Department of Primary Industries

ADVANCED METERING INFRASTRUCTURE

In Home Display Functionality Specification

8 June 2007

Functionality Working Group – document under development

Version 3.0

Victoria
The Place To Be

Contents

1 DOCUMENT CONTROL

1.1 Version Control

Version	Date	Description
1.1	November 2006	Initial draft which was put out to AMI and IHD vendors for comment
2.0	February 2007	Second draft which was put out to AMI and IHD vendors for comment
3.0	8 June 2007	First revision in a process to lead to finalisation in Sept 2007.

1.2 Distribution

Name	Purpose
FWG members	For review and continued development of the document
AMI systems vendors & IHD Vendors	For review and advice regarding the impact of requirements on ability of AMI systems and IHDs to deliver the functionality required and any cost impacts
AMI Stakeholders	For review and assessment of AMI functionality in meeting their needs

1.3 Related documents

Document	Version	Date
AMI Minimum Statewide Functionality Specification	5.0	8 June 2007
AMI Technology Trials Specification		August 2006
AMI Business and Data Requirements	1.2	27 April 2007

2 INTRODUCTION

2.1 Background

The Victorian Parliament passed legislation in August 2006 providing powers to enable a state-wide rollout of Advanced Metering Infrastructure (AMI).

A series of Governors Orders in Council (OIC) will be issued to:

- Mandate the Victorian Distribution Businesses to rollout AMI;
- Set the rollout time frame - starting 31 December 2008, and finishing 31 December 2012;
- Set the mechanism for cost recovery for Distribution Businesses;
- Set the minimum statewide functionality requirements; and
- Set the minimum service levels required for AMI systems.

The Department of Primary Industries (DPI) has continued the project established under the Department of Infrastructure (DOI) to develop, together with the industry, a framework for the implementation of AMI. To facilitate there is an Industry Steering Committee (ISC) which is the principal forum for communications and co-ordination between Government, the industry and some other key stakeholders, on all AMI matters. The ISC has a number of working groups, one of which is the Functionality Working Group (FWG) which has developed this specification that could then be recommended to the ISC and DPI for adoption. The FWG membership involved in the development of this specification has included representatives from Distribution Businesses (DBs) and Retail Businesses (RBs) from Victoria and other states, NEMMCO, ESC, CUAC and DPI.

2.2 In Home Displays

In other jurisdictions there is evidence that IHDs are one means whereby customers can be assisted to reduce both their peak demand and also reduce their overall consumption. The Victorian Government is keen to encourage such demand side responses by whatever means including IHDs. Accordingly the minimum statewide functionality specification for mandated rollout of AMI systems requires that IHDs and other devices are able to interface to AMI meters.

It is however not intended that IHDs be part of the mandated AMI rollout but will be available for customers to purchase or for retailers to provide to customers.

2.3 Purpose of Document

It is the purpose of this specification to provide a guideline on the minimum functionality of IHDs so that Retailers do not have to deal with different core IHD functionality for different AMI systems that distributors have rolled out. It is noted that IHD manufacturers may choose to add additional functionality into IHDs, above the core functionality (for example temperature and humidity displays). IHD functionality may be also integrated into other devices such as personal computers, home automation panels, intelligent thermostats, security systems etc.

2.4 Scope

This specification is not a purchase specification but rather outlines the minimum statewide functionality requirement for IHDs. It is noted that this is a minimum specification and is not intended to limit the scope of functionality that IHD vendors may include in their range of product offerings. This specification is focussed on the requirements of IHDs for electricity. Since the rollout of AMI does not include Water and Gas meters, it is not considered that the minimum requirements of IHDs need to encompass the display of water and gas consumption information. However it is noted that this specification does not preclude water and gas consumption information being included within the scope of future IHDs.

3 AMI SYSTEMS OVERVIEW AND IHDS

Figure 1~~Figure 1~~ indicates diagrammatically the assumed scope of an AMI system.

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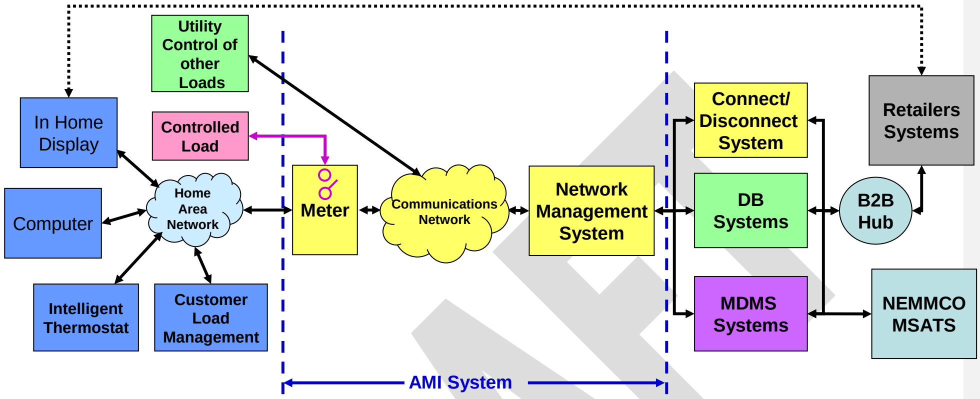

Figure 1 – Overview of AMI System

The central part of the diagram outlines the scope of AMI systems that Distributors are mandated to rollout in Victoria. Between the meter and the Network Management System (NMS) a communications network cloud is shown. It is noted that in some AMI technologies, data concentrators would be part of this communications network. "Controlled Loads" includes the load types that are typically controlled directly from contactors in meters, such are storage water heaters or space heaters. The line connecting the meter and the controlled load box is shown in a different colour to indicate that this is a physical wired connection. The connection of the "Utility control of other loads" box to the communications network is to show that there is the capability of AMI systems to directly control other loads in a customers premises (which might control a range of devices such as pool pumps, air conditioners, dishwashers etc) which might not be capable of being switched at the customers meter.

The items on the right hand side of the diagram, including the Distributor's systems, Retailers' systems, B2B e-Hub and NEMMCO MSATS system are not part of the AMI system; however there are some AMI functionality specification items which place requirements on some of these systems. For example, the connect/disconnect functionality items require the addition of a connect/disconnect system. The use of interval data requires the implementation of a Meter Data Management System (MDMS) to handle interval data. Other items of functionality may require additional systems at distributor and/or retailers and may also require additional services through the B2B e-hub.

In the left most boxes of Figure 1~~Figure 1~~ there are represented some functions that could be in a customer's premise, and may include a range of devices connected to a Home Area Network (HAN). These devices may include In Home Displays (IHD), personal computers, intelligent thermostats (for heating and cooling systems), or customer load management devices (which might control appliances such as pool pumps, air conditioners, dishwashers etc). The HAN and devices connected to the HAN are not included in the mandated rollout of AMI systems, but it is a requirement that AMI systems provide an interface from the Meter to a HAN as a means to enable connectivity to these types of devices. It is noted that Retailers may implement a direct communications link (shown in dotted lines) to an IHDs in addition to that through the AMI system.

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3.1 Home Area Network

To facilitate interoperability between AMI meters and HANs, Zigbee has been specified as the protocol for the meter to HAN interface. This is detailed in the AMI Minimum Statewide Functionality Specification.

The electricity will act as an end point device on a HAN. Hence if an IHD is the only other device on the HAN it will need to act as the co-ordinator and request information from the meter.

4 OVERVIEW OF IHD REQUIREMENTS

An In-home display (IHD) is intended to be a device that allows customers to monitor electricity usage and which may later also allow monitoring of water and gas usage:

(1) Instantaneous consumption – in monetary units ($/hour) & volumetric units (kW~~h~~)

(2) Historic consumption – in monetary & volumetric units

(3) Greenhouse gas emissions (in Kg of CO_2) arising from electricity consumption

(4) Tariff rates and times

(5) Current and previous bill values

(6) Messaging sent from retailers to customers (including notification of critical peak price events)

(7) Messaging sent from distributors to customers

(8) Ability to clear memory of historic data

(9) Ability to uniquely “bind” to the customers meter (ie: not other meters in the area)

4.1 Physical features

(1) Wall mountable or able to stand on a bench

(2) Able to be powered from 240Vac power outlet or batteries

(3) Graphical LCD display – also capable of displaying messages up to 255 characters long

(4) Coloured indicators to show tariff rates for electricity

(5) Buttons (perhaps integrated in a touch screen) to allow selection of what is to be displayed

(6) Means of entry of meter number or NMI

(7) Computer interface (eg: USB port)

5 REQUIREMENTS OF IHDS FOR ELECTRICITY

(1) The IHD shall be able to interface to electricity meters using Zigbee protocol.

(2) The IHD will be required to bind securely and exclusively to the correct meter[1] ~~by using the meters NMI or serial number~~.

(3) The following is the information that needs to come to the IHD to allow the IHD to perform the functions required

5.1 Information from electricity meter

The following is the information that will be available at the electricity meter for the IHD to read.

(1) Date and time (EST)

(2) Current demand[2] (kW) – export[3] - provided by the meter approximately every 5 to 10 seconds

(3) Current output[4] (kW) – import - provided by the meter approximately every 5 to 10 seconds

(4) Interval energy consumption at end of each half hour (kWh) – export

(5) Interval energy production at end of each half hour (kWh) - import

(6) Controlled load switching times – provided by the meter once per day

(7) Supply capacity limit (kW) - provided by the meter once per day

~~(7)~~(8) This specification does not require backward retrieval of data.

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5.2 Information delivered from AMI network through the electricity meter

(a) The AMI system will send messages through to AMI meters which are destined for IHDs. These messages can be up to 255 characters each. These messages may include:

(1) Tariff update information for electricity (including effectivity dates)

(2) Bill values, dates billed and dates paid for Electricity,

(3) Notification of Critical Peak Price event

(4) DB messages (eg: when a planned outage is scheduled)

(5) Other retailer messages

(b) The Format of these messages is given in Appendix A

5.3 Data Storage within the IHD

The following is the data storage requirements and such data shall be available to the computer interface.

5.3.1 Scope of information stored

(1) IHD number ??

(2) Electricity Meter NMI ??;

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[1] There may be instances that would require for IHDs to have the capability of binding to multiple meters.

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[2] That is the demand calculated by the meter over a period of 1 to 2 seconds.

[3] Export means exported from the power grid to the customer, and import means imported from the customer to the power grid. This is the way these terms are defined in the National Electricity Rules.

[4] That is the demand calculated by the meter over a period of 1 to 2 seconds.

(3) The last 10 messages received (255 characters per message) – addressing structures;

(4) 24 hours of half hour kWh interval data (main and controlled circuit & export and import) – effectively 34 channels of interval data;

(5) 28 days of daily consumption data – export and import (in $);

(6) Current tariff information (separate tables for export and import tariffs)

(7) New tariff information (separate tables for export and import tariffs)

(8) Two most recent bill notifications[5]

5.3.2 Data Structures

The data structures applicable to tariff information and some other items is given in Appendix B

5.4 Displayed information

This section lists what information should be displayed. Much of the information displayed will need to be calculated within the IHD, based on data provided via the electricity meter.

5.4.1 Identification information

Electricity Meter serial number or NMI – DELETE?;

5.4.2 Date and time

The IHD shall display current date and time (either 24 hour format or 12 hour format) either as a separate display or as a component of other displays. Eastern Standard Time (EST) will be available from the electricity meter. Since electricity metering only uses EST any adjustment to for Daylight Saving would need to be performed within the IHD.

5.4.3 Current consumption export and import.

(1) $/hour consumption - export

(2) kW demand – export

(3) $/hour import (generation into grid)

(4) kW import (produced)

(5) kg per day CO2 emissions

5.4.4 Historic consumption (and/or import).

(a) Last 24 hours:

(1) $ consumption for each half hour (block graph)

(2) Average kW demand for each half hour (block graph)

(3) Kg CO2 emissions for each half hour (block graph, consumption only.)

(4) $ import for each half hour (block graph)

(5) Average kW produced (import) for each half hour (block graph)

(b) Last 7 days:

(1) $ consumption for each of last 7 days (block graph)

(2) Average kW demand for each of last 7 days (block graph)

[5] The IHD needs to know the date of last billing when using block tariffs else it does not know when to re-start using first block rates again.

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(3) Kg CO2 emissions for each of last 7 days (block graph, consumption only.)

(4) $ import for each of last 7 days (block graph)

(5) Average kW import for each of last 7 days (block graph)

(c) Last 28 days:

(1) $ consumption for each of last 28 days (block graph)

(2) Average kW demand for each of last 28 days (block graph)

(3) Kg CO2 emissions for each of last 28 days (block graph, consumption only.)

(4) $ import for each of last 28 days (block graph)

(5) Average kW import for each of last 28 days (block graph)

5.4.5 Current Tariff - export[6]

(a) Main circuit tariff allowing for a minimum of: CCP event and max demand tariff

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(1) Supply charge

(2) 6 TOU rates

(3) 6 Consumption blocks for each of the first 2 TOU rates, then 2 blocks for each of the remaining 4 TOU rates - each block ($/kWh) and block limit value (kWh)

(4) 5 time periods per weekday

(5) 3 time periods per Saturday

(6) 3 times periods per Sunday

(b) Controlled circuit tariff allowing for a minimum of:

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(1) Supply charge

(2) 4 TOU rates

(3) 2 Consumption blocks for each TOU rate ($/kWh)

(4) 4 time periods per weekday

(5) 2 time periods per Saturday/Sunday

~~(b) Controlled circuit tariff allowing for a minimum of:~~

~~(1) Supply charge~~

~~(2) 4 TOU rates~~

~~(3) 2 Consumption blocks for each TOU rate ($/kWh)~~

~~(4) 4 time periods per weekday~~

~~2 time periods per Saturday/Sunday~~

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5.4.6 Current Tariff - import[7]

(a) Tariff allowing for a minimum of:

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6 Export is defined as energy being exported from the power system to a customer.

7 Import is defined as energy imported to the power system from the customer (ie: where the customer has a capability to generate electricity back into the power system.)

(1) 3 TOU rates

(2) 4 time periods per weekday

(3) 4 time periods per Saturday/ Sunday

5.4.7 Previous Tariff - export[8]

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(a) Main circuit tariff allowing for a minimum of:

(1) Supply charge

(2) 6 TOU rates

(3) 6 Consumption blocks for each of the first 2 TOU rates, then 2 blocks for each of the remaining 4 TOU rates - each block ($/kWh) and block limit value (kWh)

(4) 5 time periods per weekday

(5) 3 time periods per Saturday

(6) 3 times periods per Sunday

(b) Controlled circuit tariff allowing for a minimum of:

(1) Supply charge

(2) 4 TOU rates

(3) 2 Consumption blocks for each TOU rate ($/kWh)

(4) 4 time periods per weekday

(5) 2 time periods per Saturday/Sunday

5.4.8 Previous Tariff - import[9]

(a) Tariff allowing for a minimum of:

(1) 3 TOU rates

(2) 4 time periods per weekday

(3) 4 time periods per Saturday/ Sunday

~~5.4.7~~5.4.9 New Tariff[10] - export

A new tariff would have the same information structure as the current tariff (for main and controlled circuit), but would also have an effectivity date.

~~5.4.8~~5.4.10 New Tariff – import

A new tariff would have the same information structure as the current tariff, but would also have an effectivity date.

~~5.4.9~~5.4.11 Last bill[11]

(1) Bill amount $,

[8] Export is defined as energy being exported from the power system to a customer.

[9] Import is defined as energy imported to the power system from the customer (ie: where the customer has a capability to generate electricity back into the power system.)

[10] When the effectivity date is reached the new tariff information overwrites the current tariff information

[11] This is the most recently issued bill. "Previous bill" refers to the bill prior to the most recent bill.

(2) date billed,

(3) due date / date paid[12]

(4) Amount paid[13]

(5) Partly or fully paid

~~5.4.10~~5.4.12 Previous bill

(1) Bill amount $,

(2) date billed,

(3) due date / date paid

(4) Amount paid[14]

(5) Partly or fully paid

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[12] When paid, the "due date" changes to "paid date"

[13] If multiple payments made (e.g. Easyway) then all payments for the preceding 3 month period to be listed

[14] If multiple payments made (e.g. Easyway) then all payments for the preceding 3 month period to be listed

A. Appendix – Message Structures

[Message Structures are currently being developed as a separate document]

B. Appendix – Data Structures

[Drafting Note – these data structures are currently being developed as a separate document]

FOI 190420
Document 2

Department of Primary Industries

ADVANCED METERING INFRASTRUCTURE

Minimum AMI Service Levels

19 August 2007

Version 0.8

Victoria
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Contents

1 DOCUMENT CONTROL

1.1 Version Control

Version	Date	Description
0.1	29 June	Initial draft for FWG
0.2	15 July	Incorporates Retailers suggested changes to v0.1
0.3	17 July	Incorporates changes from FWG meeting of 17 July
0.4	31 July	Incorporates changes from FWG meeting of 31 July
0.5	7 August	Incorporates changes from FWG meeting of 7 August
0.6	11 August	Proposed changes for FWG meeting of 14 August
0.7	14 August	14 August FWG meeting working document

1.2 Distribution

Name	Purpose
FWG members	For review and continued development of the document
AMI systems vendors	For review and advice regarding the impact of requirements on ability of AMI systems to deliver the service levels required and any AMI systems cost impacts
AMI Stakeholders	For review and assessment of AMI service levels in meeting their needs

1.3 Related documents

Document	Version	Date
Minimum statewide AMI functionality specification	6.4	14 August 2007
In Home Display functionality guidelines	3.0	8 June 2007
AMI Business and Data Requirements	1.2	27 April 2007

2 INTRODUCTION

2.1 Background

In early 2006, the Victorian Government formally endorsed the deployment of Advanced Metering Infrastructure (AMI) to all Victorian electricity customers consuming less than 160MWh per annum. An amendment to the *Electricity Industry Act 2000* was passed by the Victorian Parliament in August 2006, providing the Government with legislative heads of power to make Orders in Council (OIC) establishing a range of requirements for the deployment of AMI, including the setting of minimum AMI functionality, performance levels and service levels.

2.2 Purpose of Document

This specification defines the minimum service levels for AMI systems deployed in Victoria.

2.3 Scope of application

The requirements established by this specification apply to all metered electricity customer installations where the annual consumption is less than 160 MWh and where the electricity supply is non-incidental.

3 AMI SERVICE LEVELS SCOPE

Figure 1 below depicts the scope of an AMI system and the scope of AMI service levels, in the context of the end to end systems required to support AMI.

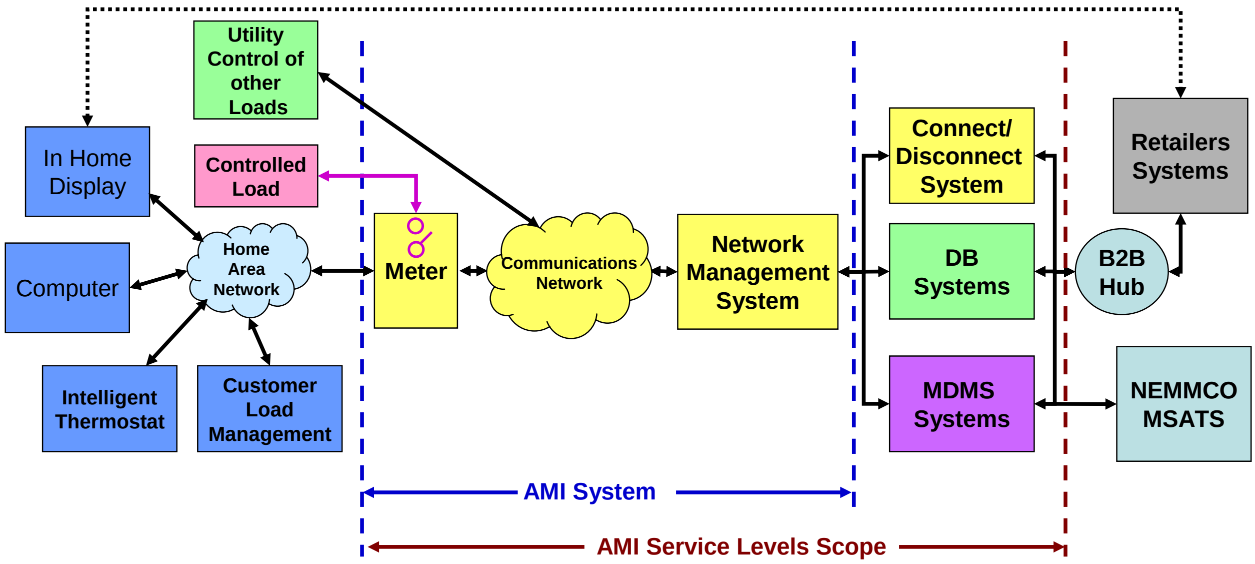

Figure 1 – Overview of AMI System

All AMI meters will support connectivity to a customer's Home Area Network (HAN) as described in the AMI minimum statewide functionality specification. There may be a range of devices connected to the customer's HAN such as an In-home Display (IHD), a computer, an intelligent thermostat and/or a range of load management devices (which might, for example control a pool pump, air conditioning unit or dishwasher). It is noted that AMI systems do not preclude alternative communications channels with HAN devices and an example of this has been illustrated in Figure 1 with a potential non-AMI communications link between a retailer's systems and a customer's IHD..

AMI metering configurations will allow for the continuation of current load control practice whereby certain appliances (such as storage water heaters or space heaters) can be directly connected to an AMI meter via a dedicated electricity circuit (shown as "Controlled Load" in Figure 1), and will allow these appliances to be remotely controlled with the ability to turn the power to an appliance on or off within the AMI meter itself.

In addition, other appliances (eg: air conditioners, pool pumps) which might not have dedicated electrical circuits at the customer's switchboard, may also be remotely controlled directly (shown as "Utility Control of other Loads" in Figure 1) with appropriate commands sent via the AMI communications infrastructure but not relayed through the AMI meter.

As illustrated in Figure 1, AMI systems include a communications network to allow communications between AMI devices at the customer's premises and the Network Management System (NMS) It is noted that in some AMI technologies, data concentrators would be part of this communications network.

The NMS provides connectivity to back-end systems including connect/disconnect system, meter data management system (MDMS) and other DB systems. Figure 1 also illustrates the connectivity with Retailers systems and NEMMCOs B2B hub and MSATS systems.

3.1 Phased rollout of AMI

The implementation plan for the rollout of AMI is based on four phases. In the first three phases DBs have exclusivity of provision of AMI services:

- Phase 1 - Piloting of AMI systems. No new market services are required. 31 December 2008 to 31 December 2009
- Phase 2 – Larger scale implementation of AMI. Basic AMI services apply. 1 January 2010 to 31 December 2011.
- Phase 3 – Completion of AMI rollout – Full AMI services apply – 1 January 2012 to 31 December 2013
- Phase 4 – DBs not the exclusive providers of AMI services. Services and service levels are not defined for this phase. 1 January 2014 and beyond.

A range of AMI Services have been identified and defined for phases 2 and 3 of the AMI rollout. These services are detailed in section 4. Many of these services are initiated by a service request from a retailer to a DB and the completion (or otherwise) of the service requires a confirmation to the requesting retailer. Although the business processes for many such services flow from a retailer through to a DB, through to a customers meter and return, the scope of the minimum service levels is only that which is within the DBs control, as shown in Figure 1 above.

Subsequent to the AMI rollout and the sunset of the period of DB exclusivity for AMI service, a Retailer may appoint a Metering Provider (MP) and an MDA that is not the incumbent distributor for the provision of AMI services. This document does not specify any minimum service levels for this scenario.

4 SERVICES AND MINIMUM SERVICE LEVELS

4.1 Definitions

In the following tables it is noted that:

– DNSP = Distribution Network Service provider (or termed DB in other parts of this document)

– FRMP – Financially Responsible Market Participant. Generally this refers to the retailer of the customer in this document.

4.2 Assumptions

In the following tables it is assumed that:

– Unless otherwise noted, the service levels are measured from the receipt of a valid request at the DNSP.

– All requests require a confirmation to the initiator of completion of the request or advice as to why the request could not be completed

– Performance against the service levels are to be measured over a 12 month period

– Unless otherwise noted, all references to days are calendar days

– All times are Eastern Standard Time (EST)

4.3 Phase 2 Services

		Service	Definition	Comments	Minimum Service Level	Output	Initiator
1		Routine Read – Remote	Daily interval energy data collection from all meters,	delivered by 6am the following day	Interval energy data from all meters for the previous day available to market participants, with: • No less than 95% being actual data from meters, (with the remainder substituted), to be available by 6am • No less than 99% of actual data within 24 hours • No less than 99.9% of actual data within ten business days	Energy data file to MSATS, FRMP, LR, DNSP	DNSP
2	a	De-energisation	Remote De-energisation of individual meters at prior notified date and time (excluding CT connected meters)	Removal of supply on the customer's side of the meter, at the meter, by use of the meters connect/disconnect contactor at a selectable date and time	The request needs to be completed (not prior to the requested date and time) for: • No less than 90% of requested meters within 1 hour • No less than 99% of requested meters within 2 hours • No less than 99.9% of requested meters within 2 days The total number of requests received in any 24 hour period shall not exceed 2% of the installed, operational AMI meter population	De-energisation of customer installation	FRMP
2	b	De-energisation	Remote De-energisation of individual meters (0 - 2 hours) (excluding CT connected meters)	Removal of supply on the customer's side of the meter, at the meter, by use of the meter's connect/disconnect contactor	The request needs to be completed for: • No less than 90% of requested meters within 1 hour • No less than 99% of requested meters within 2 hours • No less than 99.9% of requested meters within 2 days The total number of requests received in any 24 hour period shall not exceed 2% of the meter population.	De-energisation of customer installation	FRMP

		Service	Definition	Comments	Minimum Service Level	Output	Initiator
3	a	Re-energisation	Remote re-energisation (at future date and time) of individual meters (excluding CT connected meters)	Re-energise the customers electrical installation at a selectable date and time via the connect/disconnect contactor in the meter without the need for the customer's intervention.	a. Subject to b. below; The request needs to be completed (not prior to the requested date and time) for: • No less than 90% of meters within 1 hour • No less than 99% of meters within 2 hours • No less than 99.9% of meters within 2 days b. The total number of requests received in any 24 hour period shall not exceed 2% of the requestor's installed, commissioned AMI meter population	Energisation of customers installation	FRMP
3	b	Re-energisation	Remote re-energisation (0 - 2 hrs) of individual meters (excluding CT connected meters)	Re-energise the customers electrical installation via the connect/disconnect contactor in the meter without the need for the customer's intervention.	The request needs to be completed for: • No less than 90% of meters within 1 hour • No less than 99% of meters within 2 hours • No less than 99.9% of meters within 2 days The total number of requests received in any 24 hour period shall not exceed 2% of the installed, operational AMI meter population	Energisation of customers installation	FRMP
4	a	IHD message – Individual	High Priority Messages (ASAP 0 – 4 hrs) Sending a message (of up to 40 bytes) to meters that serve a customer's HAN.	Including but not limited to; messages concerning Critical Peak Pricing events,, emergency supply capacity control events	The message is to be received at no less than 98% of the requested meters within 4 hours Note: The total number of FRMP messages (across all message types) is limited to one message per meter per day Confirmation that the message has been received by the IHD (together with the time it was received) will be provided upon retrieval of the appropriate event log information from the meter	Message received at meter for collection by IHD	FRMP

		Service	Definition	Comments	Minimum Service Level	Output	Initiator
4	b	IHD message – Individual	Medium Priority Message (Within 1 day) Sending a message (of up to 128 bytes) to meters that serve a customer's HAN.	Including but not limited to messages concerning planned outage, reminder of planned outage, promotional material	The message is to be received at no less than 98% of the requested meters within 1 day Note: The total number of FRMP messages (across all message types) is limited to one message per meter per day Confirmation that the message has been received by the IHD (together with the time it was received) will be provided upon retrieval of the appropriate event log information from the meter	Message received at meter for collection by IHD	FRMP or DNSP
4	c	IHD message – Individual	Low Priority Message (Within 5 days) Sending a message (of up to 255 bytes) to meters that serve a customer's HAN.	Including but not limited to messages concerning tariff change	The message is to be received at no less than 98% of the requested meters within 5 days, and no less than 99.9% of the requested meters within 10 days Note: The total number of FRMP messages (across all message types) is limited to one message per meter per day Confirmation that the message has been received by the IHD (together with the time it was received) will be provided upon retrieval of the appropriate event log information from the meter	Message received at meter for collection by IHD	FRMP or DNSP
5		Meter event advice	Daily advice of subset of meter events at all meters pertaining to each retailer. Specifically these are: - - Tamper Detection, - Meter loss of supply, - boost activated, - connect/disconnect contactor change of state, - energy import, - controlled load override - message retrieved from meter by HAN device.	•Subset of meter events which are defined in the AMI functionality specification	Specified event data from all meters for the previous day available to market participants with: • No less than 95% of events from meters, to be available by 6am • No less than 99% of events within 24 hours • No less than 99.9% of events within ten business days	Provision of meter event information to market participants	DNSP

4.4 Phase 3 Services and Minimum Service Levels

		Service	Definition	Comments	Minimum Service Level	Output	Initiator
6	a	Remote controlled load override (to nominated individual meters)	Remote initiation of switching of controlled load (either on or off) which overrides the controlled load switching times stored in the meter for a selectable period from 0 to 48 hours in half hour increments		The request needs to be completed for: • No less than 90% of requested meters within 1 hour • No less than 99.9% of requested meters within 12 hours The total number of requests received in any 24 hour period shall not exceed 2% of the installed, operational AMI meter population	Changed status of controlled load contactor	FRMP
6	b	Remote Controlled load override (to a larger number of meters) using groups	Remote initiation of switching of controlled load (either on or off) which overrides the controlled load switching times stored in the meter for a selectable period from 0 to 48 hours in half hour increments	Utilises AMI tertiary groups. Retailers are required to manage which NMIs are in which group..	The request needs to be completed for: • No less than 90% of requested meters within 20 minutes • No less than99% of requested meters within 90 minutes Confirmation that the request has been completed will be provided upon retrieval of the appropriate event log information from the meter	Changed status of controlled load contactor	FRMP

		Service	Definition	Comments	Minimum Service Level	Output	Initiator
7		Read meter information	Subtypes are: a) Read meter event log b) Read meter settings c) Read meter status	Events, settings and status items are detailed in Appendix A of the minimum statewide AMI functionality specification There are configurable parameters (such as encryption keys) that may not be retrieved in this service.	The request needs to be completed for: • No less than 90% of requested meters in within 2 hours • No less than 99% of requested meters in within 6 hours • No less than 99.9% of requested in within 10 business days The total number of requests received in any 24 hour period shall not exceed 2% of the meter population. The number of events retrieved from the event log will be the 100 most recent events	Provision of meter information to market participants	FRMP
8		Change non metrology Meter settings	Change selected meter settings in the meter. Including:	Settings are detailed in Appendix A of the minimum statewide AMI functionality specification	The request needs to be completed for: • No less than 90% of requested meters in within 2 hours • No less than 99% of requested meters in within 6 hours • No less than 99.9% of requested in within 10 business days The total number of requests received in any 24 hour period shall not exceed 2% of the meter population.	Changed meter settings	FRMP

FOI 190420
Document 3

Department of Primary Industries

ADVANCED METERING INFRASTRUCTURE

Minimum State-wide Functionality Specification

14 August 2007

Version 6.4

Victoria
The Place To Be

Contents

1 DOCUMENT CONTROL

1.1 Version Control

Version	Date	Description
First Draft	August 2006	Initial draft which was put out to stakeholder consultation
Second Draft (V4.4)	December 2006	Second draft incorporating results of consultation
5.0	7 June 2007	First revision in a process to lead to finalisation in Sept 2007.
5.2	19 June 2007	Second revision – FWG draft
5.3	3 July	Third revision – FWG draft
6.0	17 July	Fourth revision – FWG draft
6.1	31 July	Fifth revision – FWG draft
6.2	1 August	Sixth revision – FWG draft
6.3	7 August	Seventh revision – FWG draft

1.2 Distribution

Name	Purpose
FWG members	For review and continued development of the document
AMI systems vendors	For review and advice regarding the impact of requirements on ability of AMI systems to deliver the functionality required and any AMI systems cost impacts
AMI Stakeholders	For review and assessment of AMI functionality in meeting their needs

1.3 Related documents

Document	Version	Date
In Home Display functionality guidelines	3.0	8 June 2007
AMI Service Levels Specification	0.6	7 August 2007
AMI Business and Data Requirements	1.2	27 April 2007

2 INTRODUCTION

2.1 Background

In early 2006, the Victorian Government formally endorsed the deployment of Advanced Metering Infrastructure (AMI) to all Victorian electricity customers consuming less than 160MWh per annum. An amendment to the *Electricity Industry Act 2000* was passed by the Victorian Parliament in August 2006, providing the Government with legislative heads of power to make Orders in Council (OIC) establishing a range of requirements for the deployment of AMI, including the setting of minimum AMI functionality, performance levels and service levels.

2.2 Purpose of Document

This specification defines the minimum functionality and performance levels for AMI systems deployed in Victoria.

2.3 Scope of application

The requirements established by this specification apply to all metered electricity customer installations where the annual consumption is less than 160 MWh and where the electricity supply is non-incidental.

The requirements in this specification only apply to AMI systems, the scope of which is defined in section 3. These requirements are minimum requirements only and do not limit the implementation of AMI systems that have functionality and performance that exceed the requirements of this specification.

3 AMI SYSTEMS OVERVIEW

Figure 1 below depicts the scope of an AMI system, for the purposes of this specification, in the context of the end to end systems required to support AMI.

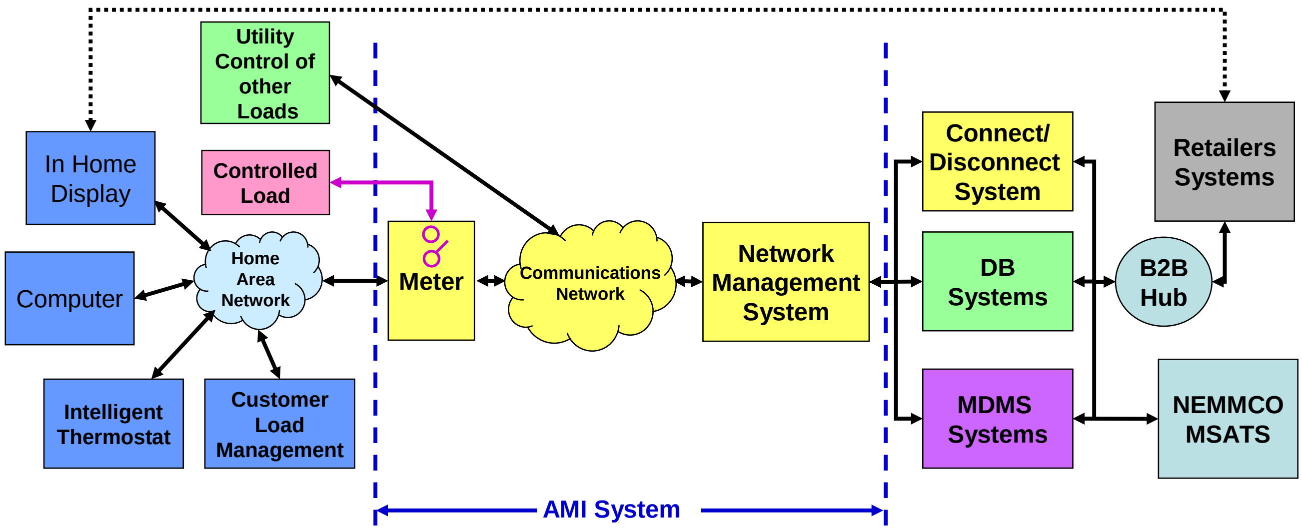

Figure 1 – Overview of AMI System

All AMI meters will support connectivity to a customer's Home Area Network (HAN) as described in this specification (refer section 4.10). There may be a range of devices connected to the customer's HAN such as an In-home Display (IHD), a computer, an intelligent thermostat and/or a range of load management devices (which might, for example control a pool pump, air conditioning unit or dishwasher). It is noted that AMI systems do not preclude alternative communications channels with HAN devices and an example of this has been illustrated in Figure 1 with a potential non-AMI communications link between a retailer's systems and a customer's IHD.

AMI metering configurations will allow for the continuation of current load control practice whereby certain appliances (such as storage water heaters or space heaters) can be directly connected to an AMI meter via a dedicated electricity circuit (shown as "Controlled Load" in Figure 1), and will allow these appliances to be remotely controlled with the ability to turn the power to an appliance on or off within the AMI meter itself.

In addition, other appliances (eg: air conditioners, pool pumps) which might not have dedicated electrical circuits at the customer's switchboard, may also be remotely controlled directly (shown as "Utility Control of other Loads" in Figure 1) with appropriate commands sent via the AMI communications infrastructure but not relayed through the AMI meter.

As illustrated in Figure 1, AMI systems include a communications network to allow communications between AMI devices at the customer's premises and the Network Management System (NMS) It is noted that in some AMI technologies, data concentrators would be part of this communications network.

The NMS provides connectivity to back-end systems including connect/disconnect system, meter data management system (MDMS) and other DB systems. Figure 1 also illustrates the connectivity with Retailers systems and NEMMCOs B2B hub and MSATS systems.

4 MINIMUM STATEWIDE FUNCTIONALITY REQUIREMENTS

4.1 Applicable meter configurations

(a) These functionality requirements apply to all AMI metering installations for Victoria. However, the following lists the minimum requirement for AMI metering configurations:

(1) Single phase, single element

(2) Single phase, single element with integrated load control

(3) Three phase direct connect

(4) Three phase direct connect with integrated single phase load control

(5) Three phase direct connect with external three phase load control

(6) Three phase CT connect (excluding connect/disconnect)

(b) All meter types shall meet the relevant requirements of AS62052.11, AS62052.21, AS62053.21, and any pattern approval requirements of the National Measurement Institute.

4.2 Metrology

(a) The following requirements shall apply to all AMI meters:

(1) Single phase meters to be two quadrant meters and separately record active energy for import[1] and export in 30 minute intervals.

(2) Three phase meters to be four quadrant meters and to separately record active and reactive energy, import[1] and export in 30 minute intervals.

(3) Record total accumulated consumption per interval channel.

(4) The minimum resolution for collection of 30 minute interval energy data shall be 0.1 kWh for active energy and 0.1 kVArh for reactive energy[2].

(5) The minimum resolution of energy consumption displayed on a meter's display shall be 0.1 kWh and 0.1 kVArh for direct connected meters.

(6) For all meters, a minimum storage of 35 days per channel of 30 minute interval energy data.

(7) All channels of 30 minute interval energy data shall be able to be read locally as well as remotely read.

(b) An AMI meter shall be capable of meeting the requirements (including accuracy) of both type 4 and type 6 meters (non-ToU capability)[3]

(c) The reading of active energy import data is only required when there is local generation capability at the premises. The values to be recorded for import and export are actual values at the Connection Point for direct connect meters[4].

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[1] It is noted that in accordance with the conventions of the National Electricity Market, export is when energy is exported from the network to a customer and import is when the customer delivers energy into the network.

[2] Subject to NMI approval.

[3] The minimum specification doesn't support the use of these meters as type 5.

[4] For example, if a customer has local generation from photovoltaic cells, and during the first 20 minutes of a half hour period there was export from the network to the customer of 3 kWh and during the next 10 minutes the network imported 2 kWh from the customer, although the mathematical total for the half hour is 1 kWh exported, the actual values recorded for that half hour would be, Export – 3 kWh, Import – 2 kWh

(d) It shall be possible to remotely and locally select or configure whether import energy interval data is collected or not

(e) It shall be possible to remotely and locally select or configure whether reactive interval data is collected from three phase meters or not.

(f) When import energy is recorded in a meter a locally and remotely readable status flag shall be set in the meter to indicate this fact.

4.3 Remote and local reading of interval data (routine reads and individual reads)

(a) When meters are remotely read, the meter's total accumulated consumption per collected channel shall also be collected in addition to the 30 minute interval energy data and be provided by the AMI system at least once every 24 hours.

(b) For individual reads of meters, it shall be possible to select up to 35 days of 30 minute interval energy data is to be collected per channel.

(c) The AMI system shall also allow collection from meters of

   (1) settings,

   (2) time,[5]

   (3) date,

   (4) status indicators and

   (5) events logs.

   Appendix A details the events, settings and status indicators.

4.4 Customer Disconnect, & Reconnect[6]

4.4.1 General Requirements

(a) All meter types excluding CT connected meters shall have a connect/disconnect contactor.

(b) The AMI system shall support both local and remote disconnection, and local and remote reconnection of customer supply via the connect/disconnect contactor. When an AMI meter performs a disconnect operation, all outgoing circuits from the meter shall be disconnected.

(c) To confirm the current state of a meter, the AMI system shall support "on-demand" remote polling of the meter to determine whether the connect/disconnect contactor is open or closed;

(d) The AMI system shall complete on-demand polling commands, returning the meter status, with the performance levels set out in section 5.

(e) The meter shall provide clear local indication of the status (open/closed) of the connect/disconnect contactor.

4.4.2 Disconnect

(a) The AMI system shall support both local and remote customer supply disconnect functionality.

[5] The meter time and date needs to be cross referenced to an upstream system

[6] The term "connect" is equivalent to the term "re-energisation" used in national electricity market documents. Similarly the term "disconnect" is equivalent to the term "de-energisation".

(b) For remote disconnects, the AMI system shall complete the disconnect command, returning the meter status, within the performance levels set out in section 5.

4.4.2.1 Local Disconnect[7]

(a) Local disconnect via the meter shall only be able to performed by an authorised technician. Unauthorised persons shall be physically prevented from operating the connect/disconnect contactor to disconnect supply.

(b) The AMI system shall support the following:

(1) Local opening of the disconnection relay;

(2) Remote communication of the status (open/closed) of the connect/disconnect contactor (if AMI communications are active) from the meter to the NMS

(3) Event logging by the AMI system of the local disconnection at that meter.

4.4.2.2 Remote Disconnect

(a) The AMI system shall support the following:

(1) Remote opening of the disconnection relay;

(2) Remote communication of the status (open/closed) of the connect/disconnect contactor (if AMI communications are active) from the meter to the NMS;

(3) Event logging by the AMI system of the remote disconnection at that meter.

4.4.3 Reconnection

(a) The AMI system shall support both local and remote customer supply reconnection functionality.

(b) When a command is performed remotely, the AMI system shall complete the command, returning the appropriate meter status to the NMS, within the performance levels set out in section 5.

4.4.3.1 Local reconnection

(a) Local reconnection via the meter shall only be able to performed by an authorised technician. Unauthorised persons shall be physically prevented from operating the connect/disconnect contactor to reconnect supply

(b) The AMI system shall support the following:

(1) Local closing of the connect/disconnect contactor;

(2) Remote communication of the status (open/closed) of the connect/disconnect contactor (if AMI communications are active) from the meter to the NMS

(3) Event logging by the AMI system of local reconnection at that meter.

4.4.3.2 Remote reconnection

(a) For safety, the meter shall support an auto-disconnect function if load is detected flowing through the meter upon remote closing of the connect/disconnect contactor.

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[7] The circumstances in which local disconnection may occur include (but is not limited to) where:

(1) A technician is already on-site performing works and it is most efficient for the technician to perform the disconnection;

(2) An AMI meter is installed; however the communications infrastructure has not been rolled out or has failed.

(b) The AMI system shall support the following:

(1) Remote closing of the connect/disconnect contactor;

(2) Remote communication of the status (open/closed) of the disconnect relay from the meter to the NMS;

(3) Event logging by the AMI system of remote activation;

(4) Meter will auto-disconnect if a minimum of "X" Watts of load is detected flowing through the meter for a minimum of "Y" seconds of the connect/disconnect contactor being remotely closed:

(i). "X" range; 20 W – 2.5 kW per element, per phase, remotely and locally settable in 20 W increments;

(ii). "Y" range; 1- 3,600 seconds, remotely and locally settable in 1 second increments;

(iii). Enabling/disabling of auto-disconnect function, remotely and locally configurable;

(iv). Remote alarming to the NMS that the meter has auto-disconnected;

(v). Event logging of auto-disconnection;

(vi). Auto-disconnect function active for "Z" seconds after remote activate (where the range for "Z" is 1- 3,600 seconds, remotely and locally settable).

4.5 Time Clock Synchronisation

Date and time within meters shall be maintained within 20 seconds of Eastern Standard Time.

4.6 Load Control

4.6.1 Load control Groups

(a) All load control, whether controlled load (section 4.6.2) or utility control of other load (section 4.6.3) shall be able to respond to group commands and individual load control commands. Group commands may be delivered by broadcast.

(b) Groups shall provide for a minimum of 20 primary groups (for use by Distributors), 200 secondary groups (for use by Distributors) and 200 tertiary groups (for use by Retailers).

(c) The 200 tertiary groups are to be allocated across the retailers to allow several groups per retailer.

4.6.2 Controlled load management at meters

The following are the features required of single phase or three phase meters with an internal controlled load contactor and three phase meters equipped to operate an external controlled load contactor:

(a) The controlled load shall be remotely and locally programmable to respond to one primary group, one secondary group and one tertiary group.

(b) Storage in the meter of 5 sets of "turn on" & "turn off" times per week day & 5 sets of "turn on" & "turn off" times per weekend day.

(c) "Turn on" and "turn off" times are remotely and locally settable for each meter individually and in groups through the AMI communications system.

(d) At "turn on" times meters would react by turning on the controlled load after a randomised time delay remotely and locally settable from 0 minute to 60 minutes in 1 minute increments (Often referred to as "spread on").

(e) Meters shall recognise “turn on” & “turn off” commands that will override the switching program stored in the meter. The “turn on” and “turn off” functionality shall be individually addressable or by groups. The action of receiving a remote “turn on” or “turn off” command shall disable or override the preset time based “turn on” and “turn off” schedule for a programmable period between 0 and 48 hours, settable in ½ hour increments.

(f) Single phase controlled load meters are to have a “boost” facility. This facility shall be able to be remotely and locally enabled or disabled. When a customer activates the meter’s “boost” facility, the meter will energise the controlled load for a preset time, which is remotely and locally programmable from 1 to 6 hours in half hour increments.

(g) Meters with integrated single phase load control shall have a controlled load contactor with a minimum current rating of 31.5 A resistive (AC1 rating) and a nominal voltage rating of 230 Vac[8].

(h) Meters for three phase load control, shall have an integral relay with a minimum rating of 1 A, and a nominal voltage rating of 230 Vac for operation of an external load control contactor.

4.6.3 Utility Control of Other Load

The AMI system shall have the capability to communicate to “other load control” devices through the AMI communications network as outlined in section 3. The following are the requirements of these “other load control” devices.

(a) “Other load control” devices shall be remotely and locally programmable to respond to one primary group, one secondary group, and one tertiary group.

(b) Storage in the “other load control” devices of 5 sets of “turn on” & “turn off” times per week day & 5 sets of “turn on” & “turn off” times per weekend day.

(c) “Turn on” and “turn off” times are remotely and locally settable individually and in groups, through the AMI communications system.

(d) At “turn on” times these devices would react by turning on load after a randomised time delay remotely and locally settable from 0 minute to 60 minutes in 1 minute increments (Often referred to as “spread on”).

(e) Recognition of “turn on” & “turn off” commands that will override the stored switching program. The “turn on” and “turn off” functionality shall be individually addressable or by groups. The action of receiving a remote “turn on” or “turn off” command shall disable or override the preset time based “turn on” and “turn off” schedule for remotely and locally settable period between 0 and 48 hours, settable in ½ hour increments.

4.7 Meter Loss of Supply detection and Outage Detection

All AMI systems shall include a means of detecting loss of supply to meters including those at individual customer’s premises.

When a meter loss of supply or outage is detected it is to be alarmed to the NMS as soon as possible.

4.8 Quality of Supply & other event recording

All AMI systems are to have the capability to record and store the 100 most recent Quality of Supply (QoS) events and other events that occur at each meter as detailed in Appendix A. The AMI system shall record the nature of the event (eg: outage, undervoltage, disconnect etc), the date and time of the beginning of the event, and the date and time of the end of the event.

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[8] The tolerance on the rated voltage is as per the Electricity Distribution Code

4.8.1 Meter Loss of Supply

The trigger for a meter loss of supply event is when the supply voltage reduces to a point where the meter shuts down, which shall be at a maximum 80% of nominal voltage.

For three phase meters where the loss of less than all phases causes the meter to shut down the phases affected shall also be recorded.

4.8.2 Undervoltage & overvoltage recording

(a) Undervoltage and overvoltage events shall be recorded. The thresholds shall be remotely and locally settable for undervoltage in the range of at least -5% to -20%[9] in 1% steps and for overvoltage in the range of at least +5% to +20%[10] in 1% steps.

(b) All events of 1 second or longer shall be recorded.

(c) For each undervoltage event the minimum voltage that occurred during the period shall be recorded. For each overvoltage event the maximum voltage that occurred during the period shall be recorded. For three phase meters, the phases affected shall also be recorded.

4.8.3 Events for daily reporting

For each meter the following events shall be recorded in the AMI system and be available for daily reporting:

(a) Meter loss of supply

(b) Boost activated

(c) Tamper detected

(d) Connect /Disconnect activated (the connect/disconnect contactor has changed state – open or closed – for any cause

(e) Energy import detected

(f) Controlled load override

(g) Message retrieved from meter by customer HAN

4.8.4 Other events

(a) The complete list of events which must be logged is detailed in Appendix A

4.9 Supply Capacity Control

(a) AMI meters (except CT connected meters) shall have two supply capacity limit settings – a normal limit and an emergency limit. This functionality applies only to direct connected meters (ie: does not apply to CT connected meters):

(b) All supply capacity control settings shall be remotely and locally configurable.

4.9.1 Normal supply capacity limit operation

4.9.1.1 When energy is exported from the network to a customer

The connect/disconnect contactor shall open if the average kW demand across the last X number of thirty minute intervals is greater than the demand limit (Y kW), where:

X is settable from 1 to 10 thirty minute intervals in increments of 1 thirty minute interval; and

[9] Detection of undervoltage levels is limited to -20% because of technical limitations of meters.

[10] Detection of overvoltage is limited to +20% because of technical limitations of meters.

Y is settable from 0.5 to 99 kW in increments of 0.5 kW up to 24 kW, then 1 kW from 24 kW to 99 kW .

4.9.1.2 When energy is imported from a customer to the network

The connect/disconnect contactor shall open if the average kW demand across the last U number of thirty minute intervals is greater than the demand limit (V kW), where:

U is settable from 1 to 10 thirty minute intervals in increments of 1 thirty minute interval; and

V is settable from 0.5 to 99 kW in increments of 0.5 kW.

4.9.1.3 Enabling, disabling and event recording

(a) The supply capacity control functionality shall be able to be remotely and locally enabled and disabled.

(b) If the connect/disconnect contactor has opened due to the demand having exceeded the demand limit, the contactor shall remain open for a period of T minutes (where T is settable from 1 to 60 minutes in 1 minute increments) and then automatically reclose.

(c) The disconnection and any subsequent reconnection shall be recorded as events as described in section 4.8.4.

4.9.2 Emergency supply capacity limit operation

(a) The AMI system shall have the capability to remotely and locally activate or de-activate the emergency supply capacity limit in AMI meters by either primary or secondary groups of meters, or by commands sent to individual meters. The primary and secondary groups shall be the same groups required in section 4.6.1.

(b) When the emergency supply capacity limit is activated this will then take precedence over the normal supply capacity setting.

(c) The emergency supply capacity limit functionality in AMI meters must be capable of being remotely and locally enabled or disabled for selected meters

(d) When the emergency supply capacity limit is activated, the connect/disconnect contactor shall open if the average kW demand across R minutes is greater than the emergency supply capacity limit (S kW) where:

R is settable from 1 to 60 minutes in increments of 1 minute

S is settable from 0.5 kW to 99kW in increments of 0.5 kW.

(e) If the connect/disconnect contactor has opened due to the demand having exceeded the emergency demand limit, the contactor shall remain open for a period of T minutes (where T is settable from 1 to 60 minutes in 1 minute increments) and then automatically reclose.

4.10 Interface to Home Area Network (HAN)

(a) All AMI meters shall have a Zigbee interface which can connect to a customer's HAN using the Zigbee AMI application profile operating in the license exempt 2.4 GHz band, and at least 50 mW power output as outlined in section 3. The meter will be an end device (not a co-ordinator) on the customer's HAN network.

(b) All communications to a customer's HAN shall be uniquely bound to the customer's meter. (This is to ensure that a customer's HAN receives information pertaining to their premises and not a neighbour's premises.)

(c) HAN devices shall be able to read from the meter at least the following:

(1) The meter's instantaneous demand (kW) with sign to indicate export or import (unvalidated data)- able to be read as frequently as every 5 seconds.

(2) The last 30 minute interval energy data (unvalidated data) for real energy export and real energy import together with the date and time.

(3) The last 28 days of interval energy data, export and import

(4) The applicable supply capacity limit (kW).

(d) The HAN co-ordinator or any other device on the HAN shall not be able to write information to the meter.

(e) The AMI system shall be able to send one message per day by individual messaging or broadcast messaging to each meter for a HAN device to retrieve from the meter. (The retrieval of messages from meters shall be logged as an event as per 4.8.3).

(f) Meters shall store the last three messages received.

4.11 Tamper Detection

(a) The AMI system shall support detection of attempts to tamper with the meter.

(b) The AMI system shall support remote communication of the tampering detected to the NMS.

4.12 Communications and data security

The AMI system shall ensure all communications between system components shall be secured in such a way as to prevent unauthorised interception and modification. All device elements shall contain the necessary security to prevent unauthorised access or modification of data.

4.13 Remote Firmware Upgrades

(a) The AMI system shall have the capability to remotely upgrade the firmware in AMI system devices including data concentrators and meters.

(b) It shall not be possible to remotely change the firmware that operates the metrology functions of the meter.

4.14 Self registration of meters

Meters shall have the capability to self register with the NMS.

5 PERFORMANCE LEVELS

The following are the AMI system performance levels required.

(a) These performance levels apply to the complete AMI system as delineated in section 3, but not to any upstream systems or downstream systems.

(b) These performance levels specifically apply from the NMS to the meter and return.

(c) It is noted that an AMI system may include communications links provided by third parties such as telecommunications carriers and which are outside of the control of the DB that operates the AMI system.

(d) The performance levels are average performance levels over the period of a year and exclude force majeure events.

5.1 Performance levels for collection of daily meter readings

The following are the performance levels required for the daily collection of the previous trading day's 30 minute interval energy data (as required in section 4.3).

(1) All data from 99% of meters within 4 hours after midnight

(2) All data from 99.9% of meters within 24 hours after midnight

5.2 Performance levels for remote reads of individual meters

An individual read (refer section 4.3) is defined as the reading of seven days of interval energy data from a particular AMI meter. The performance level required for reads of individual meters is:

(1) Action performed at 90% of meters within 30 minutes

(2) Action performed at 99% of meters within 1 hour

(3) Action performed at 99.9% of meters within 6 hours

The total number of individual meters read in any 24 hour period can be up to 2% of the installed, operational AMI meter population

5.3 Performance levels for remote connect/disconnect

The performance level required for individual meters is:

(1) Action performed at 90% of meters within 30 minutes

(2) Action performed at 99% of meters within 1 hour

(3) Action performed at 99.9% of meters within 6 hours

The total number of connects/disconnects commands to individual meters in any 24 hour period can be up to 2% of the installed, operational AMI meter population

5.4 Performance levels for remote load control commands & emergency supply capacity limiting

(a) The actions covered in this category are specified in section 4.6 for Controlled Load Management and for Utility Control of Other Loads, and in section 4.9.2 for emergency supply capacity control. For commands to any primary, secondary or tertiary group of meters the performance level required is:

(1) Action performed at 90% of meters within 10 minutes

(2) Action performed at 99% of meters within 1 hour

(b) For commands sent to individual meters, the performance level required is:

(1) Action performed at 90% of meters within 30 minutes

(2) Action performed at 99% of meters within 1 hour

(3) Action performed at 99.9% of meters within 6 hours

The total number of load control commands to individual meters in any 24 hour period can be up to 2% of the installed, operational AMI meter population

5.5 Performance levels for remotely altering settings in meters

The performance level required for individual meters is:

(1) Action performed at 90% of meters within 30 minutes

(2) Action performed at 99% of meters within 1 hour

(3) Action performed at 99.9% of meters within 6 hours

The total number of commands to alter settings at individual meters in any 24 hour period can be up to 2% of the installed, operational AMI meter population

5.6 Performance levels for remotely reading settings from meters

Performance level required for reading all the settings of an individual meter (refer section 4.3) is:

(1) Action performed at 90% of meters within 30 minutes

(2) Action performed at 99% of meters within 1 hour

(3) Action performed at 99.9% of meters within 6 hours

The total number of commands to read settings from individual meters in any 24 hour period can be up to 2% of the installed, operational AMI meter population

5.7 Performance levels to remotely read events logs

(a) The performance level required for reading the full event log that pertains to an individual meter is:

(1) Action performed for 90% of meters within 30 minutes

(2) Action performed for 99% of meters within 1 hour

(3) Action performed for 99.9% of meters within 6 hours

The total number of commands to read the full event log pertaining to individual meters in any 24 hour period can be up to 2% of the installed, operational AMI meter population

(b) To read the event logs pertaining to all meters:

(1) The data pertaining to 99.5% of meters in 1 week

(2) The data pertaining to 99.9% of meters in 2 weeks

5.8 Performance levels to send messages to meters and HANs

(a) One message per day, can be sent to meters for retrieval by a HAN, either by individual messaging or by broadcasting.

(b) The performance level required for sending high priority messages of up to 40 bytes to meters with HANs connected - message received by 98% of meters, in 3 hours

(c) The performance level required for sending medium priority messages of up to 128 bytes to meters with HANs connected - message received by 98% of meters, in 15 hours

(d) The performance levels required for sending low priority messages of up to 255 bytes to all meters with HANs connected

(1) Message received by 98% of meters in 3 days

(2) Message received by 99.9% of meters in 6 days

A. Appendix - List of Events, Settings and Status Indications

Events	Daily reporting required	Reference
Import energy generated	✓	4.2.f
Local supply disconnection		4.4.2.1(b)(3)
Remote supply disconnection		4.4.2.2(a)(3)
Local reconnection of the supply via the meter		4.4.3.3(a)(4)
Remote reconnection of the supply via the meter		4.4.3.4(b)(4)
Meter auto-disconnection		4.4.3.4(b)(5)(vi)
Connect/Disconnect activated	✓	4.8.3 (d)
Meter loss of supply	✓	4.8.1
Undervoltage event		4.8.2(b)
Overvoltage event		4.8.2(b)
A boost button is pressed	✓	4.8.3(b)
The connect/disconnect contactor is opened or closed		4.8.4(a)(2)
A tamper is detected	✓	4.8.4(a)(3)
Change in “turn on” or “turn off” times for the controlled loads		4.8.4(a)(4)
Whenever there is a change of meter settings		4.8.4(a)(7)
Controlled load override	✓	4.8.4 (a) (5)
Message retrieved from meter by customers HAN	✓	4.8.4 (a) (8)

Settings	Reference
Import interval energy data collection - Enable/Disable	4.2 (d)
Reactive interval energy data collection - Enable/Disable	4.2 (e)
Remote activate (connect) load detection power setting	4.4.3.2 (b) (4) (i)
Remote activate (connect) load detection time delay setting	4.4.3.2 (b) (4) (ii)
Remote activate –disconnection when load detected - Enable /disable	4.4.3.2 (b) (4) (iii)
Remote activate (connect) load detection time enabled setting	4.4.3.2 (b) (4) (vii)
Load control Primary Secondary & Tertiary Groups	4.6.1(a)
Five sets of load control turn “on” and “off” times - weekday	4.6.2(b) & 4.6.3 (b)
Five sets of load control turn “on” and “off” times - weekend	4.6.2(b) & 4.6.3 (b)
Randomised time delay range – 0 to 60 minutes range	4.6.2 (d) & 4.6.3 (d)
Load control override delay time	4.6.2 (e) & 4.6.3 (e)

Settings	Reference
Boost duration	4.6.2 (f)
Undervoltage and overvoltage event recording thresholds	4.8.2 (a)
Normal supply capacity – export – limits – kW and time	4.9.1.1
Normal supply capacity – import – limits – kW and time	4.9.1.2
Normal supply capacity limit - Enable / Disable	4.9.1.3 (a)
Normal supply capacity limit – auto reclose time	4.9.1.3 (b)
Emergency supply capacity – export – limits – kW and time	4.9.2 (d)
Emergency supply capacity limit - Enable / Disable	4.9.2 (a)
Emergency supply capacity limit – auto reclose time	4.9.2 (e)

Status indicators	Reference
Connect/disconnect contactor position – open or closed	4.4.1 (c)
Controlled load contactor – open or closed	4.8.4 (a) (6)

B. Glossary

active energy

Active energy means a measure of electrical energy flow, being the time integral of the product of voltage and the in-phase component of current flow across a connection point expressed in Watt-hours (Wh) and multiples thereof.

active power

Active power means the rate at which active energy is transferred.

Advanced Metering Infrastructure (AMI)

Advanced Metering Infrastructure means the infrastructure associated with the installation and operation of electricity metering and communications including interval meters designed to transmit data to and receive data from a remote locality.

AMI metering installation

An AMI metering installation is a "metering installation" which conforms with the minimum functionality requirements of this "Advanced Metering Infrastructure - Minimum State-wide Functionality Specification**"**

Australian Standard (AS)

Australian Standard means the most recent edition of a standard publication by Standards Australia (Standards Association of Australia).

B2B e-Hub

B2B e-Hub means an electronic information exchange platform established by NEMMCO to facilitate business to business (B2B) Communications.

communications network

Communications network means all communications equipment, processes and arrangements that lie between the *meter* and the *Network Management System*.

consumption energy data

Consumption energy data means total *active energy* consumed over a period of time, obtained from the difference between successive actual meter readings at a *metering point*, or by estimation.

current transformer (CT)

Current transformer means a *transformer* for use with *meters* and/or protection devices in which the current in the secondary winding is, within prescribed error limits, proportional to and in phase with the current in the primary winding.

customer's meter

Customer's meter means the meter at the customer's premises

day

Day means unless otherwise specified, the 24 hour period beginning and ending at midnight Eastern Standard Time (EST).

Distribution Line Carrier (DLC)

Distribution Line Carrier means a technology that allows data communications over low voltage distribution lines but is not able to transmit data through distribution transformers.

distribution network

Distribution network means a *network* which is not a transmission network.

distribution system

Distribution system means a *distribution network*, together with the connection assets associated with the *distribution network*, which is connected to another transmission or distribution system. Connection assets on their own do not constitute a *distribution system*.

energy

Energy means *active energy* and/or *reactive energy*.

energy data

Energy data means *interval energy data*, accumulated energy data or estimated energy data. For the purposes of this document, *energy data* also refers to *consumption energy data*.

Export

Export means the delivery of energy from the network to a customer.

Functionality Working Group (FWG)

Functionality Working Group means the working group appointed by the ISG with responsibility for developing a statewide minimum functionality requirements specification for the AMI project in Victoria.

HAN

HAN is an abbreviation for Home Area Network

In-Home Display (IHD)

In-home display means equipment which would normally be within the customer's premises and which communicates with the customer's meters and displays to the customer a range of information which may include consumption data, demand data, rate of consumption in dollars, and which may also allow the customer to initiate communication back to the meter.

Import

Import means the delivery of energy from an end-use customer into the distribution network.

Industry Strategy Group (ISG)

Industry Strategy Group means the group of representatives from the electricity industry which was established by Government to provide advice on the rollout of *AMI*.

instrument transformer

Instrument transformer means either a *current transformer (CT)* or a voltage transformer (VT).

interval energy data

Interval energy data means the data that results from the measurement of the flow of electricity in a power conductor where the data is prepared by a *data logger* into intervals which correspond to a *trading interval* or are sub-multiples of a *trading interval*.

interval meter

Interval meter means a *meter* that records *interval energy data*.

Interval Meter Rollout (IMRO)

Interval Meter Rollout means the rollout of *interval meters* that was determined by the Essential Services Commission in 2004 for Victorian electricity..

Local disconnect

Local disconnect means the operation of the AMI contactor to effect a disconnection of the customer's supply not by the AMI communications system but performed locally at the meter by alternative electronic means

market

Market means any of the markets or exchanges described in the National Electricity Rules, for so long as the market or exchange is conducted by *NEMMCO*.

Metering Data Provider (MDP)

Metering Data Provider means a service provider accredited by *NEMMCO* to undertake *metering data* collection and processing tasks within the NEM.

measurement element

Measurement element means an energy measuring component which converts the flow of electricity in a power conductor into an electronic signal and/or a mechanically recorded electrical measurement.

meter

Meter means a device complying with *Australian Standards* which measures and records the production or consumption of electrical *energy*.

meter loss of supply

Meter loss of supply means that the power system voltage has reduced to point where the meter can no longer function, generally because it's power supply has shutdown.

metering data

Metering data means the data obtained from a *metering installation*, the processed data or substituted data.

metering database

Metering database means a database of *metering data* and settlements ready data which may be supplied to *NEMMCO* under contract.

metering data services

Metering data services means the collation of *energy data* from the *meter* or *meter*/associated data logger, the processing of the *energy data* in the *metering installation* *database*, storage of the *energy data* in the metering installation database and the provision of access to the data for those parties that have rights of access to the data.

metering installation

Metering installation means the assembly of components and/or processes that are controlled for the purpose of metrology and which lie between the *metering point(s)* or non metered connection point and the point of connection to the telecommunications network. The assembly of components may include the combination of several *metering points* to derive the *metering data* for a *connection point*. The *metering installation* must be classified as a revenue metering installation and/or a check metering installation.

metering point

Metering point means the point of physical *connection* of the device measuring the current in the power conductor.

Metering Provider (MP)

Metering Provider means a person who meets the requirements listed in Schedule 7.4 of the *Rules* (which incorporates Schedules 14, 15 and 16 of the *Metrology Procedure)* and has been accredited by and is registered with *NEMMCO* as a *Metering Provider*.

meter provision

Meter provision means the provision, installation and maintenance of the *meter*, data logger (where required) and *instrument transformer(s)* (where required).

Metrology Procedure

Metrology Procedure means the procedure developed and published by NEMMCO in accordance with clause 7.14 of the *National Electricity Rules*

Market Settlement and Transfer Solution (MSATS)

Market Settlement and Transfer Solution means the system operated by NEMMCO for the recording of financial responsibility for energy flows at a connection point, the transfer of that responsibility between Market Participants and the recording of energy flows at a connection point.

National Electricity Market (NEM)

National Electricity Market means the wholesale electricity market operated by *NEMMCO* under the *National Electricity Rules*.

National Electricity Rules (NER)

National Electricity Rules means the rules made by the Australian Energy Market Commission (AEMC) under the National Electricity (South Australia) Act 1996 (the "new" National Electricity Law) that governs the operation of the *National Electricity Market*.

National Metering Identifier (NMI)

National Metering Identifier means a National Metering Identifier as described in clause 7.3.1(d) of the National Electricity Rules.

NEMMCO

NEMMCO means the National Electricity Market Management Company Limited ACN 072 010 327, the company which operates and administers the *market* in accordance with the National Electricity Rules.

network

Network means the apparatus, equipment, plant and buildings used to convey, and control the conveyance of, electricity to customers (whether wholesale or retail) excluding any *connection assets*. In relation to a Network Service Provider, a *network* owned, operated or controlled by that *Network Service Provider*.

Network Management System (NMS)

Network Management System means the head end of an *AMI* system that manages the AMI communications network.

Outage detection

Outage detection means the detection of an outage as defined in the Electricity Distribution Code.

plant

Plant means, in relation to a *connection point*, all equipment involved in generating, utilising or transmitting electrical *energy*.

power factor

Power factor means the ratio of the *active power* to the apparent power at a *metering point*.

reactive energy

Reactive energy means a measure in varhours (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 current flow across a *connection point*.

remote disconnect

Remote disconnect means the utilisation of the communication system to disconnect the customer's supply at the meter by the operation the AMI contactor

Retailer

Retailer means an entity which maintains a *retail licence* and is the market participant that is financially responsible for a customer's connection point..

retail licence

Retail licence means a *licence* issued by the *Essential Services Commission* under the Electricity Industry Act 2000 to sell electricity.

revenue meter

Revenue meter means the *meter* that is used for obtaining the primary source of *metering data*.

self registering

Self registering means the ability of the meter upon being added to the NMS of the AMI system when installed to register or configure itself with the AMI system so that it will commence performing its proper functions without further local intervention

individual read

Individual read means the reading of a selectable number of days of interval energy data and /or other information from a particular AMI meter performed outside of the usual daily reading cycle.

supply

Supply means the delivery of electricity at a connection point.

time

Time means Eastern Standard Time, being the time at the 150th meridian of longitude east of Greenwich in England, or Co-ordinated Universal Time, as required by the National Measurement Act, 1960.

total accumulated consumption

Total accumulated consumption means the total or accumulated amount of energy consumption measured and recorded per channel of a meter since the installation of the meter or the resetting of the consumption value.

trading day

Trading day is the same as a *day* and means a 24 hour period that finishes at midnight EST.

trading interval

Trading interval means a 30 minute period ending on the hour (EST) or on the half hour and, where identified by a *time*, means the 30 minute period ending at that *time*.

transformer

Transformer means a *plant* or device that reduces or increases the *voltage* or alternating current.

Type 4 meter

Type 4 meter means a remotely read electricity interval meter that is a component of a compliant type 4 *metering installation*, that meets the requirements of Schedule 7.2 of the National Electricity Rules and the metrology procedure

Type 5 meter

Type 5 meter means an electricity interval meter that is generally manually read that is a component of a compliant type 5 *metering installation*, that meets the requirements of Schedule 7.2 of the National Electricity Rules and the metrology procedure.

Type 6 meter

Type 6 meter means an accumulation electricity meter that is a component of a compliant type 6 *metering installation* that meets the requirements of Schedule 7.2 of the National Electricity Rules and the metrology procedure.

Utility

Utility means either an entity operating a distribution network or a retail entity that sells electricity to customers

voltage

Voltage means the electronic force or electric potential between two points that gives rise to the flow of electricity.

AMI Business and Data Requirements

Assumptions & Notes:

1. Service levels are measured from receipt of service order from initiator to receipt of completion advice by initiator.
2. Service order completion to be sent within 5 minutes of service completion (at present this is within 24 hours) assuming that the service was completed through an automated process. Service Orders completed through manual on-site field work will be different.
3. All Outputs also include confirmation to initiator via service order completion
4. Services based on Version 4.4 of the Minimum Statewide AMI Functionality Specification
5. Assumes roll-out program Version 3 (attached), which defines what is involved in each of phases 1 to 4 of the rollout
6. Service levels are subject to what is learned through the technology trials and phase 1 of implementation and may change as a result
7. In phases 1 to 3 Distributors retain exclusivity as RP and chooses the MDA until end of 2013 by a Rules derogation
8. AMI meters are Type 4 (unless specifically otherwise stated)
9. The entries in the executer and Responsibility columns for some services may need review. This is particularly the case in relation to which entity is responsible for some meter data services.

All Phases

		Service	Definition	Comments	Service Level	Output	Initiator	Executer	Resp	Initiation	What docs?
1		Routine Read – Manual read of an AMI meter installed as Type 5 or 6	Provision of validated and substituted interval energy data (all data streams) as per type 5 metering Or Accumulation register data – as per type 6 metering	For type 5 & 6 metering the DNSP is RP	As per current type 5 or 6 metrology procedure Separate SLA within remote scenarios	Energy data file to MSATS, FRMP, LR, DNSP and possibly other MDPs for added value customer services	MDP	MDP	DNSP	Internal business process	• Metrology procedures • SLR • B2B Procedures • MSATS

		Service	Definition	Comments	Service Level	Output	Initiator	Executer	Resp	Initiation	What docs?
2		Special Read – Manual of an AMI meter installed as Type 5 or 6	Provision of validated and substituted interval energy data (at least one data stream) as per type 5 metering - a selectable number of intervals (normally back to previous routine read) at a selectable date and time *Or* current accumulation register data – as per type 6 metering at a selectable date and time	For type 5 & 6 metering the DNSP is exclusively responsible	As per special read B2B service order procedure	Energy data file to MSATS, FRMP, LR, DNSP.	FRMP or DNSP	MDP	DNSP	B2B special read service order	• Metrology procedures • SLR • B2B procedures

Phase 1

		Service	Definition	Comments	Service Level	Output	Initiator	Executer	Resp	Initiation	What docs?
3		Routine Read – Remote	Daily data delivered 2 days after read (Type 4 large) Provision of validated and substituted interval energy data (all data streams up to 4) and accumulation register data	Meet prudential requirements	As per current Type 4 Large SLA Schedule 8 and Schedule 5.2	Energy data file to MSATS, FRMP, LR, DNSP	MDA	MDA	NEMMCO (DNSP (through derogation) chooses NEMMCO accredited agent)	Internal business process	• National Electricity Rules • Metrology Procedures • SLR • B2B Procedures • MDFF • MDM

Phase 2

		Service	Definition	Comments	Service Level	Output	Initiator	Executer	Resp	Initiation	What docs?

		Service	Definition	Comments	Service Level	Output	Initiator	Executer	Resp	Initiation	What docs?
4		Routine Read – Remote	Daily data collection, delivered 5AM next day		100% of interval energy data for the previous day (99% being actual data from meters) available to market participants 5 hours after midnight	Energy data file to MSATS, FRMP, LR, DNSP	MDA	MDA	NEMMCO (DNSP (through derogation) chooses NEMMCO accredited agent)	Internal business process	• National Electricity Rules • Metrology Procedures • SLR • B2B Procedures • MDFF • MDM
5	a	De-energisation	Remote De-energisation at prior notified date and time	Removal of supply on the customer's side of the meter, at the meter, by use of the meters connect/disconnect contactor at a selectable date and time	For 2% of all meters - action performed at 90% of meters no later than 2 hours of the selected date and time via AMI and not before. Overall 100% performed in 2 business days after selected date and time	De-energisation of customer installation	FRMP	DNSP	DNSP	B2B Service Order	• B2B procedures
5	b	De-energisation	Remote De-energisation ASAP (0 - 2 hours)	Removal of supply on the customer's side of the meter, at the meter, by use of the meter's connect/disconnect contactor	For 2% of all meters - action performed by AMI at 90% of meters within 2 hours of request being received by DNSP Overall 100% performed in 2 business days after selected date and time	De-energisation of customer installation	FRMP	DNSP	DNSP	B2B Service Order	• B2B procedures

		Service	Definition	Comments	Service Level	Output	Initiator	Executer	Resp	Initiation	What docs?
6	a	Re-energisation	Remote re-energisation – *activate* (at future date and time)	Re-energise the customers electrical installation at a selectable date and time via the connect/disconnect contactor in the meter without the need for the customer's intervention.	For 2% of all meters - action performed at 90% of meters within 2 hours of selected date and time via AMI Overall 100% performed in 2 business days after selected date and time	Energisation of customers installation	FRMP	DNSP	DNSP	B2B Service Order	• B2B procedures
6	b	Re-energisation	Remote re-energisation – *activate* (ASAP within 2 hrs)	Re-energise the customers electrical installation via the connect/disconnect contactor in the meter without the need for the customer's intervention. Assumes no requirement for prior arming	For 2% of all meters - action performed at 90% of meters via AMI within 2 hours of request being received by DNSP Overall 100% performed in 2 business days	Energisation of customers installation	FRMP	DNSP	DNSP	B2B Service Order	• B2B procedures
7	a	IHD message – Individual and broadcast	ASAP (0 – 2 hrs) Sending a 255 character message to individual meters that serves a customer's IHD, or groups of meters that serve IHDs. (eg CPP, Outage cause)	The structure of message is such that the IHD knows how to interpret. IHD specification is still under development.	Message received at 99.9% of meters in 2 hours	Message sent to IHDs	FRMP	DNSP	DNSP	Suggest - New B2B service order	
7	b	IHD message – Individual and broadcast	Within 1 business day Sending a 255 character message to individual meters that serves a customer's IHD, or groups of meters that serve IHDs. (eg Planned outage, reminder of planned outage, promotional material)	The structure of message is such that the IHD knows how to interpret. IHD specification is still under development.	Message received at 99.9% of meters within 1 day	Message sent to IHDs	FRMP	DNSP	DNSP	Suggest - New B2B service order	

		Service	Definition	Comments	Service Level	Output	Initiator	Executer	Resp	Initiation	What docs?
7	c	IHD message – Individual and broadcast	Within 5 business days Sending a 255 character message to individual meters that serves a customer's IHD, or groups of meters that serve IHDs. Includes confirmation of IHD receipt of message. (eg Tariff change)	The structure of message is such that the IHD knows how to interpret. IHD specification is still under development.	Message received at 99.9% of meters within 5 business days	Message sent to IHDs	FRMP	DNSP	DNSP	Suggest - New B2B service order	

Phase 3

		Service	Definition	Comments	Service Level	Output	Initiator	Executer	Resp	Initiation	What docs?
8	a	Re-energisation	Remote re-energisation – *arm* (at future date and time)	To remotely enable energisation of the customer's electrical installation at a selectable date and time via the connect/disconnect contactor so that the meter can be locally activated to energise the installation	For 2% of all meters - action performed at 90% of meters no later than 2 hours of selected date and time via AMI and not before Overall 100% performed in 2 business days after selected date and time	Arming of customers AMI meter	FRMP	DNSP	DNSP	B2B Service Order	• B2B procedures
8	b	Re-energisation	Remote re-energisation – *arm* (ASAP within 2 hrs)	To remotely enable energisation of the customer's electrical installation via the connect/disconnect contactor so that the meter can be locally activated to energise the installation.	For 2% of all meters - action performed at 90% of meters via AMI within 2 hours of request being received by DNSP Overall 100% performed in 2 business days	Arming of customers AMI meter	FRMP	DNSP	DNSP	B2B Service Order	• B2B procedures
9	a	Remote controlled load override (to nominated individual meters)	Remote initiation of switching of controlled load (either on or off) which overrides the controlled load switching times stored in the meter for a selectable period from 0 to 48 hours in half hour increments		For 2% of all meters - action performed at 60% of meters in 1 hour and 99.9% of meters in 6 hours	Changed status of controlled load contactor	FRMP	DNSP	DNSP	Suggest - New B2B service order	
9	b	Remote Controlled load override (to a larger number of meters)	Remote initiation of switching of controlled load (either on or off) which overrides the controlled load switching times stored in the meter for a selectable period from 0 to 48 hours in half hour increments		Action performed at 90% of meters in 20 minutes and 99% in 1.5 hours	Changed status of controlled load contactor	FRMP	DNSP	DNSP	Suggest - New B2B service order	

		Service	Definition	Comments	Service Level	Output	Initiator	Executer	Resp	Initiation	What docs?
10		Meter event advice	Sending of message to advise that a meter or group of meters, or the AMI infrastructure, has logged specifically pre-defined pushed events (eg Tamper Detection, Outage Advice, IHD Connected/Disconnected).	•Scheduled delivery of data •Meter events are listed in the AMI functionality spec •Quality of metering data issue – NEMMCO will require accreditation of service provider	Provided with interval data each day	Provision of meter event information to market participants	FRMP	MDA	NEMMCO	With routine read	
11		Read meter information	Subtypes are: a) Read meter event log b) Read meter settings c) Read meter status	Read meter event log = Ad hoc request, for detailed information of event log. Meter settings = means all configuration parameters in a meter (eg: Supply capacity control kW limit) [Includes version of software in meter] Meter status = current states of all items in the meter (eg: controlled load contactor)	For 2% of all meters – 99% in 6 hours 100% in 2 business days	Provision of meter information to market participants	FRMP	MDA	NEMMCOI	Suggest - New B2B service order	

		Service	Definition	Comments	Service Level	Output	Initiator	Executer	Resp	Initiation	What docs?
12		Change Metrology settings in meter	Change selected metrology settings in the meter	To cover all metrology meter settings that are allowable to the FRMP to change. Note: This transaction may be dropped out as unnecessary in time, however it is included here to ensure that facility is available in the event that a setting included in the non-metrology transaction (below) interferes with the metrology of the meter.	For 2% of all meters – Action performed at 90% of meters in 2 hours and 99% in 6 hours 100% in 2 business days	Changed meter settings	FRMP	MDA	NEMMCO	Suggest - New B2B service order	
13		Change non metrology Meter settings	Change selected meter settings in the meter. Including: Controlled load switching times Supply capacity control settings	To cover all meter settings that are allowable to the FRMP to change, but excludes settings which are controlled (by NEMMCO) for metrology purposes. .	For 2% of all meters – Action performed at 90% of meters in 2 hours and 99% in 6 hours 100% in 2 business days	Changed meter settings	FRMP	MDA	NEMMCO	Suggest - New B2B service order	

Phase 4

Apart from service 14 all other services are where the retailer is the responsible person

		Service	Definition	Comments	Service Level	Output	Initiator	Executer	Resp	Initiation	What docs?
14		Other load control – to individual customers or broadcast to groups	Sending a message to individual meters that serves a customer's load control device, or groups of meters that serve load control devices (up to 255 characters). Includes confirmation of load control device receipt of message.	The structure of message is such that the LC device knows how to interpret. Consideration for future date and time messages.	Action performed at 90% of load control devices in 20 minutes	Changed status of other controlled load devices Acknowledgement of receipt of messages	FRMP	DNSP	DNSP	Suggest - New B2B service order	

		Service	Definition	Comments	Service Level	Output	Initiator	Executer	Resp	Initiation	What docs?
14		Other load control – to individual customers or broadcast to groups	Sending a message to individual meters that serves a customer's load control device, or groups of meters that serve load control devices (up to 255 characters). Includes confirmation of load control device receipt of message.	The structure of message is such that the LC device knows how to interpret. Consideration for future date and time messages.	Action performed at 90% of load control devices in 20 minutes	Changed status of other controlled load devices Acknowledgement of receipt of messages	FRMP	DNSP	DNSP	Suggest - New B2B service order	
15		Routine Read – Remote	Daily data collection, delivered 5AM next day		100% of interval energy data for the previous day (99% being actual data from meters) available to market participants 5 hours after midnight	Energy data file to MSATS, FRMP, LR, DNSP	MDA	MDA	NEMMCO (FRMP chooses NEMMCO accredited agent)	Internal business process	• National Electricity Rules • Metrology Procedures • SLR • B2B Procedures • MDFF • MDM
16	a	Remote controlled load override (for nominated individual meters)	Remote initiation of switching of controlled load (either on or off) which overrides the controlled load switching times stored in the meter for a selectable period from 0 to 48 hours in half hour increments		For 2% of all meters - action performed at 60% of meters in 1 hour and 99.9% of meters in 6 hours	Changed status of controlled load contactor Advice to Distributor of the action	DNSP	MDA	FRMP	Suggest - New B2B service order	

		Service	Definition	Comments	Service Level	Output	Initiator	Executer	Resp	Initiation	What docs?
14		Other load control – to individual customers or broadcast to groups	Sending a message to individual meters that serves a customer's load control device, or groups of meters that serve load control devices (up to 255 characters). Includes confirmation of load control device receipt of message.	The structure of message is such that the LC device knows how to interpret. Consideration for future date and time messages.	Action performed at 90% of load control devices in 20 minutes	Changed status of other controlled load devices Acknowledgement of receipt of messages	FRMP	DNSP	DNSP	Suggest - New B2B service order	
16	b	Remote Controlled load override for a larger number of meters	Remote initiation of switching of controlled load (either on or off) which overrides the controlled load switching times stored in the meter for a selectable period from 0 to 48 hours in half hour increments		Action performed at 90% of meters in 20 minutes and 99% in 1.5 hours	Changed status of controlled load contactor Advice to Distributor of the action	DNSP	MDA	MDA	Suggest - New B2B service order	
17	a	Meter event advice	Sending of message to advise that a meter or group of meters, or the AMI infrastructure, has logged specifically pre-defined pushed events (eg Connected/Disconnected, Tamper Detection, Outage Advice, IHD).	•Scheduled delivery of data	Provided with interval data each day	Provision of meter event information to market participants	MDA	MDA	FRMP	??	Meter events are listed in the AMI functionality spec

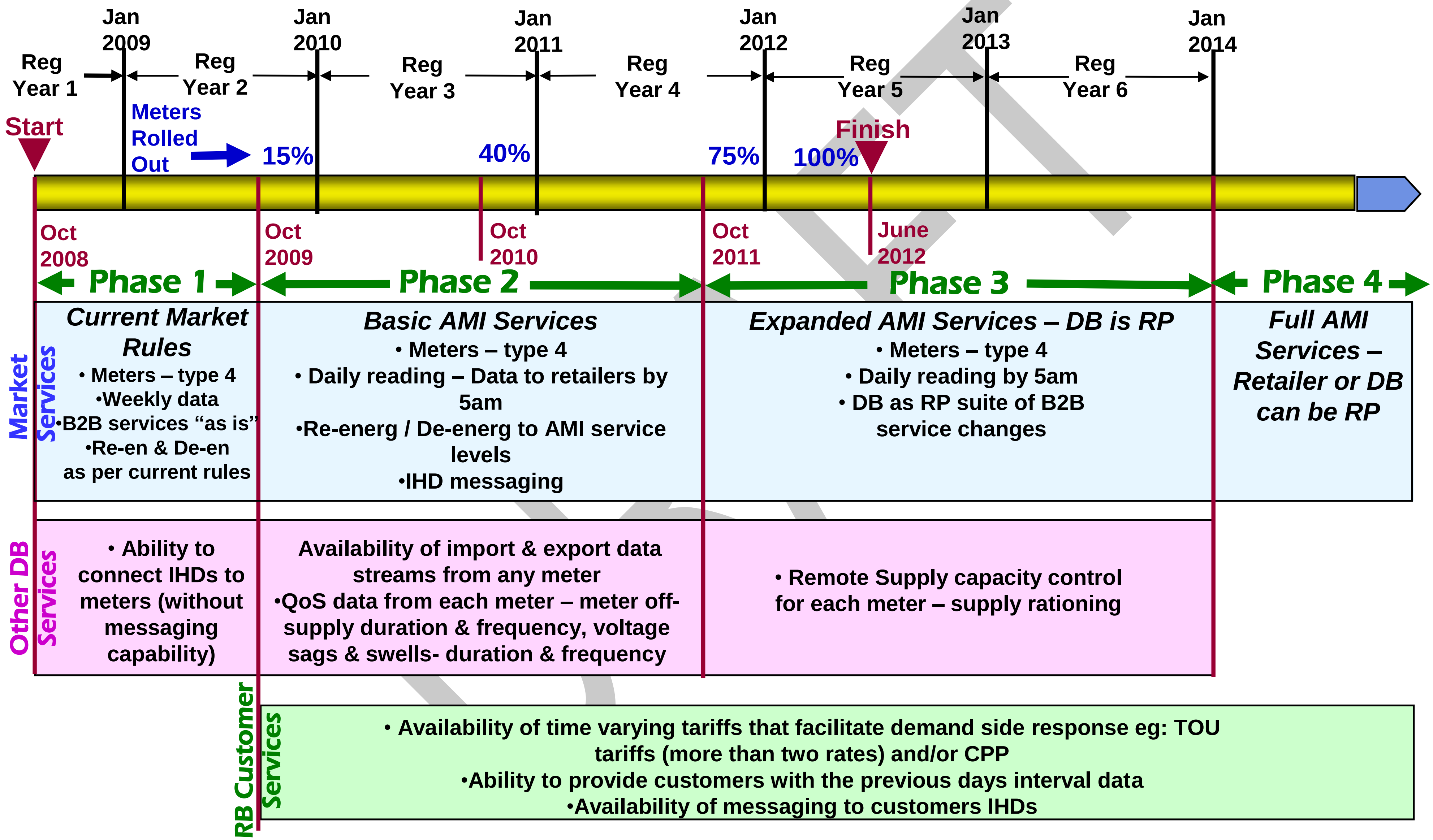
		Service	Definition	Comments	Service Level	Output	Initiator	Executer	Resp	Initiation	What docs?
14		Other load control – to individual customers or broadcast to groups	Sending a message to individual meters that serves a customer's load control device, or groups of meters that serve load control devices (up to 255 characters). Includes confirmation of load control device receipt of message.	The structure of message is such that the LC device knows how to interpret. Consideration for future date and time messages.	Action performed at 90% of load control devices in 20 minutes	Changed status of other controlled load devices Acknowledgement of receipt of messages	FRMP	DNSP	DNSP	Suggest - New B2B service order	
18		Read meter information	Subtypes are: a) Read meter event log b) Read meter settings c) Read meter status d) Read meter supply status	Read meter event log = Ad hoc request, for detailed information of event log. Meter settings = means all configuration parameters in a meter (eg: Supply capacity control kW limit) [Includes version of software in meter] Meter status = current states of all items in the meter (eg: controlled load contactor) Meter supply status - To enable DNSPs to know whether a meter is on supply or not.	For 2% of all meters – 99% in 6 hours 100% in 2 business days	Provision of meter information to market participants	DNSP, NEMMCO	MDA	FRMP	Suggest - New B2B service order	

		Service	Definition	Comments	Service Level	Output	Initiator	Executer	Resp	Initiation	What docs?
14		Other load control – to individual customers or broadcast to groups	Sending a message to individual meters that serves a customer's load control device, or groups of meters that serve load control devices (up to 255 characters). Includes confirmation of load control device receipt of message.	The structure of message is such that the LC device knows how to interpret. Consideration for future date and time messages.	Action performed at 90% of load control devices in 20 minutes	Changed status of other controlled load devices Acknowledgement of receipt of messages	FRMP	DNSP	DNSP	Suggest - New B2B service order	
19		Change Metrology settings in meter	Change selected metrology settings in the meter	To cover all metrology meter settings that are allowable to the FRMP to change. Note: This transaction may be dropped out as unnecessary in time, however it is included here to ensure that facility is available in the event that a setting included in the non-metrology transaction (below) interferes with the metrology of the meter.	For 2% of all meters – Action performed at 90% of meters in 2 hours and 99% in 6 hours 100% in 2 business days	Changed meter settings	DNSP	MDA	FRMP	Suggest - New B2B service order	
20		Change non metrology Meter settings	Change selected meter settings in the meter. Specifically: Controlled load switching times Supply capacity control settings	To cover all meter settings that are allowable to the FRMP to change, but excludes settings which are controlled (by NEMMCO) for metrology purposes.	For 2% of all meters – Action performed at 90% of meters in 2 hours and 99% in 6 hours 100% in 2 business days	Changed meter settings	DNSP	MDA	FRMP	Suggest - New B2B service order	

		Service	Definition	Comments	Service Level	Output	Initiator	Executer	Resp	Initiation	What docs?
14		Other load control – to individual customers or broadcast to groups	Sending a message to individual meters that serves a customer's load control device, or groups of meters that serve load control devices (up to 255 characters). Includes confirmation of load control device receipt of message.	The structure of message is such that the LC device knows how to interpret. Consideration for future date and time messages.	Action performed at 90% of load control devices in 20 minutes	Changed status of other controlled load devices Acknowledgement of receipt of messages	FRMP	DNSP	DNSP	Suggest - New B2B service order	
21	a	IHD message – Individual and broadcast	ASAP (0 – 2 hrs) Sending a 255 character message to individual meters that serves a customer's IHD, or groups of meters that serve IHDs. (eg Outage cause)	The structure of message is such that the IHD knows how to interpret. IHD specification is still under development. .	Message received at 99.9% of meters in 2 hours	Message sent to IHDs	DNSP	MDA	FRMP	Suggest - New B2B service order	
21	b	IHD message – Individual and broadcast	Within 1 business day Sending a 255 character message to individual meters that serves a customer's IHD, or groups of meters that serve IHDs. (eg Planned outage, reminder of planned outage)	The structure of message is such that the IHD knows how to interpret. IHD specification is still under development. .	Message received at 99.9% of meters within 1 day	Message sent to IHDs	DNSP	MDA	FRMP	Suggest - New B2B service order	

		Service	Definition	Comments	Service Level	Output	Initiator	Executer	Resp	Initiation	What docs?
14		Other load control – to individual customers or broadcast to groups	Sending a message to individual meters that serves a customer's load control device, or groups of meters that serve load control devices (up to 255 characters). Includes confirmation of load control device receipt of message.	The structure of message is such that the LC device knows how to interpret. Consideration for future date and time messages.	Action performed at 90% of load control devices in 20 minutes	Changed status of other controlled load devices Acknowledgement of receipt of messages	FRMP	DNSP	DNSP	Suggest - New B2B service order	
21	c	IHD message – Individual and broadcast	Within 5 business days Sending a 255 character message to individual meters that serves a customer's IHD, or groups of meters that serve IHDs. Includes confirmation of IHD receipt of message. (eg What would this be used for)	The structure of message is such that the IHD knows how to interpret. IHD specification is still under development.	Message received at 99.9% of meters within 7 calendar days	Message sent to IHDs	DNSP	MDA	FRMP	Suggest - New B2B service order	
22		Other load control – to individual customers or broadcast to groups	Sending a message to individual meters that serves a customer's load control device, or groups of meters that serve load control devices (up to 255 characters). Includes confirmation of load control device receipt of message.	The structure of message is such that the LC device knows how to interpret. Consideration for future date and time messages. Groups are yet to be defined	Action performed at 90% of load control devices in 20 minutes	Changed status of other controlled load devices Acknowledgement of receipt of messages	DNSP	MDA	FRMP	Suggest - New B2B service order	

Implementation Plan – version 3



FOI 190420
Document 5

Assessment of AMI Requirements

Background

On 22 June 2007, an industry working group convened by NEMMCO reviewed the *AMI Business and Data Requirements v1.2* document which the Department of Primary Industries (Vic) referred to the Information Exchange Committee (IEC) and Retail Market Executive Committee (RMEC) for advice on process and data requirements to support the AMI project. The IEC and RMEC have requested initial advice from the BDPIP for their joint meeting in August (papers due 24 July 2007). Final feedback has been requested to the AMI project by September 2007.

The purpose of the review was to assess the impact of advanced metering infrastructure on NEMMCO's Business and Data Process Improvement Program. The program's goal is to identify business and data process enhancement opportunities for the retail electricity market and deliver outcomes that lead to the improved operation of the retail electricity market, with an initial focus on the business and data process implications of smart metering.

General comments

The primary findings of the industry working group review were:

1. New business processes and associated transactions will be required to support advanced metering infrastructure.
    a. The new processes and transactions may be a mix of amendments of existing processes and transactions and new ones.
    b. For the exceptions to the AMI process (during the transition and at the end of the rollout), what is the implied process? These issues will require review as there will be less field staff to perform the work with potential implications for service levels.
    c. Key requirements related to meter and IHD 'groups' will be how these groups will be defined, how the group information will be communicated to electricity market participants, and how business transactions related to groups will be structured and managed.
2. The service levels in the AMI Business & Data Requirements document require review to ensure that they are consistent with each other, and are specific, easily understood, and measurable. Metrics should be included to support each service level.
3. Clarification is sought of the purpose, scope and proposed content of the 'service levels document' identified in the current DPI-AMI-FWG plan-Vers3-1906. This document potentially overlaps with the Business and Data Requirements Version 1.2 which is the subject of these comments, and the timing for endorsement (FWG plan indicates September 2007) is a potential concern.
4. The implementation of advanced metering infrastructure will have both installation issues, and transition issues (for installed meters).

a. A key planning issue is the ability of parties other than the DNSP to be responsible for the metering from 2014 on. This has significant regulatory and technical implications for the implementation of advanced metering infrastructure.

5. For practical and regulatory reasons, AMI meters may need to be identifiable to participants. This would accommodate AMI meters' specific metrology and Rules / procedural requirements.

The working group's assessment of each of the AMI service requirements is detailed in the table below.

	Service	Definition	Assessment
	All Phases		
1	Routine Read – Manual read of an AMI meter installed as Type 5 or 6	Provision of validated and substituted interval energy data (all data streams) as per type 5 metering. Or Accumulation register data – as per type 6 metering.	No change to existing requirements required. Does market (Retailers) need to know if this is an AMI-capable meter? This is not the current market practice for other meter types.
2	Special Read – Manual of an AMI meter installed as Type 5 or 6	Provision of validated and substituted interval energy data (at least one data stream) as per type 5 metering - a selectable number of intervals (normally back to previous routine read) at a selectable date and time. Or Current accumulation register data – as per type 6 metering at a selectable date and time.	No change to existing requirements required.

	Phase 1	**Current Market Rules**	
3	**Routine Read – Remote**	Daily data delivered 2 days after read (Type 4 large). Provision of validated and substituted interval energy data (all data streams up to 4) and accumulation register data.	No new requirement associated with data delivery 2 days after reading. Accumulation register data is not provided for Type 4 meters. This would require a change to MDFF to accommodate requirement. The diagram in the AMI Business & Data Requirements document (Implementation Plan – version 3) shows weekly reading. Need to add this detail to this row for clarity. Type 4 large: May need to specifically identify AMI meters to accommodate their specific metrology and Rules / procedural requirements? Is there a functionality difference between Type 4 large and AMI meters re reactive data stream? AMI can switch this on / off. Type 4 large cannot? Why only 4 data streams? There may be more. Type 4 data delivery needs to be specified as it is not presently. MDA must be able to read the meter daily, but doesn't have to unless asked by NEMMCO (for prudential purposes). Normal practice is daily delivery. [FWG & MRG]

	Phase 2	**Basic AMI Services**	
4	Routine Read – Remote	Daily data collection, delivered 5am next day.	Why 5 am? Networks question the cost benefit of this timing requirement with 100% of data with 99% actuals service level. There may be alternate ways to satisfy the Retailer's data requirement (e.g. data access on one timeframe and data delivery on another [longer] timeframe). Also, is 99% actuals required to satisfy the Retailer's requirement? The service level needs better definition to make it clear what the requirement is. For example, is the 99% for all possible meter readings for the previous day or 99% of meters? Current market requirement is 2 days after the reading. With meter changeover, need to ensure that timing of market notifications and meter data align to ensure that meter data is not delivered to Participant before they receive the MSATS notification. Impacts process maps 3 and 8 primarily, and possibly 4, 10 and 11. This includes the associated standing data. Can current substitution, estimation and validation process fit within this time frame?

5 a	De-energisation	Remote De-energisation at prior notified date and time.	Requires new timing requirements for ServiceOrderRequest. May affect timing requirement for ServiceOrderResponse, especially incomplete ones. Higher service level than proposed may be possible. Market must know meter is AMI (or that it has capability to perform this function). Not possible with a CT connected meter.
5 b	De-energisation	Remote De-energisation ASAP (0 - 2 hours).	Existing B2B process cannot support this. Requires new timing requirements for ServiceOrderRequest. May affect timing requirement for ServiceOrderResponse, especially incomplete ones. May affect timing requirements for message and transaction acknowledgements. May require new *ServiceOrderSubType* (De-En AMI Now). Could be satisfied by new business rules around use of *ScheduledDate* and *CustomersPreferredDataAndTime* fields. Consider impact on rules regarding timing requirement for cancellation of service orders and handling of multiple service order situations. Consider amended service order process, such as telephone notification initially, followed by confirming ServiceOrderRequest. Higher service level than proposed may be possible. Market must know meter is AMI (or that it has capability to perform this function). Not possible with a CT connected meter.
6 a	Re-energisation	Remote re-energisation – activate (at future date and time).	Requires new timing requirements for ServiceOrderRequest. May require new *ServiceOrderSubType* (Activate AMI). May affect timing requirement for ServiceOrderResponse, especially incomplete ones. Higher service level than proposed may be possible. Market must know meter is AMI. (or that it has capability to perform this function). Need to be able to identify sites (via standing data or B2B advice) where there is a safety issue with activation directly (rather than arming the meter for the customer to activate). Business process must consider the safety risk. Not possible with a CT connected meter.

6 b	Re-energisation	Remote re-energisation – activate (ASAP within 2 hrs).	Existing B2B process cannot support this. Requires new timing requirements for ServiceOrderRequest. May require new *ServiceOrderSubType* (Activate AMI). May affect timing requirement for ServiceOrderResponse, especially incomplete ones. May affect timing requirements for message and transaction acknowledgements. May require new *ServiceOrderSubType* (Re-En AMI Now). Could be satisfied by new business rules around use of *ScheduledDate* and *CustomersPreferredDataAndTime* fields. Consider impact on rules regarding timing requirement for cancellation of service orders and handling of multiple service order situations. Higher service level than proposed may be possible. Consider amended service order process, such as telephone notification initially, followed by confirming ServiceOrderRequest. Market must know meter is AMI. (or that it has capability to perform this function). Need to be able to identify sites (via standing data or B2B advice) where there is a safety issue with activation directly (rather than arming the meter for the customer to activate). Business process must consider the safety risk. Not possible with a CT connected meter.
7 a	IHD message – Individual and broadcast	ASAP (0 – 2 hrs) Sending a 255 character message to individual meters that serves a customer's IHD, or groups of meters that serve IHDs (e.g. CPP, Outage cause).	Assumed this is a message from the FRMP to the IHD. Could be used by the DNSP as well. New process and associated transactions required. Key issue is how the groups are defined and how the group details are provided to Participants. Requires new standing data (for group details). What is the maximum number of groups that the one meter may need to be included in? Will the group definition need to change/ defined or redefined as part of the customer-retailer transfer process? Will the DNSP be obliged to communicate to the Retailer any group involvement of the meters' NMIs ?
7 b	IHD message – Individual and broadcast	Within 1 business day Sending a 255 character message to individual meters that serves a customer's IHD, or groups of meters that serve IHDs (e.g. planned outage, reminder of planned outage, promotional material).	Assumed this is a message from the FRMP to the IHD. Could be used by the DNSP as well. New process and associated transactions required. Key issue is how the groups are defined and how the group details are provided to Participants. Requires new standing data (for group details). Is there a maximum allowable number of messages per day?

7 c	IHD message – Individual and broadcast	Within 5 business days. Sending a 255 character message to individual meters that serves a customer's IHD, or groups of meters that serve IHDs. Includes confirmation of IHD receipt of message (e.g. Tariff change).	Assumed this is a message from the FRMP to the IHD. Could be used by the DNSP as well. New process and associated transactions required. Key issue is how the groups are defined and how the group details are provided to Participants. Requires new standing data (for group details).

	Phase 3	**Expanded AMI Services**	
8 a	Re-energisation	Remote re-energisation – arm (at future date and time).	Question why the safer arm – activate process is after the activation only process in the roll out sequence. Requires new timing requirements for <u>ServiceOrderRequest</u>. May require new *ServiceOrderSubType* (Arm AMI). May affect timing requirement for <u>ServiceOrderResponse</u>, especially incomplete ones. Higher service level than proposed may be possible. Market must know meter is AMI. (or that it has capability to perform this function). Not possible with a CT connected meter. Need standing data that identifies meter as capable of arm-activate (vs activate only), and if there are access or customer related issues limiting use of AMI functionality.

8 b	Re-energisation	Remote re-energisation – arm (ASAP within 2 hrs).	Question why the safer arm – activate process is after the activation only process in the roll out sequence. Existing B2B process cannot support this. Requires new timing requirements for ServiceOrderRequest. May require new *ServiceOrderSubType* (Arm AMI). May affect timing requirement for ServiceOrderResponse, especially incomplete ones. May affect timing requirements for message and transaction acknowledgements. May require new *ServiceOrderSubType* (Re-En AMI Now). Could be satisfied by new business rules around use of *ScheduledDate* and *CustomersPreferredDataAndTime* fields. Consider impact on rules regarding timing requirement for cancellation of service orders and handling of multiple service order situations. Higher service level than proposed may be possible. Consider amended service order process, such as telephone notification initially, followed by confirming ServiceOrderRequest. Market must know meter is AMI. (or that it has capability to perform this function). Not possible with a CT connected meter. Need standing data that identifies meter as capable of arm-activate (vs activate only), and if there are access or customer related issues limiting use of AMI functionality.
9 a	Remote controlled load override (to nominated individual meters)	Remote initiation of switching of controlled load (either on or off) which overrides the controlled load switching times stored in the meter for a selectable period from 0 to 48 hours in half hour increments.	Requires new process. Could be addressed by new *ServiceOrderSubType* for Adds and Alts ServiceOrderRequest (for FRMP requests). May require additional fields in ServiceOrderRequest to hold period details. Requires new business rules to manage process. DNSP will have overriding control.
9 b	Remote Controlled load override (to a larger number of meters)	Remote initiation of switching of controlled load (either on or off) which overrides the controlled load switching times stored in the meter for a selectable period from 0 to 48 hours in half hour increments.	Requires new process. Could be addressed new *ServiceOrderSubType* for Adds and Alts ServiceOrderRequest (for FRMP requests). May require additional fields in ServiceOrderRequest to hold period details. Requires new business rules to manage process. DNSP will have overriding control. Requires new standing data (for group details).
10	Meter event advice	Sending of message to advise that a meter or group of meters, or the AMI infrastructure, has logged specifically pre-defined pushed events (e.g. Tamper Detection, Outage Advice, IHD Connected/Disconnected).	Requires new standing data (for group details). Requires new transaction and associated business rules. Review Service Provider accreditation to pick up new capability.

11	Read meter information	Subtypes are: a) Read meter event log b) Read meter settings c) Read meter status	Requires new transaction and associated business rules. Could be a revised ProvideMeterDataRequest.
12	Change Metrology settings in meter	Change selected metrology settings in the meter.	Requires new transaction and associated business rules. Question use of term "metrology" – prefer that this be omitted to leave "meter settings".
13	Change non metrology Meter settings	Change selected meter settings in the meter. Including: ▪ Controlled load switching times. ▪ Supply capacity control settings.	Requires new transaction and associated business rules. Question use of term "metrology" – prefer that this be omitted to leave "meter settings".

	Phase 4	**Full AMI Services**	
14	Other load control – to individual customers or broadcast to groups	Sending a message to individual meters that serves a customer's load control device, or groups of meters that serve load control devices (up to 255 characters). Includes confirmation of load control device receipt of message.	Requires new standing data (for group details). Requires new transaction and associated business rules.
15	Routine Read – Remote	Daily data collection, delivered 5AM next day.	Why 5 am? Networks question the cost benefit of this timing requirement with 100% of data with 99% actuals service level. There may be alternate ways to satisfy the Retailer's data requirement (e.g. data access on one timeframe and data delivery on another [longer] timeframe). Also, is 99% actuals required to satisfy the Retailer's requirement? The service level needs better definition to make it clear what the requirement is. For example, is the 99% for all possible meter readings for the previous day or 99% of meters? Current market requirement is 2 days after the reading. With meter changeover, need to ensure that timing of market notifications and meter data align to ensure that meter data is not delivered to Participant before they receive the MSATS notification. Impacts process maps 3 and 8 primarily, and possibly 4, 10 and 11. This includes the associated standing data. Can current substitution, estimation and validation process fit within this time frame?
16 a	Remote controlled load override (for nominated individual meters)	Remote initiation of switching of controlled load (either on or off) which overrides the controlled load switching times stored in the meter for a selectable period from 0 to 48 hours in half hour increments.	Requires new transaction and associated business rules.

16 b	Remote Controlled load override for a larger number of meters	Remote initiation of switching of controlled load (either on or off) which overrides the controlled load switching times stored in the meter for a selectable period from 0 to 48 hours in half hour increments.	Requires new standing data (for group details). Requires new transaction and associated business rules.
17 a	Meter event advice	Sending of message to advise that a meter or group of meters, or the AMI infrastructure, has logged specifically pre-defined pushed events (e.g. Connected/Disconnected, Tamper Detection, Outage Advice, IHD).	Requires new standing data (for group details). Requires new transaction and associated business rules. Review Service Provider accreditation to pick up new capability.
18	Read meter information	Subtypes are: a) Read meter event log b) Read meter settings c) Read meter status d) Read meter supply status	Requires new transaction and associated business rules.
19	Change Metrology settings in meter	Change selected metrology settings in the meter	Requires new transaction and associated business rules. Question use of term “metrology” – prefer that this be omitted to leave “meter settings”.
20	Change non metrology Meter settings	Change selected meter settings in the meter. Specifically: ▪ Controlled load switching times. ▪ Supply capacity control settings.	Requires new transaction and associated business rules. Question use of term “metrology” – prefer that this be omitted to leave “meter settings”.
21 a	IHD message – Individual and broadcast	ASAP (0 – 2 hrs) Sending a 255 character message to individual meters that serves a customer’s IHD, or groups of meters that serve IHDs (e.g. Outage cause).	Assumed this is a message from the FRMP to the IHD. Could be used by the DNSP as well. New process and associated transactions required. Key issue is how the groups are defined and how the group details are provided to Participants. Requires new standing data (for group details).
21 b	IHD message – Individual and broadcast	Within 1 business day Sending a 255 character message to individual meters that serves a customer’s IHD, or groups of meters that serve IHDs (e.g. planned outage, reminder of planned outage).	Assumed this is a message from the FRMP to the IHD. Could be used by the DNSP as well. New process and associated transactions required. Key issue is how the groups are defined and how the group details are provided to Participants. Requires new standing data (for group details).

21 c	IHD message – Individual and broadcast	Within 5 business days Sending a 255 character message to individual meters that serves a customer's IHD, or groups of meters that serve IHDs. Includes confirmation of IHD receipt of message (e.g. what would this be used for).	Assumed this is a message from the FRMP to the IHD. Could be used by the DNSP as well. New process and associated transactions required. Key issue is how the groups are defined and how the group details are provided to Participants. Requires new standing data (for group details).
22	Other load control – to individual customers or broadcast to groups	Sending a message to individual meters that serves a customer's load control device, or groups of meters that serve load control devices (up to 255 characters). Includes confirmation of load control device receipt of message.	Requires new standing data (for group details). Requires new transaction and associated business rules.

Australian Energy Market Operator

Comparison Victorian AMI to NSMP SMI Functionality Specification

Version number:	Version 1.0
Status:	Final
Author:	Dr Martin Gill
Date published:	12 September 2011
File name:	Comparison VAMI to SMI FS V1.0.docx

Table of Contents

1 Document Control

1.1 Version Control

Version	Date	Description	Amended by
0.1	24/6/2011	First Draft	Dr Martin Gill
0.2	12/7/2011	Second Draft – Directly addresses impact of identified differences on Business Processes. Minor edits and comments for clarification	Dr Martin Gill, Bob Bosler, Andrew Mann
0.3	14/7/2011	Minor edits	Andrew Mann
0.4	12/9/2011	Updates after meetings	Dr Martin Gill David Cornelius
1.0	13/9/2011	Minor edits	Andrew Mann

1.2 Approval

Authorised by	Signature	Date
NA		

1.3 References

The following documents are referred to in this document.

Document Name	Version
Standing Committee of Officials of the Ministerial Council on Energy Cost-Benefit Analysis of Options for a National Smart Meter Roll-Out (Phase Two – Regional and Detailed Analyses) Regulatory Impact Statement For Decision	June 2008
National Smart Metering Program Smart Metering Infrastructure Functionality Specification (SMI FS)	Version 1.2 10th May 2011
Minimum AMI Functionality Specification (Victoria) (VAMI FS)	Version 1.1 September 2008
National Electricity Rules Chapter 7 Metering	Version 26

2 Introduction

2.1 Background

The National Smart Metering Program (NSMP) started the development of the Smart Metering Infrastructure Functionality Specification (SMI FS) using the list of functions with positive societal benefits provided by the Ministerial Council on Energy (MCE). The original list is shown in Table 1.

Table 1: List of Recommended Functions

Core functions	
1	Half-hourly consumption measurement and recording
2	Remote reading
3	Local reading – hand-held device
4	Local reading – visual display on meter
5	Communication and data security
6	Tamper detection
7	Remote time clock synchronisation
8 &14	Load management at meters through a dedicated controlled circuit
Energy measurement	
9	Daily remote reading
10	Power factor measurement (three phase meters only)
11	Import/export metering
Switching and load management	
12	Remote connect/disconnect
13	Supply capacity control
Facilitation of customer interaction	
16	Interface to home area network using open standard
Supply and service monitoring	
19	Quality of supply and other event recording
20	Meter loss of supply and detection
Upgradeability and configurability	
25	Remote configuration
26	Remote software upgrades
29	Plug and play device commissioning

Version 1.0 of the SMI FS was approved in October 2010 and Version 1.2 in May 2011.

The Victorian Advanced Metering Infrastructure Minimum Functionality Specification (VAMI FS) was developed based on an economic analysis carried out by the Victorian Government resulting in broadly similar functionalities. Version 1.0 of the VAMI FS was published in October 2007 and Version 1.1 was published in September 2008.

During the development of the SMI FS the Business Requirements Work Group (BRWG) was encouraged to consider further functionality where there was evidence of societal benefits. The BRWG also addressed certain matters that were considered to be not fully specified in the VAMI FSV. The result is that there are some differences between the SMI FS and VAMI FS. This paper examines these differences and the implications of them especially where they are material.

2.2 Purpose

The purpose of the document is to identify the areas where there are material differences between the Version 1.1 of VAMI FS and Version 1.2 of SMI FS. These differences fall into two categories:

1. differences in the software running in the meters; and
2. differences in the metering hardware.

At the highest level the SMI FS is intended to provide consistency for market participants, enabling them to interact with the meters in a uniform manner (and provide a minimal performance level). The aim is to ensure that (existing and future) market requirements are capable of being met. A review of the SMI FS against the VAMI FS will identify any functionality differences which have a material effect on market participants and potentially customers.

Differences in the functionality specifications may affect retailers and the services they can offer to their customers. Differences might also affect the market operator, including the requirement to store additional standing data that is specific to one specification.

A comparison of the two specifications will reveal **differences in the software** required to implement the functionality. These differences may or may not affect the way in which users interact with the meters. This report will identify the software differences where procedures can be developed or back office software modified to provide equivalent services.

Software differences between the two specifications can be addressed with a change to the software run in the meter in many cases noting that both specifications support remote software upgrade. There are currently no requirements for meters meeting the VAMI FS specification to receive a software upgrade in order to meet the National SMI FS and there is no functional requirement for an SMI FS meter to be able to operate as a VAMI FS meter.

Finally the **hardware differences** between the two specifications will be identified. Where there are hardware differences, meters meeting the VAMI FS specification cannot be upgraded to meet the SMI FS. In these cases it is unlikely that additional back office procedures will be able to provide equivalent services.

When a hardware difference is discussed, the potential cost difference will be outlined, however this is not a major focus of the discussion.

2.3 Approach

Section 3.1 discusses the impact of the identified differences between meters compliant with the VAMI FS and SMI FS based on the prioritised Business Procedures.

Section 4 presents a high level comparison of the SMI F.S and the VAMI FS. This covers the scope of the two documents, the meter configurations and considers fundamental differences between how Performance Levels are documented and measured.

Section 5 presents a complete analysis the functionalities of the SMI FS compared with the corresponding functionality listed in the VAMI FS. Each section starts with a summary of the major differences and general discussion points. For those functionalities for which performance levels are detailed in the SMI FS these have been compared with those listed in VAMI FS.

Section 3.2 extracts the main summary points presented in Section 5 and considers their impact.

3 Analysis of Differences

3.1 Initial Analysis in Priority Areas

This section reviews the differences between the NSMP SMI FS and VAMI FS specification which may affect the prioritised business processes and the business processes that have related 'touch points' being developed by the Business Processes and Procedures Reference Group (BPPRG)[1].

These business processes are:

Prioritised business processes:

- BP01 Smart Metering Infrastructure (SMI) de-energisation (Section 3.1.1)
- BP03 Load Management HAN (registration only) (Section 3.1.2)
- BP06 SMI metering data collection, processing and delivery (Section 3.1.3)
- BP08 SMI re-energisation (Section 3.1.4)
- BP15 HAN customer messaging (Section 3.1.5)

Related 'touch point' business processes:

- BP05 Event log collection, processing and delivery
- BP11 SMI NMI Discovery
- BP13 SMI Service charging
- BP22 Network tariff change process

The review will identify and comment on;

(i) technical differences (hardware and software),

(ii) the implications/materiality of those differences, and

(iii) how they could be addressed (including through high-level or flexible procedures, or other means)

Section 3.2 includes a discussion of potential consequences of the selection of different HAN standards in the VAMI and SMI FS. This discussion is relevant for all business processes related to the HAN.

Section **Error! Reference source not found.** summarises the impacts of the identified differences.

3.1.1 BP01 Smart Metering Infrastructure (SMI) de-energisation

Key points:

Feature/Function	Material Difference	Implication for this BP	Comment/Consequence for Procedures
Hardware: CT meter with integrated 2A relay for control of an external supply contactor	SMI FS: Provides a CT meter with a 2A relay to control an external supply contactor. VAMI FS: does not support any	SMI FS supports remote de-energisation for all customers fitted with a smart meter (if this CT meter configuration is	Not a Procedure issue, however standing data will need to capture if the remote capability is supported (for both

[1] Note that the IEC/RMEC decided at its August 11 2011 meeting that no further work be completed by the BPPRG on Smart Metering Infrastructure Procedure development and that the focus of work would be on the resolution of the policy issues.

	supply contactor functionality for its CT meter	selected and an external supply contactor is fitted)	VAMI and SMI FS)

No business processes differences have been identified for remote de-energisation between the specifications for VAMI FS and SMI FS meters.

Both specifications indicate that the meter shall display the position of the supply contactor on the display and that it is possible to remotely determine the position of the supply contactor.

One hardware difference is that the SMI FS describes a CT meter containing a 2 A relay to control an external supply contactor. This means that these CT meters have the capacity to de-energise supply if an external supply contactor is fitted at the connection point. The VAMI FS does not require supply contactor functionality for CT meters. It is estimated that the number of small customers fitted with a CT meter (consuming less than 160 MWh p.a.) is less than 0.5%, so this is unlikely to make a significant difference.

3.1.2 BP03 Load Management HAN (registration only)

Key points:

Feature/Function	**Material Difference**	**Implications for this BP**	**Comment/Consequence for Procedures**
Software: Application layer for utility HAN	SMI FS: ZigBee SEP 2.0 VAMI FS: ZigBee SEP 1.0	SEP 1.0 devices are not 'transferable' to SEP 2.0 HAN and vice versa	Not a Procedural issue. DPI will determine any planned migration strategy to SEP 2.0
Software application layer for HAN security certificates	SEP 2.0 will support a range of security certificates (SEP 1.0 certificates are single sourced)	Different security certificates unlikely to have implications for procedures	Ensure Process/Procedure is agnostic of the SEP

Both VAMI and SMI FS have specified ZigBee Smart Energy Profile (SEP) for the Home Area Networking (HAN) application layer, however the selected SEP versions are incompatible. This is discussed in greater detail in Section 3.2, however for this business procedure it is not considered that there will be any significant impacts on business processes for device registration.

Both the VAMI FS and the SMI FS require the secure registration of HAN devices before they can share information with the smart meter, which is supported in both SEP 1.0 and 2.0 application layers. In addition both the VAMI FS and the SMI FS will support the registration of up to 16 devices on the Energy Services Interface (ESI).

Neither specification deals with how customers will register HAN devices. SEP 2.0 supports security certificates from a range of different providers in addition to the single sourced security certificates required in SEP 1.0. It is unlikely that this will have any impact on the development of business processes.

3.1.3 BP06 SMI metering data collection, processing and delivery

Key points:

Feature/Function	**Material Difference**	**Implication for this BP**	**Comment/Consequence for Procedures**
Software: Accumulated energy values	VAMI only maintains accumulated energy data for values that are being stored	For VAMI meters accumulated (total) values are only available when interval data is stored and acquired SMI FS accumulated totals	Coordination may be required to ensure all required energy data is available Unlikely to make a material difference, but should keep the difference in mind.

		are always available from the meter even when interval data is not being stored or collected	
Software: Selection of quantities to be stored in interval energy channels	SMI FS supports greater flexibility in the specification of values stored in interval energy channels	VAMI requires that Exported Active Energy is always available (accumulated value and interval data)	Must not assume that Exported Active Energy data is always available
Software: Selection of quantities	SMI FS supports greater flexibility in the specification of values stored in interval energy channels	VAMI requires that all three phase meters always capture imported active energy (accumulated value and interval data)	Must not assume that Imported Active Energy data is always available for three phase meters
Hardware/Software: Reactive Energy measurement	VAMI single phase meters are not required to support reactive energy measurement	Not all VAMI smart meters will support reactive energy measurement	Standing data will need to capture if the capability is supported
Software: Reconfiguration of values selected for interval energy channel storage will delete historical information	SMI FS allows energy values to be stored in interval energy channels without acquisition	Separation of storage and acquisition was undertaken to support occasional energy audits. This capability is not supported in VAMI	May need to approach AEMO to request separation of storage and acquisition if market intends to use occasional reactive energy audits

There are differences in specification of the type of energy data that can be collected, processed and delivered to the market. These differences have the potential to affect the energy data available from particular meters.

The most obvious difference is the inclusion of reactive energy measurement for all meters in the SMI FS. The VAMI FS only supports reactive energy measurement for three phase meters.

The SMI FS specifies that all accumulated totals will be acquired daily regardless of whether the measured quantity is being stored in an interval energy channel. The VAMI FS requires meters to maintain accumulated values for energy quantities selected for storage in interval energy channels[2]. In the VAMI FS storage and acquisition cannot be separately specified, when an interval data channel is selected for storage, it will be acquired[3].

The SMI FS separates the storage of interval data in the meter and acquisition of meter data from the meter, specifically it is possible to store values, but not acquire them. It is understood that the SMI FS selected this feature to support occasional reactive energy audits, for which reactive energy data is only acquired infrequently. It should be noted that several meter implementations will clear ALL historical meter data when changes are made to the quantities selected for interval energy storage. Procedures will need to consider the consequences of clearing historical information from the meter (for example a customer will be unable to access their historical consumption via the HAN) when performing occasional reactive energy audits to determine if this justifies changes to existing AEMO Metering procedures.

The VAMI FS places restrictions on the selection of energy channels which are not reflected in the SMI FS. Table 2 summarises the restrictions listed in Section 3.2 (especially clauses (d) through (f)) of the VAMI FS. This could be contrasted with a similar table for meters complying to the SMI FS which would state “Optionally stored and Optionally acquired” for all values for all meters.

[2] See VAMI FS section 3.2 (a) (3)
[3] It is noted that this restriction aligns with the AEMO Metrology Procedure which specifies that if a meter stores interval data then it must be acquired.

Table 2: Energy Data settings specified in VAMI FS

Quantity	Single Phase Meters	Three Phase Meters
Exported Active Energy	Always stored and acquired	Always stored and acquired
Imported Active Energy	Optionally stored and acquired	Always stored and acquired
Exported Reactive Energy	Not Measured	Optionally stored and acquired
Imported Reactive Energy	Not Measured	Optionally stored and acquired

Finally meters complying to the VAMI FS are unlikely to only record accumulated energy totals for selected channels, specifically "(3) record total accumulated energy for each recorded channel of interval data" as this would imply that if a VAMI meter is not storing interval data then the meter is not required to record an accumulated total. This will certainly have an impact when considering reverse energy flow, where the VAMI meter will indicate that reverse energy was detected, but is unable to quantify the amount.

3.1.4 BP08 SMI re-energisation

Key points:

Feature/Function	**Material Difference**	**Implication for this BP**	**Comment/Consequence for Procedures**
Hardware/Software: re-energising the supply contactor remotely	SMI FS supports three separate functions for remote re-energising the supply contactor, namely **Monitor Supply**, **Arm** and **Close immediately**	SMI FS supports two additional modes for remote re-energisation of the supply contactor which are not supported by VAMI FS	It is expected that jurisdictional regulation will specify the methods that can be used for re-energisation. Procedures will allow/disallow methods of re-energisation based on the jurisdiction's requirements. It is noted however that limiting the SMI to one mode of re-energisation will limit the ability to expand the available options.
Hardware/Software: re-energising the supply contactor locally	SMI FS supports three separate functions for local re-energising the supply contactor, namely **Monitor Supply**, **Arm** and **Close immediately**	SMI FS supports two additional modes for local re-energisation of the supply contactor which are not supported by VAMI FS	
Software for Monitor Supply threshold	VAMI FS specifies the Monitor Supply threshold as "per element per phase" while SMI FS specifies (total) exported active power	Need to ensure that BP supports a consistent (safe level) despite differences	Threshold agreed with safety regulator so unlikely to be a programmable parameter
Software: Support for Arm	ARM not described in VAMI FS	Arm functionality not specified	Most VAMI meters do support Arm
Software: Support for Close Immediately	When a re-energisation is performed remotely VAMI FS requires Monitor Supply functionality (auto-disconnect).	It is not currently possible to disable Monitor Supply functionality in VAMI	While not an issue for procedures it should be noted that for VAMI if a customer's load cannot be reduced below the auto disconnect level to allow a remote re-connection, a site visit will be required to perform local Close Immediately. This is not the case for the SMI FS where a Close immediately can be

Feature/Function	Material Difference	Implication for this BP	Comment/Consequence for Procedures
			performed remotely.
Software: Monitor Supply (performed locally)	Locally VAMI only supports Close immediately. Meter cannot be asked to Monitor Supply	Will only have an effect if the service order is to be performed manually (locally)	Unlikely to make a material difference even when the SMCN is unavailable
Software: Reporting of Monitor Supply re-opening of contactor	VAMI does not support (immediate) reporting when monitor supply opens the supply contactor	VAMI will store the close and open events in the meter event log, but settings do not allow this these events to be selected for (immediate) reporting	Validation that power has been *successfully* restored to the customer, if necessary, may require use of remote service checking for VAMI meters
Hardware: Time to open the supply contactor after detecting a load exceeds Monitor Supply threshold	VAMI FS does not state a performance level for opening the supply contactor when the meter detects that the monitor supply threshold has been exceeded	No impact on the procedure	While this difference has no impact on procedures the safety regulator may take into account the time to open in its assessment of the use of the function

There are some differences between methods offered for re-energisation by meters complying with the VAMI FS and the SMI FS with the SMI FS supporting three different methods of re-energisation of premises and the VAMI FS supporting one. It is likely that use of remote re-energisation will be controlled by relevant (jurisdictional) safety authorities, which will be considered when developing procedures.

The SMI FS supports three separate methods for re-energisation (closing the supply contactor), namely Monitor Supply, Arm and Close immediately. The SMI FS places no restrictions on the operation of each method, with each able to be performed both locally and remotely.

The VAMI FS does not specify the Arm function. While the VAMI supports Monitor Supply (referred to as auto-disconnect) and Close immediately, it restricts use of Monitor Supply to remote operation and restricts the use of Close immediately to local operation.

While both specifications describe Monitor Supply, there are differences in the way that the threshold is specified. VAMI FS specifies the threshold “per element per phase” while SMI FS specifies that the threshold is the exported active power (the total demand at the premise). It is likely that the threshold for Monitor Supply will be agreed with relevant safety authorities and will be programmed accordingly.

The SMI FS includes an Arm command which ensures the presence of the customer at the premises. Under the Arm command a message is sent to the meter allowing the customer to press a button on the meter which closes the supply contactor.

In both specifications switching of the Supply Contactor will be stored in the meter’s event log, however if Monitor Supply (auto-disconnect) reopens the Supply Contactor then the SMI FS will allow the meter to report this immediately to the SMMS.[4] This immediate reporting is not described in the VAMI FS indicating that the switching will be only be detected with the daily collection of the event log.

Another minor difference is that the SMI FS specifies Monitor Supply switching of the supply contactor will occur in under a second. This time frame is not duplicated in VAMI FS. It is anticipated that the safety regulator will take this difference into account during its assessment of the use of this functionality. The difference will not be significant during the development of procedures.

[4] The event log entry and reporting are both programmable in the SMI FS

3.1.5 BP15 HAN customer messaging

Clarification: This business procedure considers text messaging to customers separately from messaging associated with updating retail tariffs used by HAN devices.

Text message to customers

This discussion is largely focussed on SMI FS Section 7.9.1.5 which is intended to describe the transmission of text messages to customers. For example the text "A Critical Peak Price event has been declared from 2pm to 8pm on the 15th Dec." The message is intended to be read and understood by the customer.

Key points:

Feature/Function	Material Difference	Implication for this BP	Comment/Consequence for Procedures
Software: Application layer for HAN	SMI FS: ZigBee SEP 2.0 VAMI FS: ZigBee SEP 1.0	SEP 1.0 only supports messaging to a single mailbox SEP 2.0 supports messaging from multiple participants with separate mailboxes for each participant	SMI FS supports up to 8 mailboxes for messages (for different authorised parties) and that a message from one party cannot overwrite another party's message
Software: In SMMS	Message prioritisation not detailed in VAMI FS	The SMI FS requires the SMMS to support HAN Message Prioritisation.	VAMI FS may not support HAN message prioritisation.
Software: Reporting of message acknowledgement	Difference in the ability to select events	The SMI FS supports a Request for an acknowledgement to be sent from the HAN device when it receives the message.	
Software:	May depend on IHD functionality	The SMI FS supports a Request for an acknowledgement to be sent from the HAN device when a customer receives the message	
Software:	ESI Implementation supports effective date/time	Effective date/time and a separate expiry date/time. VAMI may not be able to meet same service levels	Feature is not supported in VAMI meters
Software: Back Office and Procedures	SMI FS requires all messages to identify the authorised party which is not detailed in VAMI	Messages must identify the authorised party sending the message	Feature is not supported in VAMI meters If multiple parties are authorised to send messages to HAN devices the message itself may need to be used to identify the sender

Customer privacy issues are still being developed to provide a framework for consumer protection. While both specifications support messaging to customers, high level rules and regulations will probably be required to determine who can send messages to customers (and potentially even the content of those messages). It is likely that procedures will have to consider customers opting in and out of messages from authorised parties. These considerations are relevant to meters compliant to either FS

There is a material difference between the specified HAN standards, with VAMI FS specifying ZigBee SEP 1.0 which supports messaging to a single mailbox and the SMI FS which specifies SEP 2.0 supporting separate messaging from multiple market participants to multiple mailboxes.

Assumption: A HAN device receiving a message (for now considered to be an In Home Display (IHD)) should be considered to have limited resources[5]. When multiple messages are sent to the device it is likely that older messages will be overwritten by the most recent message.

Impact: In VAMI it may not be possible to prevent messages sent by one authorised party overwriting messages sent by another party. SEP 1.0 was intended to support messaging from a vertically integrated utility to its customers, so SEP 1.0 does not provide separate mailboxes for authorised parties. When a single party is sending messages to the HAN device they can manage their messages in order to minimise the chances of overwriting current messages. If multiple parties are able to send messages (over a relatively short time period) there is a greater chance that some earlier messages will be overwritten.

SEP 2.0 provides separate mailboxes for a number of different authorised parties (it was designed to support disaggregated utilities). Messages can be sent to the HAN device and each authorised party can only overwrite their own messages (and not those of another authorised party). As such the chance of losing messages is reduced.

While the SEP 2.0 specification does not specify the number of mailboxes (or their size), the SMI FS specifies that the ESI Implementation shall support eight separate mailboxes (it does not indicate how many entries are contained in each mailbox). The SMI FS specifies that when the mailbox of an authorised party cannot store a new message, messages from that party will overwrite its own messages. This functionality is not supported in the VAMI FS.

The SMI FS also allows the ESI to report when a customer reads a HAN message. This functionality is described in greater detail when discussing Event Recording (refer Section 3.1.6). This feature could be used to manage messaging, for example sending a confirmation to the SMMS once the message is read, and this confirmation is used to indicate that another message can now be sent without overwriting the earlier message. VAMI meters do not support this feature.

In VAMI FS meters it might be possible to develop back office processes to reduce the chance of messages from one authorised party overwriting those from another. However this approach may not be fully effective. The process may delay some messages making it difficult to ensure that agreed service standards are maintained for all authorised parties.

There are a number of other differences between the VAMI FS and SMI F.S which will also affect Customer HAN messaging. Compared to the VAMI FS, the SMI FS supports:

- a priority for HAN messages
- the authorised party to request an acknowledgement from the HAN device receiving the message and/or from a customer who receives the message
- messaging to support an effective date/time and a separate expiry date/time
- identification of the authorised party sending the message .

While this functionality is not described in the VAMI FS, some of the functionality may be provided in the ZigBee SEP 1.0 specification. Further analysis would be required to determine whether SEP 1.0 supports these additional features.

The addition of an effective date and time allows messages to be sent ahead of time (for example notification that a new tariff rate has come into effect) potentially supporting a service level around the effective date and time (rather than around when the HAN message is actually sent from the SMMS).

[5] Both specifications recognise that it is not possible to detail requirements for customer purchased and installed IHDs.

An expiry date for messages could be used to automatically remove old messages which are no longer useful (for example a message to opt in to an energy offer). Note that this only applies to messages which have not been retrieved from the ESI Implementation, it does not cover messages stored elsewhere on the HAN (for example in an IHD).

HAN message prioritisation was added to the SMI FS recognising that one of the authorised parties could be government emergency service organisation. For example on days of extreme fire danger alerts could be sent over the SMCN (in addition to other communications media). It was assumed that these messages would be sent with high priority when compared to other customer messages. The VAMI FS does not support message prioritisation.

It is acknowledged that multiple multi-party access to the Smart Metering Infrastructure is still being discussed. This section has considered multi-party access for HAN Customer (text) messaging, however multi-party access needs to be considered in other business procedures, including load control of both the CLC/R and HAN devices), event reporting, meter configuration, etc. As highlighted above even when all access is coordinated through the distributor (mandated rollout) some procedural issues remain.

The standing data will need to include the SEP version that is supported in the ESI so that procedures can identify those premises where differences in the SEP version need to be handled.

Transmission of Retail Tariffs to HAN devices

This discussion is largely focussed on SMI FS Section 7.9.1.6 Retail Tariffs. Clause a) states:

a) The *ESI Implementation* shall store sufficient retail tariff information to enable a *HAN device* to convert kW and kWh readings into an estimated current cost of consumption. The estimated current cost of consumption will assist customer understanding of the consequences of changes to their behaviour.

The message is also intended to provide HAN devices with sufficient (retail) tariff information to allow them to determine optimum operating modes (for example a refrigerator avoiding cyclic defrost when electricity prices are high)

Key points:

Feature/Function	Material Difference	Implication for this BP	Comment/Consequence for Procedures
Software: Tariff information stored in ESI	VAMI does not document future settings reconfiguration	SMI FS allows future tariffs to be written to the ESI ahead of the commencement date. VAMI requires the tariffs to be written on the commencement date	This could have implications for the service levels offered to market participants when changing the tariffs stored in the ESI.

Clarification: Neither specification requires the *meter* to store the retail tariff. In both specifications the ZigBee SEP supports price information and the ESI shall store this information for HAN devices.

All versions of the ZigBee SEP describe the functionality provided by the ESI[6]. During the development of the SMI FS it was considered desirable to document additional functionality associated with the HAN, however since this functionality is SMI specific it was decided to include the requirements in the “ESI Implementation”. For example Table 7-1 in the SMI FS specifies that the ESI Implementation shall support Element 1 and Element 2 pricing components in addition to the Total.

[6] ZigBee SEP 1.0 refers to the ESI as the Energy Services Portal, however the functionality is the same

A detailed analysis of the difference between HAN functionality supported in VAMI FS SEP 1.0 and that supported by the SEP 2.0 ESI Implementation described in the SMI FS has not been undertaken. It is suggested that such a review be delayed until the final version of SEP 2.0 is released.

The SMI FS clarifies that the ESI stores *RETAIL* tariff information while VAMI FS does not specify the particular tariff information stored in the ESI. It is assumed that the tariffs supported in ZigBee SEP 1.0 are retail tariffs so the difference is unlikely to be material.

Tariff support in ZigBee SEP 2.0 has been enhanced when compared with SEP 1.0. Both VAMI FS and SMI FS require sufficient information to be stored to enable a (registered) HAN device to convert information stored in the meter into cost information. SEP 2.0 enhancements include carbon pricing which may be relevant as Australia moves towards emission trading schemes.

The VAMI may not support all current customer tariffs as it specifies “1 set of 7 TOU periods for weekdays, one for Saturday and another for Sunday”, for example this would not support an inclining block tariff. The SMI FS does not attempt to specify the tariff information that is supported.

The SMI FS allows settings to be sent to the meter with an effective date (so called future settings reconfiguration). Considering that changes to customer (retail) tariffs must be published well ahead of time, this features can be used to reduce the load on the SMCN by sending the new tariffs to devices over an extended time period (potentially even weeks).

No future settings reconfiguration is supported in VAMI FS. New tariffs must be sent to the meters only when the tariff change takes effect. This will place a very high load on the SMCN when there is a tariff change affecting a large percentage of the meter population. The consequence is that the VAMI SMCN may not be able to support the same service standards as those developed for SMI.

In Section 3.1.5 it was highlighted that customer privacy considerations may place restrictions on text messages being sent to customers. It has been assumed that tariff messages will not be subject to the same restrictions. Tariff information is required to support all HAN devices (for example so that smart appliances can adapt their energy usage to reduce costs to the consumer). As such tariff information is not only for display to the customer (for example on an IHD).

3.1.6 BP05 Event log collection, processing and delivery

Key points:

Feature/Function	Material Difference	Implication for this BP	Comment/Consequence for Procedures
Hardware: Number and size of event logs stored in the meter	SMI FS: 3 x 100 events. VAMI FS: 1 x 100 events	SMI FS made change to ensure Access and Security events could not be overwritten by events of lower importance	Unlikely to make a significant difference
Software: Storing events	SMI FS: allows users to program the events which are stored in the event logs VAMI FS: does not support user programming of events stored in the event logs	If particular events are required by market participants then procedures should be developed to ensure the SMI meters are programmed to capture events	Need to consider events required by market participants
Software: Reporting of events	SMI FS allows users to program events to report (immediately) to the SMMS VAMI does not support (immediate) event reporting to	If business processes require immediate notification this may not be supported in VAMI meters (e.g. detection of tamper)	May have implications in development of other BPs (for example reporting that remote closure of the Supply Contactor has failed due to Monitor

Feature/Function	Material Difference	Implication for this BP	Comment/Consequence for Procedures
	the SMMS		Supply)
Software: Reporting of possible event log overflow	SMI FS: event log overflow warning reporting to SMMS VAMI FS: no event log overflow report	Only the SMI FS will support reporting of likely event log overflow allowing a special read to be performed to collect the events (hopefully) before overflow	Unlikely to make a difference to procedures
Software: Detection of event log overflow	SMI FS documents that if the event log overflows the SMMS can determine how many events were overwritten (lost) The VAMI does not support this functionality	If procedures require confirmation based on events acquired from the meter, then market participants may require notification that some events have been "lost" (for example ESI acknowledgement that it received a HAN message)	Event log overflow may affect business processes for which market participants expect acknowledgement.
Hardware: Support for outage reporting ("last gasp")	VAMI FS: appears to specify last gasp report SMI FS: does not require last gasp reporting	Service level for outage reporting will differ for the two meters.	Unlikely to make a difference during a distributor lead mandated rollout, but may have to be addressed post-mandate if contestability is supported. May need to consider ensuring that the meter provider notifies the network operator when outages are detected.
Software: Support for reporting of power restore	SMI FS requires meters to report power restore VAMI does not require reporting of power restore	Service level for power restore likely to differ for the two meters	Unlikely to make a difference during a distributor lead mandated rollout, but may have to be addressed post-mandate if contestability is supported. May need to consider ensuring that the meter provider notifies the network operator when outages are detected.
Software: Under/Over Voltage events performance level	VAMI FS does not require under/over voltage events to be acquired daily. SMI FS does require daily acquisition	Service level for delivery of under/over voltage events in VAMI meters may need to be different	Unlikely to make a difference during a distributor lead mandated rollout, but may have to be addressed post-mandate if contestability is supported
Software: List of detected Events	SMI FS identifies a number of events which are not included in VAMI (including tamper, Customer Supply (Safety) Monitoring fault, etc)	Need to ensure that events required by business processes are adequately described in both specifications	Need to create a full list of all events

The SMI FS allows authorised parties to select events for which the meter will immediately report their occurrence to the SMMS. These could be used to provide acknowledgements to market participants with a higher service level than supported in the VAMI FS (for example if using the Arm function for remote re-energisation the retailer could be notified when the Arm timeout expires allowing them to contact the customer to resolve a potential issue).

The SMI FS specifies three separate event logs, namely Access and Security, Quality of Supply and HAN, and each event log can contain a minimum of 100 events. The VAMI FS specifies that all events are stored in a single event log containing the most recent 100 entries.

Another difference is that the SMI FS allows authorised parties to program which events are to be stored in the event log while the VAMI FS prescribes the events which are stored.

The SMI FS allows authorised parties to select which events are reported to the SMMS when they occur. The VAMI FS does not support reporting of any events to the SMMS (they are detected when the event log is acquired daily).

When considering the number of entries in the event log and the possibility of event log overflow (when a large number of events occur) the SMI FS supports reporting (to the SMMS) when the number of events occurring since the last time the event log was acquired exceeds a programmable threshold (this is so the meter can report when events may be about to be overwritten in the event log).

The SMI FS also requires that the SMMS can determine when events have been overwritten (due to an overflow of the event log). While this feature might only be useful when a large number of events occur, the VAMI FS does not support either of these functions.

The meter loss of supply event is also treated differently in the two specifications. The VAMI FS allows “last gasp” reporting of a loss of supply (outage), while the SMI FS does not require “last gasp” reporting. The SMI FS specifies that loss of supply is reported when power is restored as a reportable event, however this is not supported in by the VAMI FS.

Another subtle difference is that the SMI FS requires an event to be written at the start of a detected under/over voltage event and another at the end of the event, while the VAMI FS only requires a single event. A single event will only be stored in the event log at the end of the event, so if the voltage at a meter is permanently above or below the threshold, no event will be written. In the SMI FS retrieval of the event log with a start event, but no corresponding end event, clearly indicates that the voltage at a metering point is permanently outside the specified range. Processing and Delivery

In summary daily delivery of over and under voltage events is not required in the VAMI FS. Other events should be reported daily.

Both the SMI FS and the VAMI FS indicate that events should be available for delivery to market participants. The SMI FS states the performance level is for “all energy data and **event logs**”. The VAMI FS (Section 4.1) requires “daily collection of the previous trading day’s interval energy data and total accumulated energy (as required in section 3.3)”. No performance levels are specified in Section 3.3 of VAMI, but the last clause states “(e) (5) events logs”. A note refers to Appendix A which identifies events for which Daily collection [is] required (all events are collected daily excluding under and over voltage events).

3.1.7 BP11 SMI NMI Discovery

Placeholder

NMI discovery is a request to market systems that does not involve the SMI.

Key points:

Feature/Function	Material Difference	Implication for this BP	Comment/Consequence for Procedures
Software: Plug and Play device commissioning	Nil	Nil	Nil

Both specifications require a meter (to attempt) to report to the SMMS when installed. In VAMI FS this is referred to as ‘self-register’ and in the SMI FS as ‘Plug and Play device commissioning’. A meter cannot remotely determine which premise it has been installed on, as such it is emphasised that (in both specifications) additional (manual) steps are required to ensure that a meter is registered to a NMI.

3.1.8 BP13 SMI Service charging

Placeholder

SMI service charging does not involve the SMI.

Key points:

Feature/Function	Material Difference	Implication for this BP	Comment/Consequence for Procedures
SMMS Software:?	Neither specification includes requirements to measure data traffic to/from meters (assumption this will form the basis of service charges)	Basis for any service charges	Once the basis for service charges is determined the SMMS specification should be enhanced to ensure that it captures required data

Costs associated with access to the Smart Meter Communications Network (SMCN) are not considered in either VAMI FS or the SMI FS Neither specifies measurement of the amount of traffic, number of commands sent, etc.

3.1.9 BP22 Network tariff change process.

Placeholder

Changes to Network tariffs will occur outside the SMI, however there may be a requirement to change settings within the SMI.

Key points:

Feature/Function	Material Difference	Implication for this BP	Comment/Consequence for Procedures
Software: Tariff information stored in ESI	VAMI does not document future settings reconfiguration	SMI FS allows future tariffs to be written to the ESI ahead of the commencement date. VAMI requires the tariffs to be written on the commencement date	This could have implications for the service levels offered to market participants when changing the tariffs stored in the ESI.

The SMI FS allows settings to be sent to the meter with an effective date (so called future settings reconfiguration). Considering that changes to customer (retail) tariffs must be published well ahead of time, this features can be used to reduce the load on the SMCN by sending the new tariffs to devices over an extended time period (potentially even weeks).

No future settings reconfiguration is supported in VAMI FS. New tariffs must be sent to the meters only when the tariff change takes effect. This will place a very high load on the SMCN when there is a tariff change affecting a large percentage of the meter population. The consequence is that the VAMI SMCN may not be able to support the same service standards as those developed for SMI.

3.2 Discussion of the specified HAN standard

The VAMI FS and SMI FS have both selected ZigBee Smart Energy Profile (SEP) as the application layer for the Home Area Network (HAN). VAMI FS specifies SEP 1.0 while the SMI FS specifies SEP 2.0. The application layers of the two standards will offer similar functionality, both will support load management and both will support the secure registration of HAN devices. The SEP 2.0 specification is still in development so HAN devices compliant with the SEP 2.0 standard are not currently available.

While business processes will be similar for both standards it must be noted that HAN devices cannot operate on both SEP 1.0 and SEP 2.0 networks[7], This means that a customer who purchases a SEP 1.0 HAN device will not be able to operate that device on a SEP 2.0 HAN (nor can SEP 2.0 devices operate on a SEP 1.0 HAN). It is noted that while VAMI FS specifies that the HAN will use SEP 1.0, devices compliant to SEP 1.0 are no longer available, instead devices are being certified to a more modern document, specifically SEP 1.1.

It is worth noting that the incompatibility between SEP 1.x and SEP 2.0 is caused by a change to the specified Media Access Layer, from a ZigBee proprietary layer to a layer supporting internet protocol (as specified in open standards managed by the IETF). Future releases of ZigBee SEP (beyond 2.0) will interoperate with SEP 2.0.

One of the features added to SEP 1.1 is HAN device software upgrade, over the air. This feature makes it possible to remotely upgrade the software in a SEP 1.1 HAN device. The upgrade must be managed very carefully to minimize the possibility of rendering HAN devices inoperable. Detailing two potential issues:

(i) not all SEP 1.1 HAN devices will have sufficient program memory to run the larger software image required in SEP 2.0 compliant devices and

(ii) the smart meter must manage the software upgrade of the HAN device while continuing to run SEP 1.1, but once the HAN device software upgrade is complete the device will be unable to communicate with the meter until the meter is also upgraded. If there are a number of HAN devices on the network the meter must upgrade each device before it switches to SEP 2.0. It is only once the meter is upgraded to SEP 2.0 that it will be able to determine if the HAN device upgrade(s) have been successful.

While both the VAMI and SMI FS support software upgrade of the Energy Services Interface[8] (ESI), neither presents business requirements for the upgrade the ESI software. It should be mentioned that there is no clear argument supporting the upgrade of the ESI especially if the existing software is able to deliver identified benefits (for example messaging to customers and load control). At the same time if customers are purchasing and installing devices a new feature may not be supported by an ‘old’ version of the ESI, in which case customers might expect the ESI to be constantly maintained. Such considerations are well beyond the scope of either FS.

Summary

- SEP 1.0 devices can interoperate with SEP 1.1 devices.
- SEP 1.1 supports remote software upgrade of HAN devices. This will allow many devices to be upgraded from SEP 1.1 to SEP 2.0 (when the specification is finalised), however the upgrade must be carefully managed
- It is anticipated that all future releases of ZigBee SEP will be backwards compatible with SEP 2.0 devices

[7] Theoretically HAN devices could be constructed supporting both SEP 1.x and 2.0, but these are likely to be produced in limited numbers and any discussion is beyond the scope of this analysis
[8] For the purposes of this discussion consider that the ESI implements the specified ZigBee SEP (currently specified as SEP 1.0 in VAMI and SEP 2.0 in the SMI FS)

4 High level comparison of the specifications

4.1 Program Scope

Summary

- The scope of the two programs is very similar.

The SMI FS shows that part of the HAN falls within scope of the specification, as it is provided by the Energy Services Interface in the meter.

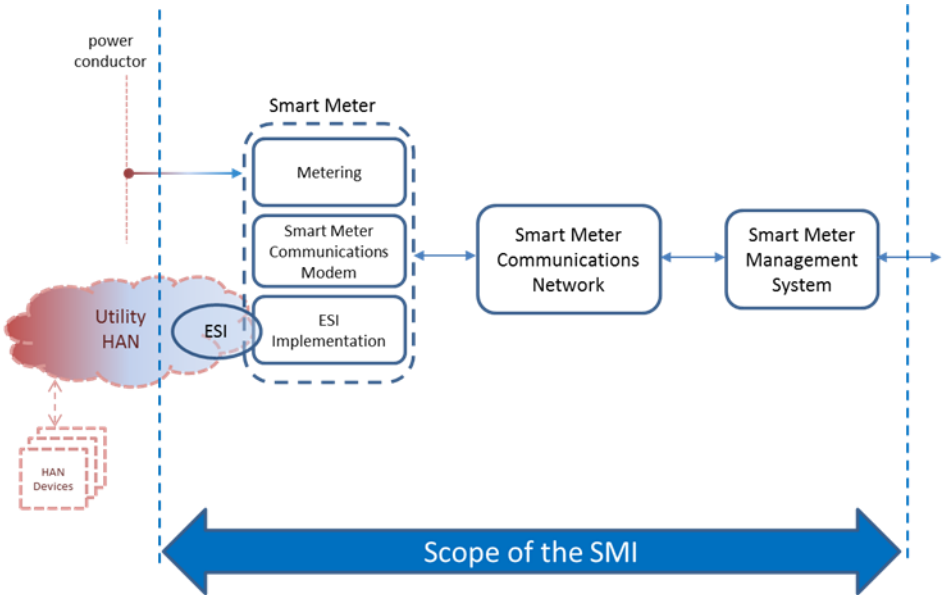


Figure 1: Scope of the SMI FS

Note it has been suggested that the Victorian AMI specification does not include any figures because "it is a legal document". The following figure is therefore taken from other Victorian material presenting the scope of the Victorian AMI Specification:

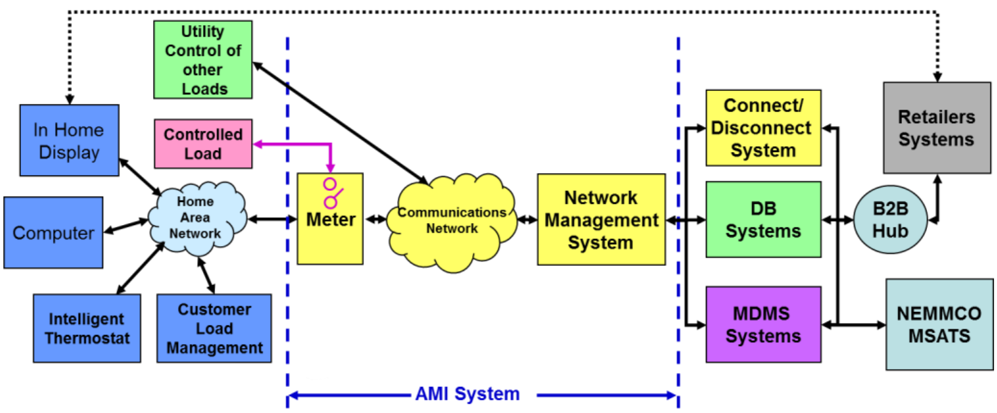


Figure 2: Scope of the Victorian AMI Specification

The SMI FS uses different terminology for the same items. The major differences are detailed in the following table:

Table 3: Identical Terms used in SMI FS and VAMI FS

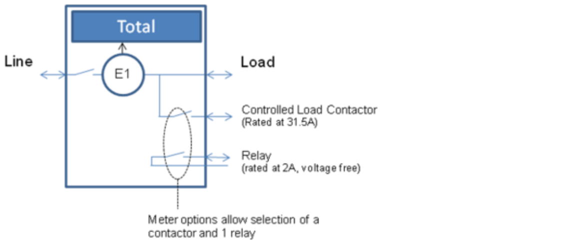
SMI FS	VAMI FS
Smart Meter	Meter
Smart Metering Infrastructure (SMI)	Advanced Metering Infrastructure (AMI)
Smart Meter Management System (SMMS)	Network Management System (NMS)
Smart Meter Communications Network (SMCN)	Communications Network
Software	Firmware
Monitor Supply	Auto-disconnect function
Whole Current meter	Direct Connect meter
Acquire	Collect
Report	Alarm
Energy Services Interface (ESI)	Energy Services Portal

4.2 Meter Configurations

Summary

- The Victorian AMI Specification does not describe single phase two element meters.
- Victorian AMI Single Phase meters are not required to measure reactive energy
- Victorian AMI CT connected meters are not required to support a HAN

Table 6-1 in the SMI FS provides details of the meter configurations

Meter Configuration	**Description of Physical variant**	**Comment**
Single Phase Single Element Meter	 31.5 A *controlled load contactor* is rated to 230 Vac 2 A *relay* is rated to 230 Vac supplied *voltage* free	Identical single phase meter with and without 31.5A controlled load contactor. SMI FS also describes (an optional) 2A relay • Providing multiple load control at a single premise • 2A voltage free selected to interface to AS4755

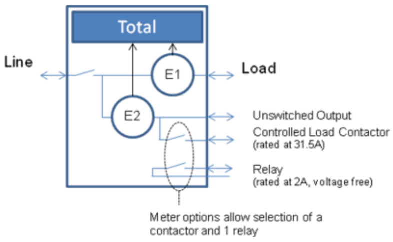
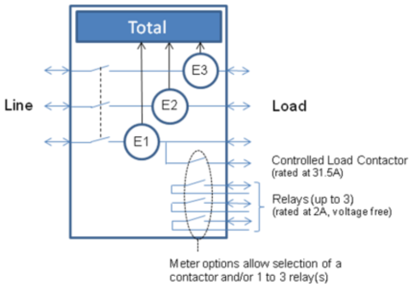
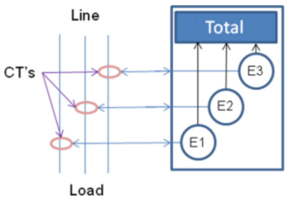
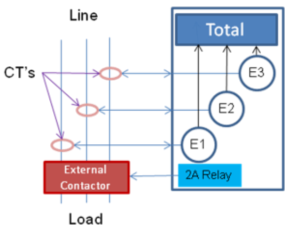
Meter Configuration	**Description of Physical variant**	**Comment**
Single Phase Two Element Meter	Suitable for sites with separate *measurement* of the Controlled Load (for example off-peak hot water tariffs) For meters with a 31.5 A *controlled load contactor* both a switched and unswitched output is available from the second element  31.5 A *controlled load contactor* is rated to 230 Vac 2 A *relay* is rated to 230 Vac but supplied *voltage* free	Two element meters are not described in the VAMI FS specification
Three Phase Whole Current Meter	 Note: The integrated 31.5 A *controlled load contactor* is only Single phase 2 A *relays* are rated to 230 Vac but are supplied *voltage* free	VAMI FS only supports either one 31.5A relay or one "integrated (1A) relay for operation of an external three phase controlled load contactor". The 2A relay(s) specified in the SMI FS can be used to control external single or three phase contactors and are rated to 230Vac. The 2A relay(s) are supplied voltage free so that they can be used to control AS4755 equipped appliances • SMI FS allows up to 3 2A relays.
Three Phase CT Connected Meter	For large *customers* where the load is too large for a *whole current meter*  No *controlled load contactor or relay* No *supply contactor*	No Material Difference
Three Phase CT Connected Meter Supporting External Supply Contactor	The 2 A relay is *voltage* free and rated to 230 Vac, capable of controlling an external *supply contactor*  No *controlled load contactor* or (load control) *relay* Note: External *supply contactor* falls outside scope of *SMI*	VAMI FS specification does not support a 2A relay to control an external supply contactor

Table 6-2 in the SMI FS describes the Accumulated energy values recorded by different meters.

Meter Configuration	*Accumulated Energy* Values Recorded in the *Meter*	Comment
Single Phase Single Element *meter* Three Phase *whole current meter* Three Phase *CT connected meter* Three Phase *CT connected meter* supporting external *supply contactor*	*Total Imported Active Energy* (kWh) *Total Exported Active Energy* (kWh) *Total Imported Reactive Energy* (kvarh) *Total Exported Reactive Energy* (kvarh)	VAMI FS does not require single phase meter to measure reactive energy Active energy measurements identical
Single Phase Two Element *meter*	*Total Imported Active Energy* (kWh) *Total Exported Active Energy* (kWh) *Total Imported Reactive Energy* (kvarh) *Total Exported Reactive Energy* (kvarh) Element 1 *Imported Active Energy* (kWh) Element 1 *Exported Active Energy* (kWh) Element 2 *Imported Active Energy* (kWh) Element 2 *Exported Active Energy* (kWh)	Not described in VAMI FS

Summary

- SMI FS attempted to ensure that all meter functions where tested to an appropriate standard, including the supply contactor, controlled load contactor and voltage measurement (tests for which were not specified in VAMI FS).

Table 4: List of applicable standards for compliant meters (Section 6.3)

Applicable Standard	Comment
a) Meters shall meet the relevant requirements of (i) AS62052.11 - Electricity metering equipment (a.c.) – General requirements, tests and test conditions – Part 11: Metering equipment (ii) AS62053.21- Electricity metering equipment (a.c.) – Particular requirements – Part 21: Static meters for active energy (classes 1 and 2) (iii) AS1284.11 - Single-phase multifunction watt hour meters and (iv) Any pattern approval requirements of the National Measurement Institute, National Electricity Rules (NER) and metrology procedure.	No Material Difference
b) Reactive energy measurement shall meet the requirements of AS 62053.23 - Electricity metering equipment (ac)— Particular requirements Part 23: Static meters for reactive energy (classes 2 and 3)	No Material Difference
c) Meters shall measure over and under voltage in accordance with the requirements of Class S devices as specified in Section 5.4 of Edition 2.0 of IEC61000-4-30 Electromagnetic compatibility (EMC) Part 4-30: Testing and measurement techniques – Power quality measurement methods	VAMI FS does not specify testing requirements for voltage measurement (the VAMI FS meter is required to measure voltage)

d) For those meters with a controlled load contactor - AS62052.21-2006 Electricity metering equipment (ac) — General requirements, tests and test conditions Part 21: Tariff and load control equipment. In particular Section 7.4 Output elements shall apply.	VAMI FS does not specify testing requirements for the load control contactor (most meters described in the VAMI FS support load contactors)
e) For those meters fitted with a voltage free relay - AS62052.21-2006 Electricity metering equipment (ac) — General requirements, tests and test conditions Part 21: Tariff and load control equipment. In particular Section 7.4 Output elements shall apply. The relay shall also be compatible with AS4755 Part 3.1	VAMI FS does not specify testing requirements for the integrated meter to control an external three phase contactor
f) For those meters with a supply contactor - IEC 62055-31-2005 Electricity metering – Payment systems – Part 31: Particular requirements – Static payment meters for active energy (classes 1 and 2). In particular Sections 7.9.2 Specified ratings and 7.9.3 Performance requirements for load switching utilisation category UC1 shall apply.	VAMI FS does not specify testing requirements for the supply contactor (all whole current meters described in the VAMI FS support a supply contactor)

4.3 Performance Levels

There is a significant difference in the way that the Performance Levels are described in the two documents. The VAMI FS specification typically states "The total number of individual meters read in any 24 hour period can be up to 2% of the installed, operational AMI meter population". An identified issue is that this does not provide sufficient clarity to determine how the performance testing should be conducted, specifically the number of meters which are required to be involved in the testing or over what time frame. This has led to an assumption that a single test is conducted on the full daily percentage of meters (typically 2%).

The SMI FS removed this ambiguity and specifies the percentage of meters that are involved in the testing. In most cases this has resulted in a significantly lower percentage of meters being tested, but the test is then repeated multiple times to achieve the required daily percentage.

The VAMI FS specification also does not indicate where the meters are located. This means that testing could be undertaken with meters in close proximity with all the communications being carried on only a few Smart Meter Communications Network (SMCN) assets. The SMI FS provides additional clarity around the testing by stating that that "the meters must the uniformly distributed across the distribution network area". The exception is for Emergency supply capacity limiting to individual meters.

The SMI FS is written to support a range of different communications solutions and supports both broadcast and non-broadcast messaging (for Group commands). The VAMI FS specification states in Section 4 Performance Levels

(b) These performance levels specifically apply from the NMS to the meter and return.

When using broadcast messaging there is no message acknowledgement so it is not possible for the performance to be measured from the NMS to the meter ***and return***. This is offset with the VAMI FS specification stating 'Group commands may be delivered by broadcast' and in each performance level 'action performed' rather than 'action acknowledged'. The ambiguity is not resolved when looking at the actual performance levels with a single performance level being stated for priority load (consistent with not receiving an acknowledgement) and an initial and recovery performance level for other functions (which implies that acknowledgements are used to trigger command retries).

The SMI FS is communications technology agnostic, and for group commands it states that the action is performed and specifically states that the SMMS ***may*** not get an immediate acknowledgement e.g. The SMMS may not get an immediate acknowledgement, however on retrieval of event logs it will be possible to determine the success rate for <particular command>. In addition without an acknowledgement it is not possible to determine the need for retries so only a single performance level is stated.

For individual commands the SMI FS requires ‘message acknowledgement’, however the VAMI FS continues to state ‘action performed’.

4.4 Summary of the impact of identified Functionality and Performance differences

The following table identifies the impact of the major differences listed in Section 5.

Description	Reference	Impact
The Victorian AMI Specification does not describe single phase two element meters.		May limit retail offers to customers. However while the VAMI FS does not specify two element meters this does not prevent two element AMI meters (or a second meter) being installed where this is justified.
Victorian AMI Single Phase meters are not required to measure reactive energy		Will affect distribution businesses ability to locate areas of poor power factor. May also limit ability to offer (true) demand based tariffs
Victorian AMI CT connected meters are not required to support a HAN		Will limit ability to provide larger customers with a HAN
SMI FS details test standard for supply contactor		A lack of testing of the contactors means that the lifetime of the supply contactor cannot be guaranteed and may affect willingness to use Supply Capacity Limiting (resulting in frequent switching)
SMI FS details test standard for the controlled load contactors		A lack of testing of the controlled load contactor means that the lifetime of the contactor cannot be guaranteed and may affect willingness to offer tariffs with frequent switching for example load cycling
VAMI FS voltage measurements untested		Voltage measurements from VAMI FS meters can only be used “as a guide” while those from SMI FS meters are referenced to a quality of supply standard
VAMI FS specifies 200 days of interval data storage		Places additional obligation on the Meter Data Provider to ensure sufficient staff to manually read meters in the event of extended communications failure
SMI FS only specifies 35 days of interval data storage		The amount of historical information that a HAN device can download from the meter is just over a month compared to the 6 months possible from a VAMI FS meter
SMI requires all settings to be available both locally and remotely		Most of the programmable features in the VAMI FS are specified as being available both locally and remotely, so unlikely difference will affect market participants. (Might affect the meter provider)

Description	Reference	Impact
SMI supports remote acquisition of multi-utility information		May restrict ability to offer combined utility tariffs
The SMI FS includes the display of power and the status of the controlled load contactor (not just its position)		SMI FS is able to provide basic information to customers without the need to install a separate IHD.
Additional items available for display on the SMI FS		Market participants will be unable to offer the availability of display items across all jurisdictions
VAMI FS does not support load cycling		Load cycling was introduced to support demand reduction, may limit some customer tariff offerings
VAMI FS does not support load cycling	Hardware	The relays in VAMI FS meters are untested and therefore do not offer any guarantees of lifetime cycle counts
VAMI FS does not support a demand limit for controlled load		Demand limit was introduced to shed controlled load before resorting to switching the supply contactor using Supply Capacity Limiting.
VAMI FS does not support under frequency load switching		Under frequency load switching is provided as an automated means of shedding controlled load during periods of distribution network stress. Dropping the controlled load may relieve network stress. Since VAMI FS meters may not be able to support under frequency load switching it was decided to describe this functionality as optional in the SMI FS
VAMI FS describes “utility control of other load” which is not supported in the SMI FS		The SMI FS only supports load control where a smart meter has been installed.
VAMI FS does not require an event to be entered into the event log when the meter time is corrected beyond NER specified limit		VAMI FS meters are unable to satisfy the NEM requirement to identify interval data where the meter clock error exceeds 20 seconds
VAMI FS does not document an Arm Command		Some jurisdictions are considering a requirement that someone must be present at the premises before power can be applied.
VAMI FS does not support switching of the supply contactor on meter loss of supply		This functionality will assist during power restoration.
SMI FS includes five supply capacity limits compared to VAMI FS which only includes three.		The two missing limits are both active between a programmable hours of the Day. It was envisioned that these could allow capacity tariffs to be offered to customers
The Emergency supply capacity limit in the SMI FS avoids the potential for synchronised load switching		Synchronised load switching can lead to issues with Security of Supply. The possibility of synchronised load switching in VAMI FS meters will limit use of this function (back office processes will be required to avoid synchronised switching)
SMI FS clarifies that the supply contactor is opened as soon as the limit is exceeded.		The VAMI FS specification does not limit the amount of energy consumed in a period of time this may limit its usefulness as part of a tariff

Description	Reference	Impact
		offering to customers and as a means of reducing network demand
VAMI FS limits Import and Export Supply Capacity limits to multiple trading intervals		The VAMI FS restricts the capacity limits to trading intervals to support demand tariffs. The difference affects the design of tariff offers to customers using this functionality.
VAMI FS limits Import and Export Supply Capacity limits to multiple trading intervals		30 minutes may be too long to protect network assets from thermal overheating
VAMI FS Supply Capacity Limit operation open to interpretation		VAMI FS does not unambiguously state when the supply contactor should be opened.
ZigBee Smart Energy Profile (SEP), 1.0 and 2.0 are not interoperable		HAN Devices cannot be transferred from a VAMI FS meter to a SMI FS
The SMI FS documents the actual requirements		The VAMI FS does not specify the amount of data that must be stored to support multi-utility metering. An optional cluster in ZigBee SEP does not provide any guidance.
The SMI FS includes a separate event log for HAN events		The HAN event log will be useful when providing assistance to customers. The VAMI FS captures HAN events in the one event log.
The SMI FS documents separate access and security and quality of supply event logs, while the VAMI FS only documents a single event log		Provides greater security
The SMI FS allows events to be individually programmed to report to the SMMS		Provides greater flexibility
The SMI FS only requires the meter to optionally report utility selected events		Provides greater flexibility
The stated performance level documents Meter loss of supply to report only AFTER meter power is restored		VAMI FS is being interpreted to require 'last gasp' transmission. Performance level requires the detection of the outage at 90% of meters within an hour of the outage occurring. The SMI FS states that it does not prescribe last gasp outage reporting. Market participants are like to be notified later
The stated performance level documents Meter loss of supply to report only AFTER meter power is restored		Detection of nested outages is seen as a potential benefit. VAMI FS does not require meters to report power restore so does not support this benefit
The ability to check the status of the meter is described in the VAMI FS Detailed functionality is not described in the VAMI FS specification		The remote checking detailed in the SMI are aimed at providing customers direct support. The VAMI FS will not be able to provide the same level of support
The SMI FS documents future settings reconfiguration		The lack of future settings reconfiguration in the VAMI FS and the associated performance level will restrict the ability to change tariff offers on a

Description	Reference	Impact
		particular date (at 2% per day will take 50 days to reprogram all the meters)
Additional requirements ensure the upgrade does not degrade the performance of the meter		
SMI FS also describes performance levels for software upgrade (which was not attempted in the VAMI FS specification)		
The VAMI FS specification does not detail message prioritisation		The lack of message prioritisation will affect the provision of service level agreements for different functionality (for example to ensure that Priority Override commands are sent when required)
The VAMI FS does not detail message queuing in the SMMS		No visibility of required functionality

5 Functionality and Performance

5.1 Measurement and Recording (Section 7.1)

Summary

- Most significant difference is SMI FS requires voltage measurements in the meter to be tested to an international standard
- Metrology has very similar functionality with some differences due to VAMI FS reference to NER Meter Types

General

The SMI FS has added reactive energy measurement capability to single phase meters. The vendor's RFI revealed that this had minimal impact on the cost of compliant meters. Within the BRWG concerns were raised about communications costs to acquire the reactive data and higher back office costs to process additional data. The use case suggests that reactive energy will be used for audit purposes however the SMI F.S does not describe business processes.

The amount of interval energy data specified in both specifications is apparently identical, with Clause (a) in Section 3.2 of VAMI FS stating:

(a) (6) for all meters, a minimum storage of 35 days per channel of interval energy data

Unfortunately the VAMI FS specification also refers to NER Meter Types. Once again from Section 3.2 of the VAMI FS specification

(b) An AMI meter shall be capable of meeting the requirements (including accuracy) of type 4, type 5 and type 6 meters (non-TOU capability).

Clause (b) requires all VAMI FS meters actually store 200 days of interval data rather than the 35 days stated in Clause (a).

Clause	Comment
a) The accuracy of energy measurement shall be:	VAMI FS does not explicitly state meter accuracy
(i) For all meters: active energy to accuracy Class 1	On advice from AEMO consistent with NER requirements up to Type 3 (Note meter accuracy only. The accuracy of the CT is out of scope of both specifications)
(ii) For whole current meters: reactive energy to accuracy Class 3	NER only specifies varh accuracy for meter types 1, 2 and 3 so selected lowest standard limit
(iii) For CT connected meters: reactive energy to accuracy Class 2	Meets accuracy requirement for meter Type 3. Consistent with specified varh testing standard
b) The resolution of energy measurement shall be (i) For active energy: 1 Wh (ii) For reactive energy: 1 varh	VAMI FS does not specify the measurement accuracy. Included to ensure accurate measurement of bi-directional energy flows.

Clause	Comment
c) Throughout this functionality specification the terms record and store have different meanings. The glossary definition of each term is repeated here: (i) record means to capture the value. For values which are recorded it is only possible to obtain a single value (see stored when multiple values must be retained) (ii) store means retain the value with the ability to determine the date and time associated with the value (for example interval energy values are stored)	Included for clarification (No impact on meter hardware or software).
d) For each Accumulated energy value described in Table 6.2 a meter shall:	
(i) Separately record the accumulated energy value and this value shall be captured in the event of meter loss of supply.	Same requirement, but SMI FS ensures that value is retained after meter loss of supply
(ii) Store interval energy values in 30 minute trading intervals	No Material Difference (both state sub-intervals in the glossary definition)
(iii) Include the facilities on site to store interval energy values for 35 days per interval energy channel	No Material Difference as a minimum requirement, however VAMI FS meters must also perform as Type 4 which requires 200 days of storage
(iv) Stored interval energy data shall have a resolution of 0.1 kWh for active energy and 0.1 kvarh for reactive energy.	Same
(v) It shall be possible to enable or disable the storing of an interval energy channel both locally and remotely.	Same
(vi) The meter shall support a secure means of resetting the accumulated energy values (to zero).	Not specified in VAMI FS
e) For each interval energy channel the summated interval energy values over any number of consecutive trading intervals shall equal the change in the accumulated energy value over the same number of trading intervals, plus or minus 0.1 kWh for active energy or 0.1 kvarh for reactive energy.	Clarification to avoid vendor implementing algorithms which truncate energy values. No impact on meter cost.
f) The meter shall be capable of measuring active power	While active power measurements are used in the VAMI FS (Vict Auto-disconnection function, HAN) no requirements are stated
(i) For all meters; the meter shall be able to measure total net active power with an indication if the value is imported or exported.	Required for VAMI FS meters but not specified
(a) For two element meters: the meter shall also be able to measure active power per measurement element with an indication if each value is imported or exported.	VAMI FS does not include two element meters
(ii) The resolution of active power shall be 10 W; (once the load is above the meter starting current)	Not specified in VAMI FS
(iii) The meter shall calculate active power every 5 seconds	Not specified in VAMI FS

Clause	Comment
g) The meter shall be capable of measuring voltage (i) The accuracy of voltage measurement shall be as defined in IEC61000-4-30 for under and over voltage measurement for Class S devices (1%) (ii) The resolution of voltage measurement shall be 0.1 volts.	VAMI FS does not specify a testing standard for voltage

5.2 Remote Acquisition (Section 7.2)

Summary

- SMI FS requires all settings to be available both locally and remotely
- SMI FS supports remote acquisition of multi-utility information

General

As noted in Table 3 the SMI FS uses the technically neutral term ‘acquired’ allowing the meter to push the data to the SMMS or for the SMMS to actively collect the information. The VAMI FS used the term ‘collected’ but the intention is the same.

Clause	Comment
a) SMI shall support remote acquisition of interval energy data, accumulated energy data and meter event logs.	Same requirements
b) SMI shall support routine acquisition of energy data and meter event logs. The enabling and disabling of routine acquisition of any interval energy channel shall be possible locally and remotely	Routine acquisition (Performance level indicates daily) Setting both locally and remotely not stated in VAMI FS
c) The SMI shall support a special meter read command to acquire energy data and event logs	Same (VAMI FS discusses under performance levels for remote reads of individual meters)
d) The SMI shall support remote acquisition of multi utility meter data from the ESI Implementation (refer to Section 7.9.1.8)	Not covered in VAMI FS

5.2.1 Performance Levels

General

The VAMI FS specification separately states a performance level for collection of daily meter readings (Section 4.1), remote read of individual meters (Section 4.2) and for remotely read event logs (Section 4.9).

Clause	Comment
Routine Daily Acquisition	
a) All energy data and event logs shall be acquired from (i) 99% of meters within 4 hours after midnight	Identical

Clause	Comment
(ii) 99.9% of meters within 24 hours after midnight.	
Individual Meters	
a) For the special meter read energy data successfully received from (i) 95% of meters within 5 minutes (ii) 99% of meters within 10 minutes	The VAMI FS specification outlines a lower performance level (1) Action performed at 90% of meters within 30 minutes; (2) Action performed at 99% of meters within 1 hour; and (3) Action performed at 99.9% of meters within 6 hours.
b) The SMI performance level shall be tested by performing special meter reads at 0.5% (5,000 meters per million (mpM)) of the number of operational SMI meters in a distribution network area. This will be tested over an 8 hour period, with the sending of special meter read commands uniformly distributed across both time and the deployed SMCN collection points. The test can be conducted once in any 24 hour period	VAMI FS specifies a higher percentage of meters specifically 2% compared to 0.5%. (b) The total number of individual meters read in any 24 hour period can be up to 2% of the installed, operational AMI meter population
c) The applicable amount of data shall be the acquisition of seven days of a single channel of interval energy data and accumulated energy data	VAMI FS specification does not limit the amount of data to a single channel of interval energy data, so represents a slightly more onus requirement

5.3 Local Acquisition (Section 7.3)

Summary

- Similar functionality (documented in a different way)
- Additional performance level and testing requirement detailed in SMI FS

Clause	Comment
a) The meter shall include a local communications port allowing information transfers between the meter and devices connected to the port.	Not explicitly stated in VAMI FS
b) The local communications port shall support the local acquisition of interval energy data, accumulated energy data and meter event logs	Identical requirement
c) The local communications port shall provide secure access to energy data, meter event logs and all settings within the meter	Similar requirement, however VAMI FS choses to state this as “locally and remotely programmable” for most meter setting

5.3.1 Performance Levels

Clause	Comment
a) The local communications port shall support the acquisition of 35 days of a single interval energy channel of 30 minute trading intervals and all energy data within	No performance level is stated in the VAMI FS specification

Clause	Comment
14 seconds	
b) The stated SMI performance level shall be maintained under all test conditions outlined in relevant Australian Standards for meters.	VAMI FS does not describe a testing requirement (test of optical ports is covered under Australian metering standards)

5.4 Visible display and indicators on meter (Section 7.4)

Summary

- The SMI FS includes the display of power and the status of the controlled load contactor (not just its position)

General

Consumer group input led to the specification of several additional items to assist customer understanding without the need for an IHD.

Clause	Comment
a) The meter shall include a visible display and indicators.	No Material Difference
b) The visible display shall be capable of displaying all accumulated energy values listed in Table 6 2	No Material Difference
c) The list of accumulated energy values enabled or disabled for visible display shall be locally and remotely configurable	VAMI FS does not indicate that the items selected for display are programmable
d) The visible display resolution for all accumulated energy values shall be: (i) active Energy: 0.1 kWh (ii) reactive Energy: 0.1 kvarh	No Material Difference
e) The visible display shall be capable of displaying total net active power clearly indicating if it is imported or exported.	VAMI FS does not require the display of power (Note that it is only the display of power that is additional as the VAMI FS meter must calculate power)
(i) For two element meters, the visible display shall also be capable of displaying active power per measurement element clearly indicating if each value is imported or exported. The list of active power values available for display shall be locally and remotely configurable. (ii) The visible display resolution for active power shall be 10 W (once the load is above the meter starting current) (iii) When displaying active power the visible display shall have an update frequency of 5 seconds	VAMI FS does not describe two element meters
f) For meters fitted with CLC/R the meter shall provide a clear visible indication of the status of each controlled load contactor and/or relay as On or Off.	VAMI FS does not specify display of the status of the CLC/R
g) For meters fitted with a supply contactor:	
(i) The meter shall have a clear visible indication of the	VAMI FS only specifies that the meter show if the supply

Clause	Comment
status of the supply contactor as On, Off, exceeded supply capacity or armed	contactor is in the open or closed position The meter shall provide clear local visual indication of the status (open/closed) of the supply contactor
(ii) When the supply contactor is in the exceeded supply capacity state (in circumstances where a supply capacity limit has been exceeded), the visible display shall display the remaining time (in minutes and seconds) before the supply contactor automatically switches to the On state (supply contactor in the closed position).	Not specified in VAMI FS Requested so that customers are aware that power will be restored shortly

5.5 Meter Clock Synchronisation (Section 7.5)

Summary

- VAMI FS does not require an event to be entered into the event log when the meter time is corrected beyond NER specified limit

Clause	Comment
a) The meter shall include a meter clock which must be maintained within ±20 seconds of Australian Eastern Standard Time (AEST).	No Material Difference
b) An event shall be stored in the access and security event log when the meter clock is adjusted by more than 20 seconds. The access and security event shall include the size of the time adjustment.	VAMI FS does not require capture of this event

5.6 Load Management through a Controlled Load Contactor or Relay (Section 7.6)

Summary

- VAMI FS does not support load cycling
- VAMI FS does not support a demand limit for controlled load
- VAMI FS does not support under frequency load switching (however this is only optional in the SMI F.S)
- VAMI FS describes “utility control of other load” which is not supported in the SMI FS

General comment

Potential smart meter deployments in NSW and Queensland meant that the SMI FS described load control behaviour that is currently supported by existing ripple control systems. These requirements have increased the functionality in this section. Concerns have been expressed that there are a number of functions that may impact the cost of the meter. The Vendor’s RFI did not highlight any concerns with additional meter costs with the exception of meter loss of supply.

The VAMI FS specification stores two programs of 5 “turn on” and “turn off” times, one is assigned for weekdays and the other for weekends. The introduction of load cycling resulted in the SMI FS allowing 10 time slots, with each specifying a switch action (turn on immediately, turn off immediately, turn on delayed, turn off delayed or start cycling (stop cycling was included but in reality another command would be used to ensure that the CLC is left in a defined position)).

The SMI FS supports two programs (of 10 switch actions) and these can be allocated to two different day types, with the days of the week being a programmable parameter. VAMI FS supports two programs but the days are fixed to weekdays and weekends.

The VAMI FS meter does not document any of the Event driven modes of operation listed in the SMI FS Meter loss of supply is supported by a large number of existing ripple control receivers (where it is often referred to as cold load pickup), Under frequency and Demand Limit operation are both documented in Australian ripple control standards.

Section 3.6.4 of the VAMI FS specification provides details of the required load control switch time randomisation. Both specifications recognise that synchronised load switching can affect network stability and therefore provide randomisation of the load switch times. The SMI FS was required to further extend the functionality due to the optional 2A relay which can be used to control an AS4755 equipped appliance. When controlling an AS4755 equipped appliance turning off the relay increases demand making it necessary to support randomisation of both switch on and switch off.

Table 5: Random Load Control Switching Delay (Table 1 in the VAMI FS specification)

Load Control Type	**“Turn on” Random Switching Delay active**	**“Turn off” Random Switching Delay active**
Controlled load management at *meters* – programmed switching	Yes	No
Controlled load management at *meters* – individual *meter* override command	No	No
Controlled load management at *meters* – primary and secondary group *meter* override command	Yes	No
Controlled load management at *meters* – tertiary group *meter* override command	Yes	Yes
Utility control of other load – programmed switching	Yes	No
Utility control of other load – Individual device override command	No	No
Utility control of other load – primary and secondary group device override command	Yes	No
Utility control of other load – tertiary group device override command	Yes	Yes

The Under frequency event driven mode of operation is the only optional functionality in this section. The SMI FS states “If the meter supports…” this was done since it is not possible to determine if hardware limitations in existing VAMI FS meters mean that they are unable to measure the mains frequency. Many current meters in the Australian market offer mains locking of the meter time clock and therefore will support frequency measurement, however this may not be the case for VAMI FS meters hence the functionality is optional.

Meter loss of supply switching requires the load control contactor to be opened when the meter detects loss of supply. This may have a material cost as the meter power supply must store sufficient energy to switch the controlled load contactor while the meter is off supply. The cost of the extra capacity is relatively minor in comparison to the cost of the CLC and the known benefits were felt to justify any additional cost.

Both the SMI FS and VAMI FS have a hierarchy of load control commands, however the list in the SMI FS is more complex due to the larger number of modes.

The BRWG agreed that the messaging to groups of meters as described in the VAMI FS was probably insufficient, however they were unable to agree on an increased number of groups. The SMI FS also does not list primary, secondary or tertiary groups. This is discussed again in Section 5.20 (below)

5.6.1 Performance Levels

Summary

- VAMI FS requirements for messaging to groups is much more challenging to meet

Clause	Comment
Pre-defined Meter Groups	
a) Requested priority override load control action performed by (i) 90% of meters within 5 minutes	The performance level stated in the VAMI FS is much more challenging (a) The actions covered in this category are specified in section 3.6 for Controlled Load Management and for Utility Control of Other Loads. For commands to any primary, secondary or tertiary group of meters the performance level required is: (1) Action performed at 99% of meters within 1 minute. To compare the figures 12.5% in 5 minutes v 100%[9] in 1 minute = (100%/12.5%) x (5/1) = 40 times more meters in the same time period
b) The SMMS may not get an immediate acknowledgement, however on retrieval of event logs it will be possible to determine the success rate	
c) Each priority override command may specify a total of 6 different meter groups.	While debate continues about who will be able to send load control commands (distributors only or the retailer as well) it was necessary to allow many more meter groups to be addressed. The groups might be small (e.g. small retailer) This allows the one message to groups of meters to address meters belonging to different groups (e.g. 6 retailers could concurrently access meters)
d) Up to 12 priority override commands can be sent in any 24 hour period to pre-defined meter groups consisting of up to 12.5% of the operational SMI meter population in a distribution network area. The meters shall be uniformly distributed among the SMCN collection points used across the distribution network area.	12 x 12.5 = 150% of the meter population In some jurisdictions load switches are installed on a higher percentage of premises than in Victoria. It was therefore important to be able to access a large percentage of the meter population to turn on (and potentially also turn off) load

[9] It is acknowledged that this calculation has assumed that clause (c) which limits the number of meters to 2% only applies to individual messaging and not group messaging.

Clause	Comment
Individual Meters	
a) For priority override commands sent to individual meters the requested load control action shall be acknowledged by (i) 95% of meters within 5 minutes (ii) 99% of meters within 10 minutes	The VAMI FS specification appears to state a lower performance level (but as discussed above the percentage of meters per unit of time is much higher) (b) For commands sent to individual meters, the performance level required is: (1) Action performed at 90% of meters within 30 minutes; (2) Action performed at 99% of meters within 1 hour; and (3) Action performed at 99.9% of meters within 6 hours.
b) The SMI performance level shall be tested by sending priority override commands from the SMMS to a total of 0.5% (5,000 mpM) of the number of operational SMI meters in a distribution network area. This will be tested over an 8 hour period, with the sending of commands uniformly distributed across both time and the deployed SMCN collection points. The test can be conducted once in any 24 hour period.	The VAMI FS specification states 2%. The Use case considered in the BRWG assumed that the majority of the messaging would be to groups of meters not individual meters hence a lower percentage of only 0.5%

5.7 Supply Contactor operation (Section 7.7)

Summary

- VAMI FS does not document an Arm Command
- VAMI FS does not support an immediate Close Command
- VAMI FS does not support switching of the supply contactor on meter loss of supply

General

The SMI FS duplicates the VAMI FS auto-disconnect function, which is referred to as Monitor Supply (Section 7.7.1.1). It was noted that in some jurisdictions it will be necessary to confirm the presence of someone at the property, so the SMI FS also documents an Arm function (Section 7.7.1.1). In those cases where customers are unable to gain access to their meter it was also considered necessary to document a command to close (the supply contactor) immediately. The VAMI FS does not document Arm or Close immediately.

The VAMI FS separately specifies requirements for local and remote operation of the supply contactor. Local operation of the supply contactor does not specify use of the auto-disconnect function. The SMI FS does not separately specify requirements for local and remote operation of the supply contactor (however it does support the Close Immediate command which would allow local operation with the same functionality as specified in VAMI FS).

VAMI FS has some additional requirements for local operation

(a) Local disconnect via the meter shall only be able to be performed by an authorised technician. Unauthorised persons shall be physically prevented from operating the supply contactor to disconnect supply.

The SMI FS does not specify physical prevention of operation of the supply contactor. The SMI FS indicates that only authorised parties can access any meter functionality, so it is anticipated that software will limit access to the supply contactor.

Section 3.4.3.1 (b) of the VAMI FS states

(2) remote communication of the status (open/closed) of the supply contactor (if AMI communications are active) from the meter to the NMS;

VAMI FS does not provide a performance level for this remote communication of the status so it is assumed that this is an event that will be detected with the acquisition of the event log. In the SMI FS it is possible for the event to be reported immediately to the SMMS (if the event is programmed to report)

The settings for VAMI FS auto-disconnect are specified as "per element, per phase". If we consider a three phase meter it would appear that VAMI FS expects the auto-disconnect function to operate if the load on any phase exceeds the specified limit. This is not supported in the SMI FS which specifies (total) exported active power.

Clause	Comment
a) A meter other than a three phase CT connected meter without an external supply contactor, shall support functionality to control a supply contactor to enable the interruption and restoration of supply to customer premises; (i) For all whole current meters the supply contactor shall be integrated into the meter;	VAMI FS requires all direct connect meters to support an integrated supply contactor.
(ii) For CT connected meters supporting an external supply contactor, a voltage free 2 A relay with a rating of 230 Vac shall be integrated into the meter.	VAMI FS does not support CT meters with capability of controlling an external supply contactor
b) In section 7.7 references to the supply contactor shall also apply to the control relay integrated into the three phase CT connected meter supporting external supply contactor	VAMI FS does not support CT meters with capability of controlling an external supply contactor
c) For whole current meters when the supply contactor in the meter is in the open position all outgoing (customer side) active circuits for the meter shall remain de-energised;	No Material Difference
d) Supply contactor operation shall be possible both locally and remotely;	No Material Difference
e) For meters with a supply contactor it shall be possible to display the status of the supply contactor on the visible display and indicators on meter (refer 7.4.1). The possible supply contactor status is: (i) On (supply contactor in the closed position) (ii) Armed (supply contactor in the open position) (iii) Off (supply contactor in the open position) (iv) Supply capacity exceeded (supply contactor in the open position, visible display shows the remaining time before the supply contactor is automatically switched to the on state)	VAMI FS only requires the display of the position of the supply contactor (Open or Closed)

<table>
<tr><th>Clause</th><th>Comment</th></tr>
<tr><td>f) The SMI shall support separate commands for switching the supply contactor. The commands shall always be actioned by the meter regardless of the initial state of the supply contactor. The four supply contactor switch commands are:
(i) Close command
(ii) Monitor supply command (refer 7.7.1.1)
(iii) Arm command (refer 7.7.1.2)
(iv) Open command</td><td>VAMI FS does not specify an Arm command</td></tr>
<tr><td>7.7.1.1 Monitor Supply
a) The meter shall support a monitor supply (auto-off) function such that if the measured exported active power is above a programmable level after receiving the monitor supply command, the supply contactor will automatically switch to the off state (open position).
b) When the monitor supply command is used:
(i) The meter shall automatically switch the supply contactor to the off state (open position) if more than “X” Watts of exported active power is measured by the meter for more than “Y” seconds during the measurement period of “Z” seconds after the meter receives the command, where:
(a) “X” range: 20 W – 25 kW programmable in 20 W increments
(b) “Y” range: 1- Z seconds programmable in 1 second increments
(c) “Z” range: 1- 3,600 seconds programmable in 1 second increments
(d) For CT connected meters (with 2A relay) the measurement of “X” shall be the value measured by the meter, the meter does not need to know the CT ratio and is not required to calculate the customer load
(ii) The supply contactor shall be switched to the off state (open position) in less than 1 second of the exported active energy exceeding the set limits.
(iii) The meter shall store a quality of supply event when the supply contactor has been automatically switched to the off state (open position) due to exceeding the monitor supply settings.</td><td>No Material Difference. The measurements are documented differently
VAMI FS specifies the measurement “per element, per phase” while the SMI FS uses the exported active power (total)

Clause (d) required in SMI FS to describe CT connected meter with 2A relay</td></tr>
</table>

Clause	Comment
7.7.1.2 Arm a) When the meter receives an arm command, the meter shall ensure that the supply contactor is in the open position. The meter shall have a clear visible indication that the supply contactor is now in the Armed state. b) When the meter is in the armed state it shall be possible for a customer to change the meter from the armed state to the on state (supply contactor in the closed position). A meter event will be stored in the quality of supply event log to indicate that the customer has moved the supply contactor to the on state. c) The meter shall support a configurable arming time out period. If during the arming time out period the customer does not turn the supply contactor to the on state the meter shall automatically return to the off state. A meter event will be stored in the quality of supply event log to indicate that a time out has occurred. The arming time out period shall be programmable from 1 hour to 48 hours in 1 hour increments.	VAMI FS does not specify ARM functionality There is a requirement for a button to be incorporated onto the front of the meter. It was assumed that “the boost button” could be used for this function therefore avoiding additional cost (when the supply contactor is open all outgoing circuits must be de-energised so standard boost functionality is not required)
7.7.1.3 Supply Contactor Functionality for Meter Loss of Supply a) The meter shall support an option to switch the supply contactor to the open position when meter loss of supply is detected. If this option is enabled the meter shall ensure the supply contactor is in the open position during meter loss of supply. Upon supply restoration the meter shall restore the supply contactor to the state before meter loss of supply. It shall be possible to locally and remotely enable and disable this option. b) If the supply contactor was in the on state before meter loss of supply. On power restore if the meter detects a power outage beyond the programmable minimum duration the meter shall wait a random delay period before switching the supply contactor to the closed position. If the outage is less than the minimum duration the supply contactor shall be switched to the closed position without the delay. (i) The meter shall have programmable settings allowing: (a) The minimum duration of the power outage to be specified from 5 seconds to 300 seconds in 5 second increments (b) The minimum time delay to be specified from 0 seconds to 300 seconds (5 minutes) in 5 second increments (c) The maximum time delay to be specified from 0 seconds to 300 seconds (5 minutes) in 5 second increments (ii) The delay calculated by the meter shall be a time in seconds from the minimum time delay to the maximum time delay. The algorithm shall use a uniform probability. (iii) Any supply contactor switch command received by	VAMI FS does not specify operation of the Supply Contactor on Meter loss of supply Included to assist in the management of inrush currents on power restore (after an outage) May have an impact on meter hardware cost with provision of sufficient energy in the meter to switch the supply contactor after meter loss of supply

Clause	Comment
the meter during the delay period will immediately terminate the delay period. c) If the supply contactor was in the armed state before meter loss of supply. On power restore the meter shall treat the event as if an Arm command has been received. d) If the supply contactor was in the monitor supply state before meter loss of supply. on power restore the meter shall treat the event as if a monitor supply command has been received. e) If the supply contactor was in the exceeded supply capacity state before meter loss of supply. on power restore the meter shall treat the event as if the supply contactor was in the on state (as described in 7.7.1.3 b)).	

5.7.1 Performance Levels

Individual Meter

Clause	Comment
a) The supply contactor switch command shall be acknowledged by: (i) 95% of meters within 5 minutes (ii) 99% of meters within 10 minutes	VAMI FS performance levels lower (1) Action performed at 90% of meters within 10 minutes; (2) Action performed at 99% of meters within 1 hour; and (3) Action performed at 99.9% of meters within 6 hours.
b) The SMI performance level shall be tested by sending supply contactor switch commands from the SMMS to a total of 0.5% (5,000 mpM) of the number of operational SMI meters in a distribution network area. This will be tested over an 8 hour period, with the sending of commands uniformly distributed across both time and the deployed SMCN collection points. The test can be conducted once in any 24 hour period.	VAMI FS allows four times the number of meters per day (b) The total number of connects/disconnects commands to individual meters in any 24 hour period can be up to 2% of the installed, operational AMI meter population.

5.8 Supply Contactor operation (Section 7.8)

Summary

- SMI FS includes five supply capacity limits compared to VAMI FS which only includes three.
- The Emergency supply capacity limit in the SMI FS has been modified to avoid the potential for synchronised load switching
- SMI FS clarifies that the supply contactor is opened as soon as the limit is exceeded.
- VAMI FS limits Import and Export Supply Capacity limits to multiple trading intervals

General comment

While the number of supply capacity limits has been increased the method described in the SMI FS is significantly easier to implement using energy measurements (in kWh) compared to the continuous calculations of the average demand as required in the VAMI FS specification. The SMI FS also uses a single measurement period, removing the complex rolling average calculations needed to implement the VAMI FS average demand across multiple trading intervals.

Supply capacity limiting provides advantages to the network operator by reducing peak demand in areas where there are network constraints (including energy feed-in which may result in Quality of Supply issues). Within the BRWG it was suggested that 30 minutes was too long to protect distribution assets.

The VAMI FS restricts the measurement period for supply capacity limits to (multiple) trading intervals was made to support customer demand tariffs, however since the functionality does not hold the supply contactor open for the remainder of the "measurement period" it does not allow a true demand tariff to be offered to the customer. The VAMI FS specification is also open to interpretation with confusion as to whether the supply contactor had to be opened as soon as the capacity limit was exceeded or only at the end of the measurement period (trading period).

Clause	Comment
7.8.1.1 Time of day export supply capacity limit	Additional export supply capacity limit which only operates for defined periods of the day
7.8.1.2 Distribution network export supply capacity limit	Reworded version of VAMI FS export supply capacity limit using a measurement period using a measurement period rather than trading intervals
7.8.1.3 Time of day import supply capacity limit	Additional import supply capacity limit which only operates for defined periods of the day
7.8.1.4 Distribution network import supply capacity limit	Reworded version of VAMI FS import supply capacity limit using a measurement period rather than trading intervals
7.8.1.5 Emergency supply capacity limit	Reworded version of VAMI FS emergency supply capacity limit avoiding synchronised load switching

5.8.1 Performance Levels

Clause	Comment
7.8.2.1.1 Pre-defined meter groups a) The requested emergency supply capacity limiting command shall be performed by (i) 90% of meters within 10 minutes b) The SMMS may not get an immediate acknowledgement, however on retrieval of event logs it will be possible to determine the success rate c) Up to two emergency supply capacity limiting commands can be sent in any 24 hour period to pre-defined groups consisting of up to 100% of the operational SMI meter population in a distribution network area.	Similar performance level (a) The actions covered in this category are specified in section 3.9.2 for emergency supply capacity control. For commands to any primary or secondary group of meters the performance level required is: (1) Action performed at 90% of meters within 10 minutes; and (2) Action performed at 99% of meters within 1 hour. Note: No limitation on the number of times the command can be sent
7.8.2.1.2 Individual Meters a) Clarification: The use case for this function	95% response in 30 minutes instead of 90% In truth not easy to compare, as the SMI FS states that

Clause	Comment
indicates that meters will be concentrated in a geographic area and cannot be assumed to be uniformly distributed across the distribution network area. It is assumed that 2000 meters will be involved in the testing. b) The requested emergency supply capacity limit command shall be acknowledged by (i) 95% of meters within 30 minutes (ii) 99% of meters within 1 hour c) The SMI performance level shall be tested by sending emergency supply capacity control commands from the SMMS to a total of 2,000 meters. The sending of commands shall be uniformly distributed across a 30 minute test period. The meters shall be clustered around collocated SMCN collection points. The test can be conducted twice in any 24 hour period.	the meters must be concentrated in a geographic area (the use case recommended that these commands would be used in a when a distribution asset fails affecting meters downstream of that asset) while the VAMI FS does not specify how the meters are deployed. VAMI FS states (b) For commands sent to individual meters, the performance level required is: (1) Action performed at 90% of meters within 30 minutes; (2) Action performed at 99% of meters within 1 hour; and (3) Action performed at 99.9% of meters within 6 hours. (c) The total number of load control commands to individual meters in any 24 hour period can be up to 2% of the installed, operational AMI meter population.

5.9 Home Area Network using Open Standard (Section 7.9)

Summary

- "Similar" with the SMI FS selecting ZigBee Smart Energy Profile (SEP), however the two specifications are not interoperable due to incompatibility between SEP 1.0 and 2.0.
- The SMI FS documents the actual requirements
- The SMI FS includes a separate event log

General comment

The VAMI FS uses the term Energy Services Portal, this term is identical to the Energy Services Interface (ESI) used throughout the SMI FS While the ESI is fully described in the ZigBee Smart Energy Profile, the SMI FS wanted to capture requirements not described in the standard, for example the ability to turn the transmitter on and off, to specify the actual transmit power and receiver sensitivity (both of which affect the performance of the HAN) and specific event logging. Within the SMI FS these requirements are assigned to the ESI Implementation (which falls in the scope of the SMI, refer to Figure **1**).

5.9.1 Performance Levels

Summary

- The VAMI FS only sets a performance level for messaging to individual meters
- Performance levels for HAN load control in the SMI FS duplicates those suggested for load control via the controlled load contactor (as detailed in Section 7.6).

Clause	Comment
Pre-defined Meter Groups	
a) Requested priority override command to ESI Implementation action performed by (i) 90% of ESI Implementations within 5 minutes	
b) The SMMS may not get an immediate acknowledgement, however on retrieval of event logs it will be possible to determine the success rate	
c) Each priority override command to the ESI Implementation may specify a total of 6 different meter groups.	
d) Up to 24 priority override commands to ESI can be sent in any 24 hour period to pre-defined groups consisting of up to 5% of the operational SMI meter population in a distribution network area. The meters shall be uniformly distributed among the SMCN collection points used across the distribution network area.	
Individual Meters	
a) For priority override load control commands sent to an individual ESI (i) The requested load control action shall be acknowledged by (a) 95% of ESI Implementations within 5 minutes (b) 99% of ESI Implementations within 10 minutes (ii) The SMI performance level shall be tested by sending priority override commands from the SMMS to a total of 0.5% (5,000 mpM) of the number of operational SMI meters in a distribution network area. This will be tested over an 8 hour period, with the sending of commands uniformly distributed across both time and the deployed SMCN collection points. The test can be conducted once in any 24 hour period.	
b) For HAN instructions sent to an individual ESI Implementation (i) The HAN instruction shall be acknowledged by (a) 95% of ESI Implementations within 30 minutes (b) 99% of ESI Implementations within 1 hour (ii) The SMI performance level shall be tested by sending HAN instructions from the SMMS to a total of 5% (50,000 mpM) of the number of operational SMI meters in a distribution network area. This will be tested over a 16 hour period, with the sending of instructions uniformly distributed across both time and the deployed SMCN collection points. The test can be conducted once in any 24 hour period.	The VAMI FS specification does not specify different classes of HAN command. While it specifies a lower performance level (3 hours compared to 30 minutes), it also suggests that 6 messages can be sent to each HAN (equating to 600% compared to 5% specified in the SMI F.S) (a) The AMI system shall support up to 6 HAN instructions per day being sent to the ESP. (b) The performance level required for HAN instructions is: (1) HAN instruction received by 98% of ESPs in 3 hours; (2) HAN instruction received by 99.9% of ESPs in 12 hours

5.10 Quality of Supply & other Event Recording (Section 7.10)

Summary

- The SMI FS documents separate *access and security* and *quality of supply* event logs, while the VAMI FS only documents a single event log
- The SMI FS documents a separate HAN event log
- The SMI FS allows events to be individually programmed to report to the SMMS

General

Some jurisdictions indicated that there are some meter events that they wanted the meter to report to the SMMS so that they could potentially take immediate action (e.g. detecting meter tamper). There was no agreement on the list of events which were required to report immediately. It was the British Gas smart meter specification which suggested the final solution adopted by the BRWG, which was to allow the utility to select which detected events are stored and reported. It is not anticipated that there are any additional hardware costs from this functionality.

5.10.1 Performance Levels

Clause	Comment
a) Events programmed to report shall be detected by the SMMS for: (i) 95% of meters within 10 minutes	The only event which can report to the SMMS in the VAMI FS specification is meter loss of supply. The performance level is discussed in Section 5.11.1 below)
b) The SMI performance level shall be tested by generating reported events at a total of 0.5% (5,000 mpM) of the number of operational SMI meters in a distribution network area. Reportable events shall be uniformly distributed across both time and the deployed SMCN collection points.	
c) Notes: (i) Meters are only required to report events for which meter event log settings specify reporting. (ii) The SMI performance levels for meter loss of supply and Power Restore event reporting are presented separately in Section 7.11.2.	

5.11 Meter Loss of Supply detection (Section 7.11)

Summary

- The SMI FS only requires the meter to optionally report utility selected events
- The stated performance level documents Meter loss of supply to report only *AFTER* meter power is restored

General

The Vendor's RFI raised serious concerns about the potential cost to support last gasp messaging. The SMI FS therefore includes additional text to clarify that we do not require last gasp messaging. The performance level stated in VAMI FS has been interpreted to imply that last gasp outage messaging is required.

Last gasp messaging means that the SMMS will receive notification when the outage first occurs, earlier detection of the outage should result in earlier power restoration.

Another advantage often assigned to outage reporting is more efficient field force utilisation with the detection of nested outages. This requires the meters to report when power is restored. The VAMI FS does not require meters to report power restoration.

Clause	Comment
a) Meter loss of supply shall be detected and stored in the meter.	
b) When a meter loss of supply event is stored and meter quality of supply settings indicate that the event should be reported to the SMI it shall be reported as soon as possible. This SMI capability is intended for the reporting of small scale outages. In a large scale outage it does not require all meters to successfully report meter loss of supply.	It is hoped that small scale outages (including tamper) will be able to report, but a performance level is not specified
c) During meter loss of supply, all programmable settings (listed in Appendix B), the meter clock, energy data, and meter event logs will be preserved, such that upon subsequent power restoration, the meter and SMI resume proper operation.	VAMI FS does not document this requirement

5.11.1 Performance Levels

While power restore is an event stored in the quality of supply event log, the BRWG felt it necessary to document a separate performance level. This decision recognises that after a power outage the SMCN may take time to recover and the geographically co-located meters that may be attempting to report.

Clause	Comment
a) Power restoration shall be detected by the SMMS for (i) 90% of meters within 1 hour	Appears similar with VAMI FS stating (a) Alarms to be received within one hour for 90% of meters. However the SMI FS only requires (user programmable) reporting of power restore while VAMI FS appears to require reporting of the actual outage (refer discussion in clause c) below)
b) The number of meters reporting a power restoration event can be up to 2% (20,000 mpM) of the operational SMI meter population in a distribution network area in a 24 hour period	VAMI FS does not limit the number of meters reporting an outage
c) Note: No SMI performance level is prescribed for reporting meter loss of supply	Clause was added after the Vendor's RFI which highlighted that there is a significant cost associated with the need to support "outage reporting" (including

Clause	Comment
	last gasp). VAMI FS "appears" to require outage reporting, with Section 3.7 stating: (b) When a meter loss of supply or outage is detected it is to be alarmed to the NMS as soon as possible. Within the BRWG it was unclear what "as soon as possible" actually implied. The majority took the VAMI FS requirements to mean that "last gasp" was required.

5.12 Remote Meter Service Checking (Section 7.12)

Summary

- The ability to check the status of the meter is described in the VAMI FS
- Detailed functionality is not described in the VAMI FS specification

General

The MCE CBA did not recommend Remote Meter Service checking. This could be attributed to limiting the functionality to only checking the presence of an outage, effectively duplicating meter loss of supply detection (last gasp). The BRWG agreed that the ability to check the status of a particular meter would allow call centre staff to directly support customer queries, avoiding unnecessary call outs, etc. It was also noted that all SMI systems already provide remote service checking capabilities.

This will have minimal impact on the meter cost and minimal effect on the SMCN (since it is already supported by SMI system vendors)

Clause	Comment
a) The smart metering infrastructure shall support remote meter service checking of the presence of supply to a meter	Not included in VAMI FS MCE CBA considered that the functionality duplicated last gasp outage reporting and therefore did not recommend its inclusion, however the SMI FS does not require last gasp outage reporting so functionality was included
b) The SMI shall be able to remotely determine	Not included in VAMI FS
(i) For the supply contactor (where fitted) (a) The status of the supply contactor as on, off, monitor supply, exceeded supply capacity or armed (b) When in the exceeded supply capacity state, the SMI shall be able to determine the remaining time before the supply contactor will automatically switch to the on state (closed position)	The VAMI FS includes this functionality (c) To confirm the current state of a meter, the AMI system shall support "on-demand" remote polling of the meter to determine whether the supply contactor is open or closed. BRWG considered important to be able to provide customers with information about the status of their supply, including the ability to diagnose why a customer may be off supply
(ii) The status of all CLC/R (where fitted) as on or off	Included in VAMI FS (collectable status Indicators are listed in Appendix A) Included to help customers understand what is happening to their load (especially if the meter is used to implement customer demand response e.g.

Clause	Comment
	air-conditioning cycling)
(iii) Instantaneous voltage at the meter (For three phase meters: the per phase voltage measurement)	Remote diagnosis of high/low voltage issues
(iv) The total net active power with an indication if imported or exported	Several uses including checking why attempts to close the supply contactor may be failing (e.g. exceeding the monitor supply limit)
(a) For single phase two element meters: the per element active power indicating if imported or exported	Two element meters are not described in the VAMI FS specification
(v) HAN status from the ESI Implementation, including measures of link quality at HAN devices and the last date and time that HAN devices were seen on the utility HAN	Supports the ability to provide remote HAN support to customers.

5.12.1 Performance Levels

Clause	**No performance level stated in VAMI FS**
Individual Meters	
a) Remote meter service checking shall obtain service data from (i) 95% of meters within 5 minutes (ii) 99% of meters within 10 minutes	In the VAMI FS the performance level for a remote poll are not stated separately from reading of meter settings (a) Performance level required for reading all the settings and status indicators of an individual meter (refer section 3.3) is: (1) Action performed at 90% of meters within 30 minutes; (2) Action performed at 99% of meters within 1 hour; and (3) Action performed at 99.9% of meters within 6 hours.
b) The SMI performance level shall be tested by performing remote meter service checks at 2% (20,000 mpM) of the number of operational SMI meters in a distribution network area. This will be tested over an 8 hour period, with the service check commands uniformly distributed across both time and the deployed SMCN collection points. The test can be conducted once in any 24 hour period.	Similar percentage of meters (b) The total number of commands to read settings and status indicators from individual meters in any 24 hour period can be up to 2% of the installed, operational AMI meter population.

5.13 Meter Settings Reconfiguration (Section 7.13)

Summary

- The SMI FS documents future settings reconfiguration

General

Future settings reconfiguration recognises that some meter changes will have an effective time and date, for example to shift all the time of use tariffs at the start or end of daylight savings time. Rather than forcing the SMCN to have sufficient data bandwidth to be able to reconfigure all meters in a very short time frame it was considered more cost effective to allow the changes to be sent out in advance of when they are required. It is anticipated that the functionality will enable more efficient utilisation of the SMCN.

Clause	Comment
a) A meter shall support all meter settings as defined in Appendix B of this specification.	Similar requirement
b) The meter shall support local and remote meter settings reconfiguration.	Similar requirement, however VAMI FS choses to state this as "locally and remotely programmable" for most meter setting
c) The meter shall store an event in the access and security event log when meter settings are configured or reconfigured.	Very similar requirement From 3.8.3 Events for Daily collection (a) (8) Whenever there is a change of AMI meter settings that is performed locally or remotely.
d) The configuration or reconfiguration of a meter setting shall not diminish the integrity of the energy data stored and recorded within the SMI.	Requirement not stated in the VAMI FS
e) The SMI shall support an effective date and time for all meter settings reconfiguration. The effective date and time shall allow meter settings to be reconfigured in advance, only taking effect when the meter time exceeds the specified date and time. It shall also be possible to specify that the meter settings take effect immediately. (i) The effective time shall allow the time to be set in whole hours. (ii) A separate effective date and time shall be supported for settings associated with each function detailed in this functionality specification. (iii) If a new effective date and time is specified for a setting it will overwrite the previous setting (note: if the meter time has not exceeded the specified date and time the previous setting will not take effect). (iv) When meter settings are changed using an effective date, an entry shall be stored in the meter's access and security event log.	Functionality not described in the VAMI FS

5.13.1 Performance Levels

For Individual Meters

Clause	Comment
a) Requested configuration or reconfiguration of a meter setting at an individual meter shall be acknowledged by (i) 95% of meters within 30 minutes (ii) 99% of meters within 1 hour	Similar performance level: (1) Action performed at 90% of meters within 30 minutes; (2) Action performed at 99% of meters within 1 hour; and (3) Action performed at 99.9% of meters within 6 hours.
b) The SMI performance level shall be tested by performing meter settings reconfiguration at 15% (150,000 mpM) of the	SMI FS supports a larger number of meters (BRWG wanted to be able to reconfigure all meters across

Clause	Comment
number of operational SMI meters in a distribution network area. This will be tested over a 16 hour period, with the meter settings reconfigurations being uniformly distributed across both time and the deployed SMCN collection points. The test can be conducted once in any 24 hour period.	the population in 7 days rather than the 50 days suggested in the VAMI FS) (b) The total number of commands to alter settings at individual meters in any 24 hour period can be up to 2% of the installed, operational AMI meter population.

5.14 Software upgrades (Section 7.14)

Summary

- Additional requirements ensure the upgrade does not degrade the performance of the meter
- SMI F.S also describes performance levels for software upgrade (which was not attempted in the VAMI FS specification)

Clause	Comment
a) The smart metering infrastructure and meter shall support local and remote software upgrades.	VAMI FS only states remote upgrade of firmware
b) It shall be possible to upgrade meter software without impacting metrology functionality of the meter (e.g. the storing of interval energy data). The meter may have a short interruption when the software is loaded but this outage shall be no longer than initial start-up of the meter as specified in AS62053.21-2005 Section 8.3.1	Same basic requirement (b) It shall be possible to remotely change firmware without impacting the metrology functions of the meter. Additional clause in SMI FS ensures that the meter is only “off line” for a short period of time
c) A software upgrade must not diminish the integrity of energy data held within the SMI	Requirement not included in the VAMI FS
d) During and after a software upgrade the meter, SMCN and HAN will continue to operate normally.	Requirement not included in the VAMI FS
e) The SMCN and meter’s ESI shall support local and remote software upgrades.	Same requirement (a) The AMI system shall have the capability to remotely upgrade the firmware in AMI system devices including data concentrators and meters (and ZigBee ® Energy Services Portal).
f) It must be possible to locally and remotely determine the version of software running in the meter, SMCN and ESI Implementation.	Requirement not included in the VAMI FS
g) The authenticity and validity of all software upgrades must be ensured before being loaded. h) All devices used in the smart metering infrastructure shall validate the authenticity of all software before running the software.	The NSMP had the advantage of seeing this vulnerability being exploited in a demonstration of a successful smart meter hack (in the USA). The BRWG decided to explicitly include requirements to avoid similar issues
i) All attempts to upgrade meter software shall be stored in the meter’s access and security event log with a success or fail status.	Not listed as an event in the VAMI FS specification

5.14.1 Performance Levels

The VAMI FS specification does not describe any performance levels for software upgrade. The SMI FS includes performance levels for both meter groups and to individual meters.

Clause	Comment
Meter Groups	
a) A software upgrade will be successfully completed by 99.9% of SMI components within 7 days.	VAMI FS does not describe a performance level for software upgrade
b) The SMI shall support one software upgrade in any 7 day period.	VAMI FS does not describe a limit for the number of software upgrades
c) The SMMS may not get an immediate acknowledgement, however on retrieval of event logs it will be possible to determine the success rate for software upgrade at meters	VAMI FS does not document unacknowledged (broadcast) messaging
Individual meters	
a) Software upgrade shall be successfully completed and acknowledged by 99.9% of SMI components within 2 days	VAMI FS does not describe a performance level for software upgrade
b) The SMI performance level shall be tested by performing a software upgrade at 2% (20,000mpM) of the SMI components as a percentage of the number of operational SMI meters in a distribution network area. This will be tested over a 48 hour period, with the sending of software upgrades being uniformly distributed across both time and the deployed SMCN collection points.	VAMI FS does not limit for the number of software upgrades

5.15 Plug and Play Device commissioning (Section 7.15)

Summary

- There are similar requirement in both specifications

Clause	Comment
a) When installed the meter shall report to the SMMS	Similar requirement (worded differently) Section 3.14 (a) Meters shall have the capability to self register with the NMS.
b) The SMI shall support a means of adding the meter details to the SMMS so that once the meter reports it has been installed the meter will commence proper operation without further local intervention	Similar requirement, but in the VAMI FS the requirement is stated in the glossary Self registering means the ability of the meter upon being added to the NMS of the AMI system when installed to register or configure itself with the AMI system so that it will commence performing its proper functions without further local intervention

5.16 Communications and Data Security (Section 7.16)

Summary

- The SMI FS indicates a risk assessment must be undertaken before deploying the infrastructure

Clause	Comment
a) The SMI shall ensure that all communications performed both locally and remotely with the meter, occurs in a secure manner	VAMI FS states (a) The AMI system shall ensure all communications between system components shall be secured in such a way as to prevent unauthorised interception and modification. (b) All device elements shall contain the necessary security to prevent unauthorised access or modification of data.
b) SMI communications and data security shall be addressed using a risk based approach.	VAMI FS does not state this requirement
c) During the planning process for the procurement, deployment and maintenance of smart metering infrastructure a comprehensive risk assessment shall be completed. The assessment shall be conducted in accordance with AS31000, AS27001 and AS27002. It is recommended that the risk assessment should address the vulnerabilities listed in the current version of the United States document Advanced Metering Infrastructure System Security Requirements (AMI-SEC) and/or other Advanced Metering Infrastructure risk assessment frameworks;	
d) The communications and data security risk assessment shall include considerations of possible vulnerabilities of the meter;	
e) The risk assessment shall set target levels. Reasonable steps shall be taken to materially address identified risks to the specified target levels.	
f) The risk assessment shall be reviewed appropriately, considering the time since the last assessment and any significant changes in the environment. The review shall include an assessment of any gaps between the desired target level and the current implementation	
g) The risk assessment shall be conducted in addition to any jurisdictional legislation covering protection of critical infrastructure and personal privacy	Victorian Government legislation covering critical infrastructure was cited in the inclusion of this clause into the SMI FS.

5.17 Tamper Detection (Section 7.17)

Summary

- The SMI FS indicates a risk assessment must be undertaken before deploying the infrastructure

Clause	Comment
a) A meter and the smart metering infrastructure shall be capable of detecting and storing tamper of the smart meter infrastructure;	Same requirement (a) The AMI system shall be capable of detecting and recording as an event attempts to tamper with the meter.
b) The meter shall detect the following possible violations: (i) Any opening of the meter terminal cover or meter main cover (ii) Any software manipulation	VAMI FS does not indicate minimum tamper requirements The addition of tamper switches to the terminal cover will have an impact on the cost of the meter
c) When a tamper is detected by the meter an event shall be stored in the access and security event log;	Same requirement (also stated in Appendix A of VAMI FS)
d) Where tamper is detected by the SMI it shall be reported to the SMMS.	No similar requirement The VAMI FS does not consider tamper of components other than the meters. In the SMI F.S this requirement allows other components of the SMI to report tamper, for example data concentrators used in the SMCN.

5.18 Interoperability for Meters/Devices at Application Layer (Section 7.18)

Summary

- The SMI FS has not documented any requirements for interoperability at the Application layer

General

The SMI FS states

> This is a placeholder allowing the specification of a single standard providing interoperability for meters and devices at the application layer when a standard meeting the functionality outlined in this specification becomes available.

5.19 Hardware Component Interoperability (Section 7.19)

Summary

- The SMI FS has not documented any requirements for interoperability at the hardware component level

General

The SMI FS states

> This is a placeholder allowing the specification of a single standard providing interoperability for hardware components when a standard providing the functionality outlined in this specification becomes available.

5.20 Meter Communications: Issuing Messages and Commands (Section 7.20)

Summary

- The VAMI FS specification does not detail message prioritisation
- The VAMI FS does not detail message queuing

Clause	Comment
a) The SMI shall have the capability to send instructions to an individual meter, groups of meters or HAN devices	Same requirement
b) The SMI shall support the ability to assign three priority levels to instructions sent to meters and HAN devices	VAMI FS does not consider the assigning of message prioritisation
c) The SMI shall have the ability to queue instructions received by the SMMS. The queue shall process high priority instructions before instructions with lower priority. For instructions with the same priority the instructions will be processed in the order that they were received (that is first in, first out).	VAMI FS does not detail what is to happen when messages are received at the SMMS.

In the VAMI FS specification group messaging is restricted to load control commands

3.6.1 Load control Groups

(a) All load control, whether controlled load (section 3.6.2) or utility control of other load (section 3.6.3) shall be able to respond to group commands and individual load control commands. Group commands may be delivered by broadcast.

(b) Groups shall provide for a minimum of 20 primary groups (for use by Distributors), 200 secondary groups (for use by Distributors) and 200 tertiary groups (for use by Retailers).

(c) The 200 tertiary groups are to be allocated across the retailers to allow several groups per retailer.

The BRWG was unable to agree on the required number of groups or the number of groups that a meter should belong to (in the VAMI FS it belongs to only three).

5.21 Customer Supply (Safety) Monitoring (Section 7.21)

Summary

- The VAMI FS specification does not detail customer supply (safety) monitoring

General

The MCE CBA was unable to recommend this functionality due to a lack of available information. There are now a number of solutions known to be available in the meter market so it was decided to document requirements to provide guidance to Pilots and Trials.

The SMI F.S notes:

> This is a placeholder allowing the Pilots and Trials to validate the costs and benefits of this functionality.

Clause	Comment
a) The meter shall support an option to enable the detection of: (i) Reverse polarity from the distribution network to the customer's premises (ii) Degradation of the neutral connection from the distribution network to the customer's premises and (iii) Degradation of the earth connection at the customer's premises	These are the faults that were evaluated in the MCE CBA
b) When one of these conditions is detected an event shall be stored in the quality of supply event log;	Storage in the event log will allow reporting (if programmed)

Appendix A – Glossary

AEMO	Australian Energy Market Operator
AMI	Advanced Metering Infrastructure (Victorian smart metering program)
AS	Australian Standard
BPPRG	Business Processes and Procedures Reference Group
BRWG	Business Requirements Working Group (established under the NSSC)
CBA	Cost Benefit Assessment
FS	Functionality Specification
HAN	Home Area Network
IEC	Information Exchange Committee (established under section 7.2A.2 of the Rules)
MCE	Ministerial Council on Energy (established under the COAG)
NER	National Electricity Rules
NSMP	National Smart Metering Program
RFI	Request for Information
RMEC	Retail Market Executive Committee (an advisory committee to AEMO)
SEP	Smart Energy Profile (ZigBee)
SMCN	Smart Metering Communication Network
SMI	Smart Metering Infrastructure
SMI FS	National Smart Metering Program Smart Metering Infrastructure Functionality Specification Version 1.2
SMMS	Smart Metering Management System
VAMI FS	Minimum AMI Functionality Specification (Victoria) Version 1.1
ZigBee	HAN standard developed by the ZigBee Allliance

AEMC

RULE CHANGE

Australian Energy Market Commission

DRAFT RULE DETERMINATION

National Electricity Amendment (Expanding competition in metering and related services) Rule 2015

National Energy Retail Amendment (Expanding competition in metering and related services) Rule 2015

Rule Proponent
COAG Energy Council

Embargoed until 26 March 2015

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Reference: ERC0169/RRC0002

Citation

AEMC 2015, Expanding competition in metering and related services, Draft Rule Determination, 26 March 2015, Sydney

About the AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

Executive summary

This draft determination sets out significant changes to the National Electricity Rules and National Energy Retail Rules in relation to the provision of metering services.

The draft rule will facilitate a market-led approach to the deployment of advanced meters where consumers drive the uptake of technology through their choice of products and services. This competitive framework for metering services is designed to promote innovation and lead to investment in advanced meters that deliver the services valued by consumers at a price they are willing to pay.

This draft determination is part of a series of changes recommended in the Commission's Power of Choice review to support demand side participation in the National Electricity Market (NEM), including network pricing arrangements and access to energy consumption information. Improved access to advanced metering services provides the missing link in this broader market reform program to give consumers opportunities to better understand and take control of how they use electricity and the costs associated with their usage decisions.

The Commission has made this draft determination in response to a rule change request from the Council of Australian Governments' (COAG) Energy Council. The Commission's draft rule is a more preferable rule, but contains many of the elements of the COAG Energy Council's rule change request.

The draft rule provides for the role and responsibilities of the existing Responsible Person to be performed by a new type of Registered Participant - a Metering Coordinator. Any person can become a Metering Coordinator subject to satisfying certain registration requirements. Retailers are required to appoint the Metering Coordinator for their retail customers, except where a large customer has appointed its own Metering Coordinator. The draft rule includes a number of other features to support the competitive framework for the provision of metering services, such as minimum requirements for new and replacement meters for small customers and obligations on the Metering Coordinator that are in addition to the existing obligations on the Responsible Person.

Why is there a need to change the current rules regarding metering services?

Only a small number of advanced meters have been deployed for small customers in the NEM outside of Victoria.

Accumulation meters are the most common type of meter used in residential and small business premises. Accumulation meters perform only a basic metering function – they record the total amount of electricity used, but not the time at which it is used. These meters must be read manually at the premises by a meter reader and the consumer is billed for the difference between meter readings over a period of time. Accumulation meters give consumers limited ability to understand and manage how they use electricity.

Technological innovation has meant that meters can now do much more than just measure the flow of electricity. Advanced meters measure both how much electricity is used and when it is used – in near real time. Depending on the functionality of the meter, the ability to send and receive data remotely enables data on electricity consumption, electricity outages and other information on the performance of the distribution network to be obtained almost instantaneously. A variety of services such as remote meter reading, remote access to appliances and different pricing options can also be enabled by advanced meters.

Like a mobile phone or a pay TV box, an advanced meter is an enabling technology which consumers can use to access a service that they value. These services can help consumers monitor, manage and adjust their electricity consumption in a way that better meets their usage and price preferences. Importantly, the draft rule does not introduce any requirement for consumers with an advanced meter to take up a different electricity tariff. Consumers may choose to remain on a flat tariff where this is offered by their retailer.

An increase in the availability of advanced meters, and the uptake of the energy products and services that they enable, can offer a wide range of benefits for all parties across the electricity supply chain. Advanced meters may provide retailers and distribution network service providers (DNSPs) the opportunity to access services that support the efficient operation of the electricity system, allowing them to provide lower cost and higher quality services to consumers.

Despite the benefits advanced meters may offer, the National Electricity Rules (NER) allow and potentially encourage the continued installation of accumulation meters. The NER and National Energy Retail Rules (NERR) also do not currently contain specific provisions to address consumer protections related to advanced meters, or detailed requirements around the security of advanced meters and access to the services they provide and the energy data they contain.

Some of the issues with the current NER and NERR provisions that were identified in the rule change request include:

- The NER currently limit who can be the "Responsible Person" and therefore have overall responsibility for the provision of metering services. Only the local network service provider (LNSP) can be responsible for metering services where manually read accumulation and interval meters are in place at a small customer's premises. Depending on the arrangement between the retailer and the LNSP, either of these parties can be responsible for providing metering services where advanced meters are in place at a small customer's premises.[1] No other party is able to be responsible for metering services for small customers, which restricts competition and reduces incentives to innovate and invest.

- In some jurisdictions, metering charges are currently bundled into distribution use of system charges. Further, at the time of the rule change request there was

1 In Victoria, only DNSPs can perform this role.

uncertainty around how an LNSP will recover residual costs where it provides metering services that are subject to economic regulation by the Australian Energy Regulator (AER) and a meter is replaced by a retailer. This creates disincentives for retailers to invest in advanced metering and could result in consumers whose accumulation meters are replaced with advanced meters effectively "paying twice" for metering services.

- The NER currently does not contain minimum requirements regarding the services that advanced meters must be capable of providing.

- There are not sufficiently detailed requirements in place so that the services enabled by advanced meters are only accessed by parties that are authorised to do so. This raises potential risks of unauthorised access to the services enabled by advanced meters, such as remote disconnection or load control services.

- Retailers, LNSPs and energy service companies also lack certainty over the regulatory framework for accessing services from advanced meters, which creates investment uncertainty.

Overview of the draft rule

The issues described above need to be addressed in order to promote efficient investment and consumer choice in advanced meters and the services they enable. The changes to the NER and NERR set out in this draft determination relate primarily to increasing competition in the provision of metering services, introducing additional minimum requirements for new and replacement meters installed at small customers' premises, and maintaining appropriate consumer protections.

The key features of the draft rule are summarised below:

- The draft rule changes who has overall responsibility for metering services under the NER to promote competition in the provision of metering and related services by:

  - providing for the role and responsibilities of the existing Responsible Person to be provided by a new type of Registered Participant - a Metering Coordinator;

  - allowing any person to become a Metering Coordinator, subject to meeting the registration requirements;

  - permitting a large customer to appoint its own Metering Coordinator; and

  - requiring a retailer to appoint the Metering Coordinator, except where a large customer has appointed its own Metering Coordinator.

- It requires a Metering Coordinator to take on roles additional to those currently performed by the Responsible Person so that the security of, and access to, advanced meters and the services provided by those meters are appropriately managed.

- It specifies the minimum services that a new or replacement meter installed at a small customer's premises must be capable of providing.
- It provides for the circumstances in which small customers may opt out of having a new meter installed at their premises.
- It clarifies the entitlement of parties to access energy data and metering data in order to reflect the changes to roles and responsibilities of parties providing metering services.
- It provides for LNSPs to continue to get the benefit of network devices installed at customers' premises that assist them to monitor and operate their networks.
- It permits a retailer to arrange for a Metering Coordinator to remotely disconnect or reconnect a small customer's premises in specified circumstances.
- It makes changes to the model terms and conditions of standard retail contracts to reflect the changes to the roles and responsibilities of parties providing metering services under the draft rule.

The following sections outline the key features of the new competitive framework in further detail.[2]

Retailer responsibility to appoint a Metering Coordinator

The current roles and responsibilities of the Responsible Person will be performed by the Metering Coordinator under the draft rule. The Metering Coordinator also has additional responsibilities related to advanced metering services.

The Financially Responsible Market Participant at a connection point will be responsible for appointing a Metering Coordinator for that connection point, other than where a large customer has appointed its own Metering Coordinator. The retailer is the Financially Responsible Market Participant for the connection points of its retail customers and will therefore be responsible for appointing Metering Coordinators at these connection points.

As is currently the case with the Responsible Person, the Metering Coordinator will arrange for the installation, provision and maintenance of the metering installation, and the collection, processing and delivery of metering data.

Currently, only retailers and LNSPs can be the Responsible Person for small customer metering installations. Under the draft rule, any party that meets the applicable registration requirements will be able to perform the Metering Coordinator role. Establishing a framework to facilitate increased competition for the provision of

2 This summary only provides an overview of the draft determination and draft rule. Stakeholders should review the more detailed description of the draft determination and draft rule that is set out in the appendices. Stakeholders should also closely review the draft rule. In particular, retailers, DNSPs, TNSPs, Metering Providers and Metering Data Providers should review the draft rule to understand how their rights and obligations would change under the draft rule.

metering services for small customers is a key feature of the draft rule, and is expected to increase innovation and the choice of electricity products and services available to consumers.

As a transitional measure, the relevant LNSP will become the initial Metering Coordinator for connection points where it is currently the Responsible Person for existing accumulation and manually read interval meters. LNSPs will continue in this role until another Metering Coordinator is appointed or these services cease to be classified by the AER as direct control services.

Consumer appointment of a Metering Coordinator

Small customers will deal solely with their retailer with respect to the supply of energy and metering services and will not be permitted or required to appoint their own Metering Coordinator. This approach has been adopted so that the arrangements are simple and practical from a small customer's perspective. Small customers will continue to be covered by existing consumer protection provisions and jurisdictional ombudsman schemes that apply to retailers.

The Commission recommends that the ability of small customers to appoint their own Metering Coordinator is reviewed three years after the commencement of the new Chapter 7 of the NER under the final rule (if made).

The draft rule allows large customers to appoint their own Metering Coordinator if they wish to do so. Large customers stand to benefit from being able to appoint their own Metering Coordinator to provide bespoke metering services.

Roles and responsibilities for the provision of metering services

Under the draft rule, the Metering Coordinator has overall responsibility for providing metering services at a connection point.

As the Responsible Person does today, the Metering Coordinator will engage a Metering Provider to carry out the installation and maintenance of the metering installation, and a Metering Data Provider to provide metering data services.

While the same party may become registered and accredited to perform all three roles, the Metering Coordinator, Metering Provider and Metering Data Provider roles have been retained as separately defined roles. These separate roles reflect the nature of each party's responsibilities and the different capabilities and registration or accreditation requirements needed for each role. Retaining separate roles allows the most appropriately resourced and qualified parties to perform the role.

Minimum services specification

The draft rule includes a minimum services specification, which all new and replacement meters that are installed for small customers must meet. This specification sets out a list of services that a meter must be capable of providing, rather than focussing on the technical components that must be included in the meter.

To meet the minimum services specification, a meter must be capable of providing the following services:

- remote disconnection service;
- remote reconnection service;
- remote on-demand meter read service;
- remote scheduled meter read service;
- meter installation inquiry service;[3] and
- advanced meter reconfiguration service.

The meter must also be connected to a telecommunications network which enables remote access to the meter.

AEMO may grant an exemption to the requirement to meet the minimum services specification where there is no existing telecommunications network which enables remote access to the meter. The effect of such an exemption is that the meter must still be capable of providing the services listed above, but it does not need to be connected to a telecommunications network.

The services included in the minimum services specification are those considered most likely to deliver benefits to most small customers at a relatively low cost. In determining not to prescribe a more exhaustive list of minimum services, the Commission is conscious of the risk of misjudging which services consumers and other parties accessing services enabled by advanced meters would value. The Commission considers that consumers and those other parties will be better placed to determine the services they want and are willing to pay for. Prescribing a broader list of services in the specification could result in all small customers paying higher costs for meters to be capable of providing services that may never be used by many consumers.

Many of the advanced meters currently available are capable of providing a number of services in addition to those listed above, such as load control. Parties will also be able to negotiate for these other services that are not included in the minimum services specification to be included in meters. The Commission expects many advanced meters at small customers' premises to exceed the minimum services specification as retailers, DNSPs and energy service companies negotiate for additional services.

It is anticipated that a minimum services specification will lower the cost of negotiations between Metering Coordinators and parties seeking access to services that are enabled by advanced meters and provide a starting point from which small customers and other parties can choose additional services that they value.

3 The metering installation must be capable of providing the following types of information at a minimum: supply status; voltage; current; power; frequency; average voltage and current; and the contents of the meter log including information on alarms.

Remote disconnection and reconnection services

The draft rule gives both retailers and DNSPs the ability (subject to negotiating access to the service with the Metering Coordinator) to arrange remote disconnection and reconnection services directly with the Metering Coordinator in certain circumstances. To manage potential safety risks associated with remote disconnection and reconnection, the draft rule requires retailers and DNSPs to share information regarding life support registers and to notify each other regarding changes to the status of customers' supply. Jurisdictional safety regulators may also develop additional requirements with respect to safely disconnecting and reconnecting customers.

Opt out arrangements

Small customers will have the ability to opt out of having an advanced meter that meets the minimum services specification installed at their premises where a retailer proposes to install a meter to replace an existing working meter. More specifically, if a retailer proposes to undertake a "new meter deployment" (as defined in the draft rule), the draft rule requires the retailer to allow a small customer to opt out of having their meter replaced as a part of that deployment.[4] The retailer must, among other things, notify a small customer of the expected date and time of the replacement of their meter and the customer's ability to opt out of having a new meter installed as part of that deployment.

However, there are certain scenarios where a right to opt out of having an advanced meter that meets the minimum services specification installed will not apply, for example where a faulty meter requires replacement, or where testing results indicate that it is necessary or appropriate in accordance with good electricity industry practice for the meter to be replaced to ensure compliance with the NER.[5] This is appropriate because in these circumstances:

- it is important that faulty meters are replaced quickly so that the consumer is not billed on the basis of estimated consumption for a prolonged period of time, which would not be in the best interests of consumers or retailers;

4 This draft rule is contained in the NERR. The NERR does not currently apply in Victoria so this opt out right will not apply in Victoria unless it adopts the NERR. The Victorian Government and Essential Services Commission should consider whether to make amendments to the Electricity Retail Code for consistency with the amendments to the NERR contained in the draft rule. If made, these amendments would provide for Victorian consumers to opt out of receiving a new meter that meets the minimum services specification where their retailer plans to replace their existing working advanced meter which was deployed under the AMI Program. The NERR will apply in Queensland from 1 July 2015, meaning that the opt out provisions in the draft rule, if made, would apply in Queensland when the draft rule commence on 1 July 2017.

5 These scenarios are discussed in further detail in Appendix C2.

- the incremental costs of installing an advanced meter that meets the minimum services specification are relatively low compared with a new accumulation meter;[6] and
- the installation of an advanced meter that meets the minimum services specification provides considerable potential benefits to the consumer, such as the ability to receive more regular bills, avoid estimated meter reads, and the choice of new products, services and pricing options.

The installation of an advanced meter may increase the range of services and pricing options that are available to consumers. However, consumers will continue to have the ability to choose the services and pricing options on offer from retailers and other service providers that best meet their needs. Depending on what price structures are offered by retailers, a consumer with an advanced meter could choose to remain on a flat-rate retail price or could choose from a range of other offers from its current retailer or another retailer.

Ring-fencing arrangements

The draft rule requires the AER to develop and publish distribution ring-fencing guidelines. These guidelines have a broader scope than just metering services, and cover the accounting and functional separation of the provision of direct control services from other services provided by DNSPs.

As part of the process of developing the guidelines, the AER may determine ring-fencing arrangements for a DNSP taking on the Metering Coordinator, Metering Provider and/or Metering Data Provider roles. Ring-fencing measures that may be considered include legal separation, accounting separation, operational separation, information sharing requirements or non-discriminatory access provisions. The AER has the flexibility to decide which types of ring-fencing measures would apply to DNSPs in different situations.

Access to Metering Coordinator services

While the Metering Coordinator is appointed by a customer's retailer, the Metering Coordinator may, subject to certain limitations, also provide services using a metering installation to other parties on a commercial basis including DNSPs and parties providing energy management services.

However, there will be no obligation on the Metering Coordinator to provide metering services and no regulation of the price of these services.[7] Subject to certain

6 Metering charges for consumers that retain an accumulation meter may increase as more advanced meters are deployed, particularly if the consumer is in an area where very few manual meter reads are required. It is therefore likely that, over time, the incremental costs of a meter that meets the minimum services specification will be less than the costs of manual meter reads for the life of the meter.

7 The Commission recommends that a review into whether some form of access regulation is required should be conducted three years after the commencement of the new Chapter 7 of the NER under the final rule (if made).

requirements with regard to access and security of meters and the services and data they provide, the provision and the price of services will be subject to commercial negotiations between the Metering Coordinator and the parties seeking those services.[8]

Advanced meters can provide services which assist DNSPs to defer the need for network augmentation and encourage more efficient utilisation of the network and manage the reliability, quality, safety and overall performance of the network.

Subject to the opt out requirements referred to above, DNSPs can facilitate the installation of advanced meters through the Metering Coordinator and seek to recover the costs of doing so through the existing regulatory process.

The draft rule also provides DNSPs with an ability to continue to use their existing network devices or install new network devices at or adjacent to a meter. However, certain restrictions apply to how DNSPs may use such devices, including (amongst other things) only being able to use the devices in connection with the operation or monitoring of their network.

The Metering Coordinator must not remove, damage or render inoperable a network device, except with the DNSP's consent. The Metering Coordinator must also cooperate with a DNSP who wishes to install a new network device.

Subject to the restrictions referred to above, Victorian DNSPs can continue to use the meters they have installed under the AMI program as network devices if the retailer appoints a new Metering Coordinator and installs a new meter.

Issues currently being addressed by the AER

There are a number of AER decisions that may affect the incentives to invest in advanced meters in a market-led deployment of advanced meters under the draft rule including:

- the unbundling of metering charges from distribution use of system charges; and
- the AER's determination of what are the appropriate means for a DNSP to recover the residual costs associated with the provision of metering services where a new Metering Coordinator replaces an existing meter in respect of which the DNSP is the initial Metering Coordinator.

The AER is considering these issues as part of its current round of distribution determinations.

Expected outcomes of the rule change

The draft rule establishes a framework to facilitate increased competition for the provision of metering services to small customers. An increased availability of advanced meters for small customers, and the uptake of energy products and services

8 Where a DNSP acts as the initial Metering Coordinator under the transitional arrangements, the price for metering services will continue to be regulated by the AER.

that advanced meters enable, is expected to result in a wide range of benefits for all parties across the electricity supply chain, including consumers.

Consumers who choose to use the information and services enabled by their advanced meter will experience a number of benefits. Many of the benefits will be shared by all consumers, regardless of their level of engagement.

For example, the increased availability of advanced meters may enable:

- consumers to better understand their electricity consumption and, if they choose, to take up products and services that better reflect their needs and preferences. Depending on what price structures are offered by retailers, a consumer with an advanced meter could choose to remain on a flat rate retail price or could choose from a range of other offers from its current retailer or another retailer;

- consumers to switch electricity retailers more quickly, to choose to receive retail bills more regularly to help with household budgeting, and to always be billed based on actual rather than estimated meter readings;

- more efficient retail services including remote meter reading and faster disconnection and reconnection services, for example when consumers move house. This is also expected to help consumers get reconnected as quickly as possible after a period of disconnection.

- the introduction of network prices that better reflect the costs of providing network services to individual consumers and allow consumers to make more informed decisions about how they want to use energy services. Analysis contained in the Commission's recent distribution network pricing rule change final determination[9] estimated that up to 80 per cent of consumers will face lower network charges over the medium term under cost reflective network prices, with average network charges estimated to fall by up to $57 a year. The full benefits of the new network pricing rules cannot be realised without advanced meters;

- DNSPs to respond more quickly, and at lower cost, to power outages or poor supply quality where advanced meters are used to support grid management technologies, which may lead to improved reliability and quality of electricity supply and/or lower network charges.

Victorian arrangements

Victoria is in a different position to other jurisdictions having undertaken a government mandated rollout of advanced meters (the AMI program) beginning in 2006. The Victorian DNSPs were required to deploy advanced meters, in accordance with a prescribed minimum specification, to almost all Victorians consuming up to 160 megawatt hours of electricity per annum. The program is now largely complete with approximately 2.8 million meters installed across the state.

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9 See http://www.aemc.gov.au/Rule-Changes/Distribution-Network-Pricing-Arrangements.

With the technology already in place in Victoria to enable small customers to make more informed decisions about their consumption and product choice, and for industry to offer more innovative products and achieve a range of efficiencies, the focus is now on realising the expected benefits of the AMI program.

The draft rule contains arrangements to support a smooth transition from the existing arrangements put in place under the AMI program to the NEM-wide competitive framework for metering services:

- At the commencement of the new Chapter 7 of the NER under the final rule (if made), the Victorian DNSPs will become the initial Metering Coordinator for the advanced meters they deployed under the AMI program and will continue in this role until another Metering Coordinator is appointed to the site by the retailer or a large customer, or those services cease to be classified by the AER as direct control services.

- The current Victorian derogation will be extended so that it ends on the date the new Chapter 7 of the NER commences. After that date, the Victorian DNSPs will no longer be exclusively responsible for metering services for AMI meters.

- If a new Metering Coordinator is appointed to replace the DNSP, an exit fee may be payable. Until 31 December 2020, the exit fee payable will be determined by the AER in accordance with the AMI Cost Recovery Order. After 2020, the AER will determine the level of any exit fee in accordance with the regulatory framework in Chapter 6 of the NER that applies to other jurisdictions.

- As noted above, Victorian DNSPs will be able to retain and continue to use the meters they deployed under the AMI program as network devices, if they choose to do so as a result of being unable to reach an agreement with a new Metering Coordinator to access equivalent services through the new meter.

- The national minimum services specification will take effect in Victoria when the new Chapter 7 of the NER commences.

Implementation

The draft rule contains a commencement date of 1 July 2017 for the new Chapter 7 of the NER and amendments to the NERR.[10] In the interim period between the final rule being made and the commencement of the new Chapter 7 of the NER and amendments to the NERR, a range of parties will need to undertake a number of steps including:

- AEMO and the Information Exchange Committee to develop, consult on and publish new and updated procedures by 1 April 2016;

10 Some other provisions of the draft rule will commence earlier, including, for example, changes to Chapter 2 of the NER, some definitions and transitional provisions under the NERR requiring retailers to make the requisite changes to their standard retail contracts by July 2017. See the draft rule for more details.

- the AER to develop, consult on and publish a distribution ring-fencing guideline by 1 July 2016;
- AEMO to publish information on the process for applying for registration as a Metering Coordinator by 1 October 2016; and
- retailers to publish amended standard retail contracts by 1 July 2017.

Leading up to the commencement of the new Chapter 7 of the NER and certain amendments to the NERR, AEMO, industry, governments and other parties will also be required to meet a range of other implementation requirements, which are outlined in this draft determination.

Consultation

We invite stakeholders to provide submissions on this draft determination, which we will consider before making a final determination in July 2015.

We will hold a public forum in late April or early May 2015. The date and location of the public forum will be confirmed shortly.

Submissions on the draft determination will close on 21 May 2015.

Once we have reviewed submissions, we may also decide to hold a public workshop to discuss legal drafting and implementation matters related to the draft rule. We will advise stakeholders after the close of submissions if we decide to hold such a workshop and, if so, the details of the workshop.

Contents

1 The COAG Energy Council's rule change request

1.1 The rule change request

In October 2013, the Council of Australian Governments' (COAG) Energy Council (formerly the Standing Council on Energy and Resources) submitted a rule change request to the Australian Energy Market Commission (the AEMC or Commission) seeking to establish arrangements that would promote competition in the provision of metering and related services in the National Electricity Market (NEM).

The rule change request sought amendments to the National Electricity Rules (NER) and the National Energy Retail Rules (NERR).

The COAG Energy Council stated in its rule change request that the objective of the proposed arrangements is to support the uptake of efficient demand side participation by residential and small business consumers by making it easier to arrange for the metering needed to support choice in electricity products and services. The COAG Energy Council also considers that the proposed arrangements would make it easier for large customers to manage their own metering requirements.[11]

The rule change request was submitted in response to recommendations made by the AEMC in its Power of Choice review.[12]

1.2 Rationale for the rule change request

The primary purpose of a metering installation is to record the production or consumption of electricity to allow financial settlement of the NEM and billing of customers. However, the rule change request recognises that advanced meters can also provide a platform for consumers and other parties to make more informed decisions about how they participate in the electricity market, for example through:

- access to improved information about the timing and quantity of electricity consumption to support decisions about managing consumption and costs;
- innovative product and service offerings, including an increased range of tariff options and services such as direct load control;
- new business practices that reduce costs, such as remote reading and remote connection and disconnection; and
- grid management technologies such as outage and supply quality detection.[13]

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11 COAG Energy Council, rule change request, October 2013, p4.

12 See http://www.aemc.gov.au/Markets-Reviews-Advice/Power-of-Choice-Stage-3-DSP-Review.

13 COAG Energy Council, rule change request, October 2013, p4.

1.2.1 Current arrangements

Box 1.1: Metering installation types and terminology

A range of different types of metering installations are currently available and defined in the NER. This box summarises the different types of metering installations and the terminology used to describe them in the NER and this draft determination.

"Accumulation metering installations" only record the total amount of electricity used over a specified period. Consumption data is generally retrieved manually from the metering installation at a consumer's premises periodically, typically every three months to match the retailer's billing cycle. This data does not record when electricity is used.

"Interval metering installations" record consumption over half hour intervals, or potentially over shorter periods. These metering installations can be used to provide information about the timing of a consumer's consumption. These metering installations can be manually read at the premises or remotely read using a communications network.

"Advanced metering installations" are remotely read interval metering installations that can also provide a range of advanced metering services beyond simply measuring electricity consumption or generation. The services available depends on the functionality of the advanced metering installation.

Types of metering installations in the NER

The NER currently refers to the following types of metering installations:

Type 1-3 metering installations are remotely read interval metering installations that are used at connection points with a load size above 750MWh (eg large factories or power stations).

Type 4 metering installations are remotely read interval metering installations that are used at connection points with loads up to 750MWh (eg medium size factories).

Type 5 metering installations are generally manually read interval metering installations that are used at connection points with loads up to 160 MWh (eg residential and small businesses). This load size threshold can be amended by individual jurisdictions. The AMI metering installations deployed by DNSPs in Victoria are also currently deemed to be type 5 metering installations.

Type 6 metering installations are accumulation metering installations that are used at connection points with loads up to 160 MWh (eg residential and small businesses). This load size threshold can also be amended by individual jurisdictions.

Type 7 metering installations do not involve a physical metering installation. Instead, there is a reconciliation between the LNSP and the user of the service using an algorithm to determine energy usage. Type 7 metering installations apply, for example, to public lighting and traffic lights.

Advanced meters are therefore generally classified as a type 1, 2, 3 or 4 metering installations in the NER depending on the size of the load at the connection point.

Under the current NER provisions, a Market Participant must ensure there is a metering installation at each of the connection points in respect of which it is participating in the NEM and that the metering installation is registered with AEMO.[14] The retailer is the Market Participant required to satisfy these requirements with respect to the connection points of its retail customers.

There must also be a Responsible Person for each such connection point that arranges for the installation, provision and maintenance of the metering installation, and the collection, processing and delivery of metering data.[15] The Market Participant is required to be the Responsible Person for a type 1-4 metering installation unless it has requested, and subsequently accepted, an offer from the Local Network Service Provider (LNSP) to take on this role. Under the NER, an LNSP is required to make an offer to act as the Responsible Person for a connection point with a type 1-4 metering installation when requested to do so by the Market Participant.[16]

For small customers using type 5 metering installations (typically manually read interval meters) and type 6 metering installations (typically accumulation meters), the role of the Responsible Person is exclusively performed by the LNSP.

All residential customers are considered small customers under the National Energy Retail Law (NERL). Business customers who consume energy at a business premise below the upper consumption thresholds set by jurisdictions, and outlined below, are also considered to be small customers under the NERL. Accordingly, metering services for retail customers is currently the responsibility of either the customer's retailer or LNSP, depending on the metering installation type.

The AER may classify distribution services provided by a DNSP, including metering services, as a direct control service or a negotiated distribution service. Direct control services are price regulated and divided into two subclasses – standard control services, which are paid for by all users of the network, and alternative control services, which are generally only paid for by the users of that service. If a service is not classified by the AER it will not be subject to economic regulation under the NER.

Services provided in respect of manually read interval meters and accumulation meters have to date generally been classified by the AER as a standard control service. This

14 Current clause 7.1.2 of the NER.

15 Current clause 7.2.1 of the NER.

16 Current clause 7.2.3(c) of the NER.

means that DNSPs' charges for these metering services form part of distribution use of system charges that all users of the network pay, regardless of whether the consumer uses the service. The AER is currently in the process of unbundling charges for metering services from the distribution use of system charges. This is discussed in Appendix D1.

Table 1.1 General overview of metering installation types under the current NER

Metering installation type	Description	When used	Responsible Person
Type 1-3	Remotely read interval metering installation	Load size is greater than 750MWh.	Market Participant, unless it has arranged for the Local Network Service Provider to be the Responsible Person.
Type 4	Remotely read interval metering installation	Load size is up to 750MWh.	Market Participant (for retail customers this is their retailer), unless it has arranged for the Local Network Service Provider to be the Responsible Person.
Type 5	Typically a manually read interval metering installation	Load size is up to 160MWh (depending on the jurisdiction). Victorian AMI metering installations are also deemed to be type 5 metering installations[17]	Local Network Service Provider
Type 6	Typically an accumulation metering installation	Load size is up to 160MWh (depending on the jurisdiction).	Local Network Service Provider
Type 7	No physical metering installation	Usage pattern is predictable and small, eg street lights.	Local Network Service Provider

Consumption thresholds for business customers

Business customers who consume at or above the upper consumption threshold are large customers under section 5(b) of the NERL. The National Energy Retail Regulations sets this upper consumption threshold at 100 MWh per annum[18], which has been adopted by the ACT[19], Queensland[20] and NSW[21]. Varying thresholds have

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17 Advanced meters installed as part of the Victorian AMI program were deemed to be type 5 metering installations so that the LNSP’s exclusive ability to perform the Responsible Person role with respect to these metering installations could be maintained according to current clause 7.2.3(a)(2) of the NER.

18 Section 7(2) *National Energy Retail Regulations*.

19 Section 7(2) *National Energy Retail Regulations*.

been set in the other jurisdictions. There is an upper threshold of: 160 MWh per annum in South Australia and 150 MWh per annum in Tasmania. The equivalent threshold in Victoria is 40 MWh per annum.

1.2.2 Issues identified with the current arrangements

The COAG Energy Council considers that the current arrangements for metering in the NER are inhibiting consumers, metering service providers and other participants from investing in metering technology that can support the outcomes listed at the start of section 1.2.[22] While the current arrangements do not prevent a retailer from installing an advanced meter, the rule change request identifies a number of barriers that are affecting decisions about metering services, which are described below.

Competition for the provision of metering services for small customers is restricted

As discussed above, currently the role of the Responsible Person for type 5 and type 6 metering services is exclusively performed by the LNSP. Accordingly, the NER provides LNSPs with the certainty of being the exclusive provider of these services and, subject to the AER regulatory determination process, receiving regulated revenues[23] to recover the costs of doing so.

The provision of type 1-4 metering services are currently not subject to economic regulation by the AER and the LNSP does not have certainty that the Market Participant will request that the LNSP take on the role of Responsible Person for those metering installations.

The COAG Energy Council notes that if a small customer or its retailer decides to upgrade from a type 5 or 6 metering installation to a type 4 metering installation, the LNSP risks losing its role as the Responsible Person. The COAG Energy Council is of the view that the current rules create a disincentive for DNSPs to help consumers and retailers take up more advanced metering technologies.

Metering charges are bundled with distribution use of system charges

In some jurisdictions, charges for metering services are bundled into distribution use of system charges that all network users pay. As a result, if a consumer's metering installation is upgraded to an advanced meter, the consumer may pay both the charges passed on by the retailer for the new metering installation and the charges passed on by the DNSP for the old metering installation and related services through distribution use of system charges.[24] The COAG Energy Council is of the view that this arrangement is a disincentive for installing advanced meters.

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20 Clause 30O *Electricity Regulation 2006* (Qld).

21 Section 4(1)(a) National Energy Retail Law (Adoption) Regulations (NSW) 2013.

22 COAG Energy Council, rule change request, October 2013, p5.

23 The AER has currently determined these services to be direct control services and are therefore price regulated.

24 This residual amount for the old metering installation would be paid by all customers.

The framework for negotiating exit fees is uncertain

Under the current rules, compensation may be payable by the retailer to the DNSP if it seeks to alter a type 5 or 6 metering installation which leads to a reclassification of that metering installation as a type 4 metering installation.

The rule change request refers to this compensation as an "exit fee" and states that a high exit fee can be a disincentive for retailers to invest in new metering technology, while a low fee might under-recover the residual costs to the distribution network business of a metering installation that is no longer required.

The COAG Energy Council considers that the current requirement in the rules for these two parties to negotiate in good faith so that the distribution network business is reasonably compensated for an alteration to a metering installation creates uncertainty and hinders investment in more advanced metering technology.

Regulation governing access to non-metrology functions of metering installations is unclear

The COAG Energy Council is of the view that there is uncertainty regarding who has a right to access the non-metrology functions of advanced meters, which may limit a business case to invest in advanced metering. These issues were explored in the AEMC's advice to the COAG Energy Council on a framework for open access and common communication standards for advanced meters, published in April 2014.[25]

Advanced meter consumer protections are still being established

The rule change request notes that appropriate consumer protections for advanced meters are still being developed and their implications are uncertain. The COAG Energy Council is addressing some consumer protection issues through parallel amendments to the NERR.[26] The rule change request asks the AEMC to make or advise of any necessary additional consumer protection arrangements to support the proposed arrangements.

The NEL provision allowing a mandated rollout of advanced meters causes investment uncertainty

At the time of writing the rule change request, there was a provision in the National Electricity Law (NEL) allowing jurisdictions to mandate a rollout of advanced meters by DNSPs. In its Power of Choice review, the AEMC noted that the risk created by the possibility of a government-mandated rollout was stalling investment in advanced meters and recommended that it be removed. The COAG Energy Council supported this recommendation, and legislation to remove the provision from the NEL was passed by the South Australian Parliament, as lead legislator, in 2013.[27]

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25 http://www.aemc.gov.au/Markets-Reviews-Advice/Framework-for-open-access-and-communication-standa

26 This amendment to the NERR is being led by the COAG Energy Council and any rule changes would be made by the South Australian Minister and not by the AEMC.

27 Statutes Amendment (Smart Meters) Act 2013 (SA).

1.3 Solution proposed in the rule change request

In its rule change request, the COAG Energy Council proposes the following amendments to the NER (and relevant provisions of the NERR) to resolve the issues outlined above and other related issues:

- separate the responsibility for metering services from the roles of the retailer and the DNSP so that no party has the exclusive right to provide these services;
- replace the term Responsible Person with Metering Coordinator;
- allow any party that is accredited with AEMO to become a Metering Coordinator;
- allow all consumers to engage a Metering Coordinator directly;
- determine what accreditations, if any, might be required for the Metering Coordinator role;
- establish arrangements to support the ongoing provision of metering services in the event a Metering Coordinator fails;
- require unbundling of metering charges from distribution use of system charges at the next regulatory reset, in jurisdictions where this has not already occurred;
- require the AER to set clear exit fees for existing, regulated meters using a set of defined criteria, including consideration of whether a cap on exit fees is appropriate;[28]
- introduce the term 'smart meter minimum functionality specification' to refer to a guideline or procedure that is established, maintained and published by AEMO regarding the minimum functionality requirements and performance levels for smart metering infrastructure;
- include provisions for jurisdictions to determine their own new and replacement and reversion policies, and to prescribe exclusivity to a particular Metering Coordinator to provide certain metering installation types;
- require retailers to inform consumers of their metering service charges and the retail tariff that would be offered if charges for metering services were removed;
- revise the current arrangements regarding the provision of electronic data transfer facilities to a metering installation; and
- establish appropriate transitional and implementation arrangements, including for Victoria where advanced meters are already in place.

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28 "Regulated meters" refer to direct control services which are price regulated by the AER.

The rule change request also asks the AEMC to consider whether the proposed arrangements are adequately supported by the existing arrangements regarding:

- ring-fencing for DNSPs;
- consumer protections; and
- retailer of last resort (ROLR) provisions.

The COAG Energy Council is of the view that the proposed arrangements would enhance the uptake of more advanced metering. It expects that this would support the uptake of new products and services that promote consumer participation and choice, and allow for the benefits of demand side participation to be captured across the supply chain.

Further detail on the rule change request is set out in the consultation paper published by the AEMC on 17 April 2014, which is available on the AEMC website.[29]

1.4 Background

1.4.1 The Power of Choice review

In December 2012, COAG endorsed a comprehensive package of national energy market reforms, developed by the COAG Energy Council, to support investment and market outcomes in the long term interests of consumers.[30] One area of reform seeks to address the impediments to, and promote the commercial adoption of, demand side participation in the NEM. The COAG Energy Council developed a work program to implement this reform, comprising three policy objectives:

1. *Improving pricing and incentives.* This objective recognises that consumers need clear signals about the cost of their energy consumption in order to efficiently manage their demand, and supply chain businesses need appropriate incentives to implement and facilitate demand side participation options.
2. *Informing choice.* This objective recognises that consumers and demand side providers need a range of information so that they can identify and implement efficient demand options.
3. *Enabling response.* This objective recognises that a range of technologies, skills, and frameworks are needed to support pricing, information, and demand management options, and to enable timely responses to market signals.[31]

As part of these reforms, COAG and the COAG Energy Council agreed to implement a number of the recommendations made by the AEMC in its Power of Choice review.[32]

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29 http://www.aemc.gov.au/Rule-Changes/Expanding-competition-in-metering-and-related-serv

30 http://www.scer.gov.au/workstreams/energy-market-reform

31 http://www.scer.gov.au/files/2014/02/Demand-Side-Participation-Update-table.pdf

The review, published in November 2012, identified opportunities for consumers to make more informed decisions about how they use electricity. The review also addressed the market conditions and incentives required for network businesses, retailers and other parties to maximise the potential of efficient demand side participation and respond to consumer choice.

An area of focus in the review related to the role of enabling technology, including advanced meters, in supporting these outcomes. The review examined the existing market and regulatory arrangements that govern investment in metering, and questioned whether these arrangements support a consumer's decision to take up a range of electricity products and services. The review also looked at whether the existing arrangements enable the full value of demand side participation and end use services to be captured across the supply chain.

The review found that the current regulatory framework is inhibiting the ability of consumers and Market Participants to invest in metering technology that supports the uptake of efficient demand side participation. The AEMC recommended that the NER be amended to introduce a framework that encourages commercial investment in advanced meters to promote consumer participation and choice in electricity products and services.[33] The COAG Energy Council's rule change request is based on this recommendation.

The rule change request forms part of a broader package of reforms recommended in the Power of Choice review, as illustrated in Table 1.2. Several of these projects are described in further detail in section 1.4.2.

Table 1.2 Power of Choice rule changes and reviews

Mechanism	Reform	Status
Rule changes	Customer access to information about their energy consumption[34]	Final determination published 6 November 2014
	Distribution network pricing arrangements[35]	Final determination published 27 November 2014
	Improving demand side participation information provided to AEMO by Registered Participants[36]	Final determination published 26 March 2015.
	Reform of the demand	Consultation paper published 19

32 In March 2013, the COAG Energy Council published its response to the recommendation in the AEMC's Power of Choice review. See http://www.scer.gov.au/workstreams/energy-market-reform/demand-side-participation

33 AEMC, Power of Choice review, final report, AEMC, 30 November 2012, Sydney, p69.

34 http://www.aemc.gov.au/Rule-Changes/Customer-access-to-information-about-their-energy

35 http://www.aemc.gov.au/Rule-Changes/Distribution-Network-Pricing-Arrangements

36 http://www.aemc.gov.au/Rule-Changes/Improving-Demand-Side-Participation-information-pr

Mechanism	Reform	Status
	management and embedded generation connection incentive scheme[37]	February 2015.
	Embedded networks[38]	Consultation paper expected to be published in late April/early May 2015.
	Multiple trading relationships[39]	Rule change request received December 2014
	Demand response mechanism[40]	Rule change request being prepared by COAG Energy Council.
Reviews and advice	Electricity customer switching[41]	Final advice provided to COAG Energy Council April 2014. Rule change request being prepared by COAG Energy Council.
	Framework for open access and common communication standards for smart meters[42] and implementation advice on a shared market protocol[43]	Final advice provided to COAG Energy Council March 2014. Consultation Paper on Implementation Advice on the Shared Market Protocol published on 18 December 2014.

1.4.2 Related reforms

This rule change is the missing link between distribution network pricing arrangements and other reforms to promote and enable consumer choice in energy markets. It is therefore closely linked to a range of issues that are being considered by the AEMC and other parties.

In developing the draft determination and draft rule we have considered the interactions between these projects, including which issues are best addressed in this rule change and which are better dealt with in other processes, for example because

37 http://www.aemc.gov.au/Rule-Changes/Demand-Management-Embedded-Generation-Connection-I

38 http://www.aemc.gov.au/Rule-Changes/Embedded-Networks

39 http://www.aemc.gov.au/Rule-Changes/Multiple-Trading-Relationships

40 On 11 December 2014, the COAG Energy Council asked its officials to prepare a rule change request to propose a demand response mechanism based on voluntary participation by Market Participants and a staged implementation. See https://scer.govspace.gov.au/workstreams/energy-market-reform/demand-side-participation/wholesale-market-demand-response-mechanism-in-the-national-electricity-market

41 http://www.aemc.gov.au/Markets-Reviews-Advice/Review-of-Electricity-Customer-Switching

42 http://www.aemc.gov.au/Markets-Reviews-Advice/Framework-for-open-access-and-communication-standa

43 http://www.aemc.gov.au/Markets-Reviews-Advice/Implementation-advice-on-the-Shared-Market-Protoco

they raise broader issues. We have also considered the extent to which implementation of these projects could be coordinated. This is discussed further in Chapter 5.

Projects of particular relevance are outlined below.

Advanced meter consumer protections

The COAG Energy Council is considering a range of measures to implement the recommendations of its National Smart Meter Consumer Protections and Safety Review, published in November 2012. The COAG Energy Council recognises that advanced meters create opportunities for businesses to offer new products and services to consumers, and is therefore looking at ways to ensure that consumer protections are appropriate where consumers have an advanced meter installed. This includes developing rules to provide additional consumer protections around supply capacity control, direct load control and customer billing.[44]

New products and services in the NEM

In December 2014, the COAG Energy Council's Energy Market Reform Working Group published a consultation paper seeking public comment on the regulatory implications of new products and services in the electricity market.[45] The paper recognises that a range of parties can offer products and services to consumers to help them manage their electricity consumption and costs, particularly where advanced meters are installed. However, some of these parties are not currently regulated under the National Electricity Customer Framework (NECF).

Submissions to the consultation paper closed on 20 March 2015 and will be used to inform a discussion paper that will be presented to Ministers at the next COAG Energy Council meeting.

Some of the issues in scope of this work have also been raised as part of this rule change request, in particular, implications for load control as it relates to network management. This issue is discussed in Appendix A4.

Establishing an energy information hub

In August 2012, the Australian Government published the results of a scoping study on the potential need for an energy information hub to provide consumers with easier access to their energy data.[46] Ministers at the COAG Energy Council meeting in December 2014 committed to working with industry to support consumer understanding and uptake of new tariff structures. COAG officials are considering ways to improve the ability of consumers to access their energy consumption data online and enable the development of information tools and services to assist

44 http://www.scer.gov.au/workstreams/energy-market-reform/demand-side-participation/smart-meters/consumer-protections

45 https://scer.govspace.gov.au/workstreams/energy-market-reform/demand-side-participation/new-products-and-services-in-the-electricty-market

46 http://www.industry.gov.au/energy/Documents/energyMarket/CEdata-scoping-study.pdf

consumer decision making. This is being considered in the context of the competition in metering rule change, the shared market protocol and broader considerations of the role of data in market operations.

Open access and common communication standards for advanced meters

In April 2014, the AEMC published its advice to the COAG Energy Council on a framework for open access and common communication standards for advanced meters.[47] The advice made recommendations on a framework to provide certain parties with the required level of access to the functionality of advanced meters. An open access framework provides the ability for service providers to offer new products and services to consumers, which would empower consumers to better manage their electricity consumption.

Shared market protocol

The AEMC's advice to the COAG Energy Council on a framework for open access and common communication standards for advanced meters recommended that a shared market protocol be adopted for advanced meter communications. A shared market protocol is an electronic platform that allows parties to communicate with each other regarding the services that will be offered by advanced meters.

The AEMC recommended that the establishment, maintenance and governance of the shared market protocol be determined through an additional rule change request once the final determination on competition in metering and related services had been made. In June 2014, the COAG Energy Council asked AEMO to develop a proposed shared market protocol, in consultation with interested parties, as the basis of this rule change proposal.[48] AEMO submitted the first part of its advice to the COAG Energy Council on 11 March 2015 and is due to submit further advice by May 2015.

In December 2014, the AEMC published a consultation paper seeking stakeholder feedback on governance arrangements and related issues regarding implementation of the shared market protocol. Together with the advice provided by AEMO, submissions received on the consultation paper will help inform the development of a rule change request for implementing a shared market protocol, for consideration by the COAG Energy Council.[49]

Interactions between the shared market protocol and this rule change are discussed in Chapter 4 and Appendix C1 in relation to the minimum services specification.

47 http://www.aemc.gov.au/Markets-Reviews-Advice/Framework-for-open-access-and-communication-standa

48 https://scer.govspace.gov.au/files/2014/12/Terms-of-Ref-MFS-Market-Protocol-June-2014.pdf

49 http://www.aemc.gov.au/Markets-Reviews-Advice/Implementation-advice-on-the-Shared-Market-Protoco

Meter replacement process

In January 2015, the AEMC received a rule change request from ERM Power relating to the obligations of various parties during the meter replacement process.[50] ERM Power considers that existing provisions in the NER are ambiguous about the rights and obligations of prospective participants at a connection point in relation to when a metering installation can be replaced, ie before a retail transfer, on the day of a retail transfer, or at another time following a retail transfer. They propose that this ambiguity be rectified by introducing new transitional roles for prospective participants and clarifying the timing of participant rights and obligations at a connection point.

We will consider the interaction between the two rule changes and how best to coordinate implementation of any changes.

Review of electricity customer switching

In April 2014, the AEMC published a review of electricity customer switching arrangements.[51] The purpose of the review was to determine whether any modifications are required to the existing arrangements for retail customer switching in the NEM, with regard to future technologies that may affect the switching process, eg advanced meters. The AEMC found that, in general, customer transfers in the NEM occur efficiently, but that some customers experience lengthy or inaccurate transfers. The review made several recommendations on how the consumer transfer process can be made more timely and accurate. These recommendations were considered by Ministers at the COAG Energy Council meeting in December 2014, who agreed to officials finalising:

- a draft rule change request to improve the timing of the transfer process by allowing the use of estimated meter reads for customers switching to a new retailer but not changing address; and
- a draft rule change request to improve the accuracy of the transfer process through the development of address standards, and improving obligations to resolve erroneous customer transfers.

The market-led provision of more advanced metering technology, as contemplated for by this draft determination, is likely to lessen some of the issues identified with the electricity customer switching process for consumers with manually read meters. For example, the time taken to process a transfer is largely determined by the current practice of transferring a customer only after an actual meter read for their electricity consumption has been recorded. Advanced meters with remote read capability may allow this process to occur much faster.

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50 ERM Power, Rule change request: Facilitating an efficient meter replacement process, 19 January 2015. See: http://www.aemc.gov.au/Rule-Changes/Meter-Replacement-Processes.

51 http://www.aemc.gov.au/Markets-Reviews-Advice/Review-of-Electricity-Customer-Switching

Customer access to information about their energy consumption

In November 2014, the AEMC made new rules to make it easier for retail customers to obtain information about their historical electricity consumption in an easy-to-understand, affordable and timely way.[52] The new rules:

- allow retail customers to obtain their electricity consumption data from their DNSP as well as their retailer;
- allow parties authorised by retail customers to obtain the customer's electricity consumption data from their retailer and DNSP; and
- require retailers and DNSPs to comply with minimum requirements relating to the format, time frames and reasonable charges when a retail customers, or party authorised by that customer, requests their electricity consumption data.

By making this information more accessible, the Commission is of the view that retail customers will be able to make more informed decisions about the energy products and services they use, particularly those that are enabled by advanced metering technologies. The rule change largely related to historical data, such as access to the last two years of usage data. In contrast, this draft determination considers how to improve access by consumers and other authorised parties to close to real time data to support emerging products and services.

Distribution network pricing arrangements

In November 2014, the AEMC made a new rule to require DNSPs to set prices that reflect the efficient cost of providing network services to individual consumers.[53] This will allow consumers to compare the value they place on using the electricity network against the costs caused by their use of it.

The competition in metering rule change is closely related to the new rule for distribution network pricing, as a greater take up of advanced meters by consumers will provide DNSPs with an opportunity to introduce more advanced network tariff structures that better reflect consumers' individual usage. A greater penetration of advanced meters in the NEM, as enabled by the competition in metering rule change, can allow for more sophisticated ways of measuring and pricing a consumer's electricity use. In particular, these technologies offer much better ways to send signals about the network costs caused by a consumer's usage and promote more efficient use of the network to the benefit of all consumers.

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52 http://www.aemc.gov.au/Rule-Changes/Customer-access-to-information-about-their-energy

53 http://www.aemc.gov.au/Rule-Changes/Distribution-Network-Pricing-Arrangements

1.5 Commencement of rule making process and extension of time

On 17 April 2014, the Commission published a notice under section 95 of the NEL and section 251 of the NERL advising of its intention to commence the rule making process and the first round of stakeholder consultation on the proposed rule change.

On the same date the Commission gave notice under section 107 of the NEL and section 266 of the NERL to extend the time for making a draft determination on the rule change request to 18 December 2014. The extension was sought in recognition of the large scope of issues raised by the rule change request and to allow the Commission time to adequately consider and consult with stakeholders on all relevant issues.

On 20 November 2014 the time for making a draft determination was further extended to 26 March 2015. This extension was sought to allow the Commission time to work through several complex policy issues and associated legal drafting and hold an additional stakeholder workshop.[54]

1.6 Consultation on the rule change request

On 17 April 2014, the Commission published a consultation paper to facilitate stakeholder comment on the issues raised by the rule change request. The Commission received 33 submissions to the consultation paper, which are available on the AEMC website.[55] Where appropriate, issues raised by stakeholders in their submissions have been addressed throughout this draft rule determination. A summary of issues that have not been explicitly addressed in Appendices A to F, and the Commission's response to each, is provided in Appendix H.

Between June 2014 and January 2015 the Commission held six stakeholder workshops to explore the issues raised by the rule change request in more detail and give stakeholders an opportunity to share their views on the proposed arrangements. The workshops held and topics covered are outlined in Table 1.3.

Table 1.3 Stakeholder workshops

	Topics covered	Date	Location
1	The Metering Coordinator role: • Proposal for independent Metering Coordinator • Gate keeper functions	26 June 2014	Sydney

54 Further information about the reasons for seeking this additional extension is available here: http://www.aemc.gov.au/getattachment/95798420-3338-4780-b38c-2d5b68218843/Information-sheet-–-extension-of-time-for-draft-de.aspx

55 http://www.aemc.gov.au/Rule-Changes/Expanding-competition-in-metering-and-related-serv

	Topics covered	Date	Location
	• Registration, accreditation and compliance obligations		
2	Network regulatory arrangements: • Cost recovery for regulated meters • Deployment of advanced meters by DNSPs • Ring-fencing arrangements • Existing load control capability	1 August 2014	Brisbane
3	Relationships between parties: • Retailer-consumer • Retailer-Metering Coordinator	28 August 2014	Melbourne
4	Supporting arrangements: • Minimum core model arrangements • Consumer-Metering Coordinator	24 September 2014	Sydney
5	Transitional and implementation: • Arrangements for Victoria • Governance of the minimum services specification • Jurisdictional arrangements • Requirements for implementation	9 October 2014	Melbourne
6	Outstanding policy issues: • The minimum services specification, including governance • Opt out arrangements • Access to Metering Coordinator services • Remote provision of disconnection and reconnection services • Network security issues related to load control • Stakeholder views on timeframes for implementation	22 January 2015	Sydney

Presentations and other materials from the workshops are available on the AEMC website.[56]

The Commission also held separate information sessions with consumer groups and met individually with many stakeholders.

1.7 Consultation on draft rule determination

The Commission invites submissions on this draft rule determination, including the draft rule, by 21 May 2015. In order for the AEMC to meet its statutory deadline for publication of the final rule determination and final rule in July 2015, it is important that submissions are provided by this date.

The Commission will hold a public forum on the draft rule determination in late April or early May 2015. A date and location for the public forum will be confirmed shortly and further information about the forum will be made available on the AEMC website.

In accordance with section 101(1a) of the NEL and section 258(2) of the NERL, any person or body may request that the Commission hold a hearing in relation to the draft rule determination. Any request for a hearing must be made in writing and must be received by the Commission no later than 2 April 2015.

Submissions and requests for a hearing should quote project number "ERC0169" and may be lodged online at www.aemc.gov.au or by mail to:

Australian Energy Market Commission
PO Box A2449
SYDNEY SOUTH NSW 1235

56 http://www.aemc.gov.au/Rule-Changes/Expanding-competition-in-metering-and-related-serv

2 The draft rule determination

2.1 Commission's draft determination

In accordance with section 99 of the NEL and section 256 of the NERL, the Commission has made this draft rule determination in relation to the rule proposed by the COAG Energy Council.

The Commission has determined that it should make a more preferable rule, but it contains many elements of COAG's rule change request.[57] Aspects of the draft rule that differ from COAG Energy Council's rule change request are discussed further in section 2.2.3.

The Commission's reasons for making this draft rule determination are set out in Chapters 3 to 5 and Appendices A to H.

A draft of the rule that the Commission proposes to make (draft rule) is attached to and published with this draft rule determination. Its key features are summarised below and described in more detail in Chapter 4 and the appendices.

Key features of the draft rule:

- The draft rule changes who has overall responsibility for metering services under the NER to promote competition in the provision of metering and related services by:
  - providing for the role and responsibilities of the existing Responsible Person to be provided by a new type of Registered Participant - a Metering Coordinator;
  - allowing any person to become a Metering Coordinator, subject to meeting the registration requirements;[58]
  - permitting a large customer to appoint its own Metering Coordinator; and
  - requiring a retailer to appoint the Metering Coordinator, except where a large customer has appointed its own Metering Coordinator.
- It requires a Metering Coordinator to take on roles additional to those currently performed by the Responsible Person so that the security of, and access to,

57 Under section 91A of the NEL and section 244 of the NERL the Commission may make a rule that is different (including materially different) from a market initiated proposed rule if it is satisfied that, having regard to the issues or issues that were raised by the market initiated proposed rule, the more preferable rule will or is likely to better contribute to the NEO and the NERO, respectively.

58 Currently the LNSP has overall responsibility for provision of metering services to most small customers and either the LNSP or the retailer is responsible for the provision metering services to other customers.

advanced meters and the services provided by those meters are appropriately managed.

- It specifies the minimum services that a new or replacement metering installation installed at a small customer's premises must be capable of providing.
- It provides for the circumstances in which small customers may opt out of having a new metering installation installed at their premises.
- It clarifies the entitlement of parties to access energy data and metering data in order to reflect the changes to roles and responsibilities of parties providing metering services.
- It provides for LNSP to continue to get the benefit of network devices installed at customers' premises that assist them to monitor and operate their distribution networks.
- It permits a retailer to arrange for a Metering Coordinator to remotely disconnect or reconnect a small customer's premises in specified circumstances.
- It makes changes to the model terms and conditions of standard retail contracts to reflect the changes to the roles and responsibilities of parties providing metering services under the draft rule.

2.2 Rule making test

2.2.1 Assessment of the draft rule against the NEO

Under section 88(1) of the NEL the Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the National Electricity Objective (NEO).

The NEO is set out in section 7 of the NEL as follows:

> "The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system."

The draft rule supports the development of a market for the provision of advanced metering services, and subsequently the uptake of efficient demand side participation by residential and small business customers.[59] The Commission is satisfied that the draft rule will, or is likely to, contribute to the achievement of the NEO for the reasons set out below.[60]

Efficient investment in metering services

The draft rule will enable a market-led deployment of advanced meters. In a market-led deployment, competition and consumer choice, rather than regulation, will drive the uptake and penetration of advanced meters. Investment in metering services driven by consumers choosing products and services they value at a price they are willing to pay can be expected to result in efficient investment.

The draft rule supports the development of a NEM-wide market for the provision of advanced metering services.[61] This framework has the potential to reduce regulatory costs and complexity for businesses operating across jurisdictional boundaries. Under a consistent framework, consumers can be expected to benefit from lower costs for metering services, including any advanced metering services provided to them.

The Commission anticipates that under the draft rule, metering installations will only be replaced where efficient to do so, such as at the end of their useful life or where a new meter can support additional services that consumers wish to take up. Unnecessary meter churn is unlikely to occur as competitive pressures are likely to drive retailers to seek efficient, lower cost outcomes to attract and retain customers.

These arrangements are expected to increase competition and support better informed decision making about investment in advanced meters based on the expected price and service outcomes for parties across the supply chain, eg retailers, DNSPs, energy service companies and consumers.

Consumer participation and choice in electricity products and services

The draft rule will support the efficient deployment of advanced meters for residential and small business customers across the NEM. Advanced meters can provide a platform for consumers to take up products and services that help them make decisions about how they use electricity. For example, better consumption information, which may be available through advanced meters, can help consumers compare retail pricing offers and choose an offer that reflects their electricity needs and usage preferences. Increasing competition for products and services, such as load control or

59 This refers to 'small customers' as defined in the NERL, being a residential customer or a business customer that consumes energy below the upper consumption threshold (100MWh per annum). Some jurisdictions have set a different threshold.

60 Under section 88(2), for the purposes of section 88(1) the AEMC may give such weight to any aspect of the NEO as it considers appropriate in all the circumstances, having regard to any relevant MCE statement of policy principles.

61 The extent to which there is a fully consistent national framework will depend on whether jurisdictions introduce or retain existing jurisdictional requirements, and the extent to which the AER's distribution determination decisions vary between jurisdictions. In addition, the NERR amendments under the draft rule will not apply in Victoria, which has currently not adopted the NECF.

time of use tariffs, is expected to place a downward pressure on the price of these products and services.

Competition for the provision of metering services is also likely to promote innovation, which will expand the technological capability of meters and consequently the range of electricity products and services that can be offered to consumers. A market with many service providers is expected to provide incentives for these parties to innovate and improve service offerings to consumers while driving prices down.

Further, the draft rule provides for a smooth transition from the existing rules to the new framework. The draft rule avoids unnecessary regulatory burden and instead promotes opportunities for consumers to become more active participants in the electricity market through engaging with a new range of products and services, should they wish to do so.

Efficiency of the national electricity system as a whole

Over time, the draft rule is expected to improve the efficiency of the national electricity system as a whole by influencing the decisions consumers and Market Participants make in respect of the electricity market. For example, the increased penetration of advanced meters may enable:

- consumers to better understand their electricity consumption and, if they choose, to change their usage to save money or take up new products and services that better reflect their needs and preferences. Depending on what price structures are offered by retailers, a consumer with an advanced meter could choose to remain on a flat rate retail price or could choose from a range of other offers from its current retailer or another retailer;
- DNSPs to implement network prices that better reflect the costs associated with each consumer's use of the electricity network. The Commission's recent final determination on distribution network pricing contained analysis that estimated that cost reflective network prices could result in 80 per cent of consumers facing lower network charges over the long term. This is on the basis of more informed consumer choices leading to more efficient utilisation of the network which would require less investment in network infrastructure over time;[62]
- consumers to switch electricity retailers more quickly (through remote meter reading) and the more efficient disconnection/ reconnection of consumers' supply, resulting in a more efficient operation of the retail market; and
- DNSPs to respond more quickly, and at lower cost, to power outages or poor supply quality where the advanced meters are used to support grid management technologies, which may lead to improved reliability and quality of electricity supply.

62 See http://www.aemc.gov.au/Rule-Changes/Distribution-Network-Pricing-Arrangements.

2.2.2 Assessment of the draft rule against the NERO

Any changes to the NERR must satisfy two tests under the NERL.

Under section 236(1) of the NERL, the Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the National Energy Retail Objective (NERO). The NERO is set out in section 13 of the NERL as follows:

> "The objective of this Law is to promote efficient investment in, and efficient operation and use of, energy services for the long term interests of consumers of energy with respect to price, quality, safety, reliability and security of supply of energy."

Under section 236(2)(b) of the NERL, the Commission must, where relevant, also satisfy itself that the rule is:

> "compatible with the development and application of consumer protections for small customers, including (but not limited to) protections relating to hardship customers."

This second requirement is referred to as the 'consumer protections test'. Where the consideration of consumer protections test is relevant in the making of a rule, the Commission must be satisfied that both the NERO test and the consumer protections test have been met.[63] If the Commission is not satisfied that both tests have been met, the rule cannot be made.

NERO test

Because the requirement to promote efficiency in the investment in, and efficient operation and use of, electricity/energy services for the long term interests of consumers is a common requirement in both the NEO and the NERO, the Commission is satisfied that the draft rule will, or is likely to, contribute to the achievement of the NERO for the reasons set out in section 2.2.1.[64]

Consumer protections test

A number of consumer protections are relevant to this rule change request, including those provided for by:

- the NERR;

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63 That is, the legal tests outlined in section 236(1) and 236(2)(b) of the NERL.

64 Under section 236(2) of the NERL, for the purposes of section 236(1) the AEMC may give such weight to any aspect of the NERO as it considers appropriate in all the circumstances; and where relevant, the AEMC must satisfy itself that the rule is compatible with the development and application of consumer protections for small customers, including (but not limited to) protections relating to hardship customers; and the AEMC must have regard to any relevant MCE statement of policy principles.

- the general law, eg Australian Consumer Law;
- retail energy laws and regulations of jurisdictions participating in the NECF (which currently includes the ACT, NSW, Queensland (from 1 July 2015), South Australia and Tasmania) and, where relevant, of jurisdictions not yet participating in the NECF (Victoria).[65]

The classes of consumer protections that are relevant to the draft rule amending the NERR are:

- safety and disconnection of the supply of electricity to a small customer's premises, given the potential ability for DNSPs and retailers to remotely disconnect or reconnect a small customer's premises;
- interruption of the supply of electricity to a customer's premises, where a customer's existing metering installation is replaced with a new one as part of a "new meter deployment";
- minimum standard terms and conditions for retail contracts, given that these will be amended to more clearly reflect the role of the retailer with respect to metering services;
- obtaining consent from customers, given the ability for customers to "opt out" of having their metering installations replaced under a new meter deployment, or alternatively to give their consent under a market retail contract to having their metering installation replaced; and
- provision of information to consumers, given that small customers will be notified of new meter deployments and their right to opt out of having their meter replaced as part of a new meter deployment.

The Commission is satisfied that the draft rule is compatible with the development and application of these consumer protections for small customers because it maintains existing relevant consumer protections and in relation to several areas, for example customers who require life support equipment, the draft rule enhances consumer protections.

2.2.3 More preferable rule

Under section 91A of the NEL and section 244 of the NERL, the Commission may make a rule that is different (including materially different) from a market initiated proposed rule if it is satisfied that, having regard to the issue or issues that were raised by the market initiated proposed rule, the more preferable rule will or is likely to better contribute to the NEO and the NERO, respectively.

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65 Relevant Victorian energy laws include the *Electricity Industry Act 2000* (Vic) and the Electricity Retail Code. Relevant Queensland energy laws include the *Electricity Act 1994* (Qld) and the Electricity Industry Code. We also considered relevant electrical safety legislation and regulations in NECF and non-NECF jurisdictions.

While the Commission's draft rule is a more preferable rule, it incorporates many elements proposed by the COAG Energy Council in the rule change request.

The Commission is satisfied that the draft rule will, or is likely to, better contribute to the NEO and the NERO than the COAG Energy Council's rule change request. Several aspects of the draft rule differ from what was proposed by the COAG Energy Council in its rule change request. In particular:

- In recognition that advanced meters can provide consumers and the market with significant long term benefits, the draft rule requires that all new metering installations installed for small customers meet the minimum services specification (subject to an ability for AEMO to grant an exemption in certain limited circumstances). The application of the minimum services specification to all metering installations installed at a small customer's premises differs to the COAG Energy Council rule change request which proposed that the minimum services specification be binding only if prescribed by a jurisdiction.[66]

- The draft rule does not provide for jurisdictions to introduce regulation to prescribe exclusivity for one or more, or a class of, Metering Coordinators to coordinate metering services for some metering installation types.[67] The Commission considers that the COAG Energy Council's concerns will be addressed by alternative means in the draft rule.[68] Further, the purpose of this rule change is to facilitate competition in the provision of metering services. This objective is achieved in part by removing exclusivity arrangements, and allowing any party that meets the applicable registration requirements to be appointed to the Metering Coordinator role;

- Complexity for small customers is minimised by the draft rule by requiring retailers to appoint a Metering Coordinator for small customer connection points and not, as proposed by the COAG Energy Council, allowing small customers to appoint their own Metering Coordinator and imposing a range of obligations on retailers to facilitate that choice by small customers;

- The draft rule enables a smooth transition for Victorian consumers to the new arrangements by including Victoria in the national framework from the outset, rather than allowing for an additional period during which DNSPs could exclusively perform the role of Metering Coordinator at the connection points of small customers as proposed by the COAG Energy Council.

66 COAG Energy Council, rule change request, October 2013, p15.

67 Ibid., p17.

68 The Commission understands that the purpose of the COAG Energy Council's proposed exclusivity arrangements is to mitigate the risk that: competition does not emerge in a particular market segment of region; consumers could be adversely affected by competition because the costs of type 5 or 6 metering services are expected to increase; and/or a market could be created for the provision of type 5 and 6 metering services, if small customers are able to opt out of having a metering installation that meets the minimum services specification installed at their premises.

The draft rule establishes a consistent framework across the NEM for the provision of metering services, which can be expected to benefit:

- consumers, through potentially lower metering charges due to increased competition for the provision of metering services and more efficient operation of the electricity market;
- Market Participants, through potentially lower regulatory and transaction costs; and
- Metering Coordinators, through the ability to generate economies of scale across jurisdictional boundaries.

Appendices A to G explain in greater detail the reasoning for making the draft rule, and why the draft rule is expected to better contribute to the achievement of the NEO and the NERO than the rule proposed by the COAG Energy Council.

2.3 Assessment framework

This section sets out the analytical framework that the Commission has used to assess the rule change request.

The Commission's assessment approach is based on the NEO and the NERO. The requirement to promote efficiency in the investment, operation and use of electricity/energy services for the long term interests of consumers is common to both the NEO and the NERO. The criteria below have therefore been used to assess the proposed changes to both the NER and NERR.

To assess whether the draft rule promotes efficiency in the investment, operation and use of electricity/energy services for the long term interest of consumers, the Commission has applied the following assessment criteria:

- *Competition*: Whether the draft rule promotes incentives for parties to supply consumers with metering services and other energy products and services that consumers want at a price that reflects the efficient costs of doing so.
- *Transparency and predictability*: Whether the draft rule promotes confidence in the market by providing a regulatory framework under which roles and responsibilities are clearly defined, and parties, including consumers, have sufficient information to make decisions.
- *Administrative burden and transaction costs*: Whether the draft rule sets out a framework that is as simple and practicable as possible in the circumstances, and without excessive regulation that might impose unnecessary complexity, risks or costs for consumers.
- *System integrity*: Whether the draft rule upholds the operational objectives of the NEM, as outlined in the NEO, particularly with regard to the quality, safety,

reliability and security of energy supply and the national electricity system as a whole.

The Commission's application of each of these criteria is described below.

2.3.1 Competition

The Commission has assessed whether the draft rule supports the development of competition for the provision of metering services. In particular, whether the framework is likely to:

- provide sufficient incentives to establish a workably competitive market;
- support the development of a NEM-wide market by minimising jurisdictional differences where possible and recognising that in some circumstances, for example in regional or remote areas, competition may not emerge as quickly;
- encourage parties to negotiate regarding access to the services enabled by advanced meters;
- minimise distortions to competition which may arise due to interactions between the regulated and competitive segments of the market, eg where DNSPs are providing services in the competitive market; and
- support innovation and efficient investment in advanced metering and energy services and whether this, in turn, is likely to have the effect of:
  - encouraging retailers to offer consumers retail energy services that align with the consumer's needs and preferences at a price that reflects the efficient cost of doing so; and
  - encouraging energy service companies to offer consumers energy products and services that align with the consumer’s needs and preferences at a price that reflects the efficient cost of doing so.

The Commission is of the view that the draft rule will support the development of a competitive market for the provision of metering services in the NEM that can achieve the objectives listed above. Through competition, the Commission expects that the benefits of advanced metering will accrue across the supply chain. A NEM-wide, competitive market would be expected to reduce transaction costs for Market Participants and increase efficiencies and economies of scale, which would be passed on to consumers in the form of lower costs, increased innovation and improved service outcomes.

2.3.2 Transparency and predictability

Transparency and predictability are integral to the success of a competitive market for the provision of metering services. The Commission has assessed whether the draft rule supports the development of a market that:

- provides Market Participants with the confidence and willingness to invest in advanced metering technologies and services;
- provides all parties, especially consumers, with sufficient information to make decisions; and
- encourages consumer participation and choice of energy products and services that reflect individual needs and preferences.

The draft rule is expected to provide a regulatory framework that is transparent and predictable for consumers and Market Participants to achieve these objectives. For example, the establishment of a minimum services specification will provide a clear understanding of the minimum service capability that is required to operate in the market.

2.3.3 Administrative burden and transaction costs

Transaction costs are those incurred when entering into an arrangement for the supply or purchase of a product or service. The Commission has assessed whether the draft rule:

- is a proportionate response to regulatory and administrative barriers to investment in, and uptake of, advanced meters and the services they enable; and
- is simple and practicable from a consumer's perspective, and allows them easy access to information to make decisions about the service offerings available to them.

A fundamental aspect of the proposed framework is the development of a competitive market for advanced metering services. The success of this market is undermined if regulation is excessive, complex or ambiguous. Such regulation can impose unnecessary risks and costs for businesses, which will inevitably be passed on to consumers in the form of higher prices.

While the model is complex, the Commission has sought to minimise changes to the current rules and keep the arrangements as simple as possible. The Commission is of the view that the draft rule provides the minimum regulation necessary to achieve the intended objectives of the rule change request. It also aims to promote consumer engagement with retailers and other energy service companies, which will encourage competitive discipline on the price and quality of services provided to them.

2.3.4 System integrity

The development of a market for the provision of metering services should not undermine the quality, safety, reliability and security of the national electricity system and the supply of energy services to consumers. The Commission has assessed whether the draft rule:

- is clear about the role that relevant parties have in helping to ensure the safe and efficient operation of the national electricity system and the provision of energy services to consumers; and
- allows DNSPs to continue to meet their obligations regarding the safety and operation of the network.

The Commission is of the view that the draft rule maintains, and in some cases strengthens, existing regulation to support the integrity of the national electricity system and the delivery of energy services to consumers.

2.4 Other requirements under the NEL and NERL

The Commission's consideration of other NEL and NERL requirements is described in Appendix G.

3 Expected outcomes for consumers

The new arrangements set out in the draft rule provide the foundation for a broad energy market reform program focussed on giving consumers opportunities to better understand and take control of how they use electricity and the costs associated with their usage decisions.

The AEMC and other parties are working on a number of changes to the regulatory framework to support this objective, including network pricing arrangements, consumer protections and access to energy consumption information. A number of these projects are described in further detail in Chapter 1. Under this new regulatory framework, retailers, DNSPs and energy service companies will be able to offer a greater range of services that meet consumers' preferences and needs.

Accumulation meters, the most common type of meter used in residential and small business premises across the National Electricity Market (NEM), give consumers little opportunity to understand and manage how they use electricity. Advances in metering technology, and the energy products and services this technology enables, can give consumers more choice and control. With the right technology, information and price signals, consumers are better able to make decisions about how and when they use electricity, and manage the costs of those decisions.

Greater consumer choice around energy use and the adoption of new technologies can influence the future direction of Australia's electricity system. New and emerging technologies like real-time energy usage displays and portals, smart air conditioners and in-home storage systems will facilitate a wider range of ways for consumers to manage their electricity consumption, particularly during peak demand periods. Electricity consumption decisions made at the household and small business level can lead to greater system efficiencies and cost savings for all consumers.

3.1 Outcomes for consumers under the current arrangements

The primary purpose of a metering installation is to measure the flow of electricity to generate data for settlement of the wholesale electricity market and customer billing.

The oldest and most common type of electricity meter used in residential and small business premises across the NEM is the accumulation meter. Accumulation meters perform only a basic metering function – they record the total amount of electricity used, but not the time at which it is used. These meters must be read manually at the premises by a meter reader. The consumer is billed for the difference between meter readings over a period of time, which is usually about three months to match the retail billing cycle.

As a consequence, the majority of residential and small business consumers in the NEM:

- are charged a flat rate for electricity consumption regardless of when the electricity is used, which, in many cases, will not reflect the actual cost of producing and transporting electricity at that time;
- have limited information available to them from which to make informed decisions about their electricity consumption and associated costs;
- are limited in the energy product and service offerings available to them;
- may experience lengthy transfers when switching retailers, because the current practice is to transfer the consumer only after an actual read of electricity consumption has been recorded;
- may be billed on an estimate of, rather than actual, electricity consumption, eg if the meter reader is unable to access the premises due to a locked gate or other obstacle.

The current NER provisions allow for, and potentially encourage, the continued installation of accumulation meters and therefore does not fully support a consumer's ability to monitor, manage and adjust their electricity consumption. On a larger scale, this restrains the efficient operation of the electricity system, which affects the prices that all consumers pay for the electricity they use.

3.2 Outcomes for consumers under the draft rule

Technological innovation has meant that meters can now do much more than just measure the flow of electricity. Advanced meters measure both how much electricity is used and when it is used – in near real time. Depending on the functionality of the metering installation, the ability to send and receive data remotely enables data on electricity consumption, electricity outages and other information on the performance of the distribution network to be obtained almost instantaneously. This information can help DNSPs lower costs and better manage the reliability of electricity supply. A variety of services such as remote meter reading, remote access to appliances and different pricing options can also be enabled by advanced meters.

Advanced meters are an enabling technology. Like a mobile phone or a pay TV box, they are the physical infrastructure that enables consumers to use a service that they value. Advanced metering technology is a tool that can help consumers monitor, manage and adjust their electricity consumption and, importantly, capture the value of doing so, if they so choose.

The draft rule establishes a framework to facilitate a market-led deployment of advanced meters. This approach is based on evidence that competition, as opposed to regulation, is more likely to drive innovation in products and services and facilitate the deployment of advanced meters and services to consumers at the lowest possible cost.

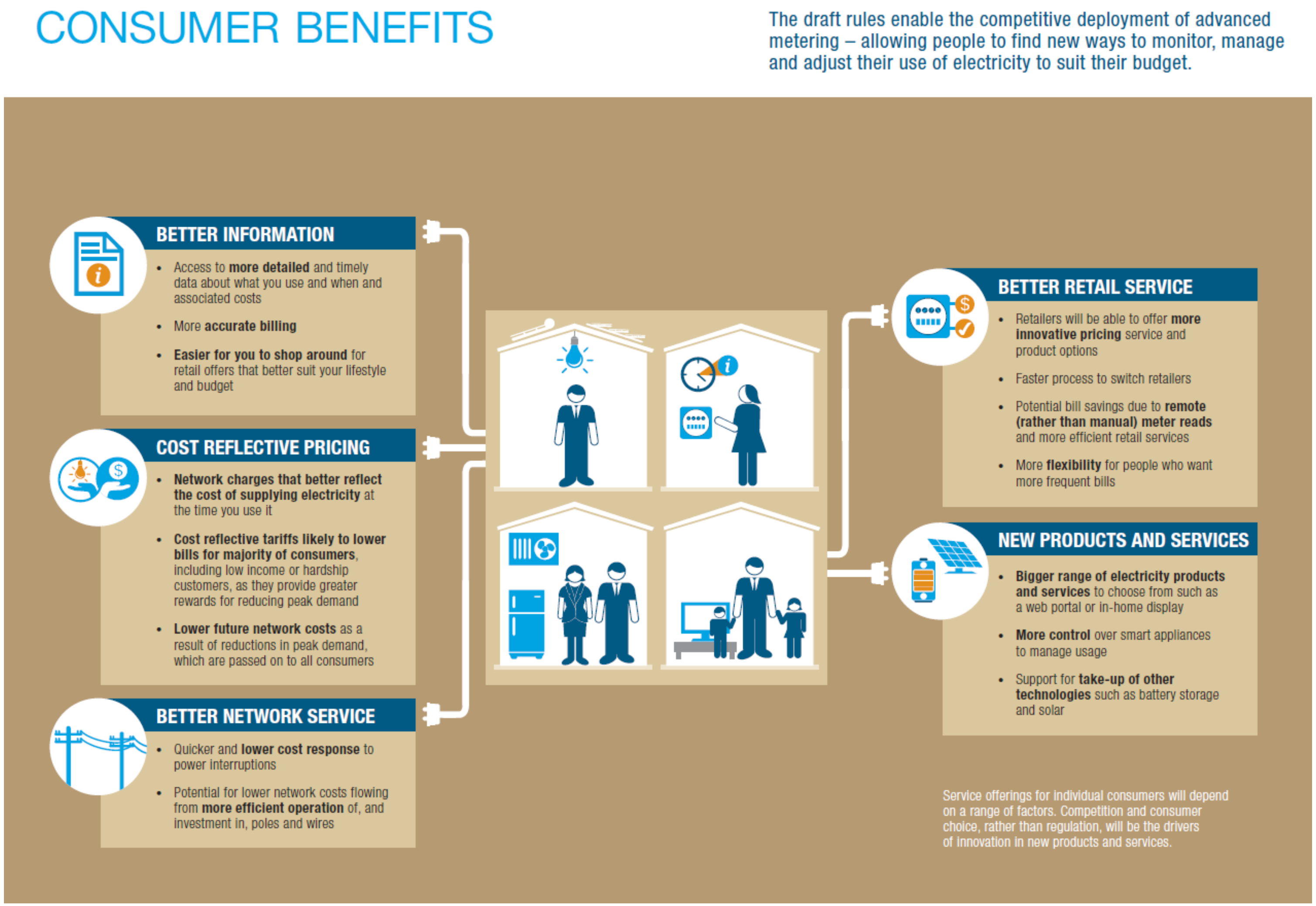
Under a competitive framework, consumer choices and preferences will influence the level of penetration of advanced meters and the types of products and services that are offered.

All new and replacement metering installations provided for small customers must meet the minimum services specification (subject to a limited AEMO exemption power). A small customer will have an advanced meter installed:

- when they choose a service or pricing option that necessitates the installation of a more advanced meter, eg an in-home display or a time of use tariff;
- where a retailer carries out a deployment of advanced meters to its retail customers, eg to achieve operational efficiencies through remote meter reading, and the consumer has not opted out;
- where the existing metering installation is faulty or needs to be replaced under a maintenance replacement (as defined in the draft rule); or
- where a new premises has a metering installation installed.

An increase in the penetration of advanced meters, and the uptake of energy products and services that this technology enables, may result in a wide range of benefits for all parties across the electricity supply chain, including consumers. The potential benefits for consumers are outlined in Figure 3.1 on the following page and described in more detail below.

Figure 3.1 Potential benefits to consumers from energy products and services enabled by advanced meters



Consumers who choose to use the information and services enabled by their advanced meter will experience a number of these benefits. However, many of the benefits may be shared by all consumers, regardless of their level of engagement.

Whether individual consumers receive the potential benefits discussed below will depend on a range of factors, including the extent and speed of deployment of advanced meters in the NEM, the range of new products and services offered by retailers and Metering Coordinators, and whether the consumer wishes to take up those new products and services.

The draft rule will not result in every consumer immediately receiving an advanced meter. All new and replacement metering installations for small customers must meet the minimum services specification, so there will be a gradual increase in the number of advanced meters over time. Under the draft rule, whether a small customer with a working metering installation[69] will have that metering installation replaced by their retailer will largely depend on whether retailers wish to deploy advanced meters for commercial reasons (such as enabling the offer of a broader range of products and services to customers).

If a retailer does wish to replace a small customer's working metering installation then under the draft rule the retailer must give the small customer an opportunity to opt out of having their metering installation replaced unless the customer has requested or otherwise agreed to the replacement.[70]

All new and replacement metering installations for small customers must be "capable of providing" the services listed in the minimum services specification. In practice, however, which of those services are activated and offered will be dependent on the arrangements between the Metering Coordinator and the retailer that appointed it and negotiations with parties seeking access to those services. Parties may also negotiate with Metering Coordinators to offer additional services over and above the services in the minimum services specification.

The outcomes of the draft rule will therefore depend to an extent on which services are offered by Metering Coordinators and which services parties seeking access desire and are willing to pay for.

Although the points above mean that there is some uncertainty about the speed of the deployment of advanced meters and the services that will ultimately be offered by those meters, the Commission considers that this market-led approach best promotes the long term interest of consumers. This approach results in the extent of investment in advanced meters, and therefore the cost associated with such investment, being driven in a large part by the market and by consumer preferences so that advanced

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69 For the purposes of this draft determination, a working metering installation is taken to mean a metering installation of a small customer that is not faulty and is not considered likely to fail based on sample testing of a meter population.

70 See Appendix C2 for further detail about these arrangements.

meters deliver the services that consumers and other parties value at a price they are willing to pay.

3.2.1 Better information

With an advanced meter, consumers may have access to more granular data about how much electricity they use and when. Consumers who access this information will be better able to understand the costs associated with their electricity use and, if they choose to, change their consumption behaviour to lower costs. An awareness of the costs associated with their electricity use may also support consumers decisions to buy more energy efficient appliances or invest in emerging technologies such as storage or smart appliances that could help them manage their energy costs.

Consumers are expected to be better able to shop around for a retail offer that suits their electricity needs and consumption preferences. As the number of advanced meters in the market increases, retailers are expected to develop offers that cater to a wider range of electricity needs and preferences.

The framework in the draft rule is intended to compliment a rule change made by the AEMC in November 2014 regarding a consumer's access to information about their energy consumption.[71] That rule change makes it easier for consumers to access their historical electricity consumption information from their retailer or DNSP in an easy-to-understand, affordable and timely way. That rule change also allows consumers to authorise another party to access this data.

If a consumer has an accumulation meter, only a limited amount of information is available for them to access under the new rules regarding customer access to information about their energy consumption. The benefits from that rule change increase for consumers with advanced meters, who will be able to obtain more detailed and useful information to assist with their decision making.

Having an advanced meter may also enable consumers to access close to real time energy usage information remotely, for example through a web portal or in-home display. Results from the Smart Grid Smart City trial indicate that consumers highly value the ability to use in-home displays to see near real time information about their electricity use. Seventy nine per cent of consumers in the trial with an in-home display were able to reduce their overall electricity use.[72]

Consumers will also be billed more accurately. Because advanced meters can be read remotely via a communications network, consumers will not be billed on an estimate of their electricity consumption.[73] In addition, the more granular information

71 See section 1.4.2 above.

72 Arup, Smart Grid Smart City: Shaping Australia's energy future, National cost benefit assessment, July 2014, p130.

73 Retailers will bill consumers on an estimate of their electricity consumption if the meter reader is unable to access the meter.

provided by advanced meters allows retailers and consumers to resolve bill disputes more quickly.

3.2.2 Cost reflective pricing

The component of a consumer's electricity bill that represents network charges in most cases does not currently reflect the costs of supplying network services to that consumer. Some consumers pay more than the costs caused by their electricity use while others, particularly those that use a greater proportion of their energy at peak times, pay less than the costs caused by their electricity use. This is because in general, distribution network charges currently over-recover for off-peak use of the network and under-recover for peak use.

A rule change recently completed by the AEMC addresses this issue by requiring DNSPs to set prices that better reflect the efficient cost of providing network services to individual consumers.[74] The benefits of this rule change will be significantly increased if more consumers have an advanced meter that is able to support different pricing arrangements.

Cost reflective prices are expected to lead to lower bills for the majority of customers because they provide stronger signals for consumers to minimise peak demand, thereby lowering future network costs, which are passed on to all consumers. Research carried out for the AEMC in 2014 found that average network charges for residential consumers under cost reflective prices could be reduced by $28 to $145 per year. The same research found that a small business could save up to $2,118, or 34 per cent of its total annual electricity network charges, by using less electricity at peak times for just 20 hours of the year when electricity networks are congested.[75]

Research has also demonstrated that low income consumers and consumers in a hardship program can benefit significantly from cost reflective tariffs. For example, research by AGL based on data from 160,000 Victorian consumers shows that under current flat rate tariffs, consumers in a hardship program are the most likely of all consumer types to be paying more than the costs caused by their energy usage. AGL estimated that 79 per cent of consumers in a hardship program would pay lower charges under a cost reflective price structure.[76]

In order to obtain the benefits of these cost reflective prices, consumers need the ability to access advanced metering services that can support more advanced price structures such as time-of-use, capacity or critical peak prices. Accumulation meters cannot support these types of tariffs, which means that these tariff structures are currently unavailable to most residential and small business consumers outside of Victoria.

74 http://www.aemc.gov.au/Rule-Changes/Distribution-Network-Pricing-Arrangements

75 This research was undertaken for the distribution network pricing arrangements rule change, and can be found at http://www.aemc.gov.au/Rule-Changes/Distribution-Network-Pricing-Arrangements.

76 Simshauser, P., Downer, D., *On the inequity of flat-rate electricity tariffs*, AGL Applied Economic and Policy Research, Working Paper No. 41, June 2014.

Time of use pricing, or other forms of cost reflective pricing structures, encourage consumers to make more informed consumption decisions by comparing the value they place on using electricity with the cost of electricity at a particular time. For example, a consumer that has chosen a time-of-use tariff might delay turning on their dishwasher or washing machine on until the peak demand period is over and the cost of electricity is lower. However, it is important to note that the draft rule does not introduce any requirement for consumers with advanced meters to take up a time-of-use tariff. Consumers may choose to remain on a flat tariff where this is offered by their retailer.

3.2.3 New products and services

The Commission's draft rule will support the development of a market for the provision of advanced metering services. Effective competition will likely increase the range of electricity products and services available to consumers, and the number of parties offering them. A market with many service providers will give incentives for these parties to improve service offerings to consumers while driving prices down.

Under the draft rule, parties may offer services beyond those listed in the minimum services specification. Some of the possible products and services that could be enabled by advanced meters include:

- Viewing electricity usage through an in-home display or web portal: These products connect remotely to the consumer's advanced meter and are used to display near real time data about the consumer's electricity consumption. This means that consumers can see detailed information about their current usage, historic usage and associated costs. These products could also allow consumers to compare their usage with similar homes in the area, set electricity budgets, pay bills and get energy saving tips. This information can help consumers monitor their electricity use and manage costs.

- Load management. Consumers who take up this service authorise a third party, often their DNSP, to control components of their electricity load (eg their pool pump) at certain times in exchange for a lower tariff or other incentive. Many consumers already benefit from load management through off peak hot water services, in which their hot water system is turned on overnight at a lower electricity rate. Advanced meters could enable consumers to take up similar services for other household appliances.

Competition for the provision of metering services is also likely to promote innovation. Innovation will expand the technological capability of meters and consequently the range of electricity products services that can be offered to consumers.

Engaged consumers may be able to have their metering installations configured to communicate remotely with programmable devices like air conditioners to adjust their settings to use less power at certain times.

Advanced meters and cost reflective price structures can also send efficient signals to consumers regarding whether to take up of other technologies, such as solar PV and battery storage, that can help them manage their energy usage and costs. The uptake and efficient use of these technologies is reliant on consumers having the metering technology to support that choice.

3.2.4 Better retail service

The increased penetration of advanced meters in the NEM is expected to encourage retailers to offer more innovative pricing, product and service options to consumers.

A number of innovative pricing offers are now available to most consumers in Victoria, who already have advanced meters in place. For example, AGL offers its customers free electricity on Saturdays, which could potentially help consumers reduce electricity costs if they shift some of their consumption. Powershop offers its customers the ability to buy power 'in bulk' for use in the months ahead. Customers can see how much electricity they have bought and how much they have used using a mobile phone application. This can help consumers budget and smooth out the cost of their electricity use.

The service quality of retail energy services provided to consumers is also expected to improve. For example, Victorian consumers with advanced meters are able to switch retailers more quickly because the commands to do so are sent remotely in near real time via the advanced meter.

The functionality of advanced meters also enables retailers to disconnect and reconnect their customers quickly, for example when they move house. This is expected to help consumers get reconnected to the electricity network as soon as possible after a period of disconnection. The Smart Grid Smart City trial estimated that the avoided operational costs for manual connections and disconnections would have a net present value of around $16 million under a national consumer-led deployment of advanced meters.[77]

Advanced meters can also allow retailers to realise economic efficiencies through the remote reading of meters via a communications network. The Smart Grid Smart City trial estimated that the net present value of avoided operational costs for manual meter reading would total around $11 million under a national consumer-led deployment of advanced meters.[78] These avoided costs would be expected to be passed on to consumers through bill savings and a more efficient retail service.

Remote reading capability also allows retailers to give their customers more flexibility over how often they are billed. For example, consumers may choose to be billed monthly or weekly, rather than three-monthly, to help reduce 'bill shock'.

77 Arup, Smart Grid Smart City: Shaping Australia's energy future, National cost benefit assessment, July 2014, p194.

78 Ibid.

3.2.5 Better network service

Over time, an increased penetration of advanced meters is expected to maximise the efficiency of the electricity system as a whole by influencing how consumers and Market Participants operate and engage in the electricity market.

Information provided by advanced meters can give DNSPs a better picture of electricity consumption patterns and enable them to make more efficient network investment decisions. Demand management technologies and consumers' responses to electricity price signals can help reduce peak demand which may, in turn, allow DNSPs to defer or avoid network expenditure. These outcomes would benefit consumers in the form of lower electricity costs.

Where it has entered into an agreement to purchase these services, advanced meters may be able to provide a DNSP with quicker notification of a power outage or distortions in the quality of electricity supply. This helps the DNSP respond to outage and supply quality distortions more quickly and a lower cost, leading to improved reliability and quality of electricity supply to consumers.

If negotiated for inclusion in the advanced meter, advanced metering technology could also provide safety benefits that existing accumulation meters do not, including the ability to automatically detect overheating or faulty wiring.

3.3 Consumer protections

The draft rule maintains existing consumer protections with regard to a retail customer's relationship with its retailer and DNSPs. It also introduces several additional protections for small customers who have an advanced metering installation that meets the minimum services specification.

In particular, under the draft rule the Metering Coordinator must ensure that access to services provided by, and metering data from, a metering installation of a small customer that meets the minimum services specification is only provided to certain parties. For example, in the case of the services listed in the minimum services specification, access must only be provided to an "access party".[79]

Access to services provided by such metering installations that are in addition to those services set out in the minimum services specification can only be provided to a person or for a purpose to which the small customer has given its prior consent. Further details regarding these regulatory arrangements are set out in Appendix C1.

The draft rule introduces protections for small customers with regard to the replacement of working metering installations. Generally, small customers will be able to elect not to have their existing working metering installations replaced by a new metering installation. The draft rule requires retailers to provide their small customers with prior written notice of a proposed replacement of the customer's working

79 An access party is a party listed in column 3 of table S7.5.1.1 of the NER in the draft rule.

metering installation, which must include (amongst other things) details regarding the customer's ability to opt out of having its metering installation replaced and the upfront charges the customer will incur under its retail contract as a result of the replacement.[80] Further details regarding these requirements are set out in Appendix C2.[81]

The draft rule gives both retailers and DNSPs the ability (subject to negotiating access to the service with the Metering Coordinator) to arrange remote disconnection and re-connection services directly with the Metering Coordinator in certain circumstances. However, the Commission is cognisant of the potential safety risks associated with remote disconnection and re-connection and in allowing multiple parties to arrange these services with the Metering Coordinator.

The draft rule requires both retailers and DNSPs to share information regarding life support registers and to notify each other regarding changes to the status of a shared customer's supply. In addition, jurisdictional safety regulators may develop further requirements with respect to safely disconnecting and reconnecting customers.

3.4 Expected outcomes for Victorian consumers

Victorian consumers are in a different position to those in other NEM jurisdictions because advanced meters have been installed in the majority of residential and small business premises under the Victorian Government's AMI program. The technology is therefore already in place to enable these consumers to make more informed decisions about their electricity use and for industry to offer more innovative products and services to them.

The focus must now be on realising the expected benefits of these advanced meters, but doing so in a way that enables new investment to support a range of products and services for Victorian consumers.

The draft rule will facilitate a smooth transition for Victorian consumers to the new framework. There remains a set of regulatory arrangements under Victorian jurisdictional instruments and the NER supporting the AMI program that mean it is unlikely that existing advanced meters rolled out under the AMI program will be replaced until they near the end of their useful lives, unless they are found to be faulty or have cause to be upgraded. As a result, the Commission expects that the majority of residential and small business consumers will continue to have their metering

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80 Metering charges for consumers that retain an accumulation meter may increase over time as more advanced meters are deployed, particularly if the consumer is in an area where very few manual meter reads are required. However, retailers will not be required to include information on possible future price changes that could occur as a consequence of opting out of having an advanced meter installed, as it will not be possible to accurately estimate those potential future price changes. This issue is discussed in Appendix C2.

81 The opt out provisions are contained in the NERR of the draft rule. The NERR does not currently apply in Victoria.

arrangements managed by their DNSP until the market develops to such a point that other parties see value in taking on this responsibility.[82]

The draft rule will mean that if a Victorian small consumer requires a new metering installation, for example for a new house or where the existing metering installation is faulty, metering services for that customer will be provided under the new competitive framework. Rather than having new and replacement metering installations installed exclusively by the DNSP under the mandate of the AMI program, parties will compete to provide these services through the consumer's electricity retailer. The Commission considers a competitive approach to the provision of metering services to these consumers is more likely to deliver the services they value at a price they are willing to pay.

3.5 Expected outcomes for large customers

The draft rule allows large customers to appoint their own Metering Coordinator at their connection point. If a large customer chooses to exercise this option, its relationship with the Metering Coordinator will be a commercial arrangement with some supporting regulatory requirements.

Large customers often require a range of services and may therefore require bespoke metering arrangements. Under the draft rule, more service providers may enter the market for metering and advanced energy services, giving large consumers a greater range of providers from which to choose. Competition to provide metering services to large customers is expected to place competitive discipline on retailers and other metering service providers on the prices, terms and conditions of the services they offer.

82 The specific transitional arrangements for Victoria are discussed in Chapter 4 and Appendix F.

4 New framework for expanding competition in the provision of metering services

4.1 Introduction

This chapter provides an overview of the new regulatory arrangements for the provision of metering services.

The draft rule removes regulatory barriers to investment in advanced meters. It will facilitate a market-led approach to the deployment of advanced meters where consumers drive the uptake of technology through their choice of products and services. This competitive framework is designed to promote innovation and lead to investment in advanced meters that deliver services valued by consumers at a price they are willing to pay.

A more detailed explanation of the new regulatory arrangements and the Commission's reasons for the draft rule are provided in Appendices A to G of this draft determination.

The chapter is set out as follows:

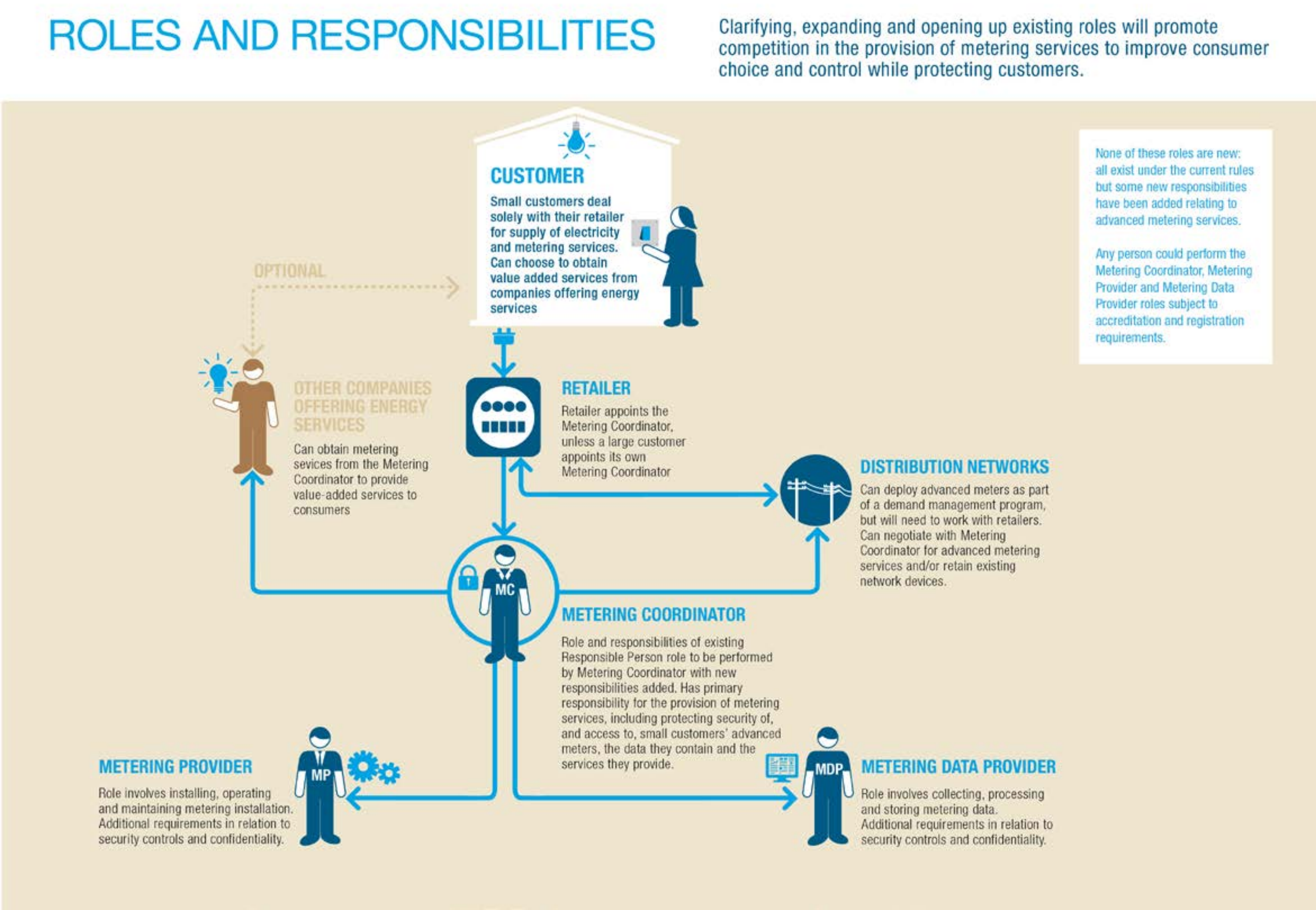
- section 4.2 provides a high-level overview of the roles of the main parties involved in the provision of metering services under the draft rule;
- section 4.3 describes a retailer's responsibilities for appointing a Metering Coordinator and the circumstances in which consumers will be able to appoint their own Metering Coordinator;
- section 4.4 summarises the roles and responsibilities of the Metering Coordinator, Metering Provider and Metering Data Provider and their registration and accreditation requirements;
- section 4.5 discusses areas where the NER and NERR are updated in the draft rule to reflect changes in roles and technology, including new responsibilities of the Metering Coordinator in relation to advanced metering services;
- section 4.6 describes the minimum services specification and its governance arrangements;
- section 4.7 summarises situations in which a small customer will be able to opt out of having a new metering installation that meets the minimum services specification installed at its premises;
- section 4.8 sets out the Commission's views on competition issues with respect to access to Metering Coordinator services, and how DNSPs can access network-related services;

- section 4.9 outlines the draft arrangements to enable a smooth transition from the existing arrangements put in place in Victoria under the AMI program to the national framework;
- section 4.10 notes the other changes to the NER and NERR that are also contained in the draft rule.

4.2 Overview of roles of the main parties involved in the provision of metering services under the draft rule

Figure 4.1 on the following page provides a high-level overview of the roles and responsibilities of parties under the new regulatory framework.

Figure 4.1 Overview of roles and responsibilities



Under the draft rule the Metering Coordinator will perform the role currently performed by the Responsible Person and certain existing exclusivity arrangements that previously applied to the Responsible Person role have been removed. This allows any party, subject to satisfying certain registration requirements, to act as a Metering Coordinator and, in turn, provide metering services in the NEM.

The Metering Coordinator also has obligations that are in addition to those that currently apply to the Responsible Person. These additional obligations relate to the provision of metering services at "small customer metering installations" (as defined in the draft rule) and address issues such as managing the security of metering installations and managing congestion of requests for access to metering services during emergency conditions.

The Commission does not consider the provision of metering services to have monopoly characteristics. It is possible to have multiple parties competing to provide metering services. Prospects are strong for a workably competitive market to develop in metering services in the NEM. Barriers to entry are low and the Commission is aware that a number of retailers and metering businesses are already considering establishing a Metering Coordinator business.

As such, the removal of existing exclusivity arrangements is anticipated to promote the development of a competitive market for the provision of metering services in the NEM and drive innovation, which is expected to be passed onto consumers in the form of lower costs and improved service outcomes.

The Commission supports a market-led, competitive approach to the investment in metering. The draft rule would put in place a regulatory framework to allow a market-led approach to the deployment of advanced meters. A market-led approach, in which consumers drive the uptake of technology through their choice of products and services, is more likely to lead to investment in advanced meters that delivers the services valued by consumers at a price they are willing to pay.

Other than in new and replacement situations, the draft rule does not mandate that advanced meters should be installed. This approach avoids inefficient investment in technology that is unlikely to be used or where there are likely to be less costly alternatives.

The Commission does not recommend mandating that a particular party must roll out advanced meters to all consumers. This approach would require that advanced meters are deployed whether or not there is a demand for services from consumers and more broadly across the supply chain from retailers, DNSPs and energy service companies.

More prescriptive standards and higher performance levels may also be required under a mandated approach, because competition cannot be relied on to drive innovation and performance. This approach may also require increased regulatory oversight of price, standards and performance in the absence of competitive pressures. The costs of higher standards and regulatory costs are likely to be ultimately passed through to consumers by way of higher charges for metering services.

Under the draft rule, the retailer will continue to be responsible for ensuring there is a metering installation at each of the connection points of its customers. The retailer (as the Financially Responsible Market Participant) will also be responsible for appointing a Metering Coordinator for each of its customers' metering installations, unless a large customer chooses to appoint its own Metering Coordinator. While a retailer may choose to establish a Metering Coordinator business, it may also procure these services on a commercial basis from another registered Metering Coordinator.[83]

Small customers will not need to, nor be able to, appoint their own Metering Coordinator. However, large customers will have the ability to appoint their own Metering Coordinator if they wish to do so.

Under the draft transitional arrangements, the DNSP (in its capacity as the LNSP) will become the initial Metering Coordinator for small customers for existing type 5 and 6 metering installations. It will continue in this role until another Metering Coordinator is appointed to the connection point by the customer's retailer or those services cease to be classified by the AER as direct control services.

In Victoria, the DNSPs will become the initial Metering Coordinator for the advanced meters they deployed under the AMI program. They will continue in this role until the relevant retailer appoints another Metering Coordinator at the connection point or the services cease to be classified by the AER as direct control services.

The Metering Coordinator will take on the Responsible Person's existing responsibility for appointing a Metering Provider and Metering Data Provider for a connection point.

The Metering Coordinator, Metering Provider and Metering Data Provider operate together to provide metering services to the market. Each of these roles are existing roles under the current NER, but with the Metering Coordinator taking over the role that was previously performed by the Responsible Person.

While the same party may become registered and accredited with AEMO to perform all three roles, the Metering Coordinator, Metering Provider and Metering Data Provider roles have been retained as separately defined roles in the draft rule.

These separate roles reflect the differences in these parties' responsibilities and the different capabilities and registration and accreditation requirements required of each role. Retaining separate roles allows the most appropriately resourced and qualified parties to perform these roles. It may also reduce the barriers to entry increasing the number of parties competing to provide different aspects of metering services.

While the Metering Coordinator is appointed by the retailer in the case of small customers, it may also provide services to other parties on a commercial basis. This may include DNSPs and energy service companies.

83 See section 4.4.2 below for details of which parties may register as a Metering Coordinator, including the prohibition against a Market Customer registering as a Metering Coordinator.

However, there will be no obligation on the Metering Coordinator to provide advanced metering services to other parties and no regulation of the price of those services. The provision and the price of services will be subject to commercial negotiations between the Metering Coordinator and the parties seeking those services.

4.3 Responsibilities for appointing a Metering Coordinator

4.3.1 Appointment of Metering Coordinators

Under the draft rule, the Financially Responsible Market Participant at a connection point is responsible for appointing a Metering Coordinator for that connection point, other than in circumstances where a large customer has appointed its own Metering Coordinator.

In a market-led deployment of advanced meters, the Commission considers that retailers, as the Financially Responsible Market Participant, should be responsible for appointing the Metering Coordinator for the connection points of their retail customers. The services consumers value are more likely to be offered when retailers hold this responsibility due to the direct relationship they have with the customer and given they will be incentivised to offer products and services to retain and attract customers.

Where a Market Generator, Market Customer (eg an aluminium smelter), Market Small Generation Aggregator or Market Network Service Provider is the Financially Responsible Market Participant, they are likely to require bespoke metering arrangements and are best placed to appoint a Metering Coordinator to provide their metering services.

Any party may act as a Metering Coordinator, provided it is registered with AEMO to perform that role. This is discussed in section 4.4.2.

- If a retailer wishes to perform the Metering Coordinator role itself, it will need to establish a separate legal entity (eg a subsidiary) to perform the role. The draft rule provides that a Market Customer may not be registered as Metering Coordinator.[84]

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84 This restriction has been introduced under the draft rule to address concerns that if a retailer is also a Metering Coordinator at a connection point and the customer at that connection point changes retailers (but the Metering Coordinator does not change), the former retailer may have continued access to the customer's energy and metering data. In such circumstances, the former retailer would no longer be entitled to access that data under the NER in its capacity as a retailer or Financially Responsible Market Participant (as it would cease to hold these positions in respect of the connection point), but the Metering Coordinator would be entitled to access the data. If the Metering Coordinator and former retailer were part of the same legal entity, the Confidential Information provisions in the NER (see clause 8.6) would not be sufficient to ensure that such data collected by the Metering Coordinator business was not provided and used by the retail business being operated by the one entity. Access to this data could limit retail competition by creating an uneven playing field where retailers that were also Metering Coordinators would have access to valuable information that other retailers are not permitted to access under the NER.

- A DNSP may be a Metering Coordinator, provided that it complies with any ring-fencing requirements established by the AER which may include legal separation, accounting separation, operational separation, information sharing requirements or other measures (see Appendix D3).

- An existing Metering Provider or Metering Data Provider, or any other party, could also become a Metering Coordinator.

The relevant Financially Responsible Market Participant will enter into a commercial arrangement to appoint the Metering Coordinator. This arrangement will set out the terms and conditions on which the Metering Coordinator provides services, including the price for those services. Metering Coordinators may also enter into agreements to provide metering services to other parties (subject to requirements in the NER, for example in relation to consumer consent requirements and restrictions on the parties that can request access to certain services), and charge those parties for those services.

Transitional arrangements

Under the draft rule, the LNSP that was acting as the Responsible Person for type 5 and 6 metering installations immediately prior to the commencement of the new Chapter 7 of the NER will become the initial Metering Coordinator at that connection point.

The LNSP will continue in this role until the retailer appoints a different Metering Coordinator to the site or the services cease to be classified by the AER as a direct control service.

Similar transitional arrangements will apply in Victoria. The Victorian DNSPs will become the initial Metering Coordinator for the advanced meters they deployed under the AMI program. They will continue as the Metering Coordinator until a new Metering Coordinator is appointed or the relevant services cease to be classified by the AER as a direct control service.

To implement this initial appointment of the LNSP as Metering Coordinator, the transitional provisions in the draft rule provide that:

- at least three months prior to the commencement of the new Chapter 7 of the NER under the final rule (if made), the LNSP must provide each Financially Responsible Market Participant with a standard set of terms and conditions on which it will agree to act as the Metering Coordinator;

- unless the parties agree other terms and conditions prior to the commencement of the new Chapter 7 of the NER, the LNSP will be deemed to be appointed as the Metering Coordinator on the LNSP's standard terms and conditions.

The draft rule also sets out certain requirements for the terms on which the LNSP will be appointed as Metering Coordinator, addressing amongst other things, price, scope of services and termination of appointment. For example, the Metering Coordinator must include terms as to price which are consistent with Chapter 6 (and, where relevant, Chapter 11) of the NER, ie the price will be the regulated price set by the AER. The requirements for the terms on which the LNSP will be appointed as Metering Coordinator are outlined in Appendix A1.

Transmission connection points and interconnectors

The requirement to appoint a Metering Coordinator will also apply to transmission connection points.

However, in relation to transmission network connection points, the draft rule provides that the Financially Responsible Market Participant may request that the LNSP offer to act as the Metering Coordinator.[85] This provision is equivalent to the current provisions that require the LNSP to offer to act as the Responsible Person in certain circumstances.

This requirement has been retained due to concerns that its removal could mean that there may not be any party with the appropriate capabilities and expertise available to provide metering services at transmission network connection points. This is because the technology for these metering installations is specialised and there are only a relatively small number of such connection points. The Commission also understands that the transmission network service provider (TNSP) is currently the Responsible Person for the majority of these connection points.

The arrangements for interconnectors are not changed under the draft rule. Under clause 7.2.1(c) of the NER in the draft rule, the TNSP (and not the Responsible Person) is responsible for the provision, installation and maintenance of metering installations for interconnectors.

The current NER provisions on joint metering installations are also not amended by the draft rule.[86]

The Commission understands that these provisions are intended to address circumstances where an interconnector has two metering installations ie there is one connection point with a metering installation at either end of the interconnector.

Type 7 metering installations

LNSPs currently act as the Responsible Person for type 7 metering installations on an exclusive basis.[87] The draft rule requires the LNSP to take on the Metering Coordinator role for type 7 metering installations. The Commission does not see value in introducing specific arrangements to allow other parties to provide type 7 metering

85 Clause 7.6.3 of the NER in the draft rule.

86 Clause 7.8.12 of the NER in the draft rule.

87 Type 7 metering installations are not a physical metering installation. Rather, there is a reconciliation between DNSPs and the users of that service using an algorithm to determine the throughput of energy, e.g. for public lighting and traffic lights.

installations where there is no evidence of significant potential for competition in this space.

4.3.2 Consumer appointment of a Metering Coordinator

The Commission has also considered whether consumers should be given the ability to engage their own Metering Coordinator. There are benefits in allowing consumers to engage their own Metering Coordinator. First, it supports consumers' choice of products and services enabled by advanced meters. Second, it may impose a competitive discipline on retailers and Metering Coordinators in terms of the price, terms and conditions of their product and service offerings.

However, providing customers with the ability to choose their own Metering Coordinator needs to be coupled with arrangements that ensure the continued provision of billing and settlements data to the market, as well as appropriate consumer protections.

Under the draft rule:

- large customers will be able to appoint their own Metering Coordinator; and
- small customers will not have the option of engaging their own Metering Coordinator.

Small customers

Small customers will not have the option of appointing their own Metering Coordinator under the draft rule. Rather a small customer's retailer will be required to appoint a Metering Coordinator and ensure there is a metering installation at the small customer's connection point.

Providing small customers with the ability to appoint their own Metering Coordinator would require additional regulatory arrangements to safeguard consumers and market integrity.

For example, additional consumer protections (such as price regulation) may be required to address circumstances where a retailer engages a new Metering Coordinator for a small customer's connection point following the customer's appointed Metering Coordinator becoming insolvent or otherwise being unable or unwilling to perform its functions.

Additional regulation to address these scenarios would be required to ensure there are sufficient processes in place to effect an efficient appointment of a Metering Coordinator by a retailer at the connection point to maintain the continued provision of metrology services essential for the operation of the electricity market. Examples of such scenarios include where:

- the contract between the Metering Coordinator and the small customer expires without replacement;
- the Metering Coordinator becomes insolvent; or
- the Metering Coordinator has not been paid for its services by the small customer and, as such, the Metering Coordinator ceases to provide services at the connection point.

Allowing small customers to directly appoint a Metering Coordinator also raises issues relating to how a market for Metering Coordinator services should be facilitated. If a small customer appoints a Metering Coordinator, it may be necessary for retailers to offer retail contracts that are both inclusive and exclusive of costs associated with the retailer appointing a Metering Coordinator at the connection point. This would most likely require the component price of Metering Coordinator services. Additional regulation may also be required to limit the ability of retailers to offer onerous terms and conditions that may discourage a small customer from appointing its own Metering Coordinator, which would introduce further regulatory complexity.

The development of substantial regulatory arrangements to provide for continuing market integrity and appropriate consumer protections risks a delay to implementing this rule change and the benefits that it is expected to bring consumers. Appointing a Metering Coordinator may also be overly complex for small customers at the commencement of the market for metering services.

Requiring the retailer, who is already subject to consumer protection provisions in the NERR, jurisdictional ombudsman schemes and Australian Consumer Law, to manage metering services on behalf of small customers will be simple and practical from a small customer's perspective and provides for a smooth transition from the existing rules to the new framework.

Despite the regulatory complexities involved, allowing small customers to appoint their own Metering Coordinator could provide a range of potential benefits for small customers. Therefore, the Commission recommends that the option for small customers to appoint their own Metering Coordinator is reviewed three years after the new Chapter 7 of the NER commences, when the market for metering services and consumer understanding of the market has had the opportunity to develop.[88]

Large customers

The draft rule provides large customers the ability to appoint their own Metering Coordinator. Large customers may utilise a range of advanced metering services and therefore may require bespoke Metering Coordinator arrangements. As large customers are likely to have sufficient bargaining power to negotiate terms and conditions and resolve any disputes with a Metering Coordinator, the Commission has

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88 Terms of reference for this review would be agreed with the COAG Energy Council closer to the scheduled date for the review.

determined that contractual relationships between a large customer and its Metering Coordinators would be on commercial terms and therefore be largely unregulated.

The regulatory changes required to enable large customers to appoint their own Metering Coordinator and ensure the continuing provision of settlements data to the market are not as substantial as for small customers. The significant benefits to large customers of being able to appoint their own Metering Coordinator would outweigh the regulatory and administrative costs involved.

There is a risk that a Metering Coordinator appointed by a large customer may cease to provide metering services and a replacement Metering Coordinator will need to be appointed to protect the continued provision of billing and settlements data to the market. To address this risk, the draft rule introduces default arrangements under which:

- the large customer's retailer must appoint a new Metering Coordinator if:
  - a "Metering Coordinator default event" occurs;[89] or
  - the contract under which the large customer appoints the existing Metering Coordinator terminates or expires and the large customer does not appoint a new Metering Coordinator within the period specified by AEMO in procedures; and
- if the retailer must appoint a new Metering Coordinator and the existing contract between the retailer and the large customer does not deal with the appointment of a Metering Coordinator in these circumstances, the terms of the contract between the retailer and the large customer relating to the appointment of the Metering Coordinator must be fair and reasonable.

4.4 Roles and responsibilities for the provision of metering services

4.4.1 Responsibilities of the Metering Coordinator

The Metering Coordinator will take on all of the current responsibilities of the Responsible Person.

The Metering Coordinator is responsible for appointing a Metering Provider and Metering Data Provider to provide metering services in accordance with the NER. However, as is the case with the Responsible Person role under the current NER provisions, the Metering Coordinator retains overall responsibility for metering issues and will be accountable for the Metering Provider and Metering Data Provider’s performance of their functions.

89 See the new Chapter 10 definition of "Metering Coordinator default event" in the draft rule. This definition includes events such as the Metering Coordinator ceasing to be registered by AEMO.

For example, the Metering Coordinator must appoint a Metering Provider for the provision, installation and maintenance of each metering installation.[90] However, the Metering Coordinator remains responsible for ensuring that the metering installation is installed and maintained in accordance with the NER and relevant procedures.[91]

A Metering Coordinator may choose to become accredited as a Metering Provider and/or Metering Data Provider and also carry out those roles.

The Metering Provider retains the responsibilities it currently has under the NER (including those related to the installation, operation and maintenance of metering installations).

The Metering Data Provider retains the responsibilities it currently has under the NER (including those related to the collection, processing, storing and delivery of metering data from each metering installation).

The Metering Provider and Metering Data Provider have a small number of additional obligations as discussed in Appendix A2.

Table 4.1 provides a general overview of the core obligations of a Metering Coordinator. This table distinguishes between those obligations which are currently obligations imposed on the Responsible Person as well other additional obligations being imposed on the Metering Coordinator under the draft rule.

Table 4.1 General overview of core obligations of a Metering Coordinator

Obligations	Existing or new obligation
Existing obligations of the Responsible Person in relation to metering installations and data	
Existing obligations of the Responsible Person in Chapter 7 of the NER with respect to the provision, installation and maintenance of metering installations. For example: • Ensure the security of metering installations and the accuracy of metering data.[92] • Appoint and coordinate the performance of the Metering Provider and the Metering Data Provider.[93] • Ensure that metering installations are provided, installed and maintained in accordance with the NER and procedures.[94]	Existing

90 Clause 7.3.2(a)(1) of the NER in the draft rule.

91 See clause 7.3.2(e)(1) of the NER in the draft rule.

92 Clause 7.3.2(e) of the NER in the draft rule.

93 Clause 7.3.2(a) of the NER in the draft rule.

94 Clause 7.3.2(e)(1) of the NER in the draft rule.

Obligations	Existing or new obligation
• Ensure that metering data services are provided in accordance with the NER and procedures.[95] • Ensure that energy data held in the metering installation is protected from direct local or remote electronic access by suitable password and security controls.[96] • Manage metering installation malfunctions, inspections, testing and auditing etc.[97] • Data obligations as required by AEMO procedures.[98]	
Minimum services specification	
Ensure that any new or replacement metering installation for small customers is a type 4 metering installation that meets the minimum services specification (see Appendix C1).[99]	New
Security controls for managing access to small customer metering installations	
For small customer metering installations (ie metering installations that meet or are required to meet the minimum services specification), ensure that: • access to energy data held in the metering installation is only given to a person and for a purpose that is permitted under the NER; and • access to services provided by the metering installation and metering data from the metering installation is only given to: — in respect of a service listed in the minimum services specification, and metering data in connection with that service, an access party listed in Table S7.5.1.1 of the NER; or — a person and for a purpose to which the small customer has given its prior consent; or — a person and for a purpose that is permitted under the NER.[100]	New
For small customer metering installations, ensure that the services provided by the metering installation are protected	New - extension of the current obligation that

95 Clause 7.3.2(g)(2) of the NER in the draft rule.

96 Clause 7.15.3(a) of the NER in the draft rule.

97 Clause 7.8.10(a) of the NER (malfunctions) and clause 7.9.1 of the NER (inspection, testing and audit) in the draft rule.

98 Clause 7.3.2(g) of the NER in the draft rule.

99 Clause 7.8.3 of the NER in the draft rule.

100 Clause 7.15.4(a) and (b) of the NER in the draft rule.

Obligations	Existing or new obligation
from local access and remote access by suitable password and security controls.[101]	applies for all customers' metering installations in relation to energy data
Emergency management	
For all connection points for which the Metering Coordinator is responsible, ensure that access to the metering installation, services provided by the metering installation and energy data held in the metering installation are managed in accordance with emergency priority procedures to be developed by AEMO.[102]	New
Other obligations	
Cooperate with an LNSP who wishes to install a network device for the purposes of operating or monitoring its network, and provide all reasonable assistance to facilitate the installation of the network device at or adjacent to the metering installation.[103]	New
Not remove, damage or render inoperable a network device that has been installed by an LNSP at or adjacent to a metering installation, except with the LNSP's consent.[104]	New
Not prevent, hinder or otherwise impede an LNSP from locally accessing a metering installation or connection point for the purposes of reconnecting or disconnecting the connection point.[105]	New
Registration	
Be registered as a Registered Participant.[106]	New

4.4.2 Metering Coordinator, Metering Provider and Metering Data Provider registration and accreditation requirements

The purpose of registration and accreditation is to provide regulatory oversight of each party's ability to perform its role in the energy market. AEMO undertakes a comprehensive registration process for Market Participants[107] as part of its role in maintaining market integrity and security. Certain rights and obligations apply to all

101 Clause 7.15.4(c) of the NER in the draft rule.

102 Clause 7.8.5 of the NER in the draft rule.

103 Clause 7.8.6(b)(1) of the NER in the draft rule.

104 Clause 7.8.6(b)(2) of the NER in the draft rule.

105 Clause 7.15.2(g) of the NER in the draft rule.

106 Clause 2A.4.1 of the NER in the draft rule.

107 A Market Participant is a person registered by AEMO as a Market Generator, Market Customer (eg a retailer or a large consumer of electricity, such as a smelter), Market Small Generation Aggregator or Market Network Service Provider.

Registered Participants under the NER.[108] In addition to these general rights and obligations, each category of Registered Participant has certain requirements that are specific to their role.

Under the draft rule, Metering Coordinators constitute a new category of Registered Participant.[109]

Metering Providers and Metering Data Providers will continue to be required to obtain accreditation and be registered with AEMO.

Registration requirements for the Metering Coordinator

The Commission has considered the nature and scope of the role and responsibilities that the Metering Coordinator will undertake in order to determine what criteria an applicant must meet in order to become registered as a Metering Coordinator.

Under the draft rule, to be eligible for registration as a Metering Coordinator, a person must:

- not be a Market Customer;[110]
- satisfy AEMO that it is complying with and will comply with the NER and the procedures authorised under the NER;
- have appropriate processes in place to determine that a person seeking access to a service listed in minimum service specification is an "access party" in respect of that service;
- have an appropriate security control management strategy and associated infrastructure and communications systems for the purposes of preventing unauthorised access to metering installations, services provided by metering installations and energy data held in metering installations;
- have insurance as considered appropriate by AEMO; and
- pay the prescribed fee.

The Commission does not consider that exemptions to the registration criteria should be available for Metering Coordinators. The exception is TNSPs acting as Metering Coordinators for transmission network connection points within their transmission networks, where AEMO may grant an exemption in certain circumstances as discussed in Appendix A1.

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108 See Appendix A1 for a list of these general rights and responsibilities.

109 Under the draft rule, Metering Coordinators are a category of Registered Participant other than for the purposes of Part A of Chapter 5 of the NER. See clause 2.4A.1(c) of the NER in the draft rule.

110 As discussed above, if a retailer wishes to perform the Metering Coordinator role itself, it will need to establish a separate legal entity (eg a subsidiary) to perform the role.

Accreditation requirements for the Metering Provider and Metering Data Provider

AEMO currently undertakes an accreditation process for Metering Providers and Metering Data Providers and carries out regular audits. Under the draft rule, parties are still required be accredited and registered by AEMO before undertaking the Metering Provider and Metering Data Provider roles. Such accreditation and registration requirements do not require Metering Providers and Metering Data Providers to be registered as a category of Registered Participant.

However, under the draft rule, Metering Providers and Metering Data Providers will be deemed to be Registered Participants for the purposes of the confidentiality obligations in Part C of Chapter 8 of the NER.

Metering Providers and Metering Data Providers must also satisfy certain technical, capability and licensing requirements in order to be accredited and registered.

Metering Providers and Metering Data Providers for small customer metering installations will be required to meet an additional accreditation requirement. This additional requirement relates to the establishment of an appropriate security control management plan and associated infrastructure and communications systems for the purposes of preventing unauthorised local access or remote access to metering installations, services provided by metering installations and energy data held in metering installations.

4.5 Updating the rules to reflect changes in roles and technology

Under the new regulatory arrangements there may be a widespread deployment of advanced meters in the NEM. This will give rise to a number of issues related to the provision of advanced metering services which require existing roles and responsibilities of the Responsible Person (now the Metering Coordinator) to be expanded to safeguard consumers and network security from risks arising from an increase in the number of parties seeking to access advanced services.

The issues addressed in this section are:

- managing access by authorised parties to the metering installation, the services it can provide and the energy data it contains;
- managing access to the metering installation, the services it can provide and the energy data it contains during emergency conditions;
- remote disconnection and reconnection services; and
- access to energy and metering data.

4.5.1 Managing access by authorised parties

The Metering Coordinator has new obligations under the draft rule in relation to security controls for managing access to small customers' metering installations, services provided by the metering installation and energy data held in the metering installation.

Under the draft rule, the Metering Coordinator must ensure that:

- access to energy data held in the metering installation is only given to a person and for a purpose that is permitted under the NER; and
- access to services provided by the metering installation and metering data from the metering installation is only given to:
  - in respect of a service listed in the minimum services specification, and metering data in connection with that service, an access party listed in Table S7.5.1.1 of the NER; or
  - a person and for a purpose to which the small customer has given its prior consent; or
  - a person and for a purpose that is permitted under the NER.[111]

The Metering Coordinator must also ensure that services provided by a small customer metering installation are protected from local access and remote access by suitable password and security controls in accordance with the NER.

4.5.2 Emergency management

Under the draft rule, a Metering Coordinator must ensure that access to a metering installation, services provided by the a metering installation and energy data held in a metering installation are managed in accordance with emergency priority procedures established by AEMO in the event of an emergency condition.

This requirement applies to all metering installations, not just small customer metering installations.

The draft rule requires AEMO to establish, maintain and publish such procedures, which must set out:

- the criteria for determining when an emergency condition is present and which metering installations will be affected by the emergency condition; and
- where a metering installation supplies services to a LNSP from a metering installation that is affected by an emergency condition, which services the Metering Coordinator may be required to prioritise at the request of the LNSP.

111 See clauses 7.15.4(a) and (b) of the NER in the draft rule.

These requirements have been introduced to address situations where it may not be possible for the Metering Coordinator, Metering Provider or Metering Data Provider to process all service commands in line with its performance requirements during emergency conditions. This scenario is more likely to occur as the penetration of advanced meters increases and substantially more requests for services are processed.

4.5.3 Remote disconnection and reconnection services

Metering Coordinators that deploy advanced meters to small customers will have the ability to disconnect and reconnect customers remotely. This ability holds a number of benefits, particularly for retailers and consumers. Remotely disconnecting and reconnecting customers has the potential to provide much faster services and reduce the costs for retailers effecting the service, and therefore consumers.

To allow these benefits to be realised, the draft rule gives both retailers and DNSPs the ability (subject to negotiating access to the service with the Metering Coordinator) to arrange remote disconnection and reconnection services directly with the Metering Coordinator in certain circumstances. However, the Commission is cognisant of the potential safety risks associated with remote disconnection and reconnection and in allowing multiple parties to arrange these services with the Metering Coordinator.

The draft rule requires retailers and DNSPs to share information regarding life support registers and to notify each other regarding changes to the status of customers' supply. Jurisdictional safety regulators may also develop additional requirements with respect to safely disconnecting and reconnecting customers.

Managing safety risks, including the particular issues related to life support customers, are discussed further in Appendix A3.

4.5.4 Facilitating access to energy and metering data

The NER currently contains restrictions on who can access energy data and metering data.

Under the draft rule, the list of people who may be granted access to energy data or receive metering data has been updated to recognise the new Metering Coordinator role. Metering Coordinators may be granted access to energy data and receive metering data in relation to metering installations for which they are responsible.

To help consumers access the products and services enabled by advanced meters, the draft rule also provides that metering data in respect of a small customer metering installation (as defined in the draft rule) may be received by a person with the relevant small customer's prior consent.

These changes will assist in facilitating the provision of services by energy service companies that allow consumers to better understand their energy use, such as applications that allow consumers to view their energy usage on an in-home display, mobile phone or tablet that is remotely connected to the metering installation. These services would be provided by energy service companies on a commercial basis.

The draft rule also provides that a large customer or its "customer authorised representative" (as currently defined in the NER) may receive data from a large customer's metering installation.

These arrangements are discussed in more detail in Appendix B3.

4.6 Minimum services specification

A key feature of the draft rule is the inclusion of a minimum services specification, which will apply to all new and replacement metering installations installed at a small customer's connection point.

This specification focuses on the services that a metering installation must be capable of providing rather than the technical functionality of the metering installation. This is expected to provide greater opportunity for innovation to help deliver customers and third parties the services that they want at a lower cost and in a technology neutral manner.

Existing specifications contained in the NER relating to requirements for metering installations, such as their components, will remain largely unchanged. These existing requirements specify the metrology-related components that all metering installations for large and small customers must contain so that they can accurately record, store and communicate energy consumption information.

The minimum services specification will sit alongside those existing component requirements and specify additional services that new and replacement metering installations for small customers must be capable of providing.

The purpose of a minimum services specification is to help capture the broader market benefits from advanced meters, particularly where the party installing the meters may not have an incentive to install a meter capable of providing services that would be of value to others. The minimum services specification, coupled with specified service levels and performance standards, provides a starting point for parties to negotiate access to services that benefit their customers.

A NEM-wide approach to the minimum services specification is expected to allow meters to be deployed efficiently across jurisdictional boundaries. A nationally applicable specification can be expected to generate economies of scale for Metering Coordinators working across jurisdictional boundaries, potentially resulting in cost savings to both consumers and Market Participants.

Under the draft rule, the minimum services specification does not apply to the connection points of large customers or consumers who are not retail customers. These consumers are better placed to negotiate for the advanced services they require. Some of the services included in the minimum services specification for small customers will not be relevant for large customers. Also, given the potentially bespoke metering services that large customers may require it would be inappropriate to attempt to anticipate and prescribe the services they may require.

4.6.1 Governance

A description of the services that are contained in the minimum services specification are set out in Schedule 7.5 of the NER in the draft rule, with more detailed service levels and performance standards for each of the services to be developed by AEMO in procedures.

The purpose of the service levels and performance standards is to provide greater certainty to metering manufacturers and others regarding the specifications that the metering installation will be required to meet. Mandating service levels and performance standards for those services included in the minimum services specification may also reduce transaction costs associated with negotiating access to services. Finally, having a consistent set of service levels and performance standards may facilitate price comparisons between Metering Coordinators.

Under these governance arrangements, any person is able to propose a change to the minimum services specification via the rule change process. The Commission considers this is appropriate, given the variety of parties that will have an interest in the minimum services specification. Further, the rule change process involves a clearly understood, consultative approach whereby any changes are assessed having regard to the NEO.

Whenever a new or replacement metering installation is installed at a small customer connection point, it is the Metering Coordinator's responsibility under the draft rule to ensure the metering installation meets the minimum services specification (subject to the limited AEMO exemption power discussed below).

4.6.2 Services included in the minimum services specification

To meet the minimum services specification, a metering installation must be capable of providing the following services:

- *Remote disconnection service*. This service is the remote disconnection of a small customer’s premises via the metering installation.

- *Remote reconnection service*: This service is the remote reconnection of a small customer’s premises via the metering installation.

- *Remote on-demand meter read service*: This service is the retrieval of metering data from the metering installation for a specified point or points in time using remote acquisition and the provision of such data to the requesting party.[112]

112 This includes the retrieval and provision of reactive energy metering data and/or active energy metering data (for imports and/or exports of energy measured by the meter), interval metering

- *Remote scheduled meter read service*: This service is the retrieval of metering data from a metering installation on a regular and ongoing basis using remote acquisition and the provision of such data to the requesting party.[113]

- *Meter installation inquiry service*: This service is the remote retrieval of information from, and related to, a specified metering installation and the provision of such information to the requesting party.[114]

- *Advanced meter reconfiguration service*: This service is the remote setting of the operational parameters of the meter. Schedule 7.5 of the NER in the draft rule sets out the four operational parameters that, as a minimum, must be capable of being set.[115]

The draft rule specifies the parties that are able to request access to each of these services.

This list of minimum services included in the draft rule have been developed using the minimum services specification recommended by AEMO to the COAG Energy Council. The Commission considers that having a relatively low minimum services specification allows the market to determine the services that consumers want at a price that they are willing to pay. Although regulating a comprehensive list of services would provide greater certainty for parties regarding the services that an advanced meter must be capable of providing, over-specifying the minimum services specification could result in consumers having to pay for meters that are capable of providing services that ultimately are not taken up, are of no benefit to them or could be provided in a more cost effective way through alternative technologies.

Therefore the Commission has only included services in the minimum services specification where it considers that, if provided, these services are likely to deliver benefits to the majority of consumers receiving those services at a relatively low cost.

Further, the Commission expects that many metering installations will exceed the minimum services specification as retailers, DNSPs and energy service companies may negotiate for additional services to be provided by the meter. Metering Coordinators may include additional services in the meter to anticipate demand for services and

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data and cumulative total energy measurement for the metering installation, and accumulated metering data at the start and the end of the period specified in the request.

113 This includes the retrieval and provision of reactive energy metering data and/or active energy metering data (for imports and/or exports of energy measured by the meter), interval metering data and cumulative total energy measurement for the metering installation, and accumulated metering data at the start and the end of the period specified in the request.

114 The metering installation must be capable of providing the following types of information at a minimum: supply status; voltage; current; power; frequency; average voltage and current; and the contents of the meter log including information on alarms.

115 Parameters that must be capable of being set, as a minimum, include: the activation or deactivation of a data stream or data streams; altering the method of presenting energy data and associated information on the meter display; thresholds for alarms; and the parameters that specify how the voltage, current, power, supply, frequency, average voltage and average current measurements are calculated.

avoid the risk of meter churn. This approach allows customers and third parties to determine and pay for the services that they want at a price that they are willing to pay. Our understanding is that most advanced meters that are currently available are capable of providing a number of services in addition to those listed above, such as load control.

4.6.3 Meeting the minimum services specification

All new or replacement metering installations in respect of connection points for small customers must be a type 4 metering installation that meets the minimum services specification, subject to the exception noted below.

A metering installation meets the minimum services specification if it is capable of providing the services listed above and it is connected to a telecommunications network which enables remote access to the metering installation.

Several stakeholders noted that there may be instances where there is no telecommunications network to facilitate remote acquisition at a particular metering installation, such as in remote areas. As it may be prohibitively expensive for a Metering Coordinator to build a telecommunications network to provide remote acquisition (or pay a telecommunications operator to extend its network), Metering Coordinators will be able to apply to AEMO for an exemption to the requirement to provide this service.

AEMO may exempt a Metering Coordinator from complying with the requirement to install a type 4 metering installation that meets the minimum services specification in respect of a connection point if the Metering Coordinator demonstrates to AEMO's reasonable satisfaction that there is no existing telecommunications network to enable remote access to the metering installation at that connection point. An exemption may be for one or more periods of up to five years each.

If such an exemption is granted, any new or replacement metering installation for a small customer at that connection point must still be capable of providing all of the services listed above, but the requirement that the metering installation is connected to a telecommunications network which enables remote access to the metering installation would not apply.

Where AEMO grants an exemption from having to provide remote acquisition at a connection point, the metering installation would need to be manually read. For the reasons explained in Appendix C1, these metering installations will be classified as type 4A metering installations rather than type 5 metering installations.

While all new and replacement metering installations installed at a small customer's connection point must be capable of providing the services set out in the minimum services specification, there will be no obligation on Metering Coordinators to provide those services. Rather, the terms and conditions on which those services are provided, if at all, will be subject to commercial negotiation between the Metering Coordinator and third parties. The Commission's reasons for not regulating access to metering services, including those services contained in the minimum services specification, are discussed in section 4.8.

4.6.4 Links to a shared market protocol

While there are other services that could be provided by advanced meters that have not been included in the minimum services specification, these other services may be captured by the shared market protocol on which AEMO is currently formulating technical advice to the COAG Energy Council. In addition, the AEMC is currently developing advice to the COAG Energy Council on the governance and implementation of the shared market protocol.

A shared market protocol is an electronic platform that allows parties to communicate with each other regarding the services that will be offered by advanced meters. It also defines the format of the associated messages sent between the parties to provide those services. A shared market protocol is a default method of communication and does not preclude parties from agreeing to alternative methods of communication.

The Commission's advice to the COAG Energy Council will need to consider how a shared market protocol could interact with services provided under the minimum services specification and by the market. The Commission's expectation is that the shared market protocol could set out a communication method for all commonly available advanced services.

4.7 Opt out arrangements

As discussed in section 4.6, the draft rule requires that all new and replacement meters installed at a small customer’s connection point must meet the minimum services specification (subject to the limited AEMO exemption power discussed above). It is anticipated that this will result in the gradual deployment of advanced meters with substantial benefits to consumers and across the supply chain. That said, a cross-section of stakeholders including jurisdictions, retailers and consumer groups have emphasised the benefits of providing consumers a choice in whether their existing metering installation is replaced with an advanced meter.

To provide certainty to small customers and other parties, the draft rule includes provisions under which small customers will have an ability to opt out of having a new metering installation installed at their premises. This opt out applies where the new metering installation would replace an existing, working metering installation as part of a "new meter deployment" initiated by a retailer (in conjunction with the Metering Coordinator, and possibly in coordination with the LNSP or another party) as defined in section 4.7.2. This is a right that is not currently provided under the NER or NERR.

Providing small customers with the ability to opt out in this scenario will support consumer confidence by requiring retailers to notify the small customer of, amongst other things, the proposed replacement of their meter under the new meter deployment and any upfront charges the customer will incur under its retail contract as a result of the deployment.

The scenarios in which the opt out provisions apply are discussed below and in further detail in Appendix C2.

4.7.1 Choice of products and services

Advanced meters enable greater consumer choice in relation to energy products and services.

However, consumers will continue to have the ability to choose from the services and pricing options on offer from retailers and other service providers that best meet their needs. Depending on what price structures are offered by retailers, a consumer with an advanced meter could choose to remain on a flat rate retail price or could choose from a range of other offers from its current retailer or another retailer.

Jurisdictions have certain powers to protect standing offer customers[116] if there are any concerns relating to the choice of services or pricing offers available to these customers. For example, if jurisdictions are concerned that retailers may cease to offer flat rate pricing structures, the NERL contains a provision that allows jurisdictions to require retailers to offer particular standing offer tariff structures to small customers with an interval meter, eg a flat tariff. The COAG Energy Council is also consulting on changes to the NERR to provide additional consumer protections on the use of load control and supply capacity control services.

Where a small customer chooses a service or pricing offer that requires a new meter to be installed, there will be no ability for the consumer to opt out of the installation of that meter. In these circumstances, the consumer has requested the new product or service and, in turn, the installation of a new meter to enable that product or service.

This opt out requirement is contained in the NERR in the draft rule. The NERR does not currently apply in Victoria, which has not currently adopted the NECF. Accordingly, the NERR amendments, including this opt out right, will not apply in Victoria unless it adopts the NECF at a later date. The Victorian Government and Essential Services Commission (Victoria) should consider whether to make amendments to the Electricity Retail Code for consistency with the amendments to the NERR contained in the draft rule. If made, these amendments would provide for Victorian consumers to opt out of receiving a new meter that meets the minimum services specification where their retailer plans to replace their existing working meter, including advanced meters which were deployed under the AMI program.[117]

116 Standing offer customers are on a retail contract based on model terms and conditions set out in Schedule 1 of the NERR.

117 The NERR will apply in Queensland from 1 July 2015, meaning that the opt out provisions in the draft rule, if made, would apply in Queensland when the draft rule commence on 1 July 2017.

4.7.2 New meter deployment

Under the draft rule, a retailer and its appointed Metering Coordinator, possibly in coordination with the LNSP or another party, may undertake a new meter deployment of advanced meters to its customers. For example, a retailer may see operational efficiencies that could be achieved through remotely reading meters and providing consumers with faster disconnection and reconnection services at no extra cost to the consumer. In this situation, the new advanced meter would replace an existing, functioning meter.

As noted in Chapter 3, advanced metering has the potential to provide a number of benefits to consumers, the market and the electricity system as a whole. The deployment of advanced meters by retailers can help realise these benefits more quickly, and possibly at a lower cost, than what could be expected if consumers had to actively opt in through bundled energy and metering products and services, eg when a consumer selects a time of use tariff that requires an advanced meter be installed.

The Commission is of the view that retailers should be able to deploy meters that meet the minimum services specification to their customers where they see a business case to do so, but that consumers should be provided with an ability to opt out of the deployment and retain their existing working metering installation.

Therefore, under the draft rule small customers are able to opt out of having a new meter installed under a new meter deployment, which is defined in the draft rule as:

> "**new meter deployment** means the replacement of the existing electricity *meter* of one or more small customers which is implemented by a retailer other than where the replacement is:
>
> (a) at the request of the relevant small customer or to enable the provision of a product or service the customer has agreed to acquire;
>
> (b) a *maintenance replacement*; or
>
> (c) as a result of a *metering installation malfunction*."

In a new meter deployment there is no technical reason why the existing meter should be replaced – the metering installation has not failed, is still functioning and is compliant with the NER.

The draft rule requires retailers to provide an initial written notice to their small customers, notifying them of the proposed replacement of their meter no earlier than 60 business days and no later than 20 business days before the date of the proposed deployment. The initial notice must state, amongst other things, that the customer may elect not to have its meter replaced as part of the new meter deployment (opt out), the way in which they may exercise their right to opt out and any upfront charges the customer will incur under a retail contract as a result of the new meter deployment.

The retailer must provide a second written notice to its small customers (which must include the same details as set out in the first notice) no earlier than 10 business days after the first notice and no later than 10 business days before the retailer proposes to replace the meter.[118]

The retailer is not required to comply with the notification and opt out requirements if the retailer is authorised to undertake the new meter deployment under the terms of the customer's market retail contract.

4.7.3 Maintenance replacements, faults and new connections

Under the draft rule, any new metering installation provided as part of a maintenance replacement, where the existing meter is faulty or at a new connection must meet the minimum services specification. Providing an ability for small customers to opt out in these scenarios is neither practical nor appropriate, and may lock in old technologies that are of no long-term benefit to consumers or the market.

Small customers do not currently have the ability under the NER or NERR to opt out of having a metering installation provided that meets the requirements of the NER during a maintenance replacement or where an existing meter is faulty or a new connection is established.[119] Not providing an opt out in these scenarios is therefore consistent with current arrangements.

Under the draft rule, a retailer can decide to replace meters as part of a maintenance replacement, which is defined in the draft rule as:

> "**maintenance replacement** means the replacement of a small customer's existing electricity *meter* by a retailer that is based on the results of sample testing of a *meter* population carried out in accordance with Chapter 7 of the NER:
>
> (a) which indicates that it is necessary or appropriate, in accordance with *good electricity industry practice*, for the *meter* to be replaced to ensure compliance with the *metering rules*; and
>
> (b) details of which have been provided to the retailer under Chapter 7 of the NER, together with the results of the sample testing that support the need for the replacement."

Providing an explicit ability for small customers to opt out in these circumstances would require additional regulation to give consumers a meaningful and enforceable choice in the period between the meter being recognised as needing replacement and the installation of a new meter.

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118 For further details regarding the opt out process and notification requirements see Appendix C2.

119 Specifically, in these scenarios small customers do not currently have an opt out right in the way that is being proposed under the new meter deployment scenario.

An ability to opt out of a maintenance replacement is likely to create confusion and may result in poorer outcomes for consumers. If an opt out were provided, a consumer would only be able to retain their existing meter until it fails, at which point it would be replaced with an advanced meter.

Opting out of a maintenance replacement would also be likely to result in more metering installations failing. This would increase costs for Market Participants and consumers and result in poorer service for consumers, who would be without a working metering installation and would be billed on an estimate of their consumption until the failed meter was replaced.

Consumers will not have the ability to opt out if their metering installation is faulty and needs to be replaced. Providing customers with an ability to opt out of receiving an advanced meter when their meter needs to be replaced due to a fault would not be workable.

Currently, repairs must be made to types 4-6 metering installations as soon as is practicable and no later than 10 business days after notification of a malfunction. Providing small customers with a meaningful and enforceable ability to opt out would require additional regulation and potentially lead to a significant time delay between a fault being discovered and a meter being replaced. A delay in having a working meter installed could increase financial risk to retailers and may cause a customer to be billed on an estimate of their energy consumption over a longer period of time. An obligation to provide an opt out in fault scenarios would likely lead to higher costs to all consumers and more estimated meter reads. Neither of these outcomes are in consumers' long term interests.

The Commission considers that small customers should not be able to opt out of having a metering installation that meets the minimum services specification established at a new connection, eg at a new house or development. Where a metering installation is established at a new connection the Metering Provider must ensure that the metering installation is a type 4 metering installation that meets the minimum services specification, unless the Metering Coordinator has obtained an exemption in respect of that connection point.[120]

Providing an ability to opt out in this scenario is not practical, particularly in large developments such as new apartment buildings. In many cases the developer will arrange connection and metering arrangements for each apartment. It is not the intent of this rule change to provide developers with an ability to install metering installations that do not meet the minimum services specification in residential developments, especially where they might have an incentive to arrange the lowest upfront cost solution, eg accumulation meters, which are unlikely to provide benefits to consumers over the long term.

120 Under clause 7.8.4 of the draft rule, AEMO may exempt a Metering Coordinator from complying with the requirement to install a type 4 metering installation that meets the minimum services specification in respect of a connection point if the Metering Coordinator demonstrates to AEMO's satisfaction that there is no existing telecommunications network to enable remote access to the metering installation at that connection point.

4.8 Managing competition concerns

4.8.1 Distribution ring-fencing

The draft rule requires the AER to develop distribution ring-fencing guidelines for the accounting and functional separation of the provision of direct control services from other services provided by DNSPs.[121]

As part of developing these guidelines, the AER may determine ring-fencing arrangements that to apply to circumstances where a DNSP takes on the role of Metering Coordinator, Metering Provider and/or Metering Data Provider.

For example, there may be a need to limit the DNSP's ability to:

- cross-subsidise the contestable services carried out by these businesses through their regulated services; and/or
- provide these businesses with access to commercially sensitive information that is not available to others in the contestable Metering Coordinator, Metering Provider and/or Metering Data Provider markets.

Under the draft rule, the AER has the flexibility to determine what ring-fencing measures are most appropriate, having regard to the services being provided.

4.8.2 Access to Metering Coordinator services

A number of stakeholders, particularly DNSPs and energy service companies have raised concerns regarding the potential for Metering Coordinators to exert market power by charging high prices or refusing to negotiate with third parties. This has been of particular concern in the context where a retailer sets up a subsidiary Metering Coordinator business.

Any Metering Coordinator, regardless of its ownership structure, has an incentive to charge as high a price as it can for the provision of metering services to third parties. They will also have some degree of market power, particularly in situations where a third party cannot choose an alternative Metering Coordinator at a particular premises.

However, the ability of Metering Coordinators to exercise market power may be constrained by a number of factors:

121 Clause 6.17.2 of the NER currently states that the AER 'may' develop the distribution ring-fencing guidelines. Under the draft rule, clause 6.17.2 has been amended to substitute the word 'may' with 'must'. The AER is required to develop the guideline within the timeframe prescribed in the transitional arrangements. In developing or amending the guidelines, the AER must consult with participating jurisdictions, Registered Participants, AEMO and other interested parties, and such consultation must be otherwise in accordance with the distribution consultation procedures.

- The number of potential entrants into the market. Barriers to entry are low and the Commission is aware that a number of retailers and metering businesses are considering establishing a Metering Coordinator business.

- The risk that metering assets will become stranded if Metering Coordinators restrict access to them. This will reduce the incentives on Metering Coordinators to deny access to their services, or to charge excessive prices to other retailers.

- The bargaining power of DNSPs as the only potential party interested in particular services. This will incentivise Metering Coordinators to negotiate with DNSPs and provide services at reasonable cost.

- The ability of consumers to switch retailers. If Metering Coordinators do not offer access to products and services that consumers value, they risk losing customers and market share. This reduces the incentives for Metering Coordinators to deny access to their services, or charge excessive prices to energy service companies.

While indicators suggest that prospects are strong for a workably competitive market to develop in metering services, given the inherent uncertainty regarding a market yet to commence, a range of potential forms of access regulation to address competition concerns have been considered.[122] These include two relatively light-handed forms of regulation: a negotiate/arbitrate framework and/or some form of price monitoring. Having considered these options in the context of metering services,[123] the Commission is concerned that even these light-handed forms of regulation will involve significant costs and could deter investment in advanced meters.

For example, there is a risk that a negotiate/arbitrate model may discourage genuine commercial negotiation.[124] A third party may consider it can achieve a better outcome by raising a dispute and going to arbitration. This possibility would increase risks for investors in metering businesses, particularly smaller businesses that may not have the resources to participate in an arbitration process, and could be a disincentive for them to enter the market.

More broadly, a negotiate/arbitrate model could undermine the development of a market for metering services by introducing substantial uncertainty. Investors will face the risk that they may be required by a third party arbitrator to provide services at prices lower than those envisaged when the business case was developed. While such regulatory frameworks typically include principles covering cost recovery and reasonable rates of return, an arbitrator is unlikely to have accurate information on what those costs and returns should be, particularly in a new market.

Price monitoring and information disclosure is also likely to be problematic in a new market, where prices are being determined competitively for the first time and new

122 See Appendix E.

123 See Appendix E.

124 See Appendix E for a fuller discussion on negotiate/arbitrate model in the context of metering services.

service offerings are likely to evolve rapidly.[125] A requirement to publish prices and/or monitor prices may therefore not be practical in the short term. Further, Metering Coordinators may bundle advanced metering services in different ways depending on the needs of the customer, which could mean that published prices may be different from actual prices being negotiated, and they will be difficult to compare across different providers. Prices will also vary depending on factors such as volume and risk profile.

The Commission has concluded that the introduction of access regulation to manage the potential emergence of competition issues is likely to introduce more costs than benefits. In particular, the Commission is concerned that the risk of arbitrated outcomes under a negotiate/arbitrate mechanism may significantly diminish incentives for investment. Without sufficient incentives, investment in advanced metering infrastructure and the services that this would facilitate may not develop.

For these reasons, the Commission does not propose to regulate access to Metering Coordinator services at market start. Rather, the Commission recommends that an assessment of whether access regulation is required be made in a review three years after the new Chapter 7 of the NER commences, when the market has had time to develop.

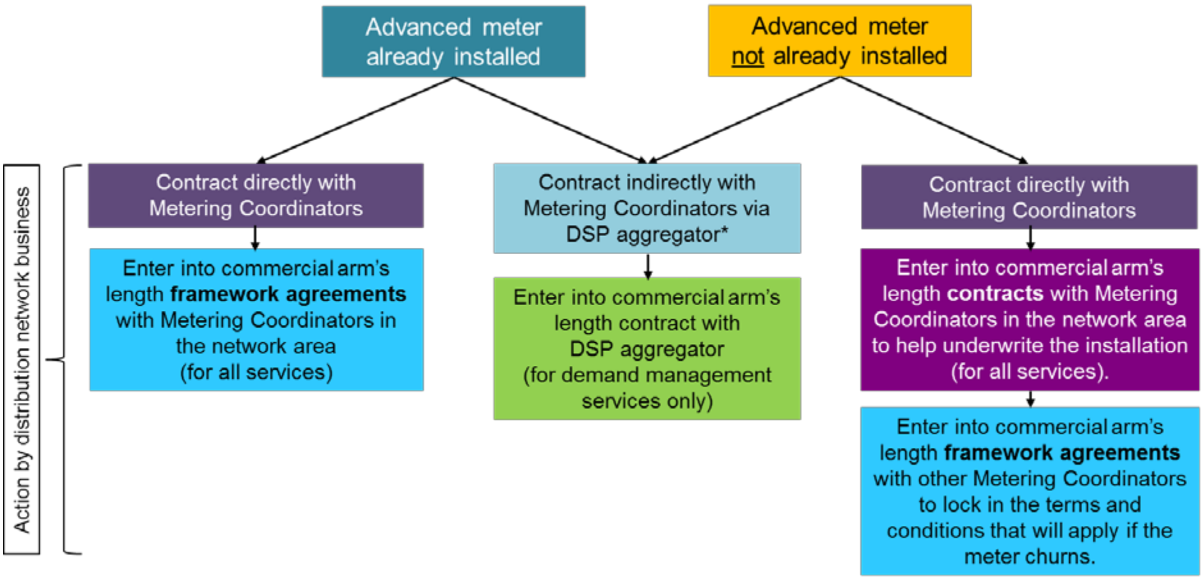
4.8.3 Role DNSPs could play in facilitating the installation of advanced meters

A DNSP may, with the cooperation of the Metering Coordinator and the relevant retailer, as the Financially Responsible Market Participant, choose to help fund the installation of advanced meters in its network area and secure access to the services provided by these meters by entering into long-term contracts with Metering Coordinators. A concern that DNSPs have raised about accessing network-related services and functions through metering installations is that they could be subject to a significant degree of uncertainty and transaction costs if the Metering Coordinator changes at a connection point.

The Commission does not expect the new regulatory arrangements to act as a barrier to the efficient take up of network-related services enabled by advanced meters by DNSPs as there are a number of commercial arrangements that can be used to overcome these risks, as summarised in Figure 4.2.

125 See Appendix E for a fuller discussion of price monitoring and information disclosure in the context of metering services.

Figure 4.2 Alternative ways a DNSP could access network-related services and functions



Note that the Metering Coordinator may be retailer owned, a third party or the distribution network business's unregulated Metering Coordinator business.
** In this case it will be the DSP aggregator that contracts directly with the Metering Coordinators to help underwrite the installation.*

To address concerns regarding uncertainty and transaction costs, DNSPs could enter into framework agreements with several Metering Coordinators so that they have greater certainty about the terms and conditions of access they will have if there is churn in Metering Coordinators. The term 'framework agreements' is used in this context to refer to an agreement that sets out the price and non-price terms and conditions of access that will apply when a DNSP deals with a particular Metering Coordinator at any site in its network. These agreements are common in overseas markets.

Another option DNSPs could consider if they are only seeking access to the demand management functions is to enter into a contract with a third party DSP aggregator. Under this option, the DSP aggregator would be responsible for contracting with a sufficient number of Metering Coordinators in the network area to guarantee the provision of the required level of demand management over the required period. It would then be up to the DSP aggregator to enter into agreements with Metering Coordinators in the network area.

Figure 4.2 illustrates some of the alternative contractual arrangements that a DNSP could use when seeking access to the services enabled by advanced meters. The manner in which DNSPs will be able to recover the costs incurred under these contractual arrangements will depend on the nature of the service acquired. However, in general they will be able to recover the prudent and efficient costs they incur in acquiring these services in one of the following ways under the existing AER regulatory determination process:

1. Including the costs in allowed expenditure at the start of the regulatory period (either operating or capital expenditure, depending on the type of project).

2. Funding the expenditure through savings created by deferring or avoiding capital expenditure that was included in the allowed expenditure for the regulatory period.

3. Including the costs in the Demand Management and Embedded Generation Connection Incentive Scheme for demand management related expenditure.

The benefits associated with this expenditure (eg the benefits of deferred network augmentation, improvements in service quality or other operational efficiencies) may be passed on to consumers by DNSPs over time in the form of lower network charges and/or higher quality service.

4.8.4 Bypass options for DNSPs

In submissions and workshops, several DNSPs proposed that they should be able to retain their existing metering installations and use them as network devices if they were replaced as the Metering Coordinator and were unable to negotiate access to network-related services from the new Metering Coordinator on acceptable terms. This was a particular issue for the Victorian DNSPs, who wished to retain access to the network-related functions of their AMI meters if a new Metering Coordinator was appointed.

Several DNSPs proposed that they should be able to install new network devices, to provide a bypass threat in negotiations with Metering Coordinators for access to network-related services.

The draft rule addresses these issues by introducing new provisions relating to network devices. A network device is defined as "an item of apparatus or equipment associated with the provision or the monitoring of *network services* which may include circuit breakers and control equipment and which may be housed within a *facility* that was previously used by the relevant *Local Network Service Provider* as a *metering installation*".

This definition is intended to cover a variety of new and existing network devices that may be used by DNSPs, including:

- existing load control equipment; and
- existing advanced meters that can be used for the purposes of operating or maintaining the DNSP's network, including the AMI meters that were deployed by Victorian DNSPs.

Under the draft rule, a DNSP may install a network device at or adjacent to a metering installation for the purposes of monitoring or operating the local network.

So that the network device provisions are not used to avoid the restrictions in the NER on access to energy data and services provided by a metering installation, the draft rule contains restrictions on the use of the network device and the disclosure of any information contained in a network device.

Metering Coordinators have new obligations in relation to network devices to:

- cooperate with a DNSP that wishes to install a network device and provide all reasonable assistance to facilitate the installation of the network device at or adjacent to the metering installation; and
- not remove, damage or render inoperable a network device that has been installed at or adjacent to a metering installation, except with the consent of the DNSP.

This second requirement means that, following the installation of a meter that meets the minimum services specification, the DNSP must still have ability to use the network device, for example to turn off and on the controlled load.[126] This requirement applies to all network devices, regardless of whether the DNSP is currently using the functionality of the device.

The Commission recognises that allowing a DNSP to install a network device at a connection point to assist in the monitoring or operation of its network could lead to an inefficient duplication of assets. However, it expects that in most cases the threat of bypassing a metering installation may be sufficient to constrain any exercise of market power by the Metering Coordinator when negotiating with the DNSP to provide equivalent network-related services through the metering installation.

4.9 Arrangements for Victoria

In 2006, the Victorian Government mandated a rollout of advanced meters (the AMI program). Subject to certain limited exceptions, the Victorian DNSPs were required to deploy advanced meters (in accordance with a prescribed Victorian minimum specification) to all Victorians consuming up to 160 MWh of electricity per annum. There are now approximately 2.8 million meters installed across the state.

The Commission has taken this into account in assessing how the proposed transitional arrangements will operate in Victoria.

With the technology already in place to enable small customers to make more informed decisions about their consumption and product choice, and for industry to offer more innovative products and achieve a range of efficiencies, the focus in Victoria is now on delivering the expected benefits of the AMI program. That is not to say that the draft rule has no role to play in Victoria.

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126 Clause 7.8.6(c) of the NER in the draft rule contains several restrictions on the use of network devices. These restrictions are intended to prevent network devices being used to avoid the NER restrictions on access to energy data and services provided by a metering installation. One of these restrictions is that the network device must not be used to reconnect or disconnect a metering installation via remote access, as these services should be performed by the Metering Coordinator using the metering installation. This restriction is not intended to prevent the DNSP using a network device for load control purposes. Load control involves stopping the flow of electricity to a particular appliance or point of consumption at the premises rather than stopping the flow of electricity entirely to the premises. Accordingly, the Commission does not consider that load control falls within the existing definitions of "disconnect" or "reconnect".

The Commission has considered whether the draft rule will:

- allow the expected benefits of the AMI program to be achieved; and
- enable new investment in metering services where that is efficient.

4.9.1 Exclusivity arrangements

The rule change request proposed that the Victorian DNSPs would be the Metering Coordinator for the advanced meters they deployed under the AMI program, and may continue in this role to the exclusion of other parties for a defined period. This period would be established by the Victorian Government through a jurisdictional instrument.

Under the draft rule's transitional arrangements, the Victorian DNSPs will assume the role of initial Metering Coordinator for the meters they have deployed. Given the exit fee that will apply in Victoria (discussed below) and the likelihood that it will take time for competition to emerge in Victoria, the Victorian DNSPs are likely to remain the Metering Coordinator for the advanced meters they have deployed for some time. In addition, the DNSPs will be permitted to retain their AMI meters as network devices. There does not, therefore, appear to be significant value in extending the exclusivity period beyond the date that the draft rule, if made, becomes effective.[127]

An extension to the exclusivity arrangements is likely to act as an impediment to competition in other segments of the market where effective competition could reasonably be expected to evolve (eg at greenfield sites or at existing sites for faults).

The exclusivity period and other aspects of the current Victorian derogation in rule 9.9C of the NER will be extended until 1 July 2017 when the new Chapter 7 of the NER under the final rule (if made) commences, and the derogation will then cease to operate.

4.9.2 Exit fees in Victoria

The current regulatory framework for establishing exit fees for meters installed under the AMI program is set out in the AMI Cost Recovery Order. The COAG Energy Council's rule change request proposed that upon expiry of the exclusivity period, a regulated exit fee would apply, to allow a retailer or consumer to subsequently replace a meter installed under the Victorian AMI program.

127 Clause 9.9C of the NER, which provides for the Victorian DNSPs to be exclusively responsible for metering services, is currently due to expire on the earlier of: (1) 31 December 2016; or (2) the commencement in Victoria of a framework for competition in metering and related services for residential and small business customers under the NER; and regulatory arrangements that provide for an orderly transfer of the regulation of relevant metering installations under rule 9.9C of the NER to the regulation of metering installations under the NER.

The Commission is aware that the exit fee principles set out in the AMI Cost Recovery Order differ from the principles the AER is using in other jurisdictions.[128] However, in the Commission's view a distinction can be drawn between the exit fee to be paid in Victoria and other jurisdictions because advanced meters are already in place and these meters already have a high degree of functionality.

The regulatory framework should not encourage the inefficient replacement of existing Victorian AMI meters. It is therefore appropriate for customers, or retailers, that are considering replacing their meter to pay an exit fee that reflects the unrecovered costs of the meter and associated infrastructure, which is what the AMI Cost Recovery Order requires.

Post 2020, the manner in which the exit fee is determined will be the same as in other NEM jurisdictions and will depend on the AER's classification of metering services.[129]

4.9.3 Access to advanced metering enabled services and functions

Concerns have been raised by the Victorian DNSPs and the ENA about the potential for Metering Coordinators to exercise market power when negotiating the terms and conditions of access to services and functions that are likely to be sought by DNSPs.

The Commission has considered the potential for this to occur, and the factors that might mitigate these concerns, as discussed above and Appendix E. Although the Commission considers that regulating access to metering services is not appropriate at the start of the market, it also recognises that if Metering Coordinators do behave in this manner then it will adversely affect consumers.

As outlined above, the draft rule allows a DNSP to install or utilise an existing "network device" at or adjacent to a metering installation for the purposes of monitoring or operating its network. As a result, if Victorian DNSPs are replaced as the Metering Coordinator and are unable to reach an agreement with the new Metering Coordinator to access equivalent services through the new metering installation, they will be able to use the meters they installed as part of the AMI program as network devices. This option will allow the expected benefits of the AMI program to be realised even if a new Metering Coordinator is appointed and decides to install its own meter before the AMI meter reaches the end of its useful life.

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128 For example in NSW, where the AER proposes to allow DNSPs to recover residual capital costs (ie the capital costs the customer would have paid through annual charges had they remained a customer of a regulated metering service) through distribution use of system charges, rather than through an exit fee. See AER, Draft decision on Ausgrid distribution determination - Attachment 16 - Alternative control services, November 2014, p29-49.

129 If metering services are classified as a direct control service, the AER will have to determine the exit fee (if any) having regard to, amongst other matters, the NEO and the revenue and pricing principles (See Appendix D2.). If the AER classifies metering services as a negotiated, the AER will have no role in determining the exit fee.

4.9.4 Minimum services specification

Some stakeholders have expressed a concern about potential differences between the minimum services specification under the draft rule and the specification of meters installed under the AMI program. The Commission notes that the Victorian specification was developed for a mandated rollout of advanced meters rather than a competitive model and specifies functional requirements rather than services.

Under the draft rule, all new metering installations installed in the NEM at the connection points of small customers must meet the minimum services specification. The Commission is of the view that the minimum services specification is more appropriate in the context of the competitive framework set out in this draft determination. If Victorian DNSPs or energy service companies consider that the benefits of additional services that are not included in the minimum services specification exceed the costs, they can negotiate with the Metering Coordinator for those services to be provided.

The value of maintaining a separate specification in Victoria is therefore likely to be small, particularly when compared with the competitive benefits and economies of scale that could be achieved through the adoption of a national minimum services specification.

4.10 Other changes to the NER and NERR

This chapter is only an overview of the Commission's draft determination and draft rule. Stakeholders should review the more detailed description of the draft determination and draft rule that is set out in the appendices.

The draft rule also contains a number of consequential changes as a result of the new arrangements for the provision of metering services. The majority of these changes are contained in Chapter 7 of the NER, but some changes are made to other chapters of the NER and to the NERR.

Stakeholders should also closely review the draft rule. In particular, retailers, DNSPs, TNSPs, Metering Providers and Metering Data Providers should review the draft rule to understand how their rights and obligations would change under the draft rule.

The draft rule renumbers Chapter 7 of the NER so that provisions are more logically grouped and ordered. Published with this draft determination is a table showing how the current clauses of Chapter 7 have been reordered under the draft rule.

Also published with this draft determination to assist stakeholders is a marked-up version of the NERR showing the changes between the current version of the NERR and the NERR under the draft rule.[130] Stakeholders can also obtain a marked-up version of the re-ordered Chapter 7 of the NER on request.[131]

130 This mark-up only contains the NERR Parts and Schedules that contain amendments.

131 Due to the nature of the re-ordering process, there is some subjectivity in what is marked as a change in this document and internal cross-references are not correct, and the Commission does not guarantee its general accuracy. If stakeholders request a copy of this document, they should only use it as a general guide and must check it against the amending rule.

5 Implementation

5.1 Introduction

This chapter sets out the proposed timetable for implementing the draft rule and the interim steps that will need to be undertaken by market institutions, industry and jurisdictions before the commencement of the new Chapter 7 of the NER and the NERR under the final rule (if made).

In determining an appropriate commencement date for the new Chapter 7 of the NER, the Commission has considered the timeframes required for:

- the AER to develop and consult on a distribution ring-fencing guideline and for DNSPs to be able to comply with that guideline;
- AEMO and the IEC to develop and consult on new and updated procedures;
- AEMO to implement the necessary IT system changes to implement the draft rule; and
- industry systems development and business process changes, including design, build and testing phases.

The Commission has also considered how implementation of this rule change is likely to interact with implementation of other Power of Choice rule changes.

5.2 Implementation date

Stakeholder views

The AEMC sought stakeholder comments in November 2014 on a high-level draft implementation plan, which had been prepared in consultation with AEMO and the AER. The Commission also met with the IEC for a workshop on implementation issues.

A range of views were given in submissions on how long would be required for industry to make changes to their systems and processes to meet the requirements of the amendments to Chapter 7 of the NER, amendments to procedures, and new AER ring-fencing guidelines. Most stakeholders indicated they could not assess firm implementation timeframes until the draft determination and draft rule had been published.

Ergon Energy, ERM Power, Origin Energy and TasNetworks suggested implementation dates ranging from at least 12-18 months after the final determination is made.[132] Several DNSPs, the IEC and the ENA considered that a significant period of time would be required from the time that AEMO's final procedures and/or final build packs become available.[133] Views were also mixed on the extent to which work could be undertaken by industry prior to AEMO publishing its final procedures and system build packs.

The IEC's submission included a detailed Gantt chart setting out the steps that need to occur before implementation of this rule change, other Power of Choice rule changes and related reforms. The IEC proposed that the implementation of these changes be coordinated by a dedicated, independent program management team.[134] AGL, the ERAA, Lumo Energy and Simply Energy supported the conclusions drawn by the IEC in its submission.

We anticipate that stakeholders will now be able to provide more informed feedback on the implementation timetable proposed in this chapter as part of their submissions on this draft determination.

Commission's analysis

The draft rule contains a commencement date of 1 July 2017 for the new Chapter 7 of the NER.

Most of the amendments to the NERR will also commence on 1 July 2017. Some provisions of the draft rule will commence earlier, for example changes to Chapter 2 of the NER and some definitions - see the draft rule for more details.

Consultation with AEMO and the AER indicated that the timeframes in the draft rule should allow sufficient time for new procedures and guidelines to be developed or updated and for changes to made to AEMO's IT systems. Stakeholder comments on the implementation plan indicated that the key uncertainty related to implementation timing is how long businesses need to make changes to their systems and processes and undertake testing of those changes.

The Commission is cognisant that many industry participants proposed a later commencement date so that industry system and process changes would not commence until AEMO's procedures and or build packs are finalised, so as to reduce the risk of re-work if AEMO's final requirements change. However, those concerns need to be balanced against the costs of delaying implementation of these significant changes and the benefits to consumers and Market Participants that will arise from implementation of the new rules.

132 Ergon Energy, submission on draft implementation plan, p2; ERM Power, submission on draft implementation plan, p2; Origin Energy, submission on draft implementation plan, p1; TasNetworks, submission on draft implementation plan, p2.

133 ENA, submission on draft implementation plan, p1; Energex, submission on draft implementation plan, p2; IEC, submission on draft implementation plan, p3; United Energy, submission on draft implementation plan, p1.

134 IEC, submission on draft implementation plan, p2.

The proposed implementation dates will require industry participants to undertake some of their systems development work in parallel with AEMO finalising its procedures and build packs. However, significant work on industry systems changes are not expected to need to commence until AEMO has published its draft procedures. This approach minimises the risk of significant re-work being required while enabling the benefits of the rule change to be realised as soon as possible.

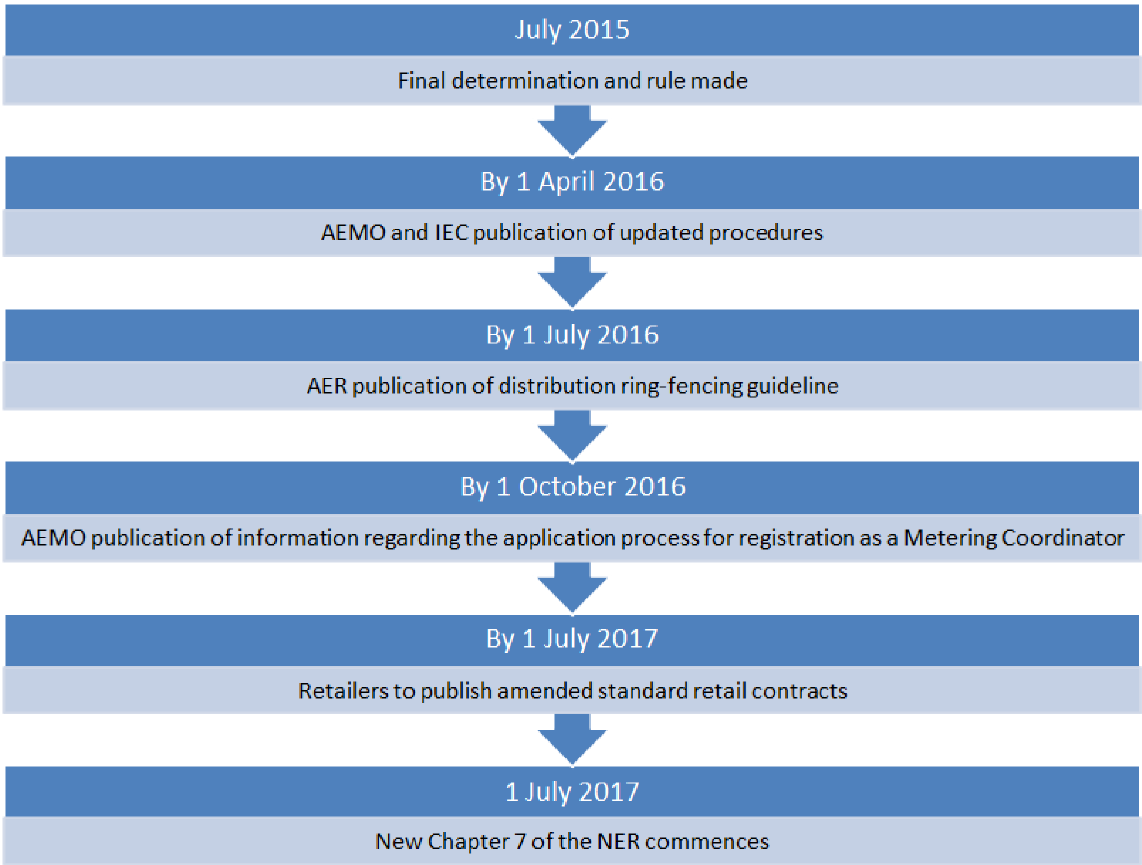
In determining an appropriate commencement date, the Commission has recognised significant inter-linkages between the various Power of Choice projects that are being undertaken and the potential to reduce costs if some of those reforms are implemented at the same time.

The AEMC will provide advice to the COAG Energy Council on the implementation and governance of the shared market protocol, including a draft rule change around the time the final determination is made on this rule change. AEMO is preparing advice to the COAG Energy Council on the content of the shared market protocol. The Commission expects the rule change and the subsequent development of the shared market protocol to be undertaken in parallel with the implementation of this metering rule change.

The AEMC intends to publish a consultation paper on the embedded networks rule change in late April/early May 2015. Depending on progress, implementation of the embedded networks rule change may be able to occur at the same time as this rule change, as was proposed by the IEC and several other stakeholders.

The implementation timeline in Figure 5.1 sets out the key interim steps that will occur leading up to the 1 July 2017 commencement date for the new Chapter 7 of the NER.

Figure 5.1 Implementation timeline



5.3 Implementation requirements

Before the new Chapter 7 of the NER commences, market institutions, the IEC, retailers and DNSPs must undertake a number of interim steps to develop procedures and guidelines and amend model contracts.

The draft rule requires the following steps to occur prior to 1 July 2017:

- It will be necessary for AEMO and the IEC to develop, or update, a number of procedures. These procedures will need to cover the matters set out in Table 5.1 below. The draft rule requires the final procedures to be published by 1 April 2016.

- The draft rule requires the AER to develop a distribution ring-fencing guideline. As outlined in Chapter 4, this guideline is expected to set out, among other things, any applicable ring-fencing requirements for a DNSP that takes on the Metering Coordinator, Metering Provider and/or Metering Data Provider roles. So that DNSPs have sufficient time to put in place the necessary ring-fencing arrangements, the AER will be required to develop and publish the guideline by 1 July 2016.

- The draft rule requires that the Metering Coordinator be a Registered Participant. Metering Coordinators will need to gain registration from AEMO prior to the new Chapter 7 of the NER commencing. The draft rule requires AEMO to develop and publish by 1 October 2016 information relating to the process for applying for registration as a Metering Coordinator.

- Electricity and gas standard retail contracts will need to be amended by retailers and published on their websites no later than 1 July 2017. These amendments are required to reflect the changes in their obligations under the draft rule, including the retailer's obligation to:[135]
  - appoint a Metering Coordinator to provide metering services at a small customer's premises; and
  - provide small customers with prior written notice of a proposed new meter deployment and provide them with an ability to opt out of having their meter replaced in accordance with the draft rule.

Table 5.1 AEMO and IEC procedures requiring updating and development[136]

Procedure	Existing or new procedure likely to be required?	Description
Service Level Procedures for Metering Providers	Existing AEMO procedure	Details the requirements for Metering Providers. Includes Metering Provider accreditation requirements.
Service Level Procedures for Metering Data Providers	Existing AEMO procedure	Details the obligations, technical requirements, measurement processes and performance requirements for Metering Data Providers. Includes Metering Data Provider accreditation requirements.
Market Settlement and Transfer Solution (MSATS) Procedures (including Consumer Administration Transfer Solution (CATS) Procedures)	Existing AEMO procedure	CATS procedures are used to update MSATS etc when a customer changes retailer. Only minor changes are expected to be required.
Metrology Procedure	Existing AEMO procedure	Details the obligations in relation to metrology on the Responsible Person (the Metering

135 Note that the model terms for standard retail contracts in Schedule 1 of the NERR apply to both electricity and gas. Accordingly, gas retailers will also need to amend their standard retail contracts so that they comply with the amended model terms.

136 Updates to the NMI procedure may also be required. This procedure is not required to be created under the NER, and is therefore not referred to in the draft rule.

Procedure	Existing or new procedure likely to be required?	Description
		Coordinator in the draft rule), the Financially Responsible Market Participant, AEMO, Metering Provider and Metering Data Provider.
Meter Churn Procedure	Existing AEMO procedure	Process for Financially Responsible Market Participants when a meter at a connection point is changed.
B2B Procedure	Existing IEC procedure	Procedures that relate to the B2B system for retailers, distribution businesses, Metering Providers and Metering Data Providers to communicate in relation to type 5 and 6 metering installations.
Procedures related to the minimum services specification	May be a new procedure or may be included in the existing Service Level Procedures	Procedures relating to the minimum services specification in accordance with cl. 7.8.3(c) of the NER in the draft rule. AEMO may amend the service level procedures to make provision for these procedures.
Emergency priority procedure	May be a new procedure or may be included in the existing Service Level Procedures	Procedures for managing congestion in the metering communications network during emergencies. AEMO may amend the service level procedures to make provision for these procedures.
NEM ROLR Processes	Part of existing MSATS procedures	AEMO to consider whether any amendments should be made to the ROLR procedures to manage the impacts of meter churn following a ROLR transfer (see Appendix A3).

A number of other steps must be taken by AEMO, industry and other parties leading up to the commencement of the new Chapter 7 of the NER on 1 July 2017.

The key additional implementation steps are outlined in Table 5.2. Each of these actions will need to occur by 1 July 2017.

Table 5.2 Key additional implementation actions

Implementation requirements	Person responsible
Updates to AEMO market systems	AEMO
Metering Coordinators apply to AEMO for registration	Any person seeking to be a Metering Coordinator (including DNSPs that will be the initial Metering Coordinator in relation to existing meters)

Implementation requirements	Person responsible
Metering Providers and Metering Data Providers apply to AEMO for accreditation	Any person seeking to be a Metering Provider and/or Metering Data Provider and who is not currently accredited with AEMO to perform that role or who AEMO considers needs to reapply for accreditation due to changes to the accreditation requirements
Appointment of Metering Coordinators	Financially Responsible Market Participants that are responsible for appointing a Metering Coordinator at a connection point
Appointment of Metering Providers and Metering Data Providers	Metering Coordinators[137]
Amendments to model standing offers for basic connection services (and standard connection services, if relevant) to reflect the new rules, including that connection services do not cover the provision, installation and maintenance of a metering installation at the customer's premises	DNSPs to submit proposed amendments to the AER for approval
Amendments to market retail contacts to comply with the final rule, including the retailer's responsibility for appointing a Metering Coordinator	Retailers with small customers
Industry changes to systems and business processes in order to comply with the final rule and amendments to AEMO/IEC procedures	Market Participants, Metering Providers, Metering Data Providers, and any person proposing to be a Metering Coordinator
Any actions that are required to comply with the AER's distribution ring-fencing guidelines	DNSPs
Any necessary amendments to jurisdictional safety legislation or regulations, including to address any safety issues related to remote disconnection and reconnections (see Appendix A3)	Jurisdictional safety regulators
COAG Energy Council to consider and, if determined appropriate, implement the AEMC's recommendations regarding civil penalty provisions (see Appendix G)	COAG Energy Council

137 Where a Responsible Person currently has an agreement with a Metering Provider or Metering Data Provider and the Responsible Person intends to become a Metering Coordinator, that agreement may need to be replaced or amended to comply with the final rule.

Implementation requirements	Person responsible
Amendments to the Victorian AMI Cost Recovery Order in Council to reflect the change from "Responsible Person" to "Metering Coordinator" and other consequential changes in the final rule, and any amendments that may be necessary to the AMI Specifications Order in Council (see Appendix F)	Victorian Government
Victorian Government Essential Services Commission (Victoria) to consider whether to make amendments to the Electricity Retail Code for consistency with the amendments to the NERR contained in the draft rule, eg opt out rights for new meter deployments (see Appendices C2 and F)	Victorian Government and Essential Services Commission
NSW Government to review the operation of the Accredited Service Providers scheme in light of the changes to the NER and NERR, and make any necessary amendments to the relevant legislation, regulations and/or scheme rules.	NSW Government

A Roles and responsibilities

Overview of Appendix A

Appendix A sets out the roles and responsibilities under the draft rule of the following parties:

A1 Metering Coordinators.

A2 Metering Providers and Metering Data Providers.

A3 Retailers.

A4 DNSPs.

A1 Metering Coordinators' roles and responsibilities

Summary

This appendix sets out the role and responsibilities of the Metering Coordinator under the draft rule.

Under the draft rule, the current roles and responsibilities of the Responsible Person will be performed by the Metering Coordinator . The Metering Coordinator also has additional responsibilities, which primarily relate to new and replacement metering installations installed at small customer connection points.

Under the draft rule, the Financially Responsible Market Participant at a connection point is responsible for appointing a Metering Coordinator for that connection point, other than where a large customer has appointed its own Metering Coordinator. The retailer is the Financially Responsible Market Participant for the connection points of its retail customers and will be responsible for appointing Metering Coordinators at these connection points.

Any party may act as a Metering Coordinator, provided it is registered with AEMO for that role. For example, the Metering Coordinator may be a subsidiary of a retailer that decides to expand into that business,[138] a DNSP (subject to the requirements of the AER's distribution ring-fencing guidelines),[139] an existing Metering Provider or Metering Data Provider, or any other party wishing to establish a Metering Coordinator business.

Under the transitional arrangements, the LNSP that is acting as the Responsible Person for a type 5 or 6 metering installation immediately before the commencement of the new Chapter 7 of the NER will become the initial Metering Coordinator at that connection point. The LNSP will continue in this role until another Metering Coordinator is appointed at that connection point, or the services cease to be classified by the AER as a direct control service.

Victorian DNSPs will become the initial Metering Coordinator for the advanced metering installations they deployed under the AMI program.

Certain exclusivity arrangements that currently apply to the Responsible Person role will cease to operate under the draft rule. Ending these exclusivity arrangements is expected to:

- allow increased competition in the provision of metering services, which is

138 The draft rule provides that a person may not be registered as both a Metering Coordinator and a Market Customer (eg retailer). The effect of this provision is that a retailer that wishes to establish a Metering Coordinator business will need to do so through a separate legal entity (eg a subsidiary). See Appendix A3.

139 See Appendix D3 for details on ring-fencing arrangements for DNSPs.

expected to result in lower costs for consumers;

- support investment and innovation in advanced metering; and
- increase the range of energy products and services available to consumers.

Under the draft rule, LNSPs will remain the exclusive provider of metering services for type 7 metering installations (eg metering for public lighting).

In addition to the existing obligations of the Responsible Person, the Metering Coordinator has additional obligations, including in relation to:

- security controls for managing access to small customer metering installations that meet the minimum services specification, including services provided by, and energy data held in, such installations;
- ensuring that access to all metering installations for which it is responsible and the services provided by, and energy data held in, such installations is managed in accordance with emergency priority procedures to be developed by AEMO; and
- network devices used by DNSPs for the purposes of operating or monitoring their networks.

Under the draft rule, the Metering Coordinator must be a Registered Participant.

A1.1 Introduction

This appendix sets outs the role and responsibilities of the Metering Coordinator under the draft rule. In particular, it sets out the rationale for establishing a Metering Coordinator role, the responsibilities of parties acting in the role, and the registration requirements that will apply to any party wanting to undertake the role.

This appendix covers:

- the existing arrangements relating to the provision of metering services in the NEM;
- the COAG Energy Council's rule change request for a Metering Coordinator and for jurisdictions to be able to introduce regulation to prescribe exclusivity for one or more, or a class of, Metering Coordinators providing metering services for some metering installation types;
- stakeholder views, including submissions to the consultation paper and outcomes of stakeholder workshops held by the AEMC; and
- the Commission's analysis of the key issues and reasons for the Commission's draft rule in relation to the appointment and role of Metering Coordinators.

A1.2 Current arrangements for provision of metering services in the NEM

A1.2.1 Responsibilities for the provision of metering services under the NER

The current Chapter 7 of the NER sets out the regulatory framework for the provision of metering services in the NEM. It outlines arrangements relating to matters including:

- provision, installation, accuracy and maintenance of a metering installation;
- collection and provision of metering data;
- security of, and rights of access to, metering data and energy data; and
- standards of performance and the accreditation requirements of Metering Providers and Metering Data Providers.

Under the current arrangements, a Market Participant must ensure there is a metering installation at each of the connection points in respect of which it is participating in the NEM and that the metering installation is registered with AEMO.[140] The retailer is the Market Participant required to satisfy these requirements with respect to the connection points of its retail customers.

There must also be a Responsible Person for each connection point that arranges for the installation, provision and maintenance of the metering installation, and the collection, processing and delivery of metering data.[141]

The Market Participant is required to act as the Responsible Person for a type 1-4 metering installation unless it has requested, and subsequently accepted, an offer from the LNSP to take on this role.[142] A LNSP is required to make an offer to act as the Responsible Person for a connection point with a type 1-4 metering installation when requested to do so by the Market Participant.[143]

The role of the Responsible Person is exclusively performed by the LNSP for types 5-6 metering installations at the premises of small customers. In Victoria, where the Victorian government mandated that Victorian DNSPs roll out advanced meters (the AMI program) to almost all Victorian customers consuming up to 160 MWh of electricity per annum (ie residential and small business customers), the LNSP is the Responsible Person for those advanced metering installations.

140 Current clause 7.1.2 of the NER.

141 Current clause 7.2.1 of the NER.

142 Current clause 7.2.2 of the NER, where the LNSP is the local DNSP.

143 Current clause 7.2.3(c) of the NER.

The Responsible Person is responsible for the installation and maintenance of a metering installation, and the collection, processing and delivery of metering data for the relevant metering installation.

In addition, the Responsible Person must, amongst other things, for each metering installation:

- engage a Metering Provider for the provision, installation and maintenance of that installation (unless the Responsible Person is the Metering Provider) or, subject to the metrology procedure, allow another person to engage a Metering Provider to install that installation;[144]

- engage a Metering Data Provider (unless the Responsible Person is the Metering Data Provider) to provide metering data services between the metering installation and the metering database and to parties entitled to such services under Rule 7.7(a) (except where the Responsible Person is a TNSP);[145]

- ensure that the installation is provided, installed and maintained in accordance with the NER, the metrology procedure and other procedures under the NER;[146]

- ensure that the components, accuracy and testing of the installation comply with the requirements of the NER, the metrology procedure and other procedures authorised under the NER;[147]

- ensure that the security control of the installation is provided in accordance with the NER and that associated links, circuits and information storage and processing systems are protected by security mechanisms acceptable to AEMO;[148]

- ensure that a communications interface is installed and maintained to facilitate connection to the telecommunications network, where remote acquisition is used or is to be used for the collection of metering data;[149] and

- not replace a device that is capable of producing interval energy data and is already installed in a metering installation, with a device that only produces accumulated energy data unless the metrology procedure permits the replacement to take place.[150]

144 Current clause 7.2.5(a) of the NER.

145 Current clause 7.2.5(c1) of the NER.

146 Current clause 7.2.5(d)(1) of the NER.

147 Current clause 7.2.5(d)(2) of the NER.

148 Current clauses 7.2.5(d)(3) and 7.8.1 of the NER.

149 Current clause 7.2.5(d)(4) of the NER.

150 Current clause 7.2.5(d)(7) of the NER.

A1.2.2 Economic regulation of type 5 and 6 metering services by the AER

As discussed above, the role of the Responsible Person is performed exclusively by the LNSP for types 5-6 metering installations at the premises of small customers. The price for these services is currently regulated by the AER.

The AER may classify distribution services provided by a DNSP, including metering services, as a direct control service or a negotiated service.[151] Direct control services are price regulated and divided into two subclasses – standard control services that are paid by all customers, and alternative control services that are generally only paid by users of that service. If a service is not classified by the AER it will not be subject to economic regulation under the NER.

Type 5 and type 6 metering services have generally been classified by the AER as a standard control service. This means that DNSPs charges for these metering services are bundled into distribution use of system charges that all users of the network pay. The AER is currently in the process of unbundling charges for metering services from the distribution use of system charges. This issue is discussed in Appendix D1.

A1.3 Rule proponent's view

A key element of the COAG Energy Council's proposed new framework is the establishment a separate Metering Coordinator role. This proposal was based on the principle that no party should have the exclusive right to provide these services in the NEM.

The COAG Energy Council proposed that the Metering Coordinator will take on the existing responsibilities of the Responsible Person for the provision of metering services in the NEM, as well as additional responsibilities related to the provision of advanced metering services.

More specifically, the COAG Energy Council's rule change request proposes that:

- The term “Responsible Person” be changed to “Metering Coordinator”.[152]
- The Metering Coordinator would retain the responsibilities of the Responsible Person, which could be performed by any suitably qualified party to provide metering services in the NEM. The COAG Energy Council’s rule change request noted that a retailer or LNSP (subject to any ring-fencing requirements) could perform the role if registered and accredited with AEMO.[153]
- Jurisdictions should be able to introduce regulation to prescribe exclusivity for one or more, or a class of, Metering Coordinators to coordinate metering services for some metering installation types to support the efficient provision of basic

151 Clause 6.2.1(a) of the NER.

152 COAG Energy Council, rule change request, October 2013, p7.

153 Ibid.

metering services.[154] As an example, the COAG Energy Council considers that jurisdictions might seek to prescribe that LNSPs continue to provide type 6 and/or type 7 metering services because:

— there may be little benefit in opening the provision of these services to competition, for example if a new and replacement policy prevents the installation of type 6 metering installations;

— LNSPs are currently able to take advantage of significant economies of scale in providing these services at low cost to consumers;

— it is unlikely that competition for the provision of type 6 metering services would provide small customers with a lower cost service, particularly if there are fewer type 6 metering installations being installed.[155]

- The Metering Coordinator must comply with the current provisions in Chapter 7 of the NER that relate to the Responsible Person role. In particular, the Metering Coordinator must:

  — retain overall responsibility for provision of metering services, including installation, maintenance and testing of the metering installation and the collection, processing and delivery of metering data;

  — ensure the accuracy of the metering installation and integrity and delivery of metering data; and

  — engage and coordinate the availability, dispatch, performance and payment of the Metering Provider and Metering Data Provider.[156]

- The functionality of a DNSP's existing load management devices will be retained if a meter is replaced in order to preserve the benefits of the load management scheme. A number of load management schemes currently operate in the NEM, such as switching off hot water heaters during peak periods.[157]

A1.4 Stakeholder views

The views expressed by stakeholders in their submissions to the consultation paper on the proposed Metering Coordinator role were varied.

154 COAG Energy Council, rule change request, October 2013, p17.

155 Ibid.

156 The rule change request proposes that a Metering Coordinator can also be a Metering Provider and/or a Metering Data Provider where accredited to fulfil these functions.

157 COAG Energy Council, rule change request, October 2013, p12.

Some stakeholders considered that there would be competition benefits from allowing any party to take on the role of Metering Coordinator, while combining the Metering Coordinator and the Metering Provider may limit competition.[158]

Other stakeholders considered that the costs of introducing the contractual arrangements and information interactions between retailers and the Metering Coordinator are likely to outweigh the benefits of having the Metering Coordinator role separate from the Market Participant (eg retailer).[159] Other stakeholders considered that the roles and responsibilities of the Metering Coordinator could be accommodated within the existing Responsible Person, Metering Provider and Metering Data Provider roles.[160]

Following the first stakeholder workshop on 26 June 2014, most stakeholders generally supported the proposal that the Metering Coordinator should take over the existing Responsible Person role and that any party should be able to perform the role provided they satisfy the relevant registration requirements. Most stakeholders were also of the view that the roles and responsibilities of the Metering Coordinator should be separate from the roles and responsibilities of the retailer, Metering Provider and Metering Data Provider. It was generally considered by stakeholders that this would better align responsibilities with the operational aspects of each role.

Stakeholders presented mixed views in submissions on the proposal that jurisdictions should be able to prescribe exclusivity for one or more, or a class of, Metering Coordinators to coordinate metering services for some metering installation types to support the efficient provision of basic metering services.

Some stakeholders were of the view that exclusivity arrangements may be suitable for type 6 and 7 metering services because there is no apparent benefit of opening these services up to competition.[161] Several DNSPs saw themselves as having an ongoing role to provide a basic, regulated metering service.[162] However, SA Power Networks considered that if the NER allowed jurisdictions to prescribe exclusivity to Metering Coordinators, this should not be limited to certain metering types.[163]

The AER suggested that exclusivity arrangements be removed where competition is possible, but maintained where competition is unlikely to emerge or be effective. It proposed that DNSPs retain exclusivity for regulated metering services for type 5 and type 6 metering installations at the time the rule change commences so that metering costs do not change in the transition.[164]

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158 Origin Energy, submission on consultation paper, p3.

159 Simply Energy, submission on consultation paper, p1; ESAA, submission on consultation paper, p2.

160 SA Power Networks, submission on consultation paper, p5.

161 Vector, submission on consultation paper, p9; EDMI, submission on consultation paper, p8; Simply Energy, submission on consultation paper, p7; Energex; submission on consultation paper, p3.

162 NSW DNSPs, submission on consultation paper, p10; Ergon Energy, submission on consultation paper, p8.

163 SA Power Networks, submission on consultation paper, p6.

164 AER, submission on consultation paper, p4,6.

Lumo Energy considered that jurisdictions should only be able to prescribe exclusivity arrangements where a consumer is not directly involved, ie for type 7 metering only. It considered that allowing exclusivity arrangements for other meter types would increase investment risks to the market and threaten national consistency.[165]

Origin Energy was of the view that exclusivity arrangements for type 6 metering would not be required because DNSPs, as the default Metering Coordinator for type 6 meters under the framework proposed in the rule change request, are unlikely to be challenged by other parties.[166] Metropolis considered that there might be a Metering Coordinator who can provide an efficient, cost effective manually read metering service, and that exclusivity arrangements would close down opportunities for competition that may be beneficial to the market.[167]

Several stakeholders were of the view that exclusivity arrangements should not be permitted at all because they would increase investment risk, limit competition and compromise national consistency.[168]

A1.5 Commission's analysis

In assessing the implications of the COAG Energy Council's rule change request to create a new role of 'Metering Coordinator', the Commission has considered whether the draft rule will:

- encourage consumer participation and increase choice of energy services and products that reflect consumer needs and preferences;
- provide energy services at an efficient cost to consumers;
- facilitate competition between commercial parties to supply consumers with the products and services they want in a cost effective way;
- reduce barriers to entry into the market for the provision of metering services;
- support innovation and efficient investment in metering services over time;
- maximise overall electricity system and market efficiency;
- allocate new obligations associated with any new responsibilities to the party best placed to carry out those obligations;

165 Lumo Energy, submission on consultation paper, p5.

166 Origin Energy, submission on consultation paper, p4.

167 Metropolis, submission on consultation paper, p5.

168 Secure Australasia, submission on consultation paper, p1; ERAA, submission on consultation paper, p2; AGL, submission on consultation paper, p5; Metropolis, submission on consultation paper, p5; PIAC, submission on consultation paper, p1; Simply Energy, submission on consultation paper, p7; EDMI, submission on consultation paper p8.

- promote transparency and predictability in the regulatory framework to assist business confidence, and information for consumers; and
- keep administrative burden and transaction costs as low as practicable, to reduce the costs passed on to consumers.

This section sets out:

- the Commission's reasons for establishing a separate Metering Coordinator role;
- the Commission's reasons for not including provisions in the draft rule that would prescribe a process by which a Metering Coordinator or class of Metering Coordinators could be given the exclusive right by jurisdictions to provide certain types of metering services;
- a description of how Metering Coordinators will be appointed;
- a description of the role of the Metering Coordinator, including its main obligations under the draft rule; and
- the Commission's reasons for requiring that a Metering Coordinator be a Registered Participant.

A1.5.1 A separate Metering Coordinator role

The Commission considered the COAG Energy Council's proposal for a separate Metering Coordinator role and potential alternatives. These alternatives included allocating responsibility for the provision of metering services exclusively to the Market Participant at the connection point, or alternatively, the Responsible Person role being combined with the existing Metering Provider role.

The Commission considers that allocating the role of providing all metering services exclusively to the Market Participant would limit the number of parties able to provide metering services and consequently hinder competition.

Metering is not a core role for retailers. Some retailers, in particular smaller retailers, may not wish to have any responsibility for metering services (other than the obligation to appoint a Metering Coordinator) and the associated liability for any breach of the metering provisions of the NER. The establishment of a Metering Coordinator role allows those retailers to appoint a party that specialises in metering services to be responsible for metering issues. Requiring the retailer to be responsible for metering may increase costs for smaller retailers or discourage entry by new retailers.

Combining the Metering Coordinator and the Metering Provider roles is also not appropriate. At a very general level, the Metering Coordinator role involves managing the relevant commercial arrangements required to provide metering services in accordance with the regulatory framework, while the Metering Provider and Metering

Data Provider roles relate to the day-to-day management and provision of such services.[169]

As the requisite capabilities and responsibilities for each role are significantly different, under the draft rule the Metering Coordinator, Metering Provider and Metering Data Provider are separate roles. This will allow different parties to enter into the market for each role, reducing the barriers to entry and potentially increasing the number of parties competing to undertake each role. Separation of the roles allows the most appropriately resourced and qualified parties to compete to provide the most efficient, safe and reliable metering services. However, the draft rule does not prevent a party from undertaking all three roles if it is registered and accredited by AEMO to do so. This allows greater flexibility for participants in the NEM when considering different business models.

While the Metering Coordinator, Metering Provider and Metering Data Provider are separate roles under the draft rule, the Commission considers that it is important that a single party is responsible for the provision of metering services.

In general terms, while the Metering Coordinator must appoint a Metering Provider for the provision, installation and maintenance of a metering installation and a Metering Data Provider to provide metering data services, the Metering Coordinator continues to have overall accountability for metering services under the NER.

The Commission considers that establishing the Metering Coordinator role and allowing any party that satisfies the applicable registration requirements to take on that role is likely to increase competition and reduce barriers to invest in advanced metering services. This is likely to lead to lower costs for consumers.

A1.5.2 Metering Coordinator exclusivity arrangements

The Commission understands that the purpose of the COAG Energy Council's proposed exclusivity arrangements is to mitigate the risk that:

- competition may not emerge in a particular market segment or region, in which case a jurisdiction might wish to impose an exclusivity arrangement such that small customers receive regulated metering services in relation to type 5 or type 6 metering installations;
- small customers could be adversely affected by competition because the costs of type 5 or 6 metering services are expected to increase, for example due to a loss of economies of scale in meter reading as other small customers have their meters read remotely; and/or
- a market could be created for the provision of type 5 and 6 metering services, which was previously only the responsibility of the DNSP, if consumers are able

169 The roles of the Metering Provider and Metering Data Provider are discussed in Appendix A2.

to opt out of receiving a metering installation that meets the minimum services specification thereby slowing the deployment of advanced meters.

The Commission considers the above concerns are addressed in the draft rule through alternative means to those proposed by the COAG Energy Council, as discussed below.

Further, the purpose of this rule change is to facilitate competition in the provision of metering services. This objective is in part achieved by removing the exclusivity that retailers (as Market Participants) and LNSPs currently have to provide metering services with respect to certain types of metering installations, and allowing other parties to offer services in this market.[170] The Commission considers that this approach is likely to lead to lower costs and increased choice for consumers.

As discussed below, an LNSP that is the Responsible Person for type 5 and 6 metering installations immediately before the commencement of the new Chapter 7 of the NER will become the initial Metering Coordinator at that connection point. The LNSP will continue in this role until another Metering Coordinator is appointed to the connection point, or the services cease to be classified by the AER as a direct control service. Small customers will therefore continue to receive metering services, which are subject to price regulation, in relation to existing type 5 and 6 metering installations for as long as the service remains classified a direct control service.

As discussed in Appendix C1, the draft rule requires that all new and replacement metering installations for small customer connection points must meet the minimum services specification. Small customers will not be able to opt out of receiving a metering installation that meets the minimum services specification in maintenance replacement, fault or new connection scenarios.[171] Consequently, there is no need for jurisdictions to prescribe exclusivity arrangements for a particular Metering Coordinator to provide services in respect of type 5 and 6 metering installations because the draft rule will prevent these metering installation types from being installed for small customers.

The draft rule does not prevent a retailer (as the Financially Responsible Market Participant) appointing a party other than the DNSP to be the Metering Coordinator for existing type 5 and 6 metering installations. However, this is unlikely to generate a large market for the provision of services for type 5 and 6 metering installations because:

- all new and replacement metering installations for small customers must meet the minimum services specification.[172] This means that existing type 5 and 6 metering installations will gradually be replaced as they become faulty, the small customer takes up a product or service that requires a new meter to be installed, or the retailer carries out a "new meter deployment" or "maintenance replacement" (see Appendix C2); and

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170 Other than for type 7 metering installations, as discussed below.

171 This is discussed further in Appendix C2.

172 Subject to a limited AEMO exemption power - see Appendix C1.

- while the retailer may replace the LNSP as Metering Coordinator where the LNSP is the initial Metering Coordinator, neither the retailer nor the incoming Metering Coordinator will acquire the existing meter at the premises as result of the retailer's appointment of another Metering Coordinator. Accordingly, a new Metering Coordinator would only be able to take over the provision of type 5 or 6 metering services from a LNSP if it also reached a commercial agreement to acquire or lease the existing meter or appoint the LNSP as the Metering Provider.

In addition, the Commission is concerned that the proposed exclusivity arrangements would:

- increase investment uncertainty;
- impede innovation; and
- limit consumer choice in energy products and services.

The Commission is therefore of the view that, other than in relation to type 7 metering installations, giving a particular party or class of parties (such as retailers or DNSPs) the exclusive right to perform the Metering Coordinator role for certain metering installation types (as proposed in the rule change request) is inconsistent with the purpose of this draft determination. Exclusivity arrangements would mean the provision of metering services would not be subject to the competitive pressures that constrain prices and encourage service improvements.

For reasons discussed in Appendix D1, the Commission agrees that it is appropriate to retain the existing arrangement that requires the LNSP to be the Responsible Person for type 7 metering installations.

The Commission does not see value in establishing arrangements to allow other parties to provide type 7 metering installations given the limited evidence that competition is likely to emerge for these services.

A1.5.3 Appointment of Metering Coordinators

Under the draft rule, the Financially Responsible Market Participant at a connection point is responsible for appointing a Metering Coordinator for that connection point, other than where a large customer has appointed its own Metering Coordinator (see Appendix B1 for appointment by large customers).[173]

The retailer is the Financially Responsible Market Participant for the connection points of its retail customers and, as such, will be responsible for appointing Metering Coordinators at these connection points.

173 Clause 7.6.2 of the NER in the draft rule.

Any party may act as a Metering Coordinator, provided it is registered with AEMO to perform that role:

- If a retailer wishes to perform the Metering Coordinator role itself, it will need to establish a separate legal entity (eg a subsidiary) to perform the role. For the reasons explained in Appendix A3, the draft rule provides that a person that is a Market Customer (eg retailer) may not be registered as a Metering Coordinator.[174]

- A DNSP may be a Metering Coordinator, provided that it complies with any distribution ring-fencing requirements established by the AER.

- An existing Metering Provider or Metering Data Provider, or any other party, could also become a Metering Coordinator.

The relevant Financially Responsible Market Participant will enter into a commercial arrangement to appoint the Metering Coordinator, other than where a large customer has entered into such arrangement with the Metering Coordinator for the relevant connection point. This arrangement will set out the terms and conditions on which the Metering Coordinator provides services, including the price for those services.

Metering Coordinators may also enter into agreements to provide services that utilise the metering installation to other parties who are entitled to access those services under the NER or have the customer's consent, subject to provisions in the draft rule relating to access to, and security of, the metering installation. The Metering Coordinator will charge those other parties for the provision of those services.

Payment for Metering Coordinator services

Generally, the Financially Responsible Market Participant is currently responsible for payment of all metering services costs at the connection point.[175]

Under the new arrangements, Financially Responsible Market Participants will appoint Metering Coordinators (other than where a large customer has done so) and will enter

174 This restriction has been introduced under the draft rule to address concerns that if a retailer is also a Metering Coordinator at a connection point and the customer at that connection point changes retailers (but the Metering Coordinator does not change), the former retailer may have continued access to the customer's energy and metering data. In such circumstances, the former retailer would no longer be entitled to access that data under the NER in its capacity as a retailer or Financially Responsible Market Participant (as it would cease to hold these positions in respect of the connection point), but the Metering Coordinator would be entitled to access the data. If the Metering Coordinator and former retailer were part of the same legal entity, the Confidential Information provisions in the NER (see clause 8.6) would not be sufficient to ensure that such data collected by the Metering Coordinator business was not provided and used by the retail business being operated by the one entity. Access to this data could limit retail competition by creating an uneven playing field where retailers that were also Metering Coordinators would have access to valuable information that other retailers are not permitted to access under the NER.

175 The current clause 7.3A(a) of the NER sets out the services to which such costs relate. This includes, amongst other things, costs associated with installing the meter, metering data services and preparing settlements ready data.

into a contract with them setting out the terms of that appointment, including payment arrangements. Metering Coordinators may also enter into agreements to provide services to other parties, as discussed above, and charge those other parties for those services.

As discussed in Appendix E, the price for access to services provided by Metering Coordinators will not be regulated under the draft rule.[176]

It is therefore not necessary or appropriate for the NER to provide that the Financially Responsible Market Participant is responsible for payment for all metering services. Instead, payment arrangements should be left for commercial agreements. Accordingly, the current clause 7.3A of the NER has been removed from the draft rule.[177]

Instead, clause 7.6.1 of the NER in the draft rule provides that:

- a Metering Coordinator assumes responsibility in respect of a connection point on terms and conditions (including as to price) to be commercially agreed between the Metering Coordinator and the Financially Responsible Market Participant or large customer who appoints the Metering Coordinator; and
- a Metering Coordinator may supply services on terms and conditions (including as to price) to be commercially agreed between the Metering Coordinator and the requesting party.

A similar approach has been taken to certain other current provisions in the NER that address payments for services provided by the Metering Provider or Metering Data Provider. The current clauses 7.11.2(b) and S7.2.1(b) of the NER have accordingly been removed in the draft rule, as the issues that they address are more appropriately dealt with by commercial arrangements under the new framework.

Transitional arrangements for existing type 5 and 6 metering installations

As noted above, the LNSP that is acting as the Responsible Person for type 5 and 6 metering installations immediately before the commencement of the new Chapter 7 of the NER will become the initial Metering Coordinator at that connection point.

The LNSP will continue in this role until another Metering Coordinator is appointed at that connection point for example when the meter is replaced because it becomes faulty or the retailer carries out a new meter deployment), or the services cease to be classified by the AER as a direct control service.

176 See Appendix E for further details. Where an LNSP is acting as the initial Metering Coordinator for existing type 5 or type 6 metering installations, the price for those services will continue to be regulated by the AER as a direct control service.

177 The current clause 7.3A(c) of the NER, which relates to payment for functions undertaken by AEMO, is retained as clause 7.5.2 of the NER in the draft rule. The current clause 7.3A(e) of the NER is retained (subject to certain consequential amendments) under the draft rule in clause 7.9.3(f) of the NER.

The Victorian DNSPs will become the initial Metering Coordinator for the advanced meters they deployed under the AMI program. They will continue as the Metering Coordinator until a new Metering Coordinator is appointed or the relevant services cease to be classified by the AER as a direct control service

To implement this initial appointment of the LNSP as Metering Coordinator, the transitional provisions in the draft rule provide that:

- at least three months prior to the commencement of the new Chapter 7 of the NER, the LNSP must provide each Financially Responsible Market Participant with a standard set of terms and conditions on which it will agree to act as the Metering Coordinator;
- unless the Financially Responsible Market Participant and LNSP agree other terms and conditions prior to the commencement of the new Chapter 7 of the NER, the LNSP will be deemed to be appointed as the Metering Coordinator on the LNSP's standard terms and conditions.

The draft rule also provides that the terms and conditions on which the LNSP is appointed as Metering Coordinator in such circumstances must:[178]

- include terms as to price which are consistent with Chapter 6 (and, where relevant, Chapter 11) of the NER (ie the price will be the price as regulated by the AER);
- include a scope of services which is consistent with the responsibilities of the Metering Coordinator under Chapter 7 of the NER;
- provide that the Financially Responsible Market Participant may terminate an appointment on reasonable notice to the Metering Coordinator;
- not prevent, hinder or otherwise impede a Financially Responsible Market Participant from replacing the LNSP with another Metering Coordinator after the commencement of the new Chapter 7 of the NER; and
- include other terms and conditions as may be agreed between the LNSP and the Financially Responsible Market Participant.

Type 7 metering installations

LNSPs currently act as the Responsible Person for all type 7 metering installations.[179] The draft rule requires the LNSP to take on the Metering Coordinator role for all type 7 metering installations.

178 See clause 11.78.7 of the NER in the draft rule.

179 Type 7 metering installations no not involve a physical metering service but rather a reconciliation between DNSPs and the users of that service using an algorithm to determine the throughput of energy, eg for public lighting and traffic lights.

To give effect to the initial appointment of the LNSP as the Metering Coordinator for type 7 metering installations, the draft rule provides that:[180]

- the LNSP must provide the Financially Responsible Market Participant with a standard set of terms and conditions on which it will agree to act as the Metering Coordinator for a type 7 metering installation;
- the terms and conditions of the LNSP's offer must be fair and reasonable and must not have the effect of unreasonably discriminating between Financially Responsible Market Participants or between customers of a Financially Responsible Market Participant; and
- a Financially Responsible Market Participant must accept an offer on the standard terms and conditions of appointment provided by the LNSP, unless the Financially Responsible Market Participant and LNSP agree other terms and conditions.

Transmission connection points and interconnectors

The requirement to appoint a Metering Coordinator will also apply to transmission network connection points.

However, in relation to transmission connection points, the draft rule provides that the Financially Responsible Market Participant may request that the LNSP offer to act as the Metering Coordinator.[181] This provision reflects the current NER arrangements that require LNSPs to offer to act as the Responsible Person for type 1 to 4 metering installations in certain circumstances.

This requirement has been included due to concerns that its removal could mean that there may not be any party with the appropriate capabilities and expertise available to act as the Metering Coordinator at transmission network connection points. This is because the technology for these metering installations is specialised and there are only a relatively small number of such connection points. The Commission also understands that currently the Responsible Person for the majority of these connection points is the TNSP.

The arrangements for interconnectors are not changed under the draft rule. Under clause 7.2.1(c) of the NER in the draft rule, the TNSP (and not the Responsible Person) is responsible for the provision, installation and maintenance of the metering installations for interconnectors.

The current NER provisions on joint metering installations are also not amended by the draft rule.[182]

180 Clause 7.6.4 of the NER in the draft rule.

181 Clause 7.6.3 of the NER in the draft rule.

182 Clause 7.8.12 of the NER in the draft rule.

The Commission understands that the joint metering installation provisions are intended to address circumstances where an interconnector has two metering installations ie there is one connection point with a metering installation at either end of the interconnector.

A1.5.4 Role and responsibilities of the Metering Coordinator

The Metering Coordinator will take on all of the current responsibilities of the Responsible Person as summarised above.

Under the draft rule, the Metering Coordinator is responsible for appointing a Metering Provider and Metering Data Provider in accordance with the NER. However, in general terms, the Metering Coordinator continues to have overall accountability for metering services under the NER.

For example, the Metering Coordinator must appoint a Metering Provider for the provision, installation and maintenance of each metering installation.[183] However, the Metering Coordinator remains responsible for ensuring that the metering installation is installed and maintained in accordance with the NER and relevant procedures.[184]

A Metering Coordinator may choose to become accredited as a Metering Provider and/or Metering Data Provider and also carry out those roles.

Table A1.1 provides a general overview of the core obligations of a Metering Coordinator. This table distinguishes between those obligations which are currently obligations imposed on the Responsible Person as well other additional obligations being imposed on the Metering Coordinator under the draft rule.

Table A1.1 General overview of core obligations of a Metering Coordinator

Obligations	Existing or new obligation
Existing obligations of the Responsible Person in relation to metering installations and data	
Existing obligations of the Responsible Person in Chapter 7 of the NER with respect to the provision, installation and maintenance of metering installations. For example: • Ensure the security of metering installations and the accuracy of metering data.[185] • Appoint and coordinate the performance of the Metering Provider and the Metering Data Provider.[186]	Existing

183 Clause 7.3.2(a)(1) of the NER in the draft rule.

184 See clause 7.3.2(e)(1) of the NER in the draft rule.

185 Clause 7.3.2(e) of the NER in the draft rule.

186 Clause 7.3.2(a) of the NER in the draft rule.

Obligations	Existing or new obligation
• Ensure that metering installations are provided, installed and maintained in accordance with the NER and procedures.[187] • Ensure that metering data services are provided in accordance with the NER and procedures.[188] • Ensure that energy data held in the metering installation is protected from direct local or remote electronic access by suitable password and security controls.[189] • Manage metering installation malfunctions, inspections, testing and auditing etc.[190] • Data obligations as required by AEMO procedures.[191]	
Minimum services specification	
Ensure that any new or replacement metering installation for small customers is a type 4 metering installation that meets the minimum services specification (see Appendix C1).[192]	New
Security controls for managing access to small customers' metering installations	
For small customers' metering installations that meet or are required to meet the minimum services specification, ensure that: • access to energy data held in the metering installation is only given to a person and for a purpose that is permitted under the NER; and • access to services provided by the metering installation and metering data from the metering installation is only given to: — in respect of a service listed in the minimum services specification, and metering data in connection with that service, an access party listed in Table S7.5.1.1 of the NER; or — a person and for a purpose to which the small customer has given its prior consent; or — a person and for a purpose that is permitted under the NER.[193]	New

187 Clause 7.3.2(e)(1) of the NER in the draft rule.

188 Clause 7.3.2(g)(2) of the NER in the draft rule.

189 Clause 7.15.3(a) of the NER in the draft rule.

190 Clause 7.8.10(a) of the NER (malfunctions) and clause 7.9.1 of the NER (inspection, testing and audit) in the draft rule.

191 Clause 7.3.2(g) of the NER in the draft rule.

192 Clause 7.8.3 of the NER in the draft rule.

Obligations	Existing or new obligation
For small customers' metering installations that meet or are required to meet the minimum services specification, ensure that the services provided by the metering installation are protected from local access and remote access by suitable password and security controls.[194]	New - extension of the current obligation that applies for all customers' metering installations in relation to energy data
Emergency management	
For all connection points for which the Metering Coordinator is responsible, ensure that access to the metering installation, services provided by the metering installation and energy data held in the metering installation are managed in accordance with emergency priority procedures to be developed by AEMO.[195]	New
Other obligations	
Cooperate with an LNSP who wishes to install a network device for the purposes of operating or monitoring its network, and provide all reasonable assistance to facilitate the installation of the network device at or adjacent to the metering installation.[196]	New
Not remove, damage or render inoperable a network device that has been installed by an LNSP at or adjacent to a metering installation, except with the LNSP's consent.[197]	New
Not prevent, hinder or otherwise impede an LNSP from locally accessing a metering installation or connection point for the purposes of reconnecting or disconnecting the connection point.[198]	New
Registration	
Be registered as a Registered Participant.[199]	New

Security controls for managing access to small customers' metering installations

People seeking to access services provided by a metering installation will need to negotiate the access with the Metering Coordinator through commercial negotiation. Such parties may include energy service companies seeking to provide services to consumers or a DNSP or retailer seeking access to services, such as remote disconnection/reconnection services.

193 Clause 7.15.4(a) and (b) of the NER in the draft rule.

194 Clause 7.15.4(c) of the NER in the draft rule.

195 Clause 7.8.5 of the NER in the draft rule.

196 Clause 7.8.6(b)(1) of the NER in the draft rule.

197 Clause 7.8.6(b)(2) of the NER in the draft rule.

198 Clause 7.15.2(g) of the NER in the draft rule.

199 Clause 2A.4.1 of the NER in the draft rule.

In its advice to the COAG Energy Council on how access to advanced metering services should be managed ("Open Access review"), the Commission outlined a framework for open access and common communication standards to support competition in energy services enabled by advanced meters. The Commission made a number of recommendations, including the need for a "gate keeper" role to manage access and security for small customer's advanced meters.[200]

The draft rule contains additional security controls for "small customer metering installations" to implement this gate keeper function.[201]

These new provisions only apply to "small customer metering installations", ie any metering installation that meets or is required to meet the minimum services specification.[202]

Under these provisions, new requirements have been introduced with respect to local and remote access to the metering installation, services provided by the metering installation (eg remote disconnection or reconnection services or load control services), and the energy data held in the metering installation.

Under the draft rule, the Metering Coordinator must ensure that:

- access to energy data held in the metering installation is only given to a person and for a purpose that is permitted under the NER; and
- access to services provided by the metering installation and metering data from the metering installation is only given to:
  - in respect of a service listed in the minimum services specification, and metering data in connection with that service, an access party listed in Table S7.5.1.1 of the NER; or
  - a person and for a purpose to which the small customer has given its prior consent; or
  - a person and for a purpose that is permitted under the NER.[203]

The draft rule provides that only certain parties are permitted to request access to the services listed in the minimum services specification. These parties are:[204]

- For the remote scheduled meter read service and the remote on-demand meter read service: Parties listed in clause 7.15.5(a) of the NER in the draft rule (ie

200 AEMC, Framework for open access and common communication standards, Final advice, AEMC, 10 April 2014.

201 See clause 7.15.4 of the NER in the draft rule.

202 See the new definition of "small customer metering installation" in Chapter 10 of the NER. This definition does not cover manually read meters that are classified as type 4A metering installations - see Appendix C1.

203 See clauses 7.15.4(a) and (b) of the NER in the draft rule.

204 See Table 7.5.1.1 of the NER in the draft rule.

parties that are entitled to access energy and metering data). These parties include:

- the Financially Responsible Market Participant and LNSP at the connection point;
- certain parties such as the AER and Ombudsmen;
- any other person who has a small customer's prior consent; or
- a large customer or a "customer authorised representative" of that large customer.

- For the remote disconnection and reconnection services, and the advanced meter reconfiguration service: The Financially Responsible Market Participant (eg retailer) and DNSP.
- For the meter installation inquiry service: The Financially Responsible Market Participant, the LNSP, and any person who has a small customer's prior consent.

Access to any additional services that are provided by a small customer's metering installation but are not listed in the minimum services specification can only be provided to a person and for a purpose:

- in relation to which the small customer has given its prior consent; or
- that is permitted under the NER.[205]

Under the draft rule, the Metering Coordinator must also ensure that services provided by a small customer metering installation are protected from local access and remote access by suitable password and security controls in accordance with the NER.[206]

The draft rule amends which parties can obtain passwords allowing local access or remote access to the metering installation, services provided by the metering installation or energy data held in the metering installation in relation to small customer metering installations. Only the Metering Coordinator, Metering Provider, Metering Data Provider and AEMO will have local or remote access.

As an extension of its current obligations, the Metering Provider must ensure that no other person receives or has access to a copy of a password allowing local access or remote access to the metering installation or energy data held in the metering installation.[207]

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205 Clause 7.15.4(b) of the NER in the draft rule.

206 Clause 7.15.4(e) of the NER in the draft rule. A similar obligation currently applies to the Responsible Person for connection points for which it is responsible in relation to energy data that is held in a metering installation - see current clause 7.8.2(a) of the NER. This existing obligation is now part of the obligations under clause 7.15.4 of the NER in the draft rule.

207 Clause 7.15.4(e)(2) of the NER in the draft rule.

Appendix B3 outlines amendments that have been made to the NER provisions that set out which parties may be granted access to energy data or may receive metering data.[208]

Emergency management

The NER currently provides that the Responsible Person must ensure that access to energy data by people authorised to access that data is scheduled appropriately to ensure that congestion does not occur.[209] This requirement is retained in the draft rule, with the obligation being imposed on the Metering Coordinator.[210]

In addition, the draft rule requires Metering Coordinators to ensure that access to the metering installation, services provided by the metering installation and energy data held in the metering installation are managed in accordance with the emergency priority procedures that are established by AEMO.[211]

This obligation applies to all current and new metering installations, not just small customer metering installations.

AEMO is responsible for establishing, maintaining and publishing the emergency priority procedures, which must set out:

- the criteria for determining when an emergency condition is present and which metering installations will be affected by the emergency condition; and
- where a Metering Coordinator supplies services to an LNSP from a metering installation that is affected by an emergency condition, which services the Metering Coordinator may be required to prioritise at the request of the LNSP.

This requirement has been introduced to address situations where it may not be possible for the Metering Coordinator, Metering Provider or Metering Data Provider to process all service commands in line with the applicable service standards under the NER or the relevant contracts during periods of an unusually high volume of requests for services. This scenario is more likely to occur as the penetration of advanced meters increases.

The emergency priority procedures will only apply during emergency conditions.[212] It will provide DNSPs with greater certainty that they can rely on the services that they have negotiated to be provided by the Metering Coordinator when managing a network security issue during an emergency condition.

If there is such congestion during emergency conditions, it may be appropriate for commands from DNSPs regarding certain services to be prioritised over other

208 Clause 7.15.5 of the NER in the draft rule.

209 Current clause 7.7(c1) of the NER.

210 Clause 7.15.5(d) of the NER in the draft rule.

211 Clause 7.8.5 of the NER in the draft rule.

212 The criteria for emergency conditions will be set out in the procedures.

commands. For example, if DNSPs are required to temporarily disconnect customers due to an extreme weather event or bushfire, there is likely to be merit in those commands being prioritised over less time sensitive commands such as scheduled meter reads or software updates.

DNSPs could negotiate such priority in their contracts with the Metering Coordinator. However, there are likely to be benefits in AEMO developing a single NEM-wide definition of an emergency condition and order of prioritisation that all Metering Coordinators must comply with.

AEMO is the most appropriate body to develop and maintain the emergency priority procedures as it:

- will be familiar with the roles of the Metering Coordinator, Metering Provider and Metering Data Provider, as it will be responsible for registration and accreditation of those roles under the draft rule;
- will be knowledgeable of the technical issues associated with congestion within the communications network; and
- has an understanding of the management of network security during emergency conditions.

DNSPs must comply with the emergency priority procedures when issuing a service prioritisation request to a Metering Coordinator under those procedures.[213]

Network devices

The COAG Energy Council proposed that the functionality of a DNSP's existing load management devices must be retained if a meter is replaced.

There are many existing load management schemes that have been implemented by DNSPs in the NEM, such as off peak hot water heating. These schemes provide benefits by reducing:

- the peak demand at a location in the network, and hence the cost of maintaining a reliable supply; and
- the costs of energy at times of peak demand.

These existing load management schemes generally involve a load control device[214] at the consumer's premises. The load control device is often accompanied by multiple meters to provide the consumer with different tariffs for the controlled load and the remainder of their consumption.

213 See clause 7.8.5(c) of the NER.

214 A typical example of a load control device would be a ripple control relay. These relays turn on or off a load such as the hot water heater in response to signals injected in the electricity network by the DNSP. This allows the DNSP to remotely turn on or off blocks of consumers' hot water heaters. This is done to reduce the peak demand in their network at a time of potential overload.

In submissions and workshops, several DNSPs proposed that DNSPs should have the right to retain their existing meters and use them as network devices if they were replaced as the Metering Coordinator and were unable to negotiate access to network-related services from the Metering Coordinator on acceptable terms.[215] This was a particular issue for Victorian DNSPs, who wished to retain access to the network related functions of their AMI meters if a new Metering Coordinator was appointed.

Several DNSPs also proposed that DNSPs should be able to install new network devices, to provide a bypass threat in negotiations with Metering Coordinators for access to network-related services.

The draft rule addresses these issues by introducing new provisions relating to network devices.[216]

A "network device" is defined in the draft rule as "an item of apparatus or equipment associated with the provision or the monitoring of *network services* which may include circuit breakers and control equipment and which may be housed within a *facility* that was previously used by the relevant *Local Network Service Provider* as a *metering installation*".

This definition covers a variety of existing and new network devices that may be used by LNSPs, including:

- existing load control devices used for the purposes of operating the LNSP's network; and
- existing advanced meters that can be used for the purposes of operating or monitoring the LNSP's network, including the AMI meters that were deployed by Victorian DNSPs.

Under the draft rule, an LNSP may install a network device at or adjacent to a metering installation for the purposes of monitoring or operating its network.

So that the network device provisions cannot be used to avoid the restrictions in the draft rule on access to energy data and services provided by a metering installation, an LNSP must not:

- use a network device except in connection with the operation or monitoring of its network;
- use a network device to reconnect or disconnect a metering installation via remote access (as these services should be performed by the Metering Coordinator using the meter);
- disclose any information obtained from a network device to any person except as permitted in the NER.[217]

215 This issue is discussed in more detail in Appendix E.

216 Clause 7.8.6 of the NER in the draft rule.

The prohibition on using a network device to reconnect or disconnect a metering installation via remote access is not intended to prevent the DNSP using a network device for load control purposes. Load control involves stopping the flow of electricity to a particular appliance or point of consumption at the premises rather than stopping the flow of electricity entirely to the premises. Accordingly, the Commission does not consider that load control falls within the existing definitions of "disconnect" or "reconnect".

An LNSP also must not remove, damage or render inoperable a metering installation.

Metering Coordinators also have new obligations in relation to network devices to:

- cooperate with a LNSP who wishes to install a network device and provide all reasonable assistance to facilitate the installation of the network device at or adjacent to the metering installation; and
- not remove, damage or render inoperable a network device that has been installed at or adjacent to a metering installation, except with the consent of the LNSP.

The requirement not to remove, damage or render inoperable a network device will mean that, following the installation of a metering installation that meets the new minimum services specification, the DNSP must still have the ability to use the device, for example to turn off and on the controlled load. This requirement applies to all network devices, regardless of whether the DNSP is using the functionality of the device at the time the new metering installation is installed by the Metering Coordinator.

B2B arrangements

The draft rule also adds Metering Coordinators to the list of parties that must use the B2B e-Hub for B2B Communications.[218]

References to Metering Coordinators are also added to several provisions relating to the method for making and changing B2B procedures, for example by adding Metering Coordinators to the list of parties that may propose a change to the B2B procedures.[219]

Broader changes to the B2B procedure provisions have not been included in the draft rule and are outside of the scope of this rule change. For example, Metering

217 This requirement is needed because the information contained in a network device will not be energy data or metering data and will not be covered by the existing restrictions on disclosure and use of that data. The draft rule also provides that information obtained from a network device is confidential and must be treated as confidential information in accordance with the NER.

218 Clause 7.17.1 of the NER.

219 Clause 7.17.3 of the NER.

Coordinators have not been added to the list of people that may be members of the Information Exchange Committee (IEC).[220]

A1.5.5 Registration requirements for a Metering Coordinator

The Commission has considered the roles and responsibilities of the Metering Coordinator to determine whether the Metering Coordinator should be required to be a Registered Participant or otherwise accredited by AEMO to perform the role.

Current arrangements

Currently, the only parties that can act as a Responsible Person are Market Participants or LNSPs. Each of those parties are already a Registered Participant, eg retailers are registered as a Market Customer. Accordingly, there is no need for a separate requirement that the Responsible Person must be a Registered Participant.

Certain rights and obligations apply to all Registered Participants under the NER, including:

- participation in the NER dispute resolution process;[221]
- confidentiality obligations with respect to confidential information;[222]
- reporting requirements as determined by the AER;[223] and
- an obligation to pay participant fees to AEMO.[224]

In addition to these general rights and obligations, each class of Registered Participant has certain rights and obligations that are specific to their respective roles.

Metering Providers and Metering Data Providers must satisfy certain technical, capability and licensing requirements in order to be accredited and registered with AEMO.[225] However, Metering Providers and Metering Data Providers are not required to be Registered Participants.

Metering Coordinator to be a new class of Registered Participant

Under the draft rule, the Responsible Person’s responsibilities in relation to the provision, maintenance and installation of metering installations and metering data

220 Some of these issues will be considered as part of the AEMC's advice on the shared market protocol. For example, that advice will consider the governance arrangements for the shared market protocol, which may partly or wholly replace the B2B e-Hub and B2B procedures.

221 Rule 8.2 of the NER.

222 Clause 8.6.1(b) of the NER

223 Clause 8.7.2(e) of the NER.

224 Clause 2.1.2 (f) of the NER.

225 See current schedule 7.4 of the NER (Metering Provider) and current schedule 7.6 of the NER (Metering Data Provider).

services will be allocated to the Metering Coordinator. Metering Coordinators will have additional responsibilities as discussed earlier in this appendix.

Due to the nature of the Metering Coordinator's role and responsibilities in providing services that are essential for the operation of the NEM, it is necessary for the Metering Coordinator to be a Registered Participant. .

Registration requirements for the Metering Coordinator

The Commission has considered the nature and scope of the role and responsibilities of the Metering Coordinator in order to determine what criteria an applicant must meet in order to become registered as a Metering Coordinator.

Under the draft rule, to be eligible for registration as a Metering Coordinator, an applicant must:[226]

- not be a Market Customer;
- satisfy AEMO that it is complying with and will comply with the NER and the procedures authorised under the NER;
- have appropriate processes in place to determine that a person seeking access to a service listed in minimum service specification is an "access party" in respect of that service;
- have an appropriate security control management strategy and associated infrastructure and communications systems for the purposes of preventing unauthorised access to metering installations, services provided by metering installations and energy data held in metering installations;
- have insurance as considered appropriate by AEMO; and
- pay the prescribed fee.

A Market Customer (eg retailer) must not be registered as a Metering Coordinator. A retailer that wishes to establish a Metering Coordinator business must do so via a separate legal entity, eg a subsidiary.

DNSPs that act as the initial Metering Coordinators under the transitional arrangements will still be required to register as a Metering Coordinator. The standard registration requirements will apply.[227]

TNSPs that act as Metering Coordinators in relation to transmission connection points would also need to be registered as a Metering Coordinator.

However, the draft rule allows AEMO to exempt TNSPs from satisfying one or more of the registration requirements when the TNSP is registering as a Metering Coordinator

226 Clause 2.4A.1 of the NER in the draft rule.

227 Clause 11.78.7(f) of the NER in the draft rule.

for transmission connection points within its transmission network, subject to conditions as AEMO deems appropriate where (in AEMO's reasonable opinion) the exemptions are not inconsistent with the NEO.[228]

This exemption power is appropriate because:

- under the current NER provisions and the draft rule, a TNSP that becomes the Metering Coordinator for a connection point in its network is only responsible for the provision, installation and maintenance of the metering installation, with AEMO being responsible for collection of metering data from that metering installation, the processing of that data and the delivery of the processed data;[229] and

- the TNSP would already need to be a Registered Participant by virtue of being registered as a TNSP.

As noted above, the arrangements for interconnections do not changed under the draft rule. Accordingly, TNSPs are not required to be registered as a Metering Coordinator for the purposes of satisfying their obligation with respect to metering installations at interconnectors.

228 Clause 2.4A.1 of the NER in the draft rule.

229 Clause 7.5.1(a) and 7.2.1(c) of the NER in the draft rule.

A2 Metering Providers and Metering Data Providers' roles and responsibilities

Summary

This appendix outlines the roles and responsibilities of the Metering Provider and Metering Data Provider under the draft rule.

The Metering Provider and Metering Data Provider retain their current roles and obligations.

The general approach under the draft rule has been to impose new obligations on the Metering Coordinator rather than the Metering Provider or Metering Data Provider. This is consistent with the approach that the Metering Coordinator has overall accountability for metering services under the NER.

However, the Metering Provider and Metering Data Provider will have new obligations under the draft rule in relation to the following matters:

- In relation to "small customer metering installations" (a new defined term in the NER), the draft rule amends which parties can obtain passwords allowing local access or remote access to the metering installation, services provided by the metering installation or energy data held in the metering installation. Only the Metering Coordinator, Metering Provider, Metering Data Provider and AEMO will have local or remote access. The Metering Provider must ensure that no other person receives or has access to a copy of a password allowing local access or remote access to the metering installation or energy data held in the metering installation.
- The Metering Provider has a new obligation to ensure that any metering installation established at a connection point for a new connection (ie new house or development) must be a type 4 metering installation that meets the minimum services specification, except where a Metering Coordinator has obtained an exemption from AEMO.
- As part of the drafting of the new Chapter 7 of the NER in the draft rule, the Commission has identified that several existing obligations do not state which person is required to comply with that obligation. This is addressed in the draft rule, which specifies who is responsible for those obligations. One such obligation has been allocated to the Metering Provider (in relation to metering installation components) and one to the Metering Data Provider (in relation to periodic energy metering).
- Metering Providers and Metering Data Provider will have new obligations as a result of being deemed to be Registered Participants for the purposes of the confidentiality obligations in the NER.
- As part of the accreditation process, Metering Providers and Metering Data

Providers for "small customer metering installations" must meet an additional requirement. This requirement relates to the establishment of an appropriate security control management plan and associated infrastructure and communications systems for the purposes of preventing unauthorised local access or remote access to metering installations, services provided by metering installations and energy data held in metering installations.

A2.1 Introduction

This appendix outlines the Commission's draft rule in relation to the roles and responsibilities of a Metering Provider and Metering Data Provider under the proposed arrangements to promote competition in metering and related services.

This appendix covers:

- the COAG Energy Council's proposal regarding the role of the Metering Provider and Metering Data Provider;
- stakeholder views including submissions to the consultation paper and outcomes of stakeholder workshops held by the AEMC; and
- the Commission's analysis with respect to the roles and responsibilities of Metering Providers and Metering Data Providers and consequential changes to existing accreditation requirements.

A2.2 Rule proponent's view

The rule change request considered that the existing roles for the Metering Provider and Metering Data Provider should not change.[230]

However, the COAG Energy Council highlighted that the rule change should consider issues raised in the AEMC's review into open access and common communication standards.[231] The Open Access review (discussed further in Appendix A1) recommended that the party responsible for managing access, security and congestion to advanced meter functionality be considered as a part of this rule change.[232]

A2.3 Stakeholder views

Some stakeholders initially expressed support for the proposal to combine all of the additional responsibilities required for managing access, security and congestion to advanced meter functionality with the Metering Provider role, as an alternative to the

230 COAG Energy Council, rule change request, October 2013, p7.

231 AEMC, Framework for open access and common communication standards, Final advice, AEMC, 10 April 2014.

232 Ibid., p62.

COAG Energy Council's proposal for a separate Metering Coordinator role.[233] Other stakeholders considered that not all of the additional responsibilities, particularly those related to contract and risk management, were appropriate for the Metering Provider to carry out.[234]

At the first stakeholder workshop on 26 June 2014 stakeholders were generally in agreement that the Metering Coordinator role and Metering Provider role should be separate. Stakeholders considered that the additional roles and responsibilities related to the provision of advanced metering services should be divided between the Metering Coordinator and Metering Provider consistent with the existing roles and responsibilities of the Responsible Person and Metering Provider.

A2.4 Commission's analysis

In assessing whether any changes are required to the Metering Provider and Metering Data Provider roles, the Commission has considered:

- the nature of any new roles and responsibilities and the party that is best placed to carry out those roles and responsibilities;
- the administrative burden and transaction costs of the new roles and responsibilities;
- reducing barriers to entry into the market for the provision of metering services; and
- supporting innovation and efficient investment in metering services over time.

This section sets out:

- the roles and responsibilities of the Metering Provider;
- the roles and responsibilities of the Metering Data Provider; and
- accreditation requirements for the Metering Provider and Metering Data Provider.

A2.4.1 Metering Provider

Current role and responsibilities

As noted in Appendix A1, under the existing arrangements the Responsible Person engages a Metering Provider. This engagement is given effect through a commercial

233 ERM Power, submission on consultation paper, p6; ERAA, submission on consultation paper, p2; AGL, submission on consultation paper, p3.

234 Vector's submission to the Consultation paper.

arrangement between the Responsible Person and the Metering Provider, with supporting requirements in the NER.

The Metering Provider's responsibilities are generally related to technology management, such as the provision, installation and maintenance of the metering installation, including fault finding and repairs. Specifically, the responsibilities of Metering Providers include:

- installing and maintaining metering installations;[235] and
- programming and certifying metering installations to required standards,[236] and providing and maintaining the security controls of a metering installation.[237]

These responsibilities require a particular skill set, including technical knowledge and understanding of meters, instrument transformers, connection configurations, software access and testing regimes.[238]

Requirements under the draft rule

The draft rule requires a Metering Coordinator to appoint a Metering Provider for the provision, installation and maintenance of each metering installation it is responsible for.[239] This appointment is given effect through a commercial arrangement between the parties, with supporting requirements in the NER.

Under the draft rule, a Metering Provider retains the responsibilities it currently has under the NER, including those related to the installation, operation and maintenance of metering installations.

New roles and obligations

A number of parties including retailers, DNSPs and energy service companies may seek access to services from advanced meters.

As explained in Appendix A1, the draft rule imposes additional obligations on the Metering Coordinator in relation to managing access to "small customer metering installations",[240] including services provided by, and energy data held in, such installations.

235 Current clause 7.4.1(a) of the NER.

236 Current clause S7.4.3(b) of the NER.

237 Current clause 7.4.1(b) of the NER.

238 Current clause S7.4.3 of the NER.

239 Clause 7.3.2(a) of the NER in the draft rule.

240 In general terms, this is any metering installation that meets or is required to meet the minimum services specification - see the new definition of "small customer metering installation" in Chapter 10 of the NER in the draft rule.

For example, a Metering Coordinator must ensure that access to a small customer's metering installation, the services provided by that metering installation and the energy data held in that metering installation are only accessed by certain parties.[241]

In practice, the Metering Provider will have a role in ensuring that these obligations are met. However, the general approach under the draft rule has been to impose these new obligations on the Metering Coordinator, rather than the Metering Provider. This is consistent with the approach that the Metering Coordinator has overall accountability for metering services under the NER.

The draft rule amends which parties can obtain passwords allowing local access or remote access to the metering installation, services provided by the metering installation or energy data held in the metering installation in relation to small customer metering installations. Only the Metering Coordinator, Metering Provider, Metering Data Provider and AEMO will have local or remote access.

As an extension of its current obligations, the Metering Provider must ensure that no other person receives or has access to a copy of a password allowing local access or remote access to the metering installation or energy data held in the metering installation.[242]

The Metering Provider has a new obligation, under clause 7.8.3(b) of the draft rule, to ensure that any metering installation established at a connection point for a new connection (ie new house or development) is a type 4 metering installation that meets the minimum services specification, except where a Metering Coordinator has obtained an exemption from AEMO. Under clause 7.8.4 of the draft rule, AEMO may exempt a Metering Coordinator from complying with the requirement to install a type 4 metering installation that meets the minimum services specification in respect of a connection point if the Metering Coordinator demonstrates to AEMO’s satisfaction that there is no existing telecommunications network to enable remote access to the metering installation at that connection point.

As part of the drafting of the new Chapter 7 of the NER in the draft rule, the Commission has identified that several existing obligations do not state which person is required to comply with that obligation. This is addressed in the draft rule, which specifies who is responsible for those obligations. In one case, such an obligation has been allocated to the Metering Provider: the obligations in relation to metering installation components that are now contained in clause 7.8.2 of the NER in the draft rule.

As noted below, Metering Providers will also have new obligations as a result of being deemed to be Registered Participants for the purposes of the confidentiality obligations in the NER.

241 Clause 7.15.4 of the NER in the draft rule.

242 Clause 7.15.4(e)(2) of the NER in the draft rule.

A2.4.2 Metering Data Provider

Current role and responsibilities

Metering Data Providers have responsibilities related to the collection, processing, storage and delivery of metering data.[243] Metering Data Providers must also provide and maintain the security controls associated with metering data services in accordance with the NER.[244]

Requirements under the draft rule

The draft rule requires a Metering Coordinator to appoint a Metering Data Provider for the collection, processing, storage and delivery of metering data from each metering installation it is responsible for.[245] This appointment is given effect through a commercial arrangement between the parties, with supporting requirements in the NER.

Under the draft rule, a Metering Data Provider retains its current under the NER in relation to metering data services.

New roles and obligations

The Metering Data Provider may also have an expanded role in relation to the provision of advanced metering services. For example, the Metering Data Provider currently has a role in providing metering data to people that are authorised to access it.

However, as with the Metering Provider, the general approach under the draft rule has been to impose new obligations on the Metering Coordinator, rather than the Metering Data Provider. This is consistent with the approach that the Metering Coordinator has overall accountability for metering services.

As part of the drafting of the new Chapter 7 of the NER in the draft rule, the Commission has identified that several existing obligations do not state which person is required to comply with that obligation. This is addressed in the draft rule, which specifies who is responsible for those obligations. In one case, such an obligation has been allocated to the Metering Data Provider: the obligations in relation to periodic energy metering that are now contained in clause 7.10.4(a) of the NER in the draft rule.

The draft rule also amends the access to data clause in the NER (clause 7.7 of the current NER and clause 7.15.5 of the NER in the draft rule) to clarify how this clause operates within the new competitive metering framework. These amendments are

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243 Current clause 7.4.1A(a) of the NER.

244 Current clause 7.4.1A(b) of the NER.

245 Clause 7.3.2(d) of the NER in the draft rule.

discussed in Appendix B3 and may affect the Metering Data Provider's role and obligations.

As noted below, Metering Data Providers will also have new obligations as a result of being deemed to be Registered Participants for the purposes of the confidentiality obligations in the NER.

A2.4.3 Accreditation requirements for the Metering Provider and Metering Data Provider

Metering Providers and Metering Data Providers must currently be accredited and registered by AEMO. The requirements for accreditation are currently set out in clauses 7.4.2 and 7.4.2A of the NER, respectively, and outlined in AEMO's service level procedures.

Metering Providers and Metering Data Providers can obtain different categories of accreditation, depending on the type of metering installation and type of work they intend to carry out.[246]

Accredited Metering Providers and Metering Data Providers are placed on a register by AEMO. To check the ongoing capability of accredited parties, AEMO carries out regular audits. A material breach of the NER or the associated procedures by a Metering Provider or a Metering Data Provider can result in loss of accreditation.[247]

The draft rule adds a new requirement to the capabilities that Metering Providers and Metering Data Providers for small customer metering installations must demonstrate to the reasonable satisfaction of AEMO in order to be accredited. This additional requirement relates to the establishment of an appropriate security control management plan and associated infrastructure and communications systems for the purposes of preventing unauthorised local access or remote access to metering installations, services provided by metering installations and energy data held in metering installations.[248]

While the Commission considers that the roles of a Metering Provider and Metering Data Provider under the draft rule are similar to their existing responsibilities, AEMO will need to determine whether any other changes are required to its accreditation procedures for Metering Providers and Metering Data Providers as a consequence of the new framework.

246 Current schedule 7.4 of the NER for Metering Providers and current schedule 7.6 of the NER for Metering Data Providers.

247 A material breach of the provisions of the NER or of the procedures under the NER is defined in current clause 7.4.3(aa) of the NER.

248 Clauses S7.2.5 and S7.3.4 of the NER in the draft rule.

Under the draft rule, Metering Providers and Metering Data Providers will also be deemed to be Registered Participants for the purposes of the confidentiality obligations in Part C of Chapter 8 of the NER.[249]

The key confidentiality obligations to which Metering Providers and Metering Data Providers would be subject as a result of this amendment are contained in rule 8.6.1 of the NER, and include obligations to:

- use all reasonable endeavours to keep confidential any confidential information that comes into their possession or control or of which they become aware;
- not disclose confidential information to any person except as permitted by the NER;
- only use or reproduce confidential information for the purpose for which it was disclosed or another purpose contemplated by the NER; and
- not permit unauthorised persons to have access to confidential information.

This change is included to ensure uniformity in the confidentiality obligations of Metering Coordinators, Metering Providers and Metering Data Providers under the draft rule.

249 Clause 8.6.1A of the NER.

A3 Retailers' roles and responsibilities

Summary

This appendix provides an overview of the role and responsibilities of retailers under the draft rule.

Retailers, as the relevant Financially Responsible Market Participant for the connection points of their retail customers, will be responsible for appointing a Metering Coordinator for the provision of metering services, other than where a large customer chooses to appoint its own Metering Coordinator. This will allow the retailer to arrange for the provision of metering services in a cost effective manner, as well as continuing to be simple and practical from a small customer's perspective.

The retailer, as the Financially Responsible Market Participant, will no longer be required to act, or otherwise be able to request that the LNSP provide an offer to act, as the Responsible Person for the provision of metering services for type 1-4 metering installations at the connection points of its retail customers.[250] The existing obligations of the Responsible Person will be performed by the Metering Coordinator, and the Metering Coordinator role will be contestable.

Under the draft rule, retailers will be able to arrange remote disconnection and reconnection services directly with a Metering Coordinator in certain circumstances (subject to having reached a commercial agreement with the Metering Coordinator for the provision of those services).

The draft rule includes a number of changes to the NERR so retailers and DNSPs inform each other when they perform disconnections and reconnections, and issues related to consumers with life support services are managed.

In addition, retailers would be subject to any applicable requirements of the relevant jurisdictional safety regulator.

A3.1 Introduction

This appendix provides an overview of the role and responsibilities of retailers in relation to metering services under the draft rule. The relationship between the retailer and the consumer are discussed in Appendix B.

This appendix covers:

- the current responsibilities of a retailer under the NER with respect to the provision of metering services;

250 See A1.2.2 for an explanation of who acts as the Responsible Person for type 1-4 metering installations.

- the COAG Energy Council's rule change request covering the proposed responsibilities of a retailer;
- stakeholder views including submissions to the consultation paper and outcomes of stakeholder workshops held by the AEMC; and
- the Commission's analysis of the key issues and reasons for its draft rule.

A3.2 Current responsibilities of a retailer in relation to metering services

Under Chapter 7 of the NER, a Market Participant must ensure that a connection point has a metering installation and that the metering installation is registered with AEMO before participating in the market in respect of that connection point.[251]

Where the retailer is the relevant Market Participant at the connection point, the retailer is required in its role as Market Participant to:

- Ensure that the Responsible Person for that connection point has obtained a National Metering Identifier (NMI). A NMI is a unique code that identifies a metering installation for billing and settlement purposes.[252]
- Act as the Responsible Person for type 1-4 metering installations or, alternatively, request and accept an offer from the LNSP to act as the Responsible Person for the relevant connection point. The role and responsibilities of the Responsible Person in relation to the provision of metering services in the NEM are discussed in Appendix A1.

The retailer has a range of other responsibilities relating to metering services.[253] For example, where a retailer is the Financially Responsible Market Participant for a connection point, it is currently responsible for the payment of all metering services costs at that connection point.[254]

Retailers also have responsibilities with respect to metering under the ROLR provisions in the NERL. The ROLR scheme seeks to ensure that a consumer's

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251 Current clause 7.1.2 of the NER. The retailer is generally the Market Participant and the Financially Responsible Market Participant in relation to the connection points of each of its retail customers.

252 Current clauses 7.1.2(a)(3) and 7.3.1(d)-(f) of the NER.

253 For example, when the retailer is the relevant Market Participant at a connection point, it has certain responsibilities with respect to joint metering installations and special sites or technology related conditions. Refer to current clauses 7.2.4 and 7.2.4A of the NER.

254 Current clause 7.3A(a) of the NER sets out the services to which such costs relate. This includes, amongst other things, costs associated with installing the meter, metering data services and preparing settlements ready data. If the Responsible Person has allowed another party to engage a Metering Provider to install the meter, the Responsible Person is not responsible for the payment of the relevant installation costs for the metering installation.

continuity of supply is maintained if a ROLR event[255] occurs, by establishing arrangements that transfer a customer of a “failed retailer” to another retailer.

Under the current ROLR arrangements in the NERL, the designated ROLR takes on the role of the Responsible Person for any metering installation for which the failed retailer was the Responsible Person. Where the failed retailer (in its capacity as the Responsible Person) has entered into an agreement with a Metering Provider under current clause 7.2.5 of the NER, the designated ROLR will, by force of law, become party to that agreement in place of the failed retailer.[256]

Retailers also have a number of responsibilities under the NERR relating to the disconnection and reconnection of consumers. These are discussed in Appendix A3.

A3.3 Rule proponent's view

The rule change request did not seek to change the existing responsibilities of retailers as Market Participants, including ensuring that a connection point has a metering installation and that the metering installation is registered with AEMO.

The COAG Energy Council proposed that retailers would be responsible for ensuring that there is a Metering Coordinator at each of their customers’ connection points. In particular, retailers would be responsible for engaging a Metering Coordinator for the provision of metering services at a connection point, unless a customer decided to engage its own Metering Coordinator.[257] The ability for a customer to engage its own Metering Coordinator is discussed in Appendix B1.

The COAG Energy Council proposed that the engagement of a Metering Coordinator by a retailer would be based on a commercial arrangement. Further, to simplify arrangements for residential and small business customers, the standard retail contract would include a provision specifying that the retailer is to arrange metering services on behalf of its customer. In addition, a retailer could choose to act as a Metering Coordinator, if registered with AEMO to perform the role.[258]

The rule change request also highlighted that the Commission should consider any consequential changes required to the existing ROLR arrangements as they relate to provision of metering services. This is to ensure that there is the continued provision of metering services when a ROLR event occurs. It was highlighted that the Commission should advise the COAG Energy Council of any ROLR scheme changes required to the NERL.[259]

255 ROLR event is defined in section 122 of the NERL.

256 Section 140(2) of the NERL.

257 COAG Energy Council rule change request, p8.

258 Ibid.

259 Ibid., p14.

A3.4 Stakeholder views

In submissions to the consultation paper, stakeholders supported the continuation of the current arrangements in which retailers are responsible for ensuring a connection point has a metering installation and that the metering installation is registered with AEMO.

Several stakeholders were of the view that retailers seeking to take on the Metering Coordinator role should be subject to ring-fencing obligations to support the development of competition and minimise the risk of insider trading.[260]

Generally, retailers and metering service providers considered that the terms and conditions of appointment of a Metering Coordinator by a retailer should be based on commercial arrangements, rather than governed under standardised terms and conditions set out in the NER or NERR.[261]

Several stakeholders were of the view that the existing ROLR arrangements would need to be expanded to accommodate the Metering Coordinator role.[262] The ENA noted that, where metering competition exists, the number of customers and data being transferred in a ROLR event may be significant.[263]

Stakeholders agreed that the current practice where the DNSPs perform manual disconnection and reconnection services should continue; that is, where a fuse or connection is physically removed at the premises. However, there was no consensus on whether DNSPs should exclusively manage the remote disconnection and reconnection services that could be provided using advanced meters. DNSPs considered that they should manage both manual and remote services to ensure that the current safety requirements would be met.

Retailers and metering service providers considered the ability to negotiate directly with a Metering Coordinator for disconnection and reconnection services would lead to significant business efficiencies and support their business case to deploy advanced meters.

260 EDMI, submission on consultation paper, p12; Ergon Energy, submission on consultation paper, p14; SA Power Networks, submission on consultation paper, p7.

261 AGL, submission on consultation paper, p7; EnergyAustralia, submission on consultation paper, p3; Origin Energy, submission on consultation paper, p6; Simply Energy, submission on consultation paper, p8; Lumo Energy, submission on consultation paper, p6; EDMI, submission on consultation paper, p3; Metropolis, submission on consultation paper, p6; Vector, submission on consultation paper, p11.

262 Energex, submission on consultation paper, p3; Origin Energy, submission on consultation paper, p4.

263 ENA, submission on consultation paper, p20.

A3.5 Commission's analysis

In assessing the relevant aspects of the COAG Energy Council's request related to the role of retailers, the Commission has considered:

- the nature of any new roles and responsibilities under the proposed regulatory framework and the party that is best placed to carry out those roles and responsibilities;
- how best to support a competitive framework for the provision of advanced meters by keeping administrative burden and transaction costs as low as practicable, to reduce the costs passed on to consumers; and
- consumer protections and safety issues, including for life support customers, particularly as they relate to remote disconnection and reconnection.

This section sets out the Commission's views regarding the roles and responsibilities of retailers with respect to:

- ensuring there is a metering installation at a connection point;
- appointing a Metering Coordinator at a connection point;
- the provision of disconnection and reconnection services; and
- other issues related to metering services.

A3.5.1 Requirement for a Financially Responsible Market Participant to establish a metering installation at a connection point

The draft rule does not change the requirement that a retailer, as a Financially Responsible Market Participant, must ensure that a connection point has a metering installation for the purposes of electricity supply before participating in the market in respect of that connection point.

Retailers could satisfy this requirement by either:

- appointing a Metering Coordinator that is registered with AEMO to perform this role; or
- establishing a Metering Coordinator business that registers with AEMO as a Metering Coordinator, and arranging metering services through this Metering Coordinator.

The current rules provide that a Market Customer that is involved in the trading of energy must not be registered as a Metering Provider or Metering Data Provider for connection points in respect of which the metering data relates to its own use of energy.[264] This restriction is retained in the draft rule. The effect of this restriction is that a person cannot be a Metering Provider or Metering Data Provider in relation to connection points where it is also the retailer. As a result, in practice retailers that also wish to establish a Metering Provider or Metering Data Provider business have done so by establishing a separate legal entity to carry out metering functions.

The draft rule also provides that a Market Customer (eg retailer) may not be registered as a Metering Coordinator.[265] The effect of this provision is that a retailer that wishes to establish a Metering Coordinator business will need to do so through a separate legal entity (eg a subsidiary). That subsidiary could be registered and accredited as a Metering Coordinator, Metering Provider and Metering Data Provider.

This restriction has been introduced under the draft rule to address concerns that if a retailer is also a Metering Coordinator at a connection point and the customer at that connection point changes retailers (but the Metering Coordinator does not change), the former retailer may have continued access to the customer's energy and metering data. In such circumstances, the former retailer would no longer be entitled to access that data under the NER in its capacity as a retailer or Financially Responsible Market Participant (as it would cease to hold these positions in respect of the connection point), but the Metering Coordinator would be entitled to access the data.

If the Metering Coordinator and former retailer were part of the same legal entity, the Confidential Information provisions in the NER (see clause 8.6 of the NER) would not be sufficient to ensure that such data collected by the Metering Coordinator business was not provided and used by the retail business being operated by the one entity. Access to this data could limit retail competition by creating an uneven playing field where retailers that were also Metering Coordinators would have access to valuable information that other retailers are not permitted to access under the NER.

Other than the new requirement set out above, the NER does not impose "ring fencing" obligations on retailers and Metering Coordinators in this scenario, as were proposed by some stakeholders in submissions.

However, the existing Confidential Information provisions will apply and will prevent a Metering Coordinator providing energy or metering data to, amongst others, a related body corporate (eg the retailer business in respect of which the Metering Coordinator is a subsidiary) unless such related body corporate requires that information for the purposes of the NER.[266]

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264 Clauses 7.4.1(e) and 7.4.2(e) of the NER in the draft rule.

265 Clause 2.4A.1 of the NER in the draft rule.

266 Clause 8.6.2 of the NER provides that the confidentiality restrictions in clause 8.6 do not prevent the disclosure of information by a Registered Participant or the Registered Participant's Disclosees to an employee or officer of the Registered Participant or a related body corporate of the Registered Participant, or consultants of the Registered Participant, which require the information for the purposes of the NER, or for the purpose of advising the Registered Participant or the Registered Participant's Disclosee.

A3.5.2 Requirement for the retailer to appoint a Metering Coordinator

A key principle underpinning the Commission's draft rule is that the arrangements should be simple and practical from a consumer's perspective.

As outlined in Appendix A1, under the draft rule the Financially Responsible Market Participant will be responsible for appointing a Metering Coordinator to provide metering services for a connection point, other than in circumstances where a large customer chooses to engage their own Metering Coordinator. The Commission considers that retailer appointment of a Metering Coordinator would be simple and practical from a small consumer's perspective and support existing consumer protections.[267]

As a transitional arrangement, the LNSP that is acting as the Responsible Person for a type 5 or 6 metering installation immediately before the commencement of the new Chapter 7 of the NER will become the initial Metering Coordinator for that connection point. The LNSP will continue in this role until another Metering Coordinator is appointed by the Market Participant or, if applicable, a large customer (see Appendix B1), or the services cease to be classified by the AER as a direct control service.

The retailer will need to appoint a Metering Coordinator when the meter is replaced, including when:

- the metering installation becomes faulty;
- the consumer takes up a product or service that requires a new meter to be installed; or
- the retailer carries out a "new meter deployment" (for example where the retailer or DNSP identifies a business case for deploying advanced meters, such as potential operational efficiencies resulting from more advanced metering technology) or a "maintenance replacement" (see Appendix C2).

A3.5.3 Requirements regarding disconnection and reconnection services

One of the benefits of advanced meters is the ability to remotely disconnect and reconnect energy supply. The Commission's draft rule recognises this benefit and enables retailers to carry out remote disconnection or reconnection of small customers' premises directly through a Metering Coordinator, if the retailer has reached a commercial agreement with the Metering Coordinator for the provision of that service.

The Commission has considered the potential impact on consumers and safety to be confident that existing consumer protections in the NERR are effectively maintained and safety risks are managed.

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267 Issues related to the ability of consumers to appoint their own Metering Coordinator are discussed further in Appendix B1.

The draft rule does not change the existing arrangements as they relate to manual disconnections and reconnections. Due to the nature of the services, these will continue to be performed exclusively by DNSPs.

This section discusses the implications of a Metering Coordinator offering remote disconnection and reconnection services, including the parties that:

- can arrange a request for disconnection and reconnection services;
- approve a request to perform the services, and are accountable for that decision; and
- can action a request and provide the service.

Current arrangements for disconnection and reconnection services

Currently disconnection and reconnection services for small consumers are regulated both through the NERR and through jurisdictional safety arrangements.[268] While both retailers and DNSPs can initiate these requests, only a DNSP is currently able to undertake a disconnection and reconnection service.

Initiating disconnection and reconnection services

Under the NERR, the DNSP can initiate disconnection of a consumer’s premises for a number of reasons, including for: failure to pay distribution network charges; interfering with energy supply to others; or for health and safety reasons.

The NERR prevents a DNSP from initiating a request for disconnection in certain circumstances, including if:[269]

- the premises is registered as having life support equipment;
- it is a protected period;[270]
- there is an extreme weather event;[271] or
- there is an unresolved complaint directly in relation to the proposed disconnection.

268 For example, in Victoria remote disconnection and reconnection services can only be provided in accordance with processes approved by Energy Safe Victoria.

269 Rule 120 of the NERR.

270 Rule 108 of the NERR defines what constitutes a protected period. It includes: business days before 8am or after 3pm; a Friday or the day before a public holiday; a weekend or a public holiday; and the days between 20 December and 31 December, inclusive.

271 An extreme weather event is defined in rule 108 of the NERR. It means an event declared by a local instrument as an extreme weather event in the jurisdiction in which the customer's premises are located.

A retailer can also arrange to disconnect a customer's premises for a number of reasons, including non-payment of energy charges.[272] Under the NERR, a retailer must not arrange for a customer's premises to be disconnected in certain prescribed circumstances, including but not limited to those that apply to disconnection initiated by the DNSP.[273]

The retailer or DNSP that arranged for disconnection is required under the NERR to arrange for reconnection of the premises once the matter that led to disconnection has been rectified and once the customer that has requested reconnection has paid any reconnection charges.

Performing disconnection and reconnection services

Under the NERR only a DNSP can perform a reconnection service.[274]In practice, the DNSP is also the only party that performs disconnection services.[275]

When a DNSP decides that it can proceed with a disconnection or reconnection service it must determine how to provide the service. Outside of Victoria generally a DNSP, or its agent, attends the premises to manually remove or replace the service fuse in order to disconnect or reconnect supply.[276] In Victoria, disconnection and reconnection services can be performed using the advanced meters already installed.

DNSPs charge a fee to retailers for the provision of disconnection and reconnection services. These fees are determined as part of the process of economic regulation by the AER. If a consumer is mistakenly disconnected from electricity supply, DNSPs are obliged to reconnect the consumer at no cost.[277]

Safety issues with disconnection and reconnection services

Obligations relating to disconnection of a consumer's premises primarily relate to confirming that the consumer does not have life support equipment, as disconnection of such premises could be fatal. The NERR requires both DNSPs and retailers to maintain registers of premises with life support equipment and they are not permitted to disconnect these premises. Where a consumer has life support at its premises, it is required to inform either the retailer[278] or the DNSP.[279]

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272 Part 6 Division 2 of the NERR.

273 Rule 116 of the NERR.

274 Rule 121 of the NERR.

275 Currently the NER states that a retailer "may arrange" for a customer's premises to be disconnected, however it does not expressly state with whom it can arrange the disconnection (rule 111 of the NERR).

276 DNSPs can use different methods to manually disconnect and reconnect a customer’s premises such as removing the service fuse in the consumer's meter box or a pole top fuse. In each case it is a physical disconnection or reconnection of the supply that is performed manually at the premises.

277 Section 13.3 of the Model terms and conditions for deemed standard connection contracts, Schedule 2 of the NERR.

278 Clause 6.3(b) of the model terms and conditions for standard retail contracts in schedule 1 of the NERR.

When a consumer informs its retailer it has life support equipment, the retailer must:

- include the premises in its life support register;
- advise the DNSP of the premises; and
- not arrange for disconnection of these premises.

When a consumer informs the DNSP it has life support equipment, the DNSP must:

- include the premises in its life support register; and
- not arrange for disconnection of these premises.

DNSPs are not required currently under the NERR to inform retailers when they become aware that a premises has life support equipment. Under the current arrangements DNSPs undertake all disconnections, and as such, retailers arguably do not have a need for this information. However, the Commission understands that:

- while it is not a requirement under the NERR, some DNSPs inform the customer's retailer when the customer advises the DNSP that the customer's premises has life support equipment; and
- the IEC[280] and AEMO are investigating how to improve the processes used by DNSPs and retailers to manage the registration of premises with life support equipment. This review includes improving the process to reconcile any differences between the registers held by DNSPs and retailers.

At the sixth stakeholder workshop on 22 January 2015, the Commission noted the potential risks that could arise from having separate life support registers held by DNSPs and retailers. As a potential alternative, the Commission proposed requiring DNSPs to hold a single register and removing the obligations on retailers to maintain a register. Retailers would be required to notify DNSPs when customers notified them that they have life support equipment.

All but one stakeholder opposed this alternative approach at the workshop. Stakeholders considered that this approach would significantly increase the risks of incorrect disconnection of life support customers compared with the current arrangements. Most retailers indicated that they would be likely to maintain their own register even if there was no longer a requirement to do so under the NER.

279 Clause 6.4(b) of the model terms and conditions for standard connection contracts in schedule 2 of the NERR.

280 The IEC is a body established under the NER to govern the procedures for B2B.

The Commission understands that reconnection of a consumer's premises also has safety implications and DNSPs typically:

- check that the consumer has not left any appliances on while the premises was disconnected before allowing reconnection, which could impose a fire hazard when the supply is restored and the appliance turns on;[281]

- inspect the wiring at the premises following a prolonged period of disconnection; and

- do not allow the reconnection during an emergency (such as flood or bush-fire), at the direction of the jurisdiction emergency coordinators.

In addition to the requirements in the NERR, DNSPs are required to manage safety risks associated with disconnection and reconnection in accordance with the requirements of the relevant jurisdictional safety regulators.

This may involve the DNSP performing the disconnection and reconnection services in accordance with operating procedures that are consistent with the relevant safety legislation and which may need to be approved by the relevant jurisdictional safety regulator. The DNSP may also be required to liaise with the relevant jurisdictional emergency coordinators during emergencies such as bush-fires and floods to ensure the safety of the emergency service workers attending to the emergency, in accordance with the emergency services or equivalent legislation in each jurisdiction.

Options for responsibility to disconnect and reconnect

The Commission considered two options for allocating responsibility for remote disconnection and reconnection services through a Metering Coordinator:

- retaining the current requirements, whereby only DNSPs are able to disconnect and reconnect premises, including remote disconnection and reconnection services (through a Metering Coordinator); and

- permitting both retailers and DNSPs to disconnect and reconnect premises remotely through a Metering Coordinator.

Option 1: DNSPs continue to perform disconnections and reconnections

The Commission considered that one option for managing remote disconnection and reconnection was to allow DNSPs to retain exclusive responsibility for the provision of disconnection and reconnection services.

281 The Commission understands that when reconnections are performed manually DNSPs, they will confirm that appliances are off with the customer. In Victoria, where remote reconnections are possible, the DNSPs can rely on retailers to checking the status of customers' appliances provided that their processes for establishing this are approved by Energy Safe Victoria, as required by legislation administered by Energy Safe Victoria.

Under this option, a retailer that seeks disconnection and reconnection services would continue to make this request to the DNSP, under the current provisions of the NERR. The DNSP would then determine whether the disconnection or reconnection service could be performed remotely, under contract with a Metering Coordinator, or manually.

The AEMC discussed this approach at its fourth stakeholder workshop in Sydney on 24 September 2014. Stakeholders in attendance generally agreed that the responsibilities associated with manual disconnections should remain with DNSPs. However, there were divergent views on the treatment of remote disconnection and reconnection services.

DNSPs generally considered that they should retain responsibility for disconnection and reconnection services. These stakeholders argued that this option is preferable because the existing arrangements provide appropriate mechanisms to maintain consumer protections and manage safety issues, as the obligations and risks are clearly assigned between the DNSP and the retailer. Changing this framework by allowing retailers to initiate disconnections and reconnections directly with a Metering Coordinator could undermine existing consumer protections and the safe operation of the power system.

DNSPs considered that the fees charged by DNSPs for disconnection and reconnection services should remain regulated through the AER's regulatory determination process. DNSPs argued that this would ensure that fees remain appropriate and reflect that many disconnection and reconnection services may be able to be performed remotely.

However, retailers and metering service providers considered that maintaining DNSP responsibility for disconnection and reconnection services would not create sufficient incentives for DNSPs to offer remote disconnection and reconnection services. Further, these stakeholders considered the DNSP fees for such services would be higher than the retailer could negotiate with a Metering Coordinator.

Retailers and metering service providers also contended that a significant component of the business case for a retailer led deployment of advanced meters relies on having the ability to deliver disconnection and reconnection services in an efficient and timely manner. These stakeholders considered that this would be more likely if the retailer were able to negotiate directly with a Metering Coordinator for these services.

Option 2: retailers able to arrange remote disconnection and reconnection services with Metering Coordinator

The Commission also considered the option of allowing retailers to directly access remote disconnection and reconnection services. Maintaining the existing consumer and safety protections was central to the Commission's assessment of this option.

Benefits of allowing retailers to negotiate for services directly with a Metering Coordinator

The Commission agrees that there would be advantages in allowing retailers to negotiate directly with a Metering Coordinator for remote disconnection and reconnection services. These benefits include:

- Retailers being able to negotiate lower cost remote services, as provision of these services could be negotiated when a Metering Coordinator is appointed. Lower costs for retailers would be expected to be reflected in lower prices for consumers.
- Retailers being able to better manage commercial risks associated with non-payment or consumers moving premises. Again, this would be expected to result in lower prices for consumers and quicker resolution of final bills when moving out of a premises.
- Improved service quality for consumers as supply could potentially be restored quickly following disconnection or when moving into a new premises.

Further, allowing retailers to negotiate directly with a Metering Coordinator would not prevent retailers from arranging a manual disconnection with DNSPs. Manual disconnections may still be necessary to manage instances of theft or illegal use of energy, safety issues at a premises, or consumer requests for disconnection for alterations at the premises.

Risks of allowing retailers to arrange disconnection directly with a Metering Coordinator

Currently under the NERR, a retailer is not permitted to arrange disconnection at a premises under certain circumstances, including if the premises is registered as having life support equipment.[282] In addition, a DNSP cannot undertake a disconnection service requested by the retailer before meeting its own requirements to check that there are no reasons under the NERR why the disconnection cannot be performed.[283] This results in a "double check" by the DNSP when the retailer is arranging the disconnection. If retailers are able to arrange disconnection directly with a Metering Coordinator these double checks would not be performed.

The Commission considers that these double checks are not necessary to mitigate the safety risks associated with the disconnection of premises with life support equipment, provided that the retailer has access to an up-to-date life support register. This would be achieved by requiring DNSPs to notify retailers when they have been advised that a premises has life support equipment.

Retailers would also need to comply with any additional requirements of the relevant jurisdictional safety arrangements before arranging for remote disconnection of a consumer's premises. This would be expected to include any additional safety

282 Clause 116(1)(a) of the NERR.

283 Rule 120 of the NERR.

requirements that the jurisdiction considers necessary to address safety risks for remote disconnections.

Risks of allowing retailers to arrange reconnection directly with a Metering Coordinator

The safety risks associated with reconnecting a consumer's premises are generally greater than for disconnection, except in the case of premises with life support equipment and possibly during an extreme weather event.

One risk is that retailers could seek to reconnect a premises that a DNSP has disconnected for safety or emergency reasons. In these instances, remote reconnection by a retailer could be unsafe. Disconnection for safety reasons is likely to be done manually, which would make it impossible for supply to be remotely reconnected. Consequently a safety issue would not arise in this instance. However, disconnection during an emergency, such as a bushfire, could be performed remotely and remote reconnection by the retailer could occur, potentially resulting in safety issues.[284] These risks would need to be managed under arrangements where retailers can organise remote disconnection and reconnection services.

The Commission considers the risks associated with retailers directly arranging remote reconnection of a consumer's premises with a Metering Coordinator would be appropriately addressed if:

- the retailer is not able to reconnect a premises that has been disconnected by a distribution business; and
- the retailer meets any obligations imposed by the relevant jurisdictional safety regulator.

The Commission's draft determination and draft rule

The draft rule allows retailers to arrange remote disconnection and reconnection services directly with a Metering Coordinator or with a DNSP, subject to any applicable requirements of the relevant jurisdictional safety regulator.

Under the draft rule, retailers will not be able to arrange for remote reconnection of premises directly with a Metering Coordinator if the premises had been disconnected by the DNSP.[285]

The Commission considers that allowing retailers to arrange disconnection and reconnection services directly with a Metering Coordinator would further the overall objectives of the rule change request and the long term interests of consumers.

284 The DNSP's decision whether to disconnect manually or remotely would need to be made in accordance with any relevant jurisdictional requirements.

285 Rule 106A of the NERR in the draft rule.

In particular it is expected to:

- provide a competitive framework for disconnection and reconnection services;
- provide disconnection and reconnection services at an efficient cost;
- reduce transaction costs for retailers when arranging remote disconnection and reconnection services; and
- reduce administrative and regulatory costs, as the services would be provided under the commercial arrangements between a retailer and a Metering Coordinator, reducing the circumstances in which the AER regulates the fees for such services.

As a result, it is likely to provide for lower costs and improved services for consumers.

The Commission considers that the benefits of allowing retailers to arrange disconnections and reconnections directly with a Metering Coordinator outweigh the risks, and that the risks involved can be appropriately managed.

To address the potential risks, the draft rule includes the following obligations:

- the DNSP must inform the retailer when it registers a retailer's customer's premises as having life support equipment (to allow the retailer to have a comprehensive life support register);[286]
- a retailer or DNSP that undertakes a disconnection service at a customer's premises must notify the other party of the disconnection, including providing reasons for the disconnection and for the DNSP whether it was performed manually or remotely;[287]
- a retailer or DNSP that undertakes a reconnection service at a customer's premises must notify the other party of the reconnection;[288]
- a retailer must not arrange reconnection of a customer's premises by a person other than the DNSP if the premises were disconnected by the DNSP;[289] and

286 Rule 125(2)(b) of the NERR in the draft rule. In addition, the retailer continues to be required to inform the DNSP when it registers premises as having life support equipment - see rule 124 of the NERR in the draft rule..

287 Rule 104(1) and (2) of the NERR in the draft rule. It is important for the retailer to inform the DNSP when it disconnects a customer's premises in order to prevent a DNSP from interpreting a lack of supply at a customer's premises as an interruption to the supply and dispatching staff to investigate. Similarly, it is important for the DNSP to inform the retailer so that it can manage any inquiries from the affected customers. This risk would be removed if the business has negotiated access to the relevant services from the advanced metering infrastructure to test the status of the supply.

288 Rule 106A of the NERR in the draft rule.

289 Rule 106A of the NERR in the draft rule.

- a DNSP must not reconnect a customer's premises if it was disconnected by the retailer, unless the customer's retailer requests the DNSP to arrange the reconnection.[290]

The draft rule maintains the current requirements on DNSPs and retailers to maintain separate registers of which premises have life support equipment. The Commission considers that this to be the most appropriate way to manage the risk of disconnection of premises with life support equipment.

Jurisdictional safety regulators may also need to consider the safety implications of allowing retailers to arrange disconnection and/or reconnection services directly with a Metering Coordinator. This may require changes to the associated jurisdictional safety regulations to impose suitable obligations on the retailer prior to such arrangements commencing.

A3.5.4 Other issues

Other amendments to the NERR

The draft rule contains a number of amendments to the NERR to recognise the Metering Coordinator role and retailers' obligations to appoint a Metering Coordinator, and to implement changes to disconnection and reconnection arrangements, opt out arrangements for new meter deployments and other matters. Stakeholders, in particular retailers, should closely review these draft amendments to the NERR.

Standard retail contracts

The COAG Energy Council proposed that the standard retail contract under the NERR include a provision specifying that a retailer is to arrange metering services on behalf of a customer (unless the customer chooses to engage its own Metering Coordinator).[291]

Currently, the model terms and conditions for standard retail contracts do not cover the physical connection of the small customer's premises to the distribution system, including metering equipment.[292] The deemed standard connection contract provides that the DNSP will provide, install and maintain equipment for the provision of customer connection services at the customer's premises.[293]

290 Rule 106A of the NERR in the draft rule.

291 COAG Energy Council rule change request, p8.

292 This is the customer retail contract for the provision of customer retail services that takes effect under section 26 of the NERL between a small customer and a designated retailer. See schedule 1 of the NERR for further details.

293 This is the customer's connection contract that is taken to be entered into under section 70 of the NERL. See clause 5.3 of schedule 2 of the NERR for further details.

In practice, small customers generally organise a connection service through their retailer, who liaises with the LNSP for the connection service or for a change to the existing connection. Large customers often deal directly with the LNSP to organise their connection to the network.

The model terms and conditions for standard retail contract are amended under the draft rule to recognise the new role and responsibilities of retailers (in their capacity as the Financially Responsible Market Participant for the connections points of their retail customers) in relation to the provision of metering services.

More specifically, the model terms and conditions for standard retail contracts in the NERR are amended to reflect the retailer's:

- role in appointing a Metering Coordinator to provide metering services at the customer’s premises;
- obligations with respect to notifying the customer of a proposed new meter deployment (see Appendix C2); and
- ability to arrange remote disconnections and reconnections directly with the Metering Coordinator in certain circumstances rather than have to request that the DNSP undertake the disconnection or reconnection.

Retailer of last resort provisions

As noted above, under the current ROLR arrangements in the NERL, the designated ROLR currently takes on the role of the Responsible Person for any metering installation for which the failed retailer was the Responsible Person. The current ROLR provisions in the NERL also provide that the designated ROLR will, by force of law, become party to the agreement between the failed retailer and the Metering Provider.

The ROLR arrangements in the NERL do not provide for the appointment of a Metering Coordinator for a connection point to continue following the transfer of customers of a failed retailer to the designated ROLR. This means that the designated ROLR will be required to appoint a new Metering Coordinator for each connection point transferred to it as a result of a ROLR event.

Under section 144 of the NERL, AEMO is empowered to make ROLR procedures that deal with a broad range of matters relating to how customers are transferred following a ROLR event and how ROLR transfers are to be dealt with under the metrology procedure and other procedures authorised under the NER.[294]

The Commission considers that prior to the commencement of the new Chapter 7 of the NER, AEMO should consider whether any amendments should be made to the ROLR procedures to manage the impacts of meter churn following a ROLR transfer.

294 These procedures are contained in the "NEM ROLR Processes", which form part of AEMO's MSATS Procedures.

This approach would avoid the need for the ROLR provisions in the NERL to be amended. The COAG Energy Council may wish to amend the relevant NERL provisions to assist with clarity, but would not need to do so before the commencement of the new Chapter 7 of the NER.

The Commission is interested in stakeholder views on this proposal.

A4 DNSPs' roles and responsibilities

Summary

This appendix sets out the roles and responsibilities of DNSPs under draft rule.

Under the draft rule the role of Responsible Person will cease to be exclusively performed by LNSPs for type 5 and type 6 metering installations. Type 7 metering installations will continue to be provided exclusively by LNSPs. The draft rule does not require LNSPs to make an offer to act as the Metering Coordinator for type 1-4 metering installations if requested to do so by a Market Participant, except in the case of transmission connection points. Consequently, the LNSP will no longer be responsible for the provision and installation of metering installations at new connections.

Under the proposed transitional arrangements, the LNSP currently acting as the Responsible Person for metering services that are classified as a direct control service will become the initial Metering Coordinator and will continue in this role until another Metering Coordinator is appointed by the Market Participant or the services cease to be classified as a direct control service.

In Victoria, DNSPs will become the initial Metering Coordinator for the advanced meters they deployed under the AMI program and will continue in this role until the relevant retailer appoints another Metering Coordinator at the site or the services cease to be classified as a direct control service.

DNSPs will be able to take on the Metering Coordinator, Metering Provider and/or Metering Data Provider roles to provide metering services in a competitive segment of the market. However, to do so a DNSP will need to comply with the national ring-fencing guidelines developed by the AER.

If DNSPs do not wish to become a Metering Coordinator, they may still be able to access these services for network management purposes by negotiating access on a commercial basis with Metering Coordinators providing those services.

The draft rule also allows DNSPs to maintain existing network devices or install new network devices for the purposes of monitoring or operating the network. Where a DNSP is replaced as the Metering Coordinator, the DNSP will have the option of retaining its existing metering installation and using it as a network device.

The draft rule allows either a DNSP or a retailer to arrange remote disconnection and reconnection services directly with a Metering Coordinator.

The Commission has also considered the potential impacts on network security that could arise from large quantities of direct load control available from advanced meters. As the risks to network security are not limited to meters and it is not possible to predict the proportion of direct load control that will be

performed by advanced meters, the Commission considers that the benefits of implementing a solution that only applies to load controlled by advanced meters are likely to be outweighed by the costs.

A4.1 Introduction

This appendix sets out the roles and responsibilities of a DNSP under the draft rule.

This appendix covers:

- the impacts of the COAG Energy Council's proposal to remove the LNSP's exclusive right to be the Responsible Person for type 5 and type 6 metering installations;
- stakeholder views including submissions to the consultation paper and outcomes of stakeholder workshops held by the AEMC;
- an overview of the role and responsibilities of DNSPs with respect to the provision of metering services, including at new connections;
- an overview of the obligations of DNSPs in relation to remote disconnection and reconnection services (further detail is set out in Appendix A3); and
- options that were considered to address the potential impact of direct load control on the security of the network.

A4.2 Rule proponent's view

The COAG Energy Council did not provide a view on the implications of the rule change proposal on the roles and responsibilities of DNSPs.

A4.3 Stakeholder views

DNSPs raised concerns during stakeholder workshops that separating the Metering Coordinator role from their regulated network role may require changes to their responsibilities under the NERR and jurisdictional licenses. DNSPs were particularly concerned about the safety, reliability and network security implications of the rule change request, including the continued supply of electricity to life support customers.

At the first stakeholder workshop on 26 June 2014, DNSPs expressed concerns that establishing a separate Metering Coordinator role may introduce risks in terms of:

- maintaining consumer protections and managing safety risks associated with remotely disconnecting or reconnecting consumer premises; and
- the risks to network security associated with one or more Metering Coordinators switching large quantities of load without reference to the DNSP.

In each case DNSPs were concerned that they may be liable for the actions of third parties who cause a breach of the current obligations on the DNSPs under the NER and NERR, particularly in relation to network security and reliability of supply.

A4.4 Commission's analysis

In assessing the implications for DNSPs of the COAG Energy Council's proposal for the Commission has considered:

- consumer protections and safety issues, including for life support customers;
- risks to network security from direct load control enabled by advanced meters; and
- the administrative burden and costs of introducing additional regulation in respect of direct load control enabled by advanced meters.

A4.4.1 The role of DNSPs

Provision of and access to metering services

Under the draft rule, the obligations of the Responsible Person will be performed by the Metering Coordinator, and that role will not be exclusively performed by LNSPs for type 5 and type 6 metering installations. Type 7 metering installations will continue to be provided exclusively by DNSPs, as discussed in Appendix A1.

In addition, the draft rule does not require LNSPs to make an offer to act as the Metering Coordinator for type 1-4 metering installations if requested to do so by a Market Participant, except where the Market Participant has requested the LNSP to make an offer to act as the Metering Coordinator for a transmission connection point. Currently, LNSPs must make an offer to act as the Responsible Person in such circumstances.

Under the transitional arrangements, the LNSP that is acting as the Responsible Person for a type 5 or 6 metering installation immediately before the commencement of the new Chapter 7 of the NER will become the initial Metering Coordinator at that connection point. The LNSP will continue in this role until another Metering Coordinator is appointed to the site by the Market Participant or, if applicable, a large customer.

This is anticipated to primarily occur when a new meter is installed, including where the metering installation becomes faulty, the consumer takes up a product or service that requires a more advanced meter to be installed, or the retailer carries out a "new meter deployment" or "maintenance replacement" (see Appendix C2).

In Victoria, DNSPs will become the initial Metering Coordinator for the advanced meters they deployed under the AMI program and will continue in this role until the

Market Participant appoints another Metering Coordinator at the site (see Appendix F for the detailed arrangements for Victoria).

The transitional appointment of DNSPs will also end if the relevant metering services cease to be classified as a direct control service.

The draft rule does not prevent a DNSP from taking on the Metering Coordinator, Metering Provider and/or Metering Data Provider roles to provide metering services in a competitive segment of the market provided they are appropriately accredited by AEMO. However, the draft rule requires the AER to determine appropriate ring-fencing requirements for DNSPs and to set these out in a distribution ring-fencing guideline. These issues are discussed further in Appendix D3.

If a DNSP does not wish to compete as a Metering Coordinator to provide advanced metering services, it will still be able to access these services for network management purposes by negotiating access on a commercial basis with the Metering Coordinators.[295] Also, a DNSP may fund, in whole or in part, a retailer's deployment of advanced meters in exchange for access to the services enabled by those meters.[296]

Under the draft rule, a DNSP will also be able to continue to use existing network devices or install new network devices for the purposes of operating or monitoring its network. Where a DNSP is replaced as the Metering Coordinator, it will therefore have the option of using its existing metering installation as a network device. For example Victorian DNSPs will be able to continue to use their existing AMI meters as network devices. The draft rule contains a number of provisions to give effect to this right, which are discussed in Appendix D4.

New connections

As a consequence of establishing a separate Metering Coordinator role, a DNSP will not be responsible for installing and maintaining metering installations at new connection points unless it either sets up a Metering Coordinator business and is appointed by a Market Participant to provide those services, or is requested to be the Metering Coordinator for a transmission connection point.

However, the LNSP will still be responsible for 'connection services' with regard to a connection point and will need to coordinate with the relevant Metering Coordinator where necessary to provide these services.

A4.4.2 Disconnection and reconnection services

As discussed in Appendix A3, while DNSPs will retain responsibility for manual disconnection and reconnection of premises, the Commission’s draft rule would allow both retailers and DNSPs to arrange for remote disconnection and reconnection

295 Some DNSPs raised concerns about gaining access to advanced metering services. This issue is discussed in Appendix E.

296 This is discussed in Appendix D4.

services through a Metering Coordinator. This is to capture efficiencies from allowing a retailer being able to directly negotiate and initiate connection services with a Metering Coordinator.

In order to maintain consumer and network safety under the new arrangements, the draft rule includes the following requirements:

- a requirement in the NERR for the DNSP to inform the retailer when it registers a retailer's customer's premises as having life support equipment (to allow the retailer to have a comprehensive life support register);[297]
- a requirement in the NERR for a DNSP that undertakes a disconnection service at a consumer’s premises to notify the retailer of the disconnection, including providing reasons for the disconnection and whether it was performed manually or remotely;
- a requirement in the NERR for a DNSP that undertakes a reconnection service at a consumer’s premises to notify the retailer of the reconnection;
- a requirement in the NERR that prevents a retailer from reconnecting a customer’s premises if it was disconnected by the DNSP; and
- a requirement in the NERR that prevents a DNSP from reconnecting of customer’s premises if it was disconnected by the retailer, unless the customer’s retailer requests the DNSP to arrange the reconnection.

A detailed analysis of the implications of a Metering Coordinator offering remote connection services and the Commission's reasons for this approach is provided in Appendix A3.

A4.4.3 Direct load control and network security management

This section discusses the implications for network security of Metering Coordinators offering direct load control services to a large number of consumers' premises.

Impact of direct load control management and network security

In the future, consumers may increasingly manage their electricity consumption by changing their usage in response to price signals. That is, a consumer, or its agent, may actively modify consumption at the consumer’s premises to manage the consumer’s electricity costs in response to the retail tariffs, or as part of another service being offered to the consumer. Direct load control services could be offered using advanced metering services, but may also be offered using alternative technology such as

297 A retailer's obligations in respect of life support equipment are contained in Part 7 (rule 124) of the NERR. A distributor's current obligations in respect of life support equipment are contained in Part 7 (rule 125) of the NERR.

internet based services. The issue of the impact on the security of the distribution network is therefore not limited to load control enabled by advanced meters.

Direct load control by individual consumers is not likely to have a material impact on the network as this already occurs when an individual consumer switches on or off some of its load. An individual consumer's load is generally small compared to the total load on the network. However, direct load control of a large amount of load in a network may cause significant fluctuations in the network voltage that could compromise network security. In extreme cases it could cause damage to consumers' equipment, or result in a blackout in part of the network.

At present there are no specific restrictions on the use of direct load control at the sites of residential and small business customers via a meter with advanced functionality, or via any other means.

The Commission has considered two options to assist DNSPs to manage the impact of direct load control on their networks:

- the provision of direct load control information to the DNSP from a Metering Coordinator; and
- the development of a network load management protocol.

Option 1: Provision of direct load control information to the DNSP

Under this option, a Metering Coordinator would provide DNSPs with information in order to monitor the performance of their networks and the extent to which their network is impacted by the direct load control services being offered to consumers within their networks. This would require a Metering Coordinator to inform DNSPs of the quantity of load that it has under direct control and to provide event logs of when and where such direct load control services have been used.

As the use of direct load control in a network increases, such information would allow the DNSP to monitor the voltage profile within its network.[298] This information could be used to determine the extent to which direct load control services performed via advanced meters are contributing to potential security risks within the distribution network.

However, in practice, a Metering Coordinator might not be able to determine the size of the load. Rather, this information would be held by the party that has arrangements with the consumer to provide load control services.

As an alternative, the Commission considered requiring Metering Coordinators to provide DNSPs with the number of premises under direct load control. However, this information is unlikely to be of value to DNSPs as it is the size of the load being

298 One of the ways that the DNSP could monitor the voltage profile within its network would be via the advanced services offered by metering installations, where this service to provide this voltage information has been negotiated with the Metering Coordinator.

controlled, rather than the number of premises with direct load control, that may impact on network security.

In addition, any information provided by Metering Coordinators on direct load control using advanced meters will only provide DNSPs with a partial understanding of the amount of load under control, as there are other sources of direct load control that will not be captured. Other factors such as electric vehicles and solar PV will also impact network voltage. Therefore, the Commission does not consider that this option would materially improve the ability of DNSPs to manage network issues over time.

Including information provision requirements would be burdensome on Metering Coordinators and would result in additional costs that may be passed on to consumers. The Commission considers that these costs are likely to outweigh the potential benefits to the DNSPs. For this reason, the Commission has not included information provision requirements in the draft rule.

Option 2: The development of a network load management protocol

Risks to the security of the distribution network could be reduced if direct load control activities within a distribution network were required to follow a network load management protocol. That is, the amount of load being switched at any time would be limited to a level that did not cause a significant risk. The AEMC considered this in its previous advice to the COAG Energy Council, *Energy Market Arrangements for Electric and Natural Gas Vehicles*, which recommended the development of:

> "technical standards to encourage arrangements that balance the need to maintain network security while enabling different providers to offer controlled electric vehicle charging services.[299]"

Under this proposal, where there are requests to switch a large quantity of load under direct load control, the Metering Provider would be required to switch the load in small blocks at a time. One method for achieving this would be to spread the switching of the individual consumer loads by introducing a random delay between the request for a direct load control service and it being implemented.[300]

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299 AEMC 2012, Energy Market Arrangements for Electric and Natural Gas Vehicles, Final Advice, 11 December 2012

300 The ability to implement random delays when performing direct load control via the meter was included in the Minimum Functionality Specification that was developed as part of the National Smart Meter Program. This is available on the AEMO website at https://link.aemo.com.au/sites/wcl/smartmetering/Document%20library/Work%20Stream%20documentation/BRWG/BRWG%20deliverable%2001%20-%20SMI%20Minimum%20Functionality%20Specification%20v1.3.pdf . In addition, the Minimum AMI Functionality Specification for Victoria includes the capability of including random delays of between zero and sixty minutes. Details of the Victorian specification are available at http://www.energyandresources.vic.gov.au/__data/assets/pdf_file/0004/201883/Minimum-AMI-Functional-Specification-v1.2.pdf .

The draft Load Management and Network Security Protocol, developed by the ENA, provides an example of a direct load control protocol.[301] This draft protocol proposed that loads over a certain threshold being switched must be registered with DNSPs, with a DNSP able to block switching to ensure security of electricity supply.

An alternative to allowing DNSPs an ability to block direct load control requests would be to give an independent body this role. When determining the load management protocol for meters, this independent body would need to consider:

- the extent to which the load control operation needs to be restricted to mitigate the risk to network security; and
- the resulting potential reductions to the value of the load control services.

The Commission does not consider that a load management protocol specifically for direct load control services from advanced meters would be sufficient to address the potential network security issues. This is because the risks to the security of the network imposed by direct load control is not limited to meters, and it is not possible to predict the proportion of direct load control that will be performed by meters or other devices in the future. Similar network security issues could also arise from the uptake of new technologies such as battery storage and electric vehicles.

Accordingly, the draft rule does not introduce any specific requirements in relation to load control. The Commission notes that the broader issue of load control and its implications for network security is being considered by the COAG Energy Council as part of its current consultation on the regulation of new products and services in the NEM.[302]

301 The ENA developed a draft Load Management and Network Security Protocol, dated 15 March 2012, and provided this to the AEMC as an attachment to its submission to the Directions Paper for the AEMC's Power of Choice review, dated 16 May 2014.

302 https://scer.govspace.gov.au/workstreams/energy-market-reform/demand-side-participation/new-products-and-services-in-the-electricty-market

B Consumer arrangements

Overview of Appendix B

Appendix B sets out the arrangements under the draft rule in relation to:

B1 The ability of consumers to engage their own Metering Coordinator.

B2 Whether basic metering charges should be itemised on a consumer's retail bill.

B3 Access by consumers and their authorised representatives to their energy and metering data.

B1 Consumer appointment of a Metering Coordinator

Summary

This appendix addresses the ability of consumers to appoint their own Metering Coordinator under the draft rule.

There would be benefits in allowing consumers to appoint their own Metering Coordinator. First, it would enable consumers to choose products and services supported by advanced meters that are consistent with their preferences. Second, it would impose additional competitive discipline on retailers regarding the prices, terms and conditions of products and services enabled by advanced meters.

However, providing consumers with the ability to choose their own Metering Coordinator needs to be coupled with arrangements to protect the continued provision of billing and settlements data to the market, as well as appropriate arrangements for consumer protection.

The regulatory changes required to enable large customers to appoint their own Metering Coordinator and ensure the continued provision of settlements data to the market are not substantial. In contrast, as explained in this appendix, the regulatory arrangements that would need to be implemented to enable small customers to appoint their own Metering Coordinator are substantial.

Under the draft rule:

- Large customers will be able to appoint their own Metering Coordinator.
- Small customers will not initially have the option of engaging their own Metering Coordinator. This approach has the advantage that small customers will deal solely with their retailer with respect to the supply of energy and metering services, and will continue to be covered by existing consumer protection provisions and jurisdictional ombudsman schemes that apply to retailers.

The Commission recommends that the ability for small customers to appoint their own Metering Coordinator should be reviewed three years after the commencement of the new Chapter 7 of the NER, once the market has had a chance to develop.

B1.1 Introduction

This appendix addresses the ability of consumers to appoint their own Metering Coordinator.

This appendix covers:

- the COAG Energy Council's proposal regarding the ability of consumers to engage a Metering Coordinator;
- stakeholder views expressed in submissions to the consultation paper and outcomes of stakeholder workshops held by the AEMC; and
- the Commission's analysis of the key issues and reasons for the Commission's draft rule.

B1.2 Rule proponent's view

The rule change request proposed that all consumers should be able to contract directly with any registered Metering Coordinator.[303]

The COAG Energy Council stated that this arrangement would be particularly relevant to large and medium sized businesses because it would allow them to arrange metering services to minimise costs or maximise opportunities to monitor and manage energy use.[304]

The COAG Energy Council also considered that allowing large and small customers to directly engage their own Metering Coordinator would be likely to increase competitive discipline on retailers, for example to provide products and services that consumers value at a price that reflects the costs of doing so.

To give effect to an ability for consumers to appoint their own Metering Coordinator, the COAG Energy Council proposed that:

- a retailer must not prevent a consumer from engaging a Metering Coordinator directly, and must inform the consumer of any changes required to their retail contract to facilitate the engagement of that Metering Coordinator;[305]
- small customers would need to enter into a standard or market retail contract with their retailer for the supply of energy, and a separate metering contract with its chosen Metering Coordinator for the provision of metering services;[306]
- a Metering Coordinator must inform its consumer of the functions required in a metering installation in the jurisdiction in which the consumer is based, and the circumstances in which the installation must be upgraded to meet those requirements;[307]

303 COAG Energy Council, rule change request, October 2013, p8.

304 Ibid., p22.

305 Ibid., p30.

306 Ibid., p8.

307 Ibid., p31.

- where a Metering Coordinator changes a metering installation or its functions, and the change has not been requested by the consumer, a Metering Coordinator must:
  - adequately inform the consumer in writing prior to the change where there is no change to the costs charged to the consumer or services available to the consumer; or
  - obtain the prior consent of the consumer where the change results in changes to the costs charged to the consumer or services available to the consumer.[308]
- a Metering Coordinator must not unreasonably block a request from a consumer to change the features of its metering installation, provided it does not affect the functions being used by other parties.[309]

B1.3 Stakeholder views

Stakeholders at the fourth stakeholder workshop on 24 September 2014 generally supported large customers being able to directly engage their own Metering Coordinator.

Submissions to the consultation paper displayed divergent views on the ability of small customers to directly engage a Metering Coordinator. Those in support of a direct relationship between a small customer and a Metering Coordinator reasoned that this would provide competitive pressure on parties.[310] However, some stakeholders considered that additional consumer protections may be required if such a relationship was allowed.[311]

Other stakeholders did not support a direct relationship between small customers and Metering Coordinators at this time, given the magnitude of the regulatory burden relative to the benefits for consumers.[312] Some stakeholders suggested that the market should be allowed to develop first and that the option for direct engagement of a Metering Coordinator by a small customer be reviewed after a few years.[313]

A number of stakeholders commented on the need for a 'Metering Coordinator of last resort' in the event that a Metering Coordinator appointed by the consumer cannot or does not want to continue to provide its services. Lumo Energy considered that specific

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308 COAG Energy Council, rule change request, October 2013, p32.

309 Ibid.

310 EnerNOC, submission on consultation paper, p4.

311 ATA and other consumer groups, submission on consultation paper, p4. For a contrary view, see Metropolis, submission on consultation paper, p6.

312 EnergyAustralia, submission on consultation paper, p2; Simply Energy, submission on consultation paper, p.8.

313 See for example: AGL, submission on consultation paper, p7; Origin, submission on consultation paper, p6.

arrangements to cater for this scenario are not needed because standard contract law should apply, and suggested that consumers should be able to select the new Metering Coordinator.[314]

Several stakeholders were of the view that the retailer should be responsible for appointing a new Metering Coordinator in the event that the existing one fails.[315] Metropolis considered that, where a Metering Coordinator fails, the role should transfer to a Metering Coordinator pre-nominated by AEMO, similar to the ROLR scheme.[316]

Ergon Energy considered that it would be imprudent to require a 'Metering Coordinator of last resort' to take on the functions of meters used by the failed Metering Coordinator if they do not have the equivalent functionality of the meters used by the 'Metering Coordinator of last resort'.[317] Vector was of the view that the AEMC, or a working group, should review whether existing market arrangements and/or general insolvency legislation are sufficient to address a Metering Coordinator's failure.[318]

The general consensus of views at the fourth stakeholder workshop was that small customers should not be able to directly appoint their own Metering Coordinator initially, but that this be reviewed in the future.

B1.4 Commission's analysis

The ability for consumers to appoint a Metering Coordinator can provide a range of benefits to consumers. It can allow a consumer to choose a Metering Coordinator that offers certain services (or facilitates the offer of services by other parties) at a price and on terms and conditions favoured by the consumer. This may be particularly relevant to a large customer who may demand a range of tailored services and therefore require bespoke Metering Coordinator arrangements.

In addition, as highlighted by the COAG Energy Council, the option for direct appointment of a Metering Coordinator may place a competitive discipline on retailers and other Metering Coordinators regarding the price, terms and conditions of their product and service offerings. It may therefore address concerns around the potential exercise of market power by Metering Coordinators.

The Commission’s view is that consumer choice should be facilitated where possible, as this is likely to lead to more efficient outcomes. However, it is also important to recognise that the provision of metering data for billing and settlements is a service essential to the operation of the NEM. Consumer choice therefore needs to be coupled

314 Lumo Energy, submission on consultation paper, p4.

315 NSW DNSPs, submission on consultation paper, p9; Origin Energy, submission on consultation paper, p4; Vector, submission on consultation paper, p8.

316 Metropolis, submission on consultation paper, p4.

317 Ergon Energy, submission on consultation paper, p8.

318 Vector, submission on consultation paper, p8.

with arrangements that protect the continuing provision of billing and settlements data to the market.

Such arrangements are also important for consumers themselves. If access to the provision of reliable metering data was compromised, bills would need to be based on estimated consumption. This introduces a risk for consumers that their energy consumption, and so bills, could be overestimated. It also introduces similar risks for retailers, who may under-recover their costs if energy consumption was underestimated. Appropriate protections may need to be implemented to manage these risks.

To evaluate whether the regulatory framework should enable consumers to directly appoint a Metering Coordinator, the Commission considered:

- the extent to which additional regulation is required and how that regulation should be implemented; and
- the respective costs and benefits of introducing such regulation at the start of the new rules.

The Commission's analysis found that while additional regulatory arrangements would be needed to enable large customers to appoint their own Metering Coordinator, the additional regulatory arrangements that would be needed to enable small customers to do so are significantly more substantial and complex.

Key areas in which regulatory arrangements may need to be developed, for both small and large consumers, are:

- to provide for appropriate consumer protections, particularly for small customers;
- to allow for a retailer to appoint another Metering Coordinator in the event that a Metering Coordinator appointed by the consumer is unable to perform its functions; and
- to facilitate a market for Metering Coordinator services.

These issues are discussed below.

B1.4.1 Consumer protections

Consumer protection provisions in the NERR currently only apply to retailers and DNSPs. Similarly, only authorised retailers and DNSPs are generally covered by jurisdictional ombudsman schemes. A large customer is likely to have sufficient bargaining power to negotiate terms and conditions and resolve any disputes with a Metering Coordinator. However, small customers are unlikely to be in such a strong position.

A new framework would need to be developed and set out in the NERR to ensure that appropriate consumer protections govern the relationship between a small customer and their Metering Coordinator. These could include:

- requirements on the Metering Coordinator to provide specific information if contacted by a small customer to obtain services, and the form that information must take;
- the basis for, frequency and content of bills;
- the framework that must be followed in the event of a billing dispute; and
- provisions outlining a consumer’s rights should they have difficulty paying a bill.

The COAG Energy Council is currently consulting on how third party energy service providers and new products and services in the NEM should be regulated.[319] It is likely to be more efficient to consider consumer protections associated with metering services as part of this broader review of the regulation of services provided to small customers, such as direct load control, embedded generation and storage, rather than creating a bespoke set of consumer protections for services provided by Metering Coordinators.

B1.4.2 Requirement for a retailer to appoint a Metering Coordinator in the event that the current Metering Coordinator is unable to perform its functions

Allowing consumers to directly appoint a Metering Coordinator creates issues in scenarios where the Metering Coordinator cannot or does not want to continue to provide its services to a consumer. Examples of such scenarios include where the:

- contract between a Metering Coordinator and a consumer expires without replacement;
- Metering Coordinator becomes insolvent; or
- Metering Coordinator has not been paid for its services.

In these circumstances, a retailer would need to appoint another Metering Coordinator or take on that role itself if no other option is available in order to provide basic metrology services. The requirement for a 'Metering Coordinator of last resort’ is necessary because basic metrology services are essential for the operation of the electricity market: that is, for market settlements and billing.

Implementing arrangements to require a retailer to appoint a Metering Coordinator in the event that an existing Metering Coordinator that was directly appointed by the

319 See https://scer.govspace.gov.au/workstreams/energy-market-reform/demand-side-participation/new-products-and-services-in-the-electricty-market/.

consumer is unable to perform its functions would involve additional regulation for all consumers, but particularly for small customers.

For large customers, there is a need for some additional regulation analogous to the requirements for the current ROLR scheme for large customers, under which prices must be fair and reasonable.[320]

For small customers, the extent of the regulation required would be greater. The NERR currently contains provisions that set out the standard terms and conditions that retailers are required to offer small customers, and customers will default to this contract if they do not choose a retailer. To provide small customers with a choice of Metering Coordinator, analogous provisions would likely be required for the supply of metering services.

The NERR would need to contain, and retailers would be required to offer, a standing offer contract that includes the provision of basic metering services. Specifically, the standing offer contract would likely need to include model terms and conditions, including the basis on which tariffs and charges for metering services would be set, and would be in addition to the existing standing offer without metering services. A small customer may need to transition to the standing offer contract in the event that the existing Metering Coordinator cannot, or does not wish to, continue to provide services at the connection point and the retailer is required to arrange an alternative Metering Coordinator.

B1.4.3 Arrangements necessary to facilitate a market for Metering Coordinator services

Allowing consumers to directly appoint a Metering Coordinator also raises issues relating to how a market for Metering Coordinator services should be facilitated. If a consumer appoints a Metering Coordinator, it may be necessary for retailers to offer market contracts that are both inclusive and exclusive of Metering Coordinator services. This would require the unbundling of the component price of Metering Coordinator services in retail electricity charges.

It is unlikely that additional regulation would be needed for large customers because they should have sufficient bargaining power to require a retailer to provide an unbundled price. However, regulation may be required for small customers to curb incentives on retailers to offer onerous terms and conditions that discourage a small customer from engaging its own Metering Coordinator. Consequently, facilitating a market for Metering Coordinator services for small customers may require greater regulatory complexity relative to that required for large customers.

B1.4.4 Draft decision

Based on the analysis set out above, the draft rule enables large customers to appoint their own Metering Coordinator.

The Commission considers that large customers are likely be in a position to commercially negotiate for the provision of products and services supported by advanced meters. The ability for them to do so is likely to place a competitive discipline on retailers. Therefore, the Commission is of the view that the benefits to large customers of having the option to appoint their own Metering Coordinator are likely to outweigh the regulatory costs involved.

Under the draft rule, if a large customer decides to appoint its own Metering Coordinator, the relationship between the large customer and the Metering Coordinator will be a commercial arrangement with some supporting regulatory requirements.

To address the risk that a Metering Coordinator appointed by a large customer ceases to provide metering services and a replacement Metering Coordinator needs to be appointed, the draft rule introduces the following Metering Coordinator default arrangements:[321]

- The Financially Responsible Market Participant (ie the large customer's retailer) must appoint a new Metering Coordinator if:
  - a "Metering Coordinator default event" occurs in relation to the existing Metering Coordinator at the connection point;[322] or
  - the contract under which the large customer appoints the existing Metering Coordinator terminates or expires and the large customer does not appoint a new Metering Coordinator within the period specified by AEMO in procedures.
- If the Financially Responsible Market Participant must appoint a new Metering Coordinator and the existing contract between the Financially Responsible Market Participant and the large customer does not deal with the appointment of a Metering Coordinator in these circumstances, the terms of the contract between the Financially Responsible Market Participant and the large customer relating to the appointment of the Metering Coordinator must be fair and reasonable.

The draft rule also requires the Metering Coordinator to notify the relevant retailer, the large customer and AEMO if a Metering Coordinator default event occurs or the contract under which the Metering Coordinator was appointed by the large customer terminates or expires.[323]

The draft rule does not enable small customers to appoint their own Metering Coordinator. The Commission considers that the development of the regulatory arrangements that would be needed to support this option for small customers, in

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320 Section 146(3) of the NERL.

321 Clause 7.7.1 of the NER.

322 See the new Chapter 10 definition of "Metering Coordinator default event" in the draft rule. This definition includes events such as the Metering Coordinator ceasing to be registered by AEMO.

323 Clause 7.7.2 of the NER.

order to provide for continuing market integrity and appropriate consumer protections, would risk delaying the start of the market for competitive metering services and the benefits that this is expected to bring to consumers.

The Commission notes that the market is undergoing significant change. If the draft rule allowed small customers the ability to appoint a Metering Coordinator, there is a risk that the significant complexity of the new arrangements could erode consumer confidence in the market. In the early stages of market development there are significant advantages to consumers in the simpler model contained in the draft rule under which they will only need to deal with a single retailer who is covered by consumer protections in the NERR and jurisdictional ombudsman schemes.

The Commission recommends that the option for small customers to appoint their own Metering Coordinator be reviewed three years after the commencement of the new Chapter 7 of the NER. This review should include an assessment of whether the benefits of allowing a small customer to appoint their own Metering Coordinator would outweigh the costs and complexity of the regulatory arrangements that may be needed to support that option.

B2 Itemising metering charges for small customers on retail bills

Summary

This appendix addresses whether metering charges should be identified separately from other energy charges on a consumer's electricity retail bill.

The draft rule does not require retailers to provide information about metering charges to small customers. Metering charges will not need to be unbundled from other charges on a consumer’s retail bill.

In light of the Commission’s draft decision that a small customer cannot appoint its own Metering Coordinator at this time, information about metering charges is unlikely to be of any value to a small customer. Rather, the more useful information relates to the charges for products and services about which a customer is making a choice; in this case, the overall bundle of products and services provided by the retailer to the consumer.

The Commission will review this position when the option of a small customer appointing its own Metering Coordinator is reviewed.

B2.1 Introduction

This appendix sets out the Commission’s draft determination in relation to whether metering charges should be identified separately from other energy charges on a consumer's retail bill.

This appendix covers:

- the COAG Energy Council’s proposal regarding separately identifying metering charges;
- stakeholder views expressed in submissions to the consultation paper and outcomes of stakeholder workshops held by the AEMC; and
- the Commission’s analysis of the key issues and reasons for the draft rule.

B2.2 Rule proponent's view

In its rule change request, the COAG Energy Council proposed that a retailer must inform the consumer of the metering service charges for that consumer. The retailer must also notify the consumer of the retail tariff that would be offered if charges for metering services were removed as a result of the consumer appointing its own Metering Coordinator.[324]

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324 COAG Energy Council, rule change request, October 2013, p10.

The COAG Energy Council asked the AEMC to consider the best approach for a retailer to provide information about basic metering charges, including:[325]

- requiring metering services information to be provided on a customer's retail bill;
- separately identifying this information from other tariffs and charges payable by a customer;
- requiring retailers to provide this information to a small customer; or
- providing such information to a small customer on request.

These issues were raised in the context of the proposal that a small customer would have the ability to engage its own Metering Coordinator.

B2.3 Stakeholder views

In submissions to the consultation paper, there were divergent views as to whether information about metering charges should be separately identified.

- Some stakeholders supported this information being identified on a consumer's bill, on the basis that it would support competition.[326] This was particularly the case if a consumer could engage their own Metering Coordinator.[327]
- Other stakeholders were concerned about requiring this information on a consumer's bill.[328] These stakeholders thought that requiring this information at the same time as a competitive advanced meter deployment could affect consumer confidence by creating confusion and a negative perception in consumers' minds. This could consequently result in a barrier to investment and innovation in advanced metering.[329]

Retailers and the ENA considered that the provision of information about metering charges, such as whether it should be on a bill or as part of discrete marketing material, should be up to the retailer or market to decide.[330]

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325 COAG Energy Council, rule change request, October 2013, p10.

326 ATA and other consumer groups, submission on consultation paper, p4; EnerNOC, submission on consultation paper, p3; Ergon Energy, submission on consultation paper, p8; NSW DNSPs, submission on consultation paper, p12.

327 Metropolis, submission on consultation paper, p6.

328 AER, submission on consultation paper, p10; AGL, submission on consultation paper, p6; Alinta Energy, submission on consultation paper, p3.

329 This view was reflected in discussions at the third stakeholder workshop.

330 AGL, submission on consultation paper, p6; ENA, submission on consultation paper, p24; ERM Power, submission on consultation paper, p12; Origin, submission on consultation paper, p6; Simply Energy, submission on consultation paper, p8.

At the third stakeholder workshop all stakeholders agreed that there should be no requirement to provide information about metering charges to small customers if small customers cannot appoint their Metering Coordinator.

B2.4 Commission's analysis

In determining whether metering charges should be itemised separately from other energy charges on a consumer's retail bill, the Commission considered if consumer access to this information would facilitate arrangements that:

- are simple and practical from a consumer perspective and reduce transaction costs;
- promote consumer participation and confidence in the market; and
- facilitate innovation in the provision of, and efficient investment in, metering and related services over time.

With these principles in mind, the Commission considered the value of this information to small customers. This involved consideration of the type of information that consumers would need to make informed decisions, which is dependent on the ability of small customers to appoint their own Metering Coordinator.

As small customers cannot appoint their own Metering Coordinator under the draft rule, the Commission considers that specific information about basic metering charges would be of little value to consumers in making informed decisions about energy products and services. It is the total bundle of energy services provided by a retailer to a consumer, which would include metering charges, that will be relevant to a consumer’s choice. This is consistent with current arrangements where the components of energy charges, such as network costs, are not separately identified on consumers’ bills.

In addition, providing specific information about metering service charges, particularly on a consumer’s bill, could result in consumer confusion. This confusion could arise as the metering services charge may be interpreted as a new charge, when in fact it is an existing charge separated out from a bundled set of charges.

For these reasons, the Commission has determined that retailers should not be required to provide specific information about metering charges to consumers.

The draft rule makes changes to the NERR to clarify that provisions that refer to the sale and supply of energy by retailers to small customers include the provision, installation and maintenance of the customer's meter. Among other things, those changes clarify that the requirements on the content of retail bills in rule 25 of the NERR do not require charges for the provision, installation and maintenance of the small customer's meter to be itemised separately from other energy charges.

The Commission’s position in relation to the provision of information about metering charges to small customers should also be reviewed as part of the broader review referred to in Appendix B1 regarding whether a small customer should be able to appoint its own Metering Coordinator.[331]

331 As noted in Appendix B1, the Commission recommends that this review occurs three years after the new Chapter 7 of the NER commences.

B3 Access to energy and metering data

Summary

This appendix sets out the arrangements under the draft rule in relation to access by Metering Coordinators, consumers and consumers' representatives to energy data and metering data.

The NER currently contains restrictions on who can access energy data and metering data.

Under the draft rule, the list of people who may be granted access to energy data or receive metering data has been updated to recognise the new Metering Coordinator role. Metering Coordinators may be granted access to energy data and receive metering data in relation to metering installations for which they are responsible.

To help consumers access the products and services enabled by advanced meters, the draft rule provides that metering data in respect of a small customer metering installation (as defined in the draft rule) may be received by a person with the relevant small customer's prior consent.

These changes will assist in facilitating the provision of services by energy service companies that allow consumers to better understand their energy use, such as applications that allow consumers to view their energy usage on an in-home display, mobile phone or tablet that is remotely connected to the metering installation. These services would be provided by energy service companies on a commercial basis.

The draft rule also provides that a large customer or its "customer authorised representative" may receive data from a large customer's metering installation.

B3.1 Introduction

This appendix addresses the arrangements under the draft rule in relation to access by consumers and their representatives to energy and metering data.

This appendix covers:

- the COAG Energy Council's proposal in relation to access to energy and metering data;
- stakeholder views expressed in submissions to the consultation paper and outcomes of stakeholder workshops held by the AEMC; and
- the Commission's analysis of the key issues and reasons for the Commission's draft rule.

B3.2 Rule proponent's view

In its rule change request, the COAG Energy Council considered that the current rules on the provision of electronic data transfer facilities to metering installations, including rights to access energy and metering data, should be revised as appropriate.[332]

B3.3 Stakeholder views

Few stakeholders commented specifically on this issue in submissions to the consultation paper. The Consumer Action Law Centre stated the importance of consumers having access to clear, simple and real-time information about their energy consumption in order to benefit from more cost-reflective pricing and other demand side initiatives.[333]

B3.4 Commission's analysis

The current clause 7.7(a) of the NER sets out the range of parties that are entitled to access energy data and receive metering data.[334]

In general terms, "energy data" is data that is obtained directly from a metering installation.[335] "Metering data", in contrast, refers to energy data after it has been collected from a metering installation.[336]

The Commission has considered whether the existing NER provisions related to access to energy and metering data need to be amended as a result of the new framework for metering services under the draft rule.

The AEMC recently completed the *Customer access to information about their energy consumption* rule change.[337] This rule change clarified the rights of retail customers or their authorised representatives to request retailers or DNSPs to provide metering data up to four times per year. Minimum requirements, such as formats and timeframes for delivery of metering data, will be set out in procedures to be developed by AEMO. The

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332 COAG Energy Council, rule change request, October 2013, p18.

333 CALC, submission on consultation paper, p1.

334 This clause also addresses NMI standing data, settlements ready data and data from the metering register.

335 For example, interval energy data is defined in the NER as "[t]he data that results from the measurement of the flow of electricity in a power conductor where the data is prepared and recorded by the metering installation in intervals which correspond to a trading interval or are submultiples of a trading interval. Interval energy data is held in the metering installation."

336 For example, interval metering data is defined in the NER as "[t]he interval energy data, once collected from a metering installation, is interval metering data. Interval metering data is held in a metering data services database and the metering database." The metering data services database is established and maintained by the relevant Metering Data Provider, while the metering database is maintained and administered by AEMO.

337 Available at http://www.aemc.gov.au/Rule-Changes/Customer-access-to-information-about-their-energy.

primary objective of this rule change was to improve the ability of retail customers or their authorised representatives to access historical consumption information, for example to help consumers make more informed decisions about switching retailers or energy plans.

The draft rule establishes the role of Metering Coordinator. The current NER provision setting out the parties entitled to access data only recognises the Metering Provider and Metering Data Provider roles. The draft rule amends this clause to add Metering Coordinators as a party that may be granted access to energy data and receive metering data in relation to metering installations for which they are responsible.[338]

The draft rule also amends the access to data clause in the NER (ie clause 7.7 of the current NER and clause 7.15.5 of the NER in the draft rule) to clarify how this clause operates within the new competitive metering framework.

The key amendments are as follows:

- Clause 7.15.5(a) of the NER now refers to "persons who may be granted access to energy data or may receive metering data". This compares with the current wording of clause 7.7(a) of the NER, which refers to "persons entitled to access energy data or receive metering data". This change is designed to clarify that the listed people do not have an absolute entitlement to access or receive this data. For example, as discussed below, in some cases these parties will need to negotiate access with the Metering Coordinator and agree on a price for access.

- Clause 7.15.5(b) provides that remote access to energy data by the parties listed in clause 7.15.5(a) must only be provided where passwords in accordance have been allocated in accordance with the NER, otherwise access shall be to metering data from the metering data services database or the metering database. Appendices A1 and A2 discuss changes to the parties to whom a password may be allocated in relation to a "small customer metering installation".[339]

- Clause 7.15.5(d) provides that the Metering Data Provider (or AEMO, where AEMO is responsible for the provision of metering data services), must ensure that access is provided to metering data from the metering data services database only to the parties referred to in clauses 7.15.5(a)(1) to (6) and (a)(11). In general terms, these parties are Registered Participants with a financial interest in the metering installation or the energy measured by that metering installation, the relevant Metering Coordinator, the relevant Metering Provider, the Financially Responsible Market Participant, the Network Service Provider associated with the connection point, AEMO and its authorised agents, and the AER or jurisdictional regulators on request to AEMO.

One effect of amendments noted in the last bullet point above is that these parties will only have an automatic entitlement to access metering data from the metering data

338 Clause 7.15.5(a)(2) of the NER in the draft rule.

339 See the new definition of this term in Chapter 10 of the NER - discussed in Appendix A1.

services database. If they wish to receive other metering data directly from the Metering Data Provider, they will need to negotiate access to that service on commercial terms. Other parties that are entitled under clause 7.15.5(a) to receive metering data will also need to access that data from the Metering Data Provider and negotiate access on commercial terms (subject to other rights that they may have to access that data, eg the rights of small customers and their authorised representatives to access metering data up to four times a year free of charge under the NERR).

The Commission has also considered whether the NER presents any barriers to an energy service company that is providing services to the consumer accessing metering data directly from the relevant Metering Coordinator or Metering Data Provider without having to go through the consumer's retailer or DNSP. Requesting data through the consumer's retailer or DNSP is unlikely to be a practical solution for services that require the ongoing provision of data to the consumer, including for services that display a consumer's energy use through in-home displays, web portals, or smart phone applications.

The draft rule amends the NER to add to the list of parties that may be granted access to energy data or receive metering data:

- In relation to small customer metering installations: a person who has the small customer's prior consent may access metering data.[340]
- In relation to large customers: the large customer or a "customer authorised representative" of the large customer may access data from the metering installation.[341]

This data would be provided to consumers or their authorised representatives on a commercial basis and would not be subject to minimum format requirements. This will allow for flexibility and innovation in the services that parties may wish to provide to consumers.

340 See clause 7.15.5(9) and 7.15.4(b)(2) of the NER in the draft rule.

341 See clause 7.15.5(10) of the NER in the draft rule. Under the current NER, "customer authorised representative" is defined as "[a] person authorised by a retail customer to request and receive information under Chapter 7 on the retail customer's behalf". The ability for a large customer to access data is consistent with the current ability of a customer to receive a "read-only" password, which has been retained in relation to large customers in clause 7.15.3 of the NER in the draft rule. Consistent with the new security controls for small customer metering installations in clause 7.15.4 of the NER in the draft rule, the Commission does not consider that small customers should be able to access energy or metering data themselves through passwords.

C Application of the minimum services specification

Overview of Appendix C

This appendix sets out the arrangements under the draft rule in relation to:

C1 The minimum services specification that applies to all new and replacement meters that are installed a small customer's premises, including the services to be included in the minimum services specification and governance arrangements for the minimum services specification.

C2 The circumstances in which a small customer will have the ability to opt out of having a new meter installed, and the requirements for those opt out arrangements.

C3 Arrangements in relation to meter reversion from an interval meter to an accumulation meter.

C1 Minimum services specification

Summary

This appendix addresses the governance, content and application of a minimum services specification for small customers' metering installations.

Under the draft rule, all new and replacement meters installed at small customer connection points must meet a new minimum services specification. This specification relates to the services that those metering installations must be capable of providing, rather than the technical functionality of the metering installation itself. This is expected to provide greater opportunity for innovation to help deliver consumers and third parties the services that they want at a lower cost and in a technology neutral manner.

The draft rule includes a description of the services that comprise the minimum services specification. AEMO must establish, maintain and publish procedures that set out the minimum service levels, standards and relevant technical requirements for each service set out in the minimum services specification.

The minimum services specification includes the following services:

- remote disconnection service;
- remote reconnection service;
- remote on-demand meter read service;
- remote scheduled meter read service;
- meter installation inquiry service;[342] and
- advanced meter reconfiguration service.

The Commission considers that a relatively low minimum services specification, such as the minimum services specification under the draft rule, allows the market to determine the services that consumers want at a price they are willing to pay. Over-specifying the minimum services specification could result in consumers having to pay for meters that are capable of providing services that ultimately are not taken up, are of no benefit to them or could be provided in a more cost effective way through alternative technologies. Therefore the minimum services specification only includes services that are expected to deliver benefits to the majority of small customers receiving those services at a relatively low cost.

342 The metering installation must be capable of providing the following types of information at a minimum: supply status; voltage; current; power; frequency; average voltage and current; and the contents of the meter log including information on alarms.

In practice, the Commission expects that most metering installations will exceed the minimum services specification because retailers, DNSPs and energy service companies will negotiate for additional services to be provided by the metering installation. Metering Coordinators may also install metering installations that are capable of providing additional services to anticipate demand for services and avoid the risk of meter churn.

While all new and replacement metering installations for small customers will need to be capable of providing the services set out in the minimum services specification, there will be no obligation on Metering Coordinators to provide those services. Rather, the terms and conditions on which those services are provided, if at all, will be subject to commercial negotiation between the Metering Coordinator and third parties.

There are a number of services that are expected to be commonly used that have not been included in the minimum services specification, such as load control. These services may be captured by a shared market protocol. The Commission and AEMO are developing advice on this protocol.

C1.1 Introduction

This appendix explains the draft rule's provisions in relation to the governance, content and application of a minimum services specification for new and replacement metering installations for small customers.

The draft rule does not mandate a minimum services specification for metering installations installed at the connection points of large customers.

The purpose of a minimum services specification is to allow the broader market benefits of advanced meters to be captured, particularly where the party installing the meters may not have an incentive to provide a metering installation capable of providing services that would be of value to others. Coupled with mandated service levels and standards, the minimum services specification provides a starting point for third parties, such as retailers, DNSPs and energy service companies, to negotiate access to services that may ultimately benefit their customers, either directly through new retail or energy management service offerings, or indirectly through lower retail and network costs.

The remainder of this appendix sets out:

- current arrangements relating to the functionality of metering installations;
- the relevant elements of the COAG Energy Council's rule change request;
- stakeholder views including submissions to the consultation paper, outcomes of stakeholder workshops held by the AEMC, and a summary of AEMO's advice to the COAG Energy Council on a minimum functionality specification; and

- the Commission's analysis of the key issues and reasoning for the draft rule.

C1.2 Current arrangements

The NER currently contains minimum functionality requirements for metering installations.[343] These requirements were primarily established to facilitate settlement of the NEM and billing of customers.

Currently, most metering installations for small customers in the NEM are accumulation meters that must be manually read at the premises and can only measure consumption on an accumulation basis. The main exceptions are the advanced meters deployed under the Victorian AMI program and some advanced meter trials in other jurisdictions.

AEMO is responsible for establishing and maintaining the procedures specified in Chapter 7 of the NER, including the metrology and service level procedure, in accordance with the rules consultation procedures.[344]

There are a number of provisions in the NER relating to the collection and provision of metering data, the provision of metering data services and accuracy and design requirements for metering installations that support market settlement and billing. These existing arrangements are different in nature to the minimum services specification and will largely remain unchanged.

C1.3 Rule proponent's view

The COAG Energy Council considered that broader market benefits would be achieved if parties have certainty and access to an agreed specification of the metering components, functions and performance levels that an advanced meter should provide.[345] To support competition and investment in the provision of metering services, the COAG Energy Council proposed that the new framework cater for a minimum functionality specification.

The COAG Energy Council rule change request proposed that the minimum functionality specification should not override the existing specifications contained in the NER. These include the accuracy, design, inspection and testing of metering installations and other requirements to meet Australian and international standards.

The COAG Energy Council proposed that the minimum functionality specification should not be binding unless prescribed by a jurisdiction.

343 Current clause 7.3.1 of the NER.

344 Current clauses 7.1.3 and 7.1.4 of the NER. The exception is the B2B procedures that provide for the operation of the B2B e-hub, which are established and maintained by the IEC (current clauses 7.1.3 and 7.2A of the NER).

345 COAG Energy Council, rule change request, October 2013, p15.

C1.3.1 Governance of the minimum services specification

The COAG Energy Council proposed that AEMO would develop, maintain and publish the minimum functionality specification. This would be in the form of a procedure that also provides an explanation of those functions and related performance levels. AEMO would need to comply with the rules consultation procedures under the NER when establishing and changing the minimum functionality specification.[346]

The COAG Energy Council noted that the final rule could provide guidance to AEMO on the factors that should be considered in establishing the minimum specification.[347]

C1.3.2 The minimum services specification

In December 2011, the COAG Energy Council endorsed the Smart Meter Infrastructure (SMI) Minimum Functionality Specification (MFS) that was developed by the National Smart Metering Program. The SMI MFS was developed in the context of the functionality requirements for the advanced metering infrastructure as part of a potential DNSP-led rollout that may be mandated by a jurisdictional Minister.[348] The COAG Energy Council attached the SMI MFS to its rule change request and noted that the SMI MFS could provide a basis for the functionality requirements and performance levels where parties may consider installing advanced meters.

The COAG Energy Council's rule change request notes that the NER currently contain "minimal regulation of the provision of remote communications in relation to a metering installation". The rule change request proposes that, in light of future developments of meters with advanced functionality, the current rules on the provision of electronic data facilities be revised.[349]

In June 2014, the COAG Energy Council asked that AEMO provide advice on a minimum functionality specification for advanced meters to, among other things, inform a competitive framework for metering services. In developing this advice, AEMO was required to consider the services an advanced meter should provide to:[350]

- support billing and settlement in the market;
- support efficient business practices;
- enable the efficient, reliable and safe operation of the national grid; and

346 COAG Energy Council, rule change request, October 2013, p15.

347 Ibid.

348 The provision for a jurisdiction to mandate a roll out of advanced meters has subsequently been removed from the NEL.

349 COAG Energy Council, rule change request, October 2013, pp17-18.

350 COAG Energy Council, terms of reference, AEMO advice on smart meter functionality and a shared market protocol, p4.

- provide an accessible and secure platform for the delivery of flexible tariffs and demand side and data services to consumers and other Market Participants.

AEMO's advice was delivered in November 2014 and forms the basis of the minimum services specification set out in the draft rule. This is discussed in section C1.4.3.

C1.4 Stakeholder views

In submissions, stakeholders generally agreed that the specification should cover services enabled by the metering installation instead of functionality. Stakeholders considered that mandating technical requirements would limit competition, innovation and technology neutrality. Metering Providers and prospective Metering Coordinators proposed that they are best placed to determine the technical aspects of their advanced metering infrastructure.

C1.4.1 Governance of the minimum services specification

There were divergent views on the party best placed to develop and maintain the minimum services specification.

Responses to the consultation paper indicated that the majority of stakeholders supported AEMO being responsible for establishing and maintaining the minimum services specification, with industry consultation.[351] However, several stakeholders considered that the IEC should either have full responsibility for determining the minimum services specification or should provide advice to AEMO.[352] Simply Energy was of the view that the appropriate governance arrangements for the minimum services specification would be a committee or working group of AEMO and industry stakeholders.[353]

At the AEMC's fifth stakeholder workshop on 9 October 2014, stakeholders were presented with several options for how a minimum services specification could be governed under the NER. Stakeholders raised divergent views on the level of detail that should be included in the NER compared with AEMO procedures. One stakeholder noted that performance standards were vital for both defining a service and determining the likely costs of providing that service.

At this workshop, there was discussion about whether AEMO should be responsible for both setting the minimum services specification and the more detailed procedures. Some considered that this approach would expedite any changes to the minimum services specification, allowing for a faster and more flexible process. However, some argued that the focus should be on outcomes rather than on the speed of the process.

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351 AGL, submission on consultation paper, p9; Origin Energy, submission on consultation paper, p9; Vector, submission on consultation paper, p19; Secure Australasia, submission on consultation paper, p3; ERM Power, submission on consultation paper, p15.

352 Energex, submission on consultation paper, p7; ENA, submission on consultation paper, p31; SA Power Networks, submission on consultation paper, p11.

353 Simply Energy, submission on consultation paper, p9.

One stakeholder expressed concern with AEMO being the ultimate decision maker. Another suggested that there be a more democratic approach to determining and changing the minimum services specification, such as an industry body whereby each participant would have a vote.

AEMO supported having the list of services in the NER, with details regarding applicable service levels and performance standards set out in procedures. AEMO considered that this would be consistent with how other metering procedures are governed under the NER. One stakeholder supported this option on the basis that it would ensure consideration of the NEO, and indicated that some consumer groups find it easier to engage with the consultation process for rule changes. However, Market Participants did not generally consider that AEMO's consultation procedures were more limited than the rule change consultation process, and noted that AEMO is also required to have regard to the NEO under the NEL.

There was discussion about whether the NER would have to include sufficient detail to ensure that the scope of the services, and thereby the likely costs of the services, are certain.

Consumer groups advocated for a role in the ongoing governance of the minimum services specification.

C1.4.2 The minimum services specification

A variety of views were held on the appropriate services to include in the minimum services specification.

Retailers were of the view that the minimum services specification should support the minimum services required for a contestable retail market. They proposed that the specification should be less exhaustive than that which was developed by the SMI MFS or the minimum functionality specification for the Victorian AMI program.

DNSPs were concerned that retailers and Metering Coordinators would develop a specification based on their commercial needs, with little consideration of potential network benefits. On this basis they argued for a more comprehensive minimum services specification.

C1.4.3 AEMO advice on a minimum functionality of advanced meters

In November 2014, AEMO delivered advice to the COAG Energy Council on a minimum functionality specification for advanced meters.[354] AEMO's advice stated that it used the following criteria to assess the services that could be mandated:

- the interests of the market to deliver efficient business processes and low transaction costs;

354 AEMO, Minimum Functionality of Advanced Meters, Advice to COAG Energy Council, November 2014.

- the broader market and society's interest in meter accuracy, safety and security; and
- the common interest in being able to provide efficient network services and efficient pricing of those services.

AEMO identified a list of the services that could be provided through advanced meters, assessed them against the above criteria and allocated them to one of three categories:

- "Primary services" were those AEMO considered should form part of any minimum services specification.
- "Secondary services" were those that AEMO considered may be included in a minimum services specification if advanced meters were rolled out on a non-competitive basis as part of a rollout mandated by a jurisdiction.
- "Value added services" were those that AEMO considered did not meet the above criteria and should not be included in the minimum services specification, but could be negotiated.

Table C1.1 outlines the services that AEMO allocated to each category.

Table C1.1 AEMO's advice on minimum specification of advanced meters

Primary services	Secondary services	Value added services
De-energisation (turn electricity supply off remotely)	Re-energisation (remotely arming the meter to enable the customer to reconnect supply via a switch at the meter)	Enabling a Home Area Network (HAN)
Re-energisation (turn electricity supply on remotely)	Load limiting (the ability to remotely establish or remove a limit that restricts the amount of energy that can be consumed)	Supply failure and restoration notifications
Meter read - on demand (obtained remotely as required by a retailer, customer or another authorised party)	Load management (turning designated loads off and on at a customer's premises, remotely on command, or under a schedule)	Metering installation asset management
Meter read - scheduled (obtained remotely as per contracted dates and times)	Local access to a metering system via a registered device (connectivity with the meter from a device owned and operated by the customer or their agent)	Safety monitoring
Meter installation enquiry (remotely obtaining energy		

Primary services	Secondary services	Value added services
information, meter status and usage data)		
Meter reconfiguration (to remotely enable access to new tariffs and new arrangements, such as solar connections and energy demand tariffs)		

C1.5 Commission's analysis

This section sets out:

- the Commission's rationale for introducing a minimum services specification rather than a minimum functionality specification;
- the Commission's draft rule and rationale for including provisions for the minimum services specification in the NER, with service levels, standards and technical requirements to be developed by AEMO in procedures;
- the Commission's draft rule and rationale for deciding which services to include in the minimum services specification;
- the conditions under which the minimum services specification will be required to be satisfied; and
- interactions between the minimum services specification and the shared market protocol.

C1.5.1 Functionality versus services specification

The Commission considers that the minimum specification for small customers should be based on the services that the metering installation must be capable of supporting rather than the functional components that the metering installation must include.

Focussing on services provides metering manufacturers with greater opportunity to innovate around how they provide particular service outcomes, rather than mandating a particular technology they must use or how it must operate. This approach is expected to help deliver consumers and other parties the services that they want at a lower cost.

Existing specifications contained in clause 7.3.1 the NER relating to requirements for metering installations, such as their components, remain unchanged under the draft rule.[355] The existing metering installation component requirements[356] specify

355 This clause is renumbered as clause 7.8.2 of the NER in the draft rule.

356 Clause 7.8.2 of the NER in the draft rule.

metrology-related components that are required for all metering installations so that they can accurately record, store and communicate energy consumption information.

The minimum services specification will sit alongside those existing requirements. It specifies the services that new and replacement metering installations for small customers must be capable of providing. These services are not related to basic metrology functions, and instead relate to advanced metering services.

C1.5.2 Governance of the minimum services specification

A list of minimum services that all new and replacement metering installations for small customers must be capable of providing is set out in the draft rule. This list of services is discussed in the next section. The Commission agrees with stakeholder comments that the services included in the NER must be specified in sufficient detail to provide certainty of the nature and scope of the services that a metering installation must be capable of providing. The draft rule sets out detailed definitions of each of the services (see Schedule 7.5 of the NER in draft rule).

AEMO will be required to establish, maintain and publish procedures that set out, for each service specified in the minimum service specification:[357]

- minimum service levels, including service availability (eg at what times the can service be requested - such as 8.00am to 8.00pm) and completion timeframes (eg the service must be completed within a period - such as within one hour of the request being received); and
- minimum standards, including completion rates against the service levels (eg 95% of services are completed and provided successfully when assessed against the minimum service levels) and accuracy requirements.

AEMO's procedures may also include technical requirements for one or more of the services specified in the minimum service specification. Applicable technical requirements are expected to be most relevant for the meter installation enquiry and advanced meter re-configuration services. For example, the draft rule sets out at a relatively high-level the four operational parameters that, as a minimum, must be capable of being set under the advanced meter re-configuration service. There is likely to be benefit in AEMO specifying further technical requirements for those parameters in the procedures.

AEMO may include these procedures within the existing Service Level Procedures or develop new procedures.

The purpose of the service levels and standards is to provide greater certainty to metering manufacturers and others regarding the specifications that the metering installation will be required to meet. Mandating service levels and standards for those services included in the minimum services specification may also reduce transaction

357 Clause 7.8.3(c) of the NER in the draft rule.

costs associated with negotiating terms and conditions for access to those services. Finally, having a consistent set of service levels and standards may facilitate price comparisons between Metering Coordinators.

Developing the minimum services specification requires an assessment of the costs and benefits of various services across the supply chain, including an assessment of:

- the broader benefits that various services are expected to bring to the market;
- incentives for parties deploying advanced meters to include services with broader market benefits;
- the likelihood that services will be taken up such that consumers will not be required to pay for meters that are capable of providing services that will not benefit them; and
- the likelihood that services will be most efficiently provided via a meter rather than some other technology.

Ultimately, the more services included in the minimum services specification, the higher the cost for small customers. Small customers would be required to pay for a metering installation capable of providing those services even if they do not use them. The Commission considers the trade-offs between costs imposed on small customers and services provided by advanced meters are best addressed through specifying the minimum service specification in the NER. This allows for a whole-of-market perspective and consideration of whether inclusion of certain services is likely to be in the long term interests of small customers.

Any person will be able to propose a change to the minimum services specification via the rule change process. This is appropriate given the variety of parties that will have an interest in the minimum services specification. Further, the rule change process involves a clearly understood, consultative approach whereby any changes will be assessed having regard to the NEO.

However, AEMO is better placed to develop the detailed service levels and standards. This is consistent with certain other arrangements related to metering in the NER whereby technical details relating to the regulatory framework are set out in procedures that are developed and maintained by AEMO. For example, Chapter 7 of the NER sets out provisions relating to, among other things, the collection and provision of metering data and the provision of metering data services.[358] These provisions are supported by AEMO's Service Level Procedures for Metering Providers and Metering Data Providers within the NEM, which detail the obligations, technical requirements and performance levels associated with the processes of meter reading, data collection, data processing and adjustment, aggregation and delivery of metering data.

358 See current clause 7.1.1(a) of the NER for a complete list of provisions that Chapter 7 covers.

Any amendments to the minimum services specification would require subsequent amendments to AEMO's service levels and standards. The Commission acknowledges that this approach may be more time consuming than if the minimum services specification was set out in procedures and determined by AEMO. However, this approach is appropriate to ensure the market-wide impacts of changing the minimum services specification are assessed via a clearly defined, consultative process, thereby minimising uncertainty for participants in the metering services market.

C1.5.3 Services to be included in the minimum services specification

The advice provided by AEMO on the minimum functionality of advanced meters forms the basis of the minimum services specification set out in the draft rule. Under the draft rule, the minimum services specification includes the following services:

- *Remote disconnection service*. This service is the remote disconnection of a small customer's premises via the metering installation. Parties that are able to request a remote disconnection will be limited to the LNSP and the Financially Responsible Market Participant.

- *Remote reconnection service*: This service is the remote reconnection of a small customer's premises via the metering installation. As for remote disconnection, the parties that are able to request a remote reconnection service will be limited to the LNSP and the Financially Responsible Market Participant.

- *Remote on-demand meter read service*: This service is the remote retrieval of metering data from the metering installation for a specified point or points in time and the provision of such data to the requesting party. This includes the retrieval and provision of reactive energy metering data and/or active energy metering data (for imports and/or exports of energy measured by the meter), interval metering data and accumulated metering data for the start and end of the period specified in the request. The parties that are able to request a remote scheduled meter read service are those parties listed in clause 7.15.5(a) of the NER in the draft rule.

- *Remote scheduled meter read service*: This service is the remote retrieval of metering data from a metering installation on a regular and ongoing basis and the provision of such data to the requesting party. This includes the retrieval and provision of reactive energy metering data and/or active energy metering data (for imports and/or exports of energy measured by the meter), interval metering data and accumulated metering data for the start and end of the period specified in the request. The parties that are able to request a remote scheduled meter read service are those parties listed in clause 7.15.5(a) of the NER in the draft rule.

- *Meter installation inquiry service*: This service is the remote retrieval of information from, and related to, a specified metering installation and the provision of such information to the requesting party. Table S7.5.1.1 of the NER in the draft rule sets out the seven types of information that the metering installation must (as a minimum) be capable of providing. These include: supply status; voltage;

current; power; frequency; average voltage and current; and the contents of the meter log including information on alarms. The parties that are able to request a remote meter installation enquiry service are the LNSP and the Financially Responsible Market Participant, and any other person to whom a small customer has given its prior consent under clause 7.15.4(b)(2) of the NER in the draft rule.

- *Advanced meter reconfiguration service*: This service is the remote setting of the operational parameters of the meter. Table S7.5.1.1 of the NER in the draft rule sets out the four operational parameters that, as a minimum, must be capable of being set. Parameters that must be capable of being set, as a minimum, include: the activation or deactivation of a data stream or data streams; altering the method of presenting energy data and associated information on the meter display; thresholds for alarms; and the parameters that specify how the voltage, current, power, supply, frequency, average voltage and average current measurements are calculated. The parties that are able to request an advanced meter reconfiguration service will be limited to the DNSP and the retailer.

The Commission considered the trade-offs in determining the list of services in the minimum services specification. Regulating a comprehensive list of services would provide greater certainty to parties regarding the services that an advanced meter must be capable of providing. However, there is a risk that regulation may over-specify the minimum services specification. This could result in consumers having to pay for meters that are capable of providing services that ultimately are not taken up, are of no benefit to them or could be provided in a more cost effective way through alternative technologies.

For example, the "last gasp" service requires an advanced meter provide an alert if the supply of energy through the meter is disrupted. This service could be used to detect network outages, provided there are a sufficient number of meters with this capability within a designated area.[359] However, this capability would add approximately $10 to the cost of each meter, which is likely to be passed on to consumers through their retail charges.[360] Alternatively a metering installation inquiry service, which forms part of the minimum services specification, potentially supports a similar outcome at a much lower cost to customers.

Having a relatively low minimum services specification would allow the market to determine the services that consumers want at a price they are willing to pay. Therefore the Commission has only included services in the minimum services specification where it considers that, if provided, these services are likely to deliver benefits to the majority of consumers receiving those services at a relatively low cost.

359 Also known as 'supply failure and restoration notifications'. AEMO classified this service as a value-added service. AEMO notes that the ENA submitted that more than 60 per cent of metering installations within a designated area would be required to support this service. See AEMO, Minimum Functionality of Advanced Meters, Advice to COAG Energy Council, November 2014, p13.

360 This figure was suggested during an AEMO workshop regarding the development of its advice on the minimum functionality of advanced meters for the COAG Energy Council.

The likely benefits of these services are set out in Table C1.2.

Table C1.2 Potential benefits to consumers of the minimum services

Service	Potential consumer benefits
Remote disconnection	Remote disconnection services will allow both retailers and DNSPs to disconnect a premises without the need for a site visit. This may provide cost savings, which could be passed through to consumers. Remote disconnections could also provide greater convenience and lower costs for consumers that vacate a premises.
Remote re-connection	Remote reconnection services will allow for faster re-connection for a customer following a remote disconnection or if a consumer moves into a new premises. It will also allow faster reconnection of customers that have been wrongfully disconnected. As with remote disconnections, retailers and DNSPs could benefit through lower costs, which are expected to be passed on to consumers.
Remote on-demand meter read	This service facilitates faster and less costly final meter reads for the purpose of a final bill. Coupled with the remote disconnection service, this may lower costs to consumers when they vacate a premises. This service could also make the process of switching retailer faster by allowing final meter reads to occur more quickly. As a consequence, consumers may have greater confidence to participate in the retail market. Third party service providers could also use this service to support the provision of new products and services to customers.
Remote scheduled meter read	This service provides for faster and more accurate market settlement and billing. Consumers may benefit from, among other things, the possibility of more regular billing to avoid "bill shock" and less reliance on estimated reads. It also allows settlement in the wholesale market to be based on a consumer's actual consumption, rather than the average load profile for a consumer in that distribution area.
Meter installation inquiry	This service allows DNSPs to better manage their networks by analysing data relating to, for example, loss of supply, voltage, current, power and supply frequency. Consumers may benefit from better management of supply interruptions, improved quality of supply, and lower network charges.
Advanced meter reconfiguration	This service allows meters to be reconfigured remotely to support the uptake of, or changes to, the above services without the need for a site visit. This may lower costs to parties accessing those services, which are expected to be passed on to consumers in the form of lower prices.

In practice, the Commission expects that most metering installations will exceed the minimum services specification. Many of the advanced meters currently available are capable of providing a number of services in addition to those listed above, such as load control. Further, retailers, DNSPs and energy service companies will be able to negotiate with Metering Coordinators prior to the installation of meters to include the services they consider necessary and are willing to pay for.

Over time, this approach will allow the market to determine the appropriate balance of services. Consumers will influence the services their meters include through their choice of retail and energy management services offered by retailers and energy service companies. DNSPs will also be able to negotiate for the services that they consider will allow them to operate their networks more efficiently or with improved reliability or quality of supply.

Metering Coordinators are expected to have an incentive to include services additional to the minimum services specification to reduce the risk of meter churn. If a Metering Coordinator installs a meter that is not capable of providing the range of services that a consumer, and therefore a retailer, is likely to want, it risks having its meter stranded. This may occur if a consumer changes retailer and the new retailer appoints a different Metering Coordinator that can provide the desired range of services.

Many services that can be provided through the meter can already be provided through alternative technologies. Therefore, over-specifying the minimum services specification could risk stifling innovation and development in those services. For example:

- Devices that sense current can be clipped onto outgoing wires from the circuit box. These sensors are Wi-Fi-enabled and allow for real-time monitoring of energy use at a level as granular as the wiring of the premises.
- Advanced meters connected to in home display arguably have already been superceded by mobile phone applications and web portals.
- Smart appliances are able to be remotely controlled via the internet without the need for load control equipment to be included in the metering installation.

The Commission is cognisant that technology is constantly evolving and developing, and therefore alternative ways to provide services may emerge. These technologies could potentially provide the same service as an advanced meter at a lower cost. Providing a relatively low minimum services specification therefore avoids the risks of locking in outdated, and potentially more expensive, technology.

Under the draft rule, the minimum services specification will apply to new and replacement metering installations installed at a small customer connection points. The minimum services specification will not apply to metering installations installed for large customers or connection points that do not have a retail customer. The Commission considers that large customers are in a better position to negotiate for the advanced metering services that they require and so a minimum services specification is not necessary. Requiring a minimum services specification to apply to large customers may unduly inhibit commercial negotiations.

C1.5.4 Meeting the minimum services specification

Under the draft rule, a Metering Coordinator must ensure that any new or replacement metering installation in respect of a connection point of a small customer is a type 4 metering installation that meets the minimum services specification, subject to the exception noted below.[361] A metering installation meets the minimum services specification if it is capable of providing the services listed in Table S7.5.1.1 of the NER in the draft rule, and it is connected to a telecommunications network[362] that enables remote access to the metering installation.[363]

Several stakeholders noted that there may be instances where there is no existing telecommunications network to facilitate remote acquisition at a metering installation, such as in remote areas. As it may be prohibitively expensive for a Metering Coordinator to build a telecommunications network to provide remote access (or pay a telecommunications operator to extend its network), the Commission has decided that Metering Coordinators in this situation will be able to apply to AEMO for an exemption.

The draft rule provides that AEMO may exempt a Metering Coordinator from complying with the requirement to install a type 4 metering installation that meets the minimum services specification in respect of a small customer connection point if the Metering Coordinator demonstrates to AEMO's reasonable satisfaction that there is no existing telecommunications network which enables remote access to the metering installation at that connection point.[364] An exemption may be for one or more periods of up to five years each.

If such an exemption is granted, any new or replacement metering installation for a small customer at that connection point must still be capable of providing all of the services listed Table S7.5.1.1 of the NER. However, the requirement that the metering installation is connected to a telecommunications network that enables remote access to the metering installation would not apply. These metering installations will be classified as type 4A metering installations.

Where AEMO grants such an exemption, the meter would need to be manually read. Currently all manually read interval metering installations are classified as type 5 metering installations.

Under the draft rule, type 4A metering installations must have sufficient memory to store at least 200 days of interval energy data, which is the current requirement for type 5 metering installations.[365] This compares to at least 35 days for a type 4 metering installation (which is remotely read and so less memory is required). Other consequential changes are made to the schedules to Chapter 7 to incorporate type 4A metering installations.[366]

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361 Clause 7.8.3 of the NER in the draft rule.

362 This is defined in the NER as "a telecommunications network that provides access for public use or an alternate telecommunications network that has been approved by AEMO for the remote acquisition of metering data".

363 Clause S7.5.1 of the NER in the draft rule.

364 Clause 7.8.4 of the NER in the draft rule.

365 Clause 7.8.2(a)(11) of the NER in the draft rule.

366 See for example the amendments to Schedule 7.4 of the NER in the draft rule.

The existing requirements and criteria related to each metering installation type, as currently set out in Schedule 7.2 of the NER, will not change. The existing metering installation types 1-7 will remain, with a new metering installation type 4A added.

The draft rule also introduces a definition of a "small customer metering installation", which is defined as a metering installation in respect of the connection point of a small customer which meets the minimum services specification or which is required to meet the minimum services specification under clauses 7.8.3(a) and 7.8.4(d) of the draft rule. A type 4A metering installation is not a small customer metering installation.

The Metering Coordinator must ensure that energy data is retrieved by remote access for each small customer metering installation for which it is responsible.[367]

While all new and replacement metering installations for small customer connection points must be *capable* of providing the services set out in the minimum services specification, the Metering Coordinator is not required to *provide* those services. This is consistent with the Commission's decision that there will be no access regulation at the start of the market, as discussed in Appendix E. Therefore DNSPs, retailers and others will need to negotiate for the provision of the services set out in the minimum services specification, just as they would for any other service.

C1.5.5 Links to a shared market protocol

While there are other services that could be provided by advanced meters that have not been included in the minimum services specification, these other services may be captured by the shared market protocol on which AEMO is currently formulating technical advice to the COAG Energy Council. In addition, the AEMC is currently developing advice to the COAG Energy Council on the governance and implementation of the shared market protocol.

A shared market protocol is an electronic platform that allows parties to communicate regarding the services that will be offered by advanced meters. It also defines the format of the messages sent between the parties to provide those services. A shared market protocol is a default method of communication and does not preclude parties from agreeing to alternative methods of communication.

A shared market protocol is intended to promote competition by reducing barriers to entry for new retailers and energy service companies, while not inhibiting innovation. For example, a shared market protocol would prevent a situation where an energy service company needs to have different systems to communicate with different Metering Coordinators.

The Commission's advice on the implementation of a shared market protocol,[368] due to be provided to the COAG Energy Council at around the same time as the final

367 Clause 7.3.2(f) of the NER in the draft rule.

determination for this rule change, will need to address how a shared market protocol would interact with services provided both under the minimum services specification and by the market. The Commission's expectation is that the shared market protocol could set out a communication method for all commonly available advanced services. This is likely to include:

- the advanced services set out in the minimum services specification;
- the "secondary services" set out in AEMO's advice on the minimum functionality of advanced meters; and
- the "value added services" set out in AEMO's advice on the minimum functionality of advanced meters.

Therefore although a number of advanced services may not be captured within the minimum services specification, these services may still be captured within the shared market protocol.

C1.5.6 Evolving technologies and processes, and development of the market

Clause 7.13 of the NER currently sets out provisions related to evolving technologies and processes and development of the market. Among other things, this clause:

- provides that evolving technologies or processes that meet or improve the performance and functional requirements of Chapter 7 or facilitate the development of the market may be used if agreed between the relevant Market Participant, LNSP and AEMO, provided that it does not materially and adversely affect the interests of others;
- requires AEMO to, at least annually, publish a report on the application of evolving technologies and processes;
- requires AEMO to, at least annually, submit a report to the AEMC on the extent to which Chapter 7 of the NER may need to be amended to accommodate evolving technologies and processes or the development of the market;
- requires AEMO to, at least annually, publish a report on the impact of the introduction of retail competition on the wholesale market; and
- requires Ministers to, by 20 June 2009, conduct a review on type 5 and 6 metering installations and the metrology procedure.

The Commission considers that this clause is no longer necessary or appropriate in the context of the new framework set out in the draft rule.

368 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Implementation-advice-on-the-Shared-Market-Protoco

Under the draft rule, parties will be free to use any evolving technologies and processes that they wish, subject to the existing NER requirement, the requirements of the minimum services specification, and any future requirements of a shared market protocol. AEMO, LNSPs and retailers should not have a role under the NER in agreeing which evolving technologies and processes can be used by other parties.

The provision referring to a report on the impact of retail competition on the wholesale market is no longer required given the time that has now passed since the introduction of retail competition in most jurisdictions.

Accordingly, this clause has been removed in the draft rule.

C2 Opt out arrangements

Summary

This appendix outlines the opt out arrangements under the draft rule.

Under the draft rule, any new metering installation installed at a small customer's connection point must be a type 4 metering installation that meets the minimum services specification (subject to a limited AEMO exemption power, as discussed in Appendix C1).

Small customers will be able to opt out of having a type 4 metering installation that meets the minimum services specification installed as part of a "new meter deployment" (as defined in the draft rule) and retain their existing metering installation.

More specifically, the draft rule requires retailers to notify their small customers of a proposed replacement of the small customer's meter under a new meter deployment and provide them with the ability to opt out of having a new meter installed. The retailer is not required to comply with the notification and opt out process if it is authorised to undertake the new meter deployment under the terms of the customer's market retail contract.

Meters installed in all other scenarios, including for "maintenance replacements" (as defined in the draft rule), faults and new houses or developments, will need to meet the minimum services specification. The Commission considers that providing an ability for small customers to opt out in these scenarios is neither practical nor appropriate, and is not in the long term interests of consumers. Accordingly, the draft rule does not provide an opt out right in these circumstances.

C2.1 Introduction

This appendix outlines the circumstances in which small customers will be able to opt out of having a new meter installed and the corresponding requirements under the draft rule.

There are five potential scenarios where a small customer would have a new meter installed:

1. The consumer chooses a product or service that their existing meter cannot support, eg a time of use tariff or load control.

2. A retailer and its appointed Metering Coordinator (possibly in coordination with the LNSP or another party) deploys advanced meters to its consumers as part of a "new meter deployment", eg to achieve operational efficiencies.

3. A new meter is installed as part of a "maintenance replacement".

4. A meter needs to be replaced due to it being found faulty or otherwise not compliant with the requirements set out in the NER.

5. A new house or residential development is built and a meter needs to be installed to enable connection to the network.

In scenario 1, the consumer has initiated the change and, in turn, the installation of an advanced meter in order to receive the new product or service. In scenarios 2-4, the consumer has not initiated the change to their meter and in scenario 5 no existing meter is in place. It is therefore relevant to consider whether the consumer should be provided with the ability to 'opt out' of receiving a meter that meets the minimum services specification in each of these scenarios.

The remainder of this appendix sets out:

- current arrangements relating to the installation of meters for small consumers;
- the relevant elements of the COAG Energy Council's rule change request;
- stakeholder views including submissions to the consultation paper and outcomes of stakeholder workshops held by the AEMC; and
- the Commission's analysis of the key issues and reasoning for the draft rule.

C2.2 Current arrangements

Under the NER the Responsible Person (typically the DNSP for small customers) must, for each metering installation for which it is responsible, ensure that (amongst other things):

- the installation is provided, installed and maintained in accordance with the NER, the metrology procedure and other procedures authorised under the NER;[369] and
- the components, accuracy and testing of metering installations complies with the requirements of the NER, metrology procedure and other procedures authorised under the NER.[370]

The NER and metrology procedure establish minimum requirements for meters to enable, among other things, the accurate collection of metering data for billing and settlement purposes.

The NER do not generally prevent a Responsible Person from installing or altering a metering installation to exceed these minimum requirements. Some jurisdictions have implemented their own regulatory requirements beyond the minimum requirements

369 Current clause 7.2.5(d)(1) of the NER.

370 Current clause 7.2.5(d)(2) of the NER.

set out in the NER and the metrology procedure for the specification of meters to be installed by the Responsible Person.

The remainder of this section sets out the current arrangements for the installation of a meter under each scenario.

C2.2.1 Scenario 1: Consumer takes up a product or service that requires a new meter to be installed

A consumer's decision to take up a new product or service that requires a new meter to be installed is given effect under a contract between the consumer and their retailer. There is currently no requirement under the NER or NERR for a retailer to give their customer an ability to opt out of the installation of a new meter to enable the product or service.[371]

C2.2.2 Scenario 2: New meter deployment

The NER does not explicitly prohibit retailers from deploying advanced metering to residential and small business premises. However, as discussed in Appendix D2, uncertainty around the exit fee payable to the DNSP for regulated meters[372] and the previous bundling of metering charges with distribution use of system charges by DNSPs has hindered retailers' business case to do so to date. As in scenario 1, there is currently no NER or NERR requirement for the retailer to provide its customer with the ability to opt out of the installation of an advanced meter in these circumstances.[373]

C2.2.3 Scenario 3: Maintenance replacement[374]

The Responsible Person must arrange for testing to be carried out to ensure that the metering installations for which it is responsible comply with the requirements set out in the NER, the metrology procedure and other procedures under the NER.

The Responsible Person must ensure that testing of a metering installation is carried out in accordance with the NER (notably, the requirements set out in current clause 7.6.1 and schedule 7.3) or in accordance with an asset management strategy that sets out an alternative testing practice and is approved by AEMO.[375] In both cases, the Responsible Person must ensure that the testing of the metering installation is carried out in accordance with a test plan that has been registered with AEMO.[376]

371 Specifically, small customers do not currently have ability to opt out in the way that is being proposed under the new meter deployment scenario.

372 A regulated meter refers to a meter in respect of which the service of providing, installing and maintaining the meter is classified as a direct control service.

373 Specifically, small customers do not currently have ability to opt out in the way that is being proposed under the new meter deployment scenario.

374 Note that the term 'maintenance replacement' is not defined in the current rules.

375 Current clause S7.3.1(c)(1)-(2) of the NER.

376 Current clause S7.3.1(c)(3) of the NER.

The Responsible Person may arrange for a replacement of meters following sample testing of meter populations. If testing shows that the accuracy of a metering installation does not comply with the requirements of the NER, the Responsible Person must advise AEMO and arrange for the accuracy of the metering installation to be restored in a timeframe agreed with AEMO.[377] In some cases, the entire population or sub-population of meters will be replaced. DNSPs, as the Responsible Person for the majority of small customers, currently replace, on average, around 0.3-3 per cent of their total meter fleets each year under a maintenance replacement.[378]

The NER does not explicitly require the Responsible Person to notify a consumer that their meter will be replaced as part of a maintenance replacement, or provide them with an ability to opt out of the specification of meter that will be installed. The new metering installation must meet the minimum requirements set out in the NER and any additional regulatory requirements established by jurisdictions.

However, meter replacement often requires an interruption to the consumer's supply of electricity. In most cases this will be a 'planned interruption', which is defined as "an interruption of the supply of energy for the planned maintenance, repair or augmentation of the transmission system; or the planned maintenance, repair or augmentation of the distribution system, including planned or routine maintenance of metering equipment; or the installation of a new connection or a connection alteration".[379]

The DNSP is required to notify the retail customer of the planned interruption at least four business days before the date of the interruption in the form specified in the NERR, and use its best endeavours to restore supply as soon as possible.[380]

C2.2.4 Scenario 4: Replacement due to fault

A "metering installation malfunction" is defined in the NER as the full or partial failure of the metering installation in which it does not:

(a) meet the requirements of schedule 7.2 of the NER; or

(b) record, or incorrectly records, energy data; or

(c) allow, or provides for, collection of energy data.[381]

The NER currently requires the Responsible Person to arrange for repairs to be made to:

377 Current clause 7.6.2 of the NER.

378 This is an approximate figure based on information provided by several DNSPs.

379 See rule 88 of the NERR.

380 Rule 90 of the NERR. This rule is a civil penalty provision.

381 See Chapter 10 of the NER.

- a type 1, 2 or 3 metering installation to address a metering installation malfunction as soon as practicable but no later than two business days after being notified of the malfunction; and
- a type 4, 5, 6 or 7 metering installation to address a metering installation malfunction as soon as practicable but no later than 10 business days of being notified of the malfunction.[382]

For small customers, the majority of whom have a type 5 or 6 metering installation, replacement meters are installed by the Metering Provider that has been appointed by the LNSP (as the Responsible Person). DNSPs currently replace, on average, around 1-3 per cent of their total meter fleets each year for reasons related to failure or non-compliance.[383]

Generally, the consumer will continue to receive electricity even though their metering installation is faulty. An estimate of the consumer's electricity consumption will be made by the Metering Data Provider until a working meter is installed. The estimate is usually performed over a longer period than the time to replace the meter because in many cases the Metering Data Provider does not know when the fault occurred.

There is no explicit requirement in the NER for the Responsible Person to notify a consumer that their metering installation is faulty and will be replaced, or provide them with an ability to opt out of the specification of meter that is installed in fault scenarios. The new metering installation must meet the requirements in the NER and any additional regulatory requirements established by jurisdictions.

As noted in scenario 3, meter replacement often requires an interruption to the consumer's supply of electricity. In the majority of fault scenarios this will be characterised as a 'planned interruption', in which case the DNSP is required to notify the consumer at least four business days before the date of the interruption in the form specified in the NERR, and use its best endeavours to restore supply as soon as possible.

If the metering installation has failed due to physical damage that was considered dangerous (eg a meter fire) the DNSP may need to carry out an 'unplanned interruption'. In general terms, an unplanned interruption is defined as an interruption of the supply of energy to carry out unanticipated or unplanned maintenance or repairs in any case where there is an actual or apprehended threat to the safety, reliability or security of the supply of energy.[384] In this case, the DNSP is required to make information about the interruption available to the consumer within 30 minutes

382 Current clause 7.3.7(a) of the NER. Such requirements do not apply if an exemption has been obtained by the Responsible Person from AEMO under current clause 7.3.7 of the NER.

383 This is an approximate figure based on information provided by several DNSPs.

384 See rule 88 of the NERR.

of being advised of the interruption, or as soon as practicable, in the form specified in the NERR, and use its best endeavours to restore supply as soon as possible.[385]

C2.2.5 Scenario 5: New house or development

Under the NER, a Market Participant must ensure that there is a registered metering installation at a connection point before the Market Participant participates in the market in respect of that connection point.[386] In the case of a new house or development, it is often the developer or builder who will organise connection to the network through the retailer or directly with the local DNSP.

The provision and installation of a meter currently forms part of the basic connection services provided by the LNSP. The DNSP will facilitate connection to the network by carrying out connection services and, as Responsible Person, providing and installing the metering installation through its Metering Provider. The ongoing provision of metering services is governed by the deemed standard connection contract between the LNSP and the consumer.[387] In NSW, under the *Scheme for the Accreditation of Service Providers to Undertake Contestable Services*, a consumer may choose a service provider accredited under the scheme to carry out connection services and install a metering installation at the consumer's premises.[388]

A meter installed in a new house or development must meet the requirements in the NER and any additional regulatory requirements established by jurisdictions.

C2.3 Rule proponent's view

C2.3.1 Scenario 1: Consumer takes up a product or service that requires a new meter to be installed

The COAG Energy Council proposed that where a consumer takes up a product or service that requires their meter be replaced or upgraded, the retailer must:

- inform the consumer of any additional costs resulting from the consumer’s request; and
- obtain the consumer's consent to the additional costs prior to proceeding with the change.[389]

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385 Rule 91 of the NERR. The requirement to use best endeavours to restore supply as soon as possible is a civil penalty provision.

386 Current clause 7.1.2(a)(1) of the NER.

387 Schedule 2 of the NERR. This applies in NECF jurisdictions only.

388 Scheme for the Accreditation of Service Providers to Undertake Contestable Services made in accordance with the Electricity Supply (General) Regulation 2001 (NSW) and administered by NSW Trade and Investment.

389 COAG Energy Council, rule change request, October 2013, p29.

C2.3.2 Scenario 2: New meter deployment

The COAG Energy Council proposed that where a retailer initiates a change or upgrade to a meter, and this change has not been requested by the consumer, then it must:

- adequately inform the consumer in writing prior to the change where there is no change to the costs charged to the consumer or services available to them; or
- obtain the prior consent of the consumer where the change in meter results in changes to the costs charged to the consumer or the services available to them.[390]

C2.3.3 Scenarios 3-5

The rule change request proposes that jurisdictions should be able to define the functions of meters that are installed in 'new and replacement'[391] situations and whether these meters must meet, or be capable of meeting, the national smart meter minimum functionality specification.[392]

The rule change request proposes that a jurisdiction may require that new and replacement metering installations provide some, all or different functions to those outlined in the minimum functionality specification, and that these provisions would be specified through the jurisdictional material in the metrology procedure.

C2.4 Stakeholder views

C2.4.1 Scenario 1: Consumer takes up a product or service that requires a new meter to be installed

Stakeholders did not comment on this scenario in submissions to the consultation paper.

C2.4.2 Scenario 2: New meter deployment

In submissions to the consultation paper, several stakeholders expressed support for the COAG Energy Council's proposed approach.[393] These stakeholders indicated support for there being a requirement on retailers to obtain the consumer's explicit

390 COAG Energy Council, rule change request, October 2013, p29.

391 The Commission's interpretation of the rule change request is that 'new and replacement' situations cover scenarios 3-5 in this draft determination.

392 COAG Energy Council, rule change request, October 2013, p16.

393 EnerNOC, submission on consultation paper, p2; SA Power Networks, submission on consultation paper, p6; CUAC, submission on consultation paper, p1.

informed consent[394] for the deployment where it would result in changes to the charges or services in the customer's contract, or its ability to use energy.[395]

However, other stakeholders considered that a requirement to obtain explicit informed consent, or 'opt in'[396] arrangements more broadly, would be costly and onerous for both retailers and consumers.[397]

Several stakeholders supported there being an ability for consumers to 'opt out'[398] of receiving an advanced meter under a new meter deployment.[399] These stakeholders considered that an opt out arrangement is more appropriate than an opt in arrangement where there is no change to the consumer's metering costs or services available to them.[400]

EWON indicated support for an opt out approach as a means of achieving greater penetration of advanced meters, but suggested that additional consumer safeguards would be needed to ensure that the consumer is clearly advised of their ability to opt out and provided with sufficient information to make an informed decision.[401] ERM Power considered that an opt out provision, if adopted, should be designed to ensure that consumers have sufficient opportunity to make an informed decision without excessively delaying the benefits enabled by the uptake of advanced meters.[402]

Secure Australasia did not favour opt in or opt out arrangements, considering that this would inhibit the uptake of more advanced metering.[403]

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394 Explicit informed consent is defined in section 39 of the NERL. In general terms, explicit informed consent is consent given by a small customer to a retailer where the retailer, or a person acting on behalf of the retailer, has clearly, fully and adequately disclosed all matters relevant to the consent of the customer, and the customer gives their consent to the relevant transaction in writing, verbally (in way that can be verified) or by electronic communication.

395 AGL, submission on consultation paper, p6; AER, submission on consultation paper, p10; CUAC, submission on consultation paper, p1; Metropolis, submission on consultation paper, p6; ATA and other consumer groups, submission on consultation paper, p4.

396 'Opt in' refers to where the prior consent of the consumer must be obtained by the retailer to make a change or upgrade the meter

397 EDMI, submission on consultation paper, p9; Simply Energy, submission on consultation paper, p7; Lumo Energy, submission on consultation paper, p5; Vector, submission on consultation paper, p10.

398 Opt out refers to where the consumer must be informed of the change or upgrade to the meter and given an opportunity to refuse the change/upgrade. If the consumer does not opt out within a prescribed period, the retailer can proceed with the change/upgrade.

399 EDMI, submission on consultation paper, p9; CUAC, submission on consultation paper, p1; Lumo Energy, submission on consultation paper, p5; ATA and other consumer groups, submission on consultation paper, p4.

400 AGL, submission on consultation paper, p6; Metropolis, submission on consultation paper, p6; Origin Energy, submission on consultation paper, p5; ERAA, submission on consultation paper, p3.

401 EWON, submission on consultation paper, p2.

402 ERM Power, submission on consultation paper, p13.

403 Secure Australasia, submission on consultation paper, p2.

C2.4.3 Scenarios 3-5

In submissions to the consultation paper, most stakeholders did not support the COAG Energy Council's proposal that jurisdictions determine the functionality of meters installed in 'new and replacement' scenarios. Their concerns were that this would:

- compromise national consistency and interoperability;
- put investment at risk;
- stifle innovation and competition;
- increase costs; and
- limit economies of scale.[404]

The ATA was strongly opposed to the proposal, suggesting that allowing jurisdictions to decide on the functionality of new and replacement meters would be a backwards step in the context of broader NEM reforms.[405] Alinta Energy was of the view that the objective and costs of jurisdictional differences need to be justified and only permitted where there is a demonstrable need or market failure.[406] Vector proposed that jurisdictions should be able to mandate service outcomes, but not the technical specifications of meters.[407] EDMI recognised that multiple minimum specifications would lead to multiple compliance standards, but suggested that jurisdictions should not be required to apply the national specification.[408]

Several DNSPs expressed support for jurisdictional provisions on new and replacement meters.[409] Some were of the view that, while a national approach to metering is preferred, jurisdictional arrangements may be appropriate given the different characteristics of each jurisdiction.[410] The NSW DNSPs also supported the proposal, provided that essential network services were included in the jurisdictional specifications.[411]

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404 Vector, submission on consultation paper, p19; EDMI, submission on consultation paper, p15; Landis+Gyr, submission on consultation paper, p2; Calvin Capital, submission on consultation paper, p2; Secure Australasia, submission on consultation paper, p2; ERM Power, submission on consultation paper, p3; ERAA, submission on consultation paper, p5; Simply Energy, submission on consultation paper, p10; AGL, submission on consultation paper, p11; Origin Energy, submission on consultation paper, p9; Lumo Energy, submission on consultation paper, p8; ESAA, submission on consultation paper, p2; Metropolis, submission on consultation paper, p9; ATA and other consumer groups, submission on consultation paper, p3.

405 ATA and other consumer groups, submission on consultation paper, p3.

406 Alinta Energy, submission on consultation paper, p2.

407 Vector, submission on consultation paper, p19.

408 EDMI, submission on consultation paper, p15.

409 Energex, submission on consultation paper, p7; Victorian DNSPs, submission on consultation paper, p23; SA Power Networks, submission on consultation paper, p11.

410 ENA, submission on consultation paper, p32.

411 NSW DNSPs, submission on consultation paper, p16.

Landis+Gyr was of the view that advanced meters should be installed in a new and replacement situations to reach a critical mass. However, it supported the ability for consumers to opt out in these scenarios so as to enable business operational efficiencies without compromising consumers' empowerment.[412]

Metropolis considered that DNSPs should be required to provide advance notice of required meter replacements to support competition.[413]

C2.4.4 Outcomes of the fifth stakeholder workshop

The fifth stakeholder workshop focused on whether small customers should have an ability to opt out of having an advanced meter installed at their premises in scenarios 2-5. The workshop considered the option of not introducing any ability for small customers to opt out in these scenarios because:

- there may be benefits in a consistent approach between the scenarios to avoid a situation where a consumer exercises its ability to opt out under a new meter deployment, but has no ability to do so if the meter is later found to be faulty; and
- introducing an ability to opt out in a way that makes it an enforceable and meaningful choice in scenarios 3-5 would require significant changes to the regulatory framework and may be difficult to achieve in practice.

Stakeholders at the workshop presented mixed views on this proposal. Several jurisdictional government representatives expressed concern about not providing small customers with an ability to opt out under scenarios 2-5.

Some retailers explained their desire to make sure that their consumers do not feel forced to accept an advanced meter as part of a new meter deployment, and therefore considered an opt out provision to be appropriate in this scenario. A number of retailers supported opt out arrangements in new meter deployment, maintenance replacement and new scenarios, but acknowledged that providing an opt out in fault scenarios would be difficult in practice.

Several other stakeholders suggested that consumers should be able to opt out of the services that the meter is capable of supporting, not the meter itself.

C2.5 Commission's analysis

The Commission's draft determination in relation to opt out arrangements distinguishes between scenarios where the consumer's meter is still functional and scenarios where it needs to be replaced.

412 Landis+Gyr, submission on consultation paper, p2.

413 Metropolis, submission on consultation paper, p9.

In the new meter deployment scenario (scenario 2), the existing meter is still functional, complies with the requirements of the NER and would otherwise not need to be replaced. Under the draft rule, in this scenario a retailer is able to deploy advanced meters to its small customers, but those customers are able to opt out of the deployment and retain their existing meter. This is a right that is not currently provided under the NER or NERR.

In scenarios 3-5, it is necessary or prudent to install a new meter in order for the metering installation to be compliant with the minimum requirements set out in the NER, including to ensure data integrity and the safety of the metering installation. The draft rule does not allow small customers to opt out of receiving a meter that meets the minimum services specification in these scenarios. This approach represents a continuation of current arrangements whilst recognising advances in technology.

Providing an ability to opt out in scenarios 3-5 would be neither practical nor appropriate. The Commission considers that a better way to protect consumers is through their ability to choose whether to take up any of the products and services that are enabled by the advanced meter, rather than choosing the meter itself. Further, providing an ability to opt out in these scenarios may lock in old technologies that are not in the long term interests of consumers.

In any scenario, consumers will continue to have the ability to choose the products and services that they consider best meet their needs. The provision of an advanced meter will not dictate consumers' choice in the products and services they receive, but rather may expand the range of products and services available to them. For example, advanced meters allow for more granular and useful energy usage information and can provide more pricing options for consumers. Advanced meters can also enable DNSPs to apply network tariff structures that send signals to consumers about the network costs associated with their electricity use.[414]

Jurisdictions have powers to protect consumers if their concerns relate to a consumer's choice in products and services. For example, the NERL contains a provision that allows jurisdictions to require retailers to offer particular standing offer tariff structures, eg a flat tariff, to small customers with an interval meter.[415] The COAG Energy Council is also proposing changes to the NERR to provide additional consumer protections on the use of load control and supply capacity control.[416]

The Commission's analysis of each scenario and the approach to each scenario under the draft rule is set out in detail below.

414 See AEMC, National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014, rule determination, 27 November 2014.

415 Section 22 of the NERL.

416 See: http://www.scer.gov.au/workstreams/energy-market-reform/demand-side-participation/smart-meters/consumer-protections

C2.5.1 Scenario 1: Consumer takes up a product or service that requires a new meter to be installed

This scenario is already permitted under the NERR. If a small customer chooses to take up a product or service that requires a new meter to be installed (eg direct load control) this arrangement would be governed by the consumer's contract with the retailer. There is currently no ability under the NER or NERR for the consumer to opt out of the installation of a new meter to enable the product or service.[417] Consequently, no changes to the NERR are proposed.

C2.5.2 Scenario 2: New meter deployment

The draft rule introduces the following definition into the NERR:

> "**new meter deployment** means the replacement of the existing electricity *meter* of one or more small customers which is implemented by a retailer other than where the replacement is:
>
> (a) at the request of the relevant small customer or to enable the provision of a product or service the customer has agreed to acquire;
>
> (b) a *maintenance replacement*; or
>
> (c) as a result of a *metering installation malfunction*."

The Commission considers that any arrangements supporting a new meter deployment should:

- be simple and practical from a consumer's perspective;
- promote consumer participation and confidence in the retail and energy services markets;
- support innovation and investment in the provision of metering and related services; and
- minimise regulatory costs.

The Commission considers that a retailer should be able to deploy advanced metering to its consumers where it sees a business case to do so, but that consumers should be provided with an ability to opt out of the deployment and retain their existing meter. Under a new meter deployment, the existing meter is still functional, complies with the requirements of the NER and would otherwise not need to be replaced. There is no technical reason why the meter should be replaced (as there is in fault or maintenance replacement situations), so it will be up to the relevant retailer to communicate the benefits of having a more advanced meter to the consumer.

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417 Specifically, small customers do not currently have ability to opt out in the way that is being proposed under the new meter deployment scenario.

The "new meter deployment" definition will cover situations where a retailer seeks to replace a small customer's existing type 6 meter installation or type 5 metering installation with a meter that meets the minimum services specification (subject to the exceptions listed in the definition above). It will also apply to situations where a retailer proposes to replace an existing, working meter that meets the minimum services specification with a new advanced meter, for example where the new meter has additional capabilities that exceed the minimum services specification.

The Commission considers it to be appropriate that the opt out arrangements apply in all circumstances where a meter is being replaced as part of a "new meter deployment". In these circumstances, consumers should be notified of the proposed replacement of their meter and any upfront charges that will apply under their retail contract as a result of the deployment, and be given an ability to opt out.

Notification process

The draft rule requires retailers to give their small customers notification of a proposed deployment and provide them with the ability to opt out of having a meter that meets the minimum services specification installed.[418]

The minimum notification requirements are set out in Table C2.1.

Table C2.1 Minimum notification requirements for a new meter deployment

Requirement	Reasoning
The retailer must provide two prior written notices to its customer: • the first no earlier than 60 business days and no later than 20 business days before the proposed installation; and • the second no earlier than 10 business days after the first notice and no later than 10 business days before the proposed installation.	This requirement gives a reasonable amount of time for the retailer to inform the consumer of the proposed replacement of their meter as part of the deployment, and for the consumer to make a decision about whether to opt out. The first notice must be sent no earlier than 60 business days prior to the installation due to, among other factors, the risk that if notices are sent a long time prior to the installation the customer at the address may change between the time of the first notice and the time of the installation.
The customer can opt out at any time after receiving the first notice, up until the date specified in the notification (last opt out date). The last opt out date must be no earlier than three business days before the expected date on which the retailer proposes to replace the customer’s meter.	Allowing the customer to opt out at any time following notification maximises the opportunity they have to opt out.

418 Rule 59A of the NERR in the draft rule.

Requirement	Reasoning
Each written notice must contain at least the following content: • that the customer may opt out of having its meter replaced as part of the proposed deployment by informing the retailer in writing, electronically or by telephone (and any other method made available by the retailer) at any time up to the date specified in the notice; • the last day on which customers may exercise their right to opt out; • any upfront charges the consumer will incur under its retail contract as a result of the new meter deployment; and • the expected date and time on which the retailer proposes to replace the customer's meter; and • the retailer's contact details.	Regulating the minimum content of the notices will ensure that consumers are informed of their right to opt out and how to exercise this right.

This notification process provides a consistent and enforceable mechanism for retailers to notify consumers of a proposed deployment and their ability to opt out, and for consumers to make a decision that is consistent with their preferences.

The draft rule provides that the retailer is not required to comply with the notification and opt out process if the retailer is authorised to undertake the new meter deployment under the terms of the customer's market retail contract.

The Commission explored the possibility of requiring retailers to communicate any price changes expected as a result of having an advanced meter installed and any price consequences of opting out. For example, the Smart Grid Smart City trial found that the cost to the consumer of retaining a manually read meter will increase over time as more advanced meters are deployed, particularly if the consumer is one of few in their area requiring a manual meter read.[419]

Providing consumers with information about the costs of having an advanced meter compared with the costs of retaining an existing meter might be useful for the consumer in deciding whether to opt out. However, under the draft rule retailers are not required to do this because:

- Retailers will have an incentive to communicate the benefits of any proposed deployment, which may include an assessment of possible price impacts if a consumer chooses to opt out and retain their existing meter.

419 Smart Grid, Smart City, National cost benefit assessment, July 2014, p196.

- It will be difficult for the retailer to quantify future price impacts (for example, potential price increases to cover changes to manual meter reading costs) in a way that accurately informs the consumer's decision to allow the installation or opt out.

- Retailers may have some flexibility to change the prices of their services within an existing retail contract.[420] While providing the consumer with information on the relative costs of each meter type may be useful for the consumer in deciding whether to opt out, it does not prevent retailers from varying the price of this service in future (subject to the NERR and contract terms and conditions).[421] It is therefore unclear whether providing consumers with this information at the time of the proposed deployment will help them make a decision.

Installing a new meter often necessitates an interruption to the consumer's electricity supply. DNSPs are currently required to notify small customers when supply is interrupted. An interruption to carry out a deployment of advanced meter would constitute a 'planned interruption', in which case the DNSP will be required to notify the customer at least four business days before the date of the interruption in a form specified in the NERR, and use its best endeavours to restore supply as soon as possible.[422] This arrangement has not been amended through the draft rule.

The draft rule inserts a new rule 91A in the NERR, which requires the Metering Coordinator and DNSP to assist each other and cooperate where the installation, maintenance, repair or replacement of metering equipment requires an interruption to supply at the customer's premises.

C2.5.3 Scenario 3: Maintenance replacement

The draft rule introduces the following definition into the NERR:

> "**maintenance replacement** means the replacement of a small customer's existing electricity *meter* by a retailer that is based on the results of sample testing of a *meter* population carried out in accordance with Chapter 7 of the NER:
>
> (a) which indicates that it is necessary or appropriate, in accordance with *good electricity industry practice*, for the *meter* to be replaced to ensure compliance with the *metering rules*; and

420 Retailers can change their standing offer prices under a standard retail contract once every 6 months (see Schedule 1, clause 8.2(b) of the NERR). Changes to market retail contracts can only occur in accordance with the terms and conditions set out in the contract.

421 Note that from 1 May 2015, retailers operating in NECF jurisdictions will be required to better inform consumers about how prices may change when they enter into a market retail contract, in particular by disclosing whether prices can vary and when the consumer will be notified of any price variation. See AEMC, National Energy Retail Amendment (Retailer price variations in market retail contracts) Rule 2014, rule determination, 23 October 2014.

422 Rule 90 of the NERR.

(b) details of which have been provided to the retailer under Chapter 7 of the NER, together with the results of the sample testing that support the need for the replacement.”

This definition is introduced for the purposes of establishing an exception in the definition of a "new meter deployment", with the effect that the opt out requirements do not apply to maintenance replacements.

The Commission considers that small customers should not be able to opt out of receiving a meter that meets the minimum services specification in maintenance replacement scenarios.

This is consistent with current arrangements. Currently, small customers do not have the ability under the NER or NERR to opt out of having a meter that meets the requirements of the NER installed if their existing meter is signalled for replacement as a result of testing.[423]

Providing an ability for small customers to opt out in these circumstances would require additional regulation to provide consumers with a meaningful and enforceable choice in the period between the meter being recognised as needing replacement and the installation of a new meter.

An ability to opt out of a maintenance replacement is likely to create confusion and may result in poorer outcomes for consumers. If an opt out were provided, consumers would only be able to retain their existing meter until it fails, at which point it would be replaced with an advanced meter.

Opting out of a maintenance replacement would be likely to result in more meters failing. This would increase costs for Market Participants and consumers, and may result in poorer service for consumers, who would be without a working meter and billed on an estimate of their electricity consumption until the failed meter was replaced.

Under the draft rule, a Metering Coordinator will be subject to the same obligations in respect of meter testing as currently apply to Responsible Persons under the NER and procedures under the NER.[424] This responsibility will remain with the DNSP where it becomes the initial Metering Coordinator under the transitional arrangements.

Under the draft rule, where the Metering Coordinator or AEMO undertakes testing of a metering installation under clause 7.9.1 of the NER, the Metering Coordinator or AEMO (as the case may be) must:

- inform the Financially Responsible Market Participant that testing has been undertaken; and

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423 Specifically, small customers do not currently have ability to opt out in the way that is being proposed under the new meter deployment scenario.

424 Note that AEMO may change aspects of the procedures to accommodate the introduction of the Metering Coordinator role.

- make the test results available in accordance with clauses 7.9.1(h) and (i) and, on request of the Financially Responsible Market Participant, to the Financially Responsible Market Participant.

C2.5.4 Scenario 4: Replacement due to a fault

The Commission considers that small customers should not be able to opt out of receiving a meter that meets the minimum services specification in fault scenarios.

This is consistent with current arrangements. Small customers do not currently have the ability under the NER or the NERR to opt out of having a meter that meets the requirements of the NER installed if their existing meter is found to be faulty.[425]

The NER currently requires the Responsible Person to arrange for repairs to be made to a type 1-3 metering installation as soon as practicable but no later than two business days after being notified of the malfunction, and a type 4-7 metering installation as soon as practicable but no later than 10 business days after being notified of the malfunction.[426]

Providing small customers with an ability to opt out could create a time delay between the fault occurring and a new meter being installed. As faults cannot be anticipated, providing consumers with a notice period in which they could opt out would necessarily extend the period between the when the fault occurs and the installation of a new meter. If the opt out provisions under the new meter deployment scenario were replicated for fault scenarios, this delay would be at least 20 business days.

This could increase the financial risk to the retailer if the consumer's electricity consumption is not being measured, and may cause the consumer to be billed on an estimate of their energy consumption over a longer period. This could lead to higher costs for all consumers and more estimated meter reads, neither of which is in the long term interest of consumers. The Commission considers that a working meter should be installed as soon as possible and therefore consumers should not have the ability to opt out in fault scenarios.

The Commission explored the possibility of allowing the retailer to determine the consumer's preference before the fault occurs. This would involve retailers providing prior notice to their customers of their ability to opt out of receiving a meter that meets the minimum services specification in the event that their existing meter is found to be faulty. Following feedback from several retailers and further analysis, the Commission considers that this is not a practical solution because:

425 Specifically, small customers do not currently have ability to opt out in the way that is being proposed under the new meter deployment scenario.

426 Current clause 7.3.7(a) of the NER.

- it would require the retailer to notify all of their customers, at a potentially significant cost, of their ability to opt out in a scenario that, in most cases, is unlikely to occur;[427]
- it will be difficult for consumers to make an informed decision about whether to exercise their opt out right in these circumstances; and
- this requirement would be difficult to implement and enforce.

The Commission considers that a requirement to provide an opt out is neither workable nor appropriate in fault situations. Additional regulation would be required to provide small customers with an ability to opt out in a way that is meaningful and enforceable.

As the initial Metering Coordinator for type 5 and 6 metering installations, the DNSP can continue to carry out repairs to a metering installation as part of its regulated business where the meter does not need to be replaced.[428] The arrangements outlined below refer only to fault scenarios where the meter needs to be replaced rather than repaired.

As noted above, the Metering Coordinator has certain obligations under the draft rule in relation to notifying other parties of test results. Where the DNSP is the Metering Coordinator for a type 5 or 6 metering installation and the meter is found to be faulty, the DNSP's appointment or deemed appointment (as the case may be) as Metering Coordinator for the connection point under the transitional arrangements will cease[429] and the retailer will need to appoint a new Metering Coordinator to arrange the installation of a new meter.

The Commission proposes to retain the existing timeframes within which the Metering Coordinator (previously the Responsible Person) must arrange for repair or replacement of a faulty metering installation.[430] The Commission recognises that the requirement for the DNSP (where it is the initial Metering Coordinator under the transitional arrangements) to notify the retailer and for the retailer to appoint a new Metering Coordinator may introduce a time lag into the process. However, it is reasonable to expect that retailers will prepare for fault scenarios by putting in place arrangements with DNSPs and other parties undertaking the Metering Coordinator

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427 As noted in section C2.2.4, DNSPs currently only replace, on average, around 1-3 per cent of their total meter fleets each year for reasons related to failure or non-compliance.

428 Provided that the services for these meters continue to be classified by the AER as direct control services.

429 If the metering installation of the small customer is faulty, a new metering installation that meets the minimum services specification will need to be installed under clause 7.8.3 of the NER in the draft rule. If the installation and maintenance of this new metering installation is not classified as a direct control service, the retailer will need to appoint a Metering Coordinator in respect of that installation. Subject to the distribution ring-fencing guidelines to be developed by the AER under rule 6.17.2 of the NER in the draft rule, this may be a Metering Coordinator business of the DNSP or another party.

430 See clause 7.8.10(a) of the NER in the draft rule.

role before the new Chapter 7 of the NER commences. This will enable it to arrange installation of a new meter within the existing regulated timeframes.

C2.5.5 Scenario 5: New house or development

The Commission considers that metering installations for small customers must meet the minimum services specification where a new house or development is built. Where a metering installation is installed at a new connection for a small customer, the Metering Provider must ensure that the metering installation is a type 4 metering installation that meets the minimum services specification, unless the Metering Coordinator has obtained an exemption in respect of that connection point.[431] .

Providing an ability to opt out in this scenario is not practical, particularly in large developments such as new apartment buildings. In these cases the developer will arrange connection and metering arrangements for each apartment. It is not the intent of this rule change to provide developers with an ability to install meters in residential developments that do not meet the minimum services specification, particularly where they may have an incentive to arrange the lowest cost solution, eg accumulation meters, which are unlikely to provide benefits to consumers over the long term.

C2.5.6 Arrangements in Victoria

This opt out requirement is contained in amendments to the NERR in the draft rule. The NERR does not currently apply in Victoria because it has not adopted the NECF.

Accordingly, this opt out right will not apply in Victoria unless it adopts the NERR at a later date. The Victorian Government and Essential Services Commission (Victoria) should consider whether to make amendments to the Electricity Retail Code for consistency with the amendments to the NERR contained in the draft rule. If made, these amendments would provide for Victorian consumers to opt out of receiving a new meter that meets the minimum services specification where their retailer plans to replace their existing working meter, including advanced meters which were deployed under the AMI Program.

431 Under clause 7.8.4 of the draft rule, a Metering Provider AEMO may exempt a Metering Coordinator from complying with the requirement to install a type 4 metering installation that meets the minimum services specification in respect of a connection point if the Metering Coordinator demonstrates to AEMO’s satisfaction that there is no existing telecommunications network to enable remote access to the metering installation at that connection point.

C3 Meter reversion

Summary

This appendix outlines the Commission's approach to meter reversion under the draft rule.

As discussed in Appendix C1, any new or replacement metering installation, installed at a small customer's premises, will be required to meet the minimum services specification (subject to a limited AEMO exemption power). The draft rule therefore prevents a Metering Coordinator from replacing an existing metering installation at a small customer's connection point with one that does not meet the minimum services specification.

Accordingly, an explicit "no reversion" clause preventing an interval meter being replaced with an accumulation meter is not necessary and is not contained in the draft rule.

The Commission is of the view that these arrangements will support investment in advanced metering and the services enabled by those meters. Allowing Metering Coordinators to remove meters that meet the minimum services specification and replace them with meters that do not meet that specification would not be in the long term interests of consumers or the market, and would undermine the benefits of having a minimum services specification.

C3.1 Introduction

This appendix outlines the Commission's draft determination with respect to meter reversion requirements in the draft rule.

A reversion policy clarifies whether an existing meter can be replaced with one of a lower functionality. For example, a reversion policy could prevent a Metering Coordinator from replacing an interval meter with an accumulation meter.

The remainder of this appendix sets out:

- current arrangements in relation to reversion policies;
- the relevant elements of the COAG Energy Council's rule change request;
- stakeholder views, including submissions to the consultation paper and outcomes of stakeholder workshops held by the AEMC; and
- the Commission's analysis of the key issues and reasoning for the draft rule.

C3.2 Current arrangements

The NER currently states that a Responsible Person cannot replace a device capable of producing interval data with a device that only produces accumulation data, unless the metrology procedure permits it.[432]

Jurisdictions can amend the application of the metrology procedure in relation to type 5, 6 or 7 metering installations, including the replacement of a device capable of producing interval energy data with a device that only produces accumulated energy data.[433] The metrology procedure outlines the jurisdictional variations under this rule, the majority of which prevent a Responsible Person from replacing an interval meter with an accumulation meter.[434]

C3.3 Rule proponent's view

The COAG Energy Council proposes to maintain the current arrangement that allows jurisdictions to determine their own reversion policies through the metrology procedure.[435]

C3.4 Stakeholder views

There were few comments on this proposal in submissions to the consultation paper. AGL supported the establishment of a no reversion policy to mitigate the risk of meter displacement.[436] The ESAA was of the view that consumers should not have the option to revert to a meter with lower functionality, considering that no reversion would ensure progression toward a more efficient system and help minimise asset stranding costs.[437]

Stakeholders discussed the issue at the fifth stakeholder workshop. The ENA expressed a concern that the availability of network services enabled by advanced meters would be compromised if consumers were able to revert from a meter that met the minimum services specification. The South Australian Government pointed out that it often receives requests from consumers who had a certain meter installed in error, and that it might be important to allow reversion to placate consumers who objected to having an advanced meter installed at their premises. Metropolis indicated that reversion is not always straightforward, as the functionality and services enabled by meters cannot be easily compared like-for-like.

432 Current clause 7.2.5(d)(7) of the NER.

433 Current clause 7.14.2(d)(1) of the NER.

434 Section 2.6 of the NEM metrology procedure.

435 COAG Energy Council, rule change request, October 2013, p17.

436 AGL, submission on consultation paper, p11.

437 ESAA, submission on consultation paper, p2.

C3.5 Commission's analysis

The Commission is of the view that allowing small customers to revert from a meter that meets the minimum services specification to a meter that does not meet that specification would not be in the long term interests of consumers.

It would threaten the investment made by parties to install and access the services enabled by advanced meters. It would also remove the benefits to consumers that are available from advanced meters. This is likely to result in increased costs to the consumer and less choice of services. The provision of an advanced meter will not dictate consumers' choice in the products and services they receive, but rather may expand the range of products and services available to them to choose from.

The draft rule requires any new or replacement metering installations for small customers to meet the minimum services specification.[438] Consequently, small customers will not be able to revert from a meter that meets the minimum services specification to a meter that does not meet that specification.

The draft rule does not contain an explicit "no reversion" provision stating that a consumer with an interval meter cannot revert to an accumulation meter. Such a clause is unnecessary, because the provisions regarding the minimum services specification have a similar effect and would prevent the installation of any new accumulation meters for small customers. The existing rules already prevent the installation of accumulation meters for large customers.

The draft rule does not amend the existing provisions regarding jurisdictional material in the metrology procedure, which allow jurisdictions to specify guidelines for the replacement of a device capable of producing interval data with a device that is only capable of producing accumulation data.[439] Jurisdictions can only include such material in relation to type 5, 6 and 7 metering installations.[440] No new type 5 or 6 metering installations can be installed under the draft rule.[441] Any jurisdictional guidelines are therefore unlikely to be necessary and will not be relevant to meters that are installed after the new Chapter 7 of the NER commences.

438 Clause 7.8.3(a) of the NER in the draft rule.

439 This clause is renumbered as clause 7.16.4 in the draft rule.

440 Type 7 metering installations relate to uses such as public lighting and are not relevant in this context.

441 All new metering installations for small customers will be classified as type 4 (remotely read interval meters) or type 4A metering installations (where an AEMO exemption allows them to be manually read interval meters).

D Network regulatory arrangements

Overview of Appendix D

This appendix sets out the arrangements under the draft rule in relation to the following network regulatory arrangements that may be required to support the competitive provision of metering, including:

D1 Unbundling of metering charges from distribution use of system charges.

D2 Cost recovery for regulated meters.

D3 Ring-fencing arrangements for a DNSP taking on the Metering Coordinator, Metering Provider and/or Metering Data Provider role.

D4 Arrangements for a DNSP to access the network-related services enabled by advanced meters.

D1 Unbundling of metering charges

Summary

This appendix outlines the Commission's draft determination in relation to the unbundling of metering charges from distribution use of system charges.

The draft rule does not amend the NER to require the AER to unbundle metering charges from distribution use of system charges, as was proposed in the rule change request.

The majority of charges for regulated metering services have been, or will be, unbundled from distribution use of system charges in recent or upcoming distribution regulatory determinations, without specific requirements in the NER. The Commission considers that it is appropriate that the AER continue to determine the classification of services and control mechanisms in accordance with the existing regulatory framework, rather than the rules being amended to specify a particular approach for metering services only.

The Commission's draft rule requires the LNSP to take on the Metering Coordinator role for type 7 metering installations.[442] The direct relationship that currently exists between the DNSP and the customer for the provision of type 7 metering services is not easily translated to the new competitive arrangements where it will be the responsibility of the retailer to appoint a Metering Coordinator. The Commission does not see value in introducing specific arrangements to allow other parties to provide type 7 metering services where there is no evidence of significant potential for competition in this space.

D1.1 Introduction

This appendix outlines the Commission's draft determination in relation to the unbundling of metering charges from distribution use of system charges. This appendix does not address the issue of whether metering charges should be separately identified on a consumer's retail bill, which is set out in Appendix B2.

This appendix covers:

- an overview of the current arrangements, including how metering charges are recovered by DNSPs;
- the COAG Energy Council's rule change request regarding the unbundling of metering charges from distribution use of system charges;
- stakeholder views on the consultation paper; and

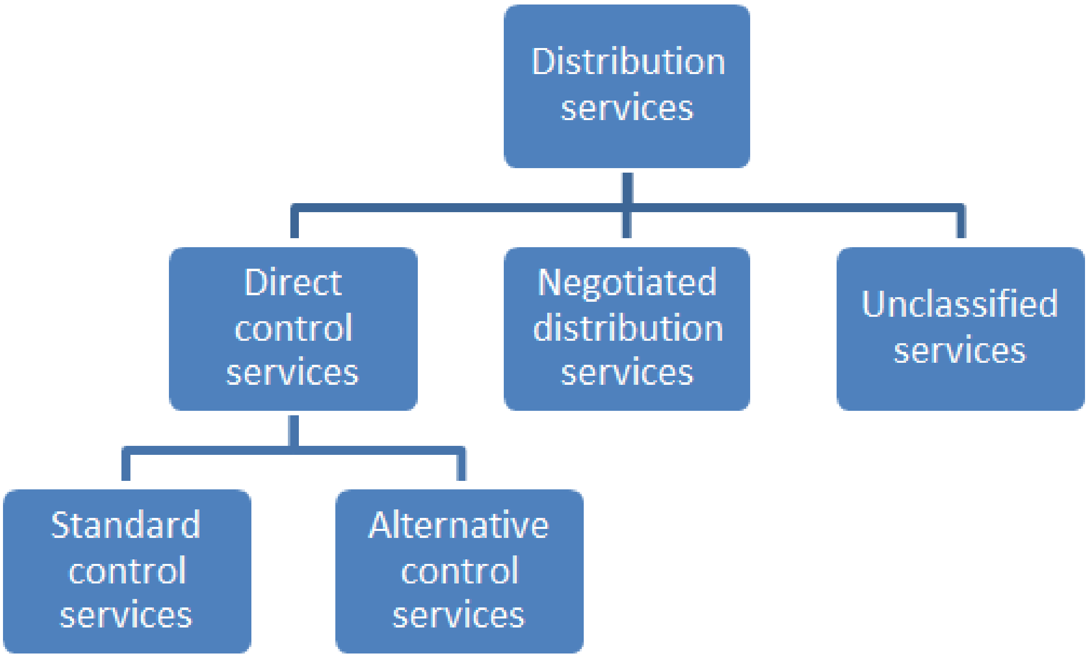
442 Type 7 metering installations are not a physical meter but rather a reconciliation between DNSPs and the users of that service using an algorithm to determine the throughput of energy, eg for public lighting and traffic lights.

- the Commission's analysis of the key issues and reasons for its draft rule.

D1.2 Current arrangements

As part of the regulatory determination process, the AER determines how, if at all, the services provided by a DNSP should be regulated. Figure D1.1 outlines the different classes of distribution services for the purposes of economic regulation under the NER.

Figure D1.1 Classification of distribution services



The AER may classify the services provided by a DNSP as either a direct control service or a negotiated distribution service.[443] If the AER decides not to classify a distribution service, the service is not regulated under the NER, ie it is unclassified.[444] The classification process determines how the costs of providing a regulated service will be recovered by the DNSP during a regulatory control period.

There are two categories within direct control services - standard control services and alternative control services. The AER classifies a service as a standard control service where it is central to electricity supply and is relied upon by most (if not all) consumers. The costs of providing standard control services are shared by all consumers. The AER classifies a service as an alternative control service where it is a customer-specific or customer-requested service that may have the potential to be provided on a competitive basis rather than exclusively by the DNSP. The costs of providing these services are charged only to consumers using the service.

443 Clause 6.2.1(a) of the NER.

444 With the exception of connection services under Chapter 5A, see note under clause 6.2.1 of the NER.

Negotiated services are those that the AER considers require a less prescriptive regulatory approach because parties have sufficient market power to negotiate the arrangements for their provision.[445] The costs of providing these services are negotiated between the DNSP and the party wishing to receive the service in accordance with a framework set out in Chapter 6 of the NER.

In classifying a direct control service as a standard control or alternative control service, the AER must have regard to a number of factors, including:

- the potential for development of competition in the relevant market and how the classification might influence that potential; and
- the extent to which the costs of providing the relevant service are directly attributable to the person to whom the service is provided.[446]

If the AER classifies a service as a direct control service, it must then determine the means by which it will impose controls over the prices of and/or revenues derived from that service. This is referred to as the control mechanism.[447]

Most distribution services are classified as standard control services, and the revenue required to provide these services is recovered in full from consumers through distribution use of system charges.

D1.2.1 Economic regulation of type 5 and 6 metering services by the AER

Services provided with respect to type 5 metering installations and type 6 metering installations meters have generally been classified by the AER as a standard control service. This means that DNSPs are able to bundle charges for these metering services into the distribution use of system charge that all consumers pay, regardless of whether the consumer uses the service. If the AER changes the classification of a service from standard control to alternative control, charges for the service are unbundled from distribution use of system charges and only paid by those consumers using the service.

Figure D1.2 outlines the AER's current (C) and proposed (P) classification of metering services by type for DNSPs across the NEM.

445 AER, Final framework and approach for Energex and Ergon Energy, AER, April 2014, p9.

446 Clause 6.2.2(c) of the NER.

447 Clause 6.2.5 of the NER.

Figure D1.2 Classification of metering services[448]

<table>
<tr><th rowspan="2"></th><th rowspan="2">Type 1-4</th><th colspan="2">Type 5-6</th><th rowspan="2">Type 7</th></tr>
<tr><th>Installation</th><th>Provision, maintenance, meter reading and data services</th></tr>
<tr><td>ACT
(2014-19)[P]</td><td rowspan="3">Unregulated</td><td>Alternative Control</td><td rowspan="5">Alternative Control</td><td>Alternative Control</td></tr>
<tr><td>NSW
(2014-19)[P]</td><td>Unregulated</td><td rowspan="3">Standard Control</td></tr>
<tr><td>Qld
(2015-20)[P]</td><td rowspan="3">Alternative Control</td></tr>
<tr><td>SA
(2015-20)[P]</td><td>Negotiated*</td></tr>
<tr><td>Tas
(2012-17)[C]</td><td>Unregulated</td><td>Alternative Control</td></tr>
<tr><td rowspan="2">Vic
(2016-21)[P]</td><td rowspan="2">Unregulated (excludes advanced meters that were installed as part of the AMI program)</td><td colspan="2">Unregulated: New type 5-6 meters.</td><td rowspan="2">Alternative Control</td></tr>
<tr><td colspan="2">Alternative Control: Existing type 5-6 meters and advanced meters installed under the AMI program.</td></tr>
</table>

As the figure shows, type 5 and 6 metering services are already, or will be at the next regulatory reset, classified as alternative control services (or unregulated as is proposed for new type 5 and 6 metering installations in Victoria). This means that charges for these services are already, or will soon be, unbundled from distribution use of system charges NEM-wide.

The AER has moved to classify type 5 and 6 metering services as alternative control services because of growing evidence that they have the potential to be provided on a competitive basis, rather than solely by DNSPs. The AER also considers that reclassifying these services as alternative control services removes a barrier to consumers taking up an unregulated advanced metering service and is consistent with the intent of this rule change.[449]

448 Sources: ACT: AER, Stage 1 Framework and approach paper for ActewAGL, March 2013, p9. NSW: Stage 1 Framework and approach paper for Ausgrid, Endeavour Energy and Essential Energy, March 2013, p26. Qld: AER, Final Framework and approach for Energex and Ergon Energy, April 2014, p40. SA: AER, Final Framework and approach for SA Power Networks, April 2014, p28. Tas: AER, Final Distribution Determination: Aurora Energy, April 2012, p9. Vic: AER, Preliminary positions on replacement framework and approach for CitiPower, Jemena, Powercor, SP AusNet, United Energy, 24 October 2014, pp50-53. * In SA there are two legacy groups of customers with type 1-4 meters for whom metering services are classified as an alternative control service (ie customers consuming 160-750 MWh p.a. that had a meter installed prior to 1 July 2000 and customers consuming more than 750 MWh p.a. that installed a meter prior to 1 July 2005).

449 AER, Final framework and approach for Energex and Ergon Energy, April 2014, p41.

D1.2.2 Type 7 metering installations

Type 7 metering installations are not a physical meter but rather a reconciliation between DNSPs and the users of that service using an algorithm to determine the throughput of energy, eg for public lighting and traffic lights.

The AER has classified type 7 metering services as standard control services in NSW, Queensland and South Australia, with charges bundled into distribution use of system charges. In its decision to classify these services as such, the AER noted that there was no indication of significant potential for type 7 metering services to be provided competitively.

In the ACT, Tasmania and Victoria, type 7 metering services are classified as alternative control services. This means that DNSPs charge the costs of providing this service directly to the customer. The customer in these jurisdictions is usually a local council or government agency, who then recovers this cost through rates or taxes. In these jurisdictions, the alternative control classification is consistent with the service classification determined by jurisdictional regulators before this responsibility was transferred to the AER.

D1.3 Rule proponent's view

The COAG Energy Council is of the view that the bundling of metering charges with distribution use of system charges in some jurisdictions is affecting decisions about metering. In particular, a consumer that has its regulated metering installation, replaced with an advanced meter would pay both the charges passed on by the retailer for the new meter and the charges passed on by the DNSP through distribution use of system charges.[450]

The rule change request proposed that each DNSP should be required to unbundle metering charges for any meters included in its regulatory asset base from its distribution use of system charges at the next regulatory determination.

D1.4 Stakeholder views

Most stakeholders have indicated support for the unbundling of metering charges from distribution use of system charges.[451] In submissions on the rule change request, several DNSPs noted that type 5 and 6 metering services had already been unbundled

450 COAG Energy Council, rule change request, October 2013, p6.

451 AER, submission on consultation paper, p5; ERM Power, submission on consultation paper, p13; EnergyAustralia, submission on consultation paper, p5; Lumo Energy, submission on consultation paper, p7; Vector, submission on consultation paper, p13.

from distribution use of system charges and therefore no changes to the NER were required.[452]

AGL considered that the NER does not effectively ensure that metering costs are separated from energy transport costs and suggested that the AER review the classification of metering services to ensure this.[453] Origin Energy agreed that metering charges should be unbundled from distribution use of system charges, but considered that the AER will need to determine the best allocation of costs to ensure that unbundled charges are not diluted by retaining some metering costs as standard control services.[454] Metropolis shared this view, and proposed that the NER clearly define which parts of a DNSP's metering services/assets are recovered where, and how further costs are to be treated.[455]

Vector considered unbundling in the context of exit fees for regulated meters, proposing that the unbundled metering charge include a portion of residual costs that would need to be recovered by the DNSP if a regulated meter is replaced or upgraded by another party.[456]

D1.5 Commission's analysis

D1.5.1 Type 5 and 6 metering services

The Commission considers that the ability of the AER to determine the classification of distribution services, including metering services, in accordance with the existing regulatory framework will support the development of competition in the provision of metering services.

Charges for type 5 and 6 metering services are already, or will be at the next regulatory determination, unbundled from distribution use of system charges NEM-wide. As noted above, the current NER provisions allow the AER to determine the classification of distribution services and how the various cost components of these services will be recovered.

The Commission considers it to be appropriate that the AER continue to determine the classification of services and control mechanisms in accordance with the existing regulatory framework. Amending the NER to specify a particular approach for metering services only would be a significant departure from current arrangements.

452 SA Power Networks, submission on consultation paper, p8; NSW DNSPs, submission on consultation paper, p13; Ergon Energy, submission on consultation paper, p9; Energex, submission on consultation paper, p5.

453 AGL, submission on consultation paper, p8.

454 Origin Energy, submission on consultation paper, p7.

455 Metropolis, submission on consultation paper, p7.

456 Vector, submission on consultation paper, p13. Exit fees are addressed in Appendix D2.

The Commission is therefore of the view that the NER does not need to be amended in this regard.

D1.5.2 Type 7 metering services

The AER has indicated in its recent regulatory determinations that it does not consider that there is significant potential for competition in providing type 7 metering services. In its framework and approach paper for the SA Power Networks 2015-2020 regulatory determination, the AER also considered that the incremental costs incurred by SA Power Networks in providing type 7 metering services were likely to be minimal relative to total service costs, and that there would be no net benefit of unbundling type 7 metering services from distribution use of system charges.[457]

The Commission is of the view that the NER should not require the AER to unbundle type 7 metering services from distribution use of system charges. The Commission considers that the AER should continue to assess the classification of type 7 metering services as part of the distribution regulatory determination process in accordance with the existing regulatory framework.

As noted above, type 7 metering services are provided through a direct relationship between the DNSP and the customer, ie there is no retailer. This direct relationship is not easily translated to the new competitive framework where it is the responsibility of a retailer to appoint a Metering Coordinator. Specific arrangements would need to be put in place for the provision of type 7 metering services.

The Commission does not see value in establishing arrangements to allow other parties to provide type 7 metering services unless there is strong evidence of potential for competition to emerge in this space. The draft rule therefore requires DNSPs to be the Metering Coordinator for type 7 metering installations. This is consistent with the current arrangement that requires the LNSP to be the Responsible Person for type 7 metering installations.[458]

457 AER, Final framework and approach for SA Power Networks, April 2014, p33.

458 Clause 7.6.4(a) of the NER in the draft rule.

D2 Cost recovery for regulated metering services

Summary

This appendix outlines the Commission's draft determination in relation to cost recovery arrangements for regulated metering services in NEM jurisdictions other than Victoria (arrangements for Victoria are discussed in Appendix F).

A DNSP may have residual costs to recover if a consumer switches from a regulated metering service to an unregulated metering service before the costs of the regulated service have been fully recovered. This is most likely to arise if a consumer's existing interval meter or accumulation meter is replaced with an advanced meter before the end of its economic life.

The draft rule maintains existing arrangements, whereby the AER determines an appropriate means for a DNSP to recover the residual costs of metering services as part of the distribution regulatory determination process, in accordance with the principles and objectives in the existing regulatory framework.

D2.1 Introduction

This appendix addresses cost recovery arrangements for regulated metering services in NEM jurisdictions other than Victoria. Cost recovery arrangements for advanced meters installed under the AMI program in Victoria are set out in Appendix F.

This appendix covers:

- an overview of how residual costs are recovered under the existing arrangements;
- a description of the COAG Energy Council's proposed approach to the recovery of residual costs related to metering services;
- stakeholder views expressed in submissions to the consultation paper and in stakeholder workshops held by the AEMC; and
- the Commission's analysis of the key issues and reasons for its draft rule.

D2.2 Current arrangements

The costs of providing type 5 and 6 metering services are currently regulated NEM-wide by the AER as a direct control service.[459] A direct control service is also referred to as a regulated metering service in this appendix. DNSPs recover the costs of providing these assets and services to consumers over a period determined by the AER

459 Refer Appendix D1. The exception is the installation of type 5 and 6 metering installations in NSW, which is an unregulated service.

in distribution regulatory determinations. In most jurisdictions, type 1-4 metering services are not regulated by the AER.[460] If a consumer or other party seeks to upgrade or replace an existing, regulated meter with an advanced meter, the DNSP may not have fully recovered the costs of the regulated investment. This is particularly likely if the meter has not yet reached the end of its useful life. Charges to recover the residual costs of regulated meters have commonly been referred to by the AER and other stakeholders as 'exit fees'.

As discussed in Appendix D1, charges for type 5 and 6 metering services are, or are in the process of becoming, unbundled from distribution use of system charges across the NEM. The proposed introduction of competition through this rule change has caused the AER to consider options for DNSPs to recover residual, regulated metering costs.

The AER has previously approved exit fees for metering services provided by SA Power Networks to allow it to recover residual costs when a customer moves to an unregulated metering service.[461] In November 2014, the AER published its draft decision on cost recovery arrangements for regulated metering services provided by the ACT and NSW DNSPs.[462] On 23 March 2015, the AER published a consultation paper on an alternative approach to that which was made in its draft decision.[463] Submissions made to the consultation paper will inform the AER's final decision for the ACT and NSW DNSPs, and the preliminary decisions for the Queensland and South Australia DNSPs.

There is also an existing provision in the NER that requires retailers and DNSPs to negotiate in good faith to ensure that the DNSP is reasonably compensated when a type 5, 6 or 7 metering installation is altered in such a way that it leads to a change in classification of the metering installation type and therefore causes the DNSP to no longer be the Responsible Person.[464] It is unclear whether DNSPs are relying on this clause to recover residual costs if the meter is replaced or upgraded, and how a commercial negotiation between the retailer and the DNSP on appropriate compensation would operate in circumstances where the AER has made a regulatory determination on arrangements for cost recovery.

460 In South Australia, type 1-4 metering services are classified as negotiated distribution services, and there are two legacy groups of customers for whom type 1-4 metering services are classified as alternative control services. Refer Appendix D1.

461 SA Power Networks, Annual pricing proposal 2014-15, SA Power Networks, 28 May 2014, p89.

462 See for example: AER, Draft decision on Ausgrid distribution determination - Attachment 16 - Alternative control services, November 2014, p29-49.

463 AER, consultation paper, Alternative approach to the recovery of the residual metering capital costs through an alternative control services annual charge, March 2015.

464 Current clause 7.3A(g) of the NER.

D2.3 Rule proponent's view

The COAG Energy Council proposed that a reasonable exit fee should be determined by the AER and applied when another party replaces a DNSP as Metering Coordinator at a connection point.[465]

The rule change request proposes to remove the current arrangement that requires retailers and DNSPs to negotiate in good faith to determine an appropriate exit fee. In its place, the COAG Energy Council proposes to give the AER explicit responsibility to assess residual metering costs and determine the exit fee to be charged to recover those costs.

The rule change request proposes the following criteria that the AER would need to have regard when determining the magnitude and components of the exit fee:

- The fee must be reasonable.
- The fee should be based on the average depreciated value of the stock of existing type 5 or 6 metering installations, and operating costs.
- The fee may include efficient and reasonable costs of transferring the consumer to another Metering Coordinator.
- The fee for type 5 metering installations may differ from the fee for type 6 installations.
- The DNSP cannot recover an exit fee for a meter installed after the commencement of a jurisdictional new and replacement policy that is not compliant with that policy.

The rule change request also proposes that the AER could consider whether a cap on the exit fee would be appropriate and, if so, the level of the cap.[466]

The COAG Energy Council indicates that the objective of the proposed arrangement is to establish an exit fee that reasonably compensates a DNSP when its regulated meter is replaced, but one not so high that it inhibits investment and innovation in advanced metering services.[467]

D2.4 Stakeholder views

Stakeholder submissions indicated that the existing regulatory frameworks do not provide sufficient certainty on:

- how a DNSP can recover its residual costs; and

465 COAG Energy Council, rule change request, October 2013, p12.

466 Ibid., p31.

467 Ibid., p6.

- the exit fee that might be payable by a party seeking to replace or upgrade a regulated meter.

Stakeholders have indicated that this uncertainty is acting as a major impediment to investment in advanced metering under the current NER provisions.

In submissions to the consultation paper and in subsequent discussions at stakeholder workshops, stakeholders agreed that DNSPs should be able to recover the costs associated with an existing, regulated meter that is no longer required.[468] Stakeholders also considered that changes need to be made to the existing provision in the NER that requires parties to negotiate in good faith to determine appropriate compensation for the DNSP in certain circumstances.

D2.4.1 Magnitude of the exit fee

In considering the magnitude of the exit fee, a number of retailers, meter providers and meter manufacturers indicated that a high, upfront exit fee would be a significant barrier to entry and would deter a market-led investment in advanced metering.[469] EDMI supported a uniform exit fee structure to allow DNSPs to recover their investment without distorting the market.[470] EnergyAustralia supported clearly defined exit fees with a transparent, reducing fee path to provide the market with investment certainty.[471]

Several consumer groups were of the view that consumers should not have to bear the costs of decisions made by DNSPs over which they had no influence. These groups were concerned that there is potential for DNSPs to be excessively compensated for previous business decisions, and sought clarification on the concept of an exit fee and the circumstances where one would apply.[472]

Some stakeholders were of the view that new investment decisions should not have to take sunk investment costs into account, and that there should be no exit fee at all.[473]

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468 Vector, submission on consultation paper, p2; AGL, submission on consultation paper, p8; ERAA, submission on consultation paper, p4; NSW DNSPs, submission on consultation paper, p14; Origin Energy, submission on consultation paper, p7; SA Power Networks, submission on consultation paper, p8.

469 Vector, submission on consultation paper, p2; ERAA, submission on consultation paper, p4; Metropolis, submission on consultation paper, p7; Origin Energy, submission on consultation paper, p7.

470 EDMI, submission on consultation paper, p11.

471 EnergyAustralia, submission on consultation paper, p5.

472 SACOSS, submission on consultation paper, p2; ATA and other consumer groups, submission on consultation paper, p5; PIAC, submission on consultation paper, p1.

473 Metropolis submission, 17 June 2014, p7; Vector submission, 29 May 2014, p2.

D2.4.2 Proposed criteria

A number of stakeholders shared the view that the proposed criteria regarding the components and magnitude of the exit fee were appropriate.[474] The NSW DNSPs considered that the exit fee should comprise only two components: residual asset costs and administration costs. This is in line with the approach put forward in their 2015-19 regulatory proposals.[475]

ERM Power emphasised the importance of determining a separate fee for type 5 and 6 metering installations and recalculating the average age of existing meter stocks annually. ERM Power considered that this would provide an efficient price signal to replace older meters first.[476]

While some stakeholders were of the view that a cap on the exit fee would be appropriate,[477] most DNSPs considered that a cap would be unnecessary because the exit fee payable should be no less than the true cost imposed by the meter's replacement.[478]

The ENA was of the view that the exit fee should apply regardless of whether the new Metering Coordinator decides to retain or replace the existing meter.[479] SA Power Networks considered that ownership of the old meter should transfer to the new retailer or Metering Provider when the exit fee is paid.[480]

D2.4.3 Party to determine the fee

Many stakeholders supported the proposal that the AER have a more explicit role in determining exit fees.[481] Two retailers were of the view that this should occur in open consultation.[482] Ergon Energy considered that the AER should not determine the

474 ENA, submission on consultation paper, p27; Energex, submission on consultation paper, p5; SA Power Networks, submission on consultation paper, p9; ERM Power, submission on consultation paper, p13.

475 NSW DNSPs, submission on consultation paper, p14.

476 ERM Power, submission on consultation paper, p14.

477 EnergyAustralia, submission on consultation paper, p5; ATA and other consumer groups, submission on consultation paper, p5.

478 ENA, submission on consultation paper, p27; Energex, submission on consultation paper, p5; NSW DNSPs, submission on consultation paper, p15; SA Power Networks, submission on consultation paper, p9.

479 ENA, submission on consultation paper, p24.

480 SA Power Networks, submission on consultation paper, p8.

481 Vector, submission on consultation paper, p16; AER, submission on consultation paper, p5; AGL, submission on consultation paper, p8; ATA and other consumer groups, submission on consultation paper, p5; Energex, submission on consultation paper, p5; ERM Power, submission on consultation paper, p14; Origin Energy, submission on consultation paper, p7; SA Power Networks, submission on consultation paper, p8; Simply Energy, submission on consultation paper, p9; Lumo Energy, submission on consultation paper, p7.

482 AGL, submission on consultation paper, p8; Simply Energy, submission on consultation paper, p9.

methodology or level of the exit fee, but rather approve the fees proposed by DNSPs in accordance with a set of high level principles in the NER.[483]

The AER proposed that it should determine exit fees using its own discretion, and that any specification of criteria in the NER should be kept at the principles level only, similar to those proposed in the rule change request. The AER also indicated that it would consult stakeholders on the development of exit fees, and that it would prefer a nationally consistent approach.[484]

D2.4.4 Terminology

Several DNSPs questioned whether the term 'exit fee' was appropriate, and suggested that 'meter transfer fee' or 'residual meter charge' would be a more accurate description.[485]

D2.4.5 Other options

The NSW DNSPs submitted that there was no lack of clarity or transparency under the current arrangements, indicating that the AER already has a role in determining exit fees for type 5 and 6 metering services because it regulates these services.[486] A number of DNSPs were of the view that the process for determining exit fees should not be any different to other fees approved by the AER through the regulatory determination process.[487]

Several stakeholders presented alternative methods of recovering the costs of a regulated metering service. The AER put forward a number of options, including recovering residual metering costs through: a higher annual metering charge with a low exit fee, a lower annual metering charge with a high exit fee, or from all consumers through distribution use of system charges.[488]

SA Power Networks considered that some cost components could be retained or transferred back into the standard control services regulatory asset base and recovered through distribution use of system charges.[489] Vector expressed support for an appropriate unbundled legacy metering charge, with residual costs remaining in the standard control services regulatory asset base and recovered through distribution use of system charges over a considerable period of time.[490]

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483 Ergon Energy, submission on consultation paper, p10.

484 AER, submission on consultation paper, p5.

485 SA Power Networks, submission on consultation paper, p8; NSW DNSPs, submission on consultation paper, p14.

486 NSW DNSPs, submission on consultation paper, p5.

487 Ergon Energy, submission on consultation paper, p10; NSW DNSPs, submission on consultation paper, p5; Energex, submission on consultation paper, p5.

488 AER, submission on consultation paper, p5.

489 SA Power Networks, submission on consultation paper, p9.

490 Vector, submission on consultation paper, p3.

Metropolis was of the view that all costs should be recovered through distribution use of system charges rather than exit fees, to spread the burden across all network users equally and provide an incentive to upgrade to more advanced metering as the costs of a regulated metering service increase.[491]

D2.5 Commission's analysis

The COAG Energy Council's rule change request is designed to remove barriers to the competitive provision of energy products and services.

The Commission considers that the application of the current clause 7.3A(g) of the NER is unclear. This clause requires retailers and DNSPs to negotiate in good faith to ensure that the DNSP is reasonably compensated when a type 5, 6 or 7 metering installation is altered in a way that it leads to a change in classification of the metering installation type causing the DNSP to no longer be the Responsible Person. This clause is deleted in the draft rule.

In determining a more efficient and transparent approach for cost recovery, the Commission has considered:

- whether DNSPs should be able to recover any residual costs associated with a regulated meter that is replaced or upgraded by another party before these costs have been fully recovered;
- the costs that would need to be recovered and the likely magnitude of these costs; and
- how the costs should be recovered, and whether any changes to the NER are required to facilitate this.

D2.5.1 Should DNSPs be able to recover any residual costs?

The NEL provides that a DNSP should be given a reasonable opportunity to recover at least the efficient costs it incurs in providing direct control network services and complying with a regulatory obligation or requirement.[492]

DNSPs are currently required to be the Responsible Person for type 5-7 metering installations and, where requested by the Market Participant, type 1-4 metering installations.[493] DNSPs have invested in assets, infrastructure and systems where they are the Responsible Person for regulated metering services, with the assumption that they would recover the costs of doing so. These investments form part of the DNSP's regulatory asset base, allowance for which has been approved by the AER in

491 Metropolis, submission on consultation paper, p7.

492 Section 7A of the NEL.

493 Current clause 7.2.3(a) of the NER. The DNSP will be the Responsible Person for type 1-4 metering installations where the Market Participant has requested an offer from the DNSP to do so, the DNSP has made an offer and the Market Participant has accepted the offer.

distribution regulatory determinations under the requirements of the existing regulatory framework.

DNSPs pay the upfront capital costs of providing metering services but recover these costs from consumers over a longer period. This arrangement benefits consumers because the cost of the service is spread over time, rather than charged upfront. However, a DNSP may not have fully recovered these costs if a consumer moves to an unregulated metering service.

The Commission’s view is that DNSPs should be able to recover the residual costs of the investments they have made to provide a regulated metering service. This view was supported by all stakeholders in submissions and at stakeholder workshops.

D2.5.2 What are the costs that would need to be recovered?

Consultation with stakeholders has indicated that there are a range of costs that may need to be recovered by a DNSP if a consumer switches from a regulated metering service. These include:

- Asset costs, including the cost of the meter itself.
- Non system asset costs, including vehicles and equipment.
- Capitalised cost of labour to install and maintain the meter.
- Operational costs, including IT/system costs and meter reading costs.
- Administration costs, including processing the transfer and disposing of the asset.

D2.5.3 Options for cost recovery

The COAG Energy Council's rule change request and the Commission's subsequent consultation paper did not explicitly discuss other means by which a DNSP could recover the costs associated with an existing, regulated type 5 or 6 metering installation that is no longer required.

As noted by some stakeholders in submissions to the consultation paper, there are a range of ways these costs could be recovered. The Commission, in consultation with the AER, has considered a number of options, including:

- an exit fee that recovers the full costs of the metering service that is no longer required directly from the party that seeks to replace or upgrade it;
- allowing all residual costs to be recovered from all consumers through distribution use of system charges; and

- a combination of the above approaches, eg some costs could be recovered directly from the party that seeks to replace or upgrade the meter, and remaining costs through distribution use of system charges.

An exit fee that recovers all residual costs associated with a metering service that is no longer required would mean that the consumer moving to an unregulated service would face the full cost of their decision to do so (assuming this cost is passed on by the retailer). This can help to promote allocative efficiency by providing consumers with an appropriate price signal to invest in a new or upgraded meter when it is efficient to do so.

High exit fees are likely to limit a business case to invest in advanced metering services, by signalling that it may not be efficient to invest in a new or upgraded meter. This may stall the uptake of advanced meters. On the other hand, a low or zero exit fee may mean that the consumer or their retailer does not face a high (or any) upfront fee to move to a competitive metering service, which may result in inefficient meter replacements.

DNSPs have indicated that they do not have detailed information on the exact technical and economic life of their existing meter stocks. Therefore, a fully cost reflective exit fee for each individual meter is not practical to achieve. A degree of cross subsidisation would occur if a flat exit fee was set based on an assumption of the average economic and technical life of existing type 5 and 6 metering installations.

In addition, in many cases the decision on what metering installation type (ie type 5 or type 6) to install was not made by the consumer but by the local DNSP. A fully cost reflective exit fee may mean that consumers with a type 5 metering service would pay a higher exit fee than consumers with a type 6 metering service, even though they had no influence over the decision on what metering installation type was installed.

A degree of cross subsidisation would also occur if costs were recovered through distribution use of system charges. Consumers who do not have their existing, regulated meter replaced or upgraded would subsidise the cost of those who do.

In their 2014-19 regulatory proposals, the NSW DNSPs set out their proposed exit fees for type 5 and 6 metering services in the 2014-19 regulatory control period. The AER held a workshop with stakeholders in September 2014 to discuss the proposed fees and put forward alternatives for the recovery of residual metering costs, in light of the implications and objectives of this rule change request.[494]

The AER published its draft decision on the ACT and NSW distribution determinations in November 2014, in which it proposed to allow the ACT and NSW DNSPs to recover the costs of the regulated metering service in the following way:

- Annual, unbundled metering charges: To recover meter asset costs (existing and replacement), supporting asset costs and operational costs.

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494 Slides from the workshop are available on the AER website.

- Upfront charges: To recover the full costs of new, customer-requested meters.
- Exit charges: To recover the administrative costs incurred as customers switch from the regulated metering service.
- Distribution use of system charges: To recover costs that remain unrecovered as customers switch from the regulated metering service.

Further information on the AER's draft decision is available on the AER website.

On 23 March 2015, the AER published a consultation paper on an alternative approach to the recovery of residual metering capital costs from that which was made in its draft decision.[495] The consultation paper notes that its draft decision to add residual metering capital costs to the regulatory asset base for standard control services on an annual basis is not appropriate under the NER.

Submissions made to the consultation paper will inform the AER's final decisions for the ACT and NSW DNSPs, and the preliminary decisions for the Queensland and South Australian DNSPs.

D2.5.4 Draft rule

The Commission considers that the arrangements for a DNSP to recover the residual costs of its regulated metering service should be determined by the AER in accordance with the existing regulatory framework. Accordingly, the draft rule maintains the existing arrangements.

The existing regulatory framework sets out a number of matters that guide the AER's assessment of how a DNSP can recover the costs of a regulated service. These include:

- The NEO, as set out in section 7 of the NEL.
- Revenue and pricing principles, as set out in section 7A of the NEL.
- Distribution pricing principles, as set out in rule 6.18 of the NER.
- Provisions regarding the classification of distribution services and applicable control mechanism, as set out in rule 6.2 of the NER.

In its draft decision for the ACT and NSW DNSPs, the AER explains that the following regulatory objectives were relevant to its consideration of cost recovery arrangements for regulated meters:

- The ability for DNSPs to recover the costs it incurred in providing a regulated metering service, as captured by the revenue and pricing principles in the NEL.

495 AER, consultation paper, Alternative approach to the recovery of the residual metering capital costs through an alternative control services annual charge, March 2015.

- Visibility on costs, as captured by the provisions regarding the classification of services in the NER and the NEO more broadly.
- Limiting cross subsidies and achieving cost reflectivity, as captured by the NEO.
- Not inhibiting competition and promoting efficient outcomes in the long term interest of consumers, as captured by the NEO and the provisions regarding the classification of services in the NER.[496]

These considerations reflect those that the AEMC, AER and a number of stakeholders have identified as important when considering the recovery of residual costs in the context of a competitive market for metering and related services.

D2.5.5 Implications of the draft rule

The draft rule does not predetermine a mechanism for the recovery of a DNSP's residual metering costs. Nor does it predetermine the extent of cross subsidisation that may result between consumers who have their meter upgraded and those who do not. The proposed approach leaves this judgement to the AER within the bounds of the existing regulatory framework.

This approach will not provide absolute certainty to parties looking to make investment decisions in advanced metering and services until regulatory determinations are finalised and the level of the exit fee, if any, becomes clear.

However, the AER's draft decision on cost recovery arrangements for the ACT and NSW regulatory determinations, the subsequent consultation paper on alternative cost recovery arrangements and its final decision in April 2015, will provide some guidance on the AER's likely approach for other jurisdictions. Stakeholders also have the opportunity to be involved in the AER's distribution regulatory determination process, through providing submissions or attending the AER's forums and workshops.

The NER could provide more certainty by either requiring that there be an exit fee, setting the level of the fee and/or prescribing the specific costs that the exit fee would comprise. This would require the NER to prescribe the service classification and control mechanism of specific metering services. This would be a significant departure from current arrangements and would restrict the AER's flexibility to determine arrangements that recognise the characteristics of each DNSP's regulated metering service.

D2.5.6 Cost recovery in practice

The AER will determine how a DNSP can recover residual, costs of regulated metering services as part of a distribution determination, including whether exit fees will apply.

496 See for example: AER, Draft decision on Ausgrid distribution determination - Attachment 16 - Alternative control services, November 2014, p36.

An exit fee payment, if any, would be triggered when a new Metering Coordinator replaces or upgrades an existing, regulated meter. For small customers, the retailer would be responsible for paying the regulated exit fee at the time it appoints a competitive Metering Coordinator to a customer's site. The retailer would decide how much, if any, of the exit fee is passed on to the consumer and how much it absorbs.

Payment of the regulated exit fee in these circumstances would not give rise to a transfer of ownership of the existing meter. Any transfer of ownership should be a commercial arrangement between the DNSP and the new Metering Coordinator.

The AER's draft decisions for the ACT and NSW DNSPs does not go into detail about the circumstances where an exit fee would apply. However, the AER may need to determine whether the exit fee should be payable when the existing meter is found to be faulty or due for replacement. The Commission considers that an exit fee should not apply in these circumstances.

D3 Distribution ring-fencing arrangements

Summary

This appendix sets out the Commission's draft determination with respect to distribution ring-fencing arrangements.

The draft rule requires the AER to develop national ring-fencing guidelines for the accounting and functional separation of the provision of direct control services from other services provided by DNSPs, which can include legal separation.

Under the current NER provisions, the AER "may" prepare such a guideline. The draft rule provides that the AER must prepare and publish this guideline by 1 July 2016.

This guideline is expected to set out, among other things, any applicable ring-fencing requirements for a DNSP that takes on the Metering Coordinator, Metering Provider or Metering Data Provider roles.

The Commission considers that a DNSP taking on the Metering Coordinator, Metering Provider and/or Metering Data Provider role in a competitive segment of the market should be subject to some form of ring-fencing from these businesses.

D3.1 Introduction

This appendix sets out the Commission's draft determination with respect to ring-fencing arrangements for DNSPs undertaking the Metering Coordinator, Metering Provider and/or Metering Data Provider roles.

This appendix covers:

- the current ring-fencing arrangements as they apply to DNSPs;
- the COAG Energy Council's proposal in relation to ring-fencing arrangements;
- stakeholder views expressed in submissions to the consultation paper and at stakeholder workshops held by the AEMC; and
- the Commission's analysis of the key issues and reasons for its draft rule.

Under the draft rule a LNSP currently acting as the Responsible Person providing metering services at a connection point will become the initial Metering Coordinator for that connection point. A DNSP's competitive metering business may also compete with other Metering Coordinators for the provision of metering services. Given the potential for a DNSP to operate in the contestable market, it is relevant to consider whether any ring-fencing is required.

ring-fencing is an economic regulatory tool that can be used to promote competitive neutrality. In simple terms, ring-fencing is designed to limit the ability a regulated service provider may otherwise have to confer an unfair advantage on an affiliate operating in a contestable market by engaging in the following types of behaviours:

- cross-subsidising the affiliate's services in the contestable market with revenue derived from its regulated services;
- providing the affiliate with access to commercially sensitive information acquired through the provision of regulated services; and/or
- restricting the access other participants in the contestable market have to the infrastructure services, or providing access on less favourable terms than its affiliate.

Some of the measures that regulators have used to ring-fence regulated services from contestable services are set out in Table D3.1.

Table D3.1 Ring-fencing measures

Measures	Behaviour targeted	What it entails
Legal separation	Decision making and cross-subsidisation of contestable services	Legal separation usually requires: • the regulated and contestable services to be carried out by separate legal entities; and • any interaction between the two entities to be established through formal contractual and reporting arrangements. The same parent company may own the two entities, so legal separation on its own will not be sufficient to prevent all the types of behaviour listed above.
Accounting (financial) separation	Cross-subsidisation of contestable services	Accounting separation usually requires the regulated service provider to maintain separate accounts for regulated and contestable services. Some regulators also require compliance with a prescribed cost allocation methodology and/or explicitly prohibit cross-subsidisation.

Measures	Behaviour targeted	What it entails
Full or partial operational separation	Sharing of commercially sensitive information and decision making	Operational separation may involve, to varying extents: • the physical separation of staff from the regulated service provider with access to confidential information from the affiliate's staff, or restrictions on working for both businesses; • the separation of information systems, or restrictions on access to systems with confidential information; and/or • the separation of the regulated service provider's decision making body from the affiliate's decision making body.
Equal access to information	Sharing information	If there are legitimate reasons for information disclosure, some regulators require certain information obtained by a regulated service provider in connection with their regulated business to be provided to third parties.
Non-discrimi natory access provisions	Discriminatory access to services	This measure requires the regulated service provider to provide access on a non-discriminatory basis.

The ring-fencing measures set out in this table may be viewed as lying on a spectrum with less onerous measures, such as accounting separation and partial operational separation, at one end of the spectrum and more onerous measures, such as legal and full operational separation, at the other end.

D3.2 Current arrangements

In electricity, ring-fencing has traditionally focused on the accounting and operational separation of DNSPs from generation, retail and other contestable works, including, connections, extensions and/or meter installation. However, provision has been made in Chapter 6 of the NER for ring-fencing to be applied more broadly.

The relevant provisions are contained in rule 6.17 of the NER. This rule states that the AER may develop a distribution ring-fencing guideline that requires the accounting and functional separation of the provision of direct control services[497] from other services. The rule sets out a non-exhaustive list of legal, operational and accounting separation measures that the AER may include in a guideline.[498] This rule also requires DNSPs to comply with any ring-fencing guideline developed by the AER.

497 A direct control service is a service that is regulated by the AER. There are two types of direct control services: standard control services and alternative control services. See Appendix D1.

498 Clause 6.17.2(b) of the NER sets out a non-exhaustive list of ring-fencing measures the AER may include in the guideline and the circumstances in which each measures could be applied. This

In 2011-12, the AER considered whether a NEM-wide distribution ring-fencing guideline should be developed and concluded that there would be merit in doing so.[499] This work was halted in late 2012 to accommodate the Better Regulation review and the rule changes that were expected to flow from the Power of Choice review, including this rule change.[500]

While a distribution ring-fencing guideline under rule 6.17 is yet to be developed, DNSPs are still required to comply with the following ring-fencing measures:

- Jurisdictional ring-fencing guidelines – These guidelines were developed by jurisdictional regulators prior to the introduction of the NER and require varying degrees of accounting and functional separation of DNSPs from specified contestable services, such as generation, retail and in some jurisdictions, contestable works.[501]
- The cost allocation principles set out in an AER approved Cost Allocation Method – Amongst other things these principles are designed to prevent costs being shifted between standard control, alternative control, negotiated distribution and unregulated services and the prices paid for these services being artificially inflated or discounted.[502]
- The annual Regulatory Information Notice (RIN) process – This AER reporting process requires DNSPs to separately account for and report on the costs incurred and revenue derived from standard control, alternative control, negotiated distribution and unregulated services using the approved Cost Allocation Method. The AER also requires an independent auditor to assess whether the Cost Allocation Method has been employed.[503]

D3.3 Rule proponent's view

Under the COAG Energy Council’s rule change request, the local DNSP will become the initial Metering Coordinator for those meters for which it is currently the Responsible Person. A DNSP’s competitive metering business may also become the Metering Coordinator at a particular site if appointed to that role.

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clause also allows the AER to include provisions to add to, or waive a DNSP’s obligations under the guidelines.

499 AER, Position paper – Electricity Distribution Ring-fencing Guidelines, September 2012, p11.

500 http://www.aer.gov.au/node/12493

501 Clause 11.14.5(b)(3) of the NER provides for these guidelines to remain in force until such time as they are amended, revoked or replaced by guidelines under a 'new regulatory regime' (as defined in clause 11.14.2 of the NER).

502 AER, Final Decision: Electricity distribution networks – Cost allocation guidelines, June 2008, p5.

503 The AER has informed the Commission that it also requires: DNSPs to include a statutory declaration from an officer of the business that the information is true and correct; an audit of financial information in accordance with Australian Audit Standards; and an assurance review of non-financial information.

So that the DNSP's Metering Coordinator business competes with other Metering Coordinators on a competitively neutral basis, the COAG Energy Council proposes that:

- the DNSP's Metering Coordinator be required to compete with others in the market on a 'ring-fenced basis';[504] and
- the AER may develop ring-fencing arrangements to facilitate competitive neutrality.[505]

D3.4 Stakeholder views

The responses to this aspect of the COAG Energy Council's rule change proposal touched on a range of issues, including:

- the circumstances in which ring-fencing should be required;
- the businesses that a DNSP should be ring-fenced from;
- the form that the ring-fencing arrangements should take; and
- how the ring-fencing arrangements should be given effect.

These issues are discussed below.

D3.4.1 Circumstances in which ring-fencing should be required

Most stakeholders agree that if a DNSP's Metering Coordinator is competing with others in a competitive segment of the market, then the DNSP should be ring-fenced from the Metering Coordinator to ensure that it does not confer an unfair advantage on its Metering Coordinator by:[506]

- cross-subsidising its contestable services through its regulated services;
- providing it with access to commercially sensitive information; or
- not informing customers that are able to appoint their own Metering Coordinator that they can choose who takes on that role.

Different views were expressed about whether ring-fencing should apply from the day the rules come into effect or from when competition becomes effective. Questions were

504 COAG Energy Council, rule change request, October 2013, p11.

505 Ibid., p13.

506 AER, submission on consultation paper, p4; AGL, submission on consultation paper, p9; ERM Power, submission on consultation paper, p10; EnergyAustralia, submission on consultation paper, p6; ERAA, submission on consultation paper, p4; EDMI, submission on consultation paper, p12; Vector, submission on consultation paper, pp21-22; SA Power Networks, submission on consultation paper, p10.

also raised about whether ring-fencing is necessary if a DNSP's Metering Coordinator is operating in a segment of the market where competition is unlikely to emerge and services remain regulated.

For example, the ENA, Ergon Energy and SA Power Networks considered that DNSPs should be able to continue to offer a metering service as part of their regulated business until such time as the market has developed and there is no longer a demand for a regulated metering service.[507]

EnergyAustralia and Simply Energy, on the other hand, considered that ring-fencing should be required as soon as the new rules come into effect.[508] Origin Energy took a slightly different view and suggested that ring-fencing be required once the costs of all meters, metrology and related services are deregulated.[509]

The AER expressed a similar view to Origin Energy and noted that for type 5-6 metering installations, measures in addition to the existing accounting separation and cost allocation requirements should only be required if these services become unregulated (ie if the service classification changes from direct control services).

Vector supported ring-fencing if DNSPs choose to enter the competitive market and noted the following:

> "Ring-fencing is most appropriate if the distributor's metering business is continuing to compete in the competitive market for smart meters. It may be more efficient and cost effective for all parties to have type 5-7 metering businesses remain with the distributors as they wind down and the meters are gradually replaced.[510]"

This view was echoed by a number of stakeholders at the second stakeholder workshop, with some noting that ring-fencing may not be required if a DNSP is operating in a segment of the market where competition is unlikely to emerge, or may take some time to emerge.

D3.4.2 Businesses that DNSPs should be ring-fenced from

The rule change proposal only contemplates ring-fencing being applied to ensure competitive neutrality between a DNSP's Metering Coordinator and other Metering Coordinators in the market. At the second stakeholder workshop, a number of retailers, prospective Metering Coordinators and meter manufacturers noted the potential for a DNSP to confer an unfair advantage on its Metering Coordinator

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507 Ergon Energy, submission on consultation paper, p14; ENA, submission on consultation paper, p35; SA Power Networks, submission on consultation paper, p12.

508 EnergyAustralia, submission on consultation paper, p6; Simply Energy, submission on consultation paper, p10.

509 Origin Energy, submission on consultation paper, p10.

510 Vector, submission on consultation paper, p22.

through a Metering Provider or Metering Data Provider subsidiary. They suggested therefore that the DNSP also be ring-fenced from these two businesses.

D3.4.3 Form of the ring-fencing arrangements

The form that the ring-fencing arrangements should take was subject to detailed comment from DNSPs, the ENA, retailers and the ERAA.

The ENA and several DNSPs were of the view that the existing accounting ring-fencing measures and reporting requirements embodied in the Cost Allocation Methods are sufficient to ensure a level playing field.[511] They also consider that subjecting DNSPs to additional ring-fencing measures, such as legal and operational separation, would increase costs and act as a barrier to achieving network benefits because most of the services are 'inward looking'.[512]

AGL, ERM Power, EnergyAustralia and the ERAA were of the view that more stringent forms of ring-fencing, including legal and full operational separation, would be required to prevent a DNSP from conferring an unfair advantage on its Metering Coordinator, Metering Provider or Metering Data Provider.[513] EnergyAustralia considered that these types of measures were required to provide certainty and confidence in the market and to encourage entry and investment.[514]

D3.4.4 How the ring-fencing arrangements should be implemented

While there was some divergence of views on the form that the ring-fencing arrangements should take, the stakeholders that attended the second stakeholder workshop generally agreed that:

- The existing jurisdictional ring-fencing guidelines, which apply to the provision of specific contestable services, cannot accommodate the proposed market arrangements.[515]
- The AER should be accorded responsibility for deciding what ring-fencing measures to employ and set these out in a new distribution ring-fencing guideline.

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511 ENA, submission on consultation paper, p30; Ergon Energy, submission on consultation paper, pp12-13; Victorian DNSPs, submission on consultation paper, p25; NSW DNSPs, submission on consultation paper, p17.

512 ENA, submission on consultation paper, p30; Ergon Energy, submission on consultation paper, p12; Energex, submission on consultation paper, p6; Victorian DNSPs, submission on consultation paper, p25.

513 AGL, submission on consultation paper, p9, ERM Power, submission on consultation paper, p10; EnergyAustralia, submission on consultation paper, p6; ERAA, submission on consultation paper, p4.

514 EnergyAustralia, submission on consultation paper, p6.

- The distribution ring-fencing guideline provisions in clause 6.17 of the NER are sufficiently flexible to enable the AER to put in place appropriate ring-fencing measures and no additional prescription is required in the NER to deal with the new market arrangements.

- The AER should be required to develop the guideline before the new Chapter 7 of the NER comes into effect so that DNSPs have time to comply with any new obligations.

D3.5 Commission's analysis

Consistent with the views of the COAG Energy Council and the majority of stakeholders, the Commission considers that if a DNSP takes on the role of Metering Coordinator, Metering Provider and/or Metering Data Provider and performs this role in a competitive segment of the market[516], it should be ring-fenced from these businesses[517] to some extent to limit its ability to:

- cross-subsidise the contestable services carried out by these businesses through its regulated services; and/or

- provide these businesses with access to commercially sensitive information that is not available to others in the market.[518]

The Commission also agrees with the COAG Energy Council and stakeholders that the AER should be responsible for determining the form that the ring-fencing arrangements should take and should set these out in the distribution ring-fencing guideline that is provided for by clause 6.17 of the NER.[519]

So that DNSPs have sufficient time to put in place the necessary ring-fencing arrangements for the new market arrangements, the AER will be required to develop

515 See also AER, submission on consultation paper, p4; AGL, submission on consultation paper, p9; ERAA, submission on consultation paper, p4; EnergyAustralia, submission on consultation paper, p6; Metropolis, submission on consultation paper, p9.

516 Refer section D3.5.1 below.

517 COAG Energy Council, rule change request, October 2013, p11. While the COAG Energy Council only referred to Metering Coordinators, the Commission agrees with stakeholders that if a DNSP has an interest in a Metering Provider or Metering Data Provider that is operating in a competitive segment of the market, it should also be ring-fenced from these businesses to ensure that they are not used as a vehicle to achieve the same anti-competitive outcomes.

518 The types of information that retailers and prospective Metering Coordinators indicated could unfairly advantage a DNSP's metering entities, include information on: the likely timing of meter replacement, which could be adduced through information on the age of a customer's existing meter or metering faults; where the meter is located and conditions at the customer's site; and applications for new connections that require a meter to be installed.

519 COAG Energy Council, rule change request, October 2013, p13.

and publish the guideline by 1 July 2016, which is one year before the new Chapter 7 of the NER will commence.[520]

When developing the guideline, the AER may wish to consider:

- the types of behaviours that DNSPs could engage in that would operate to the detriment of competition in the market;
- the extent to which existing NER provisions, such as cost allocation requirements, achieve some of the objectives of ring-fencing and therefore reduce the need for additional ring-fencing requirements; and
- the costs of implementing the measures and the effectiveness of these measures.

The Commission's views on some of the issues that the AER may wish to consider are set out in the next section.

The AER will be responsible for monitoring and enforcing a DNSP's compliance with the ring-fencing guideline. If a DNSP fails to comply with the guideline, the following enforcement options will be available:

- the AER can seek an order from the Court declaring that there has been a breach, which may include an order that the DNSP cease the activity constituting the breach, take appropriate remedial action or implement a compliance program;[521] or
- the AER can seek injunctive relief if a DNSP has engaged in, or is likely to engage in, conduct in breach of its ring-fencing obligations.[522]

D3.5.1 Potential influence of competition and service classification on when ring-fencing will be required and the degree of ring-fencing

The Commission's view is that if a DNSP's Metering Coordinator, Metering Provider and/or Metering Data Provider is operating in a competitive segment of the market then the DNSP should be ring-fenced from these businesses.

The term 'competitive segment of the market' is used because there may be segments of the market where competition does not emerge, or takes time to emerge.[523] Stakeholders have indicated that the provision of type 5-7 metering services could fall into this category.

520 Clause 6.17.2 of the NER currently states that the AER 'may' develop a guideline. The draft rule requires the AER to develop a guideline within the specified period. The development of the guideline will be subject to the standard distribution consultation process.

521 Section 61(2) of the NEL.

522 Section 61(3) of the NEL.

523 This point was made in both the AER's and Vector's submissions. See AER, submission on consultation paper, p4; Vector, submission on consultation paper, p22.

Typically, if there is no competition for the provision of a distribution service or if there is just the potential for competition, the service will be classified as a direct control service (standard control or alternative control) and regulated. It is therefore possible that metering services in some segments of the market continue to be classified as a direct control service and regulated, while in other segments of the market the services will be unregulated.

Given this potential, the AER may wish to consider whether the same degree of ring-fencing should be applied if a DNSP decides to:

- operate in the competitive segment of the market and compete with other Metering Coordinators, Metering Providers and/or Metering Data Providers; or
- just provide direct control metering services as the initial Metering Coordinator for existing type 5 and type 6 metering installations and not operate in the competitive segment of the market.

If the AER was to decide to employ this service classification based approach, then the following would need to occur if the direct control service classification changed:

- the DNSP would need to comply with the ring-fencing measures applicable to DNSPs providing unregulated services from the date the AER's service classification decision comes into effect; and
- the retailer would be required to pay an exit fee to the DNSP, to the extent that such a fee is established by the AER as part of its regulatory determination.

D4 Access to network-related services

Summary

This appendix addresses ways in which DNSPs may access the network-related services and functions enabled by advanced meters.

Under the Commission's draft rule:

- Where advanced meters are already in place, DNSPs may negotiate for access to the services enabled by advanced meters through a commercial arrangement with the Metering Coordinator. As set out in Appendix E, the draft rule does generally not regulate the terms and conditions of the provision of services by Metering Coordinators.
- Where advanced meters are not already in place, DNSPs can help facilitate the installation of advanced meters through Metering Coordinators and seek to recover the costs of doing so through the regulatory process.

If a DNSP cannot negotiate a satisfactory arrangement with the Metering Coordinator to access the services enabled by advanced meters, the draft rule allows DNSPs to continue to use their existing network devices or install new network devices for the purpose of operating or monitoring their networks. This provision will allow DNSPs in Victoria to continue to use the meters they have installed under the AMI program as network devices.

D4.1 Introduction

This appendix provides an overview of the Commission's draft determination with respect to arrangements to enable DNSPs access to the network-related services and functions enabled by advanced meters.

This appendix covers:

- an overview of the network-related services that may be enabled by advanced meters and the potential benefits of these services;
- a description of the COAG Energy Council's proposed model for DNSP access to the network-related services enabled by advanced meters;
- stakeholder views expressed in submissions to the consultation paper and in stakeholder workshops held by the AEMC; and
- the Commission's analysis of the key issues and reasons for its draft rule.

D4.2 Current arrangements

Advanced meters could be used to provide a range of services to consumers, retailers, energy service companies and DNSPs.

From a DNSP's perspective, the services that are most likely to be of value are those that can be used to:

- defer the need for network augmentation and encourage more efficient utilisation of the network including, for example, through the use of DSP measures such as direct load control, time of use pricing, critical peak pricing and other pricing options; or
- manage the reliability, quality, safety and overall performance of the network and access other operational efficiencies, including network planning and forecasting.

The potential network operational efficiencies and DSP benefits associated with these services have been found to be significant in a number of independent studies that have been conducted over the last five years.[524] It is important that under the new market arrangements DNSPs are able to negotiate access to these services to obtain the benefits and pass these on to consumers in the form of lower network tariffs and/or service quality improvements.

The manner in which DNSPs may access these services under the draft rule is explored in further detail in the remainder of this appendix.

DNSPs have been able to access many of these services in Victoria, where advanced meters have been rolled out as part of a government-mandated, DNSP-led program. In other jurisdictions, access to the full suite of advanced metering services has been limited because DNSPs have been prevented from installing advanced meters as part of their regulatory activities, unless it is required to overcome operational difficulties.[525]

524 See for example, Deloitte, Advanced metering infrastructure cost benefit analysis, 2 August 2011, Oakley Greenwood, Victorian Smart Meter Cost Benefit Analysis Repot, 2010 and Energeia, Review of the Potential Network Benefits of Smart Metering, May 2014.

525 With the exception of Victoria and South Australia, type 1-4 metering services are currently classified as unregulated services. This means that DNSPs cannot install meters with remote reading capability and recover the costs of doing so through regulated revenue unless current clause 7.3.4(f) of the NER is satisfied. This clause allows a LNSP to alter a type 5-7 metering installation to make it capable of remote acquisition if it decides that operational difficulties reasonably require the metering installation to be capable of remote acquisition. Current clause 7.3.4(h) of the NER further states that for the purposes of paragraph (f), operational difficulties may include locational difficulties where the metering installation is at a site where access is difficult or on a remote rural property.

D4.3 Rule proponent's view

Under the COAG Energy Council's rule change proposal, a DNSP seeking access to the network-related services of advanced meters will be able to offer payment for those services to the Metering Coordinators operating in its network area. The COAG Energy Council also suggested that the AER may establish competitive procurement requirements to ensure competitive neutrality between a DNSP's Metering Coordinator and any other Metering Coordinator that wishes to provide these services.[526]

D4.4 Stakeholder views

Responses to this aspect of the COAG Energy Council's rule change proposal primarily focused on:

- how DNSPs will access network-related services when advanced meters have already been installed;
- the role that DNSPs could play in facilitating the installation of advanced meters to gain access to network-related services; and
- the services or functionality that would be available in new meters. This issue is being dealt with through the minimum services specification, which is discussed in Appendix C1.

Stakeholder views on this issue form part of a broader discussion on whether there is a need to regulate the relationship between a Metering Coordinator and other parties seeking access to the services enabled by advanced meters. This is discussed further in Appendix E.

D4.4.1 Access to network-related services when meters have been installed

The AER was of the view that if advanced meters have already been installed, DNSPs should be required to negotiate with Metering Coordinators and enter into a commercial arrangement for the provision of these services.[527]

While the ENA and DNSPs accepted that under the proposed arrangements they will need to negotiate access to the services they require, they expressed a number of concerns about their ability to access services at an efficient cost because of the 'market power' Metering Coordinators may possess in these negotiations.[528] To address these concerns, the ENA, the NSW DNSPs and the Victorian DNSPs suggested that:[529]

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526 COAG Energy Council, rule change request, October 2013, p13.

527 AER, submission on consultation paper, p6.

528 ENA, submission on consultation paper, pp7-8; Victorian DNSPs, submission on consultation paper, pp19-22; NSW DNSPs, submission on consultation paper, pp2,12-13,15.

529 Ibid.

- Metering Coordinators be subject to some form of light handed regulation to ensure that network-related services are provided on a cost reflective basis; and
- if an agreement cannot be reached with a Metering Coordinator, DNSPs should have the option to bypass the Metering Coordinator if it is efficient to do so, including by leaving existing network devices in place or installing new devices, or in Victoria by using existing advanced meters as network devices.

Concerns were also raised by some DNSPs about the effect that churn in the Metering Coordinator role at a particular site would have on:

- the degree of certainty they could have about how long they will be able to access the services at a particular location and the terms and conditions they will be subject to; and
- the transaction costs they may incur.

Several DNSPs at the second stakeholder workshop claimed that the uncertainty created would not allow them to rely on access to network-related services as an alternative to network augmentation or installing their own network devices.

The ATA expressed similar concerns about the ability of DNSPs to access network functions at a fair and reasonable cost, noting that consumers may have 'little or no interest in the many smart meter functions and services that their meter is capable of'. The ATA's view was that metering access and charges should be regulated.[530]

D4.4.2 Role DNSPs could play in facilitating the installation of advanced meters

Through submissions and the second stakeholder workshop, stakeholders identified a number of ways in which DNSPs seeking to access advanced meter enabled services could facilitate the installation of advanced meters, including:

(a) Helping to fund the installation of advanced meters by providing an upfront capital contribution to Metering Coordinators in their network area in return for securing access to network-related services for a defined period of time.

(b) Helping to underwrite the installation of advanced meters by entering into a long-term agreement with Metering Coordinators in their network area for the provision of network-related metering services. The key difference between this option and option (a) is that network-related metering services would be paid for as and when they are received rather than upfront.

(c) Carrying out its own targeted installation of advanced meters as part of their regulated business, financed out of their overall revenue allowance that is approved by the AER.

530 ATA and other consumer groups, submission on consultation paper, p7.

The Metering Coordinator under options (a) and (b) may be retailer owned, a third party operator or the DNSP's own ring-fenced Metering Coordinator.

In the AER's view, DNSPs should be required to obtain services through a commercial arrangement with a Metering Coordinator[531] either through options (a) or (b), and should not be allowed to install advanced meters as part of their regulated business, option (c).[532]

The AER considered that DNSPs should not be allowed to install meters as part of their regulated business as this could:[533]

- inhibit effective competition because DNSPs are guaranteed cost recovery under the rules and they will also be a procurer of services in the market; and
- limit the choices available to customers, both in terms of who takes on the Metering Coordinator role and service offerings.

This view was echoed by AGL, Origin Energy, ERM Power, Vector and Metropolis.[534]

The AER and a number of retailers also raised concerns about the potential for DNSPs to favour their own Metering Coordinators under options (a) and (b).[535] To address this concern, Origin Energy, ERM Power and EnergyAustralia suggested that DNSPs should be required to carry out a transparent competitive tender process (potentially overseen by the AER) to ensure that they do not just grant the work to their unregulated Metering Coordinators.[536]

In contrast to the position taken by the AER and retailers on option (c), the ENA and a number of DNSPs have contended that DNSPs should be able to install meters as part of their regulated business, where it is prudent and efficient to do so for network purposes, even if only for a limited time until the competitive market develops.[537] SA Power Networks submitted:[538]

531 Either an independent Metering Coordinator or its own Metering Coordinator where the necessary ring-fencing arrangements in place.

532 AER, submission on consultation paper, p6.

533 AER, submission on consultation paper, pp6-7.

534 AGL, submission on consultation paper, p8; Origin Energy, submission on consultation paper, p8; ERM Power, submission on consultation paper, p14; Metropolis, submission on consultation paper, p8; Vector, submission on consultation paper, p17.

535 AER, submission on consultation paper, p7; Origin Energy, submission on consultation paper, p8; ERM Power, submission on consultation paper, p14; Vector, submission on consultation paper, p17; EnergyAustralia, submission on consultation paper, p5.

536 Origin Energy, submission on consultation paper, p8; ERM Power, submission on consultation paper, p14; Vector, submission on consultation paper, p17; EnergyAustralia, submission on consultation paper, p5.

537 ENA, submission on consultation paper, pp28-30; SA Power Networks, submission on consultation paper, pp9-10; Ergon Energy, submission on consultation paper, p11; Energex, submission on consultation paper, p6.

538 SA Power Networks, submission on consultation paper, pp9-10.

> "when the LNSP submits the project to the AER as part of its regulatory submission, there should ideally be certainty both that the necessary access to advanced metering can be achieved, and of the associated cost of access. Where the LNSP proposes to install its own meters, it has this certainty. In a competitive market where:
>
> - advanced metering is widely available through third party metering providers,
> - the relevant network-related services are offered in a consistent way by all providers through a common interface, and
> - LNSPs have long-term certainty of pricing for access to these services across multiple providers,
>
> then LNSPs can build a business case to put to the AER based on purchasing access from other parties. These market conditions do not yet exist, and it will take some time for them to develop in the proposed market. Moreover, LNSPs have raised concerns that the proposed market arrangements are not sufficient to guarantee these outcomes. LNSPs should have the opportunity to deploy advanced metering to support a regulated program where it is prudent and efficient to do so, at least as a transitional measure while the market develops. This does not preclude a LNSP that has budgeted to install its own meters from choosing instead to purchase access to metering services from other providers if the market can deliver the same outcome for lower cost – in fact under a RIT-D test LNSPs are required to implement the more efficient solution."

At the second stakeholder workshop, a number of other DNSPs noted that making a business case to use advanced metering enabled services provided by other parties, i.e. options (a) and (b), as an alternative to network augmentation under the RIT-D framework would be difficult given the uncertainty surrounding:

- the terms and conditions of access that will be sought by Metering Coordinators; and
- whether they will still be able access to the services if the Metering Coordinator changes.

Energex also noted that DNSPs would be reliant on retailers and other Metering Coordinators that may have little interest in providing network-related services.[539]

DNSPs stated in the second stakeholder workshop that they would be unlikely to provide an upfront capital contribution due to the uncertainty about whether they would still be able to access the services if the Metering Coordinator changes.[540] Given

539 Energex, submission on consultation paper, p6.

540 Because the meter may be replaced, or the new Metering Coordinator may decide not to offer the same terms and conditions of access.

this uncertainty, DNSPs suggested that an ongoing payment for services was more likely than upfront funding.

The ATA also supported the ability of DNSPs to carry out a targeted and regulated deployment of advanced meters, and noted that without this DNSPs may be deterred from implementing cost effective DSP because of uncertainty about cost recovery.[541] PIAC expressed a similar view and noted that allowing DNSPs to carry out a targeted deployment was more likely to be in the long term interests of consumers because they are more likely to be able to deploy the meters at a lower cost than a 'piecemeal competitive retailer-led roll out'.[542]

D4.5 Commission's analysis

In reaching its draft decision, the Commission has been cognisant of the need to allow for the potential network-related benefits associated with advanced meters to be obtained by DNSPs and passed onto consumers.

The remainder of this section sets out:

- how DNSPs will be able to access advanced metering enabled services when the meters have already been installed;
- the role that DNSPs will be able to play in facilitating the installation of advanced meters; and
- how DNSPs may seek to recover the costs of network-related services enabled by advanced metering.

D4.5.1 Access to network-related services when meters have been installed

Consistent with the COAG Energy Council's proposal, if advanced meters have already been installed and DNSPs reach an agreement with the Metering Coordinator to access the network-related services enabled by the metering installation, then the terms and conditions of access (including price) will be set out in a commercial agreement.

The following sections outline the Commission's analysis of key stakeholder concerns, including:

- the potential for Metering Coordinators to exert market power when negotiating access to network-related services;
- the uncertainties and transaction costs that DNSPs claim they will face under the new market arrangements; and

541 ATA and other consumer groups, submission on consultation paper, p3.

542 PIAC, submission on consultation paper, p1.

- the risk that a DNSP may favour its own Metering Coordinator when procuring metering services.

D4.5.2 Risk of Metering Coordinators exercising market power

As noted above, the ENA, DNSPs and the ATA have expressed concerns about the potential for a Metering Coordinator to exercise market power when dealing with DNSPs. Further analysis on this issue, and the Commission's conclusions, can be found in Appendix E.

Consumers will ultimately bear the consequences if a Metering Coordinator decides to exercise market power in its dealings with DNSPs. For example, if Metering Coordinators decide to prevent or restrict a DNSP's access to the services provided by the meters, then the network-related benefits of the meters will not be passed through to consumers in the form of lower prices or service quality improvements. Similarly, if Metering Coordinators decide to charge DNSPs prices for metering services that exceed what would prevail in a workably competitive market, then consumers will pay for this through higher distribution use of system charges.

Appendix E sets out the Commission’s views on this issue in more detail, including factors that are expected to limit Metering Coordinators’ ability to engage in this conduct.

Given the potential for consumers to be adversely affected, the Commission has decided that DNSPs will be allowed to continue to use existing network devices or install new network devices.

While the Commission recognises that allowing bypass through the installation of new network devices could lead to an inefficient duplication of assets, it expects that in most cases the threat of bypass, as opposed to actual bypass, would be sufficient to constrain any exercise of market power. The risk of inefficient duplication should be low, particularly given that this expenditure will need to be financed by the DNSP out of its overall revenue allowance that is approved by the AER.

To give effect to the bypass options, to the draft rule:

- prevents a Metering Coordinator from removing, damaging or rendering inoperable the DNSP's network devices without consent;
- provides that a DNSP may install a network device at or adjacent to a metering installation for the purpose of monitoring or operating its network; and
- requires a Metering Coordinator to cooperate with DNSPs who wish to install a network device and provide reasonable assistance to facilitate the installation.

DNSPs may only use such network devices in connection with the operation or monitoring of the DNSP’s network. Network devices cannot be used by DNSPs for remote disconnection or reconnection. Information contained in a network device (such as usage information) cannot be provided to any person except as permitted under the NER.

The network device provisions will also cover the DNSP's existing load control equipment that is contained in an existing meter or in a separate network device. The network device provisions will therefore give effect to the COAG Energy Council's proposal that a Metering Coordinator must ensure that DNSPs' existing load control equipment is retained if a meter is replaced.

In addition to the bypass options outlined above, there is certain information provided by advanced meters, for example voltage data, that is of value to DNSPs. This could potentially be provided in a similar manner to how energy data is currently provided to the market, in the standard file format via MSATS. This proposal was raised by stakeholders at the fifth stakeholder workshop and by participants in AEMO's reference group for the development of advice to the COAG Energy Council on the minimum services specification.

In its advice, AEMO indicates that there is a potential for the number of service requests through the Metering Coordinator to be reduced significantly if the standard file formats are updated to consider advanced metering information. AEMO recommended that the development of the minimum services specification and the shared market protocol be undertaken concurrently with a review of the standard format for delivering data to the market and participants.[543]

D4.5.3 Contracting uncertainties and transaction costs

DNSPs have raised concerns that their ability to access network-related services could be subject to a significant degree of uncertainty and transaction costs if the Metering Coordinator changes.

One potential remedy a DNSP could consider is to enter into framework agreements with most of the Metering Coordinators in its network. The term 'framework agreements' is used in this context to refer to an agreement that sets out the price and non-price terms and conditions of access that will apply when a DNSP deals with a particular Metering Coordinator at any site in its network.

The advantages that these types of agreements have over site specific contracts are that:

- the DNSP will have to enter into fewer contracts, which will reduce transaction costs; and
- if the Metering Coordinator changes at a site, and the new Metering Coordinator has entered into a framework agreement with the DNSP, that agreement will come into effect, which will further reduce transaction costs and provide the

543 AEMO, Minimum functionality of advanced meters, advice to COAG Energy Council, November 2014, p17.

DNSP with certainty about the conditions that will apply if the Metering Coordinator changes.

Alternatively, if DNSPs are only seeking access to the demand management functionalities they could enter into a contract with a third party DSP aggregator. Under this option, the DSP aggregator would be responsible for contracting with a sufficient number of Metering Coordinators in the network area to guarantee the provision of the required level of demand management over the required period. The contracting risks and transaction cost issues would therefore sit with the DSP aggregator, rather than the DNSP. It would then be up to the DSP aggregator to enter into framework agreements to manage these costs and risks.

As the preceding discussion highlights, there are a number of commercial arrangements that could be used to overcome the impediments cited by DNSPs. Therefore, the Commission does not expect the new market arrangements to act as a barrier to the efficient take up of network-related services by DNSPs.

D4.5.4 Risk of a DNSP favouring its Metering Coordinator business

In submissions received from a number of retailers and the AER, concerns were raised about the potential for a DNSP to favour its own Metering Coordinator when procuring access to the network-related services enabled by advanced metering. While these concerns were primarily raised in the context of advanced meters being installed by DNSPs as part of a regulated DSP program, they may also apply to an extent under a competitive framework. The Commission has therefore considered these concerns in this context.

In considering this issue, the Commission has considered the likelihood that a DNSP will be able to favour its own Metering Coordinator by only procuring services from it.

It is worth noting that under the proposed market arrangements DNSPs will have no role in the appointment of the Metering Coordinator at a particular site. They will therefore only be able to procure the services enabled by advanced meters from their own Metering Coordinator if it has been appointed to that role by a retailer, or large customer, at a relevant site. The risk of a DNSP only procuring services from its Metering Coordinator business is low.

The Commission also considered whether the rules in their current form will provide DNSPs with sufficient incentive to engage in competitive procurement practices when acquiring advanced metering enabled services.

The Commission understands that when assessing compliance with the operating and capital expenditure criteria in Chapter 6 of the NER, the AER carefully scrutinises related party transactions. Through this process, the AER has clearly signalled to

DNSPs that if their related party contracts have not been entered into as a result of a competitive tender process the following will occur:[544]

- the contracts will be subject to a greater degree of scrutiny; and
- the AER may decide not to allow some of the costs under this contract to be recovered if they are found to be imprudent or inefficient.

While the AER's review of related party transactions has to date focused on asset management contracts, there is no reason to expect that related party metering service contracts will be subject to less scrutiny. DNSPs that decide to enter into an agreement with their Metering Coordinators without conducting an open and competitive tender process will therefore risk having some of the costs payable under this contract excluded from their revenue requirement.

The Commission has therefore decided that it is unnecessary to include any requirement in the draft rule that DNSPs comply with competitive procurement principles as proposed by the COAG Energy Council.

Finally, it is worth noting that DNSPs are required by the RIT-D process to consult with interested parties on non-network solutions and to consider any non-network proposals that may be submitted through this consultation process. If the $5 million cost threshold is met, this process will provide:

- Metering Coordinators with an opportunity to submit an offer to provide the DNSP with access to the DSP functionality in their advanced meters as a non-network solution; and
- DSP aggregators with an opportunity to submit an offer to provide the DNSP with DSP services that it has aggregated across a number of Metering Coordinators.

This process can be expected to impose additional discipline on DNSPs and make it more difficult to favour its own Metering Coordinator.

D4.5.5 Role DNSPs could play in facilitating the installation of advanced meters

During the consultation process stakeholders identified the following alternative roles that DNSPs could play in facilitating the installation of advanced meters in situations

544 See AER, Final decision: Victorian electricity distribution network service providers Distribution determination 2011-2015, October 2010, p152; AER, Draft decision Murraylink 2013-14 to 2022-23, November 2012, p36. The Commission is also aware that the risk of not being able to recover all of the costs under a related party transaction has prompted a number of regulated entities to rethink their approach to contracting and to engage in more competitive procurement practices. See AER, Access arrangement final decision Multinet Gas 2013-17, Part 2: Attachments, p143; AER, Final decision: Victorian electricity distribution network service providers Distribution determination 2011-2015, October 2010, p160; JGN, 2015-20 Access Arrangement Information Appendix 4.1 – JGN's pipeline service delivery model, 30 June 2014, pv.

where there is no advanced meter in place, but a DNSP has established that there would be a network benefit associated with the installation:

(a) Provide an upfront capital contribution to Metering Coordinators in return for the provision of services over a defined period.

(b) Enter into long-term contracts with Metering Coordinators for the provision of services.[545]

(c) Install meters as part of its regulated business out of its overall revenue allowance that is approved by the AER, if it is prudent and efficient to do so.

Of the alternatives identified by stakeholders:

- Options (a) and (b) are consistent with the proposed rule change, although the Commission understands that option (a) is unlikely to be pursued by DNSPs because of the risk that the meter will churn before it receives the services it has paid for through the capital contribution.

- Option (c) is inconsistent with the proposed rule change, which envisages metering being provided under competitive arrangements.

The draft rule does not make any provision for option (c) for the following reasons:

- Allowing DNSPs to compete in a regulated capacity with others in the competitive segment of the market could have a detrimental effect on competition. It would also be contrary to the broader objectives of this rule change, which are to promote consumer choice and encourage the development of a workably competitive market.

- It would be impractical to implement this option under the proposed arrangements because to install the meters in its regulated capacity the following would need to occur:

  — The DNSP would need to be the Metering Coordinator at each site. This cannot be guaranteed without significant changes to the model set out in the draft rule because other parties can be appointed to this role and this is beyond the control of the DNSP.

  — The metering services would need to be classified as direct control services with charges for those services regulated by the AER.

As noted above, a DNSP will be able to help underwrite the installation of advanced meters and secure access to the services provided by these meters by entering into long-term contracts with the Metering Coordinators that operate within its network

545 While this option does not involve an upfront payment, it can still help to underwrite the installation of meters by the Metering Coordinator because it will provide the Metering Coordinator with a guaranteed revenue stream over the term of the contract for some of the services to be provided by the meter.

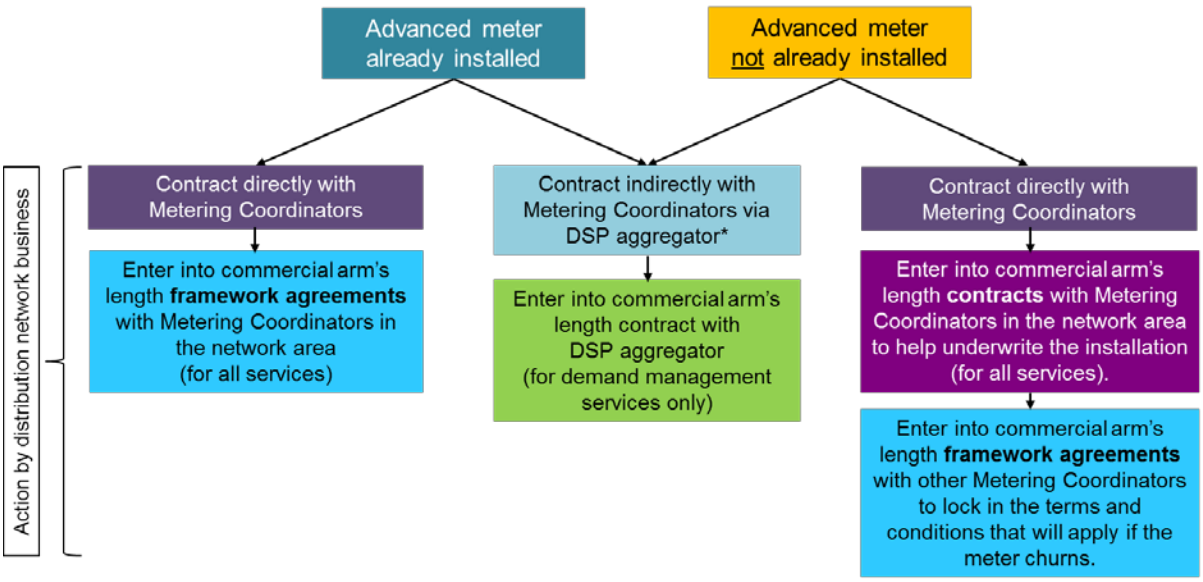
area. A DNSP could enter into framework agreements with other Metering Coordinators so that it has greater certainty about the terms and conditions of access it will face if there is churn. It could also enter into a long-term contract with a third party DSP aggregator, who would then take on the responsibility of entering into foundation contracts and framework agreements with Metering Coordinators in the network area.

The Commission considers that these commercial arrangements can be used to overcome the concerns raised by DNSPs about the lack of certainty they will have about their ability to access services and the terms and conditions of access if they do not own the meter.

D4.5.6 How DNSPs will recover the costs of acquiring these services

Figure D4.1 illustrates the alternative contractual arrangements that a DNSP could use when seeking access to the services enabled by advanced meters.

Figure D4.1 Alternative ways a DNSP could access network-related services and functions



Note that the Metering Coordinator may be retailer owned, a third party or the distribution network business's unregulated Metering Coordinator business.
** In this case it will be the DSP aggregator that contracts directly with the Metering Coordinators to help underwrite the installation.*

The manner in which DNSPs will be able to recover the costs incurred under these contractual arrangements will depend on the nature of the service acquired. However, in general they will be able to recover prudent and efficient costs they incur in acquiring these services in one of the following ways:

1. Including the costs in allowed expenditure at the start of the regulatory period (either operating or capital expenditure, depending on the type of project).

2. Funding the expenditure through savings created by deferring or avoiding capital expenditure that was included in the allowed expenditure for the regulatory period.

3. Including the costs in the Demand Management and Embedded Generation Connection Incentive Scheme for expenditure related to demand management.

From a consumer's perspective, the benefits associated with this expenditure including the benefits of deferred network augmentation, improvements in service quality or other operational efficiencies, should be passed through by DNSPs over time in the form of lower network tariffs and/or higher quality or reliability of services.

E Access to Metering Coordinator services

Summary

This appendix sets out the Commission's reasons for not regulating access to Metering Coordinator services.

Under the new arrangements contained in the draft rule, there are a number of possible risks to the effectiveness of competition. One such risk is that Metering Coordinators may be in a position where they can restrict access to metering services and products by not providing metering services under reasonable terms and conditions or at efficient prices.

However, many factors are likely to mitigate these risks. The ability of Metering Coordinators to exercise market power may be constrained by:

- The number of potential entrants into the market. Barriers to entry are low and the Commission is aware that a number of retailers and metering businesses are already considering establishing a Metering Coordinator business.
- The risk that metering assets will become stranded if Metering Coordinators restrict access to them. This will reduce the incentives on Metering Coordinators to deny access to their services, or to charge excessive prices to other retailers.
- The bargaining power of DNSPs as the only potential party interested in particular services. This will incentivise Metering Coordinators to negotiate with DNSPs and provide services at reasonable cost.
- The ability of consumers to switch retailers. If Metering Coordinators do not offer access to products and services that consumers value, their appointing retailer risks losing customers and market share. This reduces the incentives for Metering Coordinators to deny access to their services, or charge excessive prices to energy service companies.

In this context, the introduction of access regulation to better manage the potential emergence of competition issues is likely to introduce more costs than benefits. In particular, access regulation may significantly diminish the incentives for different parties to invest in metering services. Without these incentives, investment in advanced metering infrastructure and the services this would facilitate may fail to develop.

However, the Commission considers it prudent to assess the state of competition once the market has had time to evolve. Therefore the Commission recommends that the need for access regulation should be reviewed three years after the new Chapter 7 of the NER commences.

E.1 Introduction

This appendix considers the key competition issues that may emerge under a competitive framework for metering. It also considers whether some form of regulation may be required to address these issues.

The potential for competition issues to arise in the context of services provided by a Metering Coordinator were first considered in the AEMC's advice to the COAG Energy Council on a framework for open access and common communications standards for advanced meters.[546] The advice examined, among other things, whether some form of regulation was required to manage the relationship between a Metering Coordinator and parties seeking access to advanced metering services. The advice did not reach a firm conclusion on this issue and proposed that it be more comprehensively considered as part of this rule change process.[547]

This appendix sets out the Commission's reasoning for its view that regulation of access to Metering Coordinator services is not required.

In this appendix, references to "regulation of access to Metering Coordinator services" (or similar terms) relate to regulation of the price and other terms and conditions for the supply of services by Metering Coordinators (including services enabled by advanced meters) to parties seeking access to those services. Various potential forms of access regulation are discussed in section E.4.3 below.

Although the Commission has decided not to regulate access to Metering Coordinator services to address the competition concerns discussed in this Appendix, some aspects of Metering Coordinator services will regulated under the draft rule, as discussed in other Appendices. For example:

- where a DNSP acts as the initial Metering Coordinator for existing type 5 and 6 metering installations under the transitional arrangements, the draft rule contains provisions related to the terms and conditions on which the DNSP will be appointed to that role;
- prices for metering services provided in relation to type 5 and 6 metering installations will continue to be regulated by the AER (unless the AER changes how it classifies those services); and
- certain restrictions apply to who may access metering data and services provided by way of a metering installation.

This appendix covers:

- the relevant elements of the COAG Energy Council's proposal;

546 AEMC, Framework for open access and communications standards, final report, 31 March 2014.

547 Ibid., p24.

- stakeholder views expressed in submissions to the consultation paper and in workshops held by the AEMC on the relevant competition issues that may arise under the new arrangements; and
- the Commission's analysis of the competition issues, and the feasibility and implications of a light-handed regulatory framework to address them.

E.2 Rule proponent's views

The COAG Energy Council's rule change request asked the Commission to investigate whether any regulation is needed to address potential competition concerns that may emerge between Metering Coordinators and parties seeking access to their services.[548] This includes the costs and benefits of introducing standard terms and conditions in metering contracts, which could outline the contract length, termination fees and exclusivity restrictions.[549]

Specifically, the rule change request sets out a number of issues to consider regarding the implications of the proposed approach, including whether:

- it introduces any barriers that may reduce competition in retail or metering services, or innovation in retail or metering products;
- the Metering Coordinator is sufficiently incentivised to ensure its offer represents best value, and to provide a competitively priced offer to an incoming retailer;
- there are material commercial issues that may arise by deeming a contractual relationship between two competing retailers in circumstances where the incumbent Metering Coordinator is also the former retailer for the site;
- it is likely that an incoming retailer will continue the contractual relationship with the incumbent Metering Coordinator, noting that the incoming retailer will retain the right to choose another Metering Coordinator; and
- a Metering Coordinator is likely to provide metering services that offer a good range of additional functions or can be easily upgraded so that its meters will not need to be replaced as new functions are taken up by retailers, DNSPs or other service providers.

E.3 Stakeholder views

In submissions to the consultation paper and during stakeholder workshops, stakeholders expressed a range of views on the prospects for a competitive market in metering services.

548 COAG Energy Council, rule change request, October 2013, p10.

549 Ibid., p9.

Retailers were generally of the view that competition would be effective and that no regulation was required to govern commercial arrangements between Metering Coordinators and other parties seeking to use their services.

In contrast, the ENA expressed concern that Metering Coordinators may have incentives to set excessive prices for services DNSPs might require for supporting the operation of, and investment in, the network.[550] The ENA proposed that DNSPs should either be able to retain existing network devices or install new ones that could perform the required network functions if they are not able to reach agreement with the Metering Coordinator. Alternatively, some form of regulation could be introduced that guaranteed access to the required data and services at the cost of provision.[551]

Metering Providers and Metering Data Providers largely supported a competitive framework, but expressed mixed views on whether any regulation is necessary. Some metering businesses expressed the view that regulation is required to avoid meter churn, although did not provide details on what such regulation should look like.[552] Other metering businesses were strongly against any form of regulation and considered that the market is capable of preventing inefficient meter churn.[553]

EnerNOC expressed concerns about retailers performing the role of Metering Coordinator. It considered that this would introduce incentives for the Metering Coordinator to charge excessive prices for use of its metering functionality or refuse access to such functionality entirely.[554] EnerNOC proposed standard contracts be developed for governing the relationship between Metering Coordinators and third parties, with provisions that prevented Metering Coordinators from including discriminatory prices, terms and conditions in their contracts.[555]

The AER also expressed some concerns in relation to the ability of retailers to become Metering Coordinators. The AER considered that some barriers to consumers switching retailers could be created if retailers could restrict access to the meters they control through their Metering Coordinators. The AER proposed the introduction of minimum regulatory requirements to mitigate barriers to consumers switching, although they did not specify what such requirements should be.[556]

E.4 Commission's analysis

In its advice on a framework for open access and common communication standards, the Commission determined that the nature of the competition issues that may arise in

550 ENA, submission on consultation paper, p7.

551 Ibid., p9.

552 Calvin Capital, submission on consultation paper, p2.

553 EDMI, submission on consultation paper, p5; Metropolis, submission on consultation paper, p5; Landis & Gyr, submission on consultation paper, p9.

554 EnerNOC, submission on consultation paper, p1.

555 Ibid., p4.

556 AER, submission on consultation paper, p9.

relation to third party access to advanced metering services would depend in part on the role of the Metering Coordinator and who could appoint the Metering Coordinator.

The Commission noted that there is a greater case for a form of 'light-handed regulation' if the metering framework did not allow consumers the ability to appoint their own Metering Coordinator. The Commission considered that without an ability to appoint their own Metering Coordinator, consumers would need to first change their retailer in order to secure alternative metering services. This lack of transparency between consumers and Metering Coordinators could give Metering Coordinators scope to charge above efficient costs for metering services. Coupled with the costs that consumers may incur in changing retailers, this could increase costs for consumers.[557]

The Commission's draft rule gives large customers the option to appoint their own Metering Coordinator, but does not allow small customers this ability.[558] The remainder of this appendix sets out the Commission's analysis of potential competition issues, given that small customers will not able to directly appoint a Metering Coordinator. The Commission has drawn on the competitive metering market experiences of New Zealand and the United Kingdom to inform its analysis.

E.4.1 Competition issues

Three different ownership models for a Metering Coordinator are likely to arise under the draft rule:

1. A retailer sets up a Metering Coordinator business, or is otherwise affiliated with a Metering Coordinator. This is referred to as a '*Retailer Metering Coordinator*'.

2. A DNSP sets up a Metering Coordinator business, separate from its ring-fenced regulated business. This is referred as a '*Distribution Metering Coordinator*'.

3. An independent third party metering business performs the role of Metering Coordinator. This is referred to as an '*Independent Metering Coordinator*'.

The Commission assessed whether any risks to effective competition that may require regulatory intervention are likely to arise under each of these ownership models. The Commission considers that risks to effective competition could manifest in two main ways:

- Any Metering Coordinator will have a degree of market power[559] through its control of access to the consumer's meter. This may incentivise a Metering Coordinator to charge other parties wanting to access to the meter a higher price

557 AEMC, Framework for open access and communications standards, final report, 31 March 2014.

558 Refer Appendix B1.

559 Market power is used in this context to refer to the ability of the Metering Coordinator to exercise a level of discretion over the prices they charge, for a sustained period of time. Such discretion may occur in workably competitive markets but only for a limited period until new entry occurs or costs decrease.

than would otherwise be efficient. This may mean consumers pay higher than necessary charges for metering and related services.

- A Retailer Metering Coordinator could discriminate against third parties, including other retailers and energy service companies, in order to restrict the ability of that third party to provide services to a consumer. For example:
  - A Retailer Metering Coordinator may price discriminate against another retailer, raising the rival's costs and preventing it from competing effectively in the retail market.
  - Similarly, a Retailer Metering Coordinator could discriminate against an energy service company, affecting its ability to compete in the energy services market.

This behaviour could reduce competition in both the retail and energy services markets, increasing costs to consumers.

These two risks are explored in further detail below.

Risk that Metering Coordinators will set high prices

Metering Coordinators may seek to charge high prices for the services they provide as their control of access to a consumer’s meter may allow them a degree of market power. In the absence of substitute services, there may be an incentive on Metering Coordinators to charge a higher price as a buyer of the services has no alternative but to deal with the Metering Coordinator for access to the services. This incentive could arise between a Metering Coordinator and any of the following parties:

- a new retailer;
- a DNSP; and/or
- an energy service company.

These relationships are considered separately below.

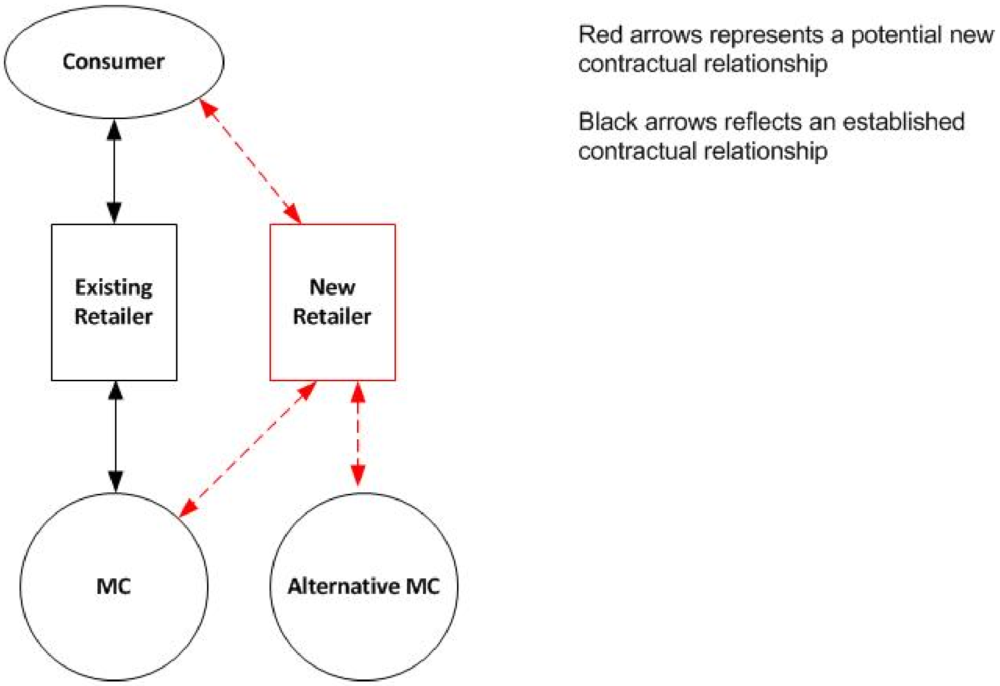
<u>SCENARIO 1:</u> *Relationship between a new retailer and an incumbent Metering Coordinator*

In this scenario a new retailer is seeking access to the services of an incumbent Metering Coordinator at one or more sites that it has acquired.

In this scenario, the term "incumbent" Metering Coordinator refers to the Metering Coordinator that is in place immediately prior to a consumer switching to a new retailer, noting that the new retailer may choose to engage a different Metering Coordinator.

Figure E.1 illustrates the relationships relevant to the pricing of metering services by a Metering Coordinator in the event of a consumer switching to a new retailer. For ease of illustrating the key issues the diagrams that follow, assume the Metering Coordinator is also the Metering Provider and the Metering Data Provider.

Figure E.1 Relationship between a new retailer and an incumbent Metering Coordinator



New Retailer seeks access to an MC's services, can appoint an alternative MC

Under this scenario, an incumbent Metering Coordinator faces an incentive to charge a retailer for access to the advanced meter and related services a price that is somewhere just below the level it considers the prospective new retailer would have to pay an alternative Metering Coordinator to replace the meter and provide metering services. This incentive is the same regardless of how much of the fixed costs of the meter have already been recovered by the incumbent Metering Coordinator as the incentive is to maximise profits not just recover costs.

This opportunity may arise where the costs facing a prospective new retailer to engage an alternative Metering Coordinator are greater than the incumbent Metering Coordinator's costs. The full cost of a new meter represents the upper limit that an incumbent Metering Coordinator could charge. This could result in a duplication of the costs of meter provision for a consumer.

If the alternative Metering Coordinator engaged by the new retailer sets a price for metering services that recovers the full upfront costs of providing and installing a new meter, these costs are likely higher than being charged by the incumbent Metering Coordinator. The new retailer would have difficulty developing a bundled energy and metering product that was sufficiently attractive to entice the consumer to switch.

Therefore, the potential for an incumbent Metering Coordinator to charge up to the replacement costs of a new meter may create a barrier to switching in the retail energy market.

What factors might constrain this behaviour?

The ability of an incumbent Metering Coordinator to charge up to the replacement cost of the meter will be constrained by a number of factors. The most important of these factors is the ability, or potential ability, for the prospective new retailer's alternative Metering Coordinator to bypass or strand the existing meter.

If there are one or more alternative Metering Coordinators in the market, or the threat of entry is high, this will improve the ability of a prospective new retailer to negotiate an efficient price for metering services. Competition would force the incumbent Metering Coordinator to offer a price that is closer to its opportunity cost of providing metering services. The following paragraphs briefly explain how an efficient price for services may be determined.

The starting position for the negotiation from the perspective of the incumbent Metering Coordinator is the full costs of an alternative new meter. This sets the upper boundary to the price of access. However, this upper price boundary to the negotiation will depend on the nature of the available alternatives open to the prospective new retailer.

As noted above, some Metering Coordinators will expect the prospective new retailer to pay the full costs of providing and installing the meter, as well as the ongoing costs of providing metering services. Other Metering Coordinators might be willing to enter into a leasing or rental arrangement with the retailer for the provision of metering services, in which case the opportunity costs of not gaining access to the incumbent Metering Coordinator's metering functionality will be much lower.

Where meters are leased, the transaction charge for the initial installation of a meter at a consumer's premises will be much lower than the upfront capital cost of the meter, or possibly even zero. The Metering Coordinator may simply install the meter and the retailer starts paying the rental charge, which is typically a monthly or annual charge for use of the meter. If a consumer decides to switch to another retailer with whom the Metering Coordinator has a contract, the Metering Coordinator and retailer would make arrangements so that the rental payments are thereafter made by the retailer to whom the consumer has switched. These types of leasing arrangements are common in the New Zealand market and in the United Kingdom.

The lower boundary to the negotiation is represented by the lowest price offer the prospective new retailer believes it can achieve without the incumbent Metering Coordinator refusing to negotiate. This offer will be the incumbent Metering Coordinator's incremental cost of providing the prospective new retailer with access. Any price the incumbent Metering Coordinator receives above incremental cost will allow it to recover some of the sunk costs of the meter.

The incumbent Metering Coordinator does not want to risk asset stranding, in which case the fixed or sunk costs of the meter would not be recovered. Therefore the incumbent Metering Coordinator is likely to accept a price somewhere above the incremental costs of providing metering services. The prospective new retailer will accept somewhere below the full installation costs of a new meter, taking into account the alternatives it has available, such as whether it needs to buy or lease the meter.

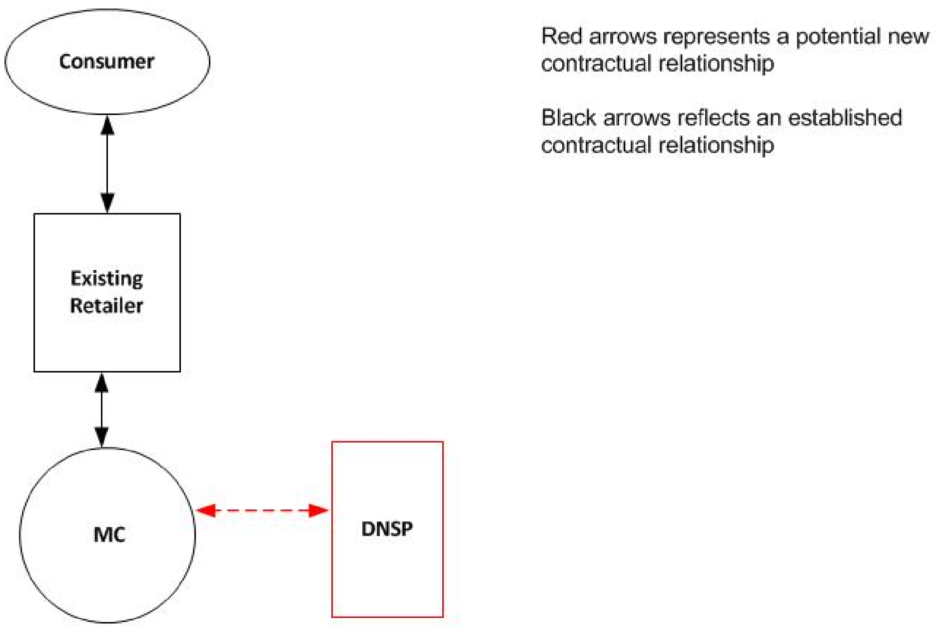
Consequently, competition should lead to efficient negotiated outcomes for the provision of metering services in a market where there is more than one Metering Coordinator, barriers to entry are low and/or there is a range of metering financing options available. The negotiated price will lie somewhere between the incremental cost of providing metering services and the full standalone costs of providing metering services by an alternative Metering Coordinator.

Such agreements for the provision of metering and related services would avoid inefficient meter churn. The benefits of this would be shared between the old retailer, the new retailer, the incumbent Metering Coordinator and the consumer.

<u>SCENARIO 2:</u> Relationship between a DNSP and a Metering Coordinator

Figure E.2 depicts a scenario in which a DNSP seeks offers from a Metering Coordinator to buy services that can assist the DNSP with operating and managing the network.

Figure E.2 Relationship between a DNSP and a Metering Coordinator



DNSP seeking access to MC services, cannot appoint an alternative MC

In the absence of competition, the Metering Coordinator will seek to charge as much as it can for its services sought by a DNSP. This will be at a level just below what it considers the next best alternative is for the DNSP. Unlike in the previous scenario, the DNSP will not have the ability to appoint an alternative Metering Coordinator as a competitive response, as Metering Coordinators are appointed by retailers.

What factors might constrain this behaviour?

While DNSPs are not in a position to appoint another Metering Coordinator to a site, there are a range of other factors that may constrain the pricing behaviour of the Metering Coordinator.

First, a DNSP will be a monopsony buyer for the metering services it needs to manage the network and therefore is likely to have significant countervailing buying power for those services. Services such as voltage or power quality data are unlikely to be of interest to any other parties. If a DNSP decides not to purchase these services, the Metering Coordinator will have no alternative buyers.

This countervailing power of DNSPs should impose a strong incentive on Metering Coordinators to charge an efficient price for these services, particularly given the incremental costs of providing these services are very low. Further, providing services to DNSPs will provide Metering Coordinators with an additional source of revenue that may help support the initial business case for the deployment of advanced meters.

Second, for some network services, DNSPs will not need access to services at all connection points in order to operate the network effectively. Consequently, provided there are sufficient alternative Metering Coordinators at other connection points, if a particular Metering Coordinator chooses to raise its prices, other Metering Coordinators could offer a lower price or offer access to functionality and services on better terms at these other connection points.

Third, DNSPs will have the option of either retaining existing devices or installing new network devices. This allows them a credible threat to bypass the services of a Metering Coordinator if they consider the price charged by that Metering Coordinator is too high. The ability of DNSPs to install their own device provides an important constraint on the maximum price a Metering Coordinator could charge. This is discussed further in Appendix D4.

Finally, DNSPs may face competition from retailers or other third parties for some of the services they require, including load control. In a competitive market, the party that values the service or functionality the most will be willing to pay the highest price. In these circumstances the efficient negotiated price would not necessarily reflect the direct costs associated with installing and maintaining load control functionality, but rather the perceived value such functionality can deliver to consumers.

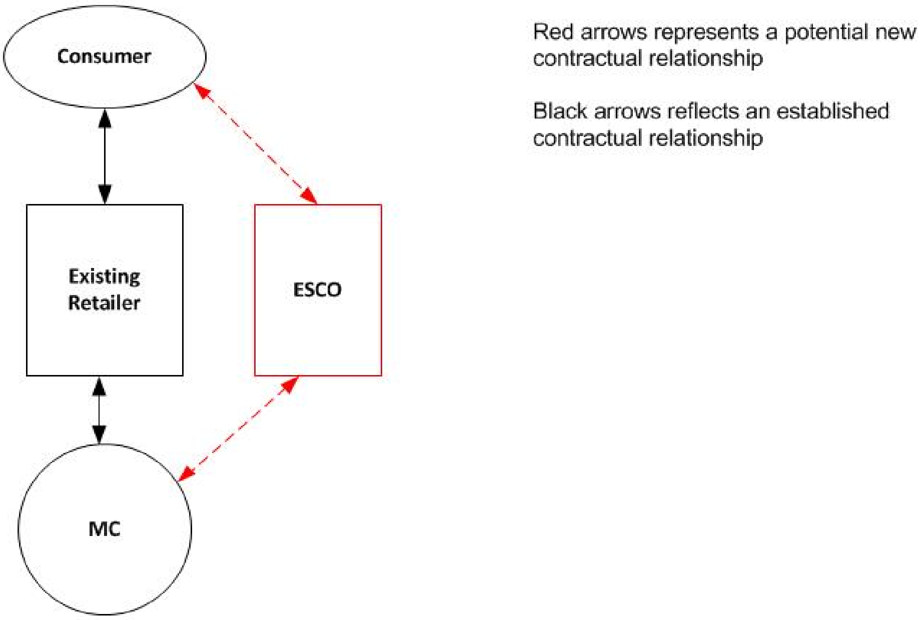
SCENARIO 3: Relationship between an energy service company and a Metering Coordinator

In this scenario an energy service company is seeking access to metering services provided by a Metering Coordinator. The Metering Coordinator will have incentives to charge as much as it can for its services sought by an energy service company. Like a

DNSP seeking access, an energy service company does not have the option of appointing its own Metering Coordinator.

This is shown in Figure E.3, which depicts a scenario in which an energy service company seeks the services of a Metering Coordinator to provide energy management services to consumers.

Figure E.3 Relationship between an energy service company and a Metering Coordinator



ESCO seeks access to MC services, does not have the option of alternative MC

What factors would constrain this behaviour?

One issue the energy service company faces is that it will be unable to appoint an alternative Metering Coordinator for a particular consumer if it is unhappy with the prices or other terms and conditions offered by the incumbent Metering Coordinator. While Metering Coordinators would have some incentive to negotiate with an energy service company on the basis that this would provide an additional source of revenue, this presents a potential competition concern for energy service companies.

A potential mitigating factor is that if consumers value energy management services, they will look for retailers, and so Metering Coordinators, that can provide these services. Provided the retail market is sufficiently competitive, a Metering Coordinator may risk losing a customer if does not provide metering services to energy service companies on sufficiently competitive terms and conditions. This may mean that if an energy service company is not satisfied with the terms and conditions offered by the incumbent Metering Coordinator, it may opt to offer its services through other Metering Coordinators and retailers operating in the market. If a consumer values the services of that energy service company it may choose to switch to one of these alternative providers.

The incentive for the Metering Coordinator to behave inefficiently in relation to an energy service company is therefore conditioned by a competitive retail market and the presence of other Metering Coordinators in the market.

Risk that a Metering Coordinator may discriminate against third parties

An important characteristic of metering services is that they form an essential input into the delivery of energy and energy management services. Further, there are strong complementarities between timely and accurate metering services and:

- efficient retailing, including billing;
- provision of innovative tariff options; and
- provision of value added energy services.

Such complementarities between metering and the provision of energy and energy management services create incentives for retailers to integrate metering services into their businesses. Integration would give them direct control over the inputs they need to deliver energy services to their customers.

Where Metering Coordinators are owned by or closely affiliated with retailers, this may create an incentive for them to discriminate against third parties with whom they are competing in a downstream market. Such discrimination may take a number of forms, such as in the quality of the services provided and/or the prices charged for services.

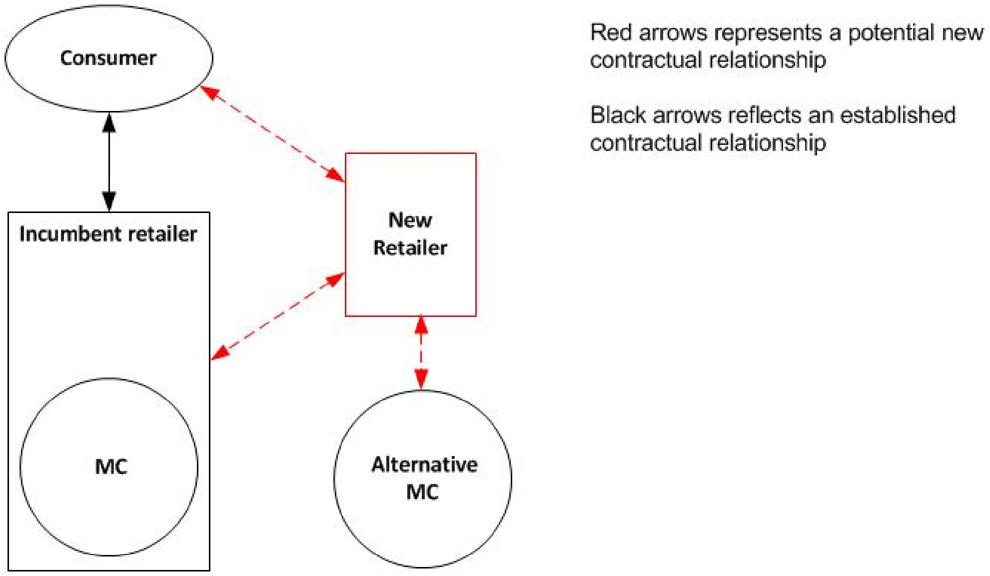
The competition issues that may arise in these circumstances are discussed below using two possible scenarios.

SCENARIO 4: Relationship between a retailer and a Retailer Metering Coordinator

This scenario addresses the situation where there is an incumbent Metering Coordinator, owned by a retailer, at one or more customer sites. A prospective new retailer is seeking to acquire a customer from the existing retailer, and is therefore seeking access to the services of the incumbent Metering Coordinator at these sites.

This scenario is illustrated in Figure E.4.

Figure E.4 Relationship between a retailer and a Retailer Metering Coordinator



New Retailer seeks access to Retailer MC services, but can appoint an alternative MC

Under this scenario the incumbent Metering Coordinator may have incentives to deny or frustrate access to its services by other retailers in order to hinder their ability to compete in the retail market. For example, the incumbent Metering Coordinator could:

- deny access completely or frustrate access by delaying negotiations or providing a poorer quality of access, which could increase the costs for the prospective new retailer in acquiring customers, as it would pay more than efficient costs for metering services; and/or
- deliberately charge the prospective new retailer a price for access to metering services that is above the level it would charge its own retailer. This could mean that the minimum price that an incumbent Metering Coordinator could be willing to accept for supplying metering services to a prospective new retailer would be higher than the minimum price acceptable to an alternative Metering Coordinator (ie above the full capital and installation costs of the next best alternative).

The effect of this behaviour is to raise the costs of supply for the prospective new retailer relative to the incumbent retailer, which may harm competition in the retail market by impacting the ability of retailers to make competitive offers.

The key characteristic of discriminatory conduct is that the incumbent Metering Coordinator chooses to forego short-term profits in the hope of securing higher returns in the long run for its affiliated retailer. Higher returns for the affiliated retailer arise from the higher metering costs faced by its competitors. These higher metering costs would be factored into the prices competitors charge, which would make their retail offers less attractive to consumers.

What factors would constrain discriminatory behaviour in this scenario?

As in Scenario 1, the ability of the incumbent Metering Coordinator to discriminate against other retailers in this scenario will be constrained by the ability, or potential ability, for the prospective new retailer to appoint its own Metering Coordinator and bypass or strand the existing meter. The incentive to deny access will be diminished if the prospective new retailer can easily obtain low cost Metering Coordinator services elsewhere, because the pay-off from refusing to negotiate will be much reduced.

Further, retailers have a mutual incentive to agree to reciprocal arrangements. For example, if a prospective new retailer is also affiliated with a Metering Coordinator and has a substantial customer base, then that retailer may charge an incumbent retailer a correspondingly high price for access to its own meters and functionality. This creates incentives for a mutually beneficial bargain to be agreed between retailers for reciprocal supply of metering services to accommodate consumer switching.

The incentive for large retailers to negotiate mutually beneficial agreements with smaller retailers who are not affiliated with a Metering Coordinator or do not have an established customer base is likely to be less strong. Smaller second tier retailers are likely to possess less bargaining power, which could lead the Metering Coordinators of larger established retailers to price discriminate between different retailers depending on the perceived strength of countervailing bargaining power.

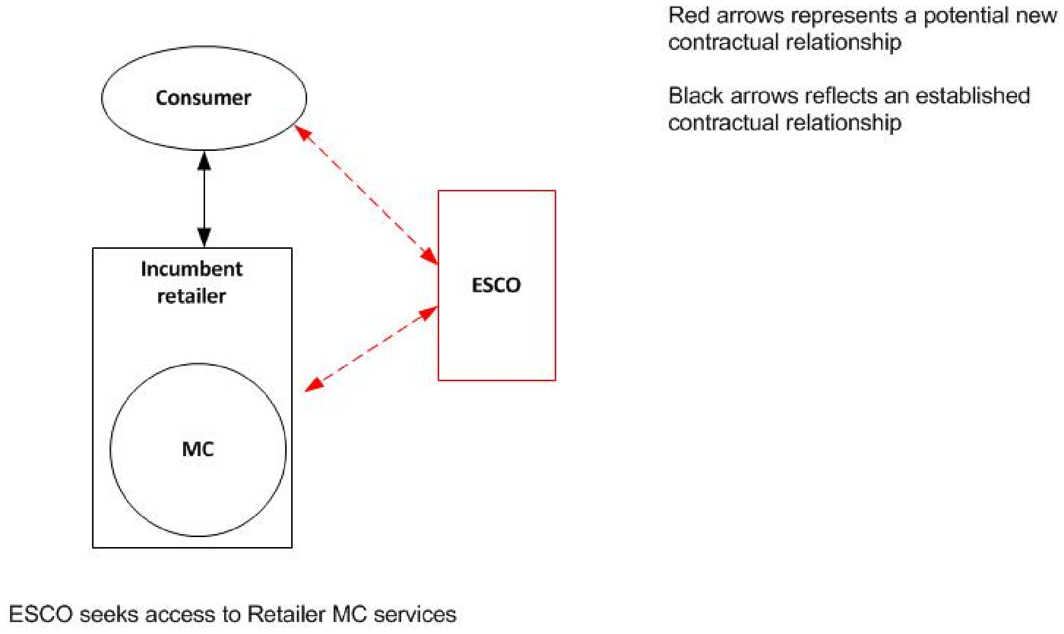
The Commission considers that the extent to which these dynamics will play out in the market will depend on the availability of low cost alternatives for retailers, such as the ability to lease rather than buy meters from the Metering Coordinator, and the emergence of independent Metering Coordinators. The prospects for such arrangements to emerge in Australia are good, as the Commission notes in its brief review of international arrangements in section E.4.2.

Finally, discriminatory behaviour that has the purpose of lessening competition may breach the Competition and Consumer Act (Cth) (CCA). This may provide a further constraint on the ability and incentive for a Metering Coordinator to engage in this type of conduct.

<u>SCENARIO 5:</u> *Relationship between an energy service company and a Retailer Metering Coordinator*

In this scenario an energy service company seeks access to services provided by a Retailer Metering Coordinator. The relevant relationships are set out in Figure E.5.

Figure E.5 **Relationship between an energy service company and a Retailer Metering Coordinator**



In this scenario an energy service company seeks access to the services of a Metering Coordinator in order to provide an energy management service to a customer of the retailer affiliated with that Metering Coordinator. The Metering Coordinator may have an incentive to deny or frustrate access for use of its functionality and data because:

- managing a consumer's energy consumption, and in particular reducing it, may conflict with the retailer's core service of supplying energy to its customers. The Metering Coordinator may perceive that denying access would increase, or prevent a decrease in, the retailer's profits; or
- the retailer also wishes to offer such services to its customers.

This could then provide incentives for the Metering Coordinator to do one or more of the following:

- choose to deliberately charge the energy service company for access to metering services at a price well above costs, if it perceives this will advantage the parent retailer. This could mean that the minimum price that the Metering Coordinator could be willing accept for supplying metering services to a new energy service company would be higher than the minimum price acceptable to an alternative Metering Coordinator;
- offer lower quality access to metering services by, for example, offering overly restrictive terms such that the energy service company is unable to access

metering services during certain times of the day, eg peak demand periods where demand management services are most attractive to consumers; and/or

- deny access completely or frustrate access by delaying negotiations.

What factors constrain discriminatory behaviour in this scenario?

Where there is a vertical relationship there will be a clear incentive for the Retailer Metering Coordinator to provide access in a way that enhances the competitiveness of its retailer owner or closely affiliated retailer in the retail market. If consumers value energy management services they will look for retailers that can provide those services. The retailer will therefore risk losing all the revenue from that consumer if it prevents the consumer accessing the energy service company's service. A lower return from the consumer may be better than losing that consumer altogether.

Alternative technologies that are currently available, and that may become more widely available in the future, may allow energy service companies to access granular consumption data and control load without requiring access to the meter. This would result in the Metering Coordinator not being a monopoly provider of that service. If a Retailer Metering Coordinator refuses to provide access to the meter, energy service companies will be more inclined to use these technologies to gain access to the services they need. This will reduce the number of revenue streams available to the Retailer Metering Coordinator, which in turn, may incentivise them to offer better access to energy service companies.

For example, devices that can sense current can be clipped onto outgoing wires from the circuit box. These sensors are Wi-Fi-enabled and allow for real-time monitoring of energy use at a level as granular as the wiring of the premises. Further, smart appliances are able to be remotely controlled via the internet. These options provide potential platforms for third party energy management that are not dependent on access to advanced metering services.[560]

Ultimately, consumers will face a choice between selecting a retailer that bundles the relevant energy management service and selecting a retailer that allows them to use an independent energy service company. Assuming the retail market is competitive, if a retailer chooses to 'tie' a service to its bundle, and its affiliated Metering Coordinator refuses access to a more efficient third party energy service company, that retailer risks losing customers if it is not competitive on price and service. Consequently, this should create incentives for any retailer to provide access to functionality it controls where this is efficient to do so.

560 An advanced meter would be required to create that pricing signal that makes energy management worthwhile from the consumer's perspective.

E.4.2 Current indicators and prospects for competition

The above section provided an analysis of competition concerns that could arise from the Metering Coordinator's control of the meter, as well as some factors that would constrain this behaviour in an effectively competitive market.

The Commission has sought to assess the available evidence for whether these factors are actually operating or are likely to operate in the new market. This has been informed by an extensive consultation process, discussions with potential market entrants and investigation of international arrangements.

A number of indicators give the Commission confidence that a market for metering services in Australia will be workably competitive and that barriers to entry will be relatively low.

Competitive markets for the provision of metering services have been working effectively in the United Kingdom and New Zealand. The most compelling evidence comes from New Zealand, where a competitive market in metering services was established in the late 1990s. Approximately 17 metering businesses have entered the market and are now competing to provide metering services to a range of different parties. Despite the fact that most metering business are either owned or affiliated with retailers, they provide services on a non-exclusive basis to other retailers and DNSPs.[561]

Many retailers and/or metering businesses have also established arrangements with one another for reciprocal use of meters in order to avoid risk of meter stranding and the destructive competition that may arise from ‘tit-for-tat’ responses between retailers who are responding to one another’s strong bargaining power. These reciprocal arrangements are typically ‘leasing arrangements’, where retailers lease or rent meters from other retailers (specifically their metering businesses) for a monthly or annual rental charge.[562]

There are also a number of independent meter leasing bodies operating in New Zealand, such as EDMI, which leases its meters on a non-exclusive basis to a range of different retailers. The availability of meter leasing arrangements may be particularly important for smaller, second tier retailers who may not otherwise provide a credible threat of a 'tit for tat response' to incumbent retailers.

Finally, there are early indications that metering businesses are already planning to enter the Australian market. Many of the metering businesses currently operating in New Zealand (eg Vector, EMDI and Metropolis) are seeking to establish themselves in Australia and have been active participants in this rule change process. Further, there appear to be a number of retailers in Australia that are in the process of establishing

561 LECG, ‘Developments in the New Zealand market for Advanced Metering Infrastructure and related services’, 3 July 2008.

562 Ibid., p3.

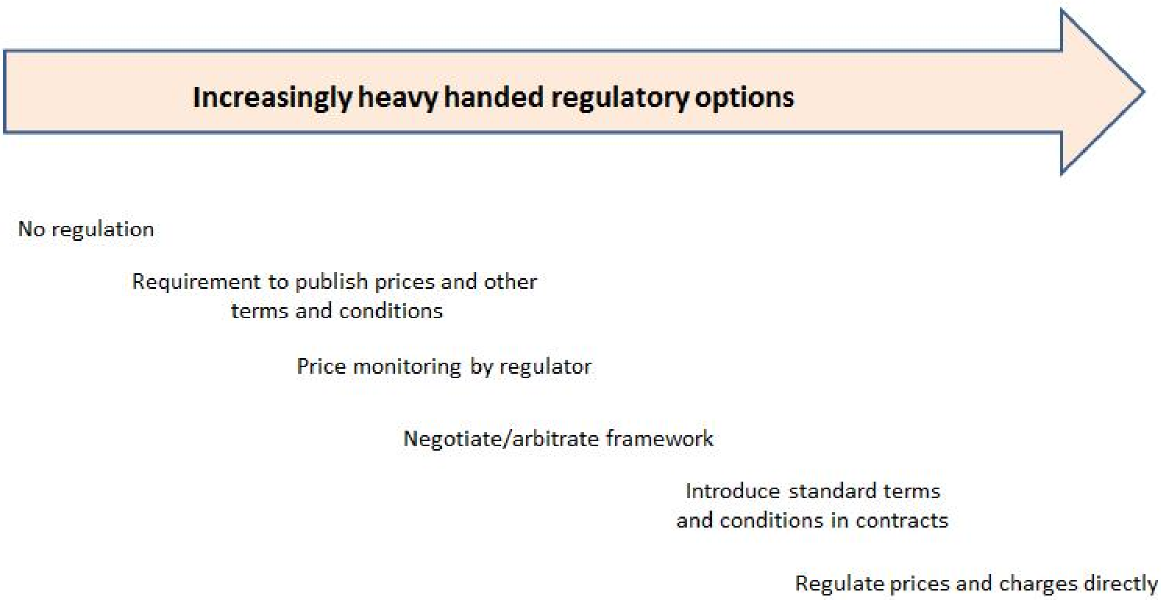
their own Metering Coordinator businesses as stand-alone subsidiaries and are likely to be motivated to seek customers beyond their retailer parent.

The Commission also notes that no second-tier retailers have expressed concerns to the Commission in submissions or in workshops about not being able to agree commercially acceptable terms with a Metering Coordinator.

E.4.3 Need for regulation

As part of assessing the costs and benefits of introducing access regulation, the Commission has considered the spectrum of regulatory options that are available to address the potential competition issues outlined above. This spectrum of options is summarised in Figure E.6 below.

Figure E.6 Spectrum of possible regulatory options



The Commission has not considered more intrusive forms of regulation, such as direct regulation of prices, terms and conditions. These forms of regulation would likely stifle incentives to invest and innovate in advanced metering services, ultimately undermining the evolution of contracting structures in the market.

Instead, the Commission considered a number of less intrusive regulatory options. These lighter forms of regulation are considered more appropriate where there is some degree of contestability or countervailing bargaining power in the provision of a good or service, but the market for supply of those services continues to be characterised by a substantial degree of bargaining power.[563]

563 See Section 4.4, Expert Panel on Energy Access Pricing, ‘Report to the Ministerial Council on Energy’, April 2006.

Relatively less intrusive forms of regulation may have one or more of the following features:[564]

- There is a reliance on commercial negotiation to deliver efficient outcomes, with availability of an arbitration mechanism as a backstop or 'circuit breaker' if negotiation fails. This is often referred to as an negotiate-arbitrate approach to regulation.
- The arbitration mechanism may also include pricing and other principles to guide negotiation and assist resolution of disputes.
- A requirement for a provider of services to publish prices, terms and conditions of access to those services.
- Price monitoring by a regulatory body such as the Australian Competition and Consumer Commission (ACCC) or the AER.

The benefits of these less intrusive forms of regulation are that they rely on markets to promote efficient outcomes for consumers, while leaving scope for regulatory intervention to deal with competition concerns as they arise in particular circumstances.

Box E.1 sets out a number of different contexts in which light-handed regulatory frameworks are applied.

Box E.1: Examples of different forms of access regulation

Different forms of regulatory approaches that may apply where a commercial arrangement cannot be reached are applied in a number of different contexts.

For example, Part IIIA of the CCA provides several pathways by which parties may gain access to services provided by monopoly infrastructure facilities. One such pathway is the ability of a party to apply to have a service provided by a particular facility "declared". If a service is a declared service, an access seeker may initiate arbitration by the ACCC in the event that the access seeker and service provider are unable to reach commercial agreement on the terms of access to the declared service and an access dispute is notified to the ACCC.

When arbitrating disputes regarding declared services, the ACCC must take into account, amongst other matters, pricing and other principles set out in Part IIIA of the CCA.

Chapters 6 and 6A of the NER, which refer to the economic regulation of distribution network and transmission network services respectively, provide a right to arbitration for disputes concerning access to certain types of services characterised by a degree of contestability and countervailing power by users.

564 Expert Panel on Energy Access Pricing, 'Report to the Ministerial Council on Energy', April 2006, p17.

Chapter 6 and 6A also contain pricing principles used to facilitate negotiations.

Part 2 of the National Gas Law (NGL) provides for certain gas pipeline services to be classified as 'light regulation services'. This classification is determined by the National Competition Council on the basis of a range of factors, including whether the pipeline in question is characterised by degree of countervailing power from users and substitutability from other services and or pipelines. Pipelines classified as light regulation pipelines are subject to a negotiate/arbitrate framework and price monitoring by the AER. The AER performs the role of arbitrator and takes into account pricing and other principles in the NGL when making decisions on disputes.

How could lighter handed regulation apply in the context of metering services?

The Commission investigated whether to implement:

- a negotiate/arbitrate framework for metering services; and/or
- a form of price monitoring for metering services.

Negotiate/arbitrate framework

Fundamental to many lighter handed regulatory frameworks is a process for arbitration if commercial negotiations fail. The threat of arbitration in itself may encourage parties to reach commercial agreements. This requirement would need to be coupled with a requirement on Metering Coordinators to offer metering and related services.

An arbitration process may comprise the following steps, which will vary depending on the specifics of the framework:

- Metering Coordinators would be required to offer to provide metering services to any person seeking access to those services.
- If the negotiating parties are unable to agree to one or more aspects of the terms and conditions of access, either party may provide notice of dispute, either directly to a regulator (eg ACCC or AER), or to a dispute resolution advisor in the first instance, depending on the framework.
- The regulator, or dispute resolution advisor, reviews the notification and nominates itself or some other party as arbitrator, and nominates parties to the dispute.
- The arbitrator gathers information and informs parties to the dispute of the process for running the arbitration. It may convene meetings and ask for submissions to inform itself of the issues.
- In making a decision the arbitrator may take into account a range of pricing principles and other matters specified in the relevant regulatory framework.

An arbitration process such as this could be implemented to govern the competition concerns identified for access to the services provided by a Metering Coordinator. Consequently, if a DNSP, energy service company or retailer was unhappy with the prices or terms and conditions being offered by a Metering Coordinator, they could trigger the arbitration process by notifying the relevant party of a dispute.

An arbitration framework for metering services may also need to specify pricing principles to guide the arbitrator in its decision making. Such pricing principles could assist the arbitrator to balance the competing interests of those seeking access to the metering services and the Metering Coordinator as the provider of the service.

A good example for how such considerations are balanced in pricing principles are those used in the context of a dispute regarding the terms of access for a declared service under Part IIIA of the Competition and Consumer Act (CCA). These are set out in Box E.2 below.

Monitoring and information disclosure

A feature of some lighter handed regulatory frameworks is a requirement that service providers publish their prices and other terms and conditions for monitoring by the regulator. The rationale for this is that it facilitates transparency which, in turn, reduces incentives for the service providers to exercise market power.

For example, providers of light regulation services under the National Gas Rules (NGR) are subject to a price monitoring regime and must publish on their website:

- the prices on offer for light regulation services; and
- the other terms and conditions of access to those services.[565]

Monitoring relies primarily on the market to provide incentives to promote efficiency. There is usually an explicit threat of more intrusive regulation if efficient outcomes are not forthcoming. In the context of the light regulation of gas pipeline services, access seekers can apply to have the light regulation applying to a pipeline revoked. Upon receiving such an application, the National Competition Council will need to reassess, amongst other things, the level of competition and may decide to implement full access regulation if it deems competition has not been operating effectively.

Box E.2: Pricing principles under Part IIIA of the CCA

Under Part IIIA of the CCA, where a service has been declared, an access seeker has a right to seek arbitration by the ACCC where the access seeker and access provider are unable to reach commercial agreement.[566]

565 An exception to this requirement is set out in rule 36(2), which allows that if a limited access arrangement is in force and is accessible on the service provider's website, the terms and conditions of access (other than price) need not be separately published on the website.

566 Note that this only applies where aspects of access are not subject to an access undertaking.

In making a determination on an access dispute, the ACCC has to take into account, amongst other matters, the pricing principles in 44ZZCA of the CCA. These are:

- that regulated access prices should:
  - be set so as to generate expected revenue for a regulated service or services that is at least sufficient to meet the efficient costs of providing access to the regulated service or services; and
  - include a return on investment commensurate with the regulatory and commercial risks involved; and
- that the access price structures should:
  - allow multipart pricing and price discrimination when it aids efficiency; and
  - not allow a vertically integrated access provider to set terms and conditions that discriminate in favour of its downstream operations, except to the extent that the cost of providing access to other operators is higher; and
- that access pricing regimes should provide incentives to reduce costs or otherwise improve productivity.

Costs of light-handed regulation

Negotiate/arbitrate frameworks and price monitoring have generally been used to regulate access to large infrastructure assets with significant natural monopoly characteristics including airports, telecommunications infrastructure and gas pipelines. There is little evidence to suggest that the market for metering services will have similar monopoly characteristics. This raises questions about whether this type of regulation is appropriate in the context of a market for metering services.

The Commission considers that while there are potential benefits of light-handed regulation as a tool for managing competition concerns in certain circumstances, there are also significant costs that need to be balanced against these benefits.

Negotiate / arbitrate model

One potential risk with implementing a negotiate/arbitrate framework for metering services is that it may discourage genuine commercial negotiation. A third party seeking access to metering services may consider it can always achieve a better outcome by raising a dispute and going to arbitration.

This is more than a theoretical possibility. In reviewing regulation of airport services, the Productivity Commission has pointed to experience in some sectors, such as telecommunications, where easy access to sector specific arbitration processes had undermined genuine negotiations and led to excessive use of arbitration to determine the price of access to services.[567] It further considered that "it would be virtually impossible to devise an [arbitration] mechanism that would retain strong incentives for all parties to negotiate rather than view arbitration as the default outcome."[568] For this reason the Productivity Commission recommended against introducing a sector specific negotiate/arbitrate framework for airport services.

Further, metering businesses commented at stakeholder workshops that the potential for arbitration over access to their services could act as disincentive to enter the market as a Metering Coordinator. In particular, small Metering Coordinators could face the costs of having to defend arbitration proceedings brought by large retailers and DNSPs. As smaller players, they are less likely to have the resources to participate effectively in such proceedings, which would also reduce their bargaining power at the negotiation stage. A negotiate/arbitrate framework could therefore introduce barriers to smaller Metering Coordinators entering the market.

A negotiate/arbitrate mechanism could also undermine the development of a market in metering services by introducing substantial uncertainty. Investors in advanced meters could face a risk that they may be required by a third party arbitrator to share this infrastructure, or the services it provides, at prices lower than those envisaged when the original business case for the investment was developed.

In addition, the arbitrator would have imperfect information regarding the actual costs incurred by a Metering Coordinator. Consequently it would have difficulty setting an efficient price. This creates a number of risks for potential Metering Coordinators that would be making significant, long term investments.

For example, service access regulation would require Metering Coordinators, at a minimum, to provide services to incoming retailers and energy service companies and potentially face arbitration to set the terms and conditions, including price, under which those services would be provided. There is therefore a risk that a Metering Coordinator may be required to provide services at a price that is lower than the level of charges that it had based its investment on.

This investment risk is particularly concerning given the relatively long life of the meters and associated investments. Metering Coordinators will need to invest significant capital on the expectation of certain returns over ten years or more. However, they may not have sufficient certainty regarding the level of returns if there is a risk of arbitration at any point over that ten year period.

This issue can be addressed to some extent in pricing principles to which an arbitrator must have regard, to increase certainty on how an arbitrator will determine prices. However, this does not address the significant risk that the arbitrator will not have sufficient information to be able to determine the efficient price.

567 Productivity Commission (2006) 'Review of the Price Regulation of Airport Services, Inquiry Report', No 40, 14 December, 2006, p90.

Arbitration may be a particular risk if the corresponding pricing principles limit, or are perceived to limit, cost recovery. While pricing principles could be included, investors may be concerned about their ability to fully recover their costs, including an appropriate return on investment. The Commission's position is therefore that the costs of introducing a negotiate/arbitrate framework for metering and related services are likely to exceed the benefits.

Monitoring and information disclosure

Price monitoring provides an alternative option for addressing competition issues. However, the Commission is concerned that a requirement to publish prices and/or monitor prices may not be practicable in a new market where prices are being competitively determined for the first time and service offerings are likely to evolve quickly.

Metering Coordinators will likely bundle or package energy and metering services in innovative ways depending on the needs of the consumer. This means that published prices may have little or no bearing on actual prices being negotiated for these services and it will be difficult to compare across different providers. Further, the cost of metering services is likely to depend on a range of factors such as:

- volume;
- risk appetite;
- location within the network; and
- the value different access seekers might place on those services.

This means it may be difficult for Metering Coordinators to publish standard prices, terms and conditions on their websites.

Consequently, published prices may not provide a credible basis for a regulatory body to impose effective discipline on a Metering Coordinator to discourage it from behaving in an anticompetitive fashion and could create an unnecessary regulatory burden for Metering Coordinators. The Commission notes that where price monitoring has been used in other sectors it has typically attracted mixed reviews on its effectiveness, including from the ACCC.[569]

The Commission therefore considers that the benefits of introducing price monitoring for metering services are likely to be outweighed by potentially significant administrative and regulatory burden. Further, price monitoring for metering services may introduce additional risks for potential investors in advanced meters, which could delay the development of the market.

568 Productivity Commission (2006) 'Review of the Price Regulation of Airport Services, Inquiry Report', No 40, 14 December, 2006, p91.

569 See for example, ACCC submission to the Productivity Commission's inquiry into the economic regulation of airport services, March 2011.

E.4.4 Draft decision

For the reasons set out above, the Commission considers that regulation of access to metering services is not appropriate at the commencement of the market.

However, the Commission recommends that the state of competition in the metering services market should be reviewed three years after the commencement of the new Chapter 7 of the NER, once the market has had time to develop.

F Arrangements for Victoria

Summary

The draft rule includes specific arrangements to enable a smooth transition from the existing arrangements put in place in Victoria under the AMI program to the national competitive framework. These are summarised below:

- At the commencement of the new Chapter 7 of the NER, the Victorian DNSPs will become the initial Metering Coordinator for the advanced meters they deployed under the AMI program and will continue in this role until another Metering Coordinator is appointed to the site or the services cease to be classified as a direct control service. .
- The derogation in rule 9.9C of the NER will be extended by six months so that it ends on the date the new Chapter 7 of the NER commences. This means that the Victorian DNSPs will no longer be able to provide metering services on an exclusive basis after that date, and other parties will be able to take on the Metering Coordinator role.
- If a new Metering Coordinator is appointed to replace the DNSP, an exit fee may be payable. Until 31 December 2020, the exit fee payable will be determined by the AER in accordance with the AMI Cost Recovery Order. After 2020, the AER will determine the level of any exit fee under the same arrangements as in other jurisdictions if the metering services continue to be classified as a direct control service.
- Victorian DNSPs will be able to continue to use the meters they deployed under the AMI program as network devices, if they choose to do so as a result of being unable to reach an agreement with a new Metering Coordinator.
- The national minimum services specification will take effect in Victoria when the new Chapter 7 of the NER commences.

The Commission is of the view that these arrangements will help to achieve the expected benefits of the AMI program, but in a way that enables new investment in metering services at an efficient cost.

The NERR does not currently apply in Victoria. Accordingly, the NERR amendments contained in the draft rule will not apply in Victoria, eg opt out rights for small customers in the event of a new meter deployment. The Victorian Government and Essential Services Commission should consider whether to make amendments to the Electricity Retail Code for consistency with the amendments to the NERR contained in the draft rule.

F.1 Introduction

This appendix provides an overview of the transitional arrangements for Victoria under the draft rule.

This appendix covers:

- an overview of the Victorian arrangements;
- the COAG Energy Council's rule change request with respect to transitional arrangements for Victoria;
- stakeholder views expressed in submissions to the consultation paper and in stakeholder workshops; and
- the Commission's analysis of the key issues and reasons for its draft rule.

F.2 Current arrangements

In 2006, the Victorian Government mandated a rollout of advanced meters (the AMI program). Through this mandate, the Victorian DNSPs were required to deploy advanced meters, in accordance with a prescribed minimum specification, to almost all Victorians consuming up to 160 MWh of electricity per annum. The program is now complete with approximately 2.8 million meters installed across the state. [570]

The Victorian Government's mandate was given effect through the following Orders in Council:

- the AMI Specifications Order, which sets out the minimum functionality and the associated service requirements that the AMI must satisfy;[571] and
- the AMI Cost Recovery Order, which, amongst other things:
    - required the Victorian DNSPs to replace existing meters with advanced meters by 31 December 2013;[572]
    - set out how a DNSP's fees and charges for the advanced metering infrastructure, associated services and systems are to be calculated to 31 December 2015; and
    - set out the regulatory framework in accordance with which the AER must determine:

570 State Government of Victoria, Smart Meters website, viewed 15 October 2014, http://www.smartmeters.vic.gov.au/about-smart-meters/end-of-rollout.

571 This Order in Council was made on 12 November 2007.

572 The original date was 31 December 2012.

- an exit fee to be paid by a retailer if it takes over the Responsible Person role from the DNSP; and
- a restoration fee to be paid by a retailer if the DNSP is required to take over the Responsible Person role.

In 2009, the AEMC made a jurisdictional derogation to vary the application of the NER in Victoria.[573] The derogation made Victorian DNSPs exclusively responsible for providing AMI and related services[574] to residential and small business consumers in Victoria. This was achieved through the derogation requiring meters that satisfy the AMI Specification Order to be designated as type 5 or 6 metering installations, rather than type 4 metering installations, even though they can be remotely read.[575] In effect, this classification means that DNSPs, rather than retailers, are the Responsible Person for these metering installations and retailers are prevented from providing this service.

This derogation was due to expire on 31 December 2013. However, in mid-2013 the Victorian Government made a rule change request for a new derogation to preserve the DNSPs' exclusivity for a further three years, or until the national arrangements for competition in metering and related services were implemented.[576] In November 2013, the Commission agreed to the proposed derogation and set the expiry date for this derogation to the earlier of:

- 31 December 2016; or
- the commencement in Victoria of:
  - a framework for competition in metering and related services for residential and small business customers under the NER; and
  - regulatory arrangements that provide for an orderly transfer of the regulation of relevant metering installations under rule 9.9C of the NER to the regulation of metering installations under the NER.[577]

In reaching this decision, the Commission noted that the derogation would be in the long term interests of consumers because:

- in the absence of the derogation, specific arrangements would have to be established for the period between the original derogation expiry (31 December 2013) and the start of a national framework for competition;

573 AEMC, Victorian Jurisdictional Derogation, Advanced Metering Infrastructure Roll Out, Rule Determination, 29 January 2009.

574 For example, remote connection, disconnection and energisation and direct load control services.

575 The exclusivity provided for under the derogation is metering installation type specific and applies to customers consuming 160 MWh pa or less.

576 Minister for Energy and Resources (Victoria), AMI Rule Change Request (Jurisdictional Derogation - Victoria), 18 June 2013.

577 AEMC, Victorian jurisdictional derogation, Advanced Metering Infrastructure, rule determination, 28 November 2013, p44-47.

- the costs of doing this were likely to outweigh the benefits, and may have affected the development of a national framework; and
- the benefits of allowing retailers to provide small customer metering services in Victoria were likely to be low until a national framework for competition in metering and related services is established.[578]

The derogation provisions are set out in rule 9.9C of the NER and provide for a derogation from what is prescribed in current clauses 7.2.2, 7.2.3, 7.11.1(d) and 7.3A(a) of the NER in Victoria.

The derogation only relates to metering classification and the designation of the Responsible Person role, not to the economic regulation of the charges, including exit fees, payable for metering services as prescribed in the AMI Cost Recovery Order. The application of this aspect of the Order in Council is instead given effect through clause 11.17.6 of the NER, which provides that while metering services remain regulated under the AMI Order in Council they will not be subject to regulation under a distribution determination. The charges and fees for these services must instead be determined in accordance with the provisions set out in the AMI Cost Recovery Order.

With the exception of exit fee and restoration fee provisions, the cost recovery provisions in the AMI Cost Recovery Order are due to expire on 31 December 2015. From 1 January 2016, the charges levied by Victorian DNSPs for AMI meters and services will be subject to Chapter 6 of the NER. This coincides with the commencement of the next regulatory control period for the Victorian DNSPs. The exit fee and restoration fee provisions in the Order in Council will continue to operate through to 31 December 2020.[579]

Victoria has currently not adopted the National Energy Customer Framework. Accordingly, the NERR does not apply in Victoria. The Electricity Retail Code applies instead of the NERR. In 2014, the Essential Services Commission made amendments to the Electricity Retail Code to increase the extent of harmonisation between it and the NERR.

F.3 Rule proponent's view

The COAG Energy Council's rule change request outlined the following transitional arrangements for Victoria:

- DNSPs would be the Metering Coordinator for the advanced meters they have deployed, and may continue in this role to the exclusion of other parties for a defined period (the exclusivity period). The exclusivity period may be established by the Victorian Government through a jurisdictional instrument.

578 AEMC, Victorian jurisdictional derogation, Advanced Metering Infrastructure, rule determination, 28 November 2013, pii.

579 This has been given effect through clauses 11.17.6(b) and (c) of the NER

- DNSPs may continue to deploy advanced meters in accordance with the Victorian mandate until the national framework applies.
- Upon expiry of the exclusivity period, the regulated exit fee would apply, to allow a retailer or consumer to subsequently replace a meter installed under mandate.
- The Victorian Government may decide, through a jurisdictional instrument, that the existing advanced metering specification in Victoria will continue to apply.[580]

F.4 Stakeholder views

Responses to this aspect of the COAG Energy Council's rule change proposal focused on:

- the proposed exclusivity arrangements;
- the exit fees to be paid in Victoria;
- the ability of DNSPs to continue to access the advanced metering enabled services and functions they currently have access to; and
- the minimum functionality specification to apply in Victoria.

An overview of the views expressed by stakeholders on these issues is provided below.

F.4.1 Exclusivity arrangements

Stakeholders broadly agreed that, as a transitional measure, the Victorian DNSPs should assume the role of initial Metering Coordinator for the meters they have deployed.[581] Mixed views were expressed about whether the DNSPs should be able to continue in this role to the exclusion of other parties once the new rules commence. For example:

- The Victorian DNSPs and the ENA believed an exclusivity period is required and should be maintained until the national framework for competition in metering is in place and transitional arrangements have been implemented in Victoria. They also noted that an exclusivity period would provide the Victorian Government with the flexibility to determine the timing of the transition, communicate this to consumers and ensure that the benefits of the mandated rollout can be catered for under the national framework.[582]

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580 COAG Energy Council, rule change request, October 2013, p33-34.

581 Victorian DNSPs, submission on consultation paper, p24; ENA, submission on consultation paper, p33; Origin, submission on consultation paper, p9; Simply Energy, submission on consultation paper, p10; Vector, submission on consultation paper, p20.

582 Victorian DNSPs, submission on consultation paper, p24; ENA, submission on consultation paper, p33.

- The Consumer Action Law Centre also supported the adoption of an exclusivity period and suggested it be maintained until the consumer-related benefits of the rollout are realised and consumers have more confidence to participate in the market.[583]

- Vector noted that while it does not object to an exclusivity period for a specified time, the arrangements "should be phased out as soon as possible".[584]

- The AER, AGL, EnergyAustralia, Origin, Simply Energy, ERAA, Metropolis and EDMI opposed any extension beyond the existing derogation.[585]

Stakeholders that supported an exclusivity period were of the view that the Victorian Government should be responsible for determining the length of the exclusivity period.[586] AGL, on the other hand, expressed some concerns about the Victorian Government's commitment to end the exclusivity period.[587]

During the stakeholder workshops a number of stakeholders noted that an extension to the exclusivity period was not required because the level of the exit fee in Victoria was likely to achieve the same purpose. Given the likely size of an exit fee under the AMI cost recovery order, stakeholders expected little, if any, competition for the Metering Coordinator role before 2021.

F.4.2 Exit fees in Victoria

The Victorian DNSPs and the ENA were the only parties that commented on regulated exit fees in Victoria.

The Victorian DNSPs submitted that there are "different drivers" that need to be considered when determining the exit fee for advanced meters, and that these should be reflected in any criteria that are included in the rules to guide the AER's assessment of exit fees. According to the Victorian DNSPs:

> "…the primary objective of exit fees should be to protect the significant sunk investments that Victorian distribution businesses have already made in AMI meters. Given the mandated nature of the rollout program, Victorian DNSPs should not be exposed to any technology or market risk.

583 CALC, submission on consultation paper, p3.

584 Vector, submission on consultation paper, p21.

585 AER, submission on consultation paper, p4-5; AGL, submission on consultation paper, p11; EnergyAustralia, submission on consultation paper, p6; Origin Energy, submission on consultation paper, p9-10; Simply Energy, submission on consultation paper, p10; ERAA, submission on consultation paper, p2; Metropolis, submission on consultation paper, p10; EDMI, submission on consultation paper, p15.

586 Victorian DNSPs, submission on consultation paper, p24; ENA, submission on consultation paper, p33; Vector, submission on consultation paper, p21.

587 AGL, submission on consultation paper, p11.

Moreover, exit fees should promote competition that improves overall economic efficiency. Costs are likely to be imposed on DNSPs, and hence on all customers, when customers change Metering Coordinators. These costs should be reflected in any exit fee, so that customers that choose to not churn Metering Coordinators are no worse off as a result of another customer's decision to churn."[588]

Elaborating further on its suggestion that consumers should face the full costs of their decision to change Metering Coordinators, the Victorian DNSPs stated that:

"…in order for competition to promote outcomes that are consistent with the NEO, any additional economic cost imposed on other participants in the electricity industry as a result of a customer's decision to change Metering Coordinators should be signalled to the market at the time at which a potential new entrant is seeking to enter that market (ie through the exit fee). Metering Coordinators would then only enter into the market if the net benefits to the two counterparties to the transaction exceeded the cost to the broader industry."[589]

The views expressed by the Victorian DNSPs on exit fees in Victoria were echoed by the ENA, who stated that a customer that decides to switch should "face the full and true cost of the decision including any lost benefits imposed on other network users". The ENA added that the exit fee in Victoria should include the cost to the DNSPs of obtaining services they can currently access from their own advanced meters, ie any charges that DNSPs may be required to pay a new Metering Coordinator to access network-related metering services.[590]

F.4.3 Access to advanced metering enabled services and functions

Concerns were raised by the ENA and the Victorian DNSPs about the potential for Metering Coordinators to exercise market power when negotiating access to the advanced metering enabled services and functions they currently access. These stakeholders suggested this issue be addressed by:

- implementing some form of light-handed regulation to ensure that access to data and services is provided at an efficient cost;

588 Victorian DNSPs, submission on consultation paper, p3. Some of the additional costs referred to in this context include costs that a DNSP incurs in accessing the AMI enabled services and functions it currently has access to (ie costs in excess of the incremental costs distribution networks would otherwise have incurred if they retained the meters); costs that a DNSP incurs in dealing with issues like data from multiple Metering Coordinators, managing meter churn, having to adopt less efficient processes for resolving outages; and costs that a DNSP incurs as a result of its inability to negotiate fair and reasonable terms of access to network related services with Metering Coordinators.

589 Victorian DNSPs, submission on consultation paper, p13-14.

590 ENA, submission on consultation paper, p27-28.

- allowing the Victorian DNSPs to retain their advanced meters and to use these as a network device if they are unable to reach an agreement with the new Metering Coordinator; and
- including the incremental costs of acquiring services and functions in the exit fee.[591]

The Victorian DNSPs also noted that if the current AMI minimum functionality specification as set out in the AMI Specifications Order ceases to apply, they will need to negotiate and pay for the network-related services that they can currently access through the meters rolled out under the AMI program.

F.4.4 Minimum functionality specification

The Victorian Government and the Victorian DNSPs expressed concern about the potential for the national minimum services specification to be lower than what is currently required by the AMI Specifications Order. These submitters were concerned that all of the services enabled by meters that meet the Victorian specification would not be available in meters that meet the national minimum services specification. The Victorian DNSPs suggested that unless the national specification is of an equal or higher functionality, the new and replacement policy in Victoria should provide for the use of the existing Victorian minimum functionality specification.[592]

F.5 Commission's analysis

In its assessment of the proposed transitional arrangements in Victoria, the Commission was conscious that Victoria is in a very different position to other jurisdictions because advanced meters have been installed in approximately 98 per cent of Victorian households and small businesses.

With the technology already in place to enable small customers to make more informed decisions about their consumption and product choice, and for industry to offer more innovative products and achieve a range of efficiencies, the focus in Victoria is now on delivering the expected benefits of the AMI program.

This means that attention needs to be paid to whether the draft rule will:

- allow the expected benefits of the AMI program to be achieved; and
- enable new investment in metering and related services where it is efficient.

591 Victorian DNSPs, submission on consultation paper, p19-22; ENA, submission on consultation paper, p1,7-8.

592 Victorian DNSPs, submission on consultation paper, p23.

In assessing the proposed transitional arrangements for Victoria the Commission has carefully considered the following:

- how competition for Metering Coordinator services is likely to evolve in Victoria;
- the role exit fees will play in providing appropriate signals to the market to invest in new meters and discouraging inefficient meter replacement in Victoria;
- whether an extension to the current exclusivity arrangements set out in rule 9.9C of the NER is required;
- how the concerns raised by the Victorian DNSPs about market power should be addressed;
- the minimum specification that should apply in Victoria when the new national framework comes into effect;
- issues arising from the fact that the NERR does not currently apply in Victoria.

The Commission's views on each of these questions are set out below along with its draft decisions on the transitional arrangements that will need to be put in place in Victoria to deal with these specific issues.

F.5.1 How is competition for the provision of Metering Coordinator services likely to evolve?

Based on the feedback provided by stakeholders it would appear that competition in the small customer segment of the Metering Coordinator market is likely to take some time to develop in Victoria.

The reasons for this are two-fold:

- First, the exit fees that will be payable at existing sites under the exit fee provisions in the Order in Council are likely to be relatively high during the initial years of the lives of the metering assets. New Metering Coordinators are therefore unlikely to enter this segment of the market until the exit fee falls to a level where it is efficient to replace the meter, or if there is a meter failure.[593]
- Second, the payment of an exit fee does not mean that ownership of the meter will automatically be transferred from the DNSP to the Metering Coordinator. It is unlikely therefore that new Metering Coordinators will enter this segment of the market to take over the operation of the existing meters, particularly given

593 If a meter fails then the DNSP (in its role as the initial Metering Coordinator) will be required to inform the relevant retailer. The retailer will then have to appoint a Metering Coordinator and it will be up to the new Metering Coordinator to replace the meter.

the interest the Victorian DNSPs have shown in retaining their meters as a bypass option (see below).[594]

Competition in the Victorian Metering Coordinator market is therefore likely to initially focus on large customers, greenfield sites for small customers including new estates, and meter failures at existing sites. Over time competition can be expected to become more prevalent at existing sites because, as the stock of existing advanced meters ages, the exit fee will fall and replacement of the existing meters will become a more realistic and cost efficient option. In the meantime, the DNSPs are likely to remain the Metering Coordinator for existing meters.

While the slower development of competition in Victoria may be viewed negatively by some, in the Commission's view it is more consistent with the NEO than the alternative of setting the exit fee at an artificially low level to encourage a greater degree of competition, because:

- Setting the exit fee at such a level will result in inefficient meter replacement, the cost of which will ultimately be borne by consumers.
- The expected benefits of competition in metering arise as a result of the greater range of services that advanced meters facilitate for consumers.[595] In Victoria, advanced meters are already in place, and so the benefits for consumers can still be delivered if the DNSPs, in their role as the initial Metering Coordinators:
    - provide retailers and other parties access to AMI services, such as re-energisation and de-energisation services; and
    - work with retailers to offer more innovative tariff products.

F.5.2 What role will the exit fee play in Victoria and how will it be determined?

In its current form, the AMI Cost Recovery Order provides for the payment of an exit fee by a retailer to a DNSP when the retailer takes over the role of Responsible Person and where the metering installation complies with the AMI Specification Order. The AMI Cost Recovery Order also sets out principles that the AER (previously the

594 Note that neither the AMI Cost Recovery Order nor the COAG Energy Council appear to contemplate a situation in which a new Metering Coordinator (or responsible person in the case of the AMI Cost Recovery Order) takes over the operation of the meters that have been rolled out as part of the AMI program. Rather, they both seem to assume that the Metering Coordinator (responsible person) will only change if the meter is replaced.

595 For example, more dynamic and innovative products that promote demand side participation and consumer choice and other efficiencies.

Essential Services Commission)[596] must apply when determining the exit fee through to the end of 2020.[597] These principles are reproduced below:

> "The Commission must determine an exit fee payable to each distributor as referred to in clause 7.1 in such a way that the exit fee enables the distributor to recover in a lump sum which is payable upon the change in responsible person referred to in clause 7.1:
>
> (a) the reasonable and efficient costs of removing the metering installation for which the distributor was the responsible person; and
>
> (b) the unavoidable costs (fixed and variable) that a prudent distributor has incurred or would incur as a result of the metering installation for which it was the responsible person being removed prior to the expiry of the life of that metering installation (which must be assumed to be as set out in clause 4.1(g)),[598] including:
>
> (i) the written down value of the meter (assuming that depreciation is calculated on a straight line basis);
>
> (ii) the proportion referable to that metering installation of the written down value of commissioned telecommunications and information technology systems; and
>
> (iii) a reasonable rate of return on the written down values determined under paragraphs (i) and (ii), calculated using the applicable WACC."

The Commission is aware that the exit fee principles set out in the AMI Cost Recovery Order differ from the principles the AER is considering using in other jurisdictions.[599] However, in the Commission's view a distinction can be drawn between the exit fee to be paid in Victoria and other jurisdictions because advanced meters are already in place and these meters already have a high degree of functionality.

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596 The AMI Order initially provided for the Essential Services Commission to set the metering charges, but this regulatory function was later transferred to the AER. Any references in the AMI Order to the 'Commission' should therefore be treated as references to the AER.

597 While some provisions in the AMI Cost Recovery Order in Council are due to expire on 31 December 2015, clauses 11.17.6(b) and (c) of the NER require the AER to apply the same exit fee and restoration principles until 31 December 2020.

598 This clause of the AMI Cost Recovery Order sets out the life of the asset to be used in the calculation of depreciation allowances, which is 15 years for the meters and measurement transformers and 7 years for the telecommunications and IT systems.

599 For example in NSW, where the AER proposes to allow DNSPs to recover residual capital costs (ie the capital costs the customer would have paid through annual charges had they remained a regulated metering customer) through distribution use of system charges, rather than through an exit fee. See AER, Draft decision on Ausgrid distribution determination - Attachment 16 - Alternative control services, November 2014, p29-49.

As the Commission noted in its decision to extend the Victorian derogation, it would be:

> "…particularly concerned at the possibility of replacement of AMI meters if a retailer elects to be responsible for a small customer metering site, given that these meters have a high degree of functionality and assets are near the beginning of their lives. It is likely to be efficient to replace such meters only if the additional benefits, through additional functionality for example, exceeded the cost of two meters – the existing one and the new one.[600]"

The most direct and allocatively efficient way to discourage the inefficient replacement of these meters is to require retailers that are considering replacing a meter to pay an exit fee that reflects the unrecovered costs of the meter and associated infrastructure, which is what the AMI Cost Recovery Order requires. Therefore, the Commission does not see any reason to alter the application of the exit fee provisions in the AMI Cost Recovery Order by amending clause 11.17.6 of the NER.

The ENA and Victorian DNSPs suggested that in addition to the unrecovered costs of the meters and associated infrastructure, the exit fee should include:

(a) any additional costs that the DNSP will incur in accessing services and functions from the Metering Coordinator;

(b) any costs or loss of efficiencies that the DNSP incurs as a result of its inability to negotiate fair and reasonable terms of access to network-related services; and

(c) any administrative or operational costs that the DNSP will incur under the new competitive framework, such as managing data from multiple Metering Coordinators.

For the reasons set out below, the Commission does not consider it necessary or appropriate to include any additional principles in the NER to supplement the exit fee provisions in the AMI Cost Recovery Order.

The Victorian DNSPs will, as noted in Appendix A1, have the option to continue to use their meters as network devices, eg if they are unable to reach agreement with the Metering Coordinator at a site. There is therefore no need to make any additional provision for the costs set out in (a) and (b).

600 AEMC, Rule Determination - National Electricity Amendment (Victorian Jurisdictional Derogation - Advanced Metering Infrastructure) Rule 2013, 28 November 2013, p. 31.

The Commission recognises that the introduction of the new competitive framework is likely to impose some administrative and operational costs on a range of parties across the supply chain. However, it expects that for consumers these costs will be more than offset by the benefits of:

- competition for the provision of metering and related services, which should drive down the cost of metering services; and
- the introduction of more dynamic and innovative products and services that promote demand side participation, consumer choice and allow market benefits to be captured across the supply chain.

Importantly, these benefits will not just accrue to those consumers that switch to a metering service which is not classified and price regulated by the AER. Rather, improvements in network, generation and other operational efficiencies are likely to flow through to other consumers in the form of lower prices and service quality improvements. It is therefore unnecessary to make any provision in the NER to include the types of costs set out in (c) in the exit fee so that consumers who are considering switching face an appropriate price signal.

To the extent that DNSPs incur efficient additional administrative and operational costs under the new framework, the businesses can seek to recover these costs through the existing AER processes.

The regulated exit fee for AMI meters in Victoria will continue to be determined by the AER having regard to the principles in section 7 of the AMI Cost Recovery Order until the end of 2020.

Post 2020, the manner in which the exit fee is determined will be the same as in other NEM jurisdictions and will depend on whether the AER classifies metering services as:

- a direct control service, in which case the AER will have to determine the exit fee (if any) having regard to, amongst other matters, the NEO and the revenue and pricing principles;[601] or
- a negotiated or unregulated service, in which case the AER will have no role in approving the exit fee.

In order for the exit fee provisions in the AMI Cost Recovery Order to be applied under the new national framework, the Commission recommends that the Victorian Government make minor consequential amendments to the order, including:

- Clause 7.1 will need to be amended to recognise that parties other than retailers may take on the Metering Coordinator role.
- The reference to 'Responsible Person' in clauses 7.1 and 7.2 will need to be replaced with the term 'Metering Coordinator'.

601 See Appendix D.2.

- Clause 7.2(a) should be amended so that it is clear that the costs of removing the meter will not be payable if the DNSP decides to leave its meter in place.[602]

F.5.3 Is an extension to the exclusivity period required?

During the consultation process, concerns were raised by a number of stakeholders about the potential for the expected benefits of the AMI program not to be realised under the new national framework.

To address this concern, a number of stakeholders suggested that:

- the Victorian DNSPs' exclusivity over the provision of metering and related services to small customers be extended beyond the dates set out in rule 9.9C of the NER; and
- the Victorian Government be accorded responsibility for determining the length of the exclusivity period.

The issue of how long the Victorian DNSPs should remain exclusively responsible for metering and related services was considered at length by the Commission when assessing the Victorian Government's proposed derogation for AMI. The Commission concluded that the commencement of the national framework for competition in metering and related services in Victoria would provide an appropriate trigger for the exclusivity arrangements and other aspects of the derogation to expire.[603]

As part of this rule change process, the Commission has given further thought to whether an extension of the exclusivity period is required to ensure that the expected benefits of the AMI program can be realised. However, as the preceding discussion on exit fees and the evolution of competition in Victoria highlights, the Victorian DNSPs are likely to remain responsible for the advanced meters they have deployed for some time, irrespective of whether or not the exclusivity period is extended.

In addition, as discussed in Appendix A1, DNSPs will be permitted to retain AMI meters as network devices, if they choose to do so. There does not therefore appear to be any value in extending the exclusivity period beyond the commencement of the new Chapter 7 of the NER.

An extension to the exclusivity arrangements beyond the commencement of the new Chapter 7 of the NER is also likely to act as an impediment to competition in other segments of the market where effective competition could reasonably be expected to

602 Note that this change is only required for consistency with the draft rule's provisions that allow Victorian DNSPs to leave their existing meters in place and use them as network devices, eg if they are unable to reach agreement with a new Metering Coordinator.

603 AEMC, Rule determination – National Electricity Amendment (Victorian Jurisdictional Derogation – Advanced Metering Infrastructure) Rule 2013, 28 November 2013, p45.

evolve, such as at greenfield sites or at existing sites for maintenance replacements or faults.[604]

As the new Chapter 7 of the NER will commence 1 July 2017, there is a six month gap between the expiry of the current Victorian derogation and the commencement of the new arrangements under the final rule.

The draft rule addresses this issue by extending the current derogation until 1 July 2017. For the reasons discussed above, the Commission has decided that it is not appropriate to extend the exclusivity period beyond the commencement of the new Chapter 7 of the NER.

F.5.4 How will market power concerns be addressed?

Concerns have been raised by the Victorian DNSPs and the ENA in relation to the potential for retailer-owned or third party Metering Coordinators to exercise market power when negotiating the terms and conditions of access to services and functions that are likely to be sought by DNSPs.

The potential for the exercise of market power by Metering Coordinators and the factors that might act to mitigate these concerns are discussed in Appendix E. Although the Commission considers that there are likely to be sufficient mitigating factors, it also recognises that if Metering Coordinators do behave in this manner then it will adversely affect consumers. The draft rule therefore allows the Victorian DNSPs to continue to use the meters they installed as part of the AMI program as a network device if they choose to do so, for example if they are unable to reach an agreement with Metering Coordinators to access equivalent services.

Apart from providing the Victorian DNSPs with a bypass option, the availability of this option will allow the expected benefits of the AMI program to be realised even if the Metering Coordinator decides to install its own meter before the AMI meter reaches the end of its useful life.

The draft rule also provides that DNSPs may install new network devices, which will provide DNSPs with a bypass option in relation to customers that do not currently have an AMI meter, eg greenfield sites.

F.5.5 What minimum specification should apply in Victoria?

The minimum functionality specification for advanced meters supplied to small customers in Victoria is currently given effect through:

- the AMI Specifications Order, which sets out the minimum specification; and

604 Refer Appendix C.

- the AMI Cost Recover Order, which requires DNSPs to use their best endeavours to comply with the AMI Specification Order when installing new meters, or replacing existing meters.[605]

Some stakeholders expressed a concern about potential differences between the minimum services specification under the draft rule and the existing Victorian specification. The Commission notes that the Victorian specification was developed for a mandated rollout of advanced meters and specifies functional requirements rather than services.

In its advice to the COAG Energy Council on the minimum functionality of advanced meters, AEMO noted that the minimum services and requirements for advanced meters under a competitive deployment might be different to those required for a regulated rollout. AEMO expressed the view that, in order to promote and encourage development and innovation under a competitive deployment of advanced meters, the requirements should be set at a level that minimises barriers to market entry.[606]

Under the draft rule, the minimum services specification will take effect in Victoria when the new Chapter 7 of the NER commences. All new metering installations installed at small customers' connection points after that date will be installed under the new competitive framework, not a regulated rollout. The Commission is of the view that the minimum services specification is more appropriate than the current Victorian specification for meters that are installed under a competitive framework. The value of maintaining a separate specification in Victoria is also likely to be outweighed by the competitive benefits and economies of scale that could be achieved through the adoption of a national specification.

F.5.6 NERR issues

The NERR does not currently apply in Victoria. Retail market issues are instead regulated by the Essential Services Commission (Victoria) under the Electricity Retail Code.

Accordingly, the NERR amendments contained in the draft rule will not apply in Victoria. In particular, the opt out rights for small customers in the event of a new meter deployment and the amended NERR provisions on disconnections and reconnections will not apply in Victoria unless it adopts the NERR at a later date.

The Victorian Government and Essential Services Commission should consider whether to make amendments to the Electricity Retail Code for consistency with the amendments to the NERR contained in the draft rule.

A number of provisions in the NERR amendments contained in the draft rule only apply to "small customers". In jurisdictions such as Victoria that have not currently

605 See clauses 14.1(a), 14.3(b)-(e) and 14AA.4 of the AMI Cost Recovery Order.

606 AEMO, Minimum functionality of advanced meters, Advice to COAG Energy Council, November 2014, p4.

adopted the NECF, the draft rule adopts the same load size threshold between large and small customers as applied under other jurisdictional electricity legislation.[607]

607 Under the NECF, a "small customer" is any residential customer, or any business customer who consumes energy at business premises below the "upper consumption threshold". The standard upper consumption threshold under NECF is 100MWh per year, but some jurisdictions have adopted different thresholds. In Victoria, the equivalent threshold is currently 40 MWh per year for certain other purposes.

G Other requirements under the NEL and NERL

This Appendix sets out the relevant legal requirements under the National Electricity Law (NEL) and National Energy Retail Law (NERL) for the AEMC in making this draft rule determination.

G.1 Commission's considerations

In assessing the rule change request the Commission considered:

- the Commission’s powers under the NEL and the NERL to make the rule;
- the rule change request;
- the fact that there is no relevant Ministerial Council on Energy (MCE) statement of policy principles;[608]
- the AEMC's Power of Choice review final report to the COAG Energy Council;
- submissions received during first round of consultation on the rule change request;
- comments made by stakeholders in stakeholder workshops held as part of the consultation undertaken for the rule change request;
- interactions with the other related projects discussed in section 1.4 of this draft determination;
- AEMO's advice on the minimum services specification; and
- the Commission’s analysis as to the ways in which the draft rule will or is likely to, contribute to the NEO and the NERO.

Revenue and pricing principles

In applying the rule making test, the Commission has taken into account the revenue and pricing principles as required under section 88B of the NEL as described below.

Section 7A(2) of the NEL states that a network service provider should be provided with a reasonable opportunity to recover at least the efficient costs it incurs in providing network services and in complying with a regulatory obligation or requirement or making a regulatory payment.

Under the draft rule, the Financially Responsible Market Participant or, if applicable, a large customer at a connection point, may appoint a party other than the distribution network business to be the Metering Coordinator for that connection point (for further

608 Under section 33 of the NEL and section 14 of the NERL the AEMC must have regard to any relevant MCE statement of policy principles in making a rule.

details see Appendix A1). The revenue and pricing principles were taken into account in the Commission's consideration of arrangements for distribution network businesses to recover residual costs for existing meters when another party takes on the Metering Coordinator role.

No changes to the existing regulatory framework are proposed in this regard because the Commission considers that the AER is best placed to determine arrangements for cost recovery in accordance with the existing regulatory framework. This is discussed further in Appendix D2.

G.2 Commission's power to make the rule

The Commission is satisfied that the draft rule falls within the subject matter about which the Commission may make rules.

The draft electricity rule falls within section 34 of the NEL as it relates to:

- regulating the operation of the national electricity market;[609]
- regulating the operation of the national electricity system for the purposes of the safety, security and reliability of that system;[610]
- regulating the activities of persons (including Registered participants) participating in the national electricity market or involved in the operation of the national electricity system;[611]
- regulating the provision of connection services to retail customers;[612] and
- facilitating and supporting the provision of services to retail customers.[613]

The draft retail rule falls within section 237 of the NERL as it relates to:

- regulating the provision of energy services to customers, including customer retail services and customer connection services;[614] and
- regulating the activities of persons involved in the sale and supply of energy to customers.[615]

609 Section 34(1)(a)(i) of the NEL.

610 Section 34(1)(a)(ii) of the NEL.

611 Section 34(1)(a)(iii) of the NEL.

612 Section 34(1)(a)(iv) of the NEL.

613 Section 34(1)(aa) of the NEL.

614 Section 237(1)(a)(i) of the NERL.

615 Section 237(1)(a)(ii) of the NERL.

G.3 Civil penalty provisions

The provisions of the NER that are classified as civil penalty provisions are listed in the National Electricity (South Australia) Regulations and the provisions of the NERR that are classified as civil penalty provisions are listed in the National Energy Retail Regulations. While the Commission cannot create new civil penalty provisions, it may recommend to the COAG Energy Council that new or existing provisions of the NER and NERR be classified as civil penalty provisions.

Where the draft rule amends an existing clause that is currently a civil penalty provision, the Commission has considered whether the civil penalty should be retained. Where the draft rule either amends an existing clause that is not currently a civil penalty provision or introduces a new clause, the Commission has considered whether that clause should be subject to a civil penalty.

In considering whether a civil penalty should apply, the Commission has taken the following general approach:

- Where an existing clause is currently a civil penalty provision and the clause has not been amended substantially, the civil penalty should continue to apply.
- Where an amended clause or a new clause introduces a new obligation that is key to the continued operation of the NEM or relates to key consumer protections, the provision should attract a civil penalty.

The clauses of the NER that the Commission recommends should attract a civil penalty are set out in Table G.1. The clauses of the NERR that the Commission recommends should attract a civil penalty are set out in Table G.2.

Table G.1 Civil penalty provisions in chapter 7 of the NER

New clause reference	Old clause reference	Recommendation
Amended clauses that we recommend should continue to attract a civil penalty		
7.3.2(a)	7.2.5(a)	Retain
7.3.2(b)	7.2.5(b)	Retain
7.3.2(d)	7.2.5(cl)	Retain
7.3.2(e)	7.2.5(d)	Retain
7.6.3(b)	7.2.3(c)	Retain
7.6.4(a)	7.2.3(e)	Retain and clarify that the civil penalty applies to the FRMP in relation to its obligation to appoint the LNSP as Metering Coordinator

New clause reference	Old clause reference	Recommendation
7.8.1(a)	7.3.1A(a)	Retain and clarify that the civil penalty applies to the Metering Coordinator
7.8.1(c)	7.4.1(a)	Retain
7.8.2(a)(1)-(11)	7.3.1(a)(1)-(13)	Retain
7.8.2(d)	7.3.1(e)	Retain
7.8.2(e)	7.3.1(f)	Retain
7.8.7(a)	7.3.2(a)	Retain
7.8.8(c)	7.3.4(d)	Retain and clarify that the civil penalty applies to the Metering Coordinator
7.8.11(a)	7.8.3(a)	Retain and clarify that the civil penalty applies to the Metering Coordinator
7.8.11(b)	7.8.3(b)	Retain and clarify that the civil penalty applies to the Metering Coordinator
7.8.11(c)	7.8.3(c)	Retain and clarify that the civil penalty applies to the Metering Coordinator
7.8.13(b)	7.2.4(b)	Retain
7.9.1(a)	7.6.1(a)	Retain and clarify that the civil penalty applies to a person who carries out testing under the clause
7.9.1(e)	7.6.1(e)	Retain
7.9.2(a)	7.6.2(a)	Retain
7.9.3(e1)	7.6.3(d)	Retain and clarify that the civil penalty applies to the Metering Coordinator in respect of providing AEMO with access to carry out random audits but not in respect of AEMO's obligation to carry out periodic random audits
7.10.1(a)	7.11.2(a)	Retain
7.10.5	7.12(a)	Retain
7.10.6(a)	7.11.1(b)	Retain and clarify that the civil penalty applies to the Metering Coordinator
7.10.6(d)	7.11.1(d)	Retain and clarify that the civil penalty applies to the Metering Coordinator
7.11.3(a)-(c)	7.8.4	Retain and clarify that the civil penalty applies to the Metering Coordinator
7.12.2(b)	7.5.2(b)	Retain

New clause reference	Old clause reference	Recommendation
7.15.2(a)	7.8.1(a)	Retain
7.15.3(a)	7.8.2(a)	Retain
7.15.3(b)	7.8.2(b)	Retain
7.15.3(c)	7.8.2(c)	Retain
7.15.3(d)	7.8.2(d)	Retain
7.15.3(e)	7.8.2(e)	Retain
7.15.5(b)	7.7(b)	Retain
7.16.2(c)	7.2.8(d)	Retain
Amended clauses that we recommend should now attract a civil penalty		
7.2.1(a)	7.1.2(a)	This clause should be classified as a civil penalty provision due to the key obligation imposed on the FRMP to ensure a Metering Coordinator has been appointed with respect to a connection point.
7.3.2(g)	7.2.5(g)	This clause imposes obligations on the Metering Coordinator that are key to the operation of the market, and so we recommend classifying this clause as a civil penalty provision.
New clauses that we recommend should attract a civil penalty		
7.3.2(f)	n/a	This clause imposes an obligation on the Metering Coordinator to ensure energy data is retrieved from a small customer metering installation via remote acquisition. This is key for the efficient operation of the NEM and so we recommend classifying it as a civil penalty provision.
7.3.2(h)	n/a	This clause imposes obligations on the Metering Coordinator that provide key consumer protections and so we recommend classifying it as a civil penalty provision.
7.7.1(a)	n/a	This clause imposes an obligation on the FRMP to ensure a new Metering Coordinator has been appointed where a Metering Coordinator default event occurs or the contract appointing the Metering Coordinator is terminated. This is key for the continued operation of the NEM and so we recommend classifying it as a civil penalty provision.

New clause reference	Old clause reference	Recommendation
7.8.3(a)	n/a	This clause imposes an obligation on the Metering Coordinator to ensure that any new or replacement metering installation in respect of the connection points of a small customer is a type 4 metering installation that meets the minimum services specification. This is key for the efficient operation of the NEM and so we recommend classifying it as a civil penalty provision.
7.8.3(b)	n/a	This clause imposes an obligation on the Metering Provider to ensure that a metering installation at a new connection point is a type 4 metering installation that meets the minimum services specification. This is key for the efficient operation of the NEM and so we recommend classifying it as a civil penalty provision.
7.8.6(b)	n/a	This clause imposes an obligation on the Metering Coordinator and the LNSP to act in certain ways in relation to the right of the Local Network Service Provider to install a network device at or adjacent to a metering installation for the purposes of monitoring or operating its network. This is key for the safe and reliable operation of the national electricity system and so we recommend classifying it as a civil penalty provision.
7.15.4	n/a	This clause imposes obligations on the Metering Coordinator and Metering Provider in relation to security controls for small customer metering installations. This is a key consumer protection and so we recommend classifying it as a civil penalty provision.

For completeness, the draft NER omits the following (old) clauses that are currently classified as civil penalty provisions from the NER and therefore the Commission will recommend that the relevant Regulations are amended to remove references to these provisions:

- 7.2.3(h)
- 7.4.2(c)
- 7.4.2(ca)
- 7.13(b).

Table G.2 Civil penalty provisions in the NERR

New clause reference	Old clause reference	Recommendation
Amended clauses that we recommend should continue to attract a civil penalty		
19(2)	19(2)	Retain
56	56	Retain
121(1)	121(1)	Retain
125(2)	125(2)	Retain
135(1)	135(1)	Retain
New clauses that we recommend should attract a civil penalty		
59A	n/a	Classify as a civil penalty provision to encourage compliance with opt out requirements.
106A	n/a	Classify as a civil penalty provision, consistent with classification of rule 106

G.4 Conduct provisions

The provisions of the NER that are classified as conduct provisions are listed in the National Electricity (South Australia) Regulations. Currently no provisions of the NERR are classified as conduct. While the Commission cannot create new conduct provisions, it may recommend to the COAG Energy Council that new or existing provisions of the NER and NERR be classified as conduct provisions.

The Commission is still assessing the need for conduct provisions to apply to the draft rule and will set out any recommendations in its final determination.

In considering whether to recommend that a provision be classified as a conduct provision, the Commission will consider the following guiding principle:

- A provision of the draft rule should, as a starting point, be classified as a conduct provision where the breach of that provision:
  - will have or be likely to have a detrimental effect on another identifiable person (such as a Registered Participant); and
  - the purpose of the provision is to confer a right or benefit on, or prevent harm to, the person who is or is likely to be affected by the breach.

For example, it may be appropriate to recommend that a provision that requires a person to prevent harm to another Registered Participant's equipment be designated as a conduct provision.

The Commission is seeking stakeholder views on those provisions where it may be appropriate for the Commission to recommend classification as a conduct provision.

G.5 Declared network functions

Under section 91(8) of the NEL, the Commission may only make a rule that has effect with respect to an adoptive jurisdiction if it is satisfied that the rule is compatible with the proper performance of the AEMO's declared network functions.

The Commission considers that the draft rule is compatible with AEMO's declared network functions as it has no impact on these functions.

H Summary of further issues raised in submissions and organisations represented in stakeholder consultation process

H.1 Summary of further issues raised in submissions

Where relevant, stakeholder comments have been addressed throughout the draft determination. Table H.1 summarises issues raised by stakeholders that were not explicitly addressed in the final determination and the Commission's response to these comments.

Table H.1 Summary of further issues raised in submissions

Stakeholder	Issue	AEMC response
General comments		
Alinta Energy	The consumer should have the option of owning the meter after paying an exit fee. (p3)	The purpose of an exit fee is to help compensate a DNSP for costs that may be unrecovered as a result of the consumer moving to an unregulated metering service. Under the draft rule, the AER will determine how DNSPs can recover residual costs, which may include through an exit fee. For small customers, the retailer would be responsible for paying the regulated exit fee, if any, when it appoints a competitive Metering Coordinator to the connection point. The retailer may choose to pass some, all or none of this cost on the consumer. Importantly, payment of the exit fee does not give rise to a transfer of ownership of the existing meter. Any transfer of ownership would be a commercial arrangement between the DNSP and the new Metering Coordinator. Consequently, the draft rule does not contemplate the transfer of ownership to the new Metering Coordinator or other party, including the consumer. Exit fees are discussed further in Appendix D2.
ATA and other consumer groups	The AEMC should make a more preferable rule that is in keeping with the recommendations made in the Power of Choice review. (p3)	The AEMC may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the NEO and the NERO as outlined in the NEL and NERL. The AEMC has made a draft rule that we consider is most likely to contribute to the achievement of the NEO and the NERO.

CALC	Important that consumer empowerment is included in priorities for rule change. The following principles should be met: (1) take account of consumer behaviour and biases rather than just pure economic theory, (2) information provision should be clear, balanced and simply communicated, (3) terms, conditions and fees must be regulated so that there are no surprises for consumers, (4) product standardisation where appropriate. (p2)	The AEMC has had regard to these issues in the context of its assessment of the NEO and the NERO.
CUAC	The AEMC should give due regard to the needs of low income and vulnerable consumers so they are able to participate and benefit from competition. (p3)	The focus of this rule change is on supporting consumer needs and preferences with regard to how they use electricity. Chapter 3 outlines the Commission's views on the benefits of the draft rule for consumers, including for low income and vulnerable consumers.
ENA	The role of the Metering Coordinator should be clear on whether voltage transformers and current transformers are managed by the consumer or the Metering Coordinator. The responsibility for testing and ongoing management of transformers needs to be made clear. (p36)	Under the draft rule, the obligations for testing that currently lie with the Responsible Person would transfer to the Metering Coordinator. Any current transformers and voltage transformers that are not being tested correctly would be addressed by the existing AER and AEMO arrangements.

ENA	Need to consider the relationship that consumers have with DNSPs. (p23)	The AEMC acknowledges that consumers have an important relationship with DNSPs, including for services such as load control. Under the draft rule, consumers will continue to have a relationship with their DNSP with regard to supply, and any direct involvement for load control and other network services.
EnerNOC	Retailers should not be allowed to bundle retail and metering services. (p4)	The success of a market for metering services partly depends on the framework being simple and easy for consumers to understand and engage with. Itemising metering charges on a consumer's retail bill may be confusing for small customers and is likely to be of little value while they are unable to engage their own Metering Coordinator. This is discussed further in Appendix B2. A bundled service allows consumers to make one decision based on an assessment of costs and the products and services being offered.
ERAA	Existing load management services should not be retained as standard control services. All access to metering services should be by commercial negotiation, regardless of whether the party seeking access is a monopoly or contestable provider. (p3)	While the Commission recognises that load control services can be provided by other parties, classification decisions are the remit of the AER.
Ergon Energy	Regarding the proposal that the DNSP, as the initial Metering Coordinator must not increase its charges to the retailer for providing metering services. Wants clarification that this would not preclude a DNSP from increasing charges in accordance with prices approved as part of annual pricing proposals. (p4)	The draft rule does not prevent a DNSP, as the initial Metering Coordinator for meters for which it was previously the Responsible Person, from increasing metering charges in accordance with prices approved as part of a DNSP's annual pricing proposal.
Ergon Energy	The benefits of introducing the Metering Coordinator role may be	The draft rule will support the competitive provision of metering services to consumers. The AEMC is of the view that the long term benefits to consumers of the draft rule are likely to

	negated by the cost to industry (system and process changes, additional transactions, administrative overheads). The changes are likely to increase costs to consumers. (p4,14)	outweigh any administrative costs incurred by industry to update their systems to accommodate the changes. The AEMC recognises the potential to reduce implementation costs if other reforms are implemented at the same time. This is discussed further in Chapter 5.
ERM Power	Does not support the proposal to require Metering Coordinator to inform retailer only when a change in meter results in a material change to customer services as Metering Coordinator may not be in a position to know. A retailer should be informed of every meter replacement which occurs. (p13)	Under the draft rule, retailers would engage a Metering Coordinator at a connection point on a commercial basis. Any information flows not addressed by requirements in the NER and NERR could form part of the contract between those two parties.
Calvin Capital	The Metering Coordinator needs access to data about the meter owner, and notification of changes to meter assets, e.g. through AEMO. (p1,2)	
NSW DNSPs	There is an inconsistency between clause 7.7 of the NER (retailers only provide data) and clause 86 of the NERR (DNSPs must provide data). DNSPs have an important relationship with consumers and should have the ability to provide information to them. (p11)	A rule change made in November 2014 allows consumers to access information about their energy consumption from their local DNSP. Further information is available at: http://www.aemc.gov.au/Rule-Changes/Customer-access-to-information-about-their-energy
PIAC	Consumers should be represented on the Information Exchange Committee and Retail Market Executive Committee. (p2)	Membership of the IEC is determined by rule 7.2A.2 of the NER. Membership of the RMEC is determined by AEMO. The make-up of the IEC and RMEC are beyond the scope of this rule change request.

SA Power Networks	Concerned about situation where a metering installation owned by a third party metering provider fails, and the customer loses supply as a result. The LNSP may be required to replace metering equipment in order to meet its supply restoration obligations, and would need to recover the associated cost. (p6)	Under the draft rule, the Metering Provider at a connection point must ensure that the metering installation is provided, installed and maintained in accordance with the rules and any relevant procedures. If the Metering Provider at a connection point is not the DNSP and the meter fails, that Metering Provider would be responsible for repairing or replacing the meter. Any liability for loss of supply would lie with that party, not the DNSP.
Vector	The Metering Provider role should be expanded to include responsibility for the provision, installation and maintenance of remote, two-way communication to the metering installation. (p6)	Under the draft rule, the Metering Coordinator is responsible for appointing a Metering Provider to provide, install and maintain a metering installation. All new meters installed for small customers after the commencement of the rule will be required to meet the minimum services specification. The services included in the minimum services specification necessitate the installation of a meter with a communications interface. Metering Providers therefore have responsibility, under the rules, for the provision of a meter that meets these requirements. The role of the Metering Provider is discussed in Appendix A2.
Vector	DNSPs should provide open access to legacy metering installations and access data (meter types, location, access requirements, etc) to facilitate market entry and smart meter deployment. (p18)	If an existing meter meets the minimum services specification, the obligations in the draft rule regarding access to those services would apply.
Comments on the assessment framework		
ATA	The assessment criteria should consider: • equity, especially by geographic location for remote and regional consumers; and	The AEMC may only make a rule if it is satisfied that the rule will, or is likely to contribute to, the NEO and the NERO as outlined in the NEL and NERL. Both the NEO and the NERO are centred on the long term interests of all consumers. The Commission is of the view that the draft rule will have benefits for all consumers, as outlined in Chapter 3. As discussed in Appendix C1, AEMO may grant an exemption to the requirement to meet the minimum services specification where there is no existing telecommunications network to enable

	• a commitment to reduce GHG emissions, as metering may be an enabler to reaching the 5% by 2020 target. (p4).	remote access to the meter, eg in remote and regional areas.
EWON	Consumers should not pay higher charges for smart meters. (p1)	The draft rule does not regulate the prices that parties can charge for the provision of metering and related services. However, the nature of the model encourages parties to compete to provide metering services, which we expect to lead to a low cost deployment of advanced meters.
Victorian DNSPs	It is unclear how the magnitude of the required changes to systems, processes and rules is consistent with proposed assessment criteria regarding administration and transaction costs. (p9)	The Commission is of the view that the benefits of the draft rule to consumers, market participants and other parties, and to the operation of the electricity market as a whole, outweigh the administrative costs involved to implement the changes. Implementation issues are discussed in Chapter 5.
Appointing the Metering Coordinator		
Alinta Energy	The AEMC should consider the impact of the rule change on standing and deemed arrangements with respect to 'move ins'. The default position should mandate that the Metering Coordinator is the retailer until consumer elects otherwise. (p3)	This issue is no longer relevant as the draft rule does not allow small customers to appoint their own Metering Coordinator.
Ergon Energy	There may be merit in a national Metering Coordinator function to ensure cost efficiency and standard access and cost arrangements. (p7)	The draft rule is based on the premise that competition, as opposed to monopoly provision of metering services, will result in the best price and service outcomes for consumers. Requiring that only one party provide the Metering Coordinator function to all retailers likely stifle innovation and would mean there are no competitive pressure to reduce costs or improve service outcomes.
Metropolis	Existing Metering Providers should be automatically accredited as a	The Metering Coordinator and Metering Provider roles are separately defined in the draft rule. The Commission considers it would not be appropriate to accredit existing Metering Providers as

	Metering Coordinator. Existing Responsible Persons should be given a 6-12 month transitional period to become accredited or make arrangements with accredited Metering Coordinators. (p4)	Metering Coordinators because of the differences in the responsibilities and capabilities required of each role. This is discussed further in Appendix A1.
Metropolis	Metering Coordinators should obtain the consumer's explicit informed consent to appoint itself to a connection point. Suggests a similar MSATS process to current process for retailer appointment. (p5)	Under the draft rule, the retailer will be responsible for appointing a Metering Coordinator to a small customer's connection point. Small customers will not be able to engage a Metering Coordinator directly. The model terms for standard retail contracts are amended in the draft rule to reflect this. This arrangement will facilitate simplicity for consumers because they will only need to deal with one party, ie their retailer. This is discussed in Appendix A3.
NSW DNSPs	Concerned that Metering Coordinators will cherry pick profitable sites to the detriment of less profitable sites (eg remote areas). (p6)	Under the draft rule, the retailer is responsible for appointing a Metering Coordinator at the connection points of each of its customers. Metering Coordinators will compete to provide their services to retailers. Once appointed by a retailer, they will be obliged to carry out their functions in accordance with the rules and any other contractual arrangements established with the retailer. It is possible that Metering Coordinators will not compete in all areas. If this is the case, the incumbent Metering Coordinator will continue to carry out this role.
Consumer protections		
AER	Existing NER/NERR and Australian Consumer Law arrangements appear sufficient to protect consumers, but a dispute resolution framework may be needed given that existing energy ombudsmen schemes appear not to apply to Metering Coordinators. (p1)	Under the draft rule, small customers are not able to engage a Metering Coordinator directly. Instead, retailers will engage a Metering Coordinator on their behalf. This approach means that small customers will continue to be covered by existing consumer protection provisions and jurisdictional ombudsman schemes that apply to retailers This is discussed in Appendix B1.
EWON	It is important that the Metering Coordinator is bound by NECF	

	arrangements where there is consumer interaction. Further, the Metering Coordinator, where it has a relationship with consumers, should be required to join and be bound by the jurisdictional ombudsman in the same way that DNSPs are. (p2)	
Alinta Energy	Need to consider privacy implications related to the collection, use and disclosure of information. (p2)	The draft rule provides that only certain parties are permitted to request access to metering data. There are also new obligations to protect meters from unauthorised access. This will ensure that the privacy of a consumer's energy data is maintained. Parties accessing this information will also be subject to compliance with any applicable privacy legislation. This is discussed further in Appendix B3.
CALC	Consumer privacy and data security concerns need to be addressed from the outset. (p2)	
CUAC	Consumers need adequate protection through the regulatory framework and access to dispute resolution. Third party consumer protections need to be addressed at the outset, prior to giving third parties access to metering data and metering service provision. (p2)	
Ergon Energy	Need to consider privacy issues if the Metering Coordinator role is created. Additional consumer protections would be required. Metering Coordinators must be held liable for promises made to consumers. (p6, p9)	

Origin Energy	All relevant consumer protections and privacy protections should apply equally to direct and indirect customer relationships with Metering Coordinators. (p6)	
ATA	Given it appears unlikely that the NEM will have a common meter protocol, lack of interoperability presents consumer protection risks that are unacceptable without regulation of arrangement between Metering Coordinators and Metering Data Providers. (p4)	The AEMC is preparing advice to the COAG Energy Council on implementing a shared market protocol. AEMO has also been asked to develop a proposed shared market protocol. These pieces of work are discussed in Chapter 1. Together, this work will inform the development of a rule change request for implementing a shared market protocol. The Commission expects the rule change and the subsequent development of the shared market protocol to be undertaken in parallel with the implementation of this metering rule change. The Commission's expectation is that the shared market protocol could set out a method of communication for all commonly available advanced services. While a shared market protocol does not preclude parties from agreeing to alternative methods of communication, feedback from stakeholders suggests that all parties have an interest in meter interoperability.
Third party providers		
Alinta Energy	It is important that the relationships between consumers and energy service providers are seamless and consistent and don't require further investment from the consumer when they change their product/service preferences. (p3)	The ability for consumers to enter into a contract with a third party energy service provider raises a broader question about whether these parties should be regulated. This question is being considered by the COAG Energy Council (see Chapter 1). Consequently, the draft rule does not seek to address this issue.
ATA	Need a specific policy to define the relationship between consumers and third parties. But, it is appropriate to allow market to take form before finalising arrangements under NECF. Until then, a code of conduct may be an appropriate measure. (p4-5)	

ATA	At 3 year review of competition, the AEMC should also review the effectiveness of consumer protections with regard to marketing, services and other matters relating to third parties. (p5)	
CALC	The COAG Energy Council's work on third parties should be done in line with principles outlined and in conjunction with rule change. (p2)	
CUAC	Consumer protection framework for third parties needs to be in place before expiration of the Victorian derogation. (p2)	
PIAC	NECF needs to be updated. It is outdated with respect to demand management technology. Update needs to define relationships of third parties with consumers, retailers, DNSPs. (p1)	
DNSPs reading meters remotely and installing communications modules to do so		
ENA	The current rules prevent DNSPs from remotely reading meters. DNSPs should be able to provide smart meters or install communications interfaces to remotely read meters. All consumers should fund DNSPs enabling remote communications, as the data is used for standard	The draft rule allows a Metering Coordinator to make a type 5 or 6 metering installation capable of remote acquisition where it determines that operational difficulties reasonably require it. This provision would allow a DNSP, as the initial Metering Coordinator for meters for which it was previously the Responsible Person, to install a communications interface for example at sites where access is difficult or on a remote rural property. Alternatively, if it is not the Metering Coordinator at that connection point, the DNSP could choose to help fund the installation of an advanced meter or communications interface at a type 5 or 6 metering installation in exchange for access to services. This is discussed in Appendix D4.

	control services. (p23, 28)	
Ergon Energy	Clauses 7.11.1 and 7.3.4 of the NER prevent DNSPs from installing communications-enabled metering to support network alternatives. The NER should be amended to allow DNSPs to do this where it is the best commercial solution and in best interests of consumers. DNSPs should not have to do this as a ring-fenced entity because it creates unnecessary costs. (p5)	
Implementation		
Alinta Energy	Changes must consider both implementation and ongoing costs and responsibilities of market participants, and the effect on current systems and procedures. (p1)	The Commission recognises that industry participants will need to make changes to their systems and processes to meet the requirements of the new rules, procedures and guidelines. Implementation is discussed further in Chapter 5.
Alinta Energy	Need to consider community and communication education programs to explain market changes. (p3)	The Commission agrees that communication and education is vital to support confidence in the market and consumer engagement. Governments, retailers, distribution network businesses, energy service companies and consumer groups all have a role to play in communicating the changes and their implications to consumers. A commencement date of 1 July 2017 gives these parties time to communicate the changes to consumers so that they can engage effectively when the rules commence.
CALC	A slow and managed transition will be needed so that consumers can develop confidence in the benefits of new meters. (p3)	
CUAC	An extensive consumer information and education campaign by retailers, governments and DNSPs	

	is needed. (p2)	
EWON	Consumer acceptance and understanding is crucial to the realisation of the benefits of smart meters. Governments and retailers have a key role in promoting consumer acceptance and understanding. (p1)	
Energex	The transitional period should align with the regulatory control period to ensure certainty of funding for DNSPs. (p8)	The draft rule proposes a start date of 1 July 2017. This date takes into account the time that Market Participants, including DNSPs, will need to make the necessary changes to comply with the new rule when it commences. DNSPs should have sufficient time to incorporate funding to support the rule changes in their regulatory proposals. Consequently, no transitional period will apply once the rules commence.

H.2 Organisations represented in stakeholder consultation process

Table H.2 lists the organisations represented in the stakeholder consultation process to date, including at AEMC workshops, submissions on the consultation paper and submissions on the draft implementation plan.

Table H.2 Organisations represented in stakeholder consultation process

	Organisation
1	1circle
2	ActewAGL
3	AEMO
4	AER
5	AGL Energy
6	Alinta Energy
7	Alphalink
8	Alternative Technology Association
9	AMS International Technologies
10	Arup Consulting
11	Ausgrid
12	AusNet Services
13	Calvin Capital
14	CitiPower and Powercor
15	Consumer Action Law Centre
16	Consumer Utilities Advocacy Centre
17	Couch & Associates
18	Department of Economic Development, Jobs, Transport and Resources (Victoria)
19	Department of Energy and Water Supply (Queensland)
20	Department of Industry (Commonwealth)
21	Department of State Development (South Australia)
22	Department of Trade and Investment (NSW)
23	Department of State Growth (Tasmania)

	Organisation
24	E3 International
25	EDMI
26	Embertec
27	Energy Networks Association
28	Endeavour Energy
29	Energeia
30	Energex
31	EnergyAustralia
32	Energy Tailors
33	EnerNOC
34	Energy Retailers Association of Australia
35	Ergon Energy
36	Ergon Energy Retail
37	Ericsson
38	ERM Power
39	Ernst and Young
40	Energy Supply Association of Australia
41	Essential Energy
42	eutility
43	Energy and Water Ombudsman NSW
44	Gentrack
45	Horizon Power
46	IBM
47	Information Exchange Committee
48	Itron
49	Jemena
50	Landis+Gyr
51	Legal Energy, Lawyers and Consultants

	Organisation
52	Lend Lease
53	Lumo Energy
54	Macquarie Bank
55	Medusa Capital
56	Metering Dynamics (Energex)
57	Metrix
58	Metropolis Metering Services
59	Momentum Energy
60	Networks NSW
61	Oakley Greenwood
62	Origin Energy
63	Public Interest Advocacy Centre
64	Red Energy
65	Rheem
66	SA Power Networks
67	SATEC
68	Secure Australasia
69	Seed Advisory
70	Select Solutions (AusNet Services)
71	Silver Spring Networks
72	Simply Energy
73	Smart Grid Australia
74	South Australian Council of Social Service
75	Standards Australia
76	Synergies Economic Consulting
77	TasNetworks
78	Telstra
79	Thinking About Energy

	Organisation
80	TransGrid
81	United Energy and Multinet Gas
82	Uniting Communities
83	University of Sydney
84	Vector

Abbreviations

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
B2B	Business to business
CCA	Competition and Consumer Act
COAG	Council of Australian Governments
Commission	See AEMC
DNSP	Distribution Network Service Provider
DSP	Demand side participation
IEC	Information Exchange Committee
LNSP	Local Network Service Provider
MSATS	Market Settlement and Transfer Solutions
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NERL	National Energy Retail Law
NERO	National Energy Retail Objective
NERR	National Energy Retail Rules
NGL	National Gas Law

NGR	National Gas Rules
NMI	National Metering Identifier
ROLR	Retailer of Last Resort
TNSP	Transmission Network Service Provider

FOI 190420
Document 8

MINIMUM FUNCTIONALITY OF ADVANCED METERS

ADVICE TO COAG ENERGY COUNCIL

November 2014

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

The purpose of this advice is to provide information about minimum functionality requirements for advanced meters in response to a request from the Council of Australian Governments (COAG) Energy Council.

This publication is based on information available to AEMO as at 14th November 2014.

Disclaimer

AEMO has made every effort to ensure the quality of the information in this publication but cannot guarantee that information is accurate or complete. Any views expressed in this report are those of AEMO unless otherwise stated, and may be based on information given to AEMO by other persons.

Accordingly, to the maximum extent permitted by law, AEMO and its officers, employees and consultants involved in the preparation of this publication:

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Acknowledgement

AEMO acknowledges the support, co-operation and contribution of all members of the stakeholder reference group, established to assist the development of the advice.

EXECUTIVE SUMMARY

On 25 June 2014, the Council of Australian Governments (COAG) Energy Council requested two pieces of advice from the Australian Energy Market Operator (AEMO) on requirements to inform a competitive framework for metering and related services. These requirements are for:

- A minimum functionality specification for advanced meters (due to be submitted to COAG EC in November 2014).
- A shared market protocol for advanced meter communications (due to be submitted to COAG EC in February 2015).

The advice sought from AEMO will support the development of a competitive, market-led roll-out of metering and related services within the National Electricity Market (NEM), which is the subject of a Rule change currently being considered by the AEMC. The draft determination on that Rule change is expected in December 2014.

Key finding

This paper provides AEMO's advice on the minimum set of services and requirements to meet the requirements of a market-led roll-out of advanced meters, and also on some additional requirements for any mandated rollout of advanced meters.

Consistent with the terms of reference received from COAG EC, AEMO's approach to developing the advice focused on the services and business outcomes delivered through advanced metering systems. AEMO considered the market's objective and developed criteria to allow a range of possible services to be tested and evaluated against the criteria to determine which functions, if any, could form a mandated minimum specification.

AEMO identified six services that met the assessment criteria, and could be mandated for both a competitive roll-out of advanced metering systems. These services enable efficiency gains across the market, support market settlements, market participants, customers and their agents in accessing the benefits of metering information and remove barriers to the development and implementation of new tariffs and customer choice:

1. De-energisation (turn electricity supply off remotely)
2. Re-energisation (turn electricity supply on remotely)
3. Meter read – on demand (obtained remotely as required by a retailer, customer or other authorised party)
4. Meter read – scheduled (obtained remotely as per contracted dates and times)
5. Meter installation enquiry (remotely obtaining energy information, meter status, and usage data)
6. Meter Reconfiguration – (to remotely enable access to new tariffs and new arrangements, such as solar connections and energy demand tariffs)

AEMO identified other advanced metering services that did not meet the assessment criteria when considered in the context of a competitive roll-out.

AEMO advises that an outcome-focused services specification is preferable to a functional specification for advanced metering devices and systems, because:

- A services specification allows meter manufacturers, service providers and retailers to innovate and compete on the basis of their products and performance. A services specification is ideally suited to a market-led approach to advanced metering.
- Mandating a functionality specification could unnecessarily limit service delivery innovations. It could also delay the adoption of new technologies as it would lock in the functional design of a particular technology at a point in time.

AEMO's advice meets the COAG E C objectives of supporting policy decision-making, providing certainty as to the required services and meter functions, and reducing the time required to develop technical documentation. It also seeks to answer all questions asked in the terms of reference.

AEMO developed this advice following consultation with an industry stakeholder reference group[1]. The majority of stakeholders consulted during the development of this advice, agreed on the range of advanced metering services that could be mandated in support of a market-led roll-out. This report also documents the contested positions to represent the views garnered through the process.

Next steps

AEMO recognises that one of the most important features of an advanced metering system is the wealth of data that can be readily provided to authorised parties.

Accordingly, COAG Energy Council could consider that an advanced metering services specification be developed concurrently with the shared market protocol under the NER, and a review of the standard format for delivering data to the market and participants, since the former informs the latter.

[1] See full list of stakeholder reference group members at Appendix A.

CONTENTS

1. INTRODUCTION

In December 2012, the Standing Council on Energy and Resources (now the Council of Australian Governments' Energy Council, or COAG EC) agreed to establish a framework to support competition in the provision of metering and related services. The COAG EC submitted a rule change request to the Australian Energy Market Commission (AEMC) to establish this framework. The rule change request included proposals relating to advanced meter capability.

On 25 June 2014, the COAG EC requested advice from AEMO on:

- The requirements for a minimum functionality specification for advanced meters.
- Requirements for a shared market protocol for advanced meter communications.

This paper provides AEMO's advice on the minimum set of services and requirements for advanced meters to meet the requirements of a market-led roll-out.

This advice is intended to inform:

- Jurisdictions developing metering policies for consideration at the COAG EC meeting in December 2014.
- The AEMC Metering Competition Rule Change on the specification of minimum service requirements for advanced meter functionality.

In February 2015, AEMO will provide its advice on the requirements for a shared market protocol for advanced meter communications.

1.1 Objectives

Advanced meters currently available on the market can provide a wide range of services. Further services have been proposed or applied for some circumstances. The question addressed in this report is, which of these services could be mandated and under which circumstances.

AEMO established the criteria for assessing the various candidate services that advanced metering might supply, and for deciding which services could be included in the minimum specification. A decision to mandate minimum requirements needs to promote the National Electricity Objective (NEO).

AEMO notes that the minimum services and requirements for advanced meters in any specified standard might be different for a competitive roll-out from those required for a mandated or regulated rollout. To promote and encourage development and innovation under a competitive roll-out, the requirements should be set at a level that minimises the barriers to market entry. Regulation should only be required in a situation of market failure.

A competitive meter provider (or retailer) would need to offer meter services and prices that are attractive to at least some customers as part of a package. While this should deliver an appropriate service/price trade-off to these customers, it would not necessarily deliver all the necessary functionality. Mandatory standards may therefore be required to ensure that the interests of the market overall, and important third parties, are considered.

AEMO used the following criteria to assess the services that could be mandated:

- The interests of the market to deliver efficient business processes and low transaction costs.
- The broader market and society's interest in meter accuracy, safety and security.
- The common interest in being able to provide efficient network services and efficient pricing of those services.

In a competitive roll-out, the provision of a range of other potential value-adding services will be decided by the market. A regulated roll-out, by contrast, would also need minimum standards specified in these areas.

In providing this advice, AEMO has taken the view that the functionality should be defined by the services or outputs that the meter provides, and the accuracy and level to which it provides them. AEMO believes this is preferable to specifying how the meter should operate. A services-based approach should then allow meter manufacturers and service providers to innovate and compete on the basis of their products and performance.

In addition, the COAG EC's stated objectives of this advice are to support:

- Implementation of a framework for competitive metering, if adopted, by reducing the time required to develop technical documentation.
- Ministerial discussion on the advanced meter functions that may be required, and jurisdictional decisions on the functions that may be required for advanced meters under a new and replacement policy.
- Certainty of the services that stakeholders expect smart meters to support in the NEM.
- The AEMC's considerations regarding the appropriate governance arrangements and status of the minimum functionality specification proposed in the metering competition rule change request.
- Consideration of the services and meter functions required to be supported through a shared market protocol.

2. METHODOLOGY

AEMO used a “top-down” approach to assess the requirements for a National Electricity Market (NEM) advanced metering minimum functionality specification. AEMO initially focused on developing a longer list of the services that could be delivered through advanced metering systems. This list of candidate services was then tested against the criteria and classified into three groups: primary, secondary and value-added services, i.e.:

***Primary* services:** COAG Energy Council to consider mandating as part of a competitive rollout.

***Secondary* services:** COAG Energy Council to consider mandating as part of a non-competitive rollout.

***Value-added* services:** other advanced metering services for COAG Energy Council consideration.

AEMO then considered the performance standards and service levels to which the primary (and secondary) services should be delivered. Finally, AEMO considered which functions, if any, could form a minimum functionality specification.

AEMO has drawn from the work undertaken by industry during the National Smart Metering Program[2], which was adjusted to reflect the outcomes of the AEMC’s Power of Choice review.[3] AEMO has also incorporated international experience to both define the potential service offerings, and to consider current international standards initiatives.

AEMO used this information to identify specifications that are not commonly available in advanced metering products and systems, as well as any specifications that would require the procurement of bespoke products. AEMO also identified specifications with the potential to create barriers for advanced metering service providers, or barriers to the adoption of advanced metering in a market-led approach.

Clearly identifying advanced metering services, will contribute to the development of advice on a shared market protocol. The objective of the shared market protocol is to deliver messaging arrangements to support a competitive metering services framework.

Regulation

By definition, regulation is a set of rules or laws designed to control or govern conduct. Regulation creates, limits, or constrains a right, creates or limits a duty, or allocates a responsibility.

One of the objectives of AEMO’s advice is to provide a framework for a market-led roll-out of advanced meters in the NEM. In the terms of reference for this advice, the COAG EC stated that it expects the provision of advanced meters to be driven primarily by customer and business choices, based on the costs and benefits available to each party. This means that to achieve the required benefits, the roll-out of advanced meters should be driven using market dynamics to roll out new technologies and services. The implication is also that the market-led roll-out is driven by the retail sector.

In this case, where the aim is to support a market-led roll-out, there should be little need to regulate market services; market dynamics will drive the roll-out and ensure that market focused outcomes are achieved. However, to fully realise the benefits of an advanced meter roll-out, the requirements of other parties also need to be considered, such as the network businesses for network management services. Accordingly, sufficient regulation will be needed to ensure that the services required by other parties, can be obtained without creating barriers for market adoption of advanced metering.

Stakeholder engagement

AEMO established a stakeholder reference group which met fortnightly from 25 July 2014. The reference group comprised representatives from:

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2 Initiated by the then Ministerial Council on Energy and ran from July 2008 to December 2010.

3 Completed in December 2012.

- Electricity retailers and distribution businesses.
- Potential third party providers of energy services via advanced meters.
- Potential metering coordinators.
- Meter manufacturers.
- Consumer representatives.
- Representatives from Standards Australia and the National Measurement Institute.
- Jurisdiction government officials.
- Representatives from the AEMC and the Australian Energy Regulator.

A complete list of the reference group members and their respective organisations is attached at Appendix A.

Meetings took the form of round table discussions that were minuted in a working document, capturing all points of agreement, dispute, actions, and issues. AEMO and the AEMC also met regularly to make sure that progress aligned with the AEMC's Metering Competition Rule change and broader Power of Choice initiatives.

This paper documents the services considered by AEMO, and for the most part, agreed by industry (via the reference group) as part of the minimum services specification required, and the rationale for each. This paper also lists services that were discussed but where no agreement was reached, and documents the contested positions to represent all views.

AEMO has used all of this information to formulate its advice to the COAG EC.

Service definition

AEMO developed a working document to facilitate the consultation process, which contained a complete list of known and developing advanced metering services in operation locally and internationally. Reference group participants were able to articulate the business outcomes, service levels, and performance standards they would require in respect to each service. Moreover, equipment manufacturers and service providers were able to confirm whether their core product suite facilitates the delivery of these services as standard.

As a result of the consultation process, AEMO identified three groups of services:

1. The services that could be mandated for both a competitive and regulated roll out of advanced metering systems:
    - De-energisation (turn electricity supply off remotely)
    - Re-energisation (turn electricity supply on remotely)
    - Meter read – on demand (obtained remotely as required by a retailer, customer or another authorised party)
    - Meter read – scheduled (obtained remotely as per contracted dates and times)
    - Meter installation enquiry (remotely obtaining energy information, meter status, and usage data)
    - Meter Reconfiguration – (to remotely enable access to new tariffs and new arrangements, such as solar connections and energy demand tariffs)
2. The services that should be not mandated for a competitive roll out of advanced metering systems, but could be mandated for a regulated roll out:
    - Re-energisation (remotely arming the meter to enable the customer to reconnect supply via a switch at the meter)
    - Load limiting (the ability remotely establish or remove a limit that restricts the amount of energy that can be consumed)
    - Load management (turning designated loads off and on at a customers' premises, remotely on command, or under a schedule)

- Local access to a metering system via a registered device (connectivity with the meter from a device owned and operated by the customer or their agent)

3. The set of services that should be not mandated for a competitive roll out of advanced metering systems, or for a regulated roll out:

   - Enabling a Home Area Network (HAN)
   - Supply failure and restoration notifications
   - Metering installation asset management
   - Safety monitoring

3. ADVANCED METERING SERVICES

In preparing this advice, AEMO considered the services of an advanced meter should be to:

- Support billing and settlement in the market, i.e., the basic metrology services of electricity meters.
- Support efficient business practices.
- Enable efficient, reliable, and safe operation of the national grid.
- Deliver an accessible and secure platform for the delivery of flexible tariffs and demand-side and data services to consumers and other market participants.

To define the required business outcomes, all identified services were classified into categories.

3.1 Service categories

In addition to remotely operated advanced metering services, the reference group discussions also addressed some infrastructure services. Infrastructure services are services that require a physical action at site, and may otherwise be covered by existing business processes.

However, this advice paper only covers services that are delivered specifically through advanced metering systems, and not the physical infrastructure services currently managed in the NEM. As a result, infrastructure services are not included.

3.2 Service classifications

AEMO identified services that can deliver required business outcomes through advanced metering systems, and classified them as primary, secondary, or value-added, as below.

Primary services:

Primary services are those that:

- Meet the stated policy objectives as described in section 1.1
- Could be mandated for a competitive roll-out of advanced metering systems.
- Would be enabled upon installation of an advanced metering system.
- Would be provided across all advanced metering installations.

Secondary services:

Secondary services are those that:

- Do not meet the stated policy objectives as described in section 1.1
- Should not be mandated under a competitive roll-out of advanced metering systems (as their value has not been tested by the market).
- Could be considered to be mandated as a minimum service under a regulated rollout.
- Would apply to some (but not all) advanced metering installations.
- Would be activated in an advanced metering system following a request from an authorised party, either upon installation or (more typically) at a later date.

Value-added services:

Value-added services are those that:

- Do not meet the stated policy objectives as described in section 1.1
- Can be implemented and delivered if required on a commercial basis under a competitive or regulated rollout.

3.3 Primary services

Energisation services

Energisation services enable the electricity supply to be remotely disconnected and reconnected, without the need for any physical action at the metering installation. These services operate in overseas markets and in the Victorian AMI programme, and have demonstrated their ability to deliver desired outcomes in reduced timeframes at a fraction of the previous cost. These services also provide low cost options for ensuring the safety and security of a premises, such as in emergencies, for supply disconnection to vacant premises, or where there are hazardous electrical installations.

- **De-energisation:** The ability to completely de-energise electricity supply from the meter by remote action, immediately or on a future date. This service turns **off** the electricity supply for reasons such as:When a customer has vacated the premises
- When a customer requests that the supply be disconnected
- Work safety, such as when electrical work is being done at the customers' premises
- Non-payment of energy bills.
- **Re-energisation:** The ability to completely re-energise supply to the meter by remote action, immediately or on a future date. This service turns **on** the electricity supply for reasons such as:When a new customer is moving into the premises
- A customer requests re-energisation following a disconnection
- Reconnection of supply after the resolution of bill payment issues.

CONCLUSION: Energisation services are commonplace in global advanced metering systems and product offerings. When mandated, they provide certainty of service availability for supply disconnection and reconnection across all metering installations to enable efficiency gains in service delivery across the market.

Information services

This group of services provides the backbone of demand side participation initiatives as well as many retailer and network efficiencies, including network fault management. They enable market participants, customers and their agents to make informed decisions based on access to a rich source of energy and metering installation status information. These services also provide assurance of the metering installations' accuracy, safety and security, and they enable the operation of market settlement processes.

These services include the measurement of real (watt-hours) and reactive energy (Volt-Amp-reactive-hours) while accounting for both forward and reverse energy flows – energy being drawn from and sent to the grid. This facilitates measurement and billing for kWh and kVARh tariffs, for both load and generation.

- **Meter Read – On Demand:** The ability to provide metering data outside the normal collection cycle any time it is requested. This service provides on-demand meter reads for:
  - Retailers to bill their customers (including Final Bills)
  - A final meter read before a customer transfers to another retailer, and a 'start' reading for the new retailer
  - A customer billing enquiry
  - To provide information that supports demand-side participation products
- **Meter Read – Scheduled:** The ability to provide scheduled meter readings for:
  - AEMO and market participants to perform energy settlement, billing and reconciliation processes
  - Monitoring vacant premises to determine whether electricity is being used, or a new customer is at the premises
  - Use profiles for load management and planning functions.

- **Metering installation enquiry:** The ability to provide up-to-date information on the status of the metering installation, including metering data, meter status, meter alarms, and quality of supply, to determine:
  - Energisation status of the meter
  - Warning alarms requiring investigation, such as metering tamper, detection of reverse energy flows, and metering device temperature
  - Information relating to the quality and reliability of the electricity supply such as voltage (volts), current (amperes) and frequency (hertz).

CONCLUSION: AEMO considers these services to be the foundation and main benefit of any advanced metering roll out. Market settlements, market participants, customers and their agents can all access the benefits of metering data when there is certainty in the ability to source that data.

Reconfiguration services

Advanced metering systems can facilitate customers' access to a broad range of tariff options and configurations without the need for costly visits to the customers' premises. Current market arrangements include options for customers to move between single rate, variable rate or full time-of-use tariff offerings.

- **Meter Reconfiguration:** to remotely enable access to new tariffs and new arrangements, such as solar connections, energy demand pricing, controlled loads and new network or retail tariffs.

CONCLUSION: A NEM wide advanced metering reconfiguration service removes cost barriers for retailers and their customers to access alternate tariff arrangements. AEMO consider that this service could be mandated to ensure certainty of service availability for all customers and market participants.

3.4 Secondary services

- **Re-energisation (arming of the meter):** This service provides the ability to remotely establish conditions for reconnecting the supply of electricity to the customer's premises. Once completed, the meter is ready for the customer, or their agent to perform an action, typically pressing a designated button or switch on the meter to reconnect their supply.

  CONCLUSION: This is an alternative method for managing reconnections to the service (identified in the Primary Services section above) and is available through most current advanced metering systems. This service provides no additional benefits to those stated in the Primary Services section, but could be negotiated should a party wish to offer this service as part of a competitive roll out. In a regulated roll out, this service could be mandated to provide market participants with the flexibility to meet customer's needs.

- **Load limiting:** This service provides the ability to establish or remove a limit that restricts the amount of energy able to be consumed whenever an agreed limit has been reached, or at a future date. Typically this service can be used as alternative to existing processes for credit management, limiting load at vacant premises and restricting supply during times of supply shortage.

  CONCLUSION: This service provides options for managing loads, either a specific load or the entire load at customers' premises, but does not meet the objectives stated in section 1.1. The service could be negotiated should a need be identified.

- **Load management:** Traditional forms of load management include load control devices such as time switches or ripple relays that are either set up or operated by the distributor to facilitate access to controlled network tariffs, typically for the control of loads such as storage heaters or immersion water heaters. These traditional forms of load management are not proposed to be altered through the adoption of advanced metering systems. However, there may be more efficient ways to control loads within a customers' premises that can be enabled through advanced metering systems and other existing and emerging technologies whether offered as an alternative to traditional network control solutions, or to facilitate customer energy management systems and demand side participation product offerings. For example, there are commercially available products on the market today that facilitate customer in-home load management,

CONCLUSION: AEMO consider that under a market-led roll-out, market forces can determine whether using advanced metering systems (as opposed to any traditional or other alternate methods of control) will lead to greater efficiencies. The service could be mandated under a regulated roll-out providing the advanced metering service provides more efficient solutions than other commercially available products.

- **Local access to a metering system via a registered device:** The ability to register devices that can access the metering system. See "Enabling a Home Area Network (HAN)" in the value added services section below.

3.5 Value-added services

AEMO discussed the following services with the reference group. In each case, solutions for the design of a minimum specification were either not immediately apparent, or there were strongly opposing views regarding the best solution for a market-led advanced metering roll-out in the NEM.

- **Enabling a Home Area Network (HAN)**

  A HAN is a network that is deployed and operated within a small boundary, typically a house or small office. It enables the communication and sharing of resources between computers, mobile devices, smart appliances, and other devices, over a network connection. The reference group considered the role of the metering device within a HAN, and in particular, providing local energy use information to make it easier for customers to access new electricity pricing and services.

  Traditionally, a HAN uses an In Home Display as the focal point for customer engagement. Smart phone and web applications are developing rapidly and they are typically available as a low-cost or no-cost alternative for customers.

  Many mandated roll-outs, including the Victorian Advanced Metering Infrastructure (AMI) program and the planned approach in the UK, specify a technology solution requiring additional hardware within the metering device, enabling it to connect to a HAN within the premises.

  The reference group acknowledged that authorised parties should be able to provide customers with close to real-time data access and connectivity to a HAN upon request. However, there was minimal support within the group for mandating any specific technology solution to facilitate this service.

  Meter device manufacturers within the reference group confirmed their ability to adopt a range of options to facilitate HAN operation. These included via internet protocol (IP), radio frequency, and other local HAN connectivity methods, all based on international standards. Accordingly, AEMO included a service requirement to provide local access to the advanced metering system via a registered device, acknowledging there are multiple methods for doing so.

  Consumer representatives did raise concerns, questioning the likelihood of services being provided unless a technology solution was mandated.

  CONCLUSION: As tools are still being developed, AEMO considers that mandating a technology solution under a market-led approach risks limiting the potential to adopt developing technologies, and imposes unnecessary costs that may inhibit the business case for a roll-out.

- **Supply failure and restoration notifications**

  Often referred to as the "last gasp" service, supply failure notification requires the advanced metering system to provide a message every time the supply of energy is disrupted. The supply failure notification could be used by the receiving party as an input to existing energy supply outage detection processes. Similarly, the supply restoration notification could be used as an input to existing processes to validate that supply of energy has been restored.

  The single proponent for these services within the reference group was the Energy Networks Association (ENA), which provided service level and performance standard requirements to enable the review. The ENA confirmed that these notification services become beneficial where there is a significant density of metering installations (more than 60%) supporting this service within a designated area.

AEMO believes there are other primary services that could provide similar business outcomes (e.g., scheduling a Metering Installation Enquiry). The communications infrastructure required to support advanced metering systems, significantly influences hardware and system design costs to support the supply failure notification service. For example, where a point-to-point cellular communications network is used, a separate power supply would be required to enable the advanced metering system to send notification messages if the energy supply failed.

As observed in New Zealand, market-led roll-outs are primarily supported through point-to-point cellular communications networks. AEMO believes it is reasonable to postulate that a market-led approach in the NEM will also rely primarily on this type of communications infrastructure.

CONCLUSION: AEMO does not consider it viable to assign these notification services as part of any minimum specification at this time, since a market-led roll-out does not provide assurance that the required density would be achieved in any designated area over any period of time. AEMO also considers that the likely additional investment required solely to deliver the supply failure notification service further precludes this service from a minimum specification. However, interested recipients could negotiate the activation and delivery of these services outside of a minimum specification.

- **Safety monitoring**

  The ENA raised customer safety monitoring as a potential service, in particular as a monitoring service for the degradation of the neutral connection from the distribution network to a customer's premises.

  In discussions with manufacturers and metering providers, AEMO understands that this concept is an emerging service and is not clearly understood or defined at this time.

  CONCLUSION: AEMO proposes that the business outcomes proposed by the ENA be enabled under the Metering Installation Enquiry Service in the short term. Hence, the service is not included in this document.

- **Metering installation asset management**

  Advanced metering systems have a range of recording and reporting capabilities to enhance metering installation asset management. Typical examples include:

  - Detection and alert of a meter terminal cover removal.
  - Detection and alert of an unexpected reverse flow of energy.
  - Measurement of the temperature internal to the metering devices.

  When combined with the rich source of metering data available through advanced metering systems, these capabilities can act as a powerful tool to identify potential anomalies that in turn may prompt the metering provider or responsible person to instigate an action such as a physical site investigation.

  The metering provider and the responsible person are obliged within the National Electricity Rules (NER) to manage metering installation assets and installation compliance. AEMO and the reference group were unable to identify another party who would either want or need access to information related to these capabilities.

  CONCLUSION: AEMO has determined that there is no requirement to include any services or functionality relating to these capabilities, as the parties interested in acquiring access are the same parties that will be investing in and deploying the advanced metering systems. In addition, AEMO considers that the Meter Installation Enquiry service could provide the specified information should a need be identified.

3.6 Performance standards and service levels

To determine the advanced metering system requirements, the following performance standards and service levels that apply to the delivery of each service were considered:

- Service availability (days/hours within a calendar week).
- Timeframes for service request acknowledgement notifications.
- Timeframes for service request completion notifications.
- Quality requirements of a service request completion notification.

AEMO identified service levels and performance standards that reflect the requirements for:

1. The requesting party's and customers' expectations.
2. Technical requirements for the management of distribution networks.
3. NEM settlements.

As a result, five categories of service levels were identified. Each service could be requested under one or more of these service categories.

1. **Instant response**
   - A one-off transaction requesting that a service be performed immediately and a single response is received to confirm completion of the service, for example, Re-Energisation.
2. **Within a specified timeframe, but before the end of the business day.**
   - A one-off transaction requesting that a service be performed within a specified timeframe and a single response is received to confirm completion of the service prior to the end of the business day, for example, Meter Installation Enquiry.
3. **By the end of the business day**
   - A one-off transaction requesting that a service be performed prior to the end of the business day, and a single response is received to confirm completion of the service. For example, De-Energisation.
4. **Set and forget**
   - A transaction requesting that a service be performed, either tomorrow or in the future, and recurs to a schedule, for example, Meter Read – Scheduled.
5. **Set and expect**
   - A one- off transaction requesting that a service be performed, either tomorrow or in the future and a single response is received to confirm completion of the service for the requested date and time, for example, Meter Reconfiguration.

AEMO considers that when creating a services specification, detailed service level and performance standard requirements be developed. In addition to the service level and performance criteria stated above, these requirements could consider:

- Requestor dependencies (such as requestor responsibilities and cancellation rules)
- Supplier dependencies (such as validations, rejection rules and notifications of acceptance, completion and failure to complete)
- Performance standards, including:
  - Currency (for example, data requested can be no later than 140 days prior to the date of the request)
  - Conditions (for example, a measure against a performance standard would not include metering installations under fault conditions)

This advice does not attempt to specify service levels or performance standards in detail. Following development of specifications for proposed minimum services, consequential changes will need to be made to the appropriate service level procedures through a Rules consultation process. Through this process, the service levels and performance standards will be quantified.

4. REGULATION, STANDARDS AND ADVANCED METERING

As instructed by COAG EC, AEMO considered the roles of Standards Australia and the National Measurement Institute regarding advanced metering specifications. Standards Australia's role in developing local standards, or adapting international standards for local use, is particularly important with respect to changes in technology.

The Standards Australia EL/011 electricity metering equipment committee has not been active for the last few years. As a result of AEMO's work with developing this advice, Standards Australia is reforming the EL/011 working group, with an initial meeting scheduled for late 2014 to consider future actions.

AEMO does not propose that any requirements already covered in other legal and regulatory instruments (such as Australian and international metering and metrology standards), are included in any minimum standard service specification for advanced metering. If there is a requirement to adapt or amend any provision, the changes should be undertaken in the relevant instrument. For example, there are existing requirements for metering device accuracy in the NER and the Metrology Procedure, and any changes to accuracy requirements should be undertaken in those instruments.

There is likely to be a need for some amendments and additions to existing NER procedures to reflect business process requirements for the operation of advanced metering services. These include the Metering Data Provider and Metering Provider Service Level Procedures, the Market Settlement and Transfer Solution (MSATS) Procedures and the shared market protocol. The shared market protocol is the subject of a separate advice paper from AEMO, due in February 2015.

AEMO advises that advanced metering systems should be considered in the same manner as other metering arrangements that support the remote acquisition of metering data in chapter 7 of the NER. This includes the requirement to remotely communicate with the metering installation and have a communications interface to enable local data collection.

AEMO reviewed the requirement to specify functional requirements, referencing both the Victorian Advanced Metering Infrastructure (AMI) and National Smart Metering Steering Committee (NSSC) minimum functionality specification. AEMO identified that the requirement to specify functions was negated by the construction of a services specification, designed to ensure certainty of business outcomes with associated performance standards and service levels.

For example, the requirement to specify that a meter function must be to designed to provide readings for measurement of real (watt-hours) and reactive energy (Volt-Amp-reactive-hours), this requirement can instead be stipulated as business outcomes to be delivered from the Information Services group.

Functions are constructed within an advanced meter and system to support the concept of delivering service outcomes rather than being directly related to a service per se. Having explored all known advanced metering services as well as some developing services, AEMO did not find that the construction of a functional specification aligned with the objectives in section 1.1.

5. CONCLUSION

Providing there is a robust, outcome-focused services specification in place, AEMO were unable to identify benefits through mandating a functional specification for the advanced metering devices and systems.

AEMO advises that COAG Energy Council consider implementing a services specification, as it provides the opportunity for the market to deliver services in a consistent fashion, whilst removing barriers to innovation in product design that could bring new technologies to the market. Creating a functionality specification risks unnecessarily limiting innovation in efficient service delivery by delaying the adoption of new technologies, as it locks in the functional design of a particular technology at a point in time.

A services approach also allows currently-installed meter stock, operating today as both type 4 and type 5 metering installations, to be modified to meet required outcomes. A functional specification would likely make those devices unnecessarily redundant.

At the time of publication, large-scale global deployments of advanced metering products and systems are underway. This has likely contributed to the reference group's understanding of the services that these systems can deliver, the value that can extracted from those services, and the ability for new services to be developed following deployment of a baseline product suite.

The services AEMO proposes for mandating (Section 3.3 Primary Services), will support the market to deliver efficient business processes and low transaction costs. Participants in the reference group were able to articulate the business outcomes, service levels and performance standards they would require in respect to each service. Moreover, equipment manufacturers and service providers were able to confirm that their core product suites will facilitate the delivery of those services as standard.

Where AEMO was able to identify an advanced metering service, but found that it did not meet the objectives, to ensure that the interests of other parties are considered in a competitive roll-out, the service has been captured as a Secondary Service (Section 3.34 Secondary Services). AEMO considers that a number of these services will be available in standard advanced metering systems. However, they are not critical to the adoption of advanced metering in the NEM under a market-led roll-out. The majority of these services could be enabled with no physical action required at the metering installation – should a customer need be identified in the future.

Other value-added services were identified that could also be delivered through advanced metering systems, if there is an agreement between parties to do so. For example, supply outage and restoration notifications are not considered part of the minimum services at present. AEMO considers the nature of a market-led roll-out, as distinct from a cost-benefit assessment per se, precludes these services from forming part of a minimum specification. These services rely on geographical density of advanced metering systems, which cannot be guaranteed over any period of time under a market-led approach. Therefore, AEMO believes that parties interested in acquiring these services could negotiate delivery on a case-by-case basis.

Importantly, all of the services considered in this advice, with the exception of the supply outage notification service, can be delivered through standard advanced metering products and systems with no need for manufacturers, communication and system providers to create bespoke designs for the NEM. Accordingly, AEMO believes that the implementation of a services specification within the NEM, as detailed within this advice resolves the need for jurisdiction specific advanced metering specifications when considering jurisdictional new and replacement policy.

If adopted, AEMO consider that an advanced metering services specification could be developed as a component of the procedures under the NER designed to support the shared market protocol. Changes would also be required in the Metrology Procedures to support the shared market protocol and the Metering Provider and Metering Data Provider Service Level Procedures would need to reflect obligations on providers related to the delivery of the services. AEMO recognises that one of the most important features of an advanced metering system is the rich source of data that can be made available to authorised parties on a frequent basis. The currently available standard file formats, known as Meter Data File Format Specification (NEM 12 and NEM 13), have been founded on traditional metering data sets and developed and maintained by AEMO under section 7.14.1A of the NER.

There is a potential for the number of service request transactions to be reduced significantly if the standard formats are updated to consider advanced metering information. Accordingly, COAG Energy Council could consider that the development of an advanced metering services specification and the shared market protocol be undertaken concurrently with a review of the standard format for delivering data to the market and participants.

APPENDIX A. REFERENCE GROUP MEMBERS

Government and regulatory bodies	Member
Australian Energy Market Commission (AEMC)	Julian Eggleston (Chantelle Bramley and Lisa Nardi, first meeting)
Australian Energy Market Operator (AEMO)	Margarida Pimentel (Chair) Lee Brown Kristen Clarke Roy Kaplan
Australian Energy Regulator (AER)	Sarah McDowell
Commonwealth – Department of Industry	Michael Whitfield
New South Wales – Department of Trade and Investment, Regional Infrastructure and Services	Andrew Burnard
Victoria – Department of State Development, Business and Innovation	Dr David Cornelius

Distribution businesses and retailers	Member
Energy Networks Association (ENA)	Michael McFarlane (Jemena) Greg Flynn and Tom Cole (Energex Limited) Dr Bryn Williams (SA Power Networks) Sam Chen (Endeavour Energy on behalf of Networks NSW) Chantal Hopwood (Tasmania Networks Pty Ltd)
Energy Retailers Association Australia (ERAA)	Stephanie Bashir (AGL) Inger Wills (EnergyAustralia) Stefanie Macri (Lumo) Jenna Polson (ERM Power) James Barton (Simply Energy)

Metering manufacturers, third party and consumer representatives	Member
Acumen Metering	Shaun Cupitt
Alternative Technology Association (ATA)	Craig Memery
EDMI	Simon Mouat
Landis+Gyr	David Mclean
Metropolis	Charles Coulson (Marco Bogaers 1st meeting)
National Measurement Institute (NMI)	Dr Phillip Mitchell
Secure Australia	Peter Taylor
Standards Australia	Varant Meguerditchian
Vector	Doug Ross

National Electricity Amendment (Expanding competition in metering and related services) Rule 2015 No. 12

under the National Electricity Law to the extent applied by:

(a) the National Electricity (South Australia) Act 1996 of South Australia;

(b) the Electricity (National Scheme) Act 1997 of the Australian Capital Territory;

(c) the Electricity - National Scheme (Queensland) Act 1997 of Queensland;

(d) the Electricity - National Scheme (Tasmania) Act 1999 of Tasmania;

(e) the National Electricity (New South Wales) Act 1997 of New South Wales;

(f) the National Electricity (Victoria) Act 2005 of Victoria; and

(g) the Australian Energy Market Act 2004 of the Commonwealth.

The Australian Energy Market Commission makes the following Rule under the National Electricity Law.

John Pierce
Chairman
Australian Energy Market Commission

National Electricity Amendment (Expanding competition in metering and related services) Rule 2015 No. 12

1 Title of Rule

This Rule is the *National Electricity Amendment (Expanding competition in metering and related services) Rule 2015 No.12*.

2 Commencement

Schedules 1 and 5 of this Rule commence operation on 26 November 2015.

Schedules 2, 3 and 4 commence operation on 1 December 2017.

3 Amendment of the National Electricity Rules

The National Electricity Rules are amended as set out in Schedule 1.

4 Amendment of the National Electricity Rules

The National Electricity Rules are amended as set out in Schedule 2.

5 Amendment of the National Electricity Rules

The National Electricity Rules are amended as set out in Schedule 3.

6 Amendment of the National Electricity Rules

The National Electricity Rules are amended as set out in Schedule 4.

7 Savings and Transitional Amendments to the National Electricity Rules

The National Electricity Rules are amended as set out in Schedule 5.

Schedule 1 Amendment to the National Electricity Rules

(Clause 3)

[1] New Rule 2.4A Metering Coordinator

After clause 2.4.2, insert:

2.4A Metering Coordinator

2.4A.1 Registration as a Metering Coordinator

(a) A *Metering Coordinator* is a person so registered by *AEMO* who engages in the coordination and provision of *metering* services at a *connection point*.

(b) *AEMO* may exempt a *Transmission Network Service Provider* from satisfying one or more registration requirements when registering as a *Metering Coordinator* for *transmission network connection points* on its *transmission network*, subject to such conditions as *AEMO* deems appropriate, where (in *AEMO*'s reasonable opinion) the exemption is not inconsistent with the *national electricity objective*.

(c) Subject to clause 2.4A.2(b), *AEMO* must not register a *Market Customer* as a *Metering Coordinator*.

(d) A person who is registered with *AEMO* as a *Metering Coordinator* is:

(1) except as specified in subparagraph (2), a *Registered Participant* for the purposes of the *Rules*; and

(2) not a *Registered Participant* for the purposes of Part A of Chapter 5 of the *Rules*, unless the person is also registered in another category of *Registered Participant*.

2.4A.2 Eligibility

(a) To be eligible for registration as a *Metering Coordinator*, a person must:

(1) subject to paragraph (b), not be a *Market Customer*;

(2) satisfy *AEMO* that it is complying with and will comply with the *Rules* and the procedures authorised under the *Rules*;

(3) in respect of a *Metering Coordinator* who is appointed, or is proposed to be appointed, as *Metering Coordinator* at a *small customer metering installation*, have appropriate processes in place to determine that a person seeking access to a service

listed in the *minimum services specification* is an *access party* in respect of that service;

(4) subject to paragraph (c), ensure that there is an appropriate security control management strategy and associated infrastructure and communications systems for the purposes of preventing unauthorised local access or remote access to *metering installations*, services provided by *metering installations* and *energy data* held in *metering installations*;

(5) have insurance as considered appropriate by *AEMO*; and

(6) pay the prescribed fees determined in accordance with rule 2.11.

(b) Clause 2.4A.1(c) and subparagraph (a)(1) do not apply to:

(1) a person who is only appointed, or is proposed to be only appointed, as *Metering Coordinator* in respect of one or more *connection points* or proposed *connection points* on a *transmission network*; or

(2) a *Generator* who is only appointed, or is proposed to be only appointed, as *Metering Coordinator* in respect of one or more *connection points* or proposed *connection points* that *connect* a *Generator's generating unit* to a *distribution network*.

(c) Subparagraph (a)(4) does not apply to a *Generator* who is only appointed, or is proposed to be only appointed, as *Metering Coordinator* in respect of one or more *connection points* or proposed *connection points* that *connect* a *Generator's generating unit* to a *distribution network*.

[2] Clause 6.17.2 Development of Distribution Ring-Fencing Guidelines

In clause 6.17.2(a), omit "may be developed" and substitute "must be developed".

[3] Clause 8.2.1 Application and guiding principles

At the end of clause 8.2.1(h)(15), omit "or".

[4] Clause 8.2.1 Application and guiding principles

At the end of clause 8.2.1(h)(16), omit "." and substitute "; or".

[5] Clause 8.2.1 Application and guiding principles

After clause 8.2.1(h)(16), insert:

(17) a decision by *AEMO* regarding an exemption under clause 2.4A.1(b).

[6] Clause 9.9C.2 Expiry Date

Omit clause 9.9C.2, and substitute "This clause 9.9C expires on 1 December 2017.".

[7] Chapter 10 New Definitions

In Chapter 10, insert the following new definitions in alphabetical order:

large customer

(a) In a *participating jurisdiction* where the *National Energy Retail Law* applies as a law of that *participating jurisdiction*, has the meaning given in the *National Energy Retail Law*.

(b) Otherwise, has the meaning given in *jurisdictional electricity legislation*.

Metering Coordinator

A person who is registered by *AEMO* as a *Metering Coordinator* under Chapter 2.

Schedule 2 Amendment to the National Electricity Rules

(Clause 4)

[1] Clause 5.3.7 Finalisation of connection agreements

In clause 5.3.7(h), omit "schedule 7.2" and substitute "schedule 7.4".

[2] Clause 5.3.7 Finalisation of connection agreements

In clause 5.3.7(g)(4), insert "4A," between "type" and "5".

[3] Schedule 5.6 Terms and Conditions of Connection agreements

In clause S5.6(l), insert "4A," between "type and "5".

[4] Clause 5A.A1 Definitions

In clause 5A.A1, substitute the following definition:

connection service

means either or both of the following:

(a) a service relating to a *new connection* for premises;

(b) a service relating to a *connection alteration* for premises,

but, to avoid doubt, does not include a service of providing, installing or maintaining a *metering installation* for premises.

[5] 5A.B.2 Proposed model standing offer for basic connection services

Omit clause 5A.B.2(b)(5)(ii) and substitute "**[Deleted]**".

[6] Clause 6.20.1 Billing for distribution services

In clause 6.20.1(e)(2), insert "4A," between "type" and "5".

[7] Clause 8.2.1 Application and guiding principles

In clause 8.2.1(h)(10), omit "clause 7.1.2(b)" and substitute "clause 7.2.1(b)".

[8] Clause 8.2.1 Application and guiding principles

In clause 8.2.1(h)(11), omit "clause 7.4.3(d)" and substitute "clause 7.4.4(d)".

[9] Clause 8.2.1 Application and guiding principles

In clause 8.2.1(h)(11), omit "clause 7.4.3(c)" and substitute "clause 7.4.4(d)".

[10] Clause 8.2.1 Application and guiding principles

At the end of clause 8.2.1(h)(16), omit "or".

[11] Clause 8.2.1 Application and guiding principles

At the end of clause 8.2.1(h)(17), omit "." and substitute "; or".

[12] Clause 8.2.1 Application and guiding principles

After clause 8.2.1(h)(17) insert:

(18) a decision by *AEMO* regarding an exemption under clause 7.8.4(a).

[13] New Clause 8.6.1A Application

After clause 8.6.1, insert:

8.6.1A Application

For the purposes of this Part C only, "*Registered Participant*" is deemed to include not just *Registered Participants* but also *Metering Providers* and *Metering Data Providers*.

[14] Clause 9.9.9 Periodic Energy Metering (clause 7.9.3)

In clause 9.9.9(a) and clause 9.9.9(b), omit each reference to "clause 7.11.5(a)" and substitute "clause 7.10.5(a)".

[15] Clause 9.9.10 Use of Alternate Technologies (clause 7.13)

In clause 9.9.10(a), omit "for the purposes of clause 7.13(a)" and substitute "between the relevant *Market Participant(s)*, the *Local Network Service Provider* and *AEMO*".

[16] Clause 9.9.10 Use of Alternate Technologies (clause 7.13)

Delete clause 9.9.10(b).

Schedule 3 Amendment to the National Electricity Rules

(Clause 5)

[1] Chapter 7 Metering

Omit Chapter 7, and substitute:

7 Metering

Part A Introduction

7.1 Introduction to the Metering Chapter

7.1.1 Contents

This Chapter sets out provisions relating to:

(a) roles and responsibilities of *financially responsible Market Participants*, *Metering Coordinators* and *AEMO*;

(b) the appointment of and the qualifications and registration requirements applying to *Metering Providers* and *Metering Data Providers*;

(c) the appointment of *Metering Coordinators* and *Metering Coordinator* default arrangements;

(d) *metering installation* requirements;

(e) *metering data services* and the *metering database*;

(f) *metering register* requirements, disclosure of *NMI* information and *metering data* provision to *retail customers*;

(g) security of, and rights to access, *metering installations*, services provided by *metering installations*, *energy data* held in *metering installations* and *metering data* from *metering installations*;

(h) procedures to be established, maintained and *published* by *AEMO* including the *metrology procedures* and *service level procedures*; and

(i) B2B arrangements.

Part B Roles and Responsibilities

7.2 Role and Responsibility of financially responsible Market Participant

7.2.1 Obligations of financially responsible Market Participants to establish metering installations

(a) Except as otherwise specified in paragraph (c), before participating in the *market* in respect of a *connection point*, and for so long as the *financially responsible Market Participant* continues to participate in the *market* in respect of a *connection point*, the *financially responsible Market Participant* must ensure that:

(1) a *Metering Coordinator* is appointed in respect of the *connection point* in accordance with clause 7.6.2;

(2) the *connection point* has a *metering installation* and that the *metering installation* is registered with *AEMO*; and

(3) prior to registration, a *NMI* has been obtained with respect to the *connection point*.

(b) *AEMO* may refuse to permit a *financially responsible Market Participant* to participate in the *market* in respect of any *connection point* in relation to which that *financially responsible Market Participant* is not in compliance with its obligations under paragraph (a).

(c) For an *interconnector*:

(1) the relevant *Transmission Network Service Provider* is responsible for the provision, installation and maintenance of a *metering installation*; and

(2) *AEMO* is responsible for the collection of *metering data* from that *metering installation*, the processing of that data and the delivery of the processed data to the *metering database*.

7.2.2 [Not used]

7.2.3 Agreements with Local Network Service Provider

For the purpose of section 140(2)(b) of the *National Energy Retail Law*, an agreement in force under the following clauses of the *Rules* is taken to be an agreement in force under 'rule 7.2.3':

(a) clause 7.6.3;

(b) clause 7.6.4; and

(c) clause 11.86.7.

7.2.4 [Not used]

7.2.5 Agreements with Metering Provider

For the purpose of section 140(2)(c) of the *National Energy Retail Law*, an agreement in force under clause 7.3.2(b) of the *Rules* is taken to be an agreement in force under 'rule 7.2.5'.

7.3 Role and Responsibility of Metering Coordinator

7.3.1 Responsibility of the Metering Coordinator

(a) For the term of its appointment in respect of a *connection point*, the *Metering Coordinator* is the person responsible for the:

(1) provision, installation and maintenance of a *metering installation* in accordance with Part D of this Chapter 7;

(2) except as otherwise specified in clause 7.5.1(a), collection of *metering data* with respect to the *metering installation*, the processing of that data, retention of *metering data* in the *metering data services database* and the delivery of the *metering data* to the *metering database* and to other persons in accordance with Part E of this Chapter 7; and

(3) managing access to and the security of the *metering installation*, services provided by the *metering installation*, *energy data* held in the *metering installation* and *metering data* from the *metering installation* in accordance with Part F of this Chapter 7.

(b) The *Metering Coordinator* must perform its role in accordance with:

(1) this Chapter 7; and

(2) procedures authorised under the *Rules*.

(c) *AEMO* must establish, maintain and *publish* relevant explanatory material that sets out the role of the *Metering Coordinator* consistent with this Chapter 7.

7.3.2 Role of the Metering Coordinator

Appointment of a Metering Provider

(a) The *Metering Coordinator* at a *connection point* (other than a *connection point* with a type 7 *metering installation*) must:

(1) appoint a *Metering Provider* or *Metering Providers* for the provision, installation and maintenance of the *metering installation*; or

(2) subject to the *metrology procedure*, appoint a *Metering Provider* or *Metering Providers* for the provision and maintenance of that installation and allow another person to appoint a *Metering Provider* to install the *metering installation*.

(b) The *Metering Coordinator* at a *connection point* (other than a *connection point* with a type 7 *metering installation*) must:

(1) appoint a *Metering Provider* or *Metering Providers*:

(i) for the provision, installation and maintenance of the *metering installation*, where the *Metering Coordinator* has appointed the *Metering Provider* under paragraph (a)(1); or

(ii) for the provision and maintenance of the *metering installation*, where another person has appointed the *Metering Provider* under paragraph (a)(2).

(c) The *Metering Coordinator* may elect to terminate an appointment made under paragraph (b)(1)(i) after the *metering installation* is installed and, if such an appointment is terminated, the *Metering Coordinator* must appoint another *Metering Provider* for the maintenance of the *metering installation*.

Appointment of a Metering Data Provider

(d) Except as otherwise specified in clause 7.5.1(a), the *Metering Coordinator* at a *connection point* must:

(1) appoint a *Metering Data Provider* to provide *metering data services*; and

(2) provide the *financially responsible Market Participant* with the name of the *Metering Data Provider* appointed under subparagraph (1).

Metering installations

(e) The *Metering Coordinator* at a *connection point* (other than a *connection point* with a type 7 *metering installation*) must:

(1) ensure that the *metering installation* is provided, installed and maintained in accordance with the *Rules* and procedures authorised under the *Rules*;

(2) ensure that the components, accuracy and testing of the *metering installation* complies with the requirements of the *Rules* and procedures authorised under the *Rules*;

(3) ensure that the security control of the *metering installation* is provided in accordance with rule 7.15;

(4) where *remote acquisition* is used or is to be used, ensure that a *communications interface* is installed and maintained to facilitate connection to the *telecommunications network*;

(5) ensure that *AEMO* is provided (when requested) with the information specified in Schedule 7.1 for any new or replacement *metering installation* or any altered *metering installation*; and

(6) ensure that no device that is capable of producing *interval energy data* and is already installed in a *metering installation* is replaced with a device that only produces *accumulated energy data* unless the *metrology procedure* permits the replacement to take place.

(f) The *Metering Coordinator* at a *connection point* with a *small customer metering installation* must ensure that *energy data* is retrieved from that *small customer metering installation* via remote access.

(g) A *Metering Coordinator* must not prevent, hinder or otherwise impede a *Local Network Service Provider* from locally accessing a *metering installation* or *connection point* for the purposes of *reconnecting* or *disconnecting* the *connection point*.

Metering data services

(h) Except as specified in clause 7.5.1(a), the *Metering Coordinator* at a *connection point* must:

(1) ensure that the *Metering Data Provider* appointed under paragraph (d) accommodates any special site or technology related conditions determined by *AEMO* in accordance with clause 7.8.12(c), and the *Metering Coordinator* must clarify any matters with *AEMO* in order to choose a *Metering Data Provider* for that *metering installation* that is mutually suitable to all parties;

(2) ensure that *metering data services* are provided in accordance with the *Rules* and procedures authorised under the *Rules*;

(3) for any type 5 *metering installation* where the annual flow of electricity through the *connection point* is greater than the *type*

5 accumulation boundary, ensure that *interval energy data* is collected;

(4) for any type 4A *metering installation*, ensure that *interval energy data* is collected; and

(5) arrange for the provision of relevant *metering data* to the *Metering Data Provider* if *remote acquisition*, if any, becomes unavailable.

Access to small customer metering installation

(i) The *Metering Coordinator* at a *connection point* with a *small customer metering installation* must:

(1) ensure that access to the *metering installation*, the services provided by the *metering installation* and *energy data* held in the *metering installation* is only granted to persons entitled to access that *metering installation*, or the services provided by the *metering installation* or *energy data* held in the *metering installation* in accordance with this Chapter 7;

(2) not arrange a *disconnection* except:

(i) on the request of the *financially responsible Market Participant* or *Local Network Service Provider*;

(ii) where such *disconnection* is effected via remote access;

(iii) in accordance with *jurisdictional electricity legislation*; and

(iv) if applicable, in accordance with the *emergency priority procedures*;

(3) not arrange a *reconnection* except:

(i) on the request of the *financially responsible Market Participant*, *Local Network Service Provider* or *Incoming Retailer*;

(ii) where such *reconnection* is effected via remote access;

(iii) in accordance with *jurisdictional electricity legislation*; and

(iv) if applicable, in accordance with the *emergency priority procedures*; and

(4) not arrange a *retailer planned interruption* of the supply of electricity at the *metering installation* except:

(i) on the request of the *retailer*;

(ii) in accordance with *jurisdictional electricity legislation*; and

(iii) if applicable, in accordance with the *emergency priority procedures*.

7.4 Qualification, Registration and nature of appointment of Metering Providers and Metering Data Providers

7.4.1 Qualifications and registration of Metering Providers

(a) **[Not used]**

(a1) A *Metering Provider* is a person who:

(1) meets the requirements set out in Schedule 7.2; and

(2) is accredited by and registered by *AEMO* in that capacity in accordance with the qualification process established under clause S7.2.1(b).

(b) Any person may apply to *AEMO* for accreditation and registration as a *Metering Provider*.

(c) *AEMO* must include requirements for accreditation of *Metering Providers* in the *service level procedures*. The adoption of the requirements by *Metering Providers* is to be included in the qualification process in accordance with clause S7.2.1(b). The requirements must include a dispute resolution process.

(d) A *Metering Provider* must comply with the provisions of the *Rules* and procedures authorised under the *Rules* that are expressed to apply to *Metering Providers* relevant to their category of registration.

(e) A *Market Generator* which is involved in the trading of *energy* must not be registered as a *Metering Provider* for *connection points* in respect of which the *metering data* relates to its own use of *energy*.

(f) Except as otherwise specified in paragraph (g), a *Market Customer* must not be registered as a *Metering Provider* at any *connection point*.

(g) If a *Market Participant* is a *Market Customer* and also a *Network Service Provider* then the *Market Participant* may be registered as a *Metering Provider* for that *connection point* notwithstanding paragraph (f), providing that at the *connection points* on the *transmission network*, the *Market Participant* must regard the

Transmission Network Service Provider with which it has entered into a *connection agreement* as the *Local Network Service Provider*.

7.4.2 Qualifications and registration of Metering Data Providers

(a) A *Metering Data Provider* is a person who:

(1) meets the requirements set out in Schedule 7.3; and

(2) is accredited by and registered by *AEMO* in that capacity in accordance with the qualification process established under clause S7.3.1(c).

(b) Any person may apply to *AEMO* for accreditation and registration as a *Metering Data Provider*.

(c) **[Not used]**

(c1) *AEMO* must include requirements for accreditation of *Metering Data Providers* in the *service level procedures*. The adoption of the requirements by *Metering Data Providers* is to be included in the qualification process in accordance with clause S7.3.1(c). The requirements must include a dispute resolution process.

(d) A *Metering Data Provider* must comply with the provisions of the *Rules* and procedures authorised under the *Rules* that are expressed to apply to *Metering Data Providers* relevant to their category of registration.

(e) A *Market Generator* which is involved in the trading of *energy* must not be registered as a *Metering Data Provider* for *connection points* in respect of which the *metering data* relates to its own use of *energy*.

(f) Except as otherwise specified in paragraph (g), a *Market Customer* must not be registered as a *Metering Data Provider* at any *connection point*.

(g) If a *Market Participant* is a *Market Customer* and also a *Network Service Provider* then the *Market Participant* may be registered as a *Metering Data Provider* for that *connection point* notwithstanding paragraph (f).

7.4.3 Nature of appointment of Metering Provider or Metering Data Provider

(a) A *Metering Provider* or *Metering Data Provider* must perform all of the obligations of a *Metering Provider* or *Metering Data Provider* (as the case may be) in respect of a *metering installation* under the *Rules* and procedures authorised under the *Rules* on terms and conditions (including as to price) to be commercially agreed between the *Metering Provider* or *Metering Data Provider* and the appointing *Metering Coordinator*.

(b) Subject to the terms of appointment by the *Metering Coordinator* and in accordance with the *Rules* and procedures authorised under the *Rules*:

(1) a *Metering Provider* appointed under clause 7.3.2(b); and

(2) a *Metering Data Provider* appointed under clause 7.3.2(d).

may supply services in respect of the *metering installation* in addition to those provided under paragraph (a), including access to the services provided by the *metering installation* and *metering data* from the *metering installation*, on terms and conditions (including as to price) to be commercially agreed between the *Metering Provider* or *Metering Data Provider* (as the case may be) and the requesting party.

7.4.4 Deregistration of Metering Providers and Metering Data Providers

(a) *AEMO* must establish, maintain and *publish* a procedure for deregistration of *Metering Providers* and *Metering Data Providers* which incorporates the principles specified in paragraph (b).

(b) A breach of the provisions of the *Rules* or of the procedures authorised under the *Rules* must be determined against the following principles:

(1) the definition of breach must contain three or more levels of severity, the highest level of severity being a ‘material breach’;

(2) the deregistration of a *Metering Provider* or a *Metering Data Provider* can only occur if it can be demonstrated that the provider has committed a material breach; and

(3) the levels of a breach with severity below a material breach are to be treated as warnings with different levels of magnitude.

(c) If *AEMO* reasonably determines that a *Metering Provider* or a *Metering Data Provider* has breached a provision of the *Rules* or of procedures authorised under the *Rules* that applies to *Metering Providers* or *Metering Data Providers*:

(1) *AEMO* must send to that *Metering Provider* or *Metering Data Provider* a notice in writing setting out the nature of the breach; and

(2) *AEMO* must, if the *Metering Provider* or *Metering Data Provider* remains in breach for a period of more than 7 days after notice in accordance with subparagraph (c)(1), conduct a review to assess the *Metering Provider's* or *Metering Data Provider's* capability for ongoing compliance with the *Rules* or procedures authorised under the *Rules*.

(d) *AEMO* may, following a review conducted under subparagraph (c)(2) and in accordance with the procedure under paragraph (a), deregister the *Metering Provider* or *Metering Data Provider*, suspend the provider from some categories of registration or allow the provider to continue to operate under constraints agreed with *AEMO*.

(e) If following a review under subparagraph (c)(2), *AEMO* deregisters or suspends from some categories of registration or allows the *Metering Provider* or *Metering Data Provider* to continue to operate under constraints, then *AEMO* must inform the relevant *Metering Coordinator(s)* and the relevant *financially responsible Market Participants* of the outcome of that review.

7.5 Role and Responsibility of AEMO

7.5.1 Responsibility of AEMO for the collection, processing and delivery of metering data

(a) Where the *Metering Coordinator* at a *connection point* or proposed *connection point* on a *transmission network* is the *Local Network Service Provider*, *AEMO* is responsible for:

(1) the collection of *metering data* with respect to the *metering installation*, the processing of that data, the delivery of the processed data to the *metering database* and the provision of *metering data* in accordance with the *Rules* and procedures authorised under the *Rules*; and

(2) the appointment of the *Metering Data Provider* to provide the *metering data services* in accordance with paragraph (b).

(b) In performing its role under paragraph (a), *AEMO* must:

(1) subject to the limitation on that choice imposed by paragraph (d), permit the *financially responsible Market Participant* to appoint a *Metering Data Provider* of its choice to perform the obligations of a *Metering Data Provider* with respect to the *metering installation* under this Chapter 7;

(2) where a *financially responsible Market Participant* has not appointed a *Metering Data Provider* in accordance with subparagraph (1), appoint a *Metering Data Provider* to

perform the obligations of a *Metering Data Provider* with respect to the *metering installation* under this Chapter 7; and

(3) comply with the processes for the collection, processing and delivery of *metering data* from the *metering installation* to the *metering database* and the provision of *metering data* to the persons who may receive *metering data* under clause 7.10.3(a) in accordance with the procedures authorised under the *Rules*, and may establish additional processes if necessary in order to fulfil that role.

(c) If any additional processes are established by *AEMO* for the purpose of fulfilling its obligations under subparagraph (b)(3), and those processes impact on other persons, the relevant parts of those processes that impact on those persons must be incorporated in the *service level procedures*.

(d) Where a *financially responsible Market Participant* chooses to appoint a *Metering Data Provider* under subparagraph (b)(1), it must:

(1) only appoint a *Metering Data Provider* who can fully accommodate any special site or technology related conditions described in the document *published* under clause 7.8.12(c)(1); and

(2) clarify any matters with *AEMO* in order to choose a *Metering Data Provider* for that *metering installation* that is mutually suitable to all parties.

7.5.2 AEMO's costs in connection with metering installation

When *AEMO* is required to undertake functions associated with a *metering installation* in accordance with the requirements of the *metrology procedure* (which could include the preparation and application of a *profile*), *AEMO's* cost is to be recovered through *Participant fees* in accordance with a budget prepared under clause 2.11.3(b)(3) unless the *metrology procedure* specifies an alternative method of cost recovery in which case *AEMO* must not recover the costs through *Participant fees*.

Part C Appointment of Metering Coordinator

7.6 Appointment of Metering Coordinator

7.6.1 Commercial nature of the Metering Coordinator appointment and service provision

(a) A *Metering Coordinator* assumes responsibility in respect of a *connection point* under this Chapter 7, and must perform all of the obligations of the *Metering Coordinator* under the *Rules* and procedures authorised under the *Rules* on terms and conditions (including as to price) to be commercially agreed between the *Metering Coordinator* and the person who appoints the *Metering Coordinator* under clause 7.6.2.

(b) Subject to the terms of its appointment under clause 7.6.2 and in accordance with the *Rules* and procedures authorised under the *Rules*, a *Metering Coordinator* may supply services in respect of the *metering installation* in addition to those provided under paragraph (a), including access to the services provided by the *metering installation* and *metering data* from the *metering installation*, on terms and conditions (including as to price) to be commercially agreed between the *Metering Coordinator* and the requesting party.

7.6.2 Persons who may appoint Metering Coordinators

(a) A *Metering Coordinator* may only be appointed:

(1) with respect to a *connection point* or proposed *connection point* on a *transmission network*, by the *Market Participant* which is *financially responsible* at the *connection point*;

(2) with respect to a *connection point* (other than the *connection point* of a *retail customer*) that connects, or is proposed to *connect*, a *generating system* to a *distribution network*, by:

(i) the *Market Participant* which is *financially responsible* at the *connection point*;

(ii) a *Non-Market Generator* who owns, controls or operates the *generating system* that is connected to the *distribution network* at the *connection point*; or

(iii) a person who owns, controls or operates the *generating system* that is connected to the *distribution network* at the *connection point* and is exempt from the requirement to register as a *Generator* under clause 2.2.1(c); and

(3) with respect to any other *connection point*, by:

(i) the *Market Participant* which is *financially responsible* at the *connection point*; or

(ii) the *large customer* whose premises are supplied at the *connection point*.

(b) A person making an appointment under paragraph (a) must do so in accordance with the *Rules* and procedures authorised under the *Rules*.

(c) The *Market Settlements and Transfer Solution Procedures* may specify that an incoming *Metering Coordinator* at a *connection point* is responsible for the *metering installation*:

(1) on the day that a *market load* transfers from one *financially responsible Market Participant* to another *financially responsible Market Participant* for the period within that day; or

(2) on any other day.

7.6.3 Appointment with respect to transmission network connection

(a) Where a *connection point* or proposed *connection point* is on a *transmission network*, only the *Local Network Service Provider* or the *financially responsible Market Participant* at the *connection point* may be appointed as *Metering Coordinator* under clause 7.6.2

(b) Where a *connection point* or proposed *connection point* is on a *transmission network,* the *financially responsible Market Participant* at the *connection point* may request in writing an offer from the *Local Network Service Provider* to act as the *Metering Coordinator* in respect of the *connection point*.

(c) If the *Local Network Service Provider* receives a request under paragraph (b), the *Local Network Service Provider* must:

(1) offer to act as the *Metering Coordinator* in respect of that *connection point*;

(2) provide the *financially responsible Market Participant* with the name of the *Metering Provider* and the *Metering Data Provider* that would be appointed under clause 7.3.2(a)(1) and 7.3.2(d), if requested by the *financially responsible Market Participant*; and

(3) provide the *financially responsible Market Participant* with the terms and conditions (including as to price) relating to that offer no later than 15 *business days* after the *Local Network Service Provider* receives a written request from the *financially responsible Market Participant*.

7.6.4 Type 7 metering installations

(a) The *financially responsible Market Participant* must appoint the *Local Network Service Provider* as the *Metering Coordinator* in respect of a *connection point* which has a type 7 *metering installation* connected to, or proposed to be connected to, the *Local Network Service Provider's network*.

(b) The *Local Network Service Provider* may provide the *financially responsible Market Participant* with a standard set of terms and conditions on which it will agree to act as the *Metering Coordinator* for a type 7 *metering installation*.

(c) Where the *Local Network Service Provider* has not provided the *financially responsible Market Participant* with a standard set of terms and conditions referred to in paragraph (b), the *financially responsible Market Participant* must request an offer from the *Local Network Service Provider* to act as the *Metering Coordinator* pursuant to paragraph (a).

(d) The *Local Network Service Provider* must, within 15 *business days* of receipt of the request under paragraph (c), make an offer to the *financially responsible Market Participant* setting out the terms and conditions on which it will agree to act as the *Metering Coordinator*.

(e) The terms and conditions of an offer made under paragraph (b) or (d) must:

(1) be fair and reasonable; and

(2) not have the effect of unreasonably discriminating between *financially responsible Market Participants*, or between customers of a *financially responsible Market Participant*.

(f) A *financially responsible Market Participant* must accept an offer on the standard terms and conditions of appointment provided by the *Local Network Service Provider* under paragraph (b) or (d), unless the *financially responsible Market Participant* and *Local Network Service Provider* agree other terms and conditions to apply to the appointment of the *Local Network Service Provider* as the *Metering Coordinator* under paragraph (a).

(g) For the avoidance of doubt, any *Metering Coordinator* appointed under paragraph (a) must comply with Chapter 2 of the *Rules*, including the requirement that a *Metering Coordinator* be registered with *AEMO* as a *Metering Coordinator* under clause 2.4A.1(a).

7.7 Metering Coordinator default arrangements

7.7.1 Obligations of financially responsible Market Participants on Metering Coordinator default event and end of contract term

(a) Without limiting the obligations of a *financially responsible Market Participant* under clause 7.2.1(a), the *financially responsible Market Participant* must appoint a new *Metering Coordinator* in respect of a *connection point* in circumstances where:

(1) a *Metering Coordinator default event* occurs with respect to the existing *Metering Coordinator* for the *connection point*; or

(2) the appointment of the existing *Metering Coordinator* by a person in accordance with clauses 7.6.2(a)(2)(ii), (2)(iii) or (3)(ii) (the **relevant person**) is terminated or expires and the relevant person does not appoint a new *Metering Coordinator* within the period specified by *AEMO* in procedures authorised under the *Rules*.

(b) The *financially responsible Market Participant* must appoint the *Metering Coordinator* in accordance with paragraph (a) as soon as practicable after the *Metering Coordinator default event* occurs or the period referred to in subparagraph (a)(2) has elapsed (as the case may be).

(c) If:

(1) the *financially responsible Market Participant* is required to appoint a new *Metering Coordinator* in respect of a *connection point* for a relevant person in accordance with paragraph (a); and

(2) the existing contract between the *financially responsible Market Participant* and the relevant person does not deal with the appointment of a *Metering Coordinator* in these circumstances,

the terms and conditions of the contract between the *financially responsible Market Participant* and the relevant person relating to the appointment of the *Metering Coordinator* (including as to price) must be fair and reasonable.

(d) The appointment of the *Metering Coordinator* in accordance with clause 7.6.2(a) must include terms to the effect that the appointment of the *Metering Coordinator* will terminate on the appointment of a new *Metering Coordinator* following the occurrence of a *Metering Coordinator default event* in respect of the *Metering Coordinator*.

7.7.2 Notices to be provided by Metering Coordinator

A *Metering Coordinator* must without delay notify:

(a) the *financially responsible Market Participant* and relevant person (as defined in clause 7.7.1(a)(2)) who has appointed it in accordance with clause 7.6.2 in respect of a *connection point*; and

(b) *AEMO*,

of:

(c) the occurrence of a *Metering Coordinator default event* in relation to the *Metering Coordinator*; or

(d) the termination or expiry of the contract under which the *Metering Coordinator* has been appointed by a relevant person.

7.7.3 AEMO may issue breach notice

(a) *AEMO* must establish, maintain and *publish* a procedure for the issue of a *Metering Coordinator default notice* in respect of *Metering Coordinators* which incorporates the principles specified in paragraph (b).

(b) A breach of the provisions of the *Rules* or of the procedures authorised under the *Rules* must be determined against the following principles:

(1) the definition of breach must contain three or more levels of severity, the highest level of severity being a 'material breach';

(2) the issue of a *Metering Coordinator default notice* can only occur if it can be demonstrated that the *Metering Coordinator* has committed a material breach; and

(3) the levels of a breach with severity below a material breach are to be treated as warnings with different levels of magnitude.

(c) If *AEMO* reasonably determines that a *Metering Coordinator* has breached a provision (or provisions) of the *Rules* or of procedures authorised under the *Rules* that applies to *Metering Coordinators* then:

(1) *AEMO* must send to that *Metering Coordinator* a notice in writing setting out the nature of the breach;

(2) *AEMO* must, if the *Metering Coordinator* remains in breach for a period of more than 7 days after notice in accordance with subparagraph (c)(1), conduct a review to assess the *Metering Coordinator's* capability for ongoing compliance with the *Rules* or procedures authorised under the *Rules*; and

(3) *AEMO* may, following a review conducted under subparagraph (c)(2), issue a notice to the *Metering Coordinator* which must identify the continuing breach and state that the notice is a notice for the purpose of paragraph (d) of the definition of a *Metering Coordinator default event*.

(d) If *AEMO* has issued a notice under subparagraph (c)(3), it must promptly issue a notice to the *financially responsible Market*

Participant and relevant person for each *connection point* for which the *Metering Coordinator* in respect of whom the *Metering Coordinator default event* occurred is appointed by the *financially responsible Market Participant* or relevant person. Such notice must:

(1) state that a *Metering Coordinator default event* under paragraph (d) of the definition of *Metering Coordinator default event* has occurred; and

(2) specify the *Metering Coordinator* in respect of whom the *Metering Coordinator default event* occurred.

Part D Metering installation

7.8 Metering installation arrangements

7.8.1 Metering installation requirements

(a) The *Metering Coordinator* at a *connection point* must ensure that there is a *metering installation* at that *connection point*.

(b) The *Metering Coordinator* at a *connection point* must ensure that *energy data* held in the *metering installation* is based on units of watthour (**active energy**) and where required varhour (**reactive energy**).

(c) Installation and maintenance of a *metering installation* must be carried out only by a *Metering Provider* appointed under clause 7.3.2(a).

7.8.2 Metering installation components

(a) A *Metering Provider* must, in accordance with the *Rules* and procedures authorised under the *Rules*, ensure that a *metering installation* (other than a type 7 *metering installation*) :

(1) contains a device that has either a visible or an equivalently accessible display of the cumulative total *energy* measured by that *metering installation* (at a minimum);

(2) is accurate in accordance with clause 7.8.8;

(3) in the case of *metering installations* types 1, 2, 3, or 4, has *electronic data transfer* facilities from the *metering installation* to the *metering data services database*;

(4) includes a *communications interface* to meet the requirements of clause 7.3.2(e)(4);

(5) is secure in accordance with rule 7.15;

(6) records *energy data* in a manner that enables *metering data* to be collated in accordance with clause 7.10.5;

(7) is capable of separately recording *energy data* for *energy* flows in each direction where bi-directional *active energy* flows occur or could occur;

(8) has a *measurement element* for *active energy* and if required in accordance with Schedule 7.4 a *measurement element* for *reactive energy*, with both measurements to be recorded;

(9) includes facilities for storing *interval energy data* for a period of at least 35 *days* if the *metering installation* is registered as a type 1, 2, 3 or 4 *metering installation*;

(10) includes facilities for storing *interval energy data* for a period of at least 200 *days* or such other period as specified in the *metrology procedure* if the *metering installation* is registered as a type 4A or type 5 *metering installation*; and

(11) in the case of a type 6 *metering installation*, includes facilities capable of continuously recording, the total accumulated *energy* supplied through it by a visible display in accordance with subparagraph (1), over a period of at least 12 months.

(b) A *metering installation* may consist of combinations of:

(1) a *current transformer*;

(2) a *voltage transformer*;

(3) secure and protected wiring from the *current transformer* and the *voltage transformer* to the *meter*;

(4) *communications interface* equipment such as a modem, isolation requirements, telephone service, radio transmitter and data link equipment;

(5) auxiliary electricity supply to the *meter*;

(6) an alarm circuit and monitoring facility;

(7) a facility to keep the *metering installation* secure from interference;

(8) test links and fusing;

(9) summation equipment; and

(10) several *metering points* to derive the *metering data* for a *connection point*.

(c) The *financially responsible Market Participant* at a *connection point* must:

(1) apply to the *Local Network Service Provider* for a *NMI*; and

(2) provide the *Metering Coordinator* with the *NMI* for the *metering installation* within 5 *business days* of receiving the *NMI* from the *Local Network Service Provider*.

(d) The *Local Network Service Provider* must:

(1) issue a unique *NMI* for each *metering installation* to the *financially responsible Market Participant*; and

(2) register the *NMI* with *AEMO* in accordance with procedures from time to time specified by *AEMO*.

(e) The *Metering Coordinator* must ensure that *AEMO* is provided with the relevant details of the *metering installation* as specified in Schedule 7.1 within 10 *business days* of receiving the *NMI* under subparagraph (c)(2).

Requirements for metering installations for non-market generating units

(f) In addition to the requirements in paragraphs (a) to (e), the *Metering Coordinator* at a *connection point* for a *non-market generating unit* must ensure that the *metering installation*:

(1) where payments for the purchase of electricity *generated* by that unit are based on different rates according to the time of the day, is capable of recording *interval energy data*;

(2) where a *current transformer*, a *voltage transformer* or a *measurement element* for *reactive energy* is installed, meets the requirements in Schedule 7.4 for the type of *metering installation* appropriate to that *connection point*;

(3) for units with a *nameplate rating* greater than 1 MW, meets:

(i) the accuracy requirements specified in Schedule 7.4; and

(ii) the measurement requirements in subparagraph (a)(8);

(4) in relation to new accumulation *metering* equipment for units with a *nameplate rating* equal to or less than 1 MW, meets the minimum standards for *active energy* class 1.0 watt hour or 2.0 watt hour *meters* in accordance with clause S7.4.6.1(f);

(5) for units with a *nameplate rating* of equal to or less than 1 MW that are capable of recording *interval energy*, meets the minimum standards of accuracy for the *active energy meter* in accordance with Schedule 7.4 for a type 3 or 4 *metering installation* which is based on projected sent out annual *energy* volumes; and

(6) if reasonably required by the *Distribution Network Service Provider* (where such a request must be in writing and with reasons), after taking into account the size of the *generating unit*, its proposed role and its location in the *network*, has the *active energy* and *reactive energy* measured where the unit has a *nameplate rating* of less than 1 MW.

Requirements for metering installations for a small generating unit classified as a market generating unit

(g) In addition to the requirements for *metering installations* for *non-market generating units* in paragraph (f), the *Metering Coordinator* for a *small generating unit* classified as a *market generating unit* must ensure that a *metering installation*:

(1) is classified as a type 1, 2, 3 or 4 *metering installation*; and

(2) is capable of recording *interval energy data* relevant to *settlements*.

7.8.3 Small customer metering installations

(a) Except as specified in clause 7.8.4, a *Metering Coordinator* must ensure that any new or replacement *metering installation* in respect of the *connection point* of a *small customer* is a type 4 *metering installation* that meets the *minimum services specification*.

(b) *AEMO* must establish, maintain and *publish* procedures relating to the *minimum services specification* that set out for each service specified in the *minimum service specification*:

(1) minimum service levels, including service availability and completion timeframes; and

(2) minimum standards, including completion rates against the service levels and accuracy requirements.

(c) The procedures established under paragraph (b) may also include technical requirements of one or more of the services specified in the *minimum services specification*.

7.8.4 Type 4A metering installation

No existing telecommunications network

(a) *AEMO* may exempt a *Metering Coordinator* from complying with clause 7.8.3(a) in respect of a *connection point* for a period of up to 5 years if the *Metering Coordinator* demonstrates to *AEMO's* reasonable satisfaction that there is no existing *telecommunications network* which enables remote access to the *metering installation* at that *connection point*.

(b) Where the *Metering Coordinator* is exempt under paragraph (a) from complying with clause 7.8.3(a) in respect of a *connection point*, the *Metering Coordinator* must ensure that any new or replacement *metering installation* in respect of that *connection point* including, for the avoidance of doubt, a *metering installation* at a *new connection*, is a type 4A *metering installation* that has the capability, if remote access is activated, of providing the services in table S7.5.1.1.

(c) Subject to the reapplication of paragraph (a), on and from the date that an exemption under paragraph (a) ceases to apply in respect of a *connection point*, the *Metering Coordinator* must ensure that the *metering installation* at that *connection point* is a type 4 *metering installation* that meets the *minimum services specification*.

Small customer refusal

(d) A *Metering Coordinator* is not required to comply with clause 7.8.3(a) where, in the *Metering Coordinator's* reasonable opinion, the *small customer* has communicated its refusal to the installation or proposed installation of a type 4 *metering installation* at a *connection point* in accordance with paragraph (e).

(e) For the purposes of paragraph (d) a *small customer* refusal to the installation or proposed installation of a type 4 *metering installation* must be communicated:

(1) verbally, in writing or by conduct; and

(2) to the *financially responsible Market Participant*, *Metering Coordinator* or *Metering Provider*.

(f) If the *small customer* communicates its refusal under paragraph (e) to the *financially responsible Market Participant* or *Metering Provider*, the *financially responsible Market Participant* or *Metering Provider* (as the case may be) must promptly provide written notice of the refusal to the *Metering Coordinator* which must include:

(1) the date of the refusal;

(2) how the refusal was communicated; and

(3) details of the *NMI* at the relevant *connection point*.

(g) A *Metering Coordinator* must retain a written record of a *small customer* refusal under paragraph (e) for a period of at least 7 years.

(h) Where paragraph (d) applies:

(1) the *Metering Coordinator* must ensure that the new or replacement *metering installation* installed at that *connection point* is a type 4A *metering installation*; and

(2) clause 7.8.3(a) will apply to any subsequent installation or proposed installation of a new or replacement *metering installation* at that *connection point*, subject to the reapplication of paragraph (d).

(i) Nothing in paragraph (h) prevents a *Metering Coordinator* from, at any time, activating the remote access capabilities of a *metering installation* with the consent of the *small customer* at the *connection point*.

7.8.5 Emergency management

(a) The *Metering Coordinator* at a *connection point* must ensure that access to the *metering installation*, services provided by the *metering installation* and *energy data* held in the *metering installation* are managed in accordance with the *emergency priority procedures* in the event of an emergency condition as determined in accordance with those *emergency priority procedures*.

(b) *AEMO* must establish, maintain and *publish* procedures that set out:

(1) the criteria for determining when an emergency condition is present and which *metering installation*s will be affected by the emergency condition; and

(2) where a *Metering Coordinator* supplies services to a *Local Network Service Provider* from a *metering installation* that is affected by an emergency condition, which services the *Metering Coordinator* must prioritise at the request of the *Local Network Service Provider*.

(c) A *Local Network Service Provider* must comply with the *emergency priority procedures* when issuing any service prioritisation request to a *Metering Coordinator* under those procedures.

7.8.6 Network devices

LNSP obligations

(a) A *Local Network Service Provider*:

(1) may install and maintain a *network device* provided that the installation and maintenance of the *network device* does not:

(i) adversely impact on the operation of the *metering installation*, including its compliance with the *Rules* and procedures authorised under the *Rules*;

(ii) damage the *metering installation*; or

(iii) prevent the *metering installation* being maintained or removed, as required, by or on behalf of the *Metering Coordinator*;

(2) must not remove a *metering installation*, or any part of a *metering installation*, in order to install or maintain a *network device*; and

(3) subject to paragraph (b), must not use a *network device* to provide services to a *retail customer* or any other third party.

(b) A *Local Network Service Provider* may use a *network device* to:

(1) *reconnect* or *disconnect* a *metering installation* via remote access, as permitted under *energy laws*; or

(2) provide services to a *retail customer* but only where those services are incidental to the provision of *network services* that are reasonably required to enable the *Local Network Service Provider* to meet its obligations to provide a safe, reliable and secure *network*.

(c) Information obtained from a *network device*:

(1) may be accessed by the *Local Network Service Provider*; and

(2) is confidential and must be treated as *confidential information* in accordance with the *Rules*; and

(3) for the purposes of clause 8.6.2(c), is deemed to have been provided by the *retail customer* at the relevant *connection point*.

Metering Coordinator obligations

(d) The *Metering Coordinator* at a *connection point*:

(1) must, at the request of the *Local Network Service Provider*, ensure that the *Local Network Service Provider* receives all reasonable assistance to facilitate access to a metering facility for:

(i) the installation of a *network device* under paragraph (a)(1); and

(ii) the maintenance of a *network device*; and

(2) unless paragraph (f) applies, must not, and must ensure that the *Metering Provider* does not:

(i) remove the *network device*;

(ii) take any action that adversely impacts on the operation of the *network device*;

(iii) damage the *network device*; or

(iv) prevent the *network device* being maintained or removed, as required, by or on behalf of the *Local Network Service Provider*,

except with the consent of the *Local Network Service Provider*.

(e) All reasonable costs incurred by the *Metering Coordinator* as a consequence of providing assistance to the *Local Network Service Provider* under paragraph (d)(1) must be borne by the *Local Network Service Provider*.

(f) The *Metering Coordinator* may remove or arrange the removal of a *network device* from the metering facility, without the consent of the *Local Network Service Provider*, if:

(1) the *Metering Coordinator* proposes to install a new or replacement *metering installation* at a *connection point*;

(2) there is a *network device* in the metering facility at the *connection point*; and

(3) in the *Metering Coordinator's* or *Metering Provider's* reasonable opinion, the *metering installation* cannot be installed in the metering facility in a manner that allows it to:

(i) operate effectively and in compliance with the *Rules* and procedures authorised under the *Rules*; and

(ii) be maintained or removed, as required, by or on behalf of the *Metering Coordinator*, without removing or impacting on the *network device* as specified in paragraphs (d)(2)(i) to (iv); and

(4) it has complied with paragraph (g) and any applicable *jurisdictional electricity legislation*.

(g) If a *Metering Coordinator* removes or arranges the removal of an existing *network device* under paragraph (f) it must:

(1) notify the *Local Network Service Provider* of its removal as soon as practicable after it is removed; and

(2) keep a record in accordance with paragraph (h) of the basis upon which the determination under paragraph (f)(3) was made.

(h) A record kept for the purposes of subparagraph (g) must include, in respect of each *network device*:

(1) the address from which the *network device* was removed;

(2) the date and time of removal of the *network device*;

(3) photographs and measurements of the *network device*, the *metering installation* and the metering facility; and

(4) any other material in relation to the determination in accordance with paragraph (f)(3) that is required by the procedures made under paragraph (i).

Network device procedures

(i) *AEMO* must develop and maintain procedures that apply to:

(1) *Metering Coordinators* and *Local Network Service Providers* and which specify when an existing *metering installation* that is to be replaced by a *Metering Coordinator* may be a *network device* for the purpose of this clause 7.8.6;

(2) *Metering Coordinators* and *Local Network Service Providers* when installing or removing *network devices*, including the return of a *network device* to the *Local Network Service Provider*; and

(3) notifications to be given in respect of activities which affect *network devices* or *metering installations*, including the provision of records maintained under paragraph (g)(2) when requested by the *Local Network Service Provider*.

Clause does not apply to transmission network connection points

(j) This clause 7.8.6 does not apply in respect of *transmission network connection points*.

Definitions

(k) In this clause 7.8.6, **metering facility** means the existing facility used to house the *metering installation*.

7.8.7 Metering point

(a) The *Metering Coordinator* must ensure that:

(1) the *metering point* is located as close as practicable to the *connection point*; and

(2) any *instrument transformers* required for a *check metering installation* are located in a position which achieves a mathematical correlation with the *metering data*.

(b) The *financially responsible Market Participant*, the *Local Network Service Provider* and *AEMO* must use their best endeavours to agree to adjust the *metering data* which is recorded in the *metering database* to allow for physical losses between the *metering point* and the relevant *connection point* where a *meter* is used to measure the flow of electricity in a power conductor.

(c) Where a *Market Network Service Provider* installs a *two-terminal link* between two *connection points*, *AEMO* in its absolute discretion may require a *metering installation* to be installed in the *facility* at each end of the *two-terminal link*. Each of these *metering installations* must be separately assessed to determine the requirement for *check metering* in accordance with Schedule 7.4.

7.8.8 Metering installation types and accuracy

(a) The type of *metering installation* and the accuracy requirements for a *metering installation* are to be determined in accordance with Schedule 7.4.

(b) A *check metering installation* is not required to have the degree of accuracy required of a *metering installation* but the *Metering Coordinator* must ensure that is has mathematical correlation with the *metering installation* and be consistent with the requirements of Schedule 7.4.

(c) The *Metering Coordinator* at a *connection point* must ensure that the accuracy of a type 6 *metering installation* is in accordance with regulations issued under the *National Measurement Act* or, in the absence of any such regulations, with the *metrology procedure*.

7.8.9 Meter churn

(a) Any alteration or replacement of a *metering installation* under this Chapter 7 must be managed in accordance with the *meter churn procedures*.

(b) A *Metering Coordinator* may arrange to alter a type 5 or 6 *metering installation* in accordance with paragraph (a) to make it capable of *remote acquisition* where:

(1) the alteration of the *metering installation* is reasonably required to address operational difficulties as defined in paragraph (d); or

(2) the *Metering Coordinator* is the *Local Network Service Provider* and the alteration of the *metering installation* is reasonably required to enable the *Local Network Service Provider* to meet its obligations to provide a safe, reliable and secure *network*.

(c) An alteration of a *metering installation* by a *Metering Coordinator* in accordance with paragraph (b) does not alter the classification of that installation to a type 4 or 4A *metering installation*.

(d) For the purposes of subparagraph (b)(1), operational difficulties arise where the *metering installation* is difficult or unsafe to access because:

(1) the *metering installation* is on a remote property;

(2) the *metering installation* is within a secure facility;

(3) the *metering installation* is in close proximity to hazardous materials; or

(4) accessing or arranging access to the *metering installation* otherwise poses a risk to the safety and security of persons or property.

(e) A *Metering Coordinator* must not arrange the alteration or replacement of a *metering installation* under paragraph (a) until the transfer of the relevant *market load* has been effected by *AEMO* in accordance with the *Market Settlement and Transfer Solution Procedures*.

(f) *AEMO* must establish, maintain and *publish* procedures for the *Metering Coordinator*, *Metering Provider*, *Metering Data Provider* and *financially responsible Market Participant* to consider in managing the *meter* churn resulting from an alteration or replacement of a *metering installation* under paragraph (a) (the '*meter churn procedures*').

7.8.10 Meter installation malfunctions

(a) Unless an exemption is obtained by the *Metering Coordinator* from *AEMO* under this clause 7.8.10, the *Metering Coordinator* must in respect of a *connection point* with:

(1) a type 1, 2 or 3 *metering installation*, if a *metering installation malfunction* occurs to the *metering installation*, cause repairs to be made to it as soon as practicable but no later than 2 *business days* after the *Metering Coordinator* has been notified of the *metering installation malfunction*; or

(2) a *metering installation* other than the installations referred to in subparagraph (1), if a *metering installation malfunction* occurs to the *metering installation*, cause repairs to be made to it as soon as practicable but no later than 10 *business days* after the *Metering Coordinator* has been notified of the *metering installation malfunction*.

(b) *AEMO* must establish, maintain and *publish* a procedure applicable to the provision of exemptions for the purpose of paragraph (a).

(c) If an exemption is provided by *AEMO* under this clause 7.8.10 then the *Metering Provider* must provide *AEMO* with a plan for the rectification of the *metering installation*.

(d) A *Registered Participant*, *Metering Provider* or *Metering Data Provider* who becomes aware of a *metering installation malfunction* of a *metering installation* that cannot be rectified within the applicable timeframes as specified in paragraph (a) must notify the *Metering Coordinator* of the *metering installation malfunction* within 1 *business day*.

7.8.11 Changes to metering equipment, parameters and settings within a metering installation

The *Metering Coordinator* at a *connection point* must ensure that changes to parameters or settings within a *metering installation* are:

(a) authorised by *AEMO* prior to the alteration being made;

(b) implemented by a *Metering Provider*;

(c) confirmed by the *Metering Coordinator* within 2 *business days* after the alteration has been made; and

(d) reported to *AEMO* to enable *AEMO* to record the changes in the *metering register*.

7.8.12 Special site or technology related conditions

(a) Special site or technology related conditions are situations where *AEMO* determines that special arrangements are required to support the integrity of the collection and processing of *metering data* from nominated *metering installations*. These conditions include, but are not limited to, the following situations:

(1) a *connection point* or proposed *connection point* on a *transmission network*, where the *metering data* collection and/or processing arrangements from *metering installations* nominated in the document *published* in subparagraph (c)(1) require a single *Metering Data Provider*;

(2) a situation where two or more *metering points* are required to form a *metering installation* and the *metering data* determined from that *metering installation* is required to be identified as a virtual *NMI* in the *settlements process*;

(3) a *metering installation* on an *interconnector*; or

(4) a *metering installation* on the *interconnection* between adjacent *distribution networks*.

(b) Special site or technology related conditions do not exist until they are described and *published* in the document specified in subparagraph (c)(1).

(c) Where *AEMO* determines that special site or technology related conditions exist under paragraph (a), it must:

(1) describe and *publish* those special site or technology related conditions including the nomination of *metering installations* affected by those conditions in a document;

(2) notify *Metering Coordinators* and *financially responsible Market Participants* of the availability of the document specified in subparagraph (1) at the time of its *publication* and each time that document is revised; and

(3) clarify any matters with the *Metering Coordinator* or the *financially responsible Market Participant* in order to enable the *Metering Coordinator* or *financially responsible Market Participant* to choose a *Metering Data Provider* for that *metering installation* that is mutually suitable to all parties.

(d) The *Metering Coordinator* or the *financially responsible Market Participant* at a *connection point* may make alterations to a *metering installation* and its *metering data* collection arrangements in order to remove its classification as a special site or technology related condition, in which case *AEMO* must remove that *metering installation* from the document specified in subparagraph (c)(1).

7.8.13 Joint metering installations

(a) Where more than one *Market Participant* uses a *metering installation* at a particular *connection point*, they must agree and notify *AEMO* as to which of them will appoint the *Metering Coordinator* for that *metering installation*.

(b) In the absence of such agreement, *AEMO* may nominate one of the *Market Participants* to appoint the *Metering Coordinator* for that *metering installation*.

(c) Where more than one *Market Participant* is subject to the same special site or technology related conditions as specified in clause 7.8.12(a), the *Metering Coordinator* must notify *AEMO* of the *Metering Data Provider* that will provide the *metering data services* for the relevant *metering installation*.

(d) In the absence of a *Metering Coordinator* notifying *AEMO* in accordance with paragraph (c), *AEMO* may nominate a *Metering Data Provider* to provide the *metering data services* for the *metering installation*.

7.9 Inspection, Testing and Audit of Metering installations

7.9.1 Responsibility for testing

(a) A person who arranges or carries out testing of a *metering installation* under this clause 7.9.1 must do so in accordance with:

(1) this clause 7.9.1; and

(2) the relevant inspection and testing requirements set out in Schedule 7.6.

(b) A *Registered Participant* may request that the *Metering Coordinator* make arrangements for the testing of a *metering installation* and if the request is reasonable, the *Metering Coordinator* must:

(1) not refuse the request; and

(2) make arrangements for the testing.

(c) Where the *Metering Coordinator* does not arrange for the testing requested under paragraph (b), the *Metering Coordinator* must advise *AEMO* that the requested testing has not been arranged and *AEMO* must make the arrangements for the testing where, in *AEMO's* reasonable opinion, it is practicable for *AEMO* to do so.

(d) The *Registered Participant* who requested the tests under paragraph (b) may make a request to the *Metering Coordinator* to witness the tests.

(e) The *Metering Coordinator* must not refuse a request received under paragraph (d) and must no later than 5 *business days* prior to the testing, advise:

(1) the party making the request; and

(2) the *financially responsible Market Participant*,

of:

(3) the location and time of the tests; and

(4) the method of testing to be undertaken.

(f) The *Metering Coordinator* and *AEMO* must co-operate for the purpose of making arrangements for *AEMO* to inspect or test the *metering installation* where:

(1) the *Metering Coordinator* must make arrangements for *AEMO* to have access to the *metering installation*; and

(2) *AEMO* must:

(i) no later than seven *business days* prior to the testing or inspection, give the *Metering Coordinator* notice of:

(A) its intention to access the *metering installation* for the purpose of inspection or testing;

(B) the name of the *representative* who will be conducting the test or inspection on behalf of *AEMO*; and

(C) the time when the test or inspection will commence and the expected time when the test or inspection will conclude; and

(ii) where reasonable, comply with the security and safety requirements of the *Metering Coordinator*.

(g) Where the *Metering Coordinator* has arranged testing of, or *AEMO* has undertaken testing of, a *metering installation* under this clause 7.9.1 and Schedule 7.6, the *Metering Coordinator* or *AEMO* (as the case may be) must:

(1) inform the *financially responsible Market Participant* that testing has been undertaken in respect of the *metering installation* in accordance with this clause 7.9.1; and

(2) make the test results available in accordance with paragraphs (h) and (i).

(h) If the test results referred to in paragraph (g) indicate deviation from the technical requirements for that *metering installation*, the *Metering Coordinator* or *AEMO* (as the case may be) must ensure that the test results are provided as soon as practicable to the persons who receive that *metering data* under clause 7.10.3(a).

(i) If the test results referred to in paragraph (g) indicate compliance with the technical requirements for that *metering installation*, the *Metering Coordinator* or *AEMO* (as the case may be) must ensure that the test results are provided as soon as practicable:

(1) in circumstances where the tests were requested by a *Registered Participant*, to the *Registered Participant* and persons receive that *metering data* under clause7.10.3(a); or

(2) to a *Registered Participant* if requested by that *Registered Participant*, where the tests are not the result of a request for testing.

(j) *AEMO* must check test results recorded in the *metering register* by arranging for sufficient audits annually of *metering installations* and to satisfy itself that the accuracy of each *metering installation* complies with the requirements of this Chapter 7.

(k) The *Metering Coordinator* must store the test results in accordance with clause 7.9.5 and provide a copy to *AEMO* upon request or as part of an audit.

(l) The cost of any test under paragraph (b) must be borne by:

(1) if paragraph (h) applies, the *Metering Coordinator*; and

(2) otherwise, the *Registered Participant* who requested the test.

7.9.2 Actions in event of non-compliance

(a) If the accuracy of the *metering installation* does not comply with the requirements of the *Rules*, the *Metering Coordinator* must:

(1) advise *AEMO* as soon as practicable of the errors detected and the possible duration of the existence of the errors; and

(2) arrange for the accuracy of the *metering installation* to be restored in a time-frame agreed with *AEMO*.

(b) *AEMO* may make appropriate corrections to the *metering data* to take account of errors referred to in paragraph (a) and to minimise adjustments to the final *settlements* account.

7.9.3 Audits of information held in metering installations

(a) *AEMO* is responsible for auditing *metering installations*.

(b) A *Registered Participant* may request *AEMO* to conduct an audit to determine the consistency between the data held in the *metering database* and the data held in the relevant *metering installation*.

(c) If there are inconsistencies between data held in a *metering installation* and data held in the *metering database*, the *Metering Coordinator* and *Registered Participants* with a financial interest in the *metering installation* or the *energy* measured by that *metering installation* must liaise together to determine the most appropriate way to resolve the discrepancy.

(d) If there is an inconsistency between the data held in a *metering installation* and the data held in the *metering database*, the data in the *metering installation* is to be taken as prima facie evidence of the *connection point's energy data*.

(e) *AEMO* must carry out periodic random audits of *metering installations* to confirm compliance with the *Rules*.

(e1) The *Metering Coordinator* must ensure that *AEMO* has unrestrained access to *metering installations* for the purpose of carrying out such random audits provided that *AEMO* agrees to comply with the *Metering Coordinator's* reasonable security and safety requirements and has first given the *Metering Coordinator* at least two *business days'* notice of its intention to carry out an audit, which notice must include:

(1) the name of the *representative* who will be conducting the audit on behalf of *AEMO*; and

(2) the time when the audit will commence and the expected time when the audit will conclude.

(f) The costs of any audit conducted under paragraph (b) will be borne by:

(1) if paragraph (c) applies, the *Metering Coordinator*; or

(2) otherwise, the *Registered Participant* who requested the audit.

7.9.4 Errors found in metering tests, inspections or audits

(a) If a *metering installation* test, inspection or audit, carried out in accordance with clause 7.9.1, demonstrates errors in excess of those prescribed in Schedule 7.4, the *Metering Coordinator* must ensure the *metering data* is substituted in accordance with this clause 7.9.4 and clause 7.10.1 as appropriate.

(b) If *AEMO* or the *Metering Coordinator* is not aware of the time at which the error that was identified in paragraph (a) arose, the error is to be 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* complied with the relevant accuracy requirement and the time when the error was detected.

(c) The time that the error was deemed to occur, as determined in paragraph (b), is to be used by the *Metering Data Provider* in performing substitution of the *metering data*.

(d) If a test or audit of a *metering installation* demonstrates an error of measurement of less than 1.5 times the error permitted by Schedule 7.4, no substitution of readings is required unless in *AEMO's* reasonable opinion a particular party would be significantly affected if no substitution were made.

(e) If any substitution is required under paragraph (d), *AEMO* must request the *Metering Coordinator* or the *financially responsible Market Participant* or the *Metering Data Provider*, as appropriate, to arrange for a suitable substitution of the incorrect *metering data* to be undertaken in accordance with the recommendations of any audit report provided by *AEMO* (under clauses 7.9.1(j), 7.9.3(b) or 7.9.3(e)), or if no audit report is provided, in accordance with the substitution requirements of the *metrology procedure*.

7.9.5 Retention of test records and documents

(a) All records and documentation of tests prepared under this Chapter 7 or for the purposes of this Chapter 7 must be retained in accordance with this clause 7.9.5.

(b) The *Metering Coordinator* must ensure records and documentation are retained as follows:

(1) for a period of at least 7 years:

(i) sample testing of *meters* while the *meters* of the relevant style remain in service;

(ii) the most recent sample test results of the *meters* referred to in subparagraph (i) after the *meters* are no longer in service;

(iii) non-sample testing of *meters* while the *meters* remain in service;

(iv) the most recent non-sample test results after the *meters* are no longer in service;

(v) the most recent sample test results of *instrument transformers* after *instrument transformers* of the relevant type are no longer in service;

(vi) the most recent non sample test results of *instrument transformers* after they are no longer in service;

(vii) tests of new *metering* equipment of the relevant style while the equipment remains in service; and

(viii) tests of new *metering* equipment of the relevant style after the equipment is no longer in service; and

(2) for a period of at least 10 years:

(i) sample testing of *instrument transformers* while *instrument transformers* of the relevant type remain in service; and

(ii) non-sample testing of *instrument transformers* while they remain in service.

(c) The *Metering Coordinator* must ensure records of type tests and pattern approvals carried out or obtained in accordance with S7.4.6.1(f) are retained while *metering* equipment of the relevant type remains in service and for at least 7 years after it is no longer in service.

7.9.6 Metering installation registration process

AEMO must establish, maintain and *publish* a registration process to facilitate the application of this Chapter 7 to *Market Participants*, *Metering Coordinators* and *Network Service Providers* in respect of:

(a) new *metering installations*;

(b) modifications to existing *metering installations*; and

(c) decommissioning of *metering installations*,

including the provision of information on matters such as application process, timing, relevant parties, fees and *metering installation* details.

Part E Metering Data

7.10 Metering Data Services

7.10.1 Metering Data Services

(a) *Metering Data Providers* must provide *metering data services* in accordance with the *Rules* and procedures authorised under the *Rules*, including:

(1) collecting *metering data* by local access or by *remote acquisition*;

(2) the validation and substitution of *metering data* for a type 1, 2, 3 and 4 *metering installation*;

(3) the validation, substitution and estimation of *metering data* for a type 4A, 5 and 6 *metering installation*;

(4) the calculation, estimation and substitution of *metering data* for a type 7 *metering installation*;

(5) establishing and maintaining a *metering data services database* associated with each *metering installation* and providing access to the *metering data services database* in accordance with clause 7.10.2;

(6) delivery of *metering data* and relevant *NMI Standing Data* for a *metering installation* in accordance with clause 7.10.3;

(7) the delivery of *metering data* and relevant *NMI Standing Data* to *AEMO* for *settlements*;

(8) ensuring the *metering data* and other data associated with the *metering installation* is protected from local access or remote access while being collected and while held in the *metering data services database* and that *data* is provided only in accordance with the *Rules*;

(9) maintaining the standard of accuracy of the time setting of the *metering data services database* and the *metering installation* in accordance with clause 7.10.6;

(10) notifying the *Metering Coordinator* of any *metering installation malfunction* of a *metering installation* within 1 *business day*; and

(11) management and storage of *metering data* in accordance with clause 7.10.2.

(b) Despite anything to the contrary in the *Rules*, *AEMO* may obtain *energy data* directly from a *metering installation* for the *settlements* process.

7.10.2 Data management and storage

(a) *Metering Data Providers* must:

(1) retain *metering data* for all relevant *metering installations* in the *metering data services database*:

(i) online in an accessible format for at least 13 months;

(ii) following the retention under subparagraph (1)(i), in an accessible format for an overall period of not less than 7 years; and

(2) archive in an accessible format for a period of 7 years:

(i) *metering data* in its original form collected from the *metering installation*;

(ii) records of each substitution to *metering data* in respect of a *metering installation*; and

(3) if required in procedures authorised by *AEMO* under this Chapter 7, provide the persons referred to in clauses 7.15.5(c)(1) to 7.15.5(c)(5) with access to the *metering data* and *NMI Standing Data* in the *metering data services database*; and

(4) except for the persons referred to in clauses 7.15.5(c)(1) to 7.15.5(c)(5), ensure that no other person has access to the *metering data services database*.

(b) *Metering Data Providers* accredited for type 7 *metering installations* must maintain techniques for determining *calculated metering data* for type 7 *metering installations* that are *market loads* under Schedule 7.4 in accordance with the *metrology procedure*.

(c) *Metering Data Providers* must maintain *electronic data transfer* facilities in order to deliver *metering data* from the *metering data services database* to the *metering database* in accordance with the relevant *service level procedures*.

(d) *Check metering data*, where available, and appropriately adjusted for differences in *metering installation* accuracy, where applicable, must be used by the *Metering Data Provider* to validate *metering data*.

(e) If the *Metering Data Provider* becomes aware that the *metering data* that has been delivered into the *metering database* from a *metering data services database* is incorrect, then the *Metering Data Provider* must provide corrected *metering data* to the persons referred to in clauses 7.15.5(c)(1) to 7.15.5(c)(5).

(f) *Metering data* may only be altered by a *Metering Data Provider* except in the preparation of *settlements ready data*, in which case *AEMO* may alter the *metering data* in accordance with clause 7.11.2(c).

(g) A *Metering Data Provider* may only alter *metering data* in the *metering data services database* in accordance with the *metrology procedure*.

(h) *Metering Data Providers* must maintain *electronic data transfer* facilities in order to deliver *metering data* from the *metering data services database* in accordance with clause 7.10.3.

(i) The *Metering Data Provider's* rules and protocols for supplying the *metering data services* must be approved by *AEMO* and *AEMO* must not unreasonably withhold such approval.

(j) The *Metering Data Provider* must arrange with the *Metering Coordinator* to obtain the relevant *metering data* if *remote acquisition*, if any, becomes unavailable.

7.10.3 Provision of metering data to certain persons

(a) The *Metering Data Provider* must provide *metering data* and relevant *NMI Standing Data* to the persons referred to in clauses 7.15.5(c)(1) to 7.15.5(c)(5) as required by and in accordance with the *Rules* and procedures authorised by *AEMO* under this Chapter 7.

(b) *AEMO* must ensure that the procedures it authorises under this Chapter 7 do not require the *Metering Data Provider* to provide *metering data* or relevant *NMI Standing Data* to a person under paragraph (a) except to the extent that such *metering data* or relevant *NMI Standing Data* is required by that person to perform its obligations under the *Rules*, the *National Energy Retail Rules* or *jurisdictional electricity legislation*.

7.10.4 Use of check metering data

(a) *Check metering data*, where available and provided that the *check metering data* has been appropriately adjusted for differences in *metering installation* accuracy, must be used by *Metering Data Providers* or *AEMO*, as the case may be, for:

(1) validation;

(2) substitution; and

(3) estimation,

of *metering data* as required by clauses 7.10.1 and 7.11.2(c).

7.10.5 Periodic energy metering

(a) The *Metering Data Provider* must, for type 1, 2, 3, 4, 4A and 5 *metering installations*, collate *metering data* relating to:

(1) the amount of *active energy*; and

(2) *reactive energy* (where relevant) passing through a *connection point*,

in *trading intervals* within a *metering data services database* unless it has been agreed between *AEMO*, the *Local Network Service Provider* and the *financially responsible Market Participant* that *metering data* may be recorded in sub-multiples of a *trading interval*.

(b) For type 6 *metering installations*, *metering data* relating to the amount of *active energy* passing through a *connection point* must be converted into *trading intervals* in the *profiling* process undertaken by *AEMO* in accordance with the *metrology procedure* and the *metrology procedure* must specify:

(1) the parameters to be used in preparing the *trading interval metering data* for each *market load*, including the algorithms;

(2) the *metering data* from *first-tier loads* that is to be used in the conversion process;

(3) the quality and timeliness of the *metering data* from the *first-tier loads*;

(4) the party responsible for providing the *metering data* from the *first-tier loads*; and

(5) if required, the method of cost recovery in accordance with clause 7.5.2.

(c) The *Metering Data Provider* must, for type 7 *metering installations*, prepare *metering data* relating to the amount of *active energy* passing through a *connection point* in accordance with clause 7.10.1(a)(4) in *trading intervals* within a *metering data services database*.

7.10.6 Time settings

(a) The *Metering Provider* must set the times of clocks of all *metering installations* with reference to *Eastern Standard Time* to a standard of accuracy in accordance with Schedule 7.4 relevant to the *load* through the *connection point* when installing, testing and maintaining *metering installations*.

(b) *AEMO* must ensure that the *metering database* clock is maintained within –1 second and +1 second of *Eastern Standard Time*.

(c) The *Metering Data Provider* must maintain the *metering data services database* clock within –1 second and + 1 second of *Eastern Standard Time*.

(d) The *Metering Data Provider* must:

(1) check the accuracy of the clock of the *metering installation* with reference to *Eastern Standard Time* to a standard of accuracy in accordance with Schedule 7.4 relevant to the *load* through the *connection point* on each occasion that the *metering installation* is accessed;

(2) reset the clock of the *metering installation* so that it is maintained to the required standard of accuracy in accordance with Schedule 7.4 relevant to the *load* through the *connection point* where the clock error of a *metering installation* does not conform to the required standard of accuracy on any occasion that the *metering installation* is accessed; and

(3) notify the *Metering Provider* where the *Metering Data Provider* is unable to reset the clock of the *metering installation* in accordance with subparagraph (2).

7.10.7 Metering data performance standards

(a) Except as otherwise specified in clause 7.5.1, the *Metering Coordinator* must ensure that *metering data* is provided to *AEMO* for all *trading intervals* where the *metering installation* has the capability for *remote acquisition* of *metering data*, and that the data is:

(1) derived from a *metering installation* compliant with clause 7.8.8(a);

(2) provided within the timeframe required for *settlements* and *prudential requirements* specified in the *metrology procedure*, and the relevant *service level procedures*;

(3) actual or substituted in accordance with the *metrology procedure*; and

(4) provided in accordance with the performance standards specified in the *metrology procedure*.

(b) The performance standards specified in subparagraph (a)(4) must be set at a level that does not impose a material risk on *AEMO's* ability to meet its *settlements* and *prudential requirements* obligations under the *Rules*.

(c) *AEMO* may relax or exempt the performance standards specified in subparagraph (a)(4) in circumstances, including those referred to in clause 7.8.9(b), when *AEMO* and the *Metering Coordinator* agree on a lower performance standard that does not place a material risk on *AEMO's* ability to meet its *settlements* and *prudential requirements* obligations under the *Rules*.

(d) Where the *metering installation* is a type 4A *metering installation* or does not have the capability for *remote acquisition* of *metering data*, the *Metering Coordinator* must ensure that *metering data* is provided to *AEMO* and that the data is:

(1) derived from a *metering installation* compliant with clause 7.8.8(a);

(2) provided within the timeframe required for *settlements* specified in the *metrology procedure* and the relevant *service level procedures*;

(3) actual, substituted or estimated in accordance with the *metrology procedure*; and

(4) provided in accordance with the performance standards specified in the *metrology procedure*.

7.11 Metering data and database

7.11.1 Metering database

(a) *AEMO* must create, maintain and administer a *metering database* (either directly or under a contract for provision of the database) containing information for each *metering installation* registered with *AEMO*.

(b) *AEMO* must ensure that the *metering database* has the capability for remote access.

(c) The *metering database* must include *metering data*, *settlements ready data*, and information for each *metering installation* registered with *AEMO* in accordance with rule 7.12.

(d) *AEMO* must:

(1) enable the persons referred to in clauses 7.15.5(c)(1) to 7.15.5(c)(5) and clause 7.15.5(e) to access or receive data in the *metering database*; and

(2) except as specified in subparagraph (1), ensure that no other person has access to the *metering database*.

(e) For all types of *metering installations*, the *metering database* must contain *metering data* that is:

(1) retained online in an accessible format for at least 13 months; and

(2) following the retention under subparagraph (1), archived in an accessible format for an overall period of not less than 7 years.

(f) The *settlements ready data* held in the *metering database* must be used by *AEMO* for *settlements* purposes.

(g) The *settlements ready data* held in the *metering database* may be used by *Distribution Network Service Providers* for the purpose of determining *distribution service charges* in accordance with clause 6.20.1.

(h) *AEMO* must retain *settlements ready data* for all *metering installations* for a period of 7 years.

(i) Despite anything to the contrary in this *Rule*, *AEMO* may provide an *energy ombudsman* with *metering data* relating to a *Registered Participant* from a *metering installation*, the *metering database*, or the *metering register*, if the *energy ombudsman* has received a complaint to which the data is relevant from a *retail customer* of the *Registered Participant*.

(j) *AEMO* must notify the relevant *Registered Participant* of any information requested by the *energy ombudsman* under paragraph (i) and, if it is requested by that *Registered Participant*, supply the *Registered Participant* with a copy of any information provided to the *energy ombudsman*.

(k) *AEMO* must, acting jointly with the *energy ombudsman*, develop procedures for the efficient management of timely access to data by the *energy ombudsman*.

7.11.2 Data validation, substitution and estimation

(a) If *AEMO* in the preparation of *settlements ready data* detects *metering data* that fails validation *AEMO* must notify the *Metering Data Provider* within 1 business day of detection.

(b) Where a *Metering Data Provider* receives notification under paragraph (a), the *Metering Data Provider* must use its best endeavours to provide corrected *metering data* to *AEMO* within 1 *business day* or advise *AEMO* that this time limit cannot be achieved, and the reason for delay, in which case the parties must agree on a revised time limit by which the corrected *metering data* will be provided.

(c) Where *metering data* fails validation by *AEMO* in the preparation of *settlements ready data* and replacement *metering data* is not available within the time required for *settlements* then *AEMO* must prepare a substitute value in accordance with the *metrology procedure*.

7.11.3 Changes to energy data or to metering data

(a) The *Metering Coordinator* must ensure that *energy data* held in a *metering installation* is not altered except when the *meter* is reset to zero as part of a repair or reprogramming.

(b) If an on-site test of a *metering installation* requires the injection of current, the *Metering Coordinator* must ensure that:

(1) the *energy data* stored in the *metering installation* is inspected; and

(2) if necessary following the inspection under subparagraph (1), alterations are made to the *metering data*, to ensure that the *metering data* in the *metering data services database* and the *metering database* is not materially different from the *energy* consumed at that *connection point* during the period of the test.

(c) If a *Metering Coordinator* considers alterations are necessary under paragraph (b)(2), the *Metering Coordinator* must:

(1) notify *AEMO* that alteration to the *metering data* is necessary; and

(2) advise the *financially responsible Market Participant* of the need to change the *metering data* and the *Metering Coordinator* must arrange for the *Metering Data Provider* to:

(i) alter the *metering data* for the *connection point* held in the *metering data services database* in accordance with the validation, substitution and estimation procedures in the *metrology procedure*; and

(ii) provide the altered *metering data* to the persons who receive that *metering data* under clause 7.10.3(a).

(d) If a test referred to in paragraph (b) is based on actual *connection point loads*, no alteration is required.

7.12 Register of Metering Information

7.12.1 Metering register

(a) As part of the *metering database*, *AEMO* must maintain a *metering register* of all *metering installations* and *check metering installations* which provide *metering data* used for *settlements*.

(b) The *metering register* referred to in paragraph (a) must contain the information specified in Schedule 7.1.

7.12.2 Metering register discrepancy

(a) If the information in the *metering register* indicates that the *metering installation* or the *check metering installation* does not comply with the requirements of the *Rules*, *AEMO* must advise affected *Registered Participants* of the discrepancy.

(b) The *Metering Coordinator* must arrange for the discrepancy to be corrected within 2 *business days* of receipt of notification under paragraph (a) unless exempted by *AEMO*.

7.13 Disclosure of NMI information

7.13.1 Application of this Rule

A *retailer* is entitled to information under this *Rule* only if the relevant information is not available to the *retailer* through the *Market Settlement and Transfer Solution Procedures*.

7.13.2 NMI and NMI checksum

(a) A *Distribution Network Service Provider* must, at the request of a *retailer*, and within 1 *business day* of the date of the request, provide the *retailer* with the *NMI* and *NMI* checksum for premises identified in the request by reference to:

(1) a unique meter identifier held by the *Distribution Network Service Provider*; or

(2) a street address; or

(3) the code used by Australia Post to provide a unique identifier for postal addresses.

(b) If a computer search by the *Distribution Network Service Provider* does not produce a unique match for the information provided by the *retailer*, the *Distribution Network Service Provider* must provide the *retailer* with any computer matches achieved up to a maximum of 99.

7.13.3 NMI Standing Data

A *Distribution Network Service Provider* must, at the request of a *retailer*, and within 2 *business days* of the date of the request, provide the *retailer* with the *NMI Standing Data* for premises identified in the request by reference to the *NMI* for the premises.

7.14 Metering data provision to retail customers

(a) *AEMO* must establish, maintain and *publish* the *metering data provision procedures* in accordance with this rule 7.14, this Chapter 7, and otherwise in accordance with the *Rules*.

(b) The objective of the *metering data provision procedures* is to establish the minimum requirements for the manner and form in which *metering data* should be provided to a *retail customer* (or its *customer authorised representative*) in response to a request for such data from the *retail customer* or *customer authorised representative* to the *retailer* or the *Distribution Network Service Provider*.

(c) The *metering data provision procedures* must:

(1) specify the manner and form in which *retail customers' metering data* must be provided, including a:

(i) detailed data format; and

(ii) summary data format;

(2) for *retail customers* for whom *interval metering data* is available, specify the summary data format, which, at a minimum should include the *retail customer's*:

(i) nature and extent of *energy* usage for daily time periods;

(ii) usage or *load* profile over a specified period; and

(iii) a diagrammatic representation of the information referred to in subparagraph (i);

(3) for *retail customers* for whom accumulated *metering data* is available, specify a summary data format;

(4) include timeframes in which a *retailer* or a *Distribution Network Service Provider* must, using reasonable endeavours,

respond to requests made by a *retail customer* or *customer's authorised representative*. The timeframe to be included must:

(i) be no more than 10 *business days*, except where requests are made by a *customer authorised representative* in relation to more than one *retail customer* of either the *retailer* or *Distribution Network Service Provider* to whom the request is made; and

(ii) take account of procedures in place relating to the validation of *metering data*; and

(5) specify a minimum method of delivery for the requested *metering data*.

(d) *Retailers* and *Distribution Network Service Providers* must comply with the *metering data provision procedures* when responding to requests by a *retail customer* or *customer authorised representative*.

Part F Security of metering installation and energy data

7.15 Security of metering installation and energy data

7.15.1 Confidentiality

(a) *Energy data*, *metering data*, *NMI Standing Data*, information included under a scheme for a NMI Standing Data Schedule as referred to in clause 3.13.12A, information in the *metering register* and passwords are confidential and must be treated as *confidential information* in accordance with the *Rules*.

(b) For the purposes of clause 8.6.2(c), *metering data* from a *metering installation* at a *retail customer's connection point* is deemed to have been provided by the *retail customer*.

7.15.2 Security of metering installations

(a) The *Metering Coordinator* at a *connection point* must ensure that the *metering installation* is secure and that associated links, circuits and information storage and processing systems are protected by security mechanisms acceptable to *AEMO*.

(b) *AEMO* may override any of the security mechanisms fitted to a *metering installation* with prior notice to the *Metering Coordinator*.

(c) If a *Local Network Service Provider*, *financially responsible Market Participant*, *Metering Provider* or *Metering Data Provider* becomes aware that a seal protecting *metering* equipment has been broken, it must notify the *Metering Coordinator* within 5 *business days*.

(d) If a broken seal has not been replaced by the person who notified the *Metering Coordinator* under paragraph (c), the *Metering Coordinator* must ensure that the broken seal is replaced no later than:

(1) the first occasion on which the *metering* equipment is visited to take a reading; or

(2) 100 days,

after receipt of notification that the seal has been broken.

(e) The costs of replacing broken seals as required by paragraph (d) are to be borne by:

(1) the *financially responsible Market Participant* if the seal was broken by a *retail customer* of that *Market Participant*;

(2) a *Registered Participant* if the seal was broken by the *Registered Participant*;

(3) the *Metering Provider* if the seal was broken by the *Metering Provider*;

(4) the *Metering Data Provider* if the seal was broken by the *Metering Data Provider*; or

(5) otherwise by the *Metering Coordinator*.

(f) If it appears that as a result of, or in connection with, the breaking of a seal referred to in paragraph (c) that the relevant *metering* equipment may no longer meet the relevant minimum standard, the *Metering Coordinator* must ensure that the *metering* equipment is tested.

7.15.3 Security controls for energy data

(a) The *Metering Coordinator* must ensure that *energy data* held in the *metering installation* is protected from local access and remote access by suitable password and security controls in accordance with paragraph (c).

(b) The *Metering Provider* must keep records of passwords secure.

(c) Except as otherwise specified in clause 7.15.4(e), the *Metering Provider* must allocate 'read only' passwords to *Market Participants*, *Local Network Service Providers* and *AEMO*, except where separate 'read only' and 'write' passwords are not available, in which case the *Metering Provider* must allocate a password to *AEMO* only. For the avoidance of doubt, a *financially responsible Market Participant* may allocate that 'read only' password to a *retail customer* who has requested access to its *energy data* in accordance with paragraph (g).

(d) The *Metering Provider* must hold 'read only' and 'write' passwords.

(e) The *Metering Provider* must forward a copy of the passwords held under paragraph (d) to *AEMO* on request by *AEMO* for *metering installations* types 1, 2, 3 and 4.

(f) *AEMO* must hold a copy of the passwords referred to in paragraph (e) for the sole purpose of revealing them to a *Metering Provider* in the event that the passwords cannot be obtained by the *Metering Provider* by any other means.

(g) Subject to the authorisation of the *Metering Coordinator* which is for the purpose of managing congestion in accordance with clause 7.15.5(b), if a *retail customer* of a *financially responsible Market Participant* requests a ‘read only’ password, the *financially responsible Market Participant* must:

(1) obtain a ‘read only’ password from the *Metering Provider* in accordance with paragraph (c); and

(2) provide a ‘read only’ password to the *retail customer* within 10 *business days*.

(h) The *Metering Coordinator* referred to in paragraph (g) must not unreasonably withhold the authorisation required by the *financially responsible Market Participant*.

(i) The *Metering Provider* must allocate suitable passwords to the *Metering Data Provider* that enables the *Metering Data Provider* to collect the *energy data* and to maintain the clock of the *metering installation* in accordance with clause 7.10.6.

(j) The *Metering Data Provider* must keep all *metering installation* passwords secure and not make the passwords available to any other person.

7.15.4 Additional security controls for small customer metering installations

In respect of a *small customer metering installation*:

(a) the *Metering Coordinator* must ensure that access to *energy data* held in the *metering installation* is only given to a person and for a purpose that is permitted under the *Rules*;

(b) the *Metering Coordinator* must ensure that access to services provided by the *metering installation* and *metering data* from the *metering installation* is only given to:

(1) in respect of a service listed in the *minimum services specification* in column 1 of table S7.5.1.1 and of *metering data* in connection with that service, an *access party* listed in column 3 of table S7.5.1.1;

(2) a person and for a purpose that is permitted under the *Rules*; or

(3) except as otherwise specified in subparagraph (1) or (2):

(i) the *Local Network Service Provider*, but only to the extent that, in the *Metering Coordinator's* reasonable opinion, such access is reasonably required by the *Local Network Service Provider* to enable it to meet its obligations to provide a safe, reliable and secure *network*; or

(ii) a person and for a purpose to which the *small customer* has given prior consent;

(c) the *Metering Coordinator* must ensure that the services provided by the *metering installation* are protected from local access and remote access by suitable password and security controls in accordance with paragraph (e);

(d) the *Metering Provider* must keep records of passwords secure; and

(e) the *Metering Provider* must ensure that:

(1) it forwards a copy of a password allowing local access and a copy of a password allowing remote access to the *metering installation*, services provided by the *metering installation* and *energy data* held in the *metering installation*, to the *Metering Coordinator*, *Metering Data Provider* and *AEMO*; and

(2) except as provided above, no other person receives or has access to a copy of a password allowing local access or remote access to the *metering installation*, services provided by the *metering installation* or *energy data* held in the *metering installation*.

7.15.5 Access to data

(a) Access to *energy data* recorded by a *metering installation* must only be provided where passwords are allocated in accordance with rule 7.15.

(b) The *Metering Coordinator* must ensure that access to *energy data* from the *metering installation* is scheduled appropriately to ensure that congestion does not occur.

(c) Except as specified in paragraphs (d) or (e), only the following persons may access or receive *metering data*, *settlements ready data*, *NMI Standing Data*, and data from the *metering register* for a *metering installation*:

(1) *Registered Participants* with a financial interest in the *metering installation* or the *energy* measured by that *metering installation*;

(2) the *Metering Coordinator* appointed in respect of the *connection point* for that *metering installation*, or a person who was previously appointed as the *Metering Coordinator* in respect of that *connection point*, as required in connection with a *Metering Coordinator default event* in accordance with procedures authorised under the *Rules*;

(3) the *Metering Provider* appointed with respect to that *metering installation*;

(4) the *Metering Data Provider* appointed with respect to that *metering installation*, or who was previously appointed with respect to a *metering installation* as required in accordance with the *Rules* and procedures authorised under the *Rules*;

(5) *AEMO* and its authorised agents; and

(6) the *AER* or *Jurisdictional Regulators* upon request to *AEMO*.

(d) In addition to the persons listed in paragraph (c), the following persons may access or receive *metering data* in accordance with the *Rules* and procedures authorised under the *Rules*:

(1) a *retail customer* or *customer authorised representative*, upon request by that *retail customer* or its *customer authorised representative* to the *retailer* or *Distribution Network Service Provider* in relation to that *retail customer's metering installation* in accordance with the *metering data provision procedures*;

(2) if a *small customer* has consented to a person accessing the *metering data* from its *small customer metering installation* in accordance with clause 7.15.4(b)(3), to that person;

(3) a *large customer* or a *customer authorised representative*, in relation to *metering data* from the *metering installation* in respect of the *connection point* of the *large customer*; and

(4) the *energy ombudsman* in accordance with paragraphs 7.11.1(i) – (k).

(e) In addition to the persons listed in paragraphs (c) and (d), a *retailer* may access and receive *NMI Standing Data*.

(f) Without limiting this clause 7.15.5 or clause 7.13.3:

(1) a *retailer* may access and receive *NMI Standing Data*;

(2) a *customer authorised representative* may receive *metering data*; and

(3) a *retailer* or a *Distribution Network Service Provider* may access, receive or provide *metering data* to a *customer authorised representative*,

after having first done whatever may be required or otherwise necessary, where relevant, under any applicable privacy legislation (including if appropriate making relevant disclosures or obtaining relevant consents from *retail customers*).

PART G Procedures

7.16 Procedures

7.16.1 Obligation to establish, maintain and publish procedures

(a) *AEMO* is responsible for the establishment and maintenance of procedures specified in Chapter 7 except for procedures established and maintained under rule 7.17.

(b) The procedures authorised by *AEMO* under Chapter 7 must be established and maintained by *AEMO* in accordance with the *Rules consultation procedures*.

(c) The *Information Exchange Committee* is responsible for the establishment and maintenance of procedures specified in rule 7.17.

(d) The procedures authorised by the *Information Exchange Committee* must be established and maintained in accordance with the requirements of rule 7.17.

(e) The procedures established or maintained under this clause 7.16.1 must be *published* by the party authorised to make the procedure.

(f) *AEMO* must establish, maintain and *publish* a list of procedures authorised under the *Rules* relevant to this Chapter 7, irrespective of who authorised those procedures.

7.16.2 Market Settlement and Transfer Solution Procedures

(a) *AEMO*, must establish, maintain and *publish Market Settlement and Transfer Solution Procedures*.

(b) *AEMO* must *publish* any amendment to the *Market Settlement and Transfer Solution Procedures*.

(c) All *Registered Participants*, *Metering Providers* and *Metering Data Providers* must comply with the *Market Settlement and Transfer Solution Procedures*.

(d) If a *Registered Participant*, *Metering Provider* or *Metering Data Provider* breaches the requirements of the *Market Settlement and Transfer Solution Procedures, AEMO* may send to that *Registered Participant*, *Metering Provider* or *Metering Data Provider* a notice in writing setting out the nature of the breach.

(e) If the *Registered Participant*, *Metering Provider* or *Metering Data Provider* remains in breach for more than 5 *business days* after receipt of the notice from *AEMO, AEMO* must advise:

(1) the *AER*; and

(2) in the case of breach by a *Registered Participant* other than a *Metering Coordinator*, the *Authority* responsible for administering *jurisdictional electricity legislation* in the *participating jurisdiction* in which the *connection point* to which the breach relates is located.

7.16.3 Requirements of the metrology procedure

(a) *AEMO* must establish, maintain and *publish* the *metrology procedure* that will apply to *metering installations* in accordance with this clause 7.16.3 and this Chapter 7.

(b) The *metrology procedure* must include a minimum period of 3 months between the date when the *metrology procedure* is *published* and the date the *metrology procedure* commences unless the change is made under clause 7.16.7(e) in which case the effective date may be the same date as the date of *publication*.

(c) The *metrology procedure* must include:

(1) information on the devices and processes that are to be used to:

(i) measure, or determine by means other than a device, the flow of electricity in a power conductor;

(ii) convey the measured or determined data under subparagraph (i) to other devices;

(iii) prepare the data using devices or algorithms to form *metering data*; and

(iv) provide access to the *metering data* from a *telecommunications network*;

(2) the requirements for the provision, installation and maintenance of *metering installations*;

(3) the obligations of *Metering Coordinators*, *financially responsible Market Participants*, *Local Network Service Providers*, *Metering Providers* and *Metering Data Providers*;

(4) details on:

(i) the parameters that determine the circumstances when *metering data* must be delivered to *AEMO* for the purposes of Chapter 3 and such parameters must include, but are not limited to, the volume limit per annum below which *AEMO* will not require *metering data* for those purposes;

(ii) the timeframe obligations for the delivery of *metering data* relating to a *metering installation* for the purpose of *settlements*; and

(iii) the performance standards for *metering data* required for the purpose of *settlements*;

(5) subject to clause 7.16.4(d)(2), zero MWh as the specification for the *type 5 accumulation boundary*;

(6) procedures for:

(i) the validation and substitution of *metering data*;

(ii) the estimation of *metering data*;

(iii) the method:

(A) by which *accumulated metering data* is to be converted by *AEMO* into *trading interval metering data*; and

(B) of managing the *first-tier load metering data* that is necessary to enable the conversion referred to in subparagraph (A) to take place; and

(7) other matters in the *Rules* required to be included in the *metrology procedure*.

7.16.4 Jurisdictional metrology material in metrology procedure

(a) Subject to this clause 7.16.4, *AEMO* may include in the *metrology procedure* other metrology material that is in the nature of a guideline, specification or other standard for a *participating jurisdiction* in relation to type 5, 6 and 7 *metering installations* which alters the application of the *metrology procedure* for that jurisdiction (*jurisdictional metrology material*).

(b) *Jurisdictional metrology material* may only be submitted to *AEMO* for inclusion in the metrology procedure by the *Ministers of the MCE*.

(c) *Jurisdictional metrology material* submitted to *AEMO* under paragraph (b) must:

(1) be in writing;

(2) be provided to *AEMO* within sufficient time for *AEMO* to meet its obligations under this clause 7.16.4;

(3) be consistent with the matters contained in clauses 7.16.3 and 7.16.5;

(4) contain a date by which the *Ministers of the MCE* will undertake a review in relation to harmonising the *jurisdictional metrology material* with the *metrology procedure* (the **review date**); and

(5) be accompanied by written reasons as to why the *jurisdictional metrology material* is required instead of the *metrology procedure*.

(d) *Jurisdictional metrology material* may address the following matters:

(1) guidelines for the replacement of a device capable of producing *interval energy data* with a device that only produces *accumulated energy data*; and

(2) the specification of the *type 5 accumulation boundary*.

(e) On receiving *jurisdictional metrology material* from the *Ministers of the MCE*, *AEMO* must undertake the *Rules consultation procedures* in relation to that material, including in that consultation the reasons referred to subparagraph (c)(5).

(f) At the conclusion of the *Rules consultation procedures* under paragraph (e), *AEMO* must provide a final report to the *Ministers of the MCE* in accordance with rule 8.9(k) of the outcome of that procedure and:

(1) in the case where the *Ministers of the MCE* do not advise *AEMO* of any amendments to the *jurisdictional metrology material*, *AEMO* must incorporate that material into a separate part of the *metrology procedure*; or

(2) in the case where the *Ministers of the MCE* advise *AEMO* of amendments to the *jurisdictional metrology material*, *AEMO* must incorporate the amended material into a separate part of the *metrology procedure*.

(g) The *jurisdictional metrology material*, as included in the *metrology procedure* by *AEMO*, expires on the review date unless the *Ministers of the MCE* submit to *AEMO* new *jurisdictional metrology material* in accordance with this clause 7.16.4.

(h) The *jurisdictional metrology material* must not prevent the *metering data* from being collected as *interval metering data* if required by the *financially responsible Market Participant* or a *Local Network Service Provider* for any purpose other than for *settlements*.

7.16.5 Additional metrology procedure matters

(a) The *metrology procedure* may:

(1) clarify the operation of the *Rules* in relation to:

(i) *load* profiling;

(ii) the provision and maintenance of *meters*;

(iii) the provision of *metering data services*;

(iv) metrology for a *market load* connected to a *network* where the owner or operator of that *network* is not a *Registered Participant*;

(v) the accreditation of *Metering Providers* and *Metering Data Providers*; and

(vi) with respect to the provision, installation and maintenance of *metering installations* and the provision of *metering data services*, the obligations of *Metering Coordinators*, *financially responsible Market Participants*, *Local Network Service Providers*, *AEMO*, *Metering Providers* and *Metering Data Providers*;

(2) specify in detail:

(i) the accuracy of *metering installations*;

(ii) inspection and testing standards;

(iii) *Metering Provider* and *Metering Data Provider* capabilities in accordance with Schedule 7.2 and Schedule 7.3 respectively, and accreditation standards;

(iv) the standards and/or technical requirements for the *metering data services database*; and

(v) the technical standards for *metering* of a *market load* that is *connected* to a *network* where the operator or owner of that *network* is not a *Registered Participant*;

(3) provide information on the application of the *Rules*, subject to a statement in the procedure that where any inconsistency arises between the *Rules* and the *metrology procedure*, the *Rules* prevail to the extent of that inconsistency;

(4) in relation to type 4A, 5, 6 and 7 *metering installations* specify in what circumstances *metering data* held in the *metering data services database* within the relevant *participating jurisdiction*, can be used by *Distribution Network Service Providers* to calculate charges for *distribution services* for the purposes of clause 6.20.1(e); and

(5) contain information to ensure consistency in practice between the *metrology procedure* and other instruments developed and *published* by *AEMO*, including the practices adopted in the *Market Settlement and Transfer Solution Procedures*.

(b) The *metrology procedure* may not include information relating to consumer protection.

7.16.6 Requirements of the service level procedures

(a) *AEMO* must establish, maintain and *publish* the *service level procedures* that will apply to the relevant categories of registration that apply to *Metering Providers* and *Metering Data Providers*, in accordance with this Chapter 7 and this clause 7.16.6.

(b) *AEMO* must establish, maintain and *publish* the *service level procedures* in accordance with clause 7.16.1.

(c) The *service level procedures* must include:

(1) the requirements for the provision, installation and maintenance of *metering installations* by *Metering Providers*;

(2) requirements for the systems and processes for the collection, processing and delivery of *metering data* by *Metering Data Providers*;

(3) the performance levels associated with the collection, processing and delivery of *metering data*;

(4) the data formats that must be used for the delivery of *metering data*;

(5) the requirements for the management of relevant *NMI Standing Data*;

(6) the requirements for the processing of *metering data* associated with *connection point* transfers and the alteration of *metering installations* where one or more devices are replaced;

(7) other matters in the *Rules* required to be included in the *service level procedures*; and

(8) information to ensure consistency in practice between the *service level procedures* and other documents developed and *published* by *AEMO*, including the practices adopted in the *Market Settlement and Transfer Solutions Procedures*.

(d) The *service level procedures* must include requirements for accreditation, and for *Metering Providers* and *Metering Data Providers* (the '**service providers**'), may include requirements relating to, without limitation:

(1) cooperation with *AEMO*;

(2) the confidentiality of information collected by the service providers;

(3) the resolution of disputes between *AEMO* and the service providers, including disputes associated with a breach of the *Rules* and procedures authorised under the *Rules*;

(4) the access of *AEMO* to and the inspection and audit by *AEMO* of any equipment or database maintained by the service providers;

(5) the insurance which must be taken out by or on behalf of the service providers;

(6) subcontracting by the service providers;

(7) the software and systems that are used by the service providers;

(8) maintenance of quality systems accreditation;

(9) the ownership of intellectual property that is developed or used by the service providers; and

(10) the delivery up to *AEMO* of data, works, material and other property that *AEMO* has the right to in the event of the deregistration of a service provider.

7.16.7 Amendment of procedures in the Metering Chapter

(a) Any person (the '**proponent**') may submit to *AEMO* a proposal (the '**proposal**') to amend any procedure in this Chapter 7 including the *metrology procedure* except:

(1) in relation to the *jurisdictional metrology material* which is contained within the *metrology procedure*; and

(2) procedures specified in rule 7.17,

and must include reasons for the proposed change.

(b) For proposals submitted under paragraph (a), *AEMO* must:

(1) give notice of receipt of the proposal to the proponent; and

(2) advise the proponent of the action that *AEMO* proposes to undertake under paragraphs (c) or (e).

(c) Where *AEMO*:

(1) accepts the proposal, *AEMO* must conduct the *Rules consultation procedures* in relation to that proposal;

(2) requests further information from the proponent in relation to a proposal, on receiving that information *AEMO* must either accept, or reject the proposal; or

(3) rejects a proposal, *AEMO* must advise the proponent of its decision and reasons for the decision in writing.

(d) *AEMO* may at the conclusion of the *Rules consultation procedures* amend the procedure (if necessary).

(e) Where, in *AEMO's* reasonable opinion, a proposal referred to in paragraph (a) relates to amendments that are of a minor or administrative nature, *AEMO* is not required to undertake the *Rules consultation procedures* but must:

(1) *publish* the proposal including the accompanying reasons;

(2) issue a notice to *Registered Participants*, *Metering Providers*, *Metering Data Providers*, *Ministers* and the *AER* advising that the amendment to the procedure has been *published*;

(3) invite submissions on the proposal;

(4) allow 10 *business days* for the receipt of submissions;

(5) allow a reasonable extension of time for submissions if requested in writing by a *Registered Participant*, *Metering Provider* or *Metering Data Provider*;

(6) *publish* submissions as soon as practicable after submissions have been received;

(7) consider the submissions; and

(8) *publish*, on or before the day of *publication* of the procedure identified in paragraph (a), reasons for the amendments to the procedure.

7.16.8 National Measurement Act

(a) *AEMO* in consultation with the National Measurement Institute must establish guidelines that clarify the application of the requirements of the *National Measurement Act* to *metering installations*.

(b) For the avoidance of doubt, to the extent that there is an inconsistency between the *Rules* and the *National Measurement Act*, the Act prevails to the extent of that inconsistency.

Part H B2B Requirements

7.17 B2B Arrangements

7.17.1 B2B e-Hub

AEMO must provide and operate a *B2B e-Hub*. As required by *B2B Procedures* and subject to clause 7.17.4(j), *Local Retailers*, *Market Customers* and *Distribution Network Service Providers* must use the *B2B e-Hub* for *B2B Communications*.

7.17.2 Information Exchange Committee

(a) *AEMO* must establish the *Information Exchange Committee* in accordance with the *Information Exchange Committee Election Procedures*.

(b) The *Information Exchange Committee* must only be constituted by:

(1) three *Distribution Network Service Provider Members*;

(2) three *Local Retailer*/*Market Customer Members*; and

(3) two *Independent Members*.

(b1) *Local Retailers* and *Market Customers* together and *Distribution Network Service Providers* must, in relation to categories of *Members* in relation to which they are entitled to vote under the *Information Exchange Committee Election Procedures*, use their reasonable endeavours to ensure that the *Information Exchange Committee* is established in accordance with the *Information Exchange Committee Election Procedures*. Each *Member* must serve on the *Information Exchange Committee* for the term specified in the *Information Exchange Committee Election Procedures* and must only be removed or replaced in accordance with the *Information Exchange Committee Election Procedures*.

(c) *Local Retailers, Market Customers* and *Distribution Network Service Providers* must ensure that the *Information Exchange Committee Election Procedures* include provisions in respect of *Member* qualifications, procedures for voting for *Members*, the term of a *Member,* determination and publication of results of elections and the removal and resignation of a *Member*.

(d) The *Information Exchange Committee Election Procedures* may only be amended in accordance with the procedure set out in the *Information Exchange Committee Election Procedures* and with the support of:

(i) not less than 75% of all *Registered Participants* registered by *AEMO* as *Distribution Network Service Providers* under clause 2.5.1; and

(ii) not less than 75% of that class of *Registered Participants* comprising:

(A) *Registered Participants* who are included on the list of *Local Retailers published* by *AEMO*; and

(B) *Market Customers* who are not included on the list of *Local Retailers published* by *AEMO* and who are not a *related body corporate* of a *Local Retailer*.

(d1) Neither a *Registered Participant* nor *AEMO* is obliged to comply with an amendment to the *Information Exchange Committee Election Procedures* unless that amendment is made in accordance with this clause. *AEMO* must *publish* the current version of the *Information Exchange Committee Election Procedures*.

(e) A *Registered Participant* must ensure that a person it nominates as a *Member* for a category satisfies the requirements for that particular category of *Member* as set out in the *Information Exchange Committee Election Procedures*.

(f) The *Information Exchange Committee Operating Manual* may only be amended in accordance with the procedure set out in the

Information Exchange Committee Election Procedures and with the support of:

(1) not less than 75% of all *Registered Participants* registered by *AEMO* as *Distribution Network Service Providers* under clause 2.5.1; and

(2) not less than 75% of that class of *Registered Participants* comprising:

(i) *Registered Participants* who are included on the list of *Local Retailers published* by *AEMO*; and

(ii) *Market Customers* who are not included on the list of *Local Retailers published* by *AEMO* and who are not a *related body corporate* of a *Local Retailer*.

(f1) Neither a *Registered Participant* nor *AEMO* is obliged to comply with an amendment to the *Information Exchange Committee Operating Manual* unless that amendment is made in accordance with this clause. *AEMO* must *publish* the current version of the *Information Exchange Committee Operating Manual*.

(g) The functions and powers of the *Information Exchange Committee* include:

(1) developing, consulting on and making an *Information Exchange Committee Recommendation*;

(2) managing the ongoing development of the *B2B Procedures* and any changes to them;

(3) establishing the *Information Exchange Committee Working Groups*;

(4) developing, consulting on and approving the *Information Exchange Committee Works Programme*;

(5) reviewing and considering work completed by the *Information Exchange Committee Working Groups*;

(6) developing proposed amendments to the *Information Exchange Committee Election Procedures*; and

(7) developing proposed amendments to the *Information Exchange Committee Operating Manual*.

(h) The *Information Exchange Committee* must provide to *AEMO* the current version of the *B2B Procedures* and the *Information Exchange Committee Works Programme*.

(i) *AEMO* must *publish* the *B2B Procedures* and the *Information Exchange Committee Works Programme* provided to it by the *Information Exchange Committee*.

(j) The *Information Exchange Committee*, *AEMO*, *Local Retailers*, *Market Customers* and *Distribution Network Service Providers* must comply with the *Information Exchange Committee Election Procedures* and the *Information Exchange Committee Operating Manual*.

(k) The *Information Exchange Committee* must meet at least once every three months.

(l) The quorum for a meeting of the *Information Exchange Committee* is five *Members* comprising two *Distribution Network Service Provider Members*, two *Local Retailer/Market Customer Members* and one *Independent Member*.

(m) A decision of the *Information Exchange Committee* is not valid and enforceable unless it is made as follows:

(1) an *Information Exchange Committee Recommendation* requires the support of six or more *Members*;

(2) any decision that a proposal under clause 7.17.3(a) should not be considered further after initial consideration under clause 7.17.3(b), and any decision to not recommend *B2B Procedures* or a change to the *B2B Procedures* for approval by *AEMO* requires the support of six or more *Members*;

(3) any decision to approve the *Information Exchange Committee Works Programme* requires the support of six or more *Members*; and

(4) any other decision by the *Information Exchange Committee* requires the support of five or more *Members*.

(n) Each *Member* in performing his or her duties or in exercising any right, power or discretion must have regard to the *B2B Objective* and the *B2B Principles* and must:

(1) at all times act honestly;

(2) exercise the degree of care and diligence that a reasonable person in a like position would exercise;

(3) not make improper use of information acquired by virtue of his or her position to gain, directly or indirectly, an advantage for himself or herself, or the *Registered Participants* by which he or she is employed and/or which nominated him or her to be a *Member*; and

(4) not make improper use of his or her position to gain, directly or indirectly, an advantage for himself or herself or the *Registered Participants* by which he or she is employed and/or which nominated him or her to be a *Member*.

(o) Subject to paragraph (n), a *Distribution Network Service Provider Member* may take into account the interests of *Distribution Network Service Providers* in performing his or her duties or in exercising any right, power or discretion.

(p) Subject to paragraph (n), a *Local Retailer*/*Market Customer Member* may take into account the interests of *Local Retailers* and *Market Customers* in performing his or her duties or in exercising any right, power or discretion.

(q) The *Information Exchange Committee* must prepare an *Information Exchange Committee Annual Report* by 31 December each year. The *Information Exchange Committee* must provide the *Information Exchange Committee Annual Report* to *AEMO* by the following 31 March and *AEMO* must *publish* that *Information Exchange Committee Annual Report*.

(r) The *Information Exchange Committee Annual Report* must contain the information required by the *Information Exchange Committee Operating Manual*.

(s) By 28 February each year the *Information Exchange Committee* must prepare a draft budget for the following *financial year* in a form which is consistent with the budget procedures of *AEMO*. Following discussion with *AEMO* the *Information Exchange Committee* must prepare a budget by 31 March and provide that budget to *AEMO*. When *AEMO publishes* its budget pursuant to clause 2.11.3, *AEMO* must advise the *Information Exchange Committee* of the final budget for the *Information Exchange Committee* for that *financial year*.

7.17.3 Method of making and changing B2B Procedures

(a) *AEMO*, a *Local Retailer*, a *Market Customer* or a *Distribution Network Service Provider* may propose *B2B Procedures*, or a change to the *B2B Procedures*, to the *Information Exchange Committee*. The proposal must be submitted in writing to the *Information Exchange Committee* and must provide details of the proposal and supporting information, including reasons for any change or *B2B Procedure*.

(b) Within 25 *business days* of receipt by the *Information Exchange Committee* of a proposal under paragraph (a), the *Information Exchange Committee* must meet to determine whether on a prima facie basis making new *B2B Procedures* and/or changing the *B2B*

Procedures is warranted having regard to the *B2B Objective* and the *B2B Principles*.

(c) If, after its consideration under paragraph (b), the *Information Exchange Committee* decides that the proposal made under paragraph (a) should not be considered further, the *Information Exchange Committee* must within five *business days* provide written reasons for that decision to whichever of *AEMO*, the *Local Retailer*, *Market Customer* or *Distribution Network Service Provider* made the proposal.

(d) If, after its consideration under paragraph (b), the *Information Exchange Committee* decides that the proposal made under paragraph (a) should be considered further, the *Information Exchange Committee* must develop the proposal into a *B2B Proposal* (which may differ from the proposal originally made) and an accompanying *B2B Procedures Change Pack* for consultation. The *Information Exchange Committee* must seek *AEMO's* advice on whether a conflict with the *Market Settlement and Transfer Solution Procedures* arises from the *B2B Proposal* and include any such advice in the *B2B Procedures Change Pack*.

(e) The *Information Exchange Committee* must comply with the *Rules consultation procedures* in relation to the *B2B Proposal*. For the purposes of rule 8.9(b), the nominated persons to whom notice must be given are *Local Retailers*, *Market Customers*, *Distribution Network Service Providers* and *AEMO*. For the purposes of the notice, the particulars of the matters under consultation must include a copy of the *B2B Procedures Change Pack*.

(f) *AEMO* must *publish* the notice of consultation within 3 *business days* of its receipt and must notify all *Local Retailers*, *Market Customers* and *Distribution Network Service Providers* of the consultation.

(g) In addition to the matters which rule 8.9(g) requires be included in the draft report, the draft report must contain details of the *Information Exchange Committee's* consideration of the *B2B Objective* and each of the *B2B Principles* and how the *Information Exchange Committee* has considered each submission made having regard to the *B2B Objective* and the *B2B Principles*.

(h) In addition to the matters which rule 8.9(k) requires be included in the final report, the final report must contain details of the *Information Exchange Committee's* consideration of the *B2B Objective* and each of the *B2B Principles* and how the *Information Exchange Committee* has considered each submission having regard to the *B2B Objective* and the *B2B Principles*.

(i) The *Information Exchange Committee* can conclude not to recommend the proposed *B2B Procedures* be made or not to recommend a change to the *B2B Procedures*. Alternatively, the *Information Exchange Committee* may make an *Information Exchange Committee Recommendation* and in doing so may recommend a different *B2B Procedure* or change to the *B2B Procedures* from that originally proposed under paragraph (a). A conclusion not to recommend the proposed *B2B Procedures* be made or not to recommend a change to the *B2B Procedures,* or the making of an *Information Exchange Committee Recommendation*, must be included in the final report required under rule 8.9(k).

(j) In coming to a conclusion not to recommend the proposed *B2B Procedures* or not to recommend a change to the *B2B Procedures*, or in making an *Information Exchange Committee Recommendation*, the *Information Exchange Committee* must seek to achieve the *B2B Objective* and, in seeking to achieve the *B2B Objective*, must have regard to the *B2B Principles*. To the extent of any conflict between the *B2B Principles*, the *Information Exchange Committee* may determine the manner in which those principles can best be reconciled or which of them should prevail.

(k) If the *Information Exchange Committee* recommends not to make the proposed *B2B Procedures* or not to change the *B2B Procedures*, *AEMO* must take no further action in respect of the proposal. If the *Information Exchange Committee* makes an *Information Exchange Committee Recommendation*, *AEMO* must consider the *Information Exchange Committee Recommendation* and must approve that *Information Exchange Committee Recommendation*, unless it concludes that:

    (1) the *Information Exchange Committee* has failed to have regard to the *B2B Objective* and/or the *B2B Principles*;

    (2) the *Information Exchange Committee Recommendation* would conflict with the *Market Settlement and Transfer Solution Procedures;* or

    (3) the *Information Exchange Committee* has not followed the *Rules consultation procedures* (as supplemented by this clause 7.17.3).

(l) In considering an *Information Exchange Committee Recommendation*, *AEMO* must not consider:

    (1) the manner in which the *Information Exchange Committee* considered the *B2B Objective* and the *B2B Principles* or the weight given by the *Information Exchange Committee* to the different *B2B Principles* or the balancing between them; or

    (2) the merits of the *Information Exchange Committee Recommendation*.

(m) *AEMO* must not amend the *Information Exchange Committee Recommendation* and must not conduct any further consultation on the *Information Exchange Committee Recommendation* prior to making its *B2B Decision*.

(n) *AEMO* must *publish* and make available on its website its *B2B Decision*, with reasons, within 10 *business days* of receiving an *Information Exchange Committee Recommendation* from the *Information Exchange Committee*.

(o) If *AEMO* decides not to approve an *Information Exchange Committee Recommendation*, the reasons for the *B2B Decision* which are to be published and made available in accordance with paragraph (n) must include an explanation of the following, where applicable:

(1) to which of the *B2B Objective* and/or the *B2B Principles* *AEMO* considers the *Information Exchange Committee* failed to have regard;

(2) how the *Information Exchange Committee Recommendation* would give rise to a conflict with the *Market Settlement and Transfer Solution Procedures*; or

(3) how the *Information Exchange Committee* did not follow the *Rules consultation procedures* (as supplemented by this clause 7.17.3).

7.17.4 Content of the B2B Procedures

(a) The *B2B Procedures* may provide for *B2B Communications*.

(b) For each *B2B Communication*, the *B2B Procedures* must contain:

(1) the required *B2B Data* inputs and *B2B Data* outputs;

(2) the required business process flows and related timing requirements;

(3) the required content and format;

(4) the required delivery method; and

(5) the back up delivery method to be used where the required delivery method cannot be used.

(c) The *B2B Procedures* may include obligations in relation to the information to be maintained and provided to support *B2B Communications*.

(d) For each *B2B Communication* the *B2B Procedures* may also include:

(1) details for testing and certification;

(2) provisions relating to contingency arrangements;

(3) examples of how a *B2B Communication* may operate in practice; and

(4) the method for dealing with a dispute (which may include provisions deferring the use of the dispute resolution procedures in the *Rules* and access to the courts).

(e) The *B2B Procedures* or a change to the *B2B Procedures* must also include a date for the commencement of the *B2B Procedures* or the change. That date must be not less than 10 *business days* after the related *B2B Decision* is *published*. The *Information Exchange Committee* may extend that date following consultation with *AEMO* and affected *Registered Participants*. If the date is extended by the *Information Exchange Committee*, the *Information Exchange Committee* must provide *AEMO* with that date and *AEMO* must *publish* that date.

(f) A change to the *B2B Procedures* may also include provisions relating to a date for the end of a process related to a *B2B Communication*. That date may be after the date of commencement of the change and may be left to the discretion of the *Information Exchange Committee*. If the date is set by the *Information Exchange Committee*, the *Information Exchange Committee* must provide *AEMO* with that date and *AEMO* must *publish* that date.

(g) The *B2B Procedures* may be constituted by one or more separate documents.

(h) The *B2B Procedures* may include roles and responsibilities for *Metering Providers* and *Metering Data Providers*.

(i) Subject to the *Information Exchange Committee* following the requirements placed upon it in the *Rules* in relation to the *B2B Procedures*, *Local Retailers*, *Market Customers*, *Distribution Network Service Providers*, *AEMO*, *Metering Providers* and *Metering Data Providers* must comply with the *B2B Procedures*.

(j) *Local Retailers*, *Market Customers* and *Distribution Network Service Providers* may, on such terms and conditions as agreed between them, communicate a *B2B Communication* on a basis other than as set out in the *B2B Procedures*, in which case the parties to the agreement need not comply with the *B2B Procedures* to the extent that the terms and conditions agreed between them are inconsistent with the *B2B Procedures*.

(k) *B2B Data* is confidential information and may only be disclosed as permitted by the *Rules*.

(l) If a change to the *B2B Procedures* is of a minor or procedural nature or is necessary to correct a manifest error in the *B2B Procedures*, the *Information Exchange Committee* may recommend the change to *AEMO* and need not consult on the change in accordance with the *Rules consultation procedures*. Clauses 7.17.3(i) to (o) (inclusive) and paragraphs (e) and (f) apply to such a change (with any necessary modifications). In addition to publishing its *B2B Decision* in relation to such a change, *AEMO* must notify all *Local Retailers*, *Market Customers* and *Distribution Network Service Providers* of the change.

7.17.5 Cost Recovery

(a) The costs of the development of the *B2B Procedures*, the costs of the establishment and operation of the *Information Exchange Committee* (including the engagement costs of specialist advisers, and the remuneration and payment of the reasonable expenses of the *Independent Members*), all of which must be set out in the budget prepared by the *Information Exchange Committee* pursuant to clause 7.17.2(s) and the *Information Exchange Committee Annual Report*, and the operational costs associated with any service provided by *AEMO* to facilitate *B2B Communications* (including providing and operating a *B2B e-Hub*) must be paid by *AEMO* in the first instance and recouped by *AEMO* as *Participant fees*.

(b) Subject to paragraph (a), the cost of any *Member* (other than an *Independent Member*) and involvement of individuals in the *Information Exchange Committee Working Groups* is not to be borne by *AEMO*.

(c) The cost to a person of implementing and maintaining the necessary systems and processes to ensure compliance with *B2B Procedures* must be met by that person.

Schedule 7.1 Metering register

S7.1.1 General

(a) The *metering register* forms part of the *metering database* and holds static *metering* information associated with *metering installations* defined by the *Rules* that determines the validity and accuracy of *metering data*.

(b) The purpose of the *metering register* is to facilitate:

(1) the registration of *connection points*, *metering points* and affected *Registered Participants*;

(2) the verification of compliance with the *Rules*; and

(3) the auditable control of changes to the registered information.

S7.1.2 Metering register information

Metering information to be contained in the *metering register* should include, but is not limited to the following:

(a) *Connection* and *metering point* reference details, including:

(1) agreed locations and reference details (eg drawing numbers);

(2) loss compensation calculation details;

(3) site identification names;

(4) details of *Market Participants* and *Local Network Service Providers* associated with the *connection point*;

(5) details of the *Metering Coordinator*; and

(6) transfer date for *Second-Tier Customer* and *Non-Registered Second-Tier Customer metering data* (i.e. to another *Market Customer*).

(b) The identity and characteristics of *metering* equipment (ie *instrument transformers*, *metering installation* and *check metering installation*), including:

(1) serial numbers;

(2) *metering installation* identification name;

(3) *metering installation* types and models;

(4) *instrument transformer* ratios (available and connected);

(5) current test and calibration programme details, test results and references to test certificates;

(6) asset management plan and testing schedule;

(7) calibration tables, where applied to achieve *metering installation* accuracy;

(8) *Metering Provider*(s) and *Metering Data Provider*(s) details;

(9) summation scheme values and multipliers; and

(10) data register coding details.

(c) Data communication details, including:

(1) telephone number(s) for access to *energy data*;

(2) communication equipment type and serial numbers;

(3) communication protocol details or references;

(4) data conversion details;

(5) user identifications and access rights; and

(6) 'write' password (to be contained in a hidden or protected field).

(d) Data validation, substitution and estimation processes agreed between affected parties, including:

(1) algorithms;

(2) data comparison techniques;

(3) processing and alarms (eg *voltage* source limits; phase angle limits);

(4) *check metering* compensation details; and

(5) alternate data sources.

(e) Data processing prior to the *settlement* process, including algorithms for:

(1) *generation* half-hourly 'sent out' calculation;

(2) customer half-hourly *load* calculation; and

(3) *Local Retailer* net *load* calculation.

Schedule 7.2 Metering Provider

S7.2.1 General

(a) A *Metering Provider* must be accredited by and registered by *AEMO*. *AEMO* must accredit and register a *Metering Provider* only for the type of work the *Metering Provider* is qualified to provide.

(b) *AEMO* must establish a qualification process for *Metering Providers* that enables registration to be achieved in accordance with the requirements of this Schedule 7.2.

(c) A *Metering Provider* must have the necessary licences in accordance with appropriate State and Territory requirements.

(d) A *Metering Provider* must ensure that any *metering* equipment it installs 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.

S7.2.2 Categories of registration

(a) Registrations for *Metering Providers* in relation to the provision, installation and maintenance of *metering installation* types 1, 2, 3, 4 and 4A must be categorised in accordance with Tables S7.2.2.1, S7.2.2.2 and S7.2.2.3, or other procedures approved by *AEMO*.

(b) Registrations for *Metering Providers* in relation to the provision, installation and maintenance (unless otherwise specified) of *metering installation* types 5 and 6 must be categorised in accordance with Table S7.2.2.4 with the capabilities established in the *metrology procedures*.

(c) Registration for *Metering Providers* in relation to the provision, installation and maintenance of *small customer metering installations* must be categorised in accordance with Tables S7.2.2.2 and satisfy the requirements in clause S7.2.5.

(d) *AEMO* may establish *Accredited Service Provider categories* of registration for a *Metering Provider* in accordance with clause S7.2.6.

Table S7.2.2.1 Categories of registration for accreditation

Category	Competency
1C	Class 0.2 CTs with < 0.1% uncertainty.
1V	Class 0.2 VTs with < 0.1% uncertainty.
1M	Class 0.2 Wh meters with < 0.1/cosφ% uncertainty and class 0.5 varh meters with <0.3/sinφ uncertainty.
1A	Class 0.2 CTs, VTs, Wh meters; class 0.5 varh meters; the total installation to 0.5%. Wh with < 0.2% uncertainty at unity *power factor*; 1.0% for varh with <0.4% uncertainty at zero *power factor*.
2C	Class 0.5 CTs with < 0.2% uncertainty.
2V	Class 0.5 VTs with < 0.2% uncertainty.
2M	Class 0.5 Wh meters with < 0.2/cosφ uncertainty and class 1.0 varh meters with <0.4/sinφ uncertainty.

Category	Competency
2A	Class 0.5 CTs, VTs, Wh meters; class 1.0 varh meters; the total installation to 1.0%. Wh with < 0.4% uncertainty at unity *power factor*; 2.0% for varh with <0.5% uncertainty at zero *power factor*.

Table S7.2.2.2 Categories of registration for accreditation

Category	Competency
3M	Class 1.0 Wh meters with < 0.3/cosφ uncertainty and class 2.0 varh meters with <0.5/sinφ% uncertainty.
3A	Class 0.5 CTs, VTs; class 1.0 Wh meters; class 2.0% varh meters; the total installation to 1.5%. Wh with < 0.5% uncertainty at unity *power factor*; 3.0% for varh with <0.6% uncertainty at zero *power factor*.
4M	Class 1.0 Wh meters and class 1.5 Wh meters with <0.3/cosφ% uncertainty.
4A	Class 1.0 Wh meters and class 1.5 Wh meters with <0.3/cosφ% uncertainty.
4S	Class 1.0Wh meters and class 1.5 Wh meters with <0.3/cosφ% uncertainty.

Table S7.2.2.3 Categories of registration for accreditation

Category	Competency
L	Approved *communications interface* installer

Table S7.2.2.4 Categories of registration for accreditation

Category	Competency
5A Installation only	Class 1.0 and class 1.5 whole current Wh *meters* with <0.3/cosΦ% uncertainty.
6A Installation only	Class 1.5 whole current Wh *meters* with <0.3/cosΦ% uncertainty.
5B	Class 1.0 and class 1.5 whole current or CT connected Wh *meters* with <0.3/cosΦ% uncertainty.

Category	Competency
6B	Class 1.5 whole current or CT connected Wh *meters* with 0.3</cosΦ% uncertainty.

S7.2.3 Capabilities of Metering Providers for metering installations types 1, 2, 3, 4 and 4A

Category 1A, 2A, 3A and 4M *Metering Providers* must be able to exhibit the following capabilities to the reasonable satisfaction of *AEMO*:

(a) Detailed design and specification of *metering* schemes, including:

(1) knowledge and understanding of this Chapter 7;

(2) knowledge of equipment (*meters*, *current transformers* and where applicable *voltage transformers*);

(3) design experience including knowledge of *current transformers* and where applicable *voltage transformers* and the effect of burdens on performance;

(4) ability to calculate summation scheme values, multipliers, etc; and

(5) ability to produce documentation, such as single line diagrams, panel layouts and wiring diagrams.

(b) Programming and certification requirements for *metering installations* to the required accuracy, including:

(1) licensed access to *metering* software applicable to all equipment being installed by the *Metering Provider*;

(2) ability to program requirements by setting variables in *meters*, summators, modems, etc;

(3) management of the testing of all equipment to the accuracy requirements specified in this Chapter 7;

(4) certifications that all calibration and other *meter* parameters have been set, verified and recorded prior to *meters*, and other components of the *metering installation* being released for installation;

(5) all reference/calibration equipment for the purpose of meeting test or inspection obligations must be tested to ensure full traceability to test certificates issued by a *NATA* accredited body or a body recognised by *NATA* under the International

Laboratory Accreditation Corporation (**ILAC**) mutual recognition scheme and documentation of the traceability must be provided to *AEMO* on request; and

(6) compliance with ISO/IEC Guide 25 "General Requirements for the Competence of Calibration and Testing Laboratories" with regard to the calculation of uncertainties and accuracy.

(c) Installation and commissioning of *metering installations* and, where necessary, the *communications interface* to facilitate the *remote acquisition* of *metering data*, including:

(1) the use of calibrated test equipment to perform primary injection tests and field accuracy tests;

(2) the availability of trained and competent staff to install and test *metering installations* to determine that installation is correct; and

(3) the use of test procedures to confirm that the *metering installation* is correct and that *metering* constants are recorded and/or programmed correctly.

(d) Inspection and maintenance of *metering installations* and equipment, including:

(1) regular readings of the measurement device where external recording is used (6 monthly) and verification with *AEMO* records;

(2) approved test and inspection procedures to perform appropriate tests as detailed in this Chapter 7;

(3) calibrated field test equipment for primary injection and *meter* testing to the required levels of uncertainty; and

(4) secure documentation system to maintain *metering* records for all work performed on a *metering installation*, including details of the security method used.

(e) Verification of *metering data* and *check metering data*, as follows:

(1) on commissioning *metering data*, verification of all readings, constraints (adjustments) and multipliers to be used for converting raw data to consumption data; and

(2) on inspection, testing and/or maintenance, verification that readings, constants and multipliers are correct by direct conversion of *meter* readings and check against the *metering database*.

(f) Quality System as AS 9000 series standards, including:

(1) a quality system to AS/NZ ISO 9000 series applicable to the work to be performed:

Type 1 full implementation of AS/NZ ISO 9002;

Type 2 full implementation of AS/NZ ISO 9002;

Type 3 – implementation of AS/NZ ISO 9002 to a level agreed with *AEMO*;

Type 4 implementation of AS/NZ ISO 9002 to a level agreed with *AEMO*;

Type 4A – implementation of AS/NZ ISO 9002 to a level agreed with *AEMO*;

(2) the calculations of accuracy based on test results are to include all reference standard errors;

(3) an estimate of Testing Uncertainties which must be calculated in accordance with the ISO "Guide to the Expression of Uncertainty in Measurement"; and

(4) a knowledge and understanding of the appropriate standards and guides, including those in the *Rules*.

(g) All of the capabilities relevant to that type of *metering installation* which are set out in the *Rules* and procedures authorised under the *Rules*.

S7.2.4 Capabilities of Metering Providers for metering installations types 5 and 6

Metering Providers, who apply for categories of *Metering Provider* accreditation of *metering installations* types 5 and/or 6, must be able to exhibit, to the reasonable satisfaction of *AEMO* all of the capabilities relevant to that type of *metering installation* which are set out in the *Rules* and procedures authorised under the *Rules*.

S7.2.5 Capabilities of Metering Providers for small customer metering installations

Category 4S *Metering Providers* must be able to exhibit, to the reasonable satisfaction of *AEMO*:

(a) all of the capabilities in S7.2.3; and

(b) the establishment of an appropriate security control management plan and associated infrastructure and communications systems for the purposes of preventing unauthorised local access or remote access to *metering installations*, services provided by *metering installations* and *energy data* held in *metering installations*.

S7.2.6 Capabilities of the Accredited Service Provider category

(a) The *Accredited Service Providers categories* established by *AEMO* under clause S7.2.2(d) may perform work relating to the installation of any types 1, 2, 3, 4, 4A, 5 or 6 *metering installations*.

(b) *AEMO* must include *Accredited Service Provider categories* in the accreditation guidelines prepared and *published* under clause 7.4.1(c).

(c) *AEMO* may determine:

(1) the competencies of a *Metering Provider* registered in each *Accredited Service Provider category* provided that those competencies are consistent with any capabilities established in the *metrology procedure* in respect of the work performed under paragraph (a); and

(2) different competencies for each *Accredited Service Provider category* for each *participating jurisdiction*.

Schedule 7.3 Metering Data Provider

S7.3.1 General

(a) A *Metering Data Provider* must be accredited by and registered by *AEMO*.

(b) *AEMO* must accredit and register a *Metering Data Provider* only for the type of work the *Metering Data Provider* is qualified to provide.

(c) *AEMO* must establish a qualification process for *Metering Data Providers* that enables registration to be achieved in accordance with the requirements of this Schedule 7.3.

S7.3.2 Categories of registration

Categories of registration are set out in Table S7.3.2.1.

Table S7.3.2.1 Categories of registration for accreditation

***Metering installation* type**	**Categories of registration**	
1, 2 3 and/or 4	Category 1D, 2D, 3D and/or 4D (for *remote acquisition*, processing and delivery of	Category 4S (for *small customer metering installations* in relation to *remote acquisition*,

***Metering installation* type**	**Categories of registration**	
	metering data for *connection points*)	processing and delivery of *metering data* for *connection points*)
4A, 5 and/or 6	Category 4AC, 5C and/or 6C (for manual collection or *remote acquisition* of *metering data*)	Category 4AD, 5D and/or 6D (for manual collection, processing and delivery of *metering data* or for *remote acquisition*, processing and delivery of *metering data*)
7	Category 7D (for processing and delivery of *calculated metering data*)	

S7.3.3 Capabilities of Metering Data Providers

Metering Data Providers must be able to exhibit to the reasonable satisfaction of *AEMO* the following capabilities, as applicable, for the categories of *Metering Data Provider* accreditation sought:

(a) Detailed understanding of the *Rules*, and all procedures authorised under the *Rules* including the relevant *service level procedures* relating to the function of a *Metering Data Provider* and the carrying out of *metering data services*.

(b) Detailed understanding of the participant role relationships and obligations that exist between the *Metering Data Provider*, *Metering Provider*, *financially responsible Market Participant*, *Local Network Service Provider*, *AEMO* and the *Metering Coordinator*.

(c) An understanding of *metering* arrangements, including knowledge of *metering* equipment (*meters*, *current transformers* and *voltage transformers*).

(d) Authorised access to *metering* software for the:

(1) collection of *metering data*;

(2) establishment, maintenance and operation of a *metering data services database* for the storage and management of *metering data* and *NMI Standing Data*; and

(3) the validation, substitution and estimation of *metering data*.

(e) Processes and systems for the collection of *metering data* including:

(1) knowledge of manual collection and *remote acquisition* of *metering data* (as applicable);

(2) collection technologies and methodologies; and

(3) *metering* protocols and equipment.

(f) Systems for the processing of *metering data* including:

(1) processes for the verification and commissioning of *metering data* and relevant *NMI Standing Data* pertaining to each *metering installation* into the *metering data services database*;

(2) processes for validation, substitution and estimation of *metering data*;

(3) processes for the storage, adjustment and aggregation of *metering data*; and

(4) the secure storage of historical data.

(g) Processes for the delivery of *metering data* and relevant *NMI Standing Data* to *Registered Participants* and *AEMO* including:

(1) delivery performance requirements for *metering data*; and

(2) an understanding of the relevant *metering data* file formats.

(h) The availability of trained and competent staff to:

(1) read or interrogate the *metering installation*;

(2) collect and process *metering data* into the *metering data services database*;

(3) validate, substitute or estimate *metering data* as the case may be;

(4) maintain the physical and logical security of the *metering data services database* and only allow access to *metering data* by those persons entitled to receive *metering data*; and

(5) ensure the ongoing performance and availability of the collection process and the *metering data services database* are maintained inclusive of necessary system supports for backup, archiving and disaster recovery.

(i) The establishment of a quality system which will:

(1) underpin all operational documentation, processes and procedures;

(2) facilitate good change control management of procedures, IT systems and software;

(3) provide audit trail management of *metering data* and *NMI Standing Data*;

(4) maintain a security control management plan;

(5) maintain security controls and data integrity; and

(6) maintain knowledge and understanding of the *Rules* and relevant procedures, standards and guides authorised under the *Rules*.

(j) Understanding of the required logical interfaces necessary to support the provision of *metering data services* including the interfaces needed to:

(1) access *AEMO's* systems for the management and delivery of *metering data*;

(2) support *B2B procedures*; and

(3) support *Market Settlement and Transfer Solution Procedures* for delivery and update of *NMI Standing Data*.

S7.3.4 Capabilities of Metering Data Providers for small customer metering installations

Category 4S *Metering Data Providers* must be able to exhibit, to the reasonable satisfaction of *AEMO*:

(a) all the capabilities in S7.3.3; and

(b) the establishment of an appropriate security control management plan and associated infrastructure and communications systems for the purposes of preventing unauthorised local access or remote access to *metering installations*, services provided by *metering installations* and *energy data* held in *metering installations*.

Schedule 7.4 Types and Accuracy of Metering installations

S7.4.1 General requirements

(a) This Schedule 7.4 sets out the minimum requirements for *metering installations*.

S7.4.2 Metering installations commissioned prior to 13 December 1998

(a) This clause provides conditions that are to apply to *metering installations* that were commissioned prior to 13 December 1998.

(b) The use of *metering* class *current transformers* and *voltage transformers* that are not in accordance with Table S7.4.3.1 are permitted provided that where necessary to achieve the overall accuracy requirements:

(1) *meters* of a higher class accuracy are installed; and/or

(2) calibration factors are applied within the *meter* to compensate for *current transformer* and *voltage transformer* errors.

(c) Protection *current transformers* are acceptable where there are no suitable *metering* class *current transformers* available and the overall accuracy and performance levels can be met.

(d) Where the requirements of paragraph (b) and (c) cannot be achieved then the *Metering Coordinator* is required to comply with transitional arrangements or obtain an exemption from *AEMO* or upgrade the *metering installation* to comply with this Schedule 7.4.

(e) The arrangements referred to in paragraph (d) may remain in force while the required accuracy and performance can be maintained within the requirements of the *Rules*.

(f) The purchase of new *current transformers* and *voltage transformers* must comply with the *Rules*.

S7.4.3 Accuracy requirements for metering installations

Table S7.4.3.1 Overall Accuracy Requirements of Metering Installation Components

Type	Volume limit per annum per connection point	Maximum allowable overall error (±%) at full load (Item 6) active	reactive	Minimum acceptable class or standard of components	Metering installation clock error (seconds) in reference to EST
1	greater than 1000GWh	0.5	1.0	0.2CT/VT/*meter* Wh 0.5 *meter* varh	±5
2	100 to 1000GWh	1.0	2.0	0.5CT/VT/*meter* Wh	±7

Type	**Volume limit per annum per connection point**	**Maximum allowable overall error (±%) at full load (Item 6)** active	reactive	**Minimum acceptable class or standard of components**	**Metering installation clock error (seconds) in reference to EST**
				1.0 *meter* varh	
3	0.75 to less than 100 GWh	1.5	3.0	0.5CT/VT 1.0 *meter* Wh 2.0 *meter* varh (Item 1)	±10
4	less than 750 MWh (Item 2)	1.5	n/a	Either 0.5 CT and 1.0 *meter* Wh; or whole current general purpose *meter* Wh: • meets requirements of clause 7.8.2(a)(9); and • meets the requirements of clause 7.10.7(a). (Item 1)	±20 (Item 2a)
4A	less than x MWh Item 3	1.5	3.0	Either 0.5 CT and 1.0 *meter* Wh; or whole current general purpose *meter* Wh: • meets the requirements of clause 7.8.2(a)(10); and • has the capability, if remote access is activated, of providing the	±20 (Item 2a)

Type	Volume limit per annum per connection point	Maximum allowable overall error (±%) at full load (Item 6) active	reactive	Minimum acceptable class or standard of components	Metering installation clock error (seconds) in reference to EST
				services in table S7.5.1.1; and • meets the requirements of clause 7.10.7(d).	
5	less than x MWh (Item 3)	1.5 (Item 3b)	n/a	Either 0.5 CT and 1.0 meter Wh; or whole current connected general purpose meter wh: • meets requirements of clause 7.8.2(a)(10); and • meets the requirements of clause 7.10.7(d). (Item 1)	'±/-20' (Item 3a)
6	less than y MWh (Item 4)	2.0 (Item 4b)	n/a	CT or whole current general purpose *meter* Wh recording *accumulated energy data* only. Processes used to convert the *accumulated metering data* into *trading interval metering data* and *estimated metering data* where necessary are included in the *metrology procedure*. (Item 1)	(Item 4a)
7	volume limit not	(Item	n/a	No *meter*. The	n/a

Type	Volume limit per annum per connection point	Maximum allowable overall error (±%) at full load (Item 6) active	reactive	Minimum acceptable class or standard of components	Metering installation clock error (seconds) in reference to EST
	specified (Item 5)	6)		*metering data* is *calculated metering data* determined in accordance with the *metrology procedure*.	

Item 1: (a) For a type 3, 4, 4A and 5 and 6 *metering installation*, whole current *meters* may be used if the *meters* meet the requirements of the relevant *Australian Standards* and International Standards which must be identified in the *metrology procedure*.

(b) The *metering installation* types referred to in paragraph (a) must comply with any applicable specifications or guidelines (including any transitional arrangements) specified by the National Measurement Institute under the *National Measurement Act*.

Item 2: *High voltage* customers that require a VT and whose annual consumption is below 750 MWh, must meet the relevant accuracy requirements of Type 3 *metering* for *active energy* only.

Item 2a: For the purpose of clarification, the clock error for a type 4 and 4A *metering installation* may be relaxed in the *metrology procedure* to accommodate evolving whole current technologies.

Item 3: The following requirements apply in relation to a type 4A and type 5 *metering installation*:

(1) the value of "x" must be determined by each *Minister* of a *participating jurisdiction* and:

(i) the "x" value must be provided to *AEMO*; and

(ii) *AEMO* must record the "x" value in the *metrology procedure*;

(2) the maximum acceptable value of “x” determined under subparagraph (1) must be 750 MWh per annum; and

Item 3a: For the purpose of clarification, the clock error for a type 5 *metering installation* may be relaxed in the *metrology procedure* to accommodate evolving whole current technologies.

Item 3b: The maximum allowable error of a type 5 *metering installation* may be relaxed in the *metrology procedure* to accommodate evolving technologies providing that such relaxation is consistent with any regulations published under the *National Measurement Act.*

Item 4: The following requirements apply in relation to a type 6 *metering installation*:

(1) a *metrology procedure* must include a procedure relating to converting *active energy* into *metering data*;

(2) the value of "y" must be determined by each *Minister* of a *participating jurisdiction* and:

(i) the "y" value must be provided to *AEMO*; and

(ii) *AEMO* must record the "y" value in the *metrology procedure*;

(3) the maximum acceptable value of “y” determined under subparagraph (2) must be 750 MWh per annum;

(4) devices within the *metering installation* may record *accumulated energy data* in pre determined daily time periods where such time periods are contained in the *metrology procedure*.

Item 4a: Any relevant clock errors for a type 6 *metering installation* are to be established in the *metrology procedure*.

Item 4b: The maximum allowable error of a type 6 *metering installation* may be relaxed in the *metrology procedure* providing that such relaxation is consistent with any regulations *published* under the *National Measurement Act*.

Item 5: (a) A type 7 *metering installation* classification applies where a *metering installation* does not require a *meter* to measure the flow of electricity in a power conductor and accordingly there is a requirement to determine by other means the *metering data* that is deemed to correspond to the flow of electricity in the power conductor.

(b) The condition referred to in paragraph (a) will only be allowed for *connection points* where *AEMO* in consultation with the *Metering Coordinator* determines:

(1) the *load* pattern is predictable;

(2) for the purposes of *settlements*, the *load* pattern can be reasonably calculated by a relevant method set out in the

metrology procedure; and

(3) it would not be cost effective to meter the *connection point* taking into account:

(i) the small magnitude of the *load*;

(ii) the *connection* arrangements; and

(iii) the geographical and physical location.

(c) The *metrology procedure* must include arrangements for type 7 *metering installations* that have been classified as *market loads*.

(d) A *connection point* that meets the condition for classification as a type 7 *metering installation* does not prevent that *connection point* from being subject to *metering* in the future.

Item 6: The maximum allowable overall error (±%) at different *loads* and *power factors* is set out in Table S7.4.3.2 to Table S7.4.3.6.

Table S7.4.3.2 Type 1 Installation – Annual Energy Throughput greater than 1,000 GWh

% Rated Load	Power Factor					
	Unity	0.866 lagging		0.5 lagging		Zero
	active	active	reactive	active	reactive	reactive
10	1.0%	1.0%	2.0%	n/a	n/a	1.4%
50	0.5%	0.5%	1.0%	0.7%	1.4%	1.0%
100	0.5%	0.5%	1.0%	n/a	n/a	1.0%

Table S7.4.3.3 Type 2 Installation – Annual Energy Throughput between 100 and 1,000 GWh

% Rated Load	Power Factor					
	Unity	0.866 lagging		0.5 lagging		Zero
	active	active	reactive	active	reactive	reactive
10	2.0%	2.0%	4.0%	n/a	n/a	2.8%
50	1.0%	1.0%	2.0%	1.5%	3.0%	2.0%
100	1.0%	1.0%	2.0%	n/a	n/a	2.0%

Table S7.4.3.4 Type 3 Installation – Annual Energy Throughput from 0.75 GWh to less than 100 GWh and Type 4A Installation - Annual Energy Throughput less than 0.75 GWh

% Rated Load	Power Factor					
	Unity	0.866 lagging		0.5 lagging		Zero
	active	active	reactive	active	reactive	reactive
10	2.5%	2.5%	5.0%	n/a	n/a	4.0%
50	1.5%	1.5%	3.0%	2.5%	5.0%	3.0%
100	1.5%	1.5%	3.0%	n/a	n/a	3.0%

Table S7.4.3.5 Type 4 or 5 Installation – Annual Energy Throughput less than 0.75 GWh

% Rated Load	Power Factor		
	Unity	0.866 lagging	0.5 lagging
	active	active	active
10	2.5%	2.5%	n/a
50	1.5%	1.5%	2.5%
100	1.5%	1.5%	n/a

Table S7.4.3.6 Type 6 Installation – Annual Energy Throughput less than 0.75 GWh

% Rated Load	Power Factor		
	Unity	0.866 lagging	0.5 lagging
	active	active	active
10	3.0%	n/a	n/a
50	2.0%	n/a	3.0%
100	2.0%	n/a	n/a

Note:

All measurements in Tables S7.4.3.2 – S7.4.3.6 are to be referred to 25 degrees Celsius.

(a) The method for 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 the *voltage transformer* and wiring;

b = the error of the *current transformer* and wiring; and

c = the error of the *meter*.

(b) If compensation is carried out then the resultant *metering data* error shall be as close as practicable to zero.

S7.4.4 Check metering

(a) *Check metering* is to be applied in accordance with the following Table:

Metering Installation Type in accordance with Table S7.2.3.1	Check Metering Requirements
1	*Check metering installation*
2	Partial *check metering*
3	No requirement
4, 4A, 5 and 6	No requirement

(b) A *check metering installation* involves either:

(1) the provision of a separate *metering installation* using separate *current transformer* cores and separately fused *voltage transformer* secondary circuits, preferably from separate secondary windings: or

(2) if in *AEMO's* absolute discretion it is considered appropriate, in the case of a *metering installation* located at the *facility* at one end of the *two-terminal link*, a *metering installation* located at the *facility* at the other end of a *two-terminal link*.

(c) Where the *check metering installation* duplicates the *metering installation* and accuracy level, the average of the two validated data sets will be used to determine the *energy* measurement.

(d) Partial *check metering* involves the use of other *metering data* or operational data available to *AEMO* in 30 min electronic format as part of a validation process in accordance with the *metrology procedure*.

(e) The physical arrangement of partial *check metering* shall be agreed between the *Metering Coordinator* and *AEMO*.

(f) *Check metering installations* may be supplied from secondary circuits used for other purposes and may have a lower level of accuracy than the *metering installation*, but must not exceed twice the level prescribed for the *metering installation*.

S7.4.5 Resolution and accuracy of displayed or captured data

Programmable settings available within a *metering installation* or any peripheral device, which may affect the resolution of displayed or stored data, must:

(a) meet the requirements of the relevant *Australian Standards* and International Standards which must be identified in the *metrology procedure*; and

(b) comply with any applicable specifications or guidelines (including any transitional arrangements) specified by the National Measurement Institute under the *National Measurement Act*.

S7.4.6 General design standards

S7.4.6.1 Design requirements

Without limiting the scope of detailed design, the following requirements must be incorporated in the design of each *metering installation*:

(a) For *metering installations* greater than 1000 GWh pa per *connection point*, the *current transformer* core and secondary wiring associated with the *meter*(s) shall not be used for any other purpose unless otherwise agreed by *AEMO*.

(b) For *metering installations* less than 1000 GWh pa per *connection point* the *current transformer* core and secondary wiring associated with the *meter*(s) may be used for other purposes (e.g. local *metering* or protection) provided the *Metering Coordinator* demonstrates to the satisfaction of *AEMO* that the accuracy of the *metering installation* is not compromised and suitable procedures/measures are in place to protect the security of the *metering installation*.

(c) Where a *voltage transformer* is required, 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.

(d) Secondary wiring must be by the most direct route and the number of terminations and links must be kept to a minimum.

(e) The incidence and magnitude of burden changes on any secondary winding supplying the *metering installation* must be kept to a minimum.

(f) *Meters* must:

(1) meet the requirements of relevant *Australian Standards* and International Standards which must be identified in the *metrology procedure*; and

(2) have a valid pattern approval issued under the authority of the National Measurement Institute or, until relevant pattern approvals exist, a valid type test certificate.

(g) New *instrument transformers* must:

(1) meet the requirements of relevant *Australian Standards* and International Standards which must be identified in the *metrology procedure*; and

(2) have a valid pattern approval issued under the authority of the National Measurement Institute or, until relevant pattern approvals exist, a valid type test certificate.

(h) Suitable *isolation* facilities are to be provided to facilitate testing and calibration of the *metering installation*.

(i) Suitable drawings and supporting information, detailing the *metering installation*, must be available for maintenance and auditing purposes.

S7.4.6.2 Design guidelines

In addition to the above design requirements, the following guidelines should be considered for each *metering installation*:

(a) The provision of separate secondary windings for each *metering installation* where a *voltage transformer* is required.

(b) A *voltage* changeover scheme where more than one *voltage transformer* is available.

Schedule 7.5 Requirements of minimum services specification

S7.5.1 Minimum services specification

A *metering installation* meets the *minimum services specification* if it:

(a) subject to paragraph (d), is capable of providing the services listed in table S7.5.1.1 in accordance with the procedures made under clause 7.8.3;

(b) is connected to a *telecommunications network* which enables remote access to the *metering installation*;

(c) achieves the maximum allowable overall error (±%) at rates not exceeding the rates set out in table S7.4.3.4; and

(d) in relation to a *metering installation* that is connected to a *current transformer*, is capable of providing the services listed in items (c) to (f) in table S7.5.1.1 in accordance with procedures made under clause 7.8.3.

Table S7.5.1.1 Minimum Services Specification – services and access parties

1. Service	2. Description	3. Access Party
(a) remote *disconnection* service	The remote *disconnection* of a *small customer's* premises via the *metering installation*.	*Local Network Service Provider* *financially responsible Market Participant*
(b) remote *reconnection* service	The remote *reconnection* of a *small customer's* premises via the *metering installation*.	*Local Network Service Provider* *financially responsible Market Participant* *Incoming Retailer*
(c) remote on-demand *meter* read service	The remote retrieval of *metering data* including quality flags for a specified point or points in time and the provision of such data to the requesting party. The service includes the retrieval and provision of: • *reactive energy metering data* and/or *active energy metering data* (for imports and/or exports of *energy* measured by the *meter*);	*Registered Participants* with a financial interest in the *metering installation* or the *energy* measured by that *metering installation* A person to whom a *small customer* has given its consent under clause 7.15.4(b)(3)(ii)

1. Service	2. Description	3. Access Party
	• *interval metering data* and cumulative total *energy* measurement for the *metering installation*; and • *accumulated metering data* at the start and the end of the period specified in the request.	
(d) remote scheduled *meter* read service	The remote retrieval of *metering data* including quality flags on a regular and ongoing basis and the provision of such data to the requesting party. The service includes the retrieval and provision of: • *reactive energy metering data* and/or *active energy metering data* (for imports and/or exports of *energy* measured by the *meter*); • *interval metering data* and cumulative total *energy* measurement for the *metering installation*; and • *accumulated metering data* at the start and the end of the period specified in the request.	*Registered Participants* with a financial interest in the *metering installation* or the *energy* measured by that *metering installation* A person to whom a *small customer* has given its consent under clause 7.15.4(b)(3)(ii)
(e) *metering installation* inquiry service	The remote retrieval of information from, and related to, a specified	*Local Network Service Provider*

1. Service	2. Description	3. Access Party
	metering installation and the provision of such information to the requesting party. The *metering installation* must be capable of providing the following information, as a minimum, when requested: • the status of the switch used to effect the *disconnection* and *reconnection* services; • the *voltage* as measured by the *metering installation*, with a date and *time stamp* for that reading; • the current as measured by the *metering installation*, with a date and *time stamp* for that reading; • the power (watts) as measured by the *metering installation*, with a date and *time stamp* for that reading; • the supply frequency (Hertz) as measured by the *metering installation*, with a date and *time stamp* for that reading; • the average *voltage* and current over a nominated *trading interval* for one or more nominated	*financially responsible Market Participant* A person to whom a *small customer* has given its consent under clause 7.15.4(b)(3)(ii)

1. Service	2. Description	3. Access Party
	trading intervals; and • events that have been recorded in *meter* log (or logs) including recorded information in the tamper detection alarm, reverse energy flow alarm and *metering* device temperature alarm.	
(f) advanced *meter* reconfiguration service	The remote setting of the operational parameters of the *meter*. The operational parameters that must be capable of being set are, as a minimum, the following: • the activation or deactivation of a data stream or data streams; and • altering the method of presenting *energy data* and associated information on the *meter* display.	*Local Network Service Provider* *financially responsible Market Participant*

Schedule 7.6 Inspection and Testing Requirements

S7.6.1 General

(a) The *Metering Coordinator* must ensure that equipment comprised in a purchased *metering installation* has been tested to the required class accuracy with less than the uncertainties set out in Table S7.6.1.1.

(b) The *Metering Coordinator* must ensure appropriate test certificates of the tests referred to in paragraph (a) are retained.

(c) The *Metering Coordinator* (or any other person arranging for testing) must ensure that testing of the *metering installation* is carried out:

(1) in accordance with clause 7.9.1 and this Schedule 7.6; or

(2) in accordance with an asset management strategy that defines an alternative testing practice (other than time based) determined by the *Metering Coordinator* and approved by *AEMO*,

and:

(3) in accordance with a test plan which has been registered with *AEMO*;

(4) to the same requirements as for new equipment where equipment is to be recycled for use in another site; and

(5) so as to include all data storage and processing components included in the *metrology procedure*, including algorithms used to prepare agreed *load* patterns.

(d) *AEMO* must review the prescribed testing requirements in this Schedule 7.6 every 5 years in accordance with equipment performance and industry standards.

(e) The testing intervals may be increased if the equipment type/experience proves favourable.

(f) The maximum allowable level of testing uncertainty (±) for all *metering* equipment must be in accordance with Table S7.6.1.1.

Table S7.6.1.1 Maximum Allowable Level of Testing Uncertainty (±)

Description		Metering Equipment Class				
		Class 0.2	Class 0.5	Class 1.0	General Purpose	Class 2.0
In Laboratory	CTs ratio phase	0.05% 0.07 crad	0.1% 0.15 crad	n/a	n/a	n/a
	VTs ratio Phase	0.05% 0.05 crad	0.1% 0.1 crad	n/a	n/a	n/a
	Meters Wh	0.05/cosφ %	0.1/cosφ%	0.2/cosφ%	0.2/cosφ%	n/a
	Meters	n/a	0.2/sinφ%	0.3/sinφ%	n/a	0.4/sinφ%

<table>
<tr><th colspan="2" rowspan="2">Description</th><th colspan="5">Metering Equipment Class</th></tr>
<tr><th>Class 0.2</th><th>Class 0.5</th><th>Class 1.0</th><th>General Purpose</th><th>Class 2.0</th></tr>
<tr><td></td><td>varh</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td rowspan="4">In Field</td><td>CTs ratio
Phase</td><td>0.1%
0.15 crad</td><td>0.2%
0.3 crad</td><td>n/a</td><td>n/a</td><td>n/a</td></tr>
<tr><td>VTs ratio
Phase</td><td>0.1%
0.1 crad</td><td>0.2%
0.2 crad</td><td>n/a</td><td>n/a</td><td>n/a</td></tr>
<tr><td>Meters Wh</td><td>0.1/cosφ%</td><td>0.2/cosφ%</td><td>0.3/cosφ%</td><td>0.3/cosφ%</td><td>n/a</td></tr>
<tr><td>Meters varh</td><td>n/a</td><td>0.3/sinφ%</td><td>0.4/sinφ%</td><td>n/a</td><td>0.5/sinφ%</td></tr>
</table>

Where cosφ is the *power factor* at the test point under evaluation.

Table S7.6.1.2 Maximum Period Between Tests

Unless the *Metering Coordinator* has developed an asset management strategy that defines practices that meet the intent of this Schedule 7.6 and is approved by *AEMO*, the maximum period between tests must be in accordance with this Table S7.6.1.2.

<table>
<tr><th rowspan="2">Description</th><th colspan="5">Metering Installation Type</th></tr>
<tr><th>Type 1</th><th>Type 2</th><th>Type 3</th><th>Type 4 & 4A</th><th>Types 5 & 6</th></tr>
<tr><td>CT</td><td>10 years</td><td>10 years</td><td>10 years</td><td>10 years</td><td>10 years</td></tr>
<tr><td>VT</td><td>10 years</td><td>10 years</td><td>10 years</td><td></td><td>n/a</td></tr>
<tr><td>Burden tests</td><td colspan="5">When meters are tested or when changes are made</td></tr>
<tr><td>CT connected Meter (electronic)</td><td>5 years</td><td>5 years</td><td>5 years</td><td>5 years</td><td>5 years</td></tr>
<tr><td>CT connected Meter (induction)</td><td>2.5 years</td><td>2.5 years</td><td>5 years</td><td>5 years</td><td>5 years</td></tr>
<tr><td>Whole current Meter</td><td colspan="5">The testing and inspection requirements must be in accordance with an asset management strategy. Guidelines for the development of the asset management strategy must be recorded in the metrology</td></tr>
</table>

Description	Metering Installation Type				
	Type 1	Type 2	Type 3	Type 4 & 4A	Types 5 & 6
	procedure.				

Table S7.6.1.3 Period Between Inspections

Unless the *Metering Coordinator* has developed an asset management strategy that meets the intent of this Schedule 7.6 and is approved by *AEMO*, the period between inspections must be in accordance with this Table S7.6.1.3.

Description	Metering Installation Type			
	Type 1	Type 2	Type 3	Type 4, 4A, 5 & 6
Metering installation equipment inspection	2.5 years	12 months (2.5 years if *check metering* installed)	> 10 GWh: 2 years 2≤ GWh ≤ 10: 3 years <2 GWh: when *meter* is tested.	When *meter* is tested.

S7.6.2 Technical Guidelines

(a) *Current transformer* and *voltage transformer* tests are primary injection tests or other testing procedures as approved by *AEMO*.

(b) The calculations of accuracy based on test results are to include all reference standard errors.

(c) An “estimate of testing uncertainties” must be calculated in accordance with the ISO “Guide to the Expression of Uncertainty for Measurement”.

(d) Where operational *metering* is associated with *settlements metering* then a shorter period between inspections is recommended.

(e) For sinφ and cosφ refer to the ISO “Guide to the Expression of Uncertainty in Measurement”, where cosφ is the *power factor*.

(f) A typical inspection may include:

(1) check the seals;

(2) compare the pulse counts;

(3) compare the direct readings of *meters*;

(4) verify *meter* parameters and physical connections; and

(5) *current transformer* ratios by comparison.

Schedule 4 Amendment to the National Electricity Rules

(Clause 6)

[1] Chapter 10 Omitted Definitions

Omit the definition of "***unmetered connection point***".

[2] Chapter 10 Substituted Definitions

In Chapter 10, substitute the following definitions:

Accredited Service Provider category

A category of registration of a *Metering Provider* established by *AEMO* under S7.2.2(b) as a consequence of requirements of a *participating jurisdiction* to install *metering installations*.

check meter

An additional *meter* used as a source of *check metering data* for Type 1 and Type 2 *metering installations* as specified in schedule 7.4.

communications interface

The modem and other devices and processes that facilitate the connection between the *metering installation* and the *telecommunications network* for the purpose of the *remote acquisition* of *energy data*.

Information Exchange Committee

The committee established under clause 7.17.2(a).

interested party

(a) In Chapter 5, a person including an end user or its *representative* who, in *AEMO's* opinion, has or identifies itself to *AEMO* as having an interest in relation to the *network* planning and development activities covered under Part B of Chapter 5 or in the determination of *plant standards* covered under clause 5.3.3(b2).

(b) Despite the definition in (a) above, in clauses 5.16.4, 5.16.5, 5.17.4 and 5.17.5, the meaning given to it in clause 5.15.1.

(c) In Chapter 6 or Chapter 6A, a person (not being a *Registered Participant* or *AEMO*) that has, in the *AER's* opinion, or identifies itself to the *AER* as having, an interest in the *Transmission Ring-Fencing Guidelines* or the *Distribution Ring-Fencing Guidelines*.

(d) In Chapter 2, a person including an end user or its *representative* who, in *AEMO's* opinion, has or identifies itself to *AEMO* as having an interest in relation to the structure of *Participant fees*.

(e) In Chapter 7, a person that has, in *AEMO's* opinion, or identifies itself to *AEMO* as having, an interest in the relevant procedure in Chapter 7.

jurisdictional metrology material

Jurisdictional metrology matters that are to be included in the *metrology procedure* for one or more of the *participating jurisdictions* and which is submitted by the *Ministers* of *the MCE* to *AEMO* under clause 7.16.4.

Market Settlement and Transfer Solution Procedures

The procedures from time to time *published* by *AEMO* under clause 7.16.2 which include those governing the recording of financial responsibility for *energy* flows at a *connection point*, the transfer of that responsibility between *Market Participants* and the recording of *energy* flows at a *connection point*.

Metering Data Provider

A person who meets the requirements listed in schedule 7.3 and has been accredited and registered by *AEMO* as a *Metering Data Provider*.

metering data provision procedures

Procedures for the provision of *metering data* requested under rule 7.14, developed and *published* by *AEMO*.

metering data services database

The database established and maintained by the *Metering Data Provider* that holds *metering data* and relevant *NMI Standing Data* relating to each *metering installation* for which the *Metering Coordinator* or the *financially responsible Market Participant* or *AEMO* (as the case may be) has engaged the *Metering Data Provider* to provide *metering data services*.

metering database

A database of *metering data* and *settlements ready data* maintained and administered by *AEMO* in accordance with clause 7.11.

metering installation

The assembly of components including the *instrument transformer*, if any, measurement element(s) and processes, if any, recording and display equipment, *communications interface*, if any, that are controlled for the purpose of metrology and which lie between the *metering point(s)* and the point at or near the *metering point(s)* where the *energy data* is made available for collection.

Note:

(1) The assembly of components may include the combination of several *metering points* to derive the *metering data* for a *connection point*.

(2) The *metering installation* must be classified as being for revenue purposes and/or as a *check metering installation*.

metering installation malfunction

The full or partial failure of the *metering installation* in which the *metering installation* does not:

(a) meet the requirements of schedule 7.4; or

(b) record, or incorrectly records, *energy data*; or

(c) allow, or provides for, collection of *energy data*; or

(d) in the case of a *small customer metering installation*, meet the requirements of schedule 7.5.

Metering Provider

A person who meets the requirements listed in schedule 7.2 and has been accredited by and registered by *AEMO* as a *Metering Provider*.

metering register

A register of information associated with a *metering installation* as required by schedule 7.1.

metering system

The collection of all components and arrangements installed or existing between each *metering point* and the *metering database*.

metrology procedure

The procedure developed and *published* by *AEMO* in accordance with rule 7.16.

NMI

A National Metering Identifier as described in clause 7.8.2(c).

Registered Participant

A person who is registered by *AEMO* in any one or more of the categories listed in rules 2.2 to 2.7. However:

(a) in the case of a person who is registered by *AEMO* as a *Trader*, such a person is only a *Registered Participant* for the purposes referred to in rule 2.5A;

(b) in the case of a person who is registered by *AEMO* as a *Metering Coordinator*, such a person is only a *Registered Participant* for the purposes referred to in rule 2.4A.1(d);

(c) as set out in clause 8.2.1(a1), for the purposes of some provisions of rule 8.2 only, *AEMO*, *Connection Applicants*, *Metering Providers* and *Metering Data Providers* who are not otherwise *Registered Participants* are also deemed to be *Registered Participants*; and

(d) as set out in clause 8.6.1A, for the purposes of Part C of Chapter 8 only, *Metering Providers* and *Metering Data Providers* who are not otherwise *Registered Participants* are also deemed to be *Registered Participants*.

remote acquisition

The acquisition of *interval metering data* from a *telecommunications network* connected to a *metering installation* that:

(a) does not, at any time, require the presence of a person at, or near, the interval *metering installation* for the purposes of data collection or data verification (whether this occurs manually as a walk-by reading or through the use of a vehicle as a close proximity drive-by reading); and

(b) includes but is not limited to methods that transmit data via:

(1) fixed-line telephone (‘direct dial-up’);

(2) satellite;

(3) the internet;

(4) wireless or radio, including mobile telephone networks;

(5) power line carrier; or

(6) any other equivalent technology.

Note:

For the requirements of clause 7.8.9(b) *remote acquisition* may collect data other than *interval metering data*.

responsible person

For the purposes of the *National Energy Retail Law*, the *Metering Coordinator*.

Note:

References to 'responsible person' in the *Rules* or a document produced under the *Rules* are deemed to be references to the *Metering Coordinator* under clause 11.86.4.

retail customer

A *small customer* or a *large customer*.

Note:

In the context of Chapter 5A, the above definition has been supplemented by a definition specifically applicable to that Chapter, See clause 5A.A.1.

service level procedures

The procedures established by *AEMO* in accordance with clause 7.16.6.

telecommunications network

A telecommunications network that provides access for public use or an alternate telecommunications network that has been approved by *AEMO* for the *remote acquisition* of *energy data*.

[3] Chapter 10 New Definitions

In Chapter 10, insert the following new definitions in alphabetical order:

access party

In respect of a service that is listed in column 1 of Table S7.5.1.1, the party listed in column 3 of Table S7.5.1.1.

emergency priority procedures

The procedures developed and *published* by *AEMO* in accordance with clause 7.8.5(b).

Incoming Retailer

A *retailer* that:

(a) has a contract with a customer at a *connection point*; and

(b) has initiated the customer transfer process in accordance with the *Market Settlement and Transfer Solution Procedures*,

but which is not yet designated the *financially responsible Market Participant* for that *connection point*.

meter churn procedures

The procedures established by *AEMO* under clause 7.8.9(f).

Metering Coordinator default event

In relation to a *Metering Coordinator*, means any of the following events or circumstances:

(a) the *Metering Coordinator* ceases to be registered by *AEMO* as a *Metering Coordinator* under Chapter 2;

(b) an *insolvency official* is appointed in respect of the *Metering Coordinator* or any property of the *Metering Coordinator*; or

(c) an order is made for the winding up of the *Metering Coordinator* or a resolution is passed for the winding up of *Metering Coordinator*; or

(d) a breach of the *Rules* or applicable procedures made under the *Rules* in relation to which *AEMO* has issued a *Metering Coordinator default notice* under clause 7.7.3(c)(3).

Metering Coordinator default notice

A notice issued by *AEMO* under clause 7.7.3(c)(3).

minimum services specification

The requirements in respect of a *metering installation* set out in Schedule 7.5.

network device

Apparatus or equipment that:

(a) enables a *Local Network Service Provider* to monitor, operate or control the *network* for the purposes of providing *network services*, which may include switching devices, measurement equipment and control equipment; and

(b) is located at or adjacent to a *metering installation* at the *connection point* of a *retail customer*.

reconnect, reconnected, reconnection

The operation of switching equipment or other action so as to enable the flow of electricity at a *connection point* following a *disconnection*.

retailer planned interruption

(a) In a *participating jurisdiction* where the *National Energy Retail Rules* apply as a law of that *participating jurisdiction*, has the meaning given in the *National Energy Retail Rules*.

(b) Otherwise, if defined in *jurisdictional electricity legislation*, has the meaning given in *jurisdictional electricity legislation*.

small customer

(a) In a *participating jurisdiction* where the *National Energy Retail Law* applies as a law of that *participating jurisdiction*, has the meaning given in the *National Energy Retail Law*.

(b) Otherwise, has the meaning given in *jurisdictional electricity legislation*.

small customer metering installation

A *metering installation* in respect of the *connection point* of a *small customer* which meets the *minimum services specification* or which is required to meet the *minimum services specification* under clause 7.8.3(a), clause 7.8.4(c) or clause 7.8.4(h)(2).

Schedule 5 Savings and Transitional Amendments to the National Electricity Rules

(Clause 7)

[1] Chapter 11 New Part ZZN

In Chapter 11, after Part ZZM, insert:

Part ZZN Expanding competition in metering and metering related services

11.86 Rules consequent on making of the National Electricity Amendment (Expanding competition in metering and related services) Rule 2015

11.86.1 Definitions

Subject to this rule 11.86, in this rule 11.86:

Amending Rule means the National Electricity Amendment (Expanding competition in metering and metering related services) Rule 2015.

effective date means 1 December 2017.

Initial Metering Coordinator means a *Local Network Service Provider* which is appointed as *Metering Coordinator* under clause 11.86.7(a) or deemed to be appointed as *Metering Coordinator* under paragraph 11.86.7(c).

old Chapter 7 means the Chapter 7 of the *Rules* as in force immediately before the effective date.

new Chapter 7 means the Chapter 7 of the *Rules* as in force immediately after the effective date.

new rule 2.4A means the new rule 2.4A of Chapter 2 of the *Rules* as in force immediately after the commencement of Schedule 1 of the Amending Rule and a reference to new clause 2.4A.1 or 2.4A.2 has a corresponding meaning.

11.86.2 References to old Chapter 7

Unless the context otherwise requires, on and from the effective date every reference to old Chapter 7 in the *Rules* or a document produced under the *Rules* is deemed to be a reference to the new Chapter 7.

11.86.3 References to provisions of the old Chapter 7

Unless the context otherwise requires, on and from the effective date every reference to a provision of the old Chapter 7 in the *Rules* or a document produced under the *Rules* is deemed to be a reference to the corresponding provision of the new Chapter 7 (if any).

11.86.4 References to responsible person

Unless the context otherwise requires, on and from the effective date every reference to a *responsible person* in the *Rules* or a document produced under the *Rules* is deemed to be a reference to a *Metering Coordinator*.

11.86.5 Continued operation of old Rules until the effective date

Subject to this rule 11.86, old Chapter 7:

(a) continues to apply until the effective date; and

(b) ceases to apply on and from the effective date.

11.86.6 New and amended procedures

(a) By 1 September 2016, *AEMO* must amend and *publish* the following procedures to take into account the Amending Rule:

(1) *service level procedures*;

(2) *Market Settlement and Transfer Solution Procedures*;

(3) *metrology procedure*;

(4) *meter churn procedures*; and

(5) *RoLR Procedures*.

(b) By 1 September 2016, *AEMO* must develop and *publish* the following procedures to take into account the Amending Rule:

(1) *emergency priority procedures*;

(2) procedures relating to the *minimum services specification* in accordance with clause 7.8.3(b) of new Chapter 7; and

(3) procedures relating to the installation and removal of *network devices* in accordance with clause 7.8.6(i) of new Chapter 7.

(c) *AEMO* in its complete discretion may amend:

(1) the *service level procedures* to make provision for the procedures listed in subparagraphs (b)(1) and b(2); and

(2) the *meter churn procedures* to make provision for the procedures listed in subparagraph (b)(3),

instead of developing new procedures.

(d) By 1 March 2017, *AEMO* must develop and *publish* information relating to the process by which persons can apply for registration as *Metering Coordinators* under new rule 2.4A to take into account the Amending Rule.

(e) The *Information Exchange Committee* must make an *Information Exchange Committee Recommendation* to change the *B2B Procedures* to take into account the Amending Rule by 1 August 2016.

(f) Subject to clause 7.2A.3(k) of old Chapter 7, *AEMO* must *publish B2B Procedures* to take into account the Amending Rule by 1 September 2016.

(g) By the date which is six months after the date on which *AEMO publishes* the information referred to in paragraph (d), *AEMO* must develop and *publish* a procedure relating to the issue of a *Metering Coordinator* default notice in accordance with clause 7.7.3(a) of new Chapter 7.

(h) *AEMO* must:

(1) comply with the *Rules consultation procedures* when meeting its obligations under paragraphs (a), (b) and (g); and

(2) for the purposes of the *Rules consultation procedures*, consult with any person that has, in *AEMO's* opinion, or identifies itself to *AEMO* as having, an interest in the relevant procedure listed in subparagraph (1).

11.86.7 Metering Coordinator for type 5 or 6 metering installation from effective date

(a) On and from the effective date, a *Local Network Service Provider* that was the *responsible person* for a type 5 or 6 *metering installation* connected to, or proposed to be connected to, the *Local Network Service Provider's network* under clause 7.2.3(a)(2) of old Chapter 7 or clause 9.9C.3 immediately before the effective date must be appointed as the *Metering Coordinator* by the *financially responsible Market Participant*.

(b) By no later than 1 September 2017, the *Local Network Service Provider* must provide each *financially responsible Market Participant* with a standard set of terms and conditions on which it will agree to act as the *Metering Coordinator* with respect to a type 5 or type 6 *metering installation* referred to in paragraph (a).

(c) Unless the *financially responsible Market Participant* and *Local Network Service Provider* agree other terms and conditions to apply to the *Local Network Service Provider's* appointment as the *Metering Coordinator* under paragraph (a) prior to the effective date, the *Local Network Service Provider* will be deemed to be appointed as the *Metering Coordinator* on the standard terms and conditions of appointment referred to in paragraph (b) on and from the effective date.

(d) The terms and conditions on which a *Local Network Service Provider* is appointed as *Metering Coordinator* under paragraph (a) or deemed to be appointed as *Metering Coordinator* under paragraph (c) must:

(1) include terms as to price which are consistent with Chapter 6 and, where relevant, Chapter 11;

(2) include a scope of services which is consistent with the responsibilities of the *Metering Coordinator* with respect to the *connection point* under new Chapter 7;

(3) provide that the *financially responsible Market Participant* may terminate the appointment or deemed appointment on reasonable notice to the *Metering Coordinator*;

(4) require the *Local Network Service Provider* promptly to notify the *financially responsible Market Participant* of a *metering installation malfunction* which occurs to a *metering installation* other than the installations referred to in clause 7.8.10(a)(1) of new Chapter 7;

(5) require the *financially responsible Market Participant* which receives a notice from the *Local Network Service Provider* under subparagraph (4) to promptly appoint a *Metering Coordinator*; and

(6) subject to paragraph (e), must not prevent, hinder or otherwise impede a *financially responsible Market Participant* from appointing a person other than the *Local Network Service Provider* as *Metering Coordinator* on any day following the effective date.

(e) Subparagraph (d)(6) does not prevent the terms and conditions on which a *Metering Coordinator* is appointed under paragraph (a) from including a requirement for the *financially responsible Market Participant* to pay the *Local Network Service Provider* an exit fee when the appointment ceases, provided that the exit fee is consistent with Chapter 6 and, where relevant, Chapter 11.

(f) An agreement between a *Local Network Service Provider* and the *financially responsible Market Participant* relating to the appointment under paragraph (a) or deemed appointment under paragraph (c) of the *Local Network Service Provider* as *Metering Coordinator* may include agreed terms and conditions that are in addition to those required by paragraph (d), provided the additional terms and conditions are consistent with paragraph (d).

(g) Any *Metering Coordinator* appointed under paragraph (a) or deemed to be appointed under paragraph (c):

(1) is not required to meet the requirements of new clause 2.4A.2(a)(4) except if, immediately before the effective date, the *Metering Coordinator* is the *responsible person* for *metering installations* that would fall within the definition of *small customer metering installations* under the Amending Rule.

(2) is not obliged to comply with clause 7.8.10(a)(2) of new Chapter 7; and

(3) must promptly notify the *financially responsible Market Participant* of a *metering installation malfunction* which occurs to a *metering installation* other than the installations referred to in clause 7.8.10(a)(1) of new Chapter 7.

(h) A *financially responsible Market Participant* which receives a notice under subparagraph (g)(3) must promptly appoint a *Metering Coordinator*.

(i) Any *Metering Coordinator* appointed by the *financially responsible Market Participant* following a notice under subparagraph (g)(3) must comply with clause 7.8.10(a)(2) of new Chapter 7 within 10 *business days* after its appointment.

(j) For the avoidance of doubt:

(1) any *Metering Coordinator* appointed under paragraph (a), or deemed to be appointed under paragraph (c), must comply with Chapter 2 of the *Rules*, including the requirement that a *Metering Coordinator* be registered with *AEMO* as a *Metering Coordinator* under new clause 2.4A.1(a) of Chapter 2 of the *Rules*; and

(2) to the extent of any inconsistency between this clause 11.86.7 and clause 7.6.1(a) of new Chapter 7, this clause 11.86.7 prevails.

(k) Despite anything to the contrary in the terms and conditions on which a *Local Network Service Provider* is appointed as *Metering*

Coordinator under paragraph (a) or a deemed appointment under paragraph (c), that appointment will continue until the earlier of:

(1) the services provided with respect to the *metering installation* ceasing to be classified by the *AER* as *direct control services*; and

(2) a *Metering Coordinator* being appointed with respect to that *connection point* under new Chapter 7.

Note

The consequence of this provision is that the appointment or deemed appointment (as the case may be) will come to an end when a new or replacement metering installation is installed in accordance with clause 7.8.3 or 7.8.4 of new Chapter 7, provided that the AER does not classify services provided by small customer metering installations or type 4A *metering installations* as direct control services.

11.86.8 Distribution Ring Fencing Guidelines

(a) *AER* must by 1 December 2016 *publish Distribution Ring-Fencing Guidelines*.

11.86.9 B2B Arrangements

On and from the effective date:

(a) in Clause 7.17.1 of new Chapter 7, a reference to *Market Customers* is deemed to be a reference to *Market Customers* and Initial Metering Coordinators;

(b) in Clause 7.17.3(a) of new Chapter 7, a reference a *Market Customer* is deemed to be a reference to a *Market Customer* and an Initial Metering Coordinator;

(c) in Clause 7.17.3(c) of new Chapter 7, a reference to *Market Customer* is deemed to be a reference to *Market Customer* and Initial Metering Coordinator;

(d) in Clause 7.17.3(e) of new Chapter 7, a reference to *Market Customers* is deemed to be a reference to *Market Customers* and Initial Metering Coordinators;

(e) in Clause 7.17.3(f) of new Chapter 7, a reference to *Market Customers* is deemed to be a reference to *Market Customers* and Initial Metering Coordinators;

(f) in Clause 7.17.4(h) of new Chapter 7, a reference to *Metering Providers* is deemed to be a reference to *Metering Providers* and Initial Metering Coordinators;

(g) in Clause 7.17.4(i) of new Chapter 7, a reference to *Market Customers* is deemed to be a reference to *Market Customers* and Initial Metering Coordinators;

(h) in Clause 7.17.4(j) of new Chapter 7, a reference to *Market Customers* is deemed to be a reference to *Market Customers* and Initial Metering Coordinators;

(i) in Clause 7.17.4(l) of new Chapter 7, a reference to *Market Customers* is deemed to be a reference to *Market Customers* and Initial Metering Coordinators;

(j) in Clause 8.2A.2(i) a reference to *Market Customer* is deemed to be a reference to *Market Customer* and Initial Metering Coordinator; and

(k) in each of the definitions: *B2B Communications*, *B2B Objective*, *B2B Principles* and *B2B Procedures Change Pack*, a reference to *Market Customers* is deemed to be a reference to *Market Customers* and Initial Metering Coordinators.

[END OF RULE AS MADE]

Name of Vendor ……………………………………………… **Date………………………**

Important Notes concerning the following tables

1. The VIC Functionality Working Group is in the process of finalizing the VIC AMI Functionality Specification. The specification will be finalised in September and the functionality requirements will then be put into VIC Law (through a Governors Order in Council). If you have concerns or issues about this specification it is vital that you detail those in this document. We are keen to obtain as much feedback from Vendors as possible.
2. Please indicate if you require that your response be treated as anonymous. We still require you to put your company name at the top of this page but Impaq Consulting (and the Vic Govt) will ensure that your company name is not attributed to any of the comments you make that are presented to the Functionality Working Group or any other organisation. For vendors that require this we propose to reference them as Vendor A, Vendor B, Vendor C etc.
3. Please complete this document electronically and return in Word format. This makes collating responses much easier
4. The items in the requirements column of the table are taken from the Second Draft of the Functionality Specification dated 13 December 2006 – provided with this document. If you have suggestions for changes to the requirements please insert those directly into the requirements text in the tables on the pages following but with track changes on so that changes can be easily seen.
5. The compliance column is about whether you can commit to providing an AMI system that complies with this requirement in readiness for the rollout commencing 31 Dec 2008. (You may not that item of functionality currently in your AMI system) If you cannot commit to this requirement please explain this in the comments column
6. The comments column is for you to detail any issues or concerns about the requirement, or any suggestions for changes or improvements.
7. **Please provide responses to Phil Perry (phil.perry@impaqconsulting.com.au) by 14 June**

Para	Requirement	Compliance (Yes or No)	Comment
3.1	Availability of the following meter types: ■ Single phase, single element ■ Single phase, single element with load control ■ Single phase, two element with load control[1] ■ Three phase direct connect ■ Three phase direct connect with integrated single phase load control ■ Three phase direct connect with external three phase load control ■ Three phase CT connect (excluding connect/disconnect)		
3.1	All meter types shall meet the relevant requirements of AS62052.11, AS62052.21, AS62053.21, and any pattern approval requirements of the National Measurement Institute		

[1] The requirement for two element metering is currently under review and a DPI policy paper on whether single element meters can be used instead of two element meters will be released by end of June 2007. Also it is noted that he use of two single phase meters may be an alternative in some circumstances

Para	Requirement	Compliance (Yes or No)	Comment
3.2	The following requirements shall apply to all AMI meters: ■ Be four quadrant meters ■ Separately record active and reactive energy, import and export in 30 minute intervals, together with total accumulated active energy imported and total accumulated active energy exported[2]. ■ Record total accumulated consumption ■ The minimum resolution of 30 minute interval energy data shall be 1 Watt hour for active energy and 1 VArh for reactive energy. ■ The minimum resolution of energy consumption displayed on a meter's display shall be 0.1kWh and 0.1 kVArh ■ A minimum storage of 200 days of 1 channel of 30 minute interval energy data or 50 days per channel for 4 channels of 30 minute interval energy data. All four channels of 30 minute interval energy data shall be able to be read locally read as well as remotely read		
3.3	When meters are remotely read, the meter's total accumulated consumption per channel shall also be provided with the 30 minute interval energy data. For special reads of meters, it shall be possible to select how many days of 30 minute interval energy data is to be read. The AMI system shall also allow reading of settings, time, date, status indicators and events logs from meters.		

[2] It is noted that for the vast majority of customers with AMI metering there will only be one channel of interval energy data (real energy exported from the network to customers) retrieved on a routine basis. For those customers that have local generation (eg: Solar Cells) there will be the requirement to retrieve two channels of interval energy data. The channels of reactive energy data are likely to be used very infrequently, however this will allow DBs to monitor the power factor at customers premises and therefore allow monitoring of compliance with clause 4.3 of the Distribution Code.

Para	Requirement	Compliance (Yes or No)	Comment
3.4	All meter types excluding CT connected meters shall have a connect/disconnect contactor. The AMI system shall support both local and remote: • de-energisation [3], • Arming • Arming and re-energising[4] (activating) of customer supply via the connect/disconnect contactor. When an AMI meter performs a de-energisation operation, all outgoing circuits from the meter shall be de-energised. To confirm the current state of a meter, the AMI system shall support "on-demand" remote polling of the meter to determine whether: - connect/disconnect contactor is closed; - connect/disconnect contactor is open and meter unarmed; - connect/disconnect contactor is open and meter is armed. The AMI system shall complete on-demand polling commands, returning the meter status, with the performance levels set out in section 4 The meter shall provide clear local indication of the status (open/closed) of the connect/disconnect contactor.		
	The AMI system shall support both local and remote customer supply disconnect functionality. For remote disconnects, the AMI system shall complete the disconnect command, returning the meter status, within the performance levels set out in section 4		

- [3] De-energisation is a term used in the NEM, which in other jurisdictions is often termed 'disconnection'
- [4] Re-energisation is a term used in the NEM, which in other jurisdictions is often termed 'connect'

Para	Requirement	Compliance (Yes or No)	Comment
	Local Disconnect Local disconnect via the meter shall only be able to performed by an Authorised technician. Unauthorised persons shall be physically prevented from operating the connect/disconnect contactor to disconnect supply. The AMI system shall support the following: - Local opening of the disconnection relay; - Remote communication of the status (open/closed) from the meter of the connect/disconnect contactor (if AMI communications are active); - Event logging by the meter of the local disconnection.		
	Remote Disconnect The AMI system shall support the following: - Remote opening of the disconnection relay; - Remote communication of the status (open/closed) from the meter of the connect/disconnect contactor; - Event logging by the meter of the remote disconnection.		

<table>
<tr><th>Para</th><th>Requirement</th><th>Compliance (Yes or No)</th><th>Comment</th></tr>
<tr><td></td><td>Local “Arm”
Local arming shall only be able to be performed by an Authorised technician. Unauthorised persons shall be prevented from “arming” the meter.

The AMI system shall support the following:
- Local “arming” of the meter;
- Remote communication of the armed status (armed/unarmed) of the meter (if AMI communications are active);
- Clear local indication that the meter is “armed”;
- Event logging by the meter that it has been locally armed.</td><td></td><td></td></tr>
<tr><td></td><td>Remote “Arm”
The AMI system shall support the following:
- Remote “arming” of the meter;
- Remote communication of the armed status (armed/unarmed) of the meter;
- Clear local indication that the meter is “armed”;
- Event logging by the meter that it has been remotely armed.</td><td></td><td></td></tr>
</table>

Para	Requirement	Compliance (Yes or No)	Comment

	Remote "Activate"
	
	For safety, the meter shall support an auto-disconnect function if load is detected flowing through the meter upon remote closing of the connect/disconnect contactor.
	
	The AMI system shall support the following:
	- Remote closing of the connect/disconnect contactor;
	- Remote communication of the status (open/closed) from the meter of the disconnect relay;
	- Clear local indication of the status (open/closed) of the disconnect relay;
	- Event logging of remote activation;
	- Meter will auto-disconnect if a minimum of "X" mA of load is detected flowing through the meter for a minimum of "Y" seconds of the disconnect relay being remotely closed:
	    - "X" range; 10-10,000 mA, remotely and locally configurable;
	    - "Y" range; 1- 3,600 seconds, remotely and locally configurable;
	    - Enabling/disabling of auto-disconnect function, remotely and locally configurable;
	    - Remote communication that meter has auto-disconnected;
	    - Meter returns to "armed" state following auto-disconnection;
	    - Event logging of auto-disconnection;
	    - Auto-disconnect function active for "Z" seconds after remote activate (where the range for "Z" is 1- 3,600 seconds, remotely and locally configurable).		

Para	Requirement	Compliance (Yes or No)	Comment
3.5	**Time Clock Synchronisation** The date and time in meters shall be able to be set remotely within an accuracy of 10 seconds of Eastern Standard Time (EST). Date and time within meters shall be maintained within 20 seconds of EST time.		

Para	Requirement	Compliance (Yes or No)	Comment
3.6	**Controlled load management at meters** The following are the features required of single phase or three phase meters with an internal controlled load contactor and three phase meters equipped to operate an external controlled load contactor: ■ Storage in the meter of 5 sets of “turn on” & “turn off” times per week day & 5 sets of “turn on” & “turn off” times per weekend day. ■ “Turn on” and “turn off” times are remotely settable for each meter separately and in groups, through the AMI communications system. ■ At “turn on” times meters would react by turning on the controlled load after a randomised time delay remotely settable from 0 minute to 60 minutes in 1 minute increments (Often referred to as “spread on”). ■ Meters shall recognise “turn on” & “turn off” commands that will override the switching program stored in the meter. The “turn on” and “turn off” functionality shall be individually addressable or grouped into broadcast groups. The broadcast groups shall provide for a minimum of 20 Primary (Master groups) and 200 secondary groups. The meter shall be remotely programmable to respond to one primary (master) group and one secondary group. The action of receiving a remote “turn on”or “turn off” command shall disable or override the preset time based “turn on” and “turn off” schedule for a programmable period between 0 and 48 hours, settable in ½ hour increments. ■ Single phase controlled load meters are to have a “boost” facility. This facility shall be able to be remotely enabled or disabled. When a customer presses the meter’s “boost” button, the meter will energise the controlled load for a preset time, which is remotely programmable from 1 to 6 hours in half hour increments. For two element meters, it shall be possible to remotely select whether energy consumed when “boost” is activated is recorded on the main or controlled load 30 minute interval energy data streams.		

Para	Requirement	Compliance (Yes or No)	Comment
3.6	**Controlled load management at meters (cont)** ■ For a two element meter, the meter shall have a terminal connected to the controlled circuit element before it passes through the controlled circuit contactor. This is to allow for the connection of storage hot water heaters where there are dual heating elements – one at the top and one at the bottom of the tank. The top element of the water heater is to be connected such that its thermostat is energised at all times, but from the second element (controlled circuit) of the meter. ■ Meters with integrated single phase load control shall have a controlled load contactor with a minimum current rating of 31.5 A resistive (AC1 rating) and a nominal voltage rating of 230 Vac[5]. ■ Meters for three phase load control, shall have an integral relay with a minimum rating of 0.2A, and a nominal voltage rating of 230 Vac for operation of an external three phase load control contactor.		
3.7	**Quality of Supply & other event recording** All AMI meters are to have the capability to record a minimum of 100 of the most recent Quality of Supply (QoS) events and other events as per 0, which can be remotely read. The meter shall record the nature of the event (eg: outage, undervoltage, disconnect etc), the date and time of the beginning of the event, and the date and time of the end of the event.		

- [5] The tolerance on the rated voltage is as per the Electricity Distribution Code

Para	Requirement	Compliance (Yes or No)	Comment
3.7.1	**Meter Loss of Supply** The trigger for a meter loss of supply event is when the supply voltage reduces to a point where the meter shuts down, which should be at a maximum 70% of nominal voltage, and this condition exists for longer than 0.1 second. For three phase meters the phases affected shall also be recorded.		
3.7.2	**Undervoltage & overvoltage recording** Undervoltage and overvoltage events shall be recorded in line with the requirements of the Electricity Distribution Code clause 4.2.2 Table 1, given in Table 1 below, for voltage levels less than 1 kV (excluding the "Less than 10 seconds[6]" and "impulse voltage" requirements). The thresholds for each of the "steady state" and "less than 1 minute" categories shall be remotely settable - for undervoltage in the range of -5% to -20%[7] in 1% steps and for overvoltage in the range of +5% to +20%[8] in 1% steps. For the purposes of this specification the "less than 1 minute" category shall apply to events between 1 second and 59 seconds. For each undervoltage event the minimum voltage that occurred during the period shall be recorded. For each overvoltage event the maximum voltage that occurred during the period shall be recorded. For three phase meters, the phases affected shall also be recorded. **Table 1 – Electricity Dist**		

STANDARD NOMINAL VOLTAGE VARIATIONS				
Voltage Level in kV	Voltage Range for Time Periods			Impulse Voltage
	Steady State	Less than 1 minute	Less than 10 seconds	
< 1.0	+10% - 6%	+14% - 10%	Phase to Earth +50%-100% Phase to Phase +20%-100%	6 kV peak

- [6] For the less than 10 seconds category, the allowance of -100% of voltage means that there can be no undervoltage events. The requirement for detection down to 0.5 cycles would significantly increase the cost of meters.
- [7] Detection of undervoltage levels is limited to -20% because of technical limitations of meters.
- [8] Detection of overvoltage is limited to +20% because of technical limitations of meters.

Para	Requirement	Compliance (Yes or No)	Comment
3.7.3	**Other events** There are a range of other events which are required to be logged, as noted in other sections of this specification. This includes: ■ Whenever a boost button is pressed; ■ Whenever the connect/disconnect contactor is opened or closed; ■ Whenever a tamper is detected; ■ Change in "turn on" or "turn off" times for controlled loads; and ■ Whenever there is a change of meter settings.		
3.8	**Supply Capacity Control** This functionality applies only to direct connected meters (ie: does not apply to CT connected meters) and has application for a range of purposes including: ■ Emulation of the operation of a supply capacity control circuit breaker[10] currently installed at a range of new customer installations; and ■ Providing the capability to limit supply capacity for short periods of time in accordance with customer contractual agreements, or in response to system events (subject to the development of appropriate regulatory arrangements).		

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[9] Steady State Variation - A voltage variation occurs if the voltage exceeds +10% or -6% of nominal supply voltage for ≥ 1 minute.

Less than 1 minute Variation - A voltage variation occurs if the voltage exceeds +14% or -10% of nominal supply voltage for < 1 minute and ≥ 10 seconds.

Less than 10 seconds Variation - Phase to Earth - A voltage variation occurs if the voltage exceeds +50% or -100% of nominal supply voltage for < 10 seconds and ≥ 0.01 seconds (0.5 cycles) Phase to Phase - A voltage variation occurs if the voltage exceeds +20% or -100% of the nominal supply voltage for <10 seconds and ≥ 0.01 seconds (0.5 cycles).

- 10 Supply Capacity Control Device Requirements as specified by Section 6.7 of the Victorian Service & Installation Rules – 2005 (SIRs)

Para	Requirement	Compliance (Yes or No)	Comment
3.8.1	**When energy is exported from the network to a customer** The connect/disconnect contactor shall open if the average kW demand across the last X number of thirty minute intervals is greater than the demand limit (Y kW), where: X is settable from 1 to 10 thirty minute intervals in increments of 1 thirty minute interval; and Y is settable from 0.5 to 99kW in increments of 0.5 kW.		
3.8.2	**When energy is imported from a customer to the network** The connect/disconnect contactor shall open if the average kW demand across the last U number of thirty minute intervals is greater than the demand limit (V kW), where: U is settable from 1 to 10 thirty minute intervals in increments of 1 thirty minute interval; and V is settable from 0.5 to 99kW in increments of 0.5 kW.		
3.8.3	**Enabling, disabling and event recording** The supply capacity control functionality shall be able to be remotely enabled and disabled. When the supply capacity control functionality causes the connect/disconnect contactor to open, the connect/disconnect contactor shall be able to reclosed by pressing the close button on the meter or utilising the remote connect command as described in section 3.4 The disconnection and any subsequent reconnection shall be recorded as events as described in section 3.7.3.		

Para	Requirement	Compliance (Yes or No)	Comment
3.9	**Interface for In Home Displays or other load control** All AMI systems shall have the capability to communicate with In-Home Display (IHD) devices or Load Control (LC) devices as indicated in section 2. Meters shall have the capability of communicating with IHD. All communications to a customer's IHD shall include a unique identifier that binds the IHD to the customer's meter(s). (This is to ensure that a customer's IHD receives information pertaining to their premises and not a neighbour's premises.)		

3.9.1	**In Home Displays** The AMI meter shall: ■ Continuously update the IHD with the meter's current demand (kW) (unvalidated data). The frequency of updating of the IHD may be varied where there are communications bandwidth issues. (For example the normal frequency of update could be every 2 minutes but changed to every 10 seconds when a button on the IHD is pressed). ■ Update the IHD every half hour with the 30 minute interval energy data (unvalidated data) together with the date and time. ■ Update the IHD daily with the controlled load switching times and the supply capacity limit (kW). The IHD shall receive from the AMI system (and receipt shall be confirmed back from IHD to NMS): ■ Tariff update messages (up to 12 times a year) to allow updating of rates (c/kWh) and times for the tariffs stored in the IHD. ■ Advice of a critical peak price event (maximum of 10 times a year) ■ Free form text messages up to 255 characters long (maximum of once per day). Should there be insufficient bandwidth to send the above to each customer individually there shall be allowance to broadcast these to customer groups according to which retailer and tariff they use. (Eg: Allowing for 20 retailers and 30 message types per retailer this would equate to 600 broadcast messages instead of unique messages to each customer). Vendors of AMI systems and AMI meters are required to provide their communications protocols to third party IHD manufacturers.[11]		

Para	Requirement	Compliance (Yes or No)	Comment
3.9.2	**Other Load Control Devices** AMI systems shall have the capability to communicate load control commands for primary groups and secondary groups (as given in section 0) through to "other load control" devices. These commands may be free form text messages that LCs can interpret.		
3.10	**Interface to other customer points of interaction** In addition to the requirements for an interface to IHDs and LCs, it is required that AMI systems have the capability to interface to other customer points of interaction. One such point of interaction could be the customer's personal computer, and the communication means could be the internet.		
3.11	**Meter Loss of Supply detection and Outage Detection** All AMI systems shall include a means of detecting loss of supply to meters including those at individual customer's premises. AMI systems shall also include means for outage detection at distribution transformers. When a meter loss of supply or outage is detected it is to be communicated to the NMS.		

- [11] This may be through a licence agreement and/or confidentiality agreement

Para	Requirement	Compliance (Yes or No)	Comment
3.12	**Communications from gas and water meters** All AMI systems shall have a means of receiving communications from gas meters and water meters in the future. This is to allow these meters to send information on the AMI system.		
3.13	**Tamper Detection** The AMI system shall support detection of attempts to tamper with the meter, which may include ■ Unauthorised lifting or removal of cover(s) to gain access to meter terminals or the meter; and ■ Reverse current detection. The AMI system shall support remote communication of the tampering detected to the NMS.		
3.14	**Communications and data security** The AMI system shall ensure the security of: ■ The data in the end point devices (including meters and data concentrators, where used); ■ The communications system; and ■ Collected data.		

Para	Requirement	Compliance (Yes or No)	Comment
3.15	**Customer Supply Monitoring** An additional requirement for customers supply monitoring is under consideration, which may be included in the update to this specification subsequent to technology trials which conclude in June 07. Should this be included it is likely that it will require all single phase AMI meters to have means for detecting: ■ Reverse polarity on customer's connection ■ Degradation of the customers neutral ■ Degradation of the customers earth connection (from switchboard to earth) Some of these requirements may also apply to three phase meters. Together with such requirements on meters there would also be a requirement on AMI systems to have the capability to remotely set the detection calculation parameters in the meters and also to alarm to the NMS when the above conditions are detected.		
4.0	**Performance levels** The following are the target AMI system performance levels required and these apply to only the AMI system, and not to any upstream systems; specifically from the NMS to the meter and return.		

Para	Requirement	Compliance (Yes or No)	Comment
4.1.1	**Performance levels for collection of daily meter readings** The following are the performance levels required for the daily collection of the previous trading day's 30 minute interval energy data (as required in section3.3). ■ All data from 99% of meters within 2 hours after midnight ■ All data from 99.5% of meters within 4 hours after midnight ■ All data from 99.9% of meters within 12 hours after midnight It is noted that some AMI systems have the capability to progressively feed interval energy data read from meters through to the NMS system throughout each day. Hence after midnight has passed, only the latter few intervals of data may be required to be collected from meters to have the full set of interval energy data from the previous day.		
4.1.2	**Performance levels for special reads** A special read (refer section 3.3) is defined as the reading of a selectable number of days of interval energy data from a particular AMI meter. Performance level required for up to 2% of all meters in any day. ■ The data from 90% of meters in 1 hour ■ The data from 95% of meters in 2 hours ■ The data from 99% of meters in 3 hours ■ The data from 99.9% of meters in 6 hours		

Para	Requirement	Compliance (Yes or No)	Comment
4.1.3	**Performance levels for connect/disconnect** The actions covered in this category, as specified in section 3.4, include “arm”, “arm and activate” and “disconnect”. The following performance level is required for up to 2% of all meters in any day. ■ Action performed at 90% of meters within 1 hour ■ Action performed at 95% of meters within 2 hours ■ Action performed at 99% of meters within 3 hours ■ Action performed at 99.9% of meters within 6 hours		

Para	Requirement	Compliance (Yes or No)	Comment
4.1.4	**Performance levels for Controlled Load Management Commands or Other Load Control commands** The actions covered in this category are specified in section 3.6 for Controlled Load Management and in section 3.9.2 for Other Load Control. For broadcast "turn on" or "turn off" commands to any super group or subgroup of meters the performance level required is: ■ Action performed at 90% of meters within 10 minutes ■ Action performed at 99% of meters within 1 hour For "turn on" and "turn off" commands sent to individual meters, up to a total of 2% of all meters in any day: ■ Action performed at 90% of meters within 1 hour ■ Action performed at 95% of meters within 2 hours ■ Action performed at 99% of meters within 3 hours ■ Action performed at 99.9% of meters within 6 hours		
4.1.5	**Performance levels for altering settings in meters** Performance level required for changing one setting in up to 2% of all meters in any day ■ Action performed at 90% of meters within 1 hour ■ Action performed at 95% of meters within 2 hours ■ Action performed at 99% of meters within 3 hours ■ Action performed at 99.9% of meters within 6 hours		

Para	Requirement	Compliance (Yes or No)	Comment
4.1.6	**Performance levels for reading settings from meters** Performance level required for reading all the settings in a meter (refer section3.3) for up to 2% of all meters in any day ■ The data from 90% of meters in 1 hour ■ The data from 95% of meters in 2 hours ■ The data from 99% of meters in 3 hours ■ The data from 99.9% of meters in 6 hours		
4.1.7	**Performance levels to read events logs** To read the full event log of any single meter, for up to 2% of meters in any day ■ The data from 90% of meters in 1 hour ■ The data from 95% of meters in 2 hours ■ The data from 99% of meters in 3 hours ■ The data from 99.9% of meters in 6 hours To read the event logs remotely for all meters: ■ The data from 99.5% of meters in 1 week ■ The data from 99.9% of meters in 2 weeks		

Para	Requirement	Compliance (Yes or No)	Comment
4.1.8	**Performance levels to send messages to IHDs** The performance level required for sending tariff update messages (refer section 3.9.1) to all meters with IHDs connected. ■ Message received by 99.5% of meters to which an IHD is connected, in 7 days ■ Message received by 99.9% of meters to which an IHD is connected, in 14 days The performance level required for sending tariff update messages (refer section 3.9.1) to 2% of meters with IHDs connected. ■ Message received by 99.5% of meters to which an IHD is connected, in 12 hours ■ Message received by 99.9% of meters to which an IHD is connected, in 24 hours The performance levels required to send CPP notification messages to IHDs ■ Message received by 99.5% of meters to which an IHD is connected, in 6 hours ■ Message received by 99.9% of meters to which an IHD is connected, in 12 hours The performance levels required to send freeform messages to IHDs (either individual messages or broadcast messages as per section 3.9.1): ■ Message received by 99.5% of meters to which an IHD is connected, in 24 hours ■ Message received by 99.9% of meters to which an IHD is connected, in 48 hours		