test.

3.10.6 Where there is a discrepancy between *energy data* determined during the testing process and the *energy data* values stored in the *metering database*, the *energy data* determined during testing shall be prima facie evidence of the amount of electricity pertaining to the affected *metering point*.

3.10.7 If requested by a *Code* Participant, the *Network Operator* must, prior to any test being undertaken in accordance with clause 3.10.1, provide an estimate of the costs of, or associated with, that test.

3.11 Procedure Changes

3.11.1 Changes to this *Metrology Procedure* will be in accordance with Part 6 of the *Metering Code*.

3.12 Disputes

3.12.1 The *Network Operator* will appoint an *Account Manager* to be available to *Code Participants* to contact during normal business hours. Each *Metering Code Participant* is also to nominate a contact person during *business hours*.

3.12.2 The *Manager of* Metering *Services* will be ultimately accountable for the relationship of the *Network Operator* with the *Metering Code Participants*.

3.12.3 Any disputes associated with this *Metrology Procedure* will be addressed in the first instance to the Account Manager for resolution. The *Account Manager* will investigate the dispute and provide a response within 10 *business days* of any dispute being notified in writing.

3.12.4 In the event that an issue cannot be resolved to the *Code Participant's* satisfaction, the matter should then be escalated to the *Manager of Metering Services*, again in writing, who will respond to the complaint within 10 *business days*.

3.12.5 In the event that the issue remains unresolved following consideration by the *Manager of* Metering *Services*, then the dispute should follow the dispute resolution process set out Part 8, Dispute Resolution, in the *Metering Code*.

3.13 Disaster Recovery

3.13.1 The *Network Operator* must ensure that disaster recovery procedures are prepared and developed in relation to the *energy data* for *metering installations* and the information stored in the metering *database.*

3.13.2 The *Network Operator* must ensure that disaster recovery procedures are prepared and developed in relation to *energy data* for *metering installations*, including the metering *database*. A disaster recovery guideline must seek to ensure that, within two business days after the day of any disaster:

a) the metering *database* can be rebuilt; and

b) *energy data* can be provided to the relevant *Code Participants* including *energy data* for any of the days during which the *Network Operator* was affected by the disaster.

{NOTES:

- *Failures necessitating the implementation of the disaster recover guidelines may include, for example, the failure of components of the computer systems hosting the* metering *database, a fire or other natural disaster impacting the data processing centre, etc.*

- *The basic principle is that services should be restored within two business days and no energy data should be lost as a result of the* metering *database being unavailable.*

- *However, it is not practical to implement redundancy and data back up facilities for every metering installation database/data logger. Thus if a physical disaster were to befall a metering installation then some data loss would occur. Under these circumstances substitution/estimation would be utilised to provide energy data values covering any such periods}*

3.13.3 The disaster recovery guideline must be prepared in accordance with:

a) the relevant requirements for dispute resolution in Part 8 of the *Code*;

b) the requirements for the repair of an outage or malfunction to a *metering installation* in clause 3.11 of the *Code*; and

c) guidelines for the substitution, estimation, and calculation of *energy data*, provided in clause 3.4 of this *Metrology Procedure*; and

d) good electricity and information technology industry practice.

3.13.4 The disaster recovery guidelines must be made available to *Code Participants* upon request.

4 Definitions

4.1.1 Within this procedure the following definitions apply:

a) AS – Australian Standard;

b) ISO – International Standards Organisation;

c) IEC – International Electrotechnical Commission.

4.1.2 Terms defined within the *Metering Code* have the same meaning in this *Metrology Procedure,* except as defined in the table below.

Phrase/term	Meaning
"access arrangement"	has the meaning given to it in the *Access Code*;
"Access Code"	means the *Code* made by the Minister under Part 8 of the *Act*.
"access contract"	means an agreement between a *Network Operator* and a person for the person to have 'access' (as defined in section 103 of the *Act*) to 'services' (as defined in section 103 of the *Act*) on a network.
"Account Manager"	Is the person appointed by the *Network Operator* under clause 3.12.1 as the main contact for *Code Participants.*
"accumulated energy data"	is to be expressed as a measure of *energy* over time, and means a measurement (including an estimated or substituted measurement) of the production or consumption of electricity at a *metering point*, which is accumulated for a period longer than a trading interval.
"accumulated energy register"	means the visible indication displayed on an *accumulation meter*, or the memory location within the *meter*, that records *accumulated energy data*.
"accumulation meter"	means a *meter* that measures *accumulated energy data* and records it in one or more *accumulated energy register*s.
"Act"	means the Electricity Industry Act 2004 (WA).
"active energy"	means a measure of electricity, being the time integral of the product of voltage and the in-phase component of electric current flow across a *metering point* expressed in Watt hours (Wh) and/or multiples thereof.
"apparent energy"	means a measure of electricity, being the time integral of the product of voltage and the electric current flow across a *metering point* expressed in Volt Amp hours (Vah) and or multiples thereof.
"applications and queuing policy"	means that part of the Western Power Access Arrangement defining the applications and queuing policy.
"AS"	followed by a designation means a standard so designated published by Standards Australia Limited and current as at the *Metering Code* commencement date.

Phrase/term	Meaning
"associate"	has the meaning given to it in the A*ccess Code*. {Note: At the time this *Code* was made, the definition in the *Access Code* was: " 'associate', in relation to a person and subject to section 13.2 [of the *Access Code*, which extends the meaning of 'associate' to include any other business of the service provider], has the meaning it would have under Division 2 of Part 1.2 of the Corporations *Act* 2001 of the Commonwealth if sections 13, 14, 16(2) and 17 of that *Act* were repealed, except that a person will not be considered to be an associate of a service provider solely because that person proposes to enter, or has entered, into a contract, arrangement or understanding with the service provider for the provision of a covered service." At the *Code* commencement date, the following are examples of persons who are associates of a body corporate under the Corporations *Act* 2001 (Cth): • a director or secretary of the body corporate; and • a related body corporate of the body corporate; and • another body corporate that can control or influence the composition of the board or the conduct of the affairs of a body corporate.}
"Attachment Point"	means a point on the *network* at which *network assets* are *connected* to assets owned by another person.
"Authority"	means the Economic Regulation *Authority* established under the Economic Regulation *Authority Act* 2003 (WA).
"average daily consumption"	for a *metering point* is to be expressed in energy units per day, and means a measurement (including an estimated or substituted measurement) of electricity production or consumption over a period at the *metering point*, divided by the number of days in the period.
"business day"	means any day that is not a Saturday, a Sunday or a public holiday throughout Western Australia.
"business hours"	means the hours from 08:00 to 17:00 on a *business day*.
"check meter"	means a *meter* used as the source of *energy data* for validation and substitution purposes but not routinely used as a source of billing data except where the revenue and check meters are of equal accuracy.
"checksum"	means a single digit numeric identifier that is calculated to reduce the frequency of NMI data entry errors.
"Code of Conduct"	means the Code made by the Minister under Schedule 3, section 1 of the *Act*.
"Code"	means the Electricity Industry *Metering Code* 2005.
"Communication Rules"	means the rules governing the file formats, protocols and timeframes for the communication of information and data between *Code* participants, which have been approved by the *Authority*
"communications link"	means all communications equipment, processes and arrangements which facilitate the collection of *energy data* from a *data logger* or a *measurement element* so as to enable a remote interface to be established that lie: a) if the *data logger* is internal to the device containing the *measurement elements* — between the *data logger* and the telecommunications network; and b) if the *data logger* is external to the device containing the *measurement elements* but is located at the same site — between the *meter* and the *data logger* and between *data logger* and the telecommunications network; and c) if the *data logger* is not located at the same site as the device containing the *measurement elements* — between the *meter* and the telecommunications network.
"connect"	means to form a physical link to or through a *network*.

Phrase/term	Meaning
"connection point"	means an *exit point* or an *entry point* identified or to be identified as such in an electricity transfer access contract.
"contact details"	means the notified electronic communication address, notified facsimile number, notified postal address and notified telephone number of a *Code Participant*.
"covered network"	has the meaning given to it under the *Access Code*; {Note: At the time this *Code* was made, the definition in the *Access Code* was: " "covered network" means a network that is covered."}
"current transformer", or "CT"	means a transformer for use with *meters* and protection devices in which the electric current in the secondary winding is, within prescribed error limits, proportional to and in phase with the electric current in the primary winding.
"current user"	means the *user* recorded as such in the *registry*;
"current"	in connection with the flow of electricity, means the flow of electricity in a conductor.
"Customer Transfer Code"	means the *Code* made by the Minister under Part 8 of the *Act*.
"customer"	has the meaning given in section 3 of the *Act*.
"data"	means *energy data* or *standing data*.
"data logger"	means a *metering installation* database, metering *database* or a device that collects electronic signals from a *measurement element* and records interval *energy data*. {Note: A *data logger* may contain data storage capability, it be a separate item of equipment and/or it be combined with the energy measuring components within one physical device or it may be a combination of the foregoing elements.}
"data logger overflow"	means the overwriting or replacement of *energy data* within a *data logger* before it has been transferred to the *metering database* resulting in the loss of that *energy data*.
"data stream"	means a stream of *energy data* or metering data associated with a *metering point*, as represented by an NMI and a NMI suffix. A NMI can have multiple data streams.
"day"	means unless otherwise specified, the 24 hour period beginning and ending at midnight Western Standard Time (WST).
"demand"	Is the power requirement in a period expressed in kW. E.g. if the consumption in a period is 1kWh and the period under consideration is half an hour long then the demand is 2kW.
"dispute"	means any dispute or difference arising in respect of any matter under or in connection with this *Code* between any *Code* participants, the subject of matter of which is not also an access dispute under the *Access Code*, a dispute under the *Market Rules*, a dispute or a complaint under the *Code* of Conduct (For the Supply of Electricity to Small Use Customers or a dispute under the Customer Transfer *Code*.
"distribution connection"	means a point at which electricity is transferred to or from the distribution system.
"distribution system"	has the meaning given to it in the *Act*.
"electric"	Of, relating to, producing, or operated by electricity.
"electricity networks corporation"	means the body corporate established under section 4 of the Electricity Corporation *Act* 1994.
"electricity"	has the meaning given to it in the *Act*.

Phrase/term	Meaning
"electronic":	in relation to connection with a *meter*, means the transfer of information into or out of the *meter* by way of a telecommunications network for the delivery of *energy data* or pulsing signals or other widely accepted communications protocols used for the transfer of data between computerised equipment.
"energy data services"	means the services related to the determination, processing or storage of *energy data*.
"energy data"	means *interval energy data* or *accumulated energy data*.
"energy"	means *active energy* and/or *reactive energy* or both as applicable.
"energy units"	means Wh, VAh or VARh as appropriate.
"enhanced technology"	In relation to a *metering installation*, means evolving technologies that provide the *metering installation* with advanced features over and above the standard specified for installations of type 1-6; for example, those features described in Division 3.4 of the *Metering Code*.
"entry point":	means a single, indivisible (except as allowed under the *applications and queuing policy*) point, that for purposes under the *access arrangement* involving the transfer of electricity, is deemed to consist of a single *attachment point*, *connected* or to be *connected* to a *user's connection point*, with a single *revenue meter* (regardless of the actual configuration of *network assets* making up the *entry point*), at which electricity is more likely to be transferred into the *network* than out of the *network*.
"estimate"	means an estimate calculation of *energy data* electricity production or consumption at a *metering point* for a period which is not yet scheduled to be read, such calculation being made in compliance with the schedules to this *Metrology Procedure*.
"estimated energy data"	means the data that results from an estimation of electricity where the data applies to a trading interval or a period in excess of a trading interval.
"exit point":	means a single, indivisible (except as allowed under the *applications and queuing policy*) point, that for purposes under the *access arrangement* involving the transfer of electricity, is deemed to consist of a single *attachment point*, *connected* or to be *connected* to a *user's connection point*, with a single *revenue meter* (regardless of the actual configuration of *network assets* making up the *entry point*), at which electricity is more likely to be transferred out of the *network* than into the *network*.
"General Purpose"	means the term applied by the National Measurement Institute constituted under Part 3 of the National Measurement *Act* to refer to the classification of a *meter*.
"generating plant"	in relation to a *connection point*, means all equipment involved in generating electricity.
"generator"	means a person who generates electricity and who holds a generation licence issued by the *Authority*.
"good electricity industry practice"	means the exercise of that degree of skill, diligence, prudence and foresight that a skilled and experienced person would reasonably and ordinarily exercise under comparable conditions and circumstances consistent with applicable written laws and statutory instruments and applicable recognised codes, standards and guidelines.
"historical energy data"	means *energy data* that relates to one or more previous *meter*-reading periods.
"IMO"	means the Independent Market Operator appointed under the *Market Rules* Part 9 of the *Act*.
"incoming Retailer"	has the same meaning as in the *Customer Transfer Code*.
"instrument transformer"	means either a *CT* or a *VT*.

Phrase/term	Meaning
"interval energy data"	is to be expressed in *energy units* or multiples thereof, and means a measurement (including an estimated or substituted measurement) of the production or consumption of electricity production or consumption at a *metering point* which is accumulated for each *trading interval*, or such sub-interval as has been previously agreed between the *Network Operator* and relevant *Code* Participant.
"interval meter"	means a *meter* that measures *interval energy data* and records it in a *data logger*.
"life support equipment"	has the meaning given to it in the *Code of Conduct* .
"load"	means the amount of electrical power energy transferred out of a network at a *connection point* at a specified time or across a specified period.
"maintain"	includes (as necessary and as applicable) renew, replace or update.
"Manager of Metering Services"	is the officer appointed by the *Network Operator* to carry overall responsibility for the provision of metering *services* for the *network*.
"market customer"	means a rule participant registered as a market customer under clauses 2.28.10, 2.28.11 or 2.28.13 under Chapter 2 of the *Market Rules*.
"market generator"	means a rule participant registered as a market generator under clauses 2.28.6, 2.28.7, 2.28.8 or 2.28.13 under Chapter 2 of the *Market Rules*.
"market rules"	has the meaning given to it in the *Act*.
"market"	means the wholesale electricity market established under Part 9 of the *Act*.
"measurement element"	means an energy measuring component of a *meter* which converts electricity into either or both of: a) an electronic signal; and b) a mechanically recorded electrical measurement.
"meter"	a device [complying with the relevant requirements of the AS 1284 series of standards] which measures and records the production or consumption of electrical energy, electricity production or consumption.
"metering data agent"	of a *Network Operator* for a network means the body appointed the *Network Operator*'s metering data agent for the network in accordance with the *Metering Code*.
"meter management plan"	means the document established under clause 2.7.4 detailing the testing and inspection requirements for whole current *meters*. At May 2006, this requirement is fulfilled by the Metering Services Metering Management Plan , as published from time to time by the *Network Operator*. The current meter management plan is provided as Appendix 3.
"meter reading period"	For past dates, is the period between the date of a *meter* reading and the date of the previous *meter* reading. For future dates, is the period between the scheduled date of a *meter* reading and the previous scheduled or actual *meter* read.
"metering database"	means a database containing the *registry* and *energy data*.
"metering equipment"	means one or more parts of a *metering installation*.

Phrase/term	Meaning
"metering installation"	means the equipment, processes and arrangements for the purpose of metrology which lie between: at one boundary, either: a) for *a connection point* of Type 1 to 6 — the *metering point*; or b) for a *connection point* of Type 7 — the *connection point*; and at the other boundary, either: a) if a telecommunications network is used for the delivery of *energy data* from the *connection point* or *metering point* — the point of connection to the telecommunications network; or b) if there is no such telecommunications network — the interface port of either the *meter* or *data logger* or both.
"metering point"	means c) for types 1-6, the point at which electricity is measured by a revenue *meter* d) for a type 7 *meter*, the connection point.
"metering protocol"	A document required under the WA Electricity Market Rules, Part 8.7. This Metrology Procedure document meets the requirements for the metering protocol and will act as the WA Electricity Market metering protocol.
"metering service order"	has the meaning given to it in the *Metering Code*.
"metering service"	means activities that are performed by or on behalf of the *Network Operator* or its metering *data agent* and are related to the provision of *metering installations*, *standing data* and *energy data*.
"metrology coordinator"	means the officer appointed by the *Network Operator* to assume responsibility for maintaining and enforcing the *Metrology Procedure.*
"Metrology Procedure"	means this document, the Western Australian Electricity Market Metrology Procedure for *Metering installations*.
"metropolitan area"	means: the region described in the Third Schedule to the Metropolitan Region Town Planning Scheme *Act* 1959; and a) the local government district of Mandurah; and b) the local government district of Murray. c) the areas constituted by: d) the townsite of Albany, in the local government district of City of Albany; and e) the townsite of Bunbury, in the local government district of City of Bunbury; and f) the townsite of Geraldton, in the local government district of City of Geraldton; and g) the townsites of Kalgoorlie and Boulder, in the local government district of City of Kalgoorlie-Boulder; and h) the townsite of Karratha, in the local government district of Shire of Ashburton; and i) the townsites of Port Hedland and South Hedland, in the local government district of Town of Port Hedland.

Phrase/term	Meaning
"model service level agreement"	in relation to a *Network Operator*'s network, means: a) if the network is a covered network with an *access arrangement*— the part or parts of the *access arrangement* which deal with metering as a "supplementary matter" under the *Access Code*; and b) otherwise — a *model service level agreement* approved by the *Authority* under the provisions of the *Metering Code*.
"National Measurement Act"	means the National Measurement *Act* 1960 (Cth) and any regulations made under that *Act*.
"National Metering Identifier", or "NMI"	means the reference number required by the *Metering Code*, which uniquely identifies a *connection point* and which is issued under the Western Australian NMI Allocation Procedures *{Note for WP internal use WP DMS reference # 2300622}.*
NEM12	means the file format established for the dissemination and transfer of *interval energy data* in the Australian National Electricity Market.
NEM13	means the file format established for the dissemination and transfer of basic *energy data* in the Australian National Electricity Market.
"Network Operator"	in relation to a network means a person who holds (a distribution licence, integrated regional licence or transmission licence issued by the *Authority*.
"network"	means the transmission system, distribution system or both, as applicable, operated by a *Network Operator*.
"operational data"	means *energy data* that is not obliged to have its accuracy and quality determined obtained via a system used to control and operate a network and the generating plant connected to a network.
"power factor"	means the ratio of the *active energy* to the *apparent energy* at a *metering point*.
"reactive energy"	means a measure in volt-ampère reactive hours (VARh) of the alternating exchange of stored energy in inductors and capacitors, which is the time-integral of the product of voltage and the out-of-phase component of electric current flow across a *metering point*.
"registered metering installation provider"	means a person registered by a *Network Operator* in accordance with the *registration process* to undertake some or all of the Activities relating to the installation of *metering installations*, and who has not been deregistered under the *registration process*.
"registration process"	means the approved *registration process* established by a *Network Operator* and approved by the *Authority* under the provisions of the *Metering Code*.
"registry"	means a registry containing standing data in accordance with the *Metering Code*.
"related body corporate"	in relation to a body corporate, means a body corporate that is related to the first mentioned body corporate under the Corporations *Act* 2001 of the Commonwealth.
"Responsible Person"	Means the person who has responsibility for the provision of a *metering installation* for a particular *connection point*.
"Retailer"	means a person who holds a retail licence or integrated regional licence issued by the *Authority*.
"revenue meter"	means the *meter* that is used for obtaining the primary source of *energy data*.
"rule participant"	means a member of the class of persons as set out in clause 2.28.1 of the *Market Rules*.
"SCADA"	means Supervisory Control and Data Acquisition.
"scheduled meter reading date"	means the date scheduled for the next scheduled *meter* reading.

Phrase/term	Meaning
"scheduled meter reading"	means a reading taken anytime between one working day ahead of, and two working days after, the *scheduled meter reading date*.
"service level agreement"	means a written agreement that sets out the terms and conditions under which a *Network Operator* must provide *metering services* to a *user*, whether or not that agreement also contains other provisions governing the parties' rights, liabilities and obligations.
"standing data"	means the periodically updated information about a *connection point* that is maintained in accordance with the *Metering Code* and the associated *Communication Rules*.
"substitute"	means the a substitution of *energy data* obtained, or scheduled to be obtained, from an actual *meter* reading with *energy data* determined in accordance with the data substitution procedures defined in clause 4.4 under the circumstances described in the *Metering Code*.
"supply"	means the delivery of electricity.
"testing class"	means a collection of *meter*s of the same physical type that are treated as a single class for testing purposes.
"trading interval"	means a 30 minute period ending on the hour (WST) or on the half hour and, where identified by a time, means the 30 minute period ending at that time.
"transfer"	in relation to a customer, has the meaning given to it in section 1.3 of the *Customer Transfer Code*.
"transformer"	means a plant or device that reduces or increases alternating voltage or electric current.
"transmission connection"	means a point at which electricity is transferred to or from the transmission system.
"transmission system"	has the meaning given to it in the *Act*.
"user"	[in respect of a *connection point*] means a person who has an *Access Contract* in respect of the *connection point* for the transfer of electricity [at the *connection point*].
"validation"	means validation in accordance with this *Metrology Procedure*.
"voltage"	means the electric force or electric potential between two points that gives rise to an electric current.
"voltage transformer" or "VT"	means a transformer for use with *meter*s and protection devices in which the voltage across the secondary terminals is, within prescribed error limits, proportional to and in phase with the voltage across the primary terminals.

5 Schedule 1 – Components of Types 1- 4 Metering Installations – Meter Provision

Ref.	Metering equipment components	Metering equipment characteristics	Requirement	Metering Code Clause or Table	Applicable Metering installation Type
5.1	Connection point	Metering Point	Electricity flowing through the *connection point* is to be greater than 1,000 GWh per annum.	Table 3	Type 1
5.2			Electricity flowing through the *connection point* is to be greater than 100 but less than 1,000 GWh per annum.	Table 3	Type 2
5.3			Electricity flowing through the *connection point* is to be greater than 0.75 but less than 100 GWh per annum.	Table 3	Type 3
5.4			Electricity flowing through the *connection point* is to be greater than 300 but less than 750 MWh per annum.	Table 3	Type 4
5.5		Metering installation	*Metering point* must have both a *revenue meter* and a *check meter*.	3.13(2) Table 1	Type 1
5.6			*Metering point* must have, a *revenue meter installation* and either a partial *check meter* or a *check meter*.	3.13(2), Table 1	Type 2
5.7			No *check meter* required.	3.13(2), Table 1	Type 3 - 6
5.8			The *metering point* is to be located as close as practicable to the *attachment point*.	3.5(4)	Type 1 - 6
5.9			The *meter* is to be mounted on an appropriately constructed panel.	3.5	Type 1 - 6
5.10		Overall accuracy	Overall accuracy for a *metering installation* shall be no greater than 0.5% for *Active energy* and 1.0% for *reactive energy*.	Table 3 & 4	Type 1
5.11			Overall accuracy for a *metering installation* shall be no greater than 1.0% for *Active energy* and 2.0% for *reactive energy*.	Table 3 & 5	Type 2
5.12			Overall accuracy for a *metering installation* shall be no greater than 1.5% for *Active energy* and 3.0% for *reactive energy*.	Table 3 & 6	Type 3
5.13			Overall accuracy for a *metering installation* shall be no greater than 1.5% for *Active energy*.	Table 3 & 7	Type 4

5.14			High voltage *connection points* with an annual consumption of less than 750 MWh per annum must meet the accuracy requirements for a type 3 *metering installation*		Type 4
5.15		Testing facilities	Suitable isolation facilities are to be provided to facilitate testing and calibration of the *metering installation*.	3.12(3)	Type 1 - 6
5 .16		Check metering	A separate check meter is required. Check meter must not exceed twice the error level permitted under clause 3.9 of the *Metering Code* for the revenue meter for the *metering point.*	3.9(4)(a), 3.12(2), Table 1	Type 1 - 2
5.17			*Check metering* shall use separate current transformer cores and separately fused voltage transformer secondary circuits preferably from separate secondary windings	3.13(2) Table 1	Type 1
5.18			*Check metering* may be supplied from secondary circuits used for other purposes.	3.13(4)(a)	Type 2
5.19			Where the *check metering* duplicates the *revenue metering* and accuracy level, the average of the two validated data sets will be used to determine the energy measurement.	3.13(5)	Type 1 - 2
5.20	Instrument Transformers				
5.21		Current transformer	The accuracy of the current transformer is to be in accordance with class 0.2.	Table 3	Type 1
5.22			The accuracy of the current transformer is to be in accordance with class 0.5.	Table 3	Type 1 - 5
5.23			The current transformer core and secondary wiring associated with the *revenue meter* may not be used for other purposes.	3.12(1)(b)	Type 1 - 5
5.24			New current transformers must meet the relevant requirements of AS 60044.1 and must also comply with any applicable specifications or guidelines (including any transitional arrangements) specified by the National Measurement Institute under the National Measurement *Act*.	3.12(2)	Type 1 - 5
5.25			Current transformers in service at the *Code* commencement date that do not comply with the accuracy requirements are acceptable providing the overall accuracy of the installation meets *Code* requirements for the applicable type *metering installation*.	3.14(3) Table 3	Type 1 - 5
5.26		Voltage transformer	The accuracy of the voltage transformer is to be in accordance with class 0.2.	Table 3	Type 1
			The accuracy of the voltage transformer is to be in accordance with class 0.5.	Table 3	Type 2 -3
5.27			If separate secondary windings are not provided, then the voltage supply to each *metering installation* must be separately fused and located in an accessible position as near as practical to the voltage transformer secondary winding.	3.12(1)(d)	Type 1 - 3

5.28			New voltage transformers must meet the relevant requirements of AS 60044.2 and must also comply with any applicable specifications or guidelines (including any transitional arrangements) specified by the National Measurement Institute under the National Measurements *Act*.	3.12(2)	Type 1 - 3
5.29			Voltage transformers in service at the *Code* commencement date that do not comply with the accuracy requirements are acceptable providing the overall accuracy of the installation meets *Code* requirements for the applicable type *metering installation*.	3.14(3)	Type 1 - 3
5.30			Secondary wiring must be by the most direct route and the number of terminations and links must be kept to a minimum.	3.12(1)(f)	Type 1 - 3
5.31			• 2.5 mm² cable is required for current transformer secondary wiring. • 1.5 mm² cable is required for voltage transformer secondary wiring		Type 1 - 5
5.32			The incidence and magnitude of burden changes on any secondary winding supplying the *metering installation* must be kept to a minimum.	3.9(3)	
5.33		Performance	Metering data is required for all trading intervals within the time agreed with the relevant *Retailer*s at a level of availability of at least 99% per annum for instrument transformers	3.11(1)(a)	
5.34		Outages	If an outage or malfunction occurs to an instrument transformer, repairs must be made as soon as practicable, and in any event within the period specified within the relevant *service level agreement*.	3.11(2)	
5.35	Measurement element				
5.36		Design standard	*Meter*s must meet the relevant requirements of AS1284 and must also comply with any applicable specifications or guidelines (including any transitional arrangements) specified by the National Measurement Institute under the National Measurement *Act*.	3.1	Type 1 - 6
5.37		Design Standard	*If Meter*ing *Class* VT's and CT's are in-service at the *Code* commencement date whose accuracy does not meet *Code* requirements then the network operator must either, or both, install meters of a higher class of accuracy and apply accuracy calibration factors within the meter to compensate for the transformer errors.	3.14	Type 1 - 4
5.38			*Meter*s must be capable of separately registering and recording flows in each direction where bi-directional *Active energy* flows.	3.16(1)(b)	
5.39		Accuracy	The accuracy of the Active and reactive measurement elements is to be class 0.2 and class 0.5 respectively.	Table 3	Type 1
5.40			The accuracy of the Active and reactive measurement elements is to be class 0.5 and class 1.0 respectively.	Table 3	Type 2

5.41			The accuracy of the Active and reactive measurement elements is to be class 1.0 and class 2.0 respectively.	Table 3	Type 3
5.42			The accuracy of the Active element is to be class 1.0	Table 3	Type 4 - 5
5.43		Visible display	To be provided on a device and to display as a minimum the accumulated total *Active energy* measured by that *metering installation*.	3.2(1)	
5.44		Location	The *metering point* is located as close as practicable to the attachment point.	3.5(4)	
5.45		Security	The measurement element must be secure and associated links, circuits and information storage and processing systems must be secured by means of seals or other devices approved by the *Network Operator*.	3.8	
5.46		Storage	The measuring device must store active and, if required, reactive *energy data* in a data logger. The data logger can be external or internal to the measuring element.	3.5(2)Table 3	Type 1 - 3
5.47			The measuring device must store *Active energy data*. The data logger can be external or internal to the measuring element.		Type 4 - 5
5.48		Access to data	Access to the visible display is to be provided without unreasonable restriction.	3.2(1)	
5.49			Access to the electronic signal from the measurement element is secured. Relays or electronic buffers to prevent accidental or malicious damage to the *meter* must isolate interfaces to customer equipment.	3.23	
5.50			Access to the electronic signal for use in evolving technologies is to be discussed with the *Network Operator*.	3.20	
5.51			Alteration to the original stored data in a *meter* is not permitted except during on-site accuracy testing.	5.21(12)	
5.52		Outages	If an outage or malfunction occurs to a measurement element or associated secondary wiring, repairs must be made as soon as practicable, and in any event within the period specified within the relevant *service level agreement*..	3.11	
5.53	Data logger				
5.54		Design standard	Any programmable settings available within a *metering installation*, data logger or any peripheral device, which may affect the resolution of displayed or stored data, must meet the relevant requirements of AS 1284 and must comply with any applicable specifications or guidelines (including any transitional arrangements) specified by the National Measurement Institute under the National Measurement *Act*.	3.10	
5.55		Location	The data logger may be located within the same housing as the measurement element or in a separate housing.	1.3	

5.56			The data logger may be located at the same site as the measuring element or at a remote site.	1.3	
5.57		Security	The data logger is to be secure and associated links, circuits and information storage and processing systems are to be secured by means of seals or other devices approved by the *Network Operator*.	3.8	
5.58		Processing of data	Data relating to the amount of Active and reactive *energy* passing through a connection point must be collated into trading intervals.	3.16(3)	
5.59		Time function	The data logger clock is to be referenced to Western Australian Standard Time and maintained to a standard of : Type 1. ±5 seconds, Type 2. ±7 seconds, Type 3 ±10 seconds, Types 4 – 5 ± 20 seconds.	Table 3	Type 1 - 5
5.60		Storage	The data logger is to have the capability of storing energy data for a period of at least 35 days.	3.16(1)(c), 3.21(2)	Type 1 - 5
5.61			A *Network Operator* must retain *energy data* in its *metering database* for each *metering point* on its *network* for the periods specified in clause 4.9 of the *Metering Code.*	4.9	Type 1 - 6
5.62		Access to data	Alteration to the original stored data in a data logger is not permitted except during on-site accuracy testing.	5.21(12)	
5.63		Performance	Energy data is required for all trading intervals a level of availability of at least 99% per annum from the data logger.	3.11(1)(a)	
5.64		Outages	If an outage or malfunction occurs to a data logger, repairs must be made as soon as practicable, and in any event within the period specified within the relevant *service level agreement*..	3.11(2)	
5.65	Communication link	Location	The electronic connection between the data logger and the telecommunications network boundary is classified as a communications link.	1.3	
5.66		Equipment	A communications link may consist of a metallic cable connecting to the telecommunications network and require isolation equipment, modem and associated connections	3.3(3)	
5.67			A communications link may include a radio, communications system, a microwave communications system or a satellite communications system or a combination of systems	3.3(3)	
5.68			A communications link may include a metering database.	3.3(3)	
5.69		Modem	Used to connect the *metering installation* to the telecommunications network at a data logger or metering database.		
5.70		Security	The communication link is to be secure and associated links, circuits and information storage and processing systems are to be secured by means of seals or other devices approved by the *Network Operator*.	3.8	

5.71		Access to data	The *metering installation* must be capable of remote electronic access	3.6	Type 1 - 4
5.72			The *metering installation* must be capable of local electronic access	4.8	Type 5
5.73			To be provided on a device and to display as a minimum the accumulated total *Active energy* measured by that *metering installation*.	3.2	Type 1 - 6
5.74			The data held in the *metering installation* is to be protected from direct or remote electronic access by suitable password and security controls.	4.8(3), 4.8(4)(a)	Type 1 - 6
5.75		Performance	*Energy data* is required for all *trading intervals* at a level of availability of at least 95% per annum from the communications link.	3.11(1)(b)	Type 1 - 5
5.76		Outages	If an outage or malfunction occurs to a communications link, repairs must be made as soon as practicable in accordance the applicable service level agreement.	3.11(2)	Type 1 – 6
5.77	Testing and inspection				
5.78		Purchase of metering equipment	At present National Measurements Institute regulations exempts Utility Meters from the National Measurements Act. Whilst the exemption is in place • All new purchased current transformers must comply with Australian Standard AS60044.1 • All new voltage transformers must comply with Australian Standard AS60044.2; and • All new *meter*s must comply with Australian Standard 1284. • All new *meters* must comply with the relevant specifications of the National Measurements Institute's M6. When the exemption is extinguished the National Measurements Act will apply.	3.1	Type 1 - 6
5.79			Appropriate test certificates are to be kept by the equipment owner.	4.3	
5.80		Testing of metering equipment	The metering equipment purchased must be tested to the following class accuracy and with less than the following uncertainties: • Class 0.2 CT & VT 0.05%, 0.05Crad • Class 0.2 Wh *meter* 0.05/cosϕ% • Class 0.5 varh *meter* 0.2/sinϕ%	Table 3,	Type 1
5.81			The uncertainties associated with testing of the components of the *metering installation* may be carried out as follows: • CT/VT in laboratory 0.05%, 0.05Crad		Type 1

			• *Meter* Wh in laboratory 0.05/cosϕ% • *Meter* Wh in field 0.1/cosϕ% • *Meter* varh in laboratory 0.2/sinϕ% • *Meter* varh in field 0.3/sinϕ%		
5.82			The maximum periods between sample testing are to be: • CT & VT 10 years • Burden tests When changes are made • *Meters* 2 years		Type 1
5.83			Overall accuracy at unity power factor Energy Rated Load 10% 50% 100% Active 0.7% 0.5% 0.5% Overall accuracy at 0.866 lagging power factor Energy Rated Load 10% 50% 100% Active 0.7% 0.5% 0.5% reactive 1.4% 1.0% 1.0% Overall accuracy 0.5 lagging power factor Energy Rated Load 10% 50% 100% Active n/a 0.5% n/a reactive n/a 1.0% n/a Overall accuracy zero power factor Energy Rated Load	Table 4	Type 1

			10% 50% 100% reactive 1.4% 1.0% 1.0% The above measurements are referenced to 25ºC Method of calculating the overall error is the vector sum of the errors of each component parts, that is, a + b + c, where: • a = the error of voltage transformer and wiring; • b = the error of the current transformer and wiring • c = the error of the *meter*. *energy data* for type 1 *metering installations* is usually based on watthour (*Active energy*). Where reactive *energy* is required the *metering installation* must also satisfy the requirements for varhour in this *Metrology Procedure*.		
5.84			The metering equipment purchased must be tested to the following class accuracy and with less that the following uncertainties: Class 0.5 CT & VT 0.1%, 0.1% Crad Class 0.5 Wh *meter* 0.1/cosΦ % Class 1.0 varh *meter* 0.3/sinΦ %	Table 3	Type 2
5.85			The uncertainties associated with testing of the components of the *metering installation* may be carried out as follows: • CT/VT in laboratory 0.1%, 0.1 Crad • *Meter* Wh in laboratory 0.1/cosΦ % • *Meter* Wh in field 0.2/cosΦ % • *Meter* varh in laboratory +0.3/sinΦ % • *Meter* Wh in field +0.4/sinΦ %		Type 2
5.86			The maximum periods between sample testing are to be: CT & VT 10 years		Type 2

			Burden tests When changes are made *meters* 4 years		
5.87			Overall accuracy at unity power factor Energy Rated Load 10% 50% 100% Active 1.4% 1.0% 1.0% Overall accuracy at 0.866 lagging power factor Energy Rated Load 10% 50% 100% Active 1.4% 1.0% 1.0% reactive 2.8% 2.0% 2.0% Overall accuracy 0.5 lagging power factor Energy Rated Load 10% 50% 100% Active n/a 1.0% n/a reactive n/a 2.0% n/a Overall accuracy zero power factor Energy Rated Load 10% 50% 100% reactive 2.8% 2.0% 2.0%	Table 5	Type 2

			The above measurements are referenced to 25ºC Method of calculating the overall error is the vector sum of the errors of each component parts, that is, a + b + c, where: • a = the error of voltage transformer and wiring; • b = the error of the current transformer and wiring • c = the error of the *meter*.		
5.88			The metering equipment purchased must be tested to the following class accuracy and with less that the following uncertainties: • Class 0.5 CT & VT 0.1% .01 Crad • Class 1.0 Wh *meter* 0.2/cosΦ % • Class 2.0 varh *meter* 0.4/sinΦ % • General Purpose *meter* 0.3/cosΦ %	Table 3	Type 3
5.89			The uncertainties associated with testing of the components of the *metering installation* may be carried out as follows: • CT/VT in laboratory ±0.1% • *Meter* Wh in laboratory +0.2/cosΦ % • *Meter* Wh in field +0.3/cosΦ % • *Meter* varh in laboratory +0.4/sinΦ % • *Meter* Wh in field +0.5/sinΦ %		Type 3
5.90			The maximum periods between sample testing are to be: • CT & VT 10 years • Burden tests when changes are made • *Meter* s 5 years		Type 3
5.91			Overall accuracy at unity power factor	Table 6	Type 3

			Energy Rated Load 10% 50% 100% Active 2.0% 1.5% 1.5% Overall accuracy at 0.866 lagging power factor Energy Rated Load 10% 50% 100% Active 2.0% 1.5% 1.5% reactive 4.0% 3.0% 3.0% Overall accuracy 0.5 lagging power factor Energy Rated Load 10% 50% 100% Active n/a 1.5% n/a reactive n/a 3.0% n/a Overall accuracy zero power factor Energy Rated Load 10% 50% 100% reactive 4.0% 3.0% 3.0% The above measurements are referenced to 25ºC Method of calculating the overall error is the vector sum of the errors of each component part, that is, A+B+C, where:		

			• A = the error of voltage transformer and wiring; • B = the error of the current transformer and wiring • C = the error of the *meter*		
5.92			The metering equipment purchased must be tested to the following class accuracy and with less that the following uncertainties: • Class 0.5 CT 0.1%, 0.5 Crad • Class 1.0 Wh *meter* 0.2/cosΦ % • General Purpose *meter* 0.3/cosΦ %	Table 3	Type 4
5.93			The uncertainties associated with testing of the components of the *metering installation* may be carried out as follows: • CT in laboratory 0.1% • CT in field 0.2% • *Meter* Wh in laboratory 0.2/cosΦ % • *Meter* Wh in field 0.3/cosΦ %	Table 3	Type 4
5.94			The maximum periods between sample tests are to be: • CT & VT 10 years • Burden tests When changes are made • *Meter* s 5 years • Whole current (direct connected) General Purpose *meter* 7 years		Type 4
5.95			Overall accuracy at unity power factor Energy Rated Load 10% 50% 100% *Act*ive 2.0% 1.5% 1.5% Overall accuracy 0.866 lagging power factor Energy Rated Load 10% 50% 100%	Table 7	Type 4 - 6

			Active 2.0% 1.5% 1.5% Overall accuracy 0.5 lagging power factor Energy Rated Load 10% 50% 100% Active 1.5% 1.5% n/a The above measurements are referenced to 25ºC Method of calculating the overall error is the vector sum of the errors of each component part, that is, A+B+C, where: • A = the error of voltage transformer and wiring; • B = the error of the current transformer and wiring • C = the error of the *meter*		
5.96			Testing of the components of the *metering installation* will be conducted in accordance with the *meter management plan*.		
5.97			Where practicable, current transformer and voltage transformer tests are primary injection tests or other testing procedures.		
5.98			Other affected parties may witness the tests on request.		
5.99			The test results must be provided as soon as practicable to the requesting *Code* participant.		
5.100			All reference/calibrated equipment shall be tested to ensure full traceability to Australian national measurement standards through verifying authorities or directly referenced to the National Measurement Laboratory.		
5.101			The calculations of accuracy based on test results, are to include all reference standard errors.		
5.102			An “estimate of testing uncertainties” must be calculated in accordance with the ISO “Guide to the Expression of Uncertainty for Measurement”.		
5.103	Inspections of metering equipment		The testing and inspection requirements must be by the *meter management plan*.		Type 1 - 6
5.104			A typical inspection must include: check the seals; compare the pulse counts; compare the direct readings of *meter*s, verify *meter* para*meter*s and physical connections, verify current transformer ratios by comparison.		
5.105		Actions in event	If the accuracy of the *metering installation* does not comply with the requirements of the		

		of non-compliance	*Code*, the *Authority* and affected *Retailer* must be advised as soon as practicable of the errors detected and the possible duration of the existence of errors, and arrange for the accuracy of the *metering installation* to be restored in a time frame agreed with the *Authority*.		
5.106			If a test or audit of the *metering installation* demonstrates an error of measurement of less than those detailed in the *meter management plan* (Table 1.), no substitution of readings is required unless in the Network Operator's opinion a particular party would be significantly affected if no substitution was made.		
5.107			If a *metering installation* test, inspection or audit demonstrates errors in excess of those prescribed, meter accounts shall be determined in accordance with Section 65 of the Energy Operators (powers) Act 1979. *{Note – the referenced act specifies that where the time at which those errors arose is not known, the error is deemed to have occurred at a time half way between the time of the most recent test or inspection which demonstrated that the metering installation, or the meter family to which the meter of the meter installation belongs, complied with the relevant accuracy requirement and the time when the error was detected.}*		
5.108	Management, maintenance and auditing				
5.109		Installation and maintenance	The *Network Operator* must ensure that any metering equipment that they install is suitable for the range of operating conditions to which it will be exposed (e.g. temperature; impulse levels), and operates within the defined limits for that equipment.	3.5(3)(c)(1)	
5.110		Supporting information	Suitable drawings and supporting information, including drawings, if applicable, detailing the *metering installation*, must be available for maintenance and auditing purposes. This information shall be stored in an appropriate depository managed by the *Network Operator*.	3.12(4)	
5.111		Security controls	Provide and maintain the security controls of a *metering installation*.	3.8	
5.112			The energy data held in the *metering installation* is to be protected from direct local or remote electronic access by suitable password and security controls.	4.8(4)(a)	
5.113			The *Network Operator* must keep records of electronic access passwords secure.	4.8(5)(b)	
5.114			Energy data and passwords are confidential data and are to be treated as confidential information.	7.4(1)	
5.115			A *Registered Metering Installation Provider* must be accredited by and registered with *Network Operator* under a registration scheme approved by the *Authority*, and only for the type of work the *Registered Metering Installation Provider* is qualified to provide.	6.9	

5.116			Where relevant, *Registered Metering Installation Providers*, who wish to apply for categories of *Registered Metering Installation Provider* accreditation of *metering installations*, must be able to exhibit, to the reasonable satisfaction of the *Network Operator* the relevant capabilities.	6.9	

6 Schedule 2 – Components of a Type 5 Metering Installation – Meter Provision

Ref.	Metering equipment components	Metering equipment characteristics	Requirement	Metering Code Clause or Table	Applicable Metering installation Type
6.1	Connection point	Metering Point	Electricity flowing through the connection point is to be greater than 50 but less than 300 MWh per annum.	Table 3	Type 5
6.2		Metering installation	No *check metering* required.	Table 1	Type 3 - 6
6.3			The *metering point* is to be located as close as practicable to the *attachment point*.	3.5(4)	Type 1 - 6
6.4			The *meter* is to be mounted on an appropriately constructed panel.	3.5	
6.5		Overall accuracy	Overall accuracy for a *metering installation* shall be no greater than 1.5% for *Active energy*.	Table 3 & 7	Type 4 - 6
6.6		Testing facilities	Suitable isolation facilities are to be provided to facilitate testing and calibration of the *metering installation*.	3.12(3)	Type 1 - 6
6.7	Instrument Transformers				
6.8		Current transformer	The accuracy of the current transformer is to be in accordance with class 0.5.	Table 3	Type 2 - 5
6.9			The current transformer core and secondary wiring associated with the revenue *meter* may not be used for other purposes.	3.12(1)(b)	Type 1 - 5
6.10			New current transformers must meet the relevant requirements of AS 60044.1 and must also comply with any applicable specifications or guidelines (including any transitional arrangements) specified by the National Measurement Institute under the National Measurement *Act*.	3.12(2)	Type 1 - 5
6.11			Current transformers in service at the *Code* commencement date that do not comply with the accuracy requirements are acceptable providing the overall accuracy of the installation meets *Code* requirements for the applicable type *metering installation*.	3.14(3)	Type 1 - 5
6.12		Secondary wiring	Separate secondary windings should be provided for each *metering installation*.		Type 1 - 5
6.13			Secondary wiring must be by the most direct route and the number of terminations and links must be kept to a minimum.	3.12(1)(f)	Type 1 - 5

6.14			• 2.5 mm² cable is required for current transformer secondary wiring. • 1.5 mm² cable is required for voltage transformer secondary wiring		Type 1 - 5
6.15			The incidence and magnitude of burden changes on any secondary winding supplying the *metering installation* must be kept to a minimum.	3.9(3)	
6.16		Performance	Energy data is required for all trading intervals within the time agreed with the relevant *Retailer*s at a level of availability of at least 99% per annum for instrument transformers	3.11(1)(a)	
6.17		Outages	If an outage or malfunction occurs to an instrument transformer, repairs must be made as soon as practicable, and in any event within the period specified within the relevant *service level agreement*.	4.7(2)	
6.18	Measurement element				
6.19		Design standard	*Meter*s must meet the relevant requirements of AS1284 and must also comply with any applicable specifications or guidelines (including any transitional arrangements) specified by the National Measurement Institute under the National Measurement *Act*.	3.1	
6.20		Design Standard	- If *metering* Class CT's are in-service at the Code commencement date whose accuracy does not meet Code requirements then the network operator must either, or both, install meters of a higher class of accuracy and apply accuracy calibration factors within the meter to compensate for the transformer errors. - For whole current installations *meters* that are in-service at the Code commencement date whose accuracy does not meet Code requirements then the network operator must replace the meters	3.14	Type 5
6.21			*Meter*s must be capable of separately registering and recording flows in each direction where bi-directional *Active energy* flows.	3.16(1)(b)	
6.22		Accuracy	The accuracy of the Active element is to be class 1.0 for CT installation or general purpose	Table 3	Type 5
6.23		Visible display	To be provided on a device and to display as a minimum the accumulated total *Active energy* measured by that *metering installation*.	3.2(1)	
6.24		Location	The revenue *metering point* is located as close as practicable to the *connection point*.	3.5(4)	
6.25		Security	The measurement element must be secure and associated links, circuits and information storage and processing systems must be secured by means of seals or other devices approved by the *Network Operator*.	3.8	
6.26		Storage	The measuring device must store Active *energy data* in a data logger. The data logger can be external or internal to the measuring element.	3.5(2)	Type 4 - 5

6.27		Access to data	Access to the visible display is to be provided without unreasonable restriction.	3.2(1)	
6.28			Access to the electronic signal from the measurement element is secured. Relays or electronic buffers to prevent accidental or malicious damage to the *meter* must isolate interfaces to customer equipment.	3.23	
6.29			Access to the electronic signal for use in evolving technologies is to be discussed with the *Network Operator*.	3.4	
6.30			Alteration to the original stored data in a *meter* is not permitted except during on-site accuracy testing.	5.21(12)	
6.31		Outages	If an outage or malfunction occurs to a measurement element or associated secondary wiring, repairs must be made as soon as practicable, and in any event within the period specified within the relevant *service level agreement*.	3.11	
6.32	Data logger				
6.33		Input connection	The data logger is to be electrically connected to the measurement element by secure means.		
6.34		Design standard	Any programmable settings available within a *metering installation*, data logger or any peripheral device, which may affect the resolution of displayed or stored data, must meet the relevant requirements of AS 1284 and must comply with any applicable specifications or guidelines (including any transitional arrangements) specified by the National Measurement Institute under the National Measurement *Act*.	3.10	
6.35		Location	The data logger may be located within the same housing as the measurement element or in a separate housing.	1.3	
6.36			The *data logger* may be located at the same site as the measuring element or at a remote site.	1.3	
6.37		Security	The data logger is to be secure and associated links, circuits and information storage and processing systems are to be secured by means of seals or other devices approved by the *Network Operator*.	3.8	
6.38		Processing of data	Data relating to the amount of Active passing through a connection point must be collated into trading intervals.	3.16(3)	
6.39		Time function	The *data logger* clock is to be referenced to Western Australian Standard Time .	3.21(1) Table 3	Type 1 - 5
6.40		Storage	The *data logger* is to have the capability of storing *energy data* for a period of at least 35 days.	3.16(1)(c), 3.21(2)	Type 1 - 5
6.41			A *metering database* will be required to store *energy data* for a period of at least 35 days if it is to be used as a remote *data logger*.	4.9	

6.42		Access to data	Alteration to the original stored data in a *data logger* is not permitted except during on-site accuracy testing.	5.21(12)	
6.43		Performance	*Energy data* is required for all *trading intervals* a level of availability of at least 99% per annum from the *data logger*.	3.11(1)(a)	
6.44		Outages	If an outage or malfunction occurs to a *data logger*, repairs must be made as soon as practicable, and in any event within the period specified within the relevant *service level agreement*.	3.11(2)	
6.45	Communication link	Location	The electronic connection between the *data logger* and the telecommunications network boundary is classified as a communications link.	1.3	
6.46		Equipment	A communications link will consist of appropriate isolation equipment, modem and associated connections required to communicate with the telecommunications network.	3.3(3)	
6.47			A communications link may include a *metering database*.	3.3(3)	
6.48		Modem	Used to connect the *metering installation* to the telecommunications network at a data logger or metering database.		
6.49		Security	The communication link is to be secure and associated links, circuits and information storage and processing systems are to be secured by means of seals or other devices approved by the *Network Operator*.	3.8	
6.50		Access to data	The *metering installation* must be capable of local electronic access	4.18	Type 5
6.51			The data held in the *metering installation* is to be protected from direct or remote electronic access by suitable password and security controls.	4.8(3) and 4.8(4)(a)	Type 1 - 5
6.52		Performance	Energy data is required for all trading intervals at a level of availability of at least 95% per annum from the communications link.	3.11(1)(b)	Type 1 - 5
6.53		Outages	If an outage or malfunction occurs to a communications link, repairs must be made as soon as practicable in accordance the applicable service level agreement.	3.11(2)	Type 1 – 6
6.54	Testing and inspection				
6.55		Purchase of metering equipment	At present National Measurements Institute regulations exempts Utility *Meter*s from the National Measurements *Act*. Whilst the exemption is in place • All new purchased current transformers must comply with Australian Standard AS60044.1 • All new voltage transformers must comply with Australian Standard AS60044.2; and • All new *meter*s must comply with Australian Standard 1284.	3.1	Type 1 - 6

			• All new *meters* must comply with the relevant specifications of the National Measurements Institute's M6. When the exemption is extinguished the National Measurements *Act* will apply.		
6.56			Appropriate test certificates are to be kept by the equipment owner.	4.3	
6.57			The CT's purchased must be tested to the required class accuracy with less than ± 0.1 % uncertainty. The testing of the CT's in the *metering installation* is carried out as follows: • Maximum allowable level of testing uncertainty in the laboratory 0.1 %., 0.1 Crad • Maximum period between tests – 10 years.	Table 3	Type 5
6.58			The CT connected *meter*s purchased must be tested to the required class accuracy with less than $0.2/\cos\phi$% uncertainty.		Type 5
6.59			The uncertainty associated with testing of the CT connected *meter*s in the *metering installation* is carried out as follows: • Maximum allowable level of testing uncertainty in the laboratory $0.3/\cos\phi$% • Maximum allowable level of testing uncertainty in the field $0.3/\cos\phi$%. • Maximum period between tests – 5 years.		Type 5
6.60			The direct connected *meter*s purchased must be tested to the required class accuracy with less than $0.3/\cos\phi$% uncertainty.		Type 5
6.61			The uncertainty associated with testing of the whole current connected *meter*s in the *metering installation* is carried out as follows: • Maximum allowable level of testing uncertainty in the laboratory $0.3/\cos\phi$% • Maximum allowable level of testing uncertainty in the field $0.3/\cos\phi$%. • Maximum period between tests – 7 years.		
6.62			The accuracy of the measurement element is to be in accordance with class 1.5 for General Purpose watthour *meter*s as per AS1284 or in accordance with class 1.0 as per AS1284 or IEC1036 standards.		
6.63			Where practicable, current transformer and voltage transformer tests are primary injection tests or other testing procedures.		
6.64			Other affected parties may witness the tests on request.		
6.65			The test results must be provided as soon as practicable to the requesting *Code*		

			participant.		
6.66			All reference/calibrated equipment shall be tested to ensure full traceability to Australian national measurement standards through verifying authorities or directly referenced to the National Measurement Laboratory.		
6.67			The calculations of accuracy based on test results, are to include all reference standard errors.		
6.68			An “estimate of testing uncertainties” must be calculated in accordance with the ISO “Guide to the Expression of Uncertainty for Measurement”.		
6.69	Inspections of metering equipment		The testing and inspection requirements must be by the *meter management plan*.		Type 1 - 6
6.70			A typical inspection must include: check the seals; compare the pulse counts; compare the direct readings of *meter*s, verify *meter* para*meter*s and physical connections, verify current transformer ratios by comparison.		
6.71		Actions in event of non-compliance	If the accuracy of the *metering installation* does not comply with the requirements of the *Code*, the *Authority* must be advised as soon as practicable of the errors detected and the possible duration of the existence of errors, and arrange for the accuracy of the *metering installation* to be restored in a time frame agreed with the *Authority*.		
6.72			If a test or audit of the *metering installation* demonstrates an error of measurement of less than those detailed in the *meter management plan* (Table 1.), no substitution of readings is required unless in *Network Operator’s* reasonable opinion a particular party would be significantly affected if no substitution was made.		
6.73			If a *metering installation* test, inspection or audit demonstrates errors in excess of those prescribed and the time at which those errors arose is not known, the error is deemed to have occurred at a time half way between the time of the most recent test or inspection which demonstrated that the *metering installation*, or the *meter* family to which the *meter* of the *meter* installation belongs, complied with the relevant accuracy requirement and the time when the error was detected.		
6.74	Management, maintenance and auditing		The testing and inspection requirements must be by an *meter management plan*.		Type 1 - 6
6.75		Installation and maintenance	The *Network Operator* must ensure that any metering equipment that they install is suitable for the range of operating conditions to which it will be exposed (e.g. temperature; impulse levels), and operates within the defined limits for that equipment.	3.5(3)(c)(1)	
6.76		Supporting information	Suitable drawings and Supporting information, including drawings, if applicable, detailing the *metering installation*, must be available for maintenance and auditing purposes. This	3.12(4)	

			information shall be stored in an appropriate depository managed by the *Network Operator*.		
6.77		Security controls	Provide and maintain the security controls of a *metering installation*.	3.8	
6.78			The energy data held in the *metering installation* is to be protected from direct local or remote electronic access by suitable password and security controls.	4.8(4)(a)	
6.79			The *Network Operator* must keep records of electronic access passwords secure.	4.8(5)(b)	
6.80			Energy data and passwords are confidential data and are to be treated as confidential information.	7.4(1)	
6.81			A *Registered Metering Installation Provider* must be accredited by and registered with *Network Operator*, and only for the type of work the *Registered Metering Installation Provider* is qualified to provide.	6.9	
6.82			*Registered Metering Installation Providers*, who wish to apply for categories of *Registered Metering Installation Provider* accreditation of *metering installations*, must be able to exhibit, to the reasonable satisfaction of the *Network Operator* the relevant capabilities.	6.9	

7 Schedule 3 – Components of a Type 6 Metering Installation – Meter Provision

Ref.	Metering equipment components	Metering equipment characteristics	Requirement	Metering Code Clause or Table	Applicable Metering installation Type
7.1	Connection point	Metering Point	Electricity flowing through the connection point is to be less than 50 MWh per annum.	Table 3	Type 6
7.2		Metering installation	No *check metering* required	Table 1	Type 3 - 6
7.3			The *metering point* is to be located as close as practicable to the *attachment point*.	3.5(4)	Type 1 - 6
7.4			The *meter* is to be mounted on an appropriately constructed panel	3.5	
7.5		Overall accuracy	Overall accuracy for a *metering installation* shall be no greater than 1.5% for *Active energy*	Table 3 & 7	Type 4 - 6
7.6		Testing facilities	Suitable isolation facilities are to be provided to facilitate testing and calibration of the *metering installation*.	3.12(3)	Type 1 - 6
7.7	Measurement element				
7.8		Design standard	*Meter*s must meet the relevant requirements of AS1284 and must also comply with any applicable specifications or guidelines (including any transitional arrangements) specified by the National Measurement Institute under the National Measurement *Act*.	3.1	
7.9		Design Standard	For *meters* that are in-service at the Code commencement date whose accuracy does not meet Code requirements the network operator must replace the meters	3.14	
7.10		Accuracy	The accuracy of the *meter* class is to be general purpose	Table 3	Type 6
711		Visible display	To be provided on a device and to display as a minimum the accumulated total *Active energy* measured by that *metering installation*.	3.2(1)	
7.12		Location	The revenue *metering point* is located as close as practicable to the *attachment point*.	3.5(4)	
7.13		Security	The measurement element must be secure and associated links, circuits and information storage and processing systems must be secured by means of seals or other devices approved by the *Network Operator*.	3.8	

7.14		Access to data	Access to the visible display is to be provided without unreasonable restriction.	3.2(1)	
7.15			Access to the electronic signal from the measurement element is secured. Relays or electronic buffers to prevent accidental or malicious damage to the *meter* must isolate interfaces to customer equipment.	3.23	
7.16			Access to the electronic signal for use in evolving technologies is to be discussed with the *Network Operator*.	3.4	
7.17			Alteration to the original stored data in a *meter* is not permitted except during on-site accuracy testing.	5.21(12)	
7.18		Outages	If an outage or malfunction occurs to a measurement element or associated wiring, repairs must be made as soon as practicable, and in any event within the period specified within the relevant *service level agreement*.	3.11	
7.19	Testing and inspection				
7.20		Purchase of metering equipment	At present National Measurements Institute regulations exempts Utility *Meter*s from the National Measurements *Act*. Whilst the exemption is in place • All new *meter*s must comply with Australian Standard 1284. • All new *meters* must comply with the relevant specifications of the National Measurements Institute's M6. • When the exemption is extinguished the National Measurements *Act* will apply.	3.1	Type 1 - 6
7.21			Appropriate test certificates are to be kept by the equipment owner.	4.3	
7.22		Testing of metering equipment	The metering equipment purchased must be tested to the following class accuracy and with less that the following uncertainties: • General Purpose meter 0.3/cosΦ%	Table 3	Type 6
7.23			The uncertainties associated with testing of the components of the *metering installation* may be carried out as follows: • *Meter* Wh in laboratory 0.2/cosΦ % • *Meter* Wh in field 0.3/cosΦ %	Table 3	Type 6
7.24			The maximum periods between sample tests are to be: • Whole current (direct connected) *meter* is to be tested in accordance with the *Meter* Provider's *meter management plan*.		Type 6

7.25			Overall accuracy at unity power factor Energy Rated Load 10% 50% 100% *Act*ive 2.0% 1.5% 1.5% Overall accuracy 0.866 lagging power factor Energy Rated Load 10% 50% 100% Active 2.0% 1.5% 1.5% Overall accuracy 0.5 lagging power factor Energy Rated Load 10% 50% 100% Active n/a 1.5% n/a The above measurements are referenced to 25ºC Method of calculating the overall error is the vector sum of the errors of each component part, that is, A+B+C, where: • A = the error of voltage transformer and wiring; • B = the error of the current transformer and wiring • C = the error of the *meter*	Table 7	Type 4 - 6
7.26			Testing of the components of the *metering installation* will be conducted in accordance with the asset management strategy		
7.27			Other affected parties may witness the tests on request.		
7.28			The test results must be provided as soon as practicable to the requesting *Code* participant.		
7.29			All reference/calibrated equipment shall be tested to ensure full traceability to Australian national measurement standards through verifying authorities or directly referenced to the National Measurement Laboratory.		
7.30			The calculations of accuracy based on test results, are to include all reference standard errors.		
7.31			An “estimate of testing uncertainties” must be calculated in accordance with the ISO “Guide to the Expression of Uncertainty for Measurement”.		

7.32	Inspections of metering equipment		The testing and inspection requirements must be by a *meter management plan*.		Type 1 - 6
7.33			A typical inspection must include: check the seals; compare the pulse counts; compare the direct readings of *meter*s, verify *meter* para*meter*s and physical connections, verify current transformer ratios by comparison.		
7.34		Actions in event of non-compliance	If the accuracy of the *metering installation* does not comply with the requirements of the *Code*, the *Authority* must be advised as soon as practicable of the errors detected and the possible duration of the existence of errors, and arrange for the accuracy of the *metering installation* to be restored in a time frame agreed with the *Authority*.		
7.35			If a test or audit of the *metering installation* demonstrates an error of measurement of less than those detailed in the *meter management plan* (Table 1.), no substitution of readings is required unless in *Network Operator's* reasonable opinion a particular party would be significantly affected if no substitution was made.		
7.36			If a *metering installation* test, inspection or audit demonstrates errors in excess of those prescribed and the time at which those errors arose is not known, the error is deemed to have occurred at a time half way between the time of the most recent test or inspection which demonstrated that the *metering installation*, or the *meter* family to which the *meter* of the *meter* installation belongs, complied with the relevant accuracy requirement and the time when the error was detected.		
7.37	Management, maintenance and auditing		The testing and inspection requirements must be by a *meter management plan*.		Type 1 - 6
7.38		Installation and maintenance	The *Network Operator* must ensure that any metering equipment that they install is suitable for the range of operating conditions to which it will be exposed (e.g. temperature; impulse levels), and operates within the defined limits for that equipment.	3.5(3)(c)(1)	
7.39		Supporting information	Suitable drawings and supporting information detailing the *metering installation*, must be available for maintenance and auditing purposes. This information shall be stored in an appropriate depository managed by the *Network Operator*. {Note for type 6 meters the drawings and supporting information will, in general, be generic in nature.}	3.12(4)	
7.40		Security controls	Provide and maintain the security controls of a *metering installation*.	3.8	
7.41			The energy data held in the *metering installation* is to be protected from direct local or remote electronic access by suitable password and security controls.	4.8(4)(a)	
7.42			The *Network Operator* must keep records of electronic access passwords secure.	4.8(5)(b)	
7.43			Energy data and passwords are confidential data and are to be treated as confidential	7.4(1)	

			information.		
7.44			A *Registered Metering Installation Provider* must be accredited by and registered with *Network Operator*, and only for the type of work the *Registered Metering Installation Provider* is qualified to provide.	6.9	
7.45			*Registered Metering Installation Providers*, who wish to apply for categories of *Registered Metering Installation Provider* accreditation of *metering installations*, must be able to exhibit, to the reasonable satisfaction of the *Network Operator* the relevant capabilities.	6.9	

8 Schedule 4 – Components of a Type 1-5 Metering Installation – Energy Data Services

The components and characteristics and requirements of a *Metrology Procedure* for type 5 *metering installations* (*energy data services*) are as follows:

Ref.	Energy data services components	Energy data services characteristics	Requirement	Clause in *Code*
8.1	Metering database	Location	The metering *database* is located at a site remote from the site of the *meter* installation.	
8.2		Security	The metering *database* is to be secure and the associated programs, links, circuits and information storage and processing systems are to be secured from unauthorised local and remote access by means of locks, seals, passwords, appropriate encryption and other electronic security controls or other devices approved by The *Network Operator* in accordance with good electricity and IT industry practice.	4.1(2), 4.8(4)
8.3			The metering *database* is to be secure and the associated programs and data are to be secured by means of passwords, appropriate encryption and other electronic security controls,	4.8(4)
8.3			Metering *database* passwords are confidential data and are to be treated as confidential information subject to clause 7.4 of the *Metering Code*.	7.4(1)
8.4		Processing and storage of data	The original energy readings must be stored in the *metering database*. Data relating to the amount of energy passing through a connection point must be collated and stored by data stream in half hourly trading intervals within the metering *database*. The *energy data* may be substituted in accordance with clause 3.3 or estimated in accordance with clause 3.4 of this *Metrology Procedure*.	4.1(1)(b)
8.5			Following a successful read, substitution or estimation, the metering *database* will store the *energy data* for a period of at least 13 months in a readily accessible online format and for a further period of five years and eleven months in archive that is accessible independently of the format in which the data is stored.	
8.6		Time function	The metering *database* clock must be referenced to Australian Western Standard TIME (AWST) and maintained within an absolute error of: Type 1. ±5 seconds, Type 2. ±7 seconds, Type 3 ±10 seconds, Types 4 – 5 ± 20 seconds.	
8.7		Access	The format of the *energy data* must be in accordance with the *Communication Rules*.	

Ref.	Energy data services components	Energy data services characteristics	Requirement	Clause in *Code*
8.8			The only persons entitled to have either direct or remote access to the *energy data* from a *metering installation* are the *Network Operator* and the *user* of the *connection point* with which the *metering installation* is associated	4.8(3), 4.8(4), 4.8(5)
8.9			*Energy data* (either actual, substituted or estimated) is required by *Network Operator* by data stream for all trading intervals (that is, 48 intervals per 24 hour period) within the timeframe required for settlements as specified in procedures established by *Network Operator*.	Market Rules 8.7.1(b)
8.10			*Energy data* (either actual, substituted or estimated) is required by *Network Operator* by data stream for all trading intervals (that is, 48 intervals per 24 hour period) in accordance with performance standards established by *Network Operator*	3.16(3)
8.11		Outages	The *metering installation* database must permit collection of data within the timeframes specified in the relevant service level agreement at a level of availability of at least 99% per annum.	3.11(1)(a)
8.12			If an outage or malfunction occurs to a *metering installation database*, repairs must be made as soon as practicable, and in any event within the period specified within the relevant *service level agreement*	3.11(2)
8.13			A *Code Participant* who becomes aware of an outage or malfunction of a *metering installation* must advise the *Network Operator* as soon as practicable.	3.11(3)
8.14	*Metering installation* database	Security	The *metering installation database* is to be secure and the associated programs and data are to be secured from unauthorised local and remote by means of passwords, appropriate encryption and other electronic security controls, in accordance with good electricity and IT industry practice.	4.1(2), 4.8(4)
8.15			*Metering installation database* passwords are confidential data and are to be treated as confidential information subject to Part 7.4 of the *Metering Code*.	7.4(1)
8.16		Processing and storage of data	The *metering installation database* must store *energy data* for a period of at least 35 calendar days from the date and time of the last successful read.	3.16(1)(c)
8.17		Time function	The metering *database* clock must be referenced to Australian Western Standard TIME (AWST) and maintained within an absolute error of: Type 1. ±5 seconds, Type 2. ±7 seconds, Type 3 ±10 seconds, Types 4 – 5 ± 20 seconds.	3.9(3)
8.18		Access to the *metering installation* database	The *metering installation database* must have electronic data transfer facilities to transfer data to the metering *database*. *{Note: 3.16(2) only requires a link for types1-4, in practice all interval capable meters will have some form of remote access.}*	

Ref.	Energy data services components	Energy data services characteristics	Requirement	Clause in *Code*
8.19			The format of the *energy data* must be in accordance with the electronic interface specification as nominated from time to time by the *Network Operator*.	
8.20			The only persons entitled to have either direct or remote access to the *energy data* from a *metering installation* are the *Network Operator* and the *user* of the *connection point* with which the *metering installation* is associated	4.8(3), 4.8(4), 4.8(5)
8.21	Communications link	Location	(Comment provided for explanation only) The electronic connection between the metering *database* and the telecommunications network boundary is classified as a communications link.	
8.22			(Comment provided for explanation only) The electronic connection between the data logger and the metering *database* is classified as a communications link.	
8.23			(Comment provided for explanation only) A communications link may consist of a manual *meter* reading process and a metering *database*.	
8.24		Modem	(Comment provided for explanation only) A modem is used to connect the metering *database* to the telecommunications network.	
8.25		Remote acquisition of data	(Comment provided for explanation only) The *Network Operator* is responsible for the remote acquisition of the *energy data* from the *metering installation*	
8.26			Relevant *energy data* must be provided to *Network Operator* or its agent should a failure of the remote acquisition facility occur, and such an arrangement has been made by *Network Operator*	
8.30			Access to the metering *database* from a telecommunications network must be provided to facilitate the remote acquisition of data	
8.31		Security	The *communications link* is to be secure and the associated links, circuits and information storage and processing systems are to be secured by means of locks, seals or other devices approved by The *Network Operator*.	4.8(4)
8.32		Outages	The *communication link* must permit collection of data within the timeframes specified in the relevant service level agreement at a level of availability of at least 95% per annum.	3.11(1)(b)

Ref.	Energy data services components	Energy data services characteristics	Requirement	Clause in *Code*
8.33			If an outage or malfunction occurs to a *communication link*, repairs must be made as soon as practicable, and in any event within the period specified within the relevant *service level agreement*	3.11(2)
8.34			A *Code Participant* who becomes aware of an outage or malfunction of a *communication link* must advise the *Network Operator* as soon as practicable.	3.11(3)
8.35	Testing	Testing by *Network Operator*	The *Network Operator* must have unrestrained access to the *metering database* for the purpose of testing the data services where *Network Operator* agrees to comply with reasonable security and safety requirements and has first given at least two business days' notice of its intention to access the *metering database* for the purpose of testing the *metering database or data services*. The notice must include the name of the representative who will be conducting the test on behalf of the *Network Operator*, and the time when the test will commence and the expected time when the inspection will conclude	
8.36		Actions in event of non-compliance	If the accuracy of the *metering database* does not comply with the requirements of the *Code*, the *Network Operator* and the affected *Code Participants* must be advised as soon as practicable of the errors detected and the possible duration of the existence of errors, and arrangements must be made for the accuracy of the *metering database* to be restored in a time frame agreed with *Network Operator.*	
8.37		Errors	If a *metering database* test, inspection or audit reveals errors in excess of those prescribed and the time at which those errors arose is not known and cannot be determined within a reasonable time or at reasonable cost, the error is deemed to have occurred half way between the time the error was detected and the time of the last test, inspection or audit that demonstrated that the *metering database* complied with the specification or, if this is the first test, inspection or audit, the time the *metering database* was commissioned.	
8.38			If the test, audit or inspection of the *metering database energy data* has revealed an error that is less then 1.5 times the maximum permitted for the equivalent *metering installation* error, no re-substitution or re-estimation is necessary unless in the reasonable opinion of the *Network Operator* a *Code Participant* would be significantly affected if no re-substitution or re-estimation were made.	
8.39			If a test, audit or inspection reveals a discrepancy between the metering *database energy data* and the *energy data* determined during the audit or test calculations, the *energy data* from the test shall take precedence.	
8.40	Management, maintenance and auditing	Installation and maintenance	Only the *Network Operator*, in accordance with this Metrology Procedure, may carry out installation and maintenance of *metering installations*.	3.5, 6.9

Ref.	Energy data services components	Energy data services characteristics	Requirement	Clause in *Code*
8.41		Security controls	The energy data held in the *metering installation* is to be protected from direct local or remote electronic access by suitable password and security controls	4.8(4)
8.42			The *metering installation* is to be secure and the associated programs and data are to be secured from unauthorised local and remote by means of passwords, and other electronic security controls, in accordance with good electricity and IT industry practice.	4.8(4)
8.43			*Metering installation passwords* are confidential data and are to be treated as confidential information subject to clause 7.4 of the *Metering Code*.	7.4(1)
8.44			"Read-only" passwords must be allocated to *Code Participant*s, Local Network Service Providers and *Network Operator*, except where separate "read-only" and" write" passwords are not available, in which case a password must be allocated to *Network Operator*, only.	
8.45			The *Network Operator* is responsible for maintaining the *metering installation* and metering *database* passwords.	

9 Schedule 5 – Components of a Type 6 Metering Installation – Energy Data Services

The components and characteristics and requirements of a *Metrology Procedure* for type 6 *metering installations* (*energy data services*) are as follows:

Ref.	Energy data services components	Energy data services characteristics	Requirement	Clause in *Code*
9.1	Metering database	Location	The metering *database* is located at a site remote from the site of the *meter* installation.	
9.2		Security	The metering *database* is to be secure and the associated links, circuits and information storage and processing systems are to be secured by means of locks, seals or other devices approved by The *Network Operator*.	4.8(4)
9.3			The metering *database* is to be secure and the associated programs and data are to be secured from unauthorised local and remote by means of passwords, appropriate encryption and other electronic security controls, in accordance with good electricity and IT industry practice.	4.1(2), 4.8(4)
9.4			Metering *database* passwords are confidential data and are to be treated as confidential information subject to clause 7.4 of the *Metering Code*.	7.4(1)
9.5		Processing and storage of data	The original energy readings must be stored in the metering *database*. Data relating to the amount of energy passing through a connection point must be collated and stored by data stream within the metering *database*. The *energy data* may be substituted in accordance with clause 3.3 or estimated in accordance with clause 3.4 of this *Metrology Procedure*.	4.1(1)(b)
9.6			Following a successful read, substitution or estimation, the metering *database* will store the *energy data* for a period of at least 13 months in a readily accessible online format and for a further period of five years and eleven months in archive that is accessible independently of the format in which the data is stored.	
9.7		Access	The format of the *energy data* must be in accordance with the *Communication Rules*.	
9.8			The only persons entitled to have either direct or remote access to the *energy data* from a *metering installation* are the *Network Operator* the *user* of the *connection point* with which the *metering installation* is associated and the end consumer at the *connection point*.	4.8(3), 4.8(4), 4.8(5)
9.9		Outages	If an outage or malfunction occurs to a metering *database*, repairs must be made as soon as practicable, and in any event within the period specified within the relevant *service level*	3.11(2)

Ref.	Energy data services components	Energy data services characteristics	Requirement	Clause in *Code*
			agreement .	
9.10			A *Code Participant* who becomes aware of an outage or malfunction of a *metering installation* must advise the *Network Operator* as soon as practicable.	3.11(3)
9.11	Testing	Testing by *Network Operator*	The *Network Operator* must have unrestrained access to the *metering database* for the purpose of testing the data services where *Network Operator* agrees to comply with reasonable security and safety requirements and has first given at least two business days' notice of its intention to access the *metering database* for the purpose of testing the *metering database or data services*. The notice must include the name of the representative who will be conducting the test on behalf of the *Network Operator*, and the time when the test will commence and the expected time when the inspection will conclude.	
9.12		Actions in event of non-compliance	If the accuracy of the *metering database* does not comply with the requirements of the *Code*, the *Network Operator* and the affected *Code Participants* must be advised as soon as practicable of the errors detected and the possible duration of the existence of errors, and arrangements must be made for the accuracy of the *metering database* to be restored in a time frame agreed with *Network Operator.*	
9.13		Errors	If a *metering database* test, inspection or audit reveals errors in excess of those prescribed and the time at which those errors arose is not known and cannot be determined within a reasonable time or at reasonable cost, the error is deemed to have occurred half way between the time the error was detected and the time of the last test, inspection or audit that demonstrated that the *metering database* complied with the specification or, if this is the first test, inspection or audit, the time the *metering database* was commissioned.	
9.14			If the test, audit or inspection of the *metering database energy data* has revealed an error that is less then 1.5 times the maximum permitted for the equivalent *metering installation* error, no re-substitution or re-estimation is necessary unless in the reasonable opinion of the *Network Operator* a *Code Participant* would be significantly affected if no re-substitution or re-estimation were made.	
9.15			If a test, audit or inspection reveals a discrepancy between the metering *database energy data* and the *energy data* determined during the audit or test calculations, the *energy data* from the test shall take precedence.	
9.16	Management, maintenance and auditing	Installation and maintenance	Only the *Network Operator*, in accordance with this Metrology Procedure, may carry out installation and maintenance of *metering installations*.	3.5, 6.9
9.17		Security controls	The *energy data* held in the *metering installation* is to be protected from tampering by suitable security controls such as seals, in accordance with good electricity industry practice.	4.8(4)

10 Schedule 6 – Metering Installation Types 1-5 – Validation

10.1 Requirement to Validate

10.1.1 The energy data from *metering installation*s of types 1-5 is required to be validated, in accordance with clause 3.4.1 of this Metrology Procedure.

10.2 Validation of energy data from Types 1-5 Metering Installations with Check Metering

10.2.1 The following checks apply to *energy data* from all *metering installations* of types 1-5 which have full *check* metering:

a) The energy data must agree with the check *meter* reading to within the uncertainty limits of both *meter*s. I.e.

$$\frac{|R-C'|}{\left(\frac{R+C'}{2}\right)} \times 100 \leq |\Delta RC|$$

Where

|R-C'| means the absolute value of *R-C'.*

R is the *revenue meter* reading for the data stream, expressed in *energy units.*

C' is the associated *check meter* reading, expressed in *energy units*, and adjusted for known losses or systemic errors such as transformer losses.

ΔRC is the maximum discrepancy between the revenue and check *meter* expressed as a percentage and with a maximum value of 1%.

{e.g. Meter A has a reading of 107.5 and the associated check meter reads 106. An analysis of historical data, systemic errors and the known uncertainties for the meters shows that the maximum acceptable difference is 0.9%. (107.5-106)/(107.5+106)/2 ×100 = 1.41% which is greater than the maximum allowable value so the reading will fail validation.

However, if we know that there is a transformer loss for the check meter of 2% then we need to first determine an adjusted check meter reading. This would be 106/0.98 = 108.1. In this case (108.1-107.5)/(107.5+108.1)/2 ×100 = 0.56% which is within the tolerance allowed and the reading would pass validation.}

b) Where the energy data is associated with a market generator then it must be validated against SCADA data.

$$\frac{|R-S'|}{\left(\frac{R+S'}{2}\right)} \times 100 \leq |\Delta RS|$$

Where

|R-S'| means the absolute value of R-S'.

R	is the *revenue meter* reading for the data stream, expressed in *energy units*.
S'	is the associated *check meter* reading, converted to *energy units*, and adjusted for known losses or systemic errors such as transformer losses.
ΔRS	is the maximum discrepancy between the revenue and check *meter* expressed as a percentage.

c) The value must be less than the registered maximum value of Wh, Varh or VAh for the *metering installation* data stream.

d) The *Network Operator* and *user* will agree to either:

1. Check the metered value is greater than the registered minimum value for the *metering installation*, or
2. Check that the number of intervals with zero data is less than a specified number.

e) If an interval has a null value then the reading for that interval will be rejected.

f) If the *meter* has registered significant *meter* alarms over the period since the last successful read, the *energy data* for the affected intervals will be rejected. The list of alarms that will be processed is given in Appendix 1, together with a note of those that are regarded as significant.

g) Where apparent, reactive and active energy are all available, these must be checked for consistency. I.e.

$$\frac{\left|\left(A^2+R^2\right)-W^2\right|}{\left(\frac{\left|\left(A^2+R^2\right)+W^2\right|}{2}\right)}\times 100 \le \left|\Delta ARW\right|$$

Where,

$\|(A^2+R^2)-W^2\|$	means the absolute value of $(A^2+R^2)-W^2$.
A	is the data stream reading for *active energy.*
R	is the data stream reading for *reactive energy.*
W	is the data stream reading for *apparent energy.*
ΔARW	is the maximum discrepancy in the apparent energy, expressed as a percentage and with a maximum value of 1%.

{Note. In the presence of significant harmonics this Pythagorean relationship will not hold (since it is only applicable for a sinusoidal waveform) and this validation check will fail where apparent energy is correctly measured by the meter (as opposed to being calculated using the same validation rule). Also the metering interval is fifteen minutes whereas the trading interval is thirty minutes. Thus, since apparent energy cannot be added arithmetically, this means that in the presence of significant harmonics it is not possible to determine the half-hourly apparent energy from the metered data. Thus the interval must be substituted. Under these circumstances the Retailer *will always be consulted.}*

h) The sum of the *interval data* readings must agree with the accumulated total for the *meter* for active and reactive energy data streams. I.e.

$$\frac{\left|\left(\sum_{i=1}^{n} R_i\right) - A'\right|}{\left(\frac{\sum_{i=1}^{n} R_i + A'}{2}\right)} \times 100 \leq \left|\Delta RA\right|$$

Where,

$|\sum_{i=1}^{n} R_i + A'|$ means the absolute value of $\sum_{i=1}^{n} R_i + A'$.

R_i is the data stream reading for interval *i,* expressed in *energy units.*

n is the total number of intervals in the period.

A' is the reading from the associated accumulated energy registers, adjusted for any known systemic error.

ΔRA is the maximum discrepancy between the sum of the interval readings and the accumulation register expressed as a percentage and with a maximum value of 1%.

10.3 Validation of energy data from Types 1-5 Metering Installations with Partial Check Metering

10.3.1 The following checks apply to *energy data* from all *metering installations* of types 1-5 which have partial *check* metering

a) The energy data must agree with the check *meter* reading to within the uncertainty limits of both *meter*s. i.e.

$$\frac{\left|R - C'\right|}{\left(\frac{R + C'}{2}\right)} \times 100 \leq \left|\Delta RC\right|$$

Where

|R-C'| means the absolute value of R-C'.

R is the revenue *meter* data stream reading, expressed in *energy units.*

C' is the associated *check meter* reading, expressed in *energy units*, and adjusted for known losses or systemic errors such as transformer losses.

ΔRC is the maximum discrepancy between the revenue and check *meter* expressed as a percentage and with a maximum value of 1%.

{e.g. Meter A has a reading of 107.5 and the associated check meter reads 106. An analysis of historical data, systemic errors and the known uncertainties for the meters shows that the maximum acceptable difference is 0.9%. (107.5-106)/(107.5+106)/2 ×100 = 1.41% which is greater than the maximum allowable value so the reading will fail validation.

However, if we know that there is a transformer loss for the check meter of 2% then we need to first determine an adjusted check meter reading. This would be 106/0.98 = 108.1. In this case (108.1-107.5)/(107.5+108.1)/2 ×100 = 0.56% which is within the tolerance allowed and the reading would pass validation.}

b) Where the energy data is associated with a market generator then it must be validated against SCADA data.

$$\frac{|R - S'|}{\left(\frac{R + S'}{2}\right)} \times 100 \leq |\Delta RS|$$

Where

|R-S'| means the absolute value of R-S'.

R is the *revenue meter* reading for the data stream, expressed in *energy units*.

S' is the associated *check meter* reading, converted to *energy units*, and adjusted for known losses or systemic errors such as transformer losses.

ΔRS is the maximum discrepancy between the revenue and check *meter* expressed as a percentage.

c) The value must be less than the registered maximum value of Wh, Varh or VAh for the *metering installation*.

d) The *Network Operator* and user will agree to either:

1. Check the metered value is greater than the registered minimum value for the *metering installation*, or
2. Check that the number of intervals with zero data is less than a specified number.

e) If an interval has a null value then the reading for that interval will be rejected.

f) If the *meter* has registered significant *meter* alarms over the period since the last successful read, the *energy data* for the affected intervals will be rejected. The list of alarms that will be processed is given in Appendix 1 together with a note of those which are regarded as significant.

g) The sum of the active and reactive *interval energy data* readings must agree with the accumulated total for the *meter* . I.e.

$$\frac{\left|\left(\sum_{i=1}^{n} R_i\right) - A'\right|}{\left(\frac{\sum_{i=1}^{n} R_i + A'}{2}\right)} \times 100 \leq |\Delta RA|$$

Where,

$\left|\left(\sum_{i=1}^{n} R_i\right) - A'\right|$ means the absolute value of $\left(\sum_{i=1}^{n} R_i\right) - A'$.

R_i is the data stream reading for interval *i.*

n is the total number of intervals in the period.

A' is the reading from the associated accumulated energy registers, adjusted for any known systemic error.

ΔRA is the maximum discrepancy between the sum of the interval readings and the accumulation register expressed as a percentage and with a maximum value of 1%.

h) Where apparent, reactive and active energy are all available, these must be checked for consistency. I.e.

$$\frac{\left|\left(A^2 + R^2\right) - W^2\right|}{\left(\frac{\left|\left(A^2 + R^2\right) + W^2\right|}{2}\right)} \times 100 \leq \left|\Delta ARW\right|$$

Where,

$\left|\left(A^2 + R^2\right) - W^2\right|$ means the absolute value of $\left(A^2 + R^2\right) - W^2$

A is the data stream reading for *active energy*

R is the data stream reading for *reactive energy*

W is the data stream reading for *apparent energy*

ΔARW is the maximum discrepancy in the apparent energy, expressed as a percentage and with a maximum value of 1%.

10.4 Validation of energy data from Types 1-5 Metering Installations without Check Metering

10.4.1 The following checks apply to *energy data* from all *metering installations* of types 1-5 which have no *check* metering

a) The value must be less than the registered maximum value of Wh, Varh or VAh for the *metering installation*.

b) The *Network Operator* and *user* will agree to either:

1 Check the metered value is greater than the registered minimum value for the *metering installation*, or

2 Check that the number of intervals with zero data is less than a specified number.

c) If an interval has a null value then the reading for that interval will be rejected.

d) If the *meter* has registered significant *meter* alarms over the period since the last successful read, the *energy data* for the affected intervals will be rejected. The list of alarms that will be processed is given in Appendix 1 together with a note of those which are regarded as significant.

e) The sum of the *interval energy data* readings must agree with the accumulated total for the *meter* for active and reactive energy data streams. I.e.

$$\frac{\left|\left(\sum_{i=1}^{n} R_i\right) - A'\right|}{\left(\frac{\sum_{i=1}^{n} R_i + A'}{2}\right)} \times 100 \leq \left|\Delta RA\right|$$

Where,

$|\left(\sum_{i=1}^{n} R_i\right) - A'|$ means the absolute value of $\left(\sum_{i=1}^{n} R_i\right) - A'$.

R_i is the data stream reading for interval *i.*

n is the total number of intervals in the period.

A' is the reading from the associated accumulated energy registers, adjusted for any known systemic error.

ΔRA is the maximum discrepancy between the sum of the interval readings and the accumulation register expressed as a percentage and with a maximum value of 1%.

f) Where apparent, reactive and active energy are all available, these must be checked for consistency. I.e.

$$\frac{\left|\left(A^2 + R^2\right) - W^2\right|}{\left(\frac{\left|\left(A^2 + R^2\right) + W^2\right|}{2}\right)} \times 100 \leq \left|\Delta ARW\right|$$

Where,

$|\left(A^2 + R^2\right) - W^2|$ means the absolute value of $\left(A^2 + R^2\right) - W^2$.

A is the data stream reading for *active energy.*

R	is the data stream reading for *reactive energy.*
W	is the data stream reading for *apparent energy.*
ΔARW	is the maximum discrepancy in the apparent energy, expressed as a percentage and with a maximum value of 1%.

11 Schedule 7 – Metering Installation Types 1-5 – Accumulation, Substitution and Estimation

11.1 Requirement to Produce Substituted or Estimated Energy Data

{Note – substitution occurs in response to a failure or problem with the metering installation, a failure to read the meter, or in response to data quality issues whereas estimation only occurs when it is necessary to provide a value for a period which is not yet scheduled to be read. Estimation is only relevant to type 6 meters}

11.1.1 In accordance with clause 3.4.4(c) of this *Metrology Procedure*, *energy data* for a type 1-5 *metering installation* may be required to be substituted.

11.2 Requirement to Accumulate Energy Data to Trading Intervals

11.2.1 Where *energy data* is recorded in fifteen-minute intervals this must be accumulated to half-hourly values to coincide with the *trading interval* in accordance with 11.4 of this Schedule 8.

11.3 Network Operator Obligations

11.3.1 When the *energy data* is required to be substituted or estimated the *Network Operator* will use Substitution Types 11, 12, 13, 14, 15, 16, 17 and 18 for *metering installations* of Types 1-4 and Substitution Types 51, 52, 53, 54, 55 and 56 for *metering installations* of Type 5, all substitution types as defined in clause 11.5 of this Schedule 8.

11.3.2 The *Network Operator* must not perform substitutions or estimations for generating plant without prior consultation with the generator unless reliable check metering is available.

11.3.3 The *Network Operator* must not perform substitution of Type 16, 55 or 56 without the prior agreement of the affected parties.

11.3.4 The *Network Operator* will notify affected *Code Participant*s where substituted *energy data* is used via the quality flag in the data file format.

11.3.5 The *Network Operator* will notify affected *Code Participant*s of the method of substitution used via the method flag in the data file format.

11.3.6 The *Network Operator* will notify affected *Code Participant*s of errors and alarms associated with the *energy data* via the reason code as listed in Appendix 1 in the data file format

11.3.7 Where one or more of the readings making up the *interval energy data* in accordance with 3.3.16 has failed validation and been substituted, this will be reflected in the reason code, quality flags, and, where relevant, method flags of the *interval energy data* reported under 11.3.4 and the status reported will reflect the most serious of the statuses associated with the constituent data. Appendix 1 lists the status and defines the order of severity.

{Note. Consider where data is collected in 15 minute intervals and aggregated to half hour periods. If one period had a warning status but the data was manually approved while the other

15 minute period failed and was substituted, the entire trading interval would be marked as a substitute.}

11.3.8 The *Network Operator* must ensure that for all Substitution Types, substituted *energy data* is based on an actual *meter* reading, and is not based on *energy data* that has previously been estimated or substituted.

11.3.9 Where a substitution type requires the use of historical data, the data source for historical data shall be data stream specific rather than *meter* specific.

{I.e. if a meter is swapped out the process will look at the history for the same data stream for the previous meter not just the limited data set available that is associated with the replacement meter.}

11.4 Accumulation of data to trading intervals

11.4.1 The formulae used for converting fifteen-minute interval readings to half-hourly interval readings are as listed in the following table:

Variable	Formula
Half-Hourly (HH) Consumption	HH Consumption at interval $_{i+1}$ = sum (Consumption at Quarter-Hourly (QH) interval $_{i}$, Consumption at QH interval $_{i+1}$) { I.e. Sum the reading values (kWh) of the two adjacent QH intervals to form the HH Consumption for the HH interval. For example, QH Consumption @ 00:15 = 20 kWh QH Consumption @ 00:30 = 50 kWh then HH Consumption @ 00:30 = 70 kWh}
HH Demand	HH Demand can be determined when data for HH Consumption is present HH Demand in kW at interval $_{i+1}$ = HH Consumption in kWh at interval $_{i+1}$ x 2
HH Reactive Energy	HH Reactive Energy at interval $_{i+1}$ = sum (Reactive Energy at QH interval $_{i}$, Reactive Energy at QH interval $_{i+1}$) {I.e. Sum the reading values (kVARh) of the two adjacent QH intervals to form the HH Reactive Energy for the HH interval. For example , QH Reactive Energy @ 00:15 = 20 kVARh

Variable	Formula
	QH Reactive Energy @ 00:30 = 50 kVARh then HH Consumption @ 00:30 = 70 kVARh}
HH Apparent Energy	HH Apparent Energy at interval $_{i+1}$ is not summed from quarter-hourly readings but is derived when data for HH Consumption and HH Reactive Energy are present. HH Apparent Energy in kVAh at interval $_{i+1}$ $= \sqrt{\text{HH Consumption}^2 + \text{HH Reactive Energy}^2}$ The units of Consumption = kWh The units of Reactive Energy = kVArh *{ Note – summing QH apparent energy could result in inconsistencies in the Power Factor.}*
Power Factor	Power Factor can only be determined when data for HH Consumption and HH Apparent Energy are present. Power Factor = $\frac{\text{HH Consumption in kWh}}{\text{HH Apparent Energy in kVAh}}$ The Power Factor should be between 0 and 1 inclusive.

11.5 Substitution and Estimation Types for Metering Installation Types 1-4

11.5.1 Substitution Method 11

Interval energy data obtained from another *meter* at the same measurement point for the same interval data periods as that being substituted for may be used for substitution purposes, e.g. installations where revenue and check *meter*s are installed.

Method 11 substitutions also include the use of data from similar *meter*s where the load profile of the second *meter* is a good match to the load profile of the *meter* for which substitutions are being made, e.g. where *meter*s are installed on each end of a transmission line where the difference due to line losses can be accurately determined; where *meter*s are installed on parallel feeders where supply is 'to' and 'from' common buses and line impedances are similar.

11.5.2 Substitution Method 12

Data values may be calculated for an unknown feed to a node based on the other known energy flows to or from that node.

{Note: For example if sub meters are available then a value could be determined by summing the readings from the submeters.}

11.5.3 Substitution Method 13

Data from an energy management system or SCADA data shall only be used for substitution purposes where the data originates from a similar measurement point to the *meter* for which substitutions are being made.

Data from an energy management system or SCADA data may be data which is inferior in accuracy or resolution and which is in a dissimilar format to the energy data, (e.g. 30 Min. demand values). Where necessary the data will be adjusted in both magnitude and form in order that the substitution is of an acceptable quality.

11.5.4 Substitution Method 14

Where data substitution methods 11, 12, and 13 cannot be carried out, then the *Network Operator* may substitute for the missing data using the "Nearest Equivalent Day" or "Like Day" method, as detailed in the table below.

METHOD 14	
Substitution Day	**"Nearest Equivalent Day" or "Like Day" (in order of availability)**
Monday	Monday ♦♦
Tuesday	Tuesday ♦♦ Wednesday♦♦ Thursday ♦♦ Wednesday ♦ Thursday ♦
Wednesday	Wednesday ♦♦ Tuesday ♦ Thursday ♦♦ Thursday ♦ Tuesday ♦♦
Thursday	Thursday ♦♦ Wednesday ♦ Tuesday ♦ Wednesday ♦♦ Tuesday ♦♦
Friday	Friday ♦♦
Saturday	Saturday ♦♦
Sunday	Sunday ♦♦

Substitutions for 'Like Day' to be as detailed above, unless:

1) If no readings are available on the first listed day, then the next listed preferred day is to be used.
2) The substitution day was a public holiday, in which case the most recent Sunday is to be used.
3) The substitution day was not a public holiday and the 'Like Day' is a public holiday, in which case the substitution 'Like Day' to be used must be the most recent business day.

♦♦ Occurring in the week preceding that in which the substitution day occurs.

♦ Occurring in the same week as the substitution day

11.5.5 Substitution Method 15

Where data substitution methods 11, 12, and 13 cannot be carried out, then the *Network Operator* may substitute for the missing data using the "Nearest Equivalent Day" or "Like Day" method, as detailed in the Table below.

METHOD 15
The intervals to be substituted will be plugged using an average of each interval from the proceeding 4 weeks, or part thereof.
This averaging technique may be applied in the following ways:
1) where the averaged intervals are simply 'plugged' into the intervals requiring substitution.
2) where the averaged intervals are used to provide the profile for the ones to be 'plugged' to a predetermined number of pulses for the total substitution period.
However if data is required to be substituted for a public holiday then the most recent available Sunday will be used.

11.5.6 Substitution Method 16

(a) Where data substitution is required for any period greater than 7 days, consideration, consultation and agreement must take place between the affected parties to resolve any abnormal equivalent days that may be applicable.

(b) Method 16 substitutions are:

i. data substitutions of any format for periods greater than 7 days that are based on an agreement between all the affected parties;

ii. changes to existing substitutions for any period that are carried out where the affected parties have directed that as a result of site or customer specific information, the original substitutions are in error.

11.5.7 Substitution Method 17

Data substitutions for periods up to, but not exceeding 2 hours, may be carried out by simple linear interpolation.

11.5.8 Substitution Method 18

This substitution method covers the situation where an alternate method of substitution has been agreed with the *Code Participant*, the applicable user and the *Network Operator*. This may be a globally applied method or a site specific method where an adjusted profile is used to take into account local conditions which affect consumption (e.g. local holiday or customer shutdown), or where alternate data may be able to be used for quality checks and minor adjustments of an estimated profile such as using *meter* register data.

11.6 Substitution and Estimation Types for Metering Installation Type 5

11.6.1 Substitution Method 51

This method is known as the Previous Years Method. The *Network Operator* substitutes for the missing data using the "Nearest Equivalent Day" or "Like Day" method, as detailed in the Table below.

METHOD 51	
Substitution Day	**"Nearest Equivalent Day" or "Like Day" (in order of availability)**
Monday	Monday ♦♦ Monday ♦
Tuesday	Tuesday ♦♦ Wednesday♦♦ Tuesday ♦ Wednesday ♦
Wednesday	Wednesday ♦♦ Tuesday ♦♦ Thursday ♦♦ Wednesday ♦ Thursday ♦ Tuesday ♦
Thursday	Thursday ♦♦ Wednesday ♦♦ Tuesday ♦♦ Thursday ♦ Wednesday ♦ Tuesday ♦
Friday	Friday ♦♦ Friday ♦
Saturday	Saturday ♦♦ Saturday ♦
Sunday	Sunday ♦♦ Sunday ♦
Substitutions for 'Like Day' to be as detailed above, unless: If no readings are available on the first listed day, then the next listed preferred day is to be used.	

METHOD 51	
Substitution Day	**"Nearest Equivalent Day" or "Like Day" (in order of availability)**
	1 The substitution day was a public holiday, in which case the most recent Sunday is to be used. 2 The substitution day was not a public holiday and the 'Like Day' is a public holiday, in which case the substitution 'Like Day' to be used must be the most recent business day. ♦♦ Occurring in the same week as the substitution day in the previous year. ♦ Occurring in the week preceding that in which the substitution day occurs in the previous year.

11.6.2 Substitution Method 52

This method is known as the Previous Meter Reading Method. The *Network Operator* substitutes for the missing data using the "Nearest Equivalent Day" or "Like Day" method, as detailed in the Table below.

METHOD 52	
Substitution Day	**"Nearest Equivalent Day" or "Like Day" (in order of availability)**
Monday	Monday ♦♦ Monday ♦
Tuesday	Tuesday ♦♦ Wednesday♦♦ Tuesday ♦ Wednesday ♦
Wednesday	Wednesday ♦♦ Tuesday ♦♦ Thursday ♦♦ Wednesday ♦ Thursday ♦ Tuesday ♦
Thursday	Thursday ♦♦ Wednesday ♦♦ Tuesday ♦♦ Thursday ♦ Wednesday ♦ Tuesday ♦
Friday	Friday ♦♦ Friday ♦
Saturday	Saturday ♦♦ Saturday ♦
Sunday	Sunday ♦♦ Sunday ♦
Substitutions for 'Like Day' to be as detailed above, unless: If no readings are available on the first listed day, then the next listed preferred day is to be used. 1 The substitution day was a public holiday, in which case the most recent Sunday is to be used. 2 The substitution day was not a public holiday and the 'Like Day' is a public holiday, in which case the substitution 'Like Day'to be used must be the most recent business day. ♦♦ Occurring in the last whole week of the previous *meter* reading period. ♦ Occurring in the week preceding the last whole week of the previous meter reading period.	

11.6.3 Substitution Method 53

(a) Where data substitution is required for any period greater than 7 days, consideration, consultation and agreement must take place between the affected parties to resolve any abnormal equivalent days that may be applicable.

(b) Method 53 substitutions are:

i. data substitutions of any format for periods greater than 7 days that are based on an agreement between all the affected parties;

ii. changes to existing substitutions for any period that are carried out where the affected parties have directed that as a result of site or customer specific information, the original substitutions are in error.

11.6.4 Substitution Method 54

Data substitutions for periods up to, but not exceeding 2 hours, may be carried out by simple linear interpolation.

11.6.5 Substitution Method 55

This substitution method covers the situation where an alternate method of substitution has been agreed with the *Code Participant*, the applicable user and the *Network Operator*. This may be a globally applied method or a site specific method where an adjusted profile is used to take into account local conditions which affect consumption (e.g. local holiday or customer shutdown), or where alternate data may be able to be used for quality checks and minor adjustments of an estimated profile such as using *meter* register data.

11.6.6 Substitution Method 56

This substitution method covers the situation where a substitution for *interval energy data* is required for a period prior to the first *meter* read. The data substitution must be done by a method agreed to by the *Network Operator* and the affected *Code Participant*.

12 Schedule 8 – Metering Installation Type 6 – Validation, Substitution and Estimation

12.1 Requirement to Validate Meter Readings

12.1.1 *Actual meter* readings will be required to be validated in accordance with clause 3.3.1 of this *Metrology Procedure*. The validation rules that will be applied to the *energy data* read from the *meter* of a type 6 *metering installation* are:

a) *Energy data* value is numeric, and

b) *Energy data* value is greater than or equal to the minimum value specified for that *meter*; and

c) *Energy data* value is less than or equal to the maximum value specified for that *meter*; and

d) *Meter* read date > previous *meter* read date; and

e) *Meter* read value is not missing (null) for any type 6 *meter*; and

f) Dial capacity, rollover and decimal point check. A register will be deemed to have failed a rollover check where the calculated value from a rollover exceeds 50% of the register capacity.

{These checks mainly apply to older styles of mechanical meters. For example:

- *A dial capacity check means ensuring that if a meter dial has 5 digits then the maximum value recorded against that dial should be 99999 – a larger number should be flagged.*
- *A roll over check is required where upon successive reads a meter is showing a lower reading. For example consider a hypothetical mechanical meter with four digits. If on the last reading the value was 9995 and on the next reading it is 0010 then the dial is deemed to have "rolled over". The correct interpretation is that consumption is 10 + 10000 – 9995, or 15, units. On the other hand if the last reading was 0010 and this reading is 0009 then something is wrong since it is highly unlikely that the connection point consumed 9999 units since it was last read. It is more likely that the reading was wrong (perhaps the last two digits were swapped around when it was recorded) or the meter is faulty.*
- *A decimal point check means checking that the reading has the correct number of digits after the decimal point for the dial. For example if a dial has 4 digits and the last digit denotes tenths of a unit then the reading should be in the range 000.0 to 999.9. If the reading is recorded as 12.34 then it needs to be flagged up and checked. E.g. should it really be 123.4. }*

12.2 Requirement to Produce Substituted or Estimated Energy Data

{Note – substitution occurs in response to a failure or problem with the metering installation, a failure to read the meter, or in response to data quality issues whereas estimation only occurs when it is necessary to provide a value for a period which is not yet scheduled to be read. Estimation is only relevant to type 6 meters}

12.2.1 In accordance with clause 3.4.4(c) of this *Metrology Procedure*, *energy data* for a type 6 *metering installation* may be required to be substituted or estimated.

12.3 Network Operator Obligations

12.3.1 When the *energy data* is required to be substituted or estimated the *Network Operator* may use Substitution Types 61, 62, 63, 64 or 65, as defined in clause 12.4 of this Schedule 9.

12.3.2 The *Network Operator* will notify affected *Code Participants* where substituted *energy data* is used via the status flag in the data file format.

12.3.3 The *Network Operator* must ensure that for all Substitution Types, substituted *energy data* is based on an actual *meter* reading, and is not based on *energy data* that has previously been estimated or substituted.

12.3.4 Where a substitution type requires the use of historical data, the data source for historical data shall be data stream specific rather than *meter* specific.

{I.e. if a meter is replaced the process will look at the history for the same data stream for the previous meter not just the limited data set available that is associated with the replacement meter.}

12.4 Substitution and Estimation Types

12.4.1 Substitution/Estimation Type 61 – Previous Year Method

a) Value = Average daily consumption from same, or similar, *meter* read period last year × Number of days required to be substituted

12.4.2 Substitution/Estimation Type 62 – Previous *Meter* Reading Method

a) Value = Average daily consumption from previous *meter* read period × Number of days required to be substituted

b) Where the scheduled *meter* reading frequency is less frequent than monthly, Substitution Type 62 is to be used only when the consumption from the same, or similar, *meter* read period last year is not available.

12.4.3 Substitution/Estimation Type 63 – Customer Class Method

a) Value = Average daily consumption for this same customer class with the same type of usage for this period × Number of days required to be substituted

b) Substitution Type 63 is to be used only when the consumption from the same, or similar, *meter* read period last year and the consumption from the previous *meter* read period are not available.

c) Customer classes for Substitution Type 63 are

ii. Residential,

iii. Non-Residential,

iv. Farm, and

v. Public Lighting, or

vi. As defined in the latest Communication Rules build-pack or other approved metering documentation.

{Note: Customer Class corresponds to the Communication Rules Build Pack Property Type and will utilise the full set of Build Pack property types.}

c) The usage types for Substitution type 63 are:

i. peak, or

ii. off-peak, or

iii. as appropriate to the metering configuration.

12.4.4 Substitution/Estimation Type 64 – Agreed Method

a) The *Code Participant*, the applicable *user* and the *Network Operator* may agree to use another method of substitution (which may be a modification of an existing Substitution Type) where none of the existing Substitution Types is applicable.

b) The specifics of this Substitution Type may involve a globally applied method or a site-specific method.

12.4.5 Substitution/Estimation Type 65 – Estimation by Average Daily Consumption

a) Value = Average daily consumption × Number of days required to be substituted

b) Substitution Type 65 is to be used only when the consumption from the same, or similar, meter read period last year and the consumption from the previous meter read period are not available.

c) The average daily consumption is a configurable attribute of the load, agreed with the *Retailer*.

Appendix 1 - Metering Statuses

This schedule shows the statuses currently received from the metering systems and how these translate into the statuses disseminated by the *Network Operator*. Should the method of collecting and/or processing metering data change in the future then the available information and priority will be preserved unless this Metrology Procedure is formally amended. Thus the following statuses represent the full set that will be issued for metering data in the Western Australian market.

Metrology Procedure Reference	*Check description*	*Where check is performed*	*Applies to*			*NEM*			*Data Substituted?*	*Retailer routinely consulted over action?*
			Interval	*Basic*	*Channel*	*Quality Flag*	*Reason Code*	*Reason Description*		
10.2.1(a) 10.3.1(a)	Consistency with check metering	HUB	Y	N	N	S/F	45	Readings failed to validate	Y	N
10.2.1(b) 10.3.1(b)	Consistency with SCADA data	HUB	Y	N	N	S/F	45	Readings failed to validate	Y	N
10.2.1(c) 10.3.1(c) 10.4.1(a) 12.1.1(c)	Accumulated value > maximum	HUB	Y	Y	N	S/F	74	Hgh consumption	Y	N
10.2.1(c) 10.3.1(c) 10.4.1(b) 12.1.1(b)	Accumulated value < minimum	HUB	Y	Y	N	S/F	73	Low consumption	Y	N
10.2.1(d) 10.3.1(d) 10.4.1(b)	Minimum throughput	HUB	Y	Y	N	S/F	68	Zero consumption	Y	N
10.2.1(e) 10.3.1(e) 10.4.1(c) 12.1.1(e)	Null check	HUB	Y	N	N	S/F	78	Null data	Y	N
10.2.1(h) 10.3.1(h)	Sum of Interval vs. Accumulation	MV90	Y	N	N	S/F	45	Readings failed to validate	Y	N
12.1.1(a)	Numeric data	HUB	N	Y	N	S/F	45	Readings failed to validate	Y	N
12.1.1(d)	Read date > prev read date	HUB	N	Y	N	S/F	18	Read below previous	Y	N
12.1.1(f)	Dial capacity	HUB	N	Y	N	S/F	96	Data out of limits	Y	N
12.1.1(f)	rollover	HUB	N	Y	N	S/F	45	Readings failed to validate	Y	N
12.1.1(f)	decimal point check	HUB	N	Y	N	S/F	45	Readings failed to validate	Y	N
3.4.8(d) 3.4.10(d)	Communications error	HUB	Y	Y	N	S/F	76	Communications fault	Y	N

==========> Decreasing priority ==========>

3.4.8(d) 3.4.10(d)	Estimation required	HUB	Y	Y	N	E	77	Estimation forecast	Y	N
3.4.12	Unable to gain access	HUB	Y	Y	N	S/F	Varies	Appropriate code indicating why a manual read was not possible	Y	N
10.2.1(f) 10.3.1(f) 10.4.1(e)	Replaced Interval (Data Correction)	Meter/MV90	N	N	Y	S/F	93	Replaced interval	Y - in MV90	N
10.2.1(f) 10.3.1(f) 10.4.1(e)	Estimated Interval (Data Correction)	Meter/MV90	N	N	Y	S/F	94	Estimated interval	Y - in MV90	N
10.2.1(f) 10.3.1(f) 10.4.1(e)	Retransmitted / Updated Data	Meter/MV90	N	N	Y	S/F	N/A		Manually replaced	N
10.2.1(f) 10.3.1(f) 10.4.1(e)	Added Interval (Data Correction)	Meter/MV90	N	N	Y	S/F	92	Added interval (data correction)	Manually replaced	N
10.2.1(f) 10.3.1(f) 10.4.1(e)	Pulse Overflow	Meter/MV90	N	N	Y	S/F	95	Pulse overflow alarm	Y - if not spurious	Y
10.2.1(f) 10.3.1(f) 10.4.1(e)	Data Out of Limits	Meter/MV90	N	N	Y	S/F	96	Data out of limits	Y - if not spurious	Y
10.2.1(f) 10.3.1(f) 10.4.1(e)	Parity	Meter/MV90	N	N	Y	S/F	98	Parity error	Y	N
10.2.1(f) 10.3.1(f) 10.4.1(e)	Harmonic Distortion	Meter/MV90	N	N	Y	S/F	96	Data out of limits	Y - if reactive measured	Y
10.2.1(g) 10.3.1(g) 10.4.1(f)	Pythagorean check	HUB	Y	N	N	S/F	96	Data out of limits	Y	Y
10.2.1(f) 10.3.1(f) 10.4.1(e)	Estimation type indicator	Meter/MV90	N	N	Y	S/F	93	Replaced interval	Y	N
10.2.1(f) 10.3.1(f) 10.4.1(e)	Data Missing	Meter/MV90	N	N	N	S/F	85	Data missing alarm	Y	N
10.2.1(f) 10.3.1(f) 10.4.1(e)	Short Interval (False for Mag Tape)	Meter/MV90	Y	N	N	S/F/A	80	Short interval alarm	Possibly	N
10.2.1(f) 10.3.1(f) 10.4.1(e)	Long Interval (Missing For Mag Tape)	Meter/MV90	Y	N	N	S/F/A	81	Long interval alarm	Possibly	N
10.2.1(f) 10.3.1(f) 10.4.1(e)	CRC Error	Meter/MV90	Y	N	N	S/F/A	82	CRC error	Possibly	N
10.2.1(f) 10.3.1(f) 10.4.1(e)	RAM Checksum Error	Meter/MV90	Y	N	N	S/F/A	83	RAM checksum error	Possibly	N
10.2.1(f) 10.3.1(f) 10.4.1(e)	ROM Checksum Error	Meter/MV90	Y	N	N	S/F/A	84	ROM checksum error	Possibly	N
10.2.1(f) 10.3.1(f) 10.4.1(e)	Alarm	Meter/MV90	N	N	Y	A	96	Data out of limits	N	N
10.2.1(f) 10.3.1(f) 10.4.1(e)	Excluded Data	Meter/MV90	N	N	Y	A	97	Excluded data	N	N
10.2.1(f) 10.3.1(f) 10.4.1(e)	Load Control	Meter/MV90	Y	N	N	A	91	Load control	N	N

10.2.1(f)	10.3.1(f)	10.4.1(e)	Energy Type (Register Changed)	Meter/MV90	N	N	Y	A	99	Energy type (register changed)	N	N
10.2.1(f)	10.3.1(f)	10.4.1(e)	Power Outage	Meter/MV90	Y	N	N	A	79	Power outage alarm	N	N
10.2.1(f)	10.3.1(f)	10.4.1(e)	Clock Error	Meter/MV90	Y	N	N	A	86	Clock error alarm	N	N
10.2.1(f)	10.3.1(f)	10.4.1(e)	Reset Occurred	Meter/MV90	Y	N	N	A	87	Reset occurred	N	N
10.2.1(f)	10.3.1(f)	10.4.1(e)	Watchdog Time-out	Meter/MV90	Y	N	N	A	88	Watchdog timeout	N	N
10.2.1(f)	10.3.1(f)	10.4.1(e)	Time Reset Occurred	Meter/MV90	Y	N	N	A	89	Time reset occurred	N	N
10.2.1(f)	10.3.1(f)	10.4.1(e)	Test Mode	Meter/MV90	Y	N	N	A	90	Test mode	N	N

Notes:

Load control	This is a meter hardware event/condition that occurs whenever the load control relay is activated. The availability of this event is dependent upon the meter hardware. When available, this meter event/condition is collected during the data retrieval process and stored as an event code in the Remote Interrogation Log File.
Test Mode	This is a meter hardware event/condition that occurs whenever test mode is activated. The availability of this event is dependent upon the meter hardware. When available, this meter event/condition is collected during the data retrieval process and is stored as an event code in the Remote Interrogation Log File.
Time Reset Occurred	This is a meter hardware event/condition that occurs as a result of any time change in the meter, including DST. This meter event/condition is collected during the data retrieval process and stored as an interval status for review/reporting purposes. It is also stored as a Time Reset event code in the Remote Interrogation Log File.
Watchdog Time-out	This is a meter hardware event/condition that occurs whenever the watchdog timer is tripped or activated. The availability of this error condition is dependent on the meter hardware. When available, this meter event/condition is collected during the data retrieval process and stored in the Remote Interrogation Log File.
Reset Occurred	This is a meter hardware error condition that occurs whenever an internal meter hardware reset occurs. The availability of this error condition is dependent upon the meter hardware. When available, this interval status information is collected during the data retrieval process and stored for review/reporting purposes.
Clock Error	This is a meter hardware error condition that can occur whenever an internal meter hardware clock error results in an invalid date or time. The availability of this error condition is dependent upon the meter hardware. When available, this interval status information is collected during the data retrieval process and stored for review/reporting purposes.
ROM Checksum Error	This is a general hardware error condition that can occur during an internal status check or an internal read/write function within the meter. The availability of this error condition is dependent upon the meter hardware. When available, this interval status information is collected during the data retrieval process and stored for review/reporting purposes. May be substituted depending on data error "Graphically and TOU Report." Meter may also be reprogrammed to remove error or replaced.
RAM Checksum Error	This is a general hardware error condition that can occur during an internal status check or an internal read/write function within the meter. The availability of this error condition is dependent upon the meter hardware. When available, this interval status information is collected during the data retrieval process and stored for review/reporting purposes. May be substituted depending on data error "Graphically and TOU Report." Meter may also be reprogrammed to remove error or replaced.
CRC Error	This is a general hardware error condition that can occur during an internal status check or an internal read/write function within the meter. The availability of this error condition is dependent upon the meter hardware. When available, this interval status information is collected during the data retrieval process and stored for review/reporting purposes. May be substituted depending on data error "Graphically and TOU Report." Meter may also be reprogrammed to remove error or replaced.

Long Interval (Missing For Mag Tape)	This is a meter hardware error condition that can occur whenever the time length of an interval is identified as being different (too short or long) from other intervals in the data file. The availability of this error condition is dependent on the meter hardware. When available, this interval status information is collected during the data retrieval process and stored for review/reporting purposes. May be substituted depending on data error "Graphically and TOU Report."
Short Interval (False for Mag Tape)	This is a meter hardware error condition that can occur whenever the time length of an interval is identified as being different (too short or long) from other intervals in the data file. The availability of this error condition is dependent on the meter hardware. When available, this interval status information is collected during the data retrieval process and stored for review/reporting purposes. May be substituted depending on data error "Graphically and TOU Report."
Energy Type (Register Changed)	This status indicates that the value of the channel register was changed manually, or that the type of data being measured by the channel register changed.
Estimated Interval	Where a check is performed in MV90 that replaces data then it is possible that only an “Estimated Interval” will be reported via the reason code. It is anticipated that only the check of interval to accumulation values could result in this reason code being reported.

The missing data alarm will take precedence over all other codes but in general channel status codes are deemed more serious than interval status codes and will take priority. In addition checks that take further downstream take priority. Thus a consistency check in the metering database that triggers substitution will take priority over an alarm raised in the meter.

Where a check results in a “data out of limits” reason code more information on the cause of the error can be provided on request.

Appendix 2 – Default Metering Installation Settings

Interval Duration

Within the Western Australian market all interval meters are configured to record energy data at 15 minute intervals. These are then aggregated within the metering systems to 30 minute trading intervals.

Timezone

All daily quantities are based on 24-hour days and the Australian Western Standard Time (WST).

Channels

The following table shows the channels and associated NMI suffixes provided by default for each type of *metering installation*.

Table 1. Default channels for WA meters

Metering Installation Type	Import		Export		Import Check		Export Check		Import Average		Export Average		Anytime	Peak	Offpeak	*Description*
	kWh	KVARh	kWh	KVARh	kWh	KVARh	kWh	KVARh	kWh	KVARh	kWh	KVARh	kWh	kWh	kWh	*Units*
	Bn	Kn	En	Qn	Cn	Ln	Fn	Rn	An	Jn	Dn	Pn	1n	2n	3n	*Suffix*
1	I	I	E	E	I	I	E	E	IS	IS	ES	ES	N	N	N	
2	I	I	E	E	I	I	E	E	IS	IS	ES	ES	N	N	N	
3	I	I	E	E	N	N	N	N	N	N	N	N	N	N	N	
4	I	I*	E	E*	N	N	N	N	N	N	N	N	N	N	N	
5	I	N	E	N	N	N	N	N	N	N	N	N	N	N	N	
6	N	N	N	N	N	N	N	N	N	N	N	N	I,E	I†,E†	I†,E†	

Key:
- *I* Provided by default for import meter
- *E* Provided by default for export meter
- *IS* Provided by default in addition to individual check and revenue values for import meter where Check and Revenue precision is the same
- *ES* Provided by default in addition to individual check and revenue values for export meter where Check and Revenue precision is the same

N Not provided by default

* Provided only where installed meter is compatible with the requirement

† Provided for time of use (TOU) meters only

Other channels can be configured upon request providing they are supported by the installed meter. Available channels include:

Table 2: NMI Suffixes for Consumption metered data

NMI Suffix (1)	Description	Register Use	Second Character
0	Register Unspecified (placeholder)		Meter numbers or measuring elements are to be 1-9 then A-Z
1	First Register	007 (Anytime)	
2	Second Register	010 (Peak)	
3	Third Register	020 (Off Peak)	
4	First LNSP defined register	030 (High Shoulder)	
5	Second LNSP defined register	040 (Low Shoulder)	
6	Third LNSP defined register	AMD (Maximum Monthly Demand)	
7	Fourth LNSP defined register	CMD (Cumulative Demand)	
8	Fifth LNSP defined register		

Table 2: NMI Suffixes for interval metered data

First Character

	AVE	MASTER	CHECK	NET
IMPORT kWh	A	B	C	N
EXPORT kWh	D	E	F	
IMPORT kvarh	J	K	L	X
EXPORT kvarh	P	Q	R	
KVAh	S	T	U	

Second Character

Meter Numbers of measuring elements are to be 1 – 9 then A-Z

Power Factor pF	G					
Q Metering Qh		H	Y			
Par Metering parh		M	W			
VOLTS (or V2h)		V	Z			

Note: Import kWh is electricity generated at site and fed into the network, while export kWh is electricity provided from the network to the site.

Remarks:

- The B, E, K and Q will be the norm in the WA market (in stead of N and X).
- The I and O are not used as second character in the NMI Suffix.

Measurement Type:

This field is on the meter supply point and is included in the standing data to market. The field summarises the registers defined on the meter, and should therefore be maintained automatically as a result of changes to the registers on the meter, resulting in one of the following measurement types:

- EB Bi-directional energy only
- E Uni-directional energy only
- EQ Uni-directional energy + reactive
- EBQK Bi-directional energy + reactive

Appendix 3– Meter Management Plan

[Included under separate cover]