Final determination

Victorian advanced metering infrastructure review

2009–11 AMI budget and charges applications

October 2009

Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001

Tel: (03) 9290 1444
Fax: (03) 9290 1457
Email: AERInquiry@aer.gov.au
Web: www.aer.gov.au

Contents

Shortened forms

AAM	Alinta Asset Management
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advance metering infrastructure
CALC	Consumer Action Law Centre
capex	capital expenditure
CEG	Competition Economics Group
CIS	Customer information system
CP	CitiPower Ltd
CUAC	Consumer Utilities Advocacy Centre
current price determination	Essential Services Commission of Victoria’s 2006 Electricity Distribution Price Review
DNSP	distribution network service provider
DPI	Department of Primary Industries (Victoria)
DRP	Debt risk premium
DUOS	distribution use of system
ECM	Efficiency carryover mechanism
ESCV	Essential Services Commission – Victoria
EWOV	Energy and Water Ombudsman (Victoria)
GFC	Global financial crisis
IMRO	Interval meter rollout
IT	information technology
JEN	Jemena Energy Networks
KEMA	KEMA Inc.
MWh	mega-watt hour
NER	National Electricity Rules
NERL	National Energy Retail Law
NERR	National Energy Retail Rules (currently under consultation)
NMI	National meter identifier
NPV	Net present value
opex	operational and maintenance expenditure
original Order	The Order in Council made on 28 August 2007 by the Governor in Council under sections 15A and 46D of the Electricity Industry Act 2000 (Vic)
PC	Powercor Australia Ltd
revised Order	The original Order as amended on 25 November 2008, 22 January 2009 and 31 March 2009
SPA	SP AusNet
SVDP	St Vincent de Paul
UED	United Energy Distribution
WACC	Weighted average cost of capital

Summary

In 2006, the Victorian Government decided there should be a rollout of advanced interval meters to all Victorian electricity customers. The regulatory arrangements relating to the rollout are set out in an August 2007 Order in Council made by the Victorian Governor in Council under sections 15A and 46D of the Electricity Industry Act 2000. An amending Order in Council was made on 25 November 2008 (the 'revised Order'). The revised Order sets out the regulatory framework and the AER's role, including the determination of budgets, revenues and charges.[1] The Order requires Victorian DNSPs to install remotely read interval meters for all households and businesses consuming less than 160 MWh per annum by 31 December 2013.

The revised Order provides for a pass through arrangement for metering costs incurred by DNSPs, whereby metering charges are to be set with reference to a combination of actual costs and forecasts of expenditure budgets determined by the AER using a building block approach and applying the tests set out in the revised Order. The building block approach provides for the capital cost of metering assets to be amortised and recovered from customers over time. Each year charges are to be revised under this approach by updating forecast data with actual costs incurred and revenues received to ensure revenue neutrality for the DNSPs over the rollout period.

This determination relates to the expenditure budgets and forecast revenues for 2009 to 2011 and associated metering charges for 2010 and 2011.

Under the revised Order the AER is required to apply a series of tests in approving capital and operating expenditure budgets to ensure they are within the scope of activities and specifications as set out in the revised Order and otherwise prudent. In determining the prudence of expenditures the AER is required to consider the extent to which they stem from competitive tendering arrangements, the likelihood of expenditures being incurred and whether expenditures are in line with general commercial standards. The revised Order sets out requirements in relation to the calculation of building block revenue requirements and how these are translated into metering charges. In January 2009 the AER published a framework and approach paper outlining how it would discharge its functions under the revised Order with respect to determining budgets and metering charges.

On 31 July 2009, the AER released its draft determination on the DNSPs' AMI budget and charges applications for 2009–11. The AER engaged a technical consultant, Energeia, to assist in its review of the DNSPs' proposed budgets, and Energeia's final report was provided as an attachment to the draft determination.

In relation to the proposed budgets, the draft determination stated that the AER considered that the bulk of the submitted budgets were within scope and prudent, with the exception of UED's equity raising and self insurance costs, expenditure for customer response trials proposed by CitiPower (CP), Powercor (PC) and SP AusNet (SPA) and SPA's direct load control relays.

[1] Responsibility for regulatory oversight of Victorian DNSPs generally and the AMI rollout in particular transferred from the Essential Services Commission of Victoria (ESCV) to the AER on 1 January 2009.

The draft determination also considered indicative charges resulting from the AER's decisions. For a single phase, single element meter, the draft determination noted that charges would range from $67.79 to $104.79 in 2010; and from $92.12 to $130.52 in 2011. These indicative 2010 charges represented an average increase of $53 on current (2009) metering charges, approved by the Essential Services Commission of Victoria, with a further $25 increase in 2011.

Following the draft determination, on 21 August 2009 the AER held a public forum to give stakeholders an opportunity to comment and ask questions on the draft determination. DNSPs submitted revised budget applications in late August as well as further information in relation to proposed charges, and the AER received submissions from seven stakeholders throughout September and early October. This final determination sets out the AER's consideration of the DNSPs' revised submitted budgets, charges, further information submitted and issues raised at the public forum and in stakeholders' submissions.

Following the AER's consideration of further information and issues raised, this final determination results in the following changes to the DNSPs' approved budgets and charges from the draft determination:

- CP's PC's, JEN's and UED's related party margins were excluded from their approved budgets on the basis that they do not arise from activities associated with the provision of regulated (metering) services and are therefore outside scope.

- CP's, PC's and SPA's proposed budget costs have decreased following the signing of contracts since the AER's draft determination.

- Costs removed from SPA's proposed budget in the draft determination relating to direct load control have been re-instated, correcting an error.

- Audited historical information submitted by CP, JEN and PC resulted in increases to charges.

- Changes in the provisions allocations proposed by SPA resulted in minor changes to its charges.

- Change in the calculation of the debt risk premium, reflecting the AER's assessment of alternatives in light of appropriate market data.

The AER also received several submissions from stakeholders on its draft determination. The AER's considerations on these issues are outlined in this final determination. Many of the AER's responses did not relate to the AMI budgets and charges, rather provide general information to stakeholders regarding the AER's draft determination approach and the broader implications of AMI, including:

- Clarification of the AER's application of revised Order requirements

- Re-examination of proposed costs in relation to areas such as customer complaint handling, information technology (IT) costs potentially compensated for through distribution tariffs and related party margins.

- Customer information and other AMI impacts, such as billing information, hardship policies, transparency, substituted data and customer access to direct load control information and the potential for unregulated services stemming from spare AMI bandwidth capacity.

- the AER's enforcement of charges, separation of charges for meter provision and meter data provision, and the potential for smoothing and allocation of charges across the 2010–11 period.

- Clarification of the regulatory framework in relation to the AER's enforcement of charges, potential non-metering services delivered through AMI infrastructure, and customer access to information, including the pass through of AMI benefits to consumers.

For a customer receiving a single phase, single element meter, the charges stemming from AER's final determination range from $69.21 to $134.63 in 2010; and from $89.18 to $136.70 in 2011. This represents an average increase across all DNSPs of $67.97 in 2010 from 2009 charges for a customer whose meter is read quarterly, with a further average increase of $8.42 in 2011.

Approved charges have increased from the AER's draft determination. This is in part due to the AER's reconsideration of the DNSPs' debt risk premium and the receipt of audited information on historical expenditures which are allowed to be recovered through future charges.

Going forward, DNSPs will be required to report actual expenditure incurred against the budgets as approved by the AER. The revised Order provides for actual expenditure to be reflected in prices where it is within scope, certified in an audit report, and no more than 120 per cent (for the period 2009 to 2011) of the budgets determined by the AER. Where actual expenditure is outside these ranges the AER may only not permit it to be recovered where it establishes that it is not prudent.

The AER notes that the Victorian Government expects the following benefits to result from the net increase in metering charges:

- introduction of cost reflective time of use tariffs, resulting in more efficient network utilisation and potential deferral of network augmentations

- operational cost savings for the DNSPs arising from remote meter reading and connection and disconnection of customers' supplies

- more efficient outage detection and rectification

- improved accuracy of customer billing.

As the AMI rollout progresses, the AER will review the level of, and trends in, DNSPs' reported actual metering opex. In particular the AER will have regard to DNSPs' future and on-going opex which should reflect the anticipated cost savings from the AMI rollout. In addition, the AER will consider how AMI affects the DNSPs' proposed network augmentation plans in making future distribution determinations, such as through improved price signals and associated reductions in peak demand. The AER will be mindful of these expected operational cost savings and other positive impacts on network service delivery in the future, and will aim to ensure that these benefits are reflected in future electricity tariffs.

The charges proposed in revised charges applications and determined by the AER for each DNSP are listed in Tables 1 to 5 below. Note that all DNSPs except Jemena and SP AusNet charge on a National Meter Identifier (NMI) basis.

Table 1: CitiPower ($ per NMI)

Annual metering charge	**2010**		**2011**	
	proposed	**AER decision**	**proposed**	**AER decision**
Single phase	104.79	104.79	120.12	108.43
Three phase direct connected	136.98	136.98	162.30	146.51
Three phase current Transformer connected	172.99	172.99	201.87	182.23

Table 2: Jemena ($ per meter)

Annual metering charge	**2010**		**2011**	
	proposed	**AER decision**	**proposed**	**AER decision**
Single phase single element	134.63	134.63	136.70	136.70
Single phase single element, with contactor	134.63	134.63	136.70	136.70
Three phase direct connected	165.46	165.46	167.99	167.99
Three phase current Transformer connected	183.95	183.95	186.77	186.77

Table 3: Powercor ($ per NMI)

Annual metering charge	**2010**		**2011**	
	proposed	**AER decision**	**proposed**	**AER decision**
Single phase	96.67	96.67	116.98	105.35
Three phase direct connected	127.50	127.50	158.47	142.71
Three phase current Transformer connected	168.94	168.94	209.09	188.29

Table 4: SP AusNet ($ per meter)

Annual metering charge	2010		2011	
	proposed	AER decision	proposed	AER decision
Single phase, single element with contactor	87.29	86.10	94.99	93.83
Single phase, two–element with contactor	100.29	98.93	109.15	107.81
Multi-phase, one contactor (1 load control)	121.16	119.51	131.86	130.25
Multi-phase, two contactors (2 load controls)	134.41	132.58	146.28	144.49
Multi-phase Current Transformer connected	173.07	170.71	188.35	186.05

Table 5: UED ($ per NMI)

Annual metering charge	2010		2011	
	proposed	AER decision	proposed	AER decision
Single phase single element	71.80	69.21	92.12	89.18
Single phase single element with contactor	73.30	70.65	94.02	91.03
Three phase direct connected	81.01	78.08	103.89	100.58
Three phase CT connected	86.40	83.27	110.82	107.28

1 Introduction

1.1 Background

In 2006, the Victorian Government decided that there should be a rollout of advanced interval meters (AMI) to all Victorian electricity customers. The regulatory arrangements relating to the rollout were initially set out in an August 2007 Order in Council made by the Governor in Council under sections 15A and 46D of the *Electricity Industry Act 2000* (Vic) (referred to hereafter as 'the original Order'). In September 2008, the Victorian Government published minimum AMI functionality and service levels specifications for the AMI rollout, setting out the minimum requirements that the DNSPs must comply with in procuring and implementing their AMI systems.[2]

The original Order was revised on 25 November 2008 following discussions between the Victorian Government, DNSPs and stakeholders, during which the rollout was limited to Victorian households and small businesses consuming less than 160 MWh per annum. The revised Order also amended the original timing, regulatory arrangements and regulatory responsibility for the rollout. On 22 January 2009, the revised Order was amended again to incorporate Schedule 3, which sets out the scope of AMI activities for CitiPower and Powercor.

The revised Order provides for a cost pass through model under which budgets for the rollout are established at the beginning of the period and then annual charges are determined based on actual expenditure. The focus of the regulatory framework is on the regulator ensuring that the expenditure is within scope and is otherwise prudent, in accordance with the tests set out in the revised Order.

The revised Order divides the regulatory process into two separate periods. The first is the initial budget period, which applies from 1 January 2009 to 31 December 2011. This final determination is for this initial budget period.

The second budget period applies from 1 January 2012 to 31 December 2015. From 2016 onwards the determination of prices for metering services and other fees and charges will be undertaken by the AER in accordance with the process provided in chapter 6 of the National Electricity Rules (NER). Final 'true-ups' in relation to total AMI expenditure and revenue from 2009 to 2015 will be reflected in prices in 2016 and 2017.

The AER's 2011–15 Victorian distribution determinations will not deal with the costs and revenues associated with the AMI rollout.

The following sections summarise the requirements of the revised Order in making a determination on the DNSPs' AMI budgets and charges for 2009–11, and the process

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2 Department of Primary Industries (Victoria), *Advanced metering infrastructure – Minimum AMI functionality Specification (Victoria)*, September 2008, and Department of Primary Industries (Victoria), *Advanced metering infrastructure – Minimum AMI Service Levels Specification (Victoria)*, September 2008.

which will be carried out in making a determination for the second budget period, 2012–15.

1.1.1 Budgets

The framework under the revised Order in respect of the two budget periods is similar. It requires a DNSP to provide a submitted budget as part of its budget application to the regulator, which the regulator must approve unless it can establish that the submitted budget expenditure is for activities that are out of scope, as set out in the revised Order, or that the submitted budget expenditure is not prudent. Submitted budget expenditure is taken to be prudent unless:

- in the case where expenditure is a contract cost, the regulator establishes the contract was not let in accordance with a competitive tender process
- in the case of other expenditure, the regulator establishes it is more likely than not that the expenditure will not be incurred or that incurring the expenditure involves a substantial departure from the commercial standard that a reasonable business would exercise in the circumstances.

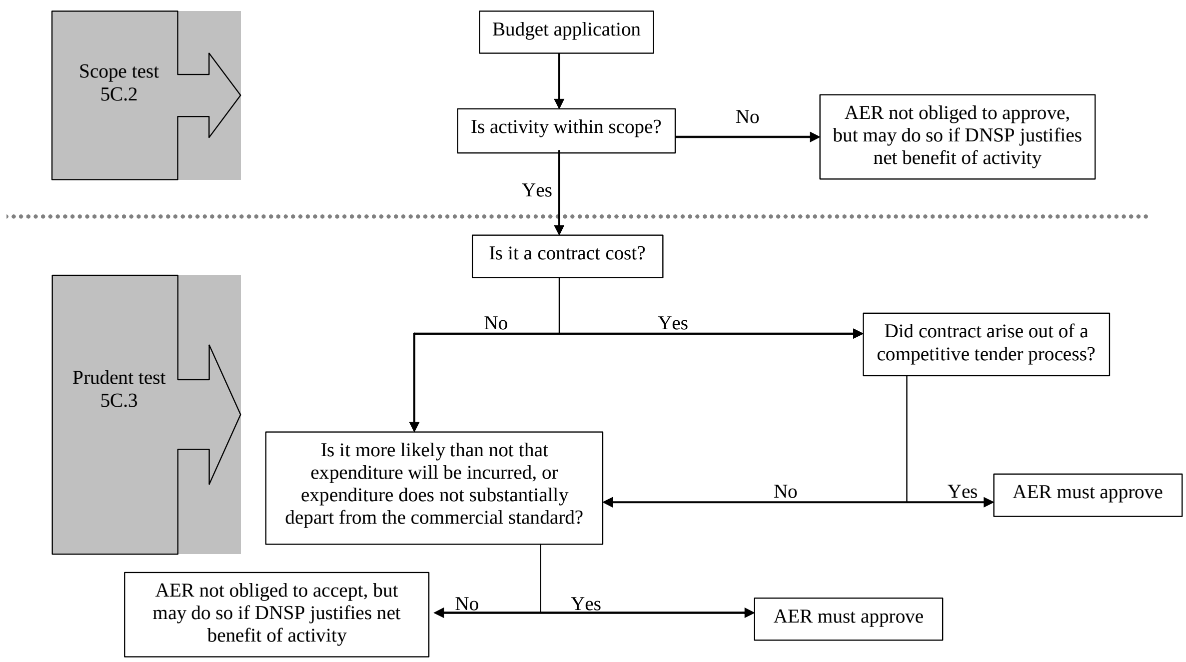
Accordingly, the AER's assessment of the submitted budgets is separated into a series of 'tests' which it must undertake: the scope test and the prudent test. The prudent test is comprised of the competitive tender test, expenditure incurred test and commercial standard test. In summary, the AER must approve submitted budget expenditures unless it can establish that such expenditure does not pass any one of these tests. In such a situation, the AER is not required to accept the submitted budget and must state in its reasons what new submitted budget it would determine to approve.[3] Further details on the AER's application of the tests are provided in the draft determination.

An important aspect to note regarding these tests is that the revised Order did not require the AER to reject expenditures where they were attached to activities that were deemed to be out of scope or imprudent. Accordingly, in such cases, the AER's framework and approach (discussed below) noted that the AER may still approve a DNSP's proposed expenditure if a net benefit from the activity is demonstrated.

Figure 1 below provides a flowchart outlining the AER's initial AMI budget assessment tests, as set out in clause 5C of the revised Order.

3 Revised Order, clause 5C.5(a).

Figure 1: Budget assessment tests under revised Order



1.1.2 Charges

The revised Order did not require the AER to publish a draft determination on the DNSPs' charges applications, however, the AER did so in combination with a draft budget determination in order to provide stakeholders information on potential price impacts and to facilitate further consultation generally.

Under the revised Order, charges determined by the AER for 2010 and 2011 are for the following service categories:

- single phase single element meter
- single phase single element meter with contactor
- single phase two–element meter with contactor
- three phase direct connected meter
- three phase direct connected meter with contactor
- three phase current transformer connected meter; and
- any other customer or metering class proposed by the DNSP and approved by the AER.[4]

The revised Order requires charges for a particular year to be set such that the net present value (NPV) of total costs incurred by the DNSP from 1 January 2009 to the

4 Revised Order, clause 4.1(n).

end of that year be equal to the NPV of the total revenue for the same period. Costs and revenues are to be calculated using a combination of actual historical data and forecasts arising out of a DNSP's approved budget.

The revised Order also provides for the building block approach to be used in calculating costs that are to be reflected in charges, including a return on capital, depreciation, efficiency carryover amounts relating to the rollout of manually read interval meters prior to 1 January 2009, and tax liabilities.

Charges are to be adjusted annually to reflect actual expenditure incurred. The revised Order provides for actual expenditure to be reflected in charges where it is within scope, certified in an audit report, and no more than 120 per cent (in relation to the initial budget period) or 110 per cent (in relation to the second budget period) of the approved budget. Where actual expenditure is outside these ranges the regulator may further scrutinise that expenditure before approving charges. Whether excess expenditure is prudent involves applying the same tests discussed above in section 1.1.1 of this determination, with the exception of the expenditure incurred test.[5]

1.2 Rollout and AER review timeframes

In January 2009 the AER published a framework and approach paper which outlined the AER's likely approach to reviewing the DNSPs' charges and budget applications.

The AER received the Victorian DNSPs' Initial AMI Budget Applications (budget applications) on 27 February 2009 and their Initial AMI Charges Applications (charges applications) on 1 June 2009. On 31 July 2009, the AER released its AMI draft determination on the DNSPs' initial AMI budgets and charges applications. A public forum was held on 21 August 2009, at which stakeholders were given an opportunity to raise issues and ask questions regarding the draft determination. Submissions on the draft determination closed on 11 September 2009. A record of the issues raised at the public forum and submissions received are available on the AER's website, www.aer.gov.au.

The timetable for determining budgets and charges for the initial AMI budget period is set out in Table 1.1. Dates prescribed in the revised Order are in normal text and milestones identified by the AER are shown in italics.

5 Revised Order, clause 5I.6, 5I.7.

Table 1.1: Milestones for the initial AMI budget period

Milestone	Date
Final determination on initial AMI budget period budget application and 2010-11 initial charges application	31 October 2009
2010-11 initial charges take effect	1 January 2010
Charges revision application to be submitted	31 August 2010
Submissions on charges revision application close	*30 September 2010*
Determination of revised charges for 2011	31 October 2010
2011 charges take effect	1 January 2011

Under the revised Order, DNSPs are required to commence installing advanced interval meters by the middle of 2010, with the rollout to be completed by the end of 2013. The full rollout schedule is shown in Table 1.2.

Table 1.2: AMI rollout schedule

Timeline	Rollout percentage
30 June 2010	5%
31 December 2010	10%
30 June 2011	25%
30 June 2012	60%
30 June 2013	95%
31 December 2013	100%

The DNSPs are required to use their best endeavours to meet the percentage targets for each year, as stated in clause 14 of the revised Order. Should a DNSP fail to meet these targets, the AER must consider whether the DNSP used its best endeavours in aiming to meet the targets, taking into consideration factors outlined in clause 14.2(c)(i), (ii) and (iii). Where the AER considers that the DNSP did not use its best endeavours to aim to meet the rollout targets, the DNSP is considered to have failed its license condition and may face penalties.

1.2 Structure of this determination

This document makes a determination for the DNSPs' initial AMI budgets for 2009–11 and for their charges for 2010–11. Section 2 outlines the draft determination released by the AER on 31 July 2009. Section 3 outlines the AER's assessment and determinations on each Victorian DNSP's proposed initial budget, following revised submitted budgets and submissions responding to the draft determination. Sections 4 and 5 respectively outline the AER's assessment and determination on the DNSPs' required revenues and proposed charges for 2010 and 2011, incorporating the AER's determination on the DNSPs' budget applications. Section 6 outlines the AER's response to a number of issues raised in submissions that are related to the AMI rollout, however, decisions on these issues do not explicitly form part of this determination.

2 Draft determination

This section summarises the draft determination on the DNSPs' proposed initial AMI budgets, revenues and charges, published on 31 July 2009.

2.1 AMI budgets for 2009–11

2.1.1 CitiPower and Powercor

The AER elected to review the budget applications of CitiPower Ltd (CP) and Powercor Australia Ltd (PC) concurrently, as the applications were almost identical due to their collaboration on the AMI rollout. The two DNSPs operate from a common IT platform and have together engaged a related party, CHED Services, to manage the procurement program and facilitate the AMI rollout.

Following its investigations of the proposals and supporting information, the AER did not establish that CP's and PC's proposed expenditures were related to out of scope activities or were not prudent, with the exception of costs for customer response trials, which the AER established it is more likely than not that they will not be incurred.

The draft determination rejected CP and PC's submitted budgets. The new submitted budgets it determined to approve are set out in Tables 2.1 and 2.2.

Table 2.1: AER draft determination- new submitted budget for CitiPower ($'000s, real 2008)

	2009	2010	2011
CP proposed capex	23,683	42,829	46,976
CP proposed opex	13,988	10,089	10,358
CP proposed customer response trial costs	433	191	133
AER draft determination – CP capex	23,683	42,829	46,976
AER draft determination – CP opex	13,555	9,897	10,225

Source: CitiPower, Advanced Metering Infrastructure Budget Application 2009-11, 27 February 2009, budget templates (confidential).

Table 2.2: AER draft determination- new submitted budget for Powercor ($'000s, real 2008)

	2009	2010	2011
PC proposed capex	41,232	98,460	117,520
PC proposed opex	29,505	20,588	22,708
PC proposed customer response trial costs	1,010	446	311
AER draft determination – PC capex	41,232	98,460	117,520
AER draft determination – PC opex	28,495	20,142	22,397

Source: Powercor, Advanced Metering Infrastructure Budget Application 2009-11, 27 February 2009, budget templates (confidential).
Note: Totals may not add due to rounding

2.1.2 Jemena and United Energy

The AER elected to review Jemena Energy Networks' (JEN) and United Energy Distribution's (UED) initial AMI budget applications concurrently, as the DNSPs formed a partnership to undertake the AMI rollout in order to reduce the costs and risks associated with meeting their obligations under the revised Order. JEN and UED engaged Alinta Asset Management (AAM) to manage the delivery of the AMI program, including the budget and charges applications. The parties submitted very similar budget applications, and attached a combined appendix prepared by AAM with further details of their submitted budgets. This appendix is referred to as the combined budget application.

Following its investigations of the proposals and supporting information, the AER did not establish that JEN's and UED's proposed expenditures were related to out of scope activities or were not prudent, with the exception of costs proposed by UED for self insurance and equity raising, for which the AER established it is more likely than not that they will not be incurred.

The draft determination accepted JEN's submitted budget, set out in Table 2.3.

Table 2.3: AER draft determination- budget for JEN ($'000s, real 2008)

	2009	2010	2011
AER draft determination – JEN capex	54,607	31,940	34,044
AER draft determination – JEN opex	3,921	8,738	13,464

Source: JEN, budget templates (confidential), and AER analysis.
Note: Totals may not add due to rounding.

The draft determination rejected UED's submitted budget. The new submitted budget the AER determined to approve for UED is set out in Table 2.4.

Table 2.4: AER draft determination- new submitted budget for UED ($’000s, real 2008)

	2009	2010	2011
UED proposed capex	65,403	51,373	69,780
UED proposed opex	7,253	20,766	19,980
UED proposed self insurance costs	-	200	200
UED proposed equity raising costs	-	7,068	-
AER draft determination – UED capex	65,403	51,373	69,780
AER draft determination – UED opex	7,253	13,498	19,780

Source: UED, budget templates (confidential), and AER analysis.
Note: Totals may not add due to rounding.

2.1.3 SP AusNet

Following its investigations of the proposals and supporting information, the AER did not establish that SPA’s proposed expenditures were related to out of scope activities or were not prudent, with the exception of:

- $16.3 million of proposed contract costs (as defined in the revised Order and set out in SPA’s submitted budget), which the AER established were associated with contracts that were not let in accordance with competitive tender processes
- costs for customer response trials, where the AER established it is more likely than not that they will not be incurred.

The draft determination rejected SPA’s submitted budget. The new submitted budget the AER determined to approve is set out in Table 2.5.

Table 2.5: AER draft determination— new submitted budget for SPA ($'000s, real 2008)

	2009	2010	2011
SPA proposed capex	68,472	51,837	105,120
SPA proposed opex	29,874	28,997	27,501
SPA proposed direct load control costs	0	1,576	4,519
SPA proposed customer response trial costs	872	385	269
AER draft determination – SPA capex	68,472	50,261	100,602
AER draft determination – SPA opex	29,002	28,612	27,232

Source: SPA, *Advanced Metering Infrastructure Initial Budget Application,* 27 February 2009 (revised 3 March 2009), budget template (confidential)
Note: Totals may not add due to rounding.

2.2 Required revenues

The draft determination resulted in reductions to the revenue requirements for each DNSP compared to their proposals to reflect the AER:

- amending the offset of costs and revenues 2006–08
- did not accept the DNSPs' amendments to regulatory accounting data, which were in the form of written letters to the AER and not audited accounts. Instead, the AER used audited regulatory accounts provided to it in May and June 2009
- did not accept DNSPs' cost allocation that impacted the efficiency carryover mechanism (ECM), specifically regarding allocation of customer service and meter data services – IT related costs
- determined a weighted average cost of capital (WACC) of 8.96 per cent compared to the 10.01 per cent adopted by the DNSPs in their charges applications, arising from the measurement of the debt risk premium (DRP)
- adjusted the DNSP's proposed budget applications for operation and maintenance expenditure and capital expenditure over 2009.

With respect to the pricing principles of cost of service provision, cost allocation and simplicity established in the framework and approach paper, the draft determination accepted the pricing methodologies developed and applied by all DNSPs in their initial charges submissions.

The draft determination with respect to the revenues and charges of each DNSP is outlined in more detail below.

2.2.1 CitiPower

The draft determination rejected CP’s proposed revenue requirements in its charges application because:

- CP’s cost allocations for 2006 and 2007 were inconsistent with the 2006 and 2007 regulatory accounting statements. This included CP’s requested changes to the 2006 regulatory accounts, via unaudited letters to the AER, which transferred costs from Metering – regulated by price cap – excluding metering.
- The AER did not approve CP’s proposed initial budget application.
- The AER determined a WACC of 8.96 per cent compared to the 10.01 per cent proposed by the CP in its charges application.

The draft determination on CP’s revenue requirements is set out in Table 2.6.

Table 2.6: AER draft determination—CP revenue requirement ($’000s, nominal)

	2009	2010	2011
Return on capital	3,018	4,974	8,449
Depreciation	3,651	7,595	10,844
Operating & maintenance costs	14,230	10,656	11,290
Tax liability	0	0	0
Offset of costs and revenues 2006–08	6,584	N/A	N/A
Total revenue requirement	27,483	23,225	30,584

Source: AER, *Draft determination, Victorian Advanced Metering Infrastructure Review: 2009-11 AMI budget and charges applications,* July 2009.

CP’s proposed revenues were reduced by $4.39 million as a result of the draft determination. The AER therefore reduced 2011 charges to align with draft determination revenues in net present value (NPV) terms. Therefore, for a single phase single element meter in 2011, the draft determination charge was $15.79 less than that proposed by CP.

Having made the appropriate amendments to the revenue requirements, the draft determination for CP’s charges is set out in Table 2.7 below.

Table 2.7: AER draft determination—CP AMI charges, per annum, per NMI ($, nominal)

	2010	2011
Single phase	104.79	113.00
Three phase direct connected	136.98	147.72
Three phase CT connected	172.99	186.55

Source: AER, *Draft determination, Victorian Advanced Metering Infrastructure Review: 2009-11 AMI budget and charges applications*, July 2009.

2.2.2 Jemena

The draft determination rejected JEN's proposed revenue requirements in its charges application because:

- JEN did not substantiate the data used to develop its charges application, as these were inconsistent with its regulatory accounts. Further, reconciliations provided by JEN did not match its regulatory accounting statements
- The AER determined a WACC of 8.96 per cent compared to the 10.01 per cent proposed by JEN.

The draft determination on JEN's revenue requirements is set out in Table 2.8.

Table 2.8: AER draft determination—JEN revenue requirement ($'000s, nominal)

	2009	2010	2011
Return on capital	5,774	7,713	9,574
Depreciation	6,429	13,078	16,363
Operating & maintenance costs	4,116	9,408	14,867
Tax liability	0	0	0
Offset of costs and revenues 2006–08	-13,853	N/A	N/A
Total revenue requirement	2,466	30,199	40,804

Source: AER, *Draft determination, Victorian Advanced Metering Infrastructure Review: 2009-11 AMI budget and charges applications*, July 2009.

In the draft determination, the AER reduced JEN's 2009-11 proposed revenue requirements by $27.9 million. Therefore, proposed charges were not compliant with the revised Order.

For JEN's charges to be compliant with the draft determination revenue requirements in NPV terms, the AER reduced charges in 2010 and 2011. These are shown in Table 2.9. As a result of the draft determination, customers with a single phase single element meter would pay $66.84 less in 2010 than proposed by JEN and $6.18 less in 2011.

Table 2.9: AER draft determination—JEN AMI charges per annum, per NMI ($, nominal)

	2010	2011
Single phase single element	67.79	130.52
Single phase single element with contactor	67.79	130.52
Three phase direct connected	83.31	160.39
Three phase CT connected	92.62	178.32

Note: JEN's initial charges submission on 1 June 2009 proposed charges per NMI. This was an unintentional error by JEN, who intended to propose charges per meter. JEN's revised initial charges submission, made 30 September 2009 proposed charges per meter.

2.2.3 Powercor

The draft determination rejected PC's proposed revenue requirements in its charges application because:

- PC's cost allocations for 2006 and 2007 are not consistent with the 2006 and 2007 regulatory accounting statements. This included PC's requested changes to the 2006 regulatory accounts, via unaudited letters to the AER, which transferred costs from Metering – regulated by price cap– excluding metering.
- The AER did not approve PC's proposed initial budget application.
- The AER determined a WACC of 8.96 per cent compared to the 10.01 per cent proposed by PC.

The draft determination on PC's revenue requirements is set out in Table 2.10.

Table 2.10: AER draft determination—PC revenue requirement ($'000s, nominal)

	2009	2010	2011
Return on capital	5,698	10,013	18,682
Depreciation	7,140	14,852	22,387
Operating & maintenance costs	29,915	21,687	24,732
Tax liability	0	0	0
Offset of costs and revenues 2006–08	25,055	N/A	N/A
Total revenue requirement	67,807	46,551	65,800

Source: AER, *Draft determination, Victorian Advanced Metering Infrastructure Review: 2009-11 AMI budget and charges applications*, July 2009.

PC's revenues were reduced by $8.45 million as a result of draft determination. The AER therefore reduced 2011 charges to align with draft determination revenues in NPV terms. A customer with a single phase meter would pay $13.69 less in that year than what PC proposed. Table 2.11 shows the draft determination charges per meter type.

Table 2.11: AER draft determination- PC AMI charges, per annum, per NMI ($, nominal)

	2010	2011
Single phase	96.67	111.48
Three phase direct connected	127.50	147.04
Three phase CT connected	168.94	194.82

Source: AER, *Draft determination, Victorian Advanced Metering Infrastructure Review: 2009-11 AMI budget and charges applications*, July 2009.

2.2.4 SP AusNet

The draft determination rejected SPA's proposed revenue requirements in its charges application because:

- SPA attempted to reclassify expenditure from capital to operating and maintenance in its 2006 and 2007 regulatory accounting statements, to be consistent with its 2008 regulatory accounting statements, which the AER did not accept.
- The AER did not approve SPA initial budget application.
- The AER determined a WACC of 8.96 per cent compared to the 10.01 per cent proposed by SPA.

The draft determination on SPA's revenue requirements is set out in Table 2.12.

Table 2.12: AER draft determination—SPA revenue requirement ($'000s, nominal)

	2009	2010	2011
Return on capital	7,352	10,080	15,396
Depreciation	9,495	18,475	24,482
Operating & maintenance costs	30,447	30,806	30,071
Tax liability	0	0	0
Offset of costs and revenues 2006–08	-12,913	N/A	N/A
Total revenue requirement	34,380	59,362	69,949

Source: AER, *Draft determination, Victorian Advanced Metering Infrastructure Review: 2009-11 AMI budget and charges applications*, July 2009.

The AER made amendments to SPA's charges application and the budget applications, the effect of which was to reduce the 2009-11 revenue requirements by $11.15 million.

The AER has therefore reduced charges in 2010 and 2011 to align with draft determination revenues in NPV terms. A single phase single element meter charge reduced by $1.08 in 2010 and by $15.95 in 2011 compared to SPA's proposed charges. All charges resulting from the draft determination are set out in Table 2.13.

Table 2.13: AER draft determination—SPA AMI charges, per annum, per meter ($, nominal)

	2010	2011
Single phase single element 1 contactor (1 load control)	75.88	94.23
Single phase, two–element 2 contactors (2 load controls)	86.69	107.66
Multi phase, one contactor (1 load control)	100.69	125.04
Multi phase, two contactor (2 load controls)	111.70	138.71
Multi phase CT connected	143.82	178.60

Source: AER, *Draft determination, Victorian Advanced Metering Infrastructure Review: 2009-11 AMI budget and charges applications*, July 2009.

2.2.5 UED

The draft determination rejected UED's proposed revenue requirements in its charges application because of:

- Minor discrepancies in unmetered supplies revenue and costs that were incorrectly included in the charges application.
- The AER only accepted adjustments to 2006-08 revenues and costs that were consistent with UED's regulatory accounting statements.

- The AER did not approve UED's initial budget application.
- The AER determined a WACC of 8.96 per cent compared to the 10.01 per cent proposed by SPA.

As a consequence, the draft determination on UED's revenue requirements is set out in Table 2.14.

Table 2.14:AER draft determination—UED revenue requirement ($'000s, nominal)

	2009	2010	2011
Return on capital	8,704	11,007	14,905
Depreciation	10,083	18,927	24,091
Operating & maintenance costs	7,615	14,533	21,842
Tax liability	0	0	0
Offset of costs and revenues 2006–08	-5,778	N/A	N/A
Total revenue requirement	20,624	44,467	60,838

Source: AER, *Draft determination, Victorian Advanced Metering Infrastructure Review: 2009-11 AMI budget and charges applications*, July 2009.

UED's revenues were reduced by $12.72 million as a result of draft determination. The AER therefore reduced 2010 charges to align with draft determination revenues in NPV terms. A single phase single element meter charge reduced by $16.64 in 2010 and by $3.00 in 2011 compared to UED's proposed charges. Table 2.15 shows the draft determination charges for each meter type.

Table 2.15: AER draft determination—UED AMI charges, per annum, per NMI ($, nominal)

	2010	2011
Single phase single element	71.80	92.12
Single phase single element with contactor	73.30	94.02
Three phase direct connected	81.01	103.89
Three phase CT connected	86.40	110.82

Source: AER, *Draft determination, Victorian Advanced Metering Infrastructure Review: 2009-11 AMI budget and charges applications*, July 2009.

3 AMI budgets

3.1 DNSPs’ revised submitted budgets

3.1.1 CitiPower and Powercor

CP and PC submitted revised budget applications in response to the draft determination, responding to certain areas of the draft determination and informing the AER of changes that occurred in their forecast budgets subsequent to their initial February 2009 budget applications. The revised budget applications are highly similar, reflecting their collaboration in delivering the AMI rollouts.[6]

In their revised submitted budget applications, CP and PC identified the following variations from their February 2009 AMI budget applications:

- removal of costs associated with customer response trials, as per the draft determination
- reductions in costs for meter supply, communications supply, field installation costs and exchange rate assumptions, resulting from the execution of contracts that were estimated in the February 2009 budget applications
- revision of the capitalised portion of project management costs reflecting a change in the capital expenditure to operating expenditure ratio. The parties stated that total project management costs had not changed, and PC noted that the change is reflected in a higher overhead allocation to the opex categories of meter maintenance and backhaul services.[7]

CP and PC noted that they had not changed the prescribed metering offset or their calculation of the weighted average cost of capital, as required by the draft determination, as they intended to provide further information on these issues as part of their revised charges applications. CP’s and PC’s revised charges applications are outlined in Section 5.

3.1.2 Jemena and United Energy Distribution

JEN did not submit a revised budget as the draft determination accepted the proposed budget in its February 2009 budget application.

UED submitted a revised budget that accorded with the submitted budget that the AER stated it would approve, in Table 2.15 of the draft determination.[8]

3.1.3 SP AusNet

SPA submitted a revised budget in response to the draft determination, providing further information and responding to certain areas of the draft determination.[9]

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6 CitiPower, *Revised Budget Application*, 31 August 2009, pp. 1-2, and Powercor, *Revised Budget Application*, 31 August 2009, pp. 1-2.

7 Ibid.

8 UED, *Application for amended submitted budget*, 2 September 2009.

In its revised submitted budget, SPA provided clarification on its AMI contracts that were signed prior to 27 February 2009 (contract costs, as defined in the revised Order), which the AER rejected under the contract cost test in the draft determination.[10] SPA provided some signed contracts, quotes and purchase orders for goods and services supplied for metering 'business as usual' activities.

SPA also provided clarification and further information surrounding its proposed load control technology and two-element meters. SPA stated that:

- for two-element meters to enable control of off peak loads, an integrated contactor is needed for the second element
- for new single phase single element meter customers connecting to SPA's network with electric hot water or slab heating, a contactor is needed in the meter to enable SPA to control the load on such appliances. SPA stated that these new customers could be immediately transitioned to a time of use tariff once the meter is installed.

SPA considered that the AER had mistakenly removed costs for contactors on the second element of its two-element meters, and its revised submitted budget templates incorporated costs for these contactors. SPA's revised submitted budget templates did not include costs for contactors for single phase single element meters.

3.2 Submissions on the draft determination

The AER received submissions from six stakeholders on its draft determination, four of which commented on the draft determinations on the DNSPs' budget applications.[11] The AER also received a late submission from the Department of Primary Industries Victoria (DPI) on 2 October 2009.

3.2.1 Consumer Action Law Centre

The Consumer Action Law Centre (CALC) submitted that it is concerned that some of the approved AMI budget costs are 'business as usual costs' which may have been taken into account in previous general price determinations, or would be more appropriately assessed as part of future price determinations. CALC indicated the following costs may fall into this category:

- meter maintenance costs
- general systems implementations (for example new SAP operating systems)
- ombudsman charges

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[9] SPA, *Advanced Metering Infrastructure Revised Budget Application*, 28 August 2009.

[10] ibid, pp. 4-5 and AER, *Draft determination, Victorian Advanced Metering Infrastructure Review: 2009-11 AMI budget and charges applications*, July 2009 (draft determination), pp. 91-92.

[11] Where submissions made comments on other aspects of the draft determination (such as required revenues or charges), these are considered in sections 4 and 5 of this determination. Comments made in submissions that relate to other aspects of the AMI rollout are considered in section 6 of this determination.

- development of new call centres that could have been expanded or modified at a lesser cost

- costs relating to compliance with regulatory obligations, such as the Distribution Code.

CALC stated that it was unclear whether the AER had considered whether costs for these and other various items were only partially attributable to the rollout and otherwise outside scope.[12]

3.2.2 Consumer Utilities Advocacy Centre

The Consumer Utilities Advocacy Centre (CUAC) submitted comments and made recommendations on a number of issues surrounding the draft determination on the DNSPs' AMI budgets, including:

- that the AER should clarify the relationship between the revised Order and AMI minimum specifications documents, and consult with the Victorian Government regarding its interpretation of the revised Order. CUAC requested that the AER reconsider its draft determination to approve costs that are above the minimum specifications[13]

- that there is 'some perception' that the AER has been overly generous in allowing most costs because Victoria is the testing ground for the national smart meter rollout, in particular in the draft determination to allow the setting up of new customer call centres and Energy and Water Ombudsman (Victoria) (EWOV) complaints. CUAC stated that customers should not need to pay for trial and experimental systems which might solely benefit DNSPs, and that the AER must review all expenditure to ensure that unnecessary expenditure is not passed onto consumers[14]

- that the AER should review the competitive tendering process of DNSPs to ensure that their proposed expenditure is appropriate before the final determination is made[15]

- that the AER should review related party margins before the AMI final determination is made to ensure that costs are not inappropriately passed on to consumers[16]

- that it is unclear why there should be additional costs for complying with Electricity Distribution Code and Electricity Industry Guideline 11 since any costs should have been allowed under previous network price determinations. CUAC

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12 Consumer Action Law Centre, *Draft Decision – Victorian advanced metering infrastructure review 2009-11 AMI budget and charges applications*, 11 September 2009, p. 3.

13 Consumer Utilities Advocacy Centre, *Submission on AER draft determination Victorian advanced metering infrastructure review 2009-11 AMI budget and charges applications (July 2009)*, 11 September 2009, p. 3.

14 Ibid., pp. 7-8.

15 Ibid., pp. 8-9.

16 Ibid., p. 10.

requested that the AER clarify those components in the relevant electricity codes and guidelines that are additional to compliance requirements under licensing conditions or which have not been allowed for in previous DNSP price determinations.[17]

3.2.3 Department of Primary Industries Victoria

DPI raised a number of concerns relating to the draft determination, including:

- contract costs—that the AER has taken a narrow interpretation of what is meant by entering into a contract; that the draft determination did not indicate that the AER has assessed whether the DNSPs have, through actual conduct with suppliers prior to formal signing of contract documents, effectively entered into contracts that relate to such budget costs; that there is insufficient evidence in the draft determination to indicate whether the AER has assessed whether the expenditure incurred or commercial standard tests have been met; that if the AER is not satisfied with its assessment of various contract documents and cost estimates it is able to determine appropriate costs

- related party transactions—that DPI disagrees with the AER's assertion that the revised Order does not permit the AER to undertake an efficient cost review of AMI related party margins; that in the case of related party margins, a competitive tendering process is the commercial standard for a reasonable business

- functionality and service level specifications—that it is concerned that some expenditure has been approved in the draft determination for activities which are above minimum specifications, and that in this case, the AER is able to determine an appropriate level of expenditure

- double counting—that the AER should provide assurance that it has assessed whether any DNSP has included expenditure (particularly IT related) in their budget application for which revenue was already provided for in the Essential Services Commission of Victoria's (ESCV) 2006 Electricity Distribution Price Review (current price determination).[18]

3.2.4 Energy and Water Ombudsman (Victoria)

EWOV stated that it was strongly opposed to the concept that DNSPs will be able to directly recover costs associated with the treatment of Ombudsman complaints. EWOV stated that this removes any incentive for DNSPs to take a proactive approach to preventing complaints from occurring or managing complaints effectively and efficiently.

EWOV stated that it considered that a reasonable business would put resources into resolving its customers' complaints as early as possible and that it accepts that general customer service costs should be recoverable. However, EWOV argued that if DNSPs do not handle complaints efficiently and they are then escalated to the Ombudsman,

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[17] Ibid., pp. 11-12.

[18] Department of Primary Industries Victoria, *Draft determination Victorian advanced metering infrastructure review 2009-11 AMI budget and charges applications*, 2 October 2009.

Ombudsman costs are not directly attributable to the AMI rollout and should be borne by DNSPs rather than customers.[19]

3.2.5 Integral Energy

Integral Energy's (Integral) submission commented on the acceptance of the rollout of two-element meters proposed by PC and SPA in the draft determination. Integral noted that it currently has 340 000 customers on controlled load tariffs connected to its NSW distribution network.

Integral disagreed with the AER's position that network demand management currently provided by using two-element meters can be effectively managed using time of use pricing through a single element AMI meter, once any transitional issues related to tariff reassignment costs and the timing of the availability of AMI communications technology are addressed. Integral argued that this is incorrect, stating that the two-element meters (controlled load tariffs) provide Integral with certainty in managing the timing of network load. Integral provided some load profile information demonstrating the impact that removing two-element meters would have on peak demand on its network.

Integral sought clarification from the AER that the use of two-element meters can provide a cost effective demand management solution.[20]

3.3 AER considerations

This section sets out the AER's consideration of issues raised in the DNSPs' revised submitted budget applications and submissions by stakeholders on the draft determination on AMI budgets.

3.3.1 Revised Order and minimum specifications documents

CUAC's submission stated that there needs to be further clarification regarding the scope and intent of the revised Order, in particular whether the revised Order constrains the AER in how it is able to determine the DNSPs' budgets and charges against cost efficiency exercises normally carried out in a distribution price review. CUAC requested that the AER seek to clarify DPI's intentions regarding the scope of the revised Order, to allow consumers confidence in the integrity of the process and to ensure that the costs allowed under the draft determination accord with the revised Order.

DPI stated its concern that the draft determination approved some expenditure for activities which are above minimum specifications. DPI submitted that where expenditure is above the minimum specifications, the AER is able to determine an appropriate level of expenditure.[21]

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[19] Energy and Water Ombudsman (Victoria), *RE: Draft Determination – Victorian advanced metering infrastructure review 2009-11 AMI budget and charges applications*, 11 September 2009.

[20] Integral Energy, *Draft Determination on Victorian AMI Rollout*, 11 September 2009.

[21] Department of Primary Industries Victoria, *Draft determination Victorian advanced metering infrastructure review 2009-11 AMI budget and charges applications*, 2 October 2009.

The AER notes CUAC's comparison of the AER's role under the revised Order and its role in carrying out cost efficiency exercises within a distribution price review.[22] As noted in the draft determination, these roles are not the same. During a distribution price review, it is up to the DNSP to prove that its costs are efficient and meet the capex and opex objectives in clauses 6.5.6 and 6.5.7 of the NER. For example, clause 6.5.7(c) of the NER states:

> The AER must accept the forecast of required capital expenditure of a Distribution Network Service Provider that is included in a building block proposal if the AER is satisfied that the total of the forecast capital expenditure for the regulatory control period reasonably reflects:
>
> (1) the efficient costs of achieving the capital expenditure objectives; and
>
> (2) the costs that a prudent operator in the circumstances of the relevant Distribution Network Service Provider would require to achieve the capital expenditure objectives; and
>
> (3) a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives. A distribution price review conducted under chapter 6 of the NER.

During this AMI review, rather than the DNSP being required to provide information to ensure that the AER is satisfied the proposed expenditure is efficient, the revised Order requires that the proposed expenditure is deemed to be approved unless the AER can establish otherwise.[23]

The revised Order provides for a cost pass through of actual expenditures incurred by the DNSPs in rolling out AMI subject to the setting of expenditure budgets which the DNSPs are required to report against throughout the initial AMI period. In relation to budget proposals the revised Order requires the AER to approve expenditures which it cannot establish as being outside scope or not prudent. However, where the AER does establish that proposed costs are outside scope or not prudent, it has discretion to determine whether the costs should be rejected, approved or replaced with different costs. That is, for items that are established as being outside scope, the AER is not required to simply reject associated costs.

The framework and approach paper stated:

> In considering the matter of scope it is also necessary to take into account the relevant specifications for providing the services. For performance in excess of the minimum Victorian specifications, distributors will need to provide a separate cost/benefit analysis quantifying benefits to the distributor, retailers and end customers, and demonstrating why regulated tariffs should provide the revenue required.[24]

[22] Consumer Utilities Advocacy Centre, *Submission on AER draft determination Victorian advanced metering infrastructure review 2009-11 AMI budget and charges applications (July 2009)*, 11 September 2009, p. 3.

[23] Revised Order, clause 5C.

[24] AER, *Final decision - Framework and approach paper – Victorian advanced metering infrastructure review*, January 2009, p. 29.

In deciding whether or not to reject costs, the AER has taken a number of factors into account including:

- the efficiency of the decision to incur the costs, such as whether there is a positive business case or technical reason why the costs need to be incurred
- the long term interests of consumers
- the security and safety of the electricity supply system.

DPI's submission pointed out the AER's discretion with regards to determining appropriate levels of expenditure for items which are above the minimum specifications. Clauses S2.1, S2.6 and S2.10 of the revised Order state:

> Activities within scope are those activities reasonably required:
>
> (a) for the provision of Regulated Services; and
>
> (b) to comply with a metering regulatory obligation or requirement.

In developing its framework and approach for this determination, the AER considered closely the discretion the revised Order provided it when applying the scope test. The AER considered that where proposed activities or items of expenditure were above the minimum specifications, the scope test enabled it to determine, on a case by case basis, whether the proposed expenditure would provide a net benefit to DNSPs, customers or retailers in the context of the AMI rollout. The AER's consultant, Energeia, noted in its report the specific areas where it had found proposed activities and costs to be above the minimum specifications:

> Although relatively limited, there were a number of examples of DNSPs specifying solution component or sub-component performance levels which appeared to be in excess of minimum specifications:
>
> - Two-element metering arrangements to support network tariffs,
> - 100% disaster recovery redundancy to support 99% service availability specifications,
> - Near real time IT processing requirements to meet performance specifications,
> - Additional IT systems to support multiple vendors to manage risk,
> - 100% of meters read within 25 minutes to meet performance specifications,
> - 100% of connect / disconnects performed within 10 minutes to meet performance specifications,
> - 100% of load control performed within 1 minute to meet performance specifications,
> - 100% of supply limiting performed within 1 minute to meet performance specifications,

- Broadband communication to support future AMI functionality and transaction growth, and

- NMS availability of 99.9% to meet performance specifications.[25]

The AER and Energeia closely examined each of these instances of expenditure above the minimum specifications. In each case, documents provided by the DNSPs demonstrated that there was a net benefit in incurring the cost or carrying out the activity which outweighed the additional cost (if any) of the related activity. The DNSPs provided technical analysis of their existing systems which demonstrated the options considered for implementation of AMI. In some cases, the DNSPs have purchased solutions that go above the minimum functionality specifications to enable them to meet service level specifications. The AER has also considered that individually tailored solutions designed to meet the minimum specifications overall may prove to be more expensive than readily available solutions. As such, the AER has taken many factors into consideration in assessing the appropriateness of investments which go beyond the minimum specifications.

Spectrum bandwidth was a key area identified by stakeholders and the AER's consultant as being potentially above minimum specifications and outside scope for a number of DNSPs. The DNSPs require spectrum to perform AMI functions including data collection and load control.

Energeia's report noted that SPA's AMI communications technology enabled 100 per cent of its AMI meters to be read within 25 minutes, which is above the minimum specifications. [26] The AMI minimum functionality specifications require that:

> 'Where meters are remotely read the interval energy data per collected channel shall be able to be collected by the AMI system at least once every 24 hours.'[27]

In addition, the AMI minimum service level specifications require that that from 1 January 2012, no less than 95 per cent of actual data from AMI meters is to be available to market participants by 6am the following day.[28] While the AER considered that SPA's proposed WiMAX communications solution was potentially above minimum functionality specifications, as noted in the draft determination, in presenting its communications solution to the AER, SPA demonstrated that it had optimised its communications to meet the AMI minimum service levels specifications, including the provision of data to market and execution of load control within specified time frames.[29] SPA demonstrated that it had made a reasonable commercial decision to employ WiMAX based on the overall costs, risks and suitability of available technologies. The AER was satisfied that SPA's selection of a WiMAX communications solution would provide a net benefit to consumers, retailers

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[25] Energeia, *Review of Victorian Distribution Network Service Provider's Advanced Metering Infrastructure Budget Applications 2009-11*, July 2009, p. 16.

[26] Ibid., p. 32.

[27] Department of Primary Industries (Victoria), *Advanced metering infrastructure – Minimum AMI functionality Specification (Victoria)*, September 2008, p. 4.

[28] Department of Primary Industries (Victoria), *Advanced metering infrastructure – Minimum AMI Service Levels Specification (Victoria)*, September 2008, p. 6.

[29] AER, *draft determination*, pp. 78-79.

and to SPA, and accordingly decided to approve costs for the solution despite it being outside scope, as defined by the revised Order.

Similarly, CP's and PC's chosen AMI meter and communications vendor proposed that once installed, it would be able to read 100 per cent of AMI meters in 6 hours.[30] JEN's and UED's meter and communications solutions were subject to an independent technical review which found that the DNSPs' chosen AMI and IT technology was appropriate for the initial and future requirements of the Victorian mandated rollout, and that risk of the technology failing to meet functionality specifications was low to medium.[31]

In such cases where proposed activities were above the minimum specifications, the AER applied its discretion in examining the proposed costs to determine whether there was a net benefit in going beyond minimum specifications. The AER considers that independent technical consultant reports demonstrating that the chosen AMI technologies are likely to be appropriate, given the current state of each DNSP's infrastructure and the minimum specifications requirements, gives some confidence that the proposed solutions are reasonable.

Therefore, while the AER has determined that certain proposed investments have elements that are out of scope, the AER considers that the DNSPs have taken reasonable steps to minimise costs with respect to the service and functionality requirements of the revised Order.

3.3.2 'Business as usual' costs

Submissions from CALC and CUAC highlighted their concerns that the DNSPs' AMI budgets included costs associated with meter maintenance, general data and management systems, compliance with regulatory instruments and overheads, which were already provided for in the current price determination. DPI stated its concern that the draft determination may have approved some IT costs which were provided for in the current price determination, and for which costs are currently being recovered from customers via distribution use of system (DUOS) charges.

The draft determination set out the AER's consideration of proposed costs under the tests prescribed in the revised Order. The AER considered costs according to whether they were contract or non-contract costs, as defined in the revised Order. Generally, operational costs were considered as non-contract costs, as they are provided by the DNSPs or their related parties. Contracts with related parties were not competitively tendered and accordingly were considered to be non-contract costs and subject to the expenditure incurred and commercial standard tests under the revised Order.

The AER considers that costs already provided for in previous regulatory allowances may be rejected under the expenditure incurred test, as it would be more likely than not that these costs would not be incurred for the AMI rollout.

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30 KEMA, *CHED Services Advanced Metering Infrastructure Independent Technical Review-Technical Assessment Report*, 24 October 2008, p. 17.

31 KEMA, *The SmartNet Program – Victorian Advanced Meter Infrastructure Rollout for United Energy Distribution and Jemena Electricity Networks-Technical Assessment and Cost Validation Due Diligence Report*, November 2008, Summary p. 1.

3.3.2.1 Meter maintenance

All DNSPs included costs for meter maintenance from 1 January 2009, including maintenance, repairs and replacement of accumulation meters. Metering costs for 2006–08 were also included in the DNSPs' initial AMI budget proposals, in accordance with the revised Order.

Clause 6.1 of the revised Order (unchanged from the original Order) states:

> 6.1 Current Price Determination
>
> Notwithstanding anything to the contrary in the Current Price Determination, the maximum charges that each distributor may make for the provision of metering services to unmetered connection points are the prices determined by the Commission for each distributor as follows:
>
> (a) the prices to 31 December 2008 (if any) are the prices determined in accordance with the Current Price Determination applicable in the year ended 31 December 2007 multiplied by $CPI_{2007\text{-}2006}$, where $CPI_{2007\text{-}2006}$ means:
>
>> (i) the Consumer Price Index – All Groups Index for the Eight State Capitals as published by the Australian Bureau of Statistics for the September Quarter of 2007;
>>
>> **divided by**
>>
>> (ii) the Consumer Price Index – All Groups Index for the Eight State Capitals as published by the Australian Bureau of Statistics for the September Quarter of 2006; and
>
> (b) for the period from 1 January 2009 to the commencement of the first Subsequent Price Determination, the prices for each year (or part thereof) in this period are the prices determined under this Order applicable on 31 December of the previous year multiplied by CPI_t, where CPI_t means:
>
>> (i) the Consumer Price Index – All Groups Index for the Eight State Capitals as published by the Australian Bureau of Statistics for the September Quarter of the previous year;
>>
>> **divided by**
>>
>> (ii) the Consumer Price Index – All Groups Index for the Eight State Capitals as published by the Australian Bureau of Statistics for the September Quarter of the year preceding the year referred to in paragraph (i).

Clause 6.1(b) of the revised Order supersedes the current price determination and provides that no double counting or recovery of metering costs, including meter maintenance costs, is possible.

The current price determination allowed the DNSPs to recover some revenues for the planned interval meter rollout (IMRO). As noted in the introduction above, the decision to rollout IMRO was overturned when the Victorian Government decided to rollout AMI. At the time of that decision, the Victorian DNSPs were advised by the ESCV that they would not be held liable for non-compliance with its 2006 determination.

Clause 5D.4(a) of the revised Order allows for prescribed metering costs incurred between 1 January 2006 and 31 December 2008, including some IMRO related costs (which have not already been recovered via metering tariffs) to be recovered in AMI charges from 1 January 2010.

All meter reading costs incurred and recovered in this 2006–08 period are subject to a separate price control for metering, as per the current price determination. The revised Order requires that these costs and revenues are offset as part of this determination, discussed in section 4.4.7.1, such that any under or over recovery of revenue in relation to metering services over 2006–08 is accounted for in the charges for 2010 and 2011 approved as part of this determination. Only meter reading costs to be incurred over 2009–11 have been included in the DNSPs' budget applications for this initial budget period.

The AER's review of the DNSPs' initial AMI budget proposals for 2009–11 demonstrates they did not incorporate prescribed metering or IMRO meter reading costs that had already been provided via the current price determination.

3.3.2.2 IT, data and management systems costs

In considering the DNSPs' proposed costs under the costs incurred and commercial standard tests in its draft determination, the AER had regard to the extent to which DNSPs had sought to meet their AMI requirements under the revised Order by using or amending existing data and management systems. In order for the AER and its consultant to be satisfied that incurring expenditure on data and management systems did not involve a substantial departure from the commercial standard that a reasonable business would exercise in the circumstances, it needed to ensure that the DNSPs had considered and costed all options for meeting their AMI obligations. This includes options for utilising existing systems where possible.

CP and PC engaged CSC to review the AMI minimum functionality and associated service levels against their current IT environments.[32] The AER reviewed documentation prepared by CSC which discussed options for replacement and upgrade of the existing business applications and system management, having regard to the minimum functionality and service level requirements specified by DPI.[33] The AER is satisfied that CSC undertook a reasonable level of options analysis in designing CP's and PC's AMI solutions, commensurate with a reasonable commercial standard.

JEN and UED, via AAM, engaged Accenture to undertake an independent replacement review of the DNSPs' customer information systems incorporating meter data management, network revenue management, meter asset management and outage management systems, collectively known as CISPlus+, as well as the consumption data management application.[34] The DNSPs' used this review to inform their AMI procurement decisions. The AER is satisfied that JEN and UED have made sufficient

[32] CitiPower, *Advanced Metering Infrastructure Budget Application 2009-11*, 27 February 2009, p. 44, Powercor, *Advanced Metering Infrastructure Budget Application 2009-11*, February 2009, p.45.

[33] CSC, *Powercor – AMI Project Infrastructure – Logical Technology Model*, 1 February 2008.

[34] Accenture, *CIS Replacement Option Review*, confidential, 25 February 2009.

efforts to investigate options for maintaining their customer information systems and consumption data management applications in order to make efficient decisions based on the lowest cost option.

SPA adopted an in-house approach to its AMI technology options analysis. For the draft determination the AER reviewed numerous documents outlining SPA's AMI technology selection process.[35] The AER is satisfied that SPA thoroughly considered the use and upgrade of its existing IT and network management systems to facilitate AMI, and has adopted an approach that does not reflect a substantial departure from the commercial standard that a reasonable business in SPA's circumstances would undertake.

The current price determination states that in assessing the appropriate IT costs to be apportioned to the metering price control, the ESCV's consultant developed a benchmark generic metering data system and estimated a range of costs based on this benchmark system.[36] The ESCV considered this benchmark and its consultant's recommendations in approving cost recovery for the DNSPs' metering data services IT costs.[37]

The AER notes that most of the DNSPs' proposed AMI IT costs are, or will be, subject to competitively tendered contracts. The AER considers that the test in the revised Order for contract costs relied on the assumption that where costs had been competitively tendered, they were likely to reflect a prudent and efficient outcome. In assessing the IT non-contract costs under the expenditure incurred and commercial standard tests, the draft determination noted that the AER had regard to whether the DNSP was in the late stages of a competitive tendering process, and the extent to which its forecast costs were based on either an average of tender responses and/or the recommendations of independent technical experts.[38] The different approaches to assessing metering IT costs between the current price determination and the AER's AMI draft determination are due to the differences between chapter 6 of the NER and the revised Order.

Following DPI's submission, the AER conducted further analysis of the DNSPs' regulatory proposals submitted to the ESCV in October 2004, specifically the IT related costs. The AER also examined IT costs approved in the current price determination, both under Non-network capex—IT and Metering price control—meter data management cost categories.

The metering price control was established to separate the recovery of costs related to the Victorian government's decision to rollout remotely read interval meters (IMRO). The AER notes that the IT costs approved in the current price determination relating to the IMRO rollout and recovered over 2006–08 (considered in section 4.4.7.4) were specific to the IMRO decision, and differ significantly from the IT systems necessary

35 SPA, Email to the AER - *RE: AER Questions on SP AusNet Budget Application,* 22 June 2009, attachments.

36 ESCV, *Electricity Distribution Price Review 2006-10—October 2005 Price Determination as amended in accordance with a decision of the Appeal Panel dated 17 February 2006—Final Decision Volume 1 Statement of Purpose and Reasons,* October 2006, pp. 533-534.

37 Ibid., p. 534.

38 AER, *draft determination*, p. 42, 70, 102.

to complete the DNSPs' AMI rollouts. This is due to the different nature of the IMRO and AMI rollout obligations.

The AER requested further explanation from the DNSPs as to the differences between costs being recovered under DUOS tariffs over 2006–10 and those which were recovered under metering price control tariffs in 2006–08.[39]

In requesting this information, the AER considered that where IT costs could be identified as having been recovered under DUOS tariffs over 2006–10, they are unlikely to be incurred again in rolling out AMI and would accordingly not be approved under the expenditure incurred test. The AER notes that this logic could be applied to numerous cost categories within the DNSPs' budget applications, however, it considered that the tendency for shared costs across general business and AMI technology costs is greatest for IT applications. In general, network IT applications are used for numerous business functions. The type of applications required to enable the DNSPs to evolve their internal business and information systems to interval meter data collection and AMI go beyond the DNSPs' metering related functions. The DNSPs have attempted to apportion costs of larger IT applications and existing contracts to their AMI budgets based on the number of additional interfaces and functions required especially to facilitate AMI, which the AER considers is reasonable.

The AER acknowledges the importance of ensuring the DNSPs are not recovering costs more than once and therefore inflating AMI charges. The AER notes that, as is typically the case, the current price determination provided IT capex costs on an aggregate level. As alluded to above, in investigating this issue the AER attempted to identify the following:

- projects and costs which were sought in the DNSPs' regulatory proposals submitted to the ESCV over five years ago
- costs which were subsequently approved
- the extent to which costs for IT investments had been recovered from customers following the current price determination
- costs the DNSPs are seeking recovery under AMI charges.

The AER identified some IT investments that were common across these information sources, however, where they were expressed they were typically at a high level. Furthermore, the ESCV used an aggregate approach when approving costs in the current price determination. The difficulties in identifying specific investments were reflected by the DNSPs in response to the AER's further questions, where they were also unsure what IT applications were to be recovered under the current determination. The AER's considerations for each DNSP are considered below.

[39] AER, Email to the DNSPs - *Information request – IT costs provided for in the 2006 EDPR*, 5 October 2009.

CitiPower and Powercor

The current price determination approved $109.6 million of IT capex to be recovered via CP's and PC's DUOS tariffs over 2006–10.[40] In addition, the current price determination approved $23 million of IT capex for CP and PC to facilitate the IMRO rollout over 2006–10, to be recovered under the separate metering price control.[41] In their revised AMI budget application, CP and PC proposed a total of $80 million of IT capex over 2009–11.[42]

CP and PC stated that the current price determination did not approve 100 per cent of their proposed IT expenditure, nor did it specifically approve or reject any specific project. The ESCV determined capex requirements on an aggregate level rather than an asset category level.[43] The AER identified several IT applications for which CP and PC sought cost recovery in both their 2004 regulatory proposals for IT capex and initial AMI budget proposals, to which the DNSPs responded:

- geographic information system and SAP (works management and logistics application) enhancement—costs sought in 2004 were to enable customers to make inquiries with respect to applications for supply extensions or augmentations. Related costs sought in the AMI budget application are to support the AMI field deployment program, including creating the visibility of meter exchanges and the ordering, receipt and distribution of meters across the network

- customer service systems costs sought in 2004 cover the annual business as usual compliance upgrades to existing systems, while the associated AMI customer service systems relates to compliance upgrades to new AMI systems

- costs associated with increased data storage, the Meter Data Management and Network Transaction Management Systems—these costs were allocated in the current price determination to the separate metering price control. Clause 5D.4(a) of the revised Order requires costs incurred to be offset by revenue earned over 2006–08 as part of this determination.[44]

Jemena Energy Networks

The current price determination approved $41.4 million of IT capex to be recovered via JEN's DUOS tariffs over 2006–10.[45] In addition, the current price determination approved $10.8 million of IT capex for JEN to facilitate the IMRO rollout over 2006–

40 ESCV, *Electricity Distribution Price Review 2006-10—October 2005 Price Determination as amended in accordance with a decision of the Appeal Panel dated 17 February 2006—Final Decision Volume 1 Statement of Purpose and Reasons*, October 2006, p. 315.

41 Ibid., p. 536.

42 CitiPower, *Revised Budget Application*, 31 August 2009, confidential budget templates, and Powercor, *Revised Budget Application*, 31 August 2009, confidential budget templates.

43 CitiPower and Powercor, Email to the AER - *Response to AMI queries*, 12 October 2009, p. 2.

44 Ibid., pp. 2-3.

45 ESCV, *Electricity Distribution Price Review 2006-10—October 2005 Price Determination as amended in accordance with a decision of the Appeal Panel dated 17 February 2006—Final Decision Volume 1 Statement of Purpose and Reasons*, October 2006, p. 315.

10, to be recovered under the separate metering price control.[46] In its AMI budget application, JEN proposed $46.5 million of IT related capex.[47]

The AER identified the following IT applications and costs which JEN sought recovery via DUOS tariffs (IT capex – Non-network expenditure) in its 2004 regulatory proposal to the ESCV and for which it is seeking recovery in its initial AMI budget application:

- geographic information system upgrades[48]
- SAP updates[49]
- Meter Data Management System replacement[50]
- outage management system[51]
- customer information system (CIS) enhancement/replacement.[52]

JEN responded that its AMI budget application only proposes expenditure which is required for the AMI rollout, and that IMRO related expenditure is dealt with in the 2006–08 revenue offset, as required by clause 5D.4(a) of the revised Order.[53] JEN did not provide details on the differences between the IT costs sought in 2004 and those forming part of its AMI budget application.

SP AusNet

The current price determination approved $29.1 million of IT capex to be recovered via SPA's DUOS tariffs over 2006–10.[54] In addition, the current price determination approved $12.2 million of IT capex for SPA to facilitate the IMRO rollout over 2006–

46 Ibid., p. 536.

47 JEN, *Advance Infrastructure Roll out Budget Application from Jemena Energy Networks (VIC) Ltd*, 27 February 2009, budget templates (confidential).

48 AGL, *2006 Electricity Distribution Price Review Submission By AGL Electricity Limited*, October 2004, p. 60 and Alinta Asset Management, *AMI Budget Application 2009-11*, 26 February 2009,, p. 53.

49 AGL, *2006 Electricity Distribution Price Review Submission By AGL Electricity Limited*, October 2004, p. 60 and Alinta Asset Management, *AMI Budget Application 2009-11*, 26 February 2009, p. 54.

50 AGL, *2006 Electricity Distribution Price Review Submission By AGL Electricity Limited*, October 2004, p. 61 and 120, and Alinta Asset Management, *AMI Budget Application 2009-11*, 26 February 2009, p. 52.

51 AGL, *2006 Electricity Distribution Price Review Submission By AGL Electricity Limited*, October 2004, p. 62 and Alinta Asset Management, *AMI Budget Application 2009-11*, 26 February 2009, p. 53.

52 AGL, *2006 Electricity Distribution Price Review Submission By AGL Electricity Limited*, October 2004, p. 63 and Alinta Asset Management, *AMI Budget Application 2009-11*, 26 February 2009, p. 52.

53 JEN, Email to the AER - *AMI Further Questions*, 9 October 2009.

54 ESCV, *Electricity Distribution Price Review 2006-10—October 2005 Price Determination as amended in accordance with a decision of the Appeal Panel dated 17 February 2006—Final Decision Volume 1 Statement of Purpose and Reasons*, October 2006, p. 315.

10, to be recovered under the separate metering price control.[55] In its revised AMI budget application, SPA proposed $72.2 million of IT related capex.[56]

The AER identified that Enterprise Application Integration was proposed as a cost item by SPA in its 2004 regulatory proposal to the ESCV, and was also proposed as part of SPA's initial AMI budget proposal.[57] The AER queried which costs had already been recovered via DUOS prices over 2006–10. SPA explained the difference between Enterprise Application extension and upgrade costs relating to its general business which have been recovered under DUOS, and Enterprise Application Integration costs, of which 94 per cent of interfaces are related to AMI.[58]

United Energy Distribution

The current price determination approved $62.6 million of IT capex to be recovered via UED's DUOS tariffs over 2006–10.[59] In addition, the current price determination approved $12.2 million of IT capex for UED to facilitate the IMRO rollout over 2006–10, to be recovered under the separate metering price control.[60] In its revised AMI budget application, UED proposed $44.6 million of IT related capex.[61]

The AER identified the following IT applications and costs which UED sought recovery via DUOS tariffs (IT capex – Non-network expenditure) in its 2004 regulatory proposal to the ESCV and for which it is seeking recovery in its initial AMI budget application:

- CISPlus replacement[62]
- billing systems (including a Network Revenue Management System)[63]
- meter data management.[64]

UED responded that it is unable to distinguish between the IT applications it proposed in 2004 and those which were approved in the current price determination.[65]

55 Ibid., October 2006, p. 536.
56 SPA, *SP AusNet - updated AMI pricing and budget templates*, 13 October 2009.
57 Singapore Power, *TXU Networks Electricity Distribution Price Review 2006 Price-Service Proposals for the Period 2006-2010*, October 2004, p. 95; and SPA, SPA, *Advanced Metering Infrastructure Initial Budget Application,* 27 February 2009 (revised 3 March 2009), p. 5.
58 SPA, Email to the AER - *Response to AER questions 5 October*, 9 October 2009.
59 ESCV, *Electricity Distribution Price Review 2006-10—October 2005 Price Determination as amended in accordance with a decision of the Appeal Panel dated 17 February 2006—Final Decision Volume 1 Statement of Purpose and Reasons*, October 2006, p. 315.
60 Ibid., October 2006, p. 536.
61 UED, *AMI Budget Application 2009-11 to the Australian Energy Regulator*, 27 February 2009, budget templates (confidential).
62 UED, *2006 Electricity Distribution Price-Service Offering*, October 2004, p. 74, and Alinta Asset Management, *AMI Budget Application 2009-11*, 26 February 2009, p. 52.
63 Ibid., p. 52.
64 Ibid., p. 53.
65 UED, Email to the AER– *AMI further questions*, 9 October 2009.

Conclusion- double recovery of IT costs

Following further investigation, and in the context of the difficulties noted above, the AER did not establish that IT costs proposed by the DNSPs for the initial AMI budget period have been recovered under DUOS over 2006–10.

The AER notes that the double recovery of common costs is a generic issue for regulators, in particular when making concurrent revenue determinations. The revised Order requires that DNSPs' submit audited regulatory accounts in the annual AMI cost true-up process, for which the AER must approve an auditor.[66] In developing agreements between the AER, each DNSP and its auditors as required by clause 5I.3(e), the AER will ensure that the potential for double recovery of common costs between DUOS and metering charges is closely examined, in particular for 2010 charges. The AER and its consultants will closely examine the DNSPs' 2011–15 regulatory proposals to ensure costs allocated and approved for the AMI rollout are not also approved for recovery via DUOS in 2011–15.

3.3.2.3 Costs for compliance with regulatory obligations and requirements

CUAC's submission drew particular attention to costs allocated for compliance with regulatory instruments and codes, and requested that the AER clarify those components in the relevant electricity codes and guidelines that are additional to compliance requirements under licensing conditions, or which have not been provided in previous price determinations.[67]

In considering JEN's and UED's proposed costs under the scope test, the draft determination indicated that Outage Management System and Rollout Compensation and Claims costs were required by Electricity Distribution Code (ESCV, March 2008), clauses 5.2 and 6.3, and Electricity Industry Guideline 11 – Voltage variation compensation guideline, respectively. Schedule 2 part 1 of the revised Order states that

> Activities within scope are those activities reasonably required:
>
> a) for the provision of Regulated Services; and
>
> b) to comply with a metering regulatory obligation or requirement.[68]

The AER considered that as these costs were required to enable JEN and UED to comply with regulatory obligations and requirements, these activities were accordingly within scope. For all other cost items proposed by JEN, UED, CP, PC and SPA, each was specifically linked to a requirement under the revised Order, as set out in Tables 2.5, 2.13 and 2.18 of the draft determination. The AER does not consider it necessary for this determination to outline all codes and guidelines for which DNSP compliance costs are increased beyond any other regulatory allowance due to the AMI rollout, however, it agrees that those regulatory obligations that have been relied on as the sole justification for AMI costs deserve consideration.

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66 Revised Order, clause 5I.3(c), (d) and (e).

67 Consumer Utilities Advocacy Centre, *Submission on AER draft determination Victorian advanced metering infrastructure review 2009-11 AMI budget and charges applications (July 2009)*, 11 September 2009, pp. 11-12.

68 Revised Order, clause S2.1(a).

Following CUAC's submission, the AER requested that JEN and UED provide further information on regulated revenues previously allowed for Outage Management Systems and voltage compensation and claims costs, in order to meet the Electricity Distribution Code (ESCV, March 2008), clauses 5.2 and 6.3, and Electricity Industry Guideline 11 – Voltage variation compensation guideline.

JEN and UED responded that they were not allowed to recover DUOS revenue in the current price determination to cover costs for outage management systems and voltage compensation and claims.[69] UED indicated that rollout compensation and claims costs were included in the prescribed metering allowance for IMRO, the true-up for which is allowed under clause 5D of the revised Order.

The DNSPs indicated that, while their initial AMI budget applications did not link the costs for outage management and voltage compensation and claims directly to the list of items within scope in the revised Order, the activities are in fact listed as within scope, as per clauses S2.4.1(c)(ii), S2.4.2(c)(ii), S2.1.(b)(2)(iii)(c). Further, the DNSPs confirmed that the entirety of their proposed costs for outage management and voltage compensation and claims are incremental costs required as a result of the AMI rollout.[70]

The current price determination rejected JEN's proposal for a step change in costs to implement a planned new outage management system, stating that it considered that the base level of operating and maintenance expenditure would likely be sufficient to cover these costs.[71] The current price determination also noted that:

> 'any business process improvements which resulted in lower costs will be self financing because the net costs would be expected to be less than those reflected in the revenue requirement.'[72]

The revised Order explicitly lists enhancement and configuration of an outage management system and infrastructure to manage unplanned outages of AMI technology as within scope and therefore, in principle, cost recoverable.[73] The AER notes this is contrary to the current price determination, however, it considers it reflects the Victorian Government's view that the DNSPs should be able to recover costs for outage management systems directly rather than out of any anticipated business efficiencies resulting from the new systems, due to the AMI rollout mandate and necessary impact this will have on the DNSPs' outage performance management.

3.3.2.4 Call centre costs

CUAC and CALC both submitted that the AER should closely consider the DNSPs' budgeted costs for new call centres where these services could have been provided using existing call centres. The DNSPs' included costs in their initial AMI budget

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69 JEN, Email to the AER - *JEN Response to AER AMI Further Questions,* 6 October 2009; and UED, Email to the AER - *Response to AER questions*, 5 October 2009.

70 JEN, Email to the AER - *JEN Response to AER AMI Further Questions,* 6 October 2009; and UED, Email to the AER - *Response to AER questions*, 5 October 2009.

71 ESCV, *Electricity Distribution Price Review 2006-10—October 2005 Price Determination as amended in accordance with a decision of the Appeal Panel dated 17 February 2006—Final Decision Volume 1 Statement of Purpose and Reasons,* October 2006, p. 242.

72 Ibid., p. 242 and 618.

73 Revised Order, clause S2.4.1(c)(ii).

proposals to handle an increased level of customer complaints and enquiries during the AMI rollout period. Following the issues raised by CUAC and CALC, the AER requested further information on the DNSPs' proposed call centre costs.

CP and PC advised the AER that they will utilise their existing call centres to manage the expected increased number of calls arising from the AMI rollout. CP and PC stated that the expected call rates were estimated using information gained in an AMI trial undertaken in 2007, which indicated that 41 per cent of customers receiving an AMI meter will contact the call centres.[74] The trial involved a rollout of 1500 AMI meters, in which 615 customers that received a meter contacted the call centre. The majority of the calls (345) were for booking appointments and solving access issues surrounding the physical meter exchanges.[75]

JEN and UED stated that they had contracted an installation services provider to provide an AMI Customer Contact Centre to manage customer calls. The DNSPs stated that they have estimated 10 per cent of customers who receive an AMI meter will contact the AMI Customer Contact Centre, and 0.5 per cent of customers who receive an AMI meter will make a complaint. These estimates were derived from research gathered from AMI installations in the United States and JEN's and UED's own trials and pre-rollout site surveys.[76] JEN and UED stated that in the first month of the AMI rollout (September 2009), 3223 meters were installed and 324 AMI-related calls were received by the project call centre. Of these, around 70 per cent were calls to arrange installation appointments.[77]

SPA stated that it expects that of all AMI meter installations, 25 per cent will result in an enquiry to its customer service phone line, which will function from its existing Customer Service Centre. Appointment and access related enquiries will be managed by SPA's installation provider (which was selected following a competitive tender process). SPA estimated that 5.5 per cent of customers receiving an AMI meter will make a complaint in 2010, while 4 per cent will make a complaint in 2011.[78] SPA has based its assumed call rates on the outcome of a 1000 AMI meter trial, in which around 11 per cent of customers receiving a meter made a compliant and were subsequently removed from the trial. SPA stated that this is despite the participants being selected on the basis that they were unlikely to oppose the trial, and indicates that the call rate will be higher during the mandatory full-scale rollout.[79]

The AER notes the differences in the assumed number of customer calls resulting from the AMI rollout, however, it is satisfied that the assumptions on which the

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74 CP and PC, Email to the AER - *Questions for CitiPower and Powercor Revised Budget Application*, 25 September 2009.

75 CP and PC, Email to the AER – *Call centre queries*, 14 October 2009.

76 UED, Email to the AER - *Questions for UED – AMI final determination*, 25 September 2009; and JEN, Email to the AER - *JEN response to AER AMI questions*, 30 September 2009; UED, Email to the AER - *AMI Customer Service/relations costs*, 12 October 2009; and JEN, Email to the AER - *AMI – further questions,* 12 October 2009.

77 JEN, Email to the AER - *AMI- further questions*, 12 October 2009; and UED, *AMI – customer service/relations costs*, 12 October 2009.

78 SPA, Email to the AER - *SP AusNet response to AER questions of 18 September 2009,* 6 October 2009, pp. 13-17; and SPA, Email to the AER - *AMI Customer Service/relations costs,* 12 October 2009.

79 SPA, Email to the AER - *AMI Customer service/relations costs*, 12 October 2009.

estimates are made are based on the DNSPs' own research and trials. The DNSPs have undertaken different approaches to handling an increased number of customer complaints and inquiries which will result from the AMI rollout, based on their differing approaches to procurement and management of their AMI obligations. The AER is satisfied that the DNSPs have forecast their customer handling costs based on reasonable assumptions and research, and have built in expected efficiencies to be gained from learning as their rollouts progress. Where possible, the DNSPs have planned to utilise their existing call centre assets, as recommended by CUAC and CALC.

3.3.3 Energy and Water Ombudsman (Victoria) costs

Submissions from the EWOV, CUAC and CALC highlighted concerns with the DNSPs' budgeted costs for handling complaints made by customers to EWOV.

Specifically, EWOV stated that providing an allowance for recovery of EWOV costs removes any incentive for the DNSPs to take a proactive approach to preventing complaints from occurring or managing complaints effectively and efficiently. EWOV stated that it considers that Ombudsman costs are not directly attributable to the AMI rollout and should be borne by DNSPs rather than customers.[80]

The AER requested information from the DNSPs on their budget costs that are attributable to handling complaints that have been escalated to EWOV. The AER received the following information:

- CP and PC's total forecast of costs incurred in dealing with complaints that are escalated to EWOV over 2009–11, including labour costs of complaints handling, is $959 220.[81] CP and PC have assumed that around 0.2 per cent of customers receiving an AMI meter will make a complaint that is escalated to EWOV.[82]

- UED's forecast of costs for handling EWOV complaints is $1 341 000 over 2009–11, which is based on an assumed 18 per cent of total AMI complaints being escalated to EWOV, or 0.1 per cent of customers receiving an AMI meter. UED indicated that in a normal year (pre-AMI), it receives around 60 complaints that are escalated to EWOV. This compares to the forecast of 485 complaints being made over the two year initial budget period, 2009–11[83]

- JEN's forecast of costs for handling EWOV complaints is $636 000 over 2009–11, which is based on an assumed 18 per cent of total AMI complaints being escalated to EWOV, or 0.1 per cent of customers receiving an AMI meter. JEN indicated that in a normal year (pre-AMI), it receives around 30 complaints

80 Energy and Water Ombudsman (Victoria), *RE: Draft Determination – Victorian advanced metering infrastructure review 2009-11 AMI budget and charges applications*, 11 September 2009.
81 CP and PC, Email to the AER - *Further questions for CitiPower and Powercor*, 12 October 2009, spreadsheet *'Customer Management Reconciliation 2009–11 AER Version.'*
82 CP and PC, Email to the AER - *Questions for CitiPower and Powercor Revised Budget Application*, 25 September 2009.
83 UED, Email to the AER - *Questions for UED – AMI final determination*, 28 September 2009.

that are escalated to EWOV. This compares to the forecast of 229 complaints being made over the two year initial budget period, 2009–11[84]

- SPA forecast $1.5 million will be incurred in handling complaints associated with the AMI rollout that are escalated to EWOV over 2009–11. This is based on an assumed 25 per cent of all customer complaints being escalated to EWOV over 2009–11, or 1.4 per cent of all customers receiving an AMI meter.[85]

SPA indicated to the AER that it had discussed its AMI customer service plans with EWOV, and found that SPA's assumed complaint per meter installed rates appeared to be in proportion to those assumed by EWOV.[86]

The AER notes the concerns raised by EWOV, CUAC and CALC in relation to the budgeted costs for handling EWOV complaints. However, the revised Order states that costs are to be approved unless the AER establishes that they are outside scope or not prudent. In listing activities that are within scope for each DNSP, the revised Order makes specific reference to 'management and responsibility arising from Ombudsman complaints' in clauses S2.1(b)(2)(iii)(D), S2.6(b)(2)(iii)(D) and S2.10(b)(2)(iii)(D).

Costs for handling EWOV complaints are generally non-contract costs, as defined in the revised Order. The draft determination outlined the AER's consideration of non-contract costs under the expenditure incurred and commercial standard tests.

The AER considers that given the nature of the AMI rollout and its likely impact on customers, it is reasonable to assume that some level of costs for dealing with complaints to EWOV will be incurred.

The AER notes the different assumptions on EWOV complaints that each DNSP has incorporated into its forecast costs. Differences in associated expenditures also arise in the assumed time taken for staff handling of complaints, which is based on each DNSP's own experiences pre-AMI rollout. While the AER would expect the number and cost of EWOV complaints per meter installed to be relatively similar across the DNSPs, and that this should be substantiated by trial outcomes and experience, this is not the case. The AER also notes that the highest rate of complaints assumed by SPA were based on comparisons with those of EWOV. In the context of the uncertainty surrounding actual expected outcomes, the AER did not establish that the associated costs are unlikely to be incurred nor that they reflect a substantial departure from a reasonable commercial standard. The AER notes that only costs which are actually incurred by the DNSPs will be passed through to customers in the annual true-up process.

The AER considers that the DNSPs have made reasonable efforts to forecast their costs for handling the complaints made to EWOV, based on the outcomes of their individual trials and research. The DNSPs stated that they had each included some expected efficiency gains to be made as the AMI rollout progresses and they learn

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84 JEN, Email to the AER - *JEN response to AER AMI questions,* 30 September 2009.
85 SPA, Email to the AER - *AMI Customer Service/relations costs,* 12 October 2009.
86 Ibid.

from previous complaints handling, and have included these gains in their EWOV cost forecasts.

The AER maintains its view that the DNSPs' EWOV cost forecasts are within scope, likely to be incurred and do not reflect a substantial departure from a reasonable commercial standard. Accordingly, the AER maintains its draft determination that costs for handling complaints made to EWOV are approved.

3.3.3.1 General customer service costs

In conducting further investigation into the DNSPs' proposed costs for call centres and EWOV complaints handling, the AER discovered significant variations in the costs proposed for customer service and relations costs among the DNSPs. In particular, the AER discovered that CP's and PC's total customer service cost category was approximately double that proposed by JEN and UED and one third greater than that proposed by SPA, on a per meter installed basis.

The AER requested further information from the DNSPs as to the breakdown of their customer service costs and assumptions. The DNSPs' responses indicated that they had undertaken differing cost allocations in completing their AMI budget templates, with some customer services costs being allocated to overall program management cost categories. It was difficult for the AER to draw conclusions on a cost a per meter installed or per complaint basis due to the differing approaches. In addition, the AER notes that the DNSPs' customer service costs differ in their assumptions about customer calls and complaints, starting points, and approaches to customer service (including outsourcing these services).

The revised Order listed numerous customer service activities that are deemed to be inside scope, including:

> (iii) customer service associated with the AMI Technology and
>
> (A) management of guaranteed service level payments;
>
> (B) management of complaints and enquiries;
>
> (C) management of and meeting claims;
>
> (D) management and responsibility arising from Ombudsman complaints;
>
> (E) call centre;
>
> (F) customer communications and notifications; and
>
> (G) focus groups, surveys, retailer communications and process audits.[87]

The AER was not able to establish that the DNSPs' proposed customer service costs were outside scope.

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87 Revised Order, clauses S2.1(b)(2)(iii), S2.6(b)(2)(iii), S2.10(b)(2)(iii).

The AER acknowledges that while the DNSPs have undertaken different approaches to estimating their customer service costs, none of the approaches appear so unreasonable such that the AER would be able to establish a substantial departure from the commercial standard, as required by the revised Order. Similarly, given the forecast customer service costs are based on estimates of likely customer response to the AMI rollout, which is generally uncertain, the AER was unable to establish that the costs would be unlikely to be incurred.

Accordingly, following further analysis of the information provided, the AER did not establish that the DNSPs' customer services' costs were outside scope or not prudent, despite the significant variations in costs among them.

3.3.4 Related party margins

The draft determination noted that CP, PC, JEN and UED had proposed costs for margins and management fees arising from contracts with the DNSPs' related parties. The AER considered that the revised Order does not permit an efficient cost review of AMI related party margins. It noted that it would investigate the DNSPs' related party contracts more generally as part of its Victorian distribution review for 2011–15 under the NER. It also noted that the AER's findings as part of this broader review may inform its assessment of related party margins and management fees within the DNSPs' second AMI budget period applications for 2012–15.[88]

In its submission responding to the AER's draft determination, DPI stated its disagreement with the view that the AER could not undertake an efficient cost review of AMI related party margins under the revised Order. DPI considered that where these costs arise from contracts, the AER could assess whether they had arisen from a competitive tender process. DPI also referred the AER to the ESCV's consideration of related party margins in the current price determination. DPI considered that where the related party margins were non-contract costs, the AER could use its information gathering powers to assess whether there had been a substantial departure from a commercial standard.

CUAC submitted that it was concerned that costs associated with related party margins were not competitively tendered. It stated that a review of related party margins should be undertaken before the next Victorian price review, so that consumers can be assured that unreasonable margins are not passed through to prices during the initial budget period.[89]

As highlighted by DPI, the regulatory treatment of related party margins was a significant issue considered in the current price determination. The final decision sets out the ESCV's considerations.[90]

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88 AER, *draft determination*, pp. 43, 73.

89 Consumer Utilities Advocacy Centre, *Submission on AER draft determination Victorian advanced metering infrastructure review 2009-11 AMI budget and charges applications (July 2009)*, 11 September 2009, p. 10.

90 ESCV, *Electricity Distribution Price Review 2006-10—October 2005 Price Determination as amended in accordance with a decision of the Appeal Panel dated 17 February 2006—Final Decision Volume 1 Statement of Purpose and Reasons*, October 2006, pp. 168-185.

For the purposes of this final determination on the DNSPs' 2009–11 budgets, and in response to stakeholder comments, the AER has reconsidered the nature and treatment of related party margins and management fees. As recommended by DPI, the AER reconsidered the DNSPs' proposed related party margins and management fees as non-contract costs under the commercial standard test, including in light of the ESCV's prior treatment. The AER closely re-examined the associated contracts in light of comments in submissions, and maintains its position in the draft determination that it was unable to conduct an efficiency assessment of these costs under the revised Order, particularly given the complexities involved in establishing a notional 'commercial standard' and determining 'substantial' departures from this standard. However the AER has examined these costs through the particular provisions in relation to the revised Order's scope test.

The application of the scope test in the draft determination focused mainly on the lists of activities inside and outside scope for each DSNP, and the minimum specifications. However, Schedule 2 of the revised order (e.g. S2.1(a) for UED and JEN) also requires that activities within scope are those reasonably required for the provision of Regulated Services, where regulated services are defined in the revised Order as:

> ''Regulated Services' means:
>
> (a) metering services supplied to or on behalf of:
>
> (i) first tier customers; or
>
> (ii) second tier customers,
>
> with annual electricity consumption of 160 MWh or less where:
>
> (iii) the electricity consumption of that customer is (or is to be) measured using a revenue meter that is either an accumulation meter or a manually read interval meter; and
>
> (iv) the distributor is the responsible person in respect of those services;
>
> and
>
> (b) metering services supplied to or on behalf of:
>
> (i) first tier customers; or
>
> (ii) second tier customers,
>
> with annual electricity consumption of 160 MWh or less where:
>
> (iii) the electricity consumption of that customer is (or is to be) measured using a revenue meter that is a remotely read interval meter; and
>
> (iv) the distributor is the responsible person in respect of those services.[91]

The AER considers that the costs proposed for related party margins and management fees are not reasonably required for the provision of regulated services, as defined in

[91] Revised Order, clauses 2.1(a) and 2.10(a) and 2(g).

the revised Order. In reaching this conclusion the AER has closely reviewed the contracts between CP/PC and CHED Services, and between JEN/UED and AAM in relation to services associated with the AMI rollout. In both cases, the DNSPs' engaged their related party to undertake the AMI rollouts on their behalf, and perform all procurement, solution selection and project management required to achieve the AMI rollout obligations. In providing services to meet the DNSPs' rollout obligations, the related parties charge the DNSPs a margin on top of incurred costs.

While SPA did engage some related parties to provide services as part of the AMI rollout, the AER did not identify any margins or management fees associated with SPA's related party contracts**.**

Contracts between CP/PC and CHED Services, and between JEN/UED and AAM, incorporate the payment of margins and management fees over and above the costs incurred by the related parties, often added to the contract costs as a percentage of actual incurred costs. The AER notes that the services delivered under the related party contracts already incorporate management costs, such as the provision of program management offices, corporate services, provision of a CEO and other overheads. In most related party contracts reviewed by the AER, these costs are incorporated into the cost build up, and in addition, a margin is applied to actual incurred costs as a 'management fee' or an explicit 'margin'. In other cases, margins are determined by the related party's ability to incur costs under an established total contract value. In these cases the AER used audited regulatory account data to identify the margin paid to the related party.

Accordingly, in accordance with clause 5C.2(a), the AER has established that the margins and management fees quoted in these contracts do not reflect costs associated with any activity (including any potential in-scope activities) that is reasonably required in the provision of regulated services. Rather, they represent an additional margin above all other costs and activities identified in the relevant contracts and by the DNSPs in their budget applications and subsequent information.

The AER notes that, in making this determination on the DNSPs' charges for 2010–11, clause 5D.6 of the revised Order requires DNSPs to include details of their actual expenditures attributable to regulated services for 2006–08 as per their audited regulatory accounting statements. The ESCV's Electricity Industry Guideline No. 3—Regulatory Information Requirements (Guideline 3) specifies the ESCV's requirements for the collection, allocation and recording of business data by the Victorian DNSPs.[92] Guideline 3 also excludes management fees and related party margins from DNSPs' costs in their regulatory accounting statements.[93] Accordingly, the charges for 2010 and 2011 determined in section 5 below do not include any related party margins or management fees which were incurred under AMI contracts in 2006–08, as these were not included in regulatory accounting statements as per Guideline 3.

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92 ESCV, *Electricity Industry Guideline No. 3—Regulatory Information Requirements Issue No. 6*, December 2006.

93 ESCV, *Final decision: Revisions to guideline no. 3 – regulatory accounting information requirements*, December 2006, p. 13.

The AER considers it appropriate to maintain consistency in the treatment of actual reported costs and the budgeted costs in this determination, given the need to make a like for like comparison of expenditures in performing its annual 'true-up' of charges, including reviews of expenditures against budgeted amounts under clause 5I.5 of the revised Order. Accordingly, in calculating charges as per the annual true-up process for 2011 and 2012, the AER will determine costs based on those reported in regulatory accounting statements for years 2009, 2010 and 2011, as it has done for the years 2006–08 in making this determination. These regulatory accounting statements do not incorporate related party margins, in accordance with Guideline 3.

In conclusion, the AER has established that related party margins and management fees are outside scope for the purposes of the revised Order, and therefore will be excluded from the budgets of CP, PC, JEN and UED for 2009–11. This results in the following total reductions to the DNSPs' proposed AMI budgets for 2009–11:

- CitiPower – $4.7 million
- Powercor – $11.3 million
- Jemena – $8.4 million
- United Energy Distribution – $13.1 million.

As stated in the draft determination, the AER is intending to conduct a review of the Victorian DNSPs' related party margins and management fees generally as part of the upcoming distribution price review for 2011–15 under the Chapter 6 of the NER, which includes broader considerations on the efficiency of such margins. The AER intends to use the information gathered in reviewing the AMI contracts in this determination to inform this review as is relevant. However, it should be recognised that this determination to reject related party margins and management fees is a result which follows the unique regulatory framework provided for in the revised Order and is distinct from and different to the framework under Chapter 6 of the NER which the AER will apply in undertaking the 2011–15 distribution price review. .

3.3.5 Two-element meters

In its draft determination, the AER considered that PC's and SPA's proposals to install two–element meters were outside the AMI minimum functionality specifications, and accordingly determined that they were outside scope under clause S2.11 (iii) of the revised Order.[94] The AER's framework and approach paper noted that AMI activities which exceed the minimum specifications and are accordingly outside scope may still be approved if the DNSP is able to demonstrate that there are associated net benefits to customers and market participants.[95]

The AER concluded that replacing two–element accumulation meters with two–element, remotely read interval meters was likely to result in a lower net cost than replacement with single element meters in the period before supporting AMI

[94] Department of Primary Industries (Victoria), *Advanced metering infrastructure – Minimum AMI functionality Specification (Victoria)*, September 2008, clause 3.1.
[95] AER, framework and approach paper, p. 29.

communications are operational. The AER approved PC and SPA's proposals largely on the basis that a like for like meter replacement would avoid transitional costs in the form of an interim tariff reassignment for affected customers. In doing so, the AER noted that the transitional benefit associated with installing a two–element meter would reduce over time as the AMI communications technology is rolled out, facilitating immediate transfers into time of use tariffs.

Following the draft determination, the AER received a submission from Integral Energy as well as further information from SPA and PC regarding other benefits provided by two–element meters from direct load control and related certainty in managing demand.

PC argued that the direct control of loads leading into and during peak periods is a prime justification for maintaining a two-element arrangement under AMI. Its argument depends on the ability to maintain discounted tariff arrangements in relation to direct load control appliances (in addition to typical time of use tariffs for general energy consumption) which results in customers being willing to accept a direct load control arrangement. In the event that a DNSP loses the ability to maintain specific tariffs for controlled loads (under a single element meter, as required by the revised Order specifications) and customers do not agree to direct load control under a single time of use tariff, the affected appliances would be used at the discretion of customers and the DNSP loses the ability to effectively manage and diversify its network demand. PC estimated that the loss of diversification in the event single–element meters were installed would be a step increase in demand in the order of 3 to 5 per cent in many parts of its network.[96] PC estimates that the loss of this load control would result in the need for network augmentation costing $36.2 million for the period 2010-15.[97]

Regarding the benefits arising under current load control arrangements, SPA indicated that it has spent $143,544 to adjust two–element meter timeclocks etc, and this has resulted in the deferral of network augmentation works estimated at approximately $14.6 million.[98]

SPA's submission also provided further information on the cost involved in transferring two–element meter customers onto transitional tariffs, and then shifting them again to a permanent ToU tariff once new meters had been tested and deemed fit for purpose. If customers require two tariff reassignments, they estimated an additional cost of $2,158,365 or $29.83 per customer.[99]

The further submissions by the DNSPs, including Integral Energy, have clarified that the concerns over the continuing need for two-element meters may not be linked solely to transitional costs. While the AER has not scrutinised or placed full weight on the estimates provided by PC and SPA, it considers that the cessation of existing direct load control tariff arrangements for some customers would result in uncertainty for DNSPs in peak demand impacts and a potential need for further network

96 PowerCor, Email to the AER - response to AER questions of 5 October 2009.
97 Ibid.
98 SP AusNet, Email to the AER - response to AER questions of 18 September 2009.
99 Ibid.

augmentation as compared to what would otherwise be required. The AER notes, however, that this effectively runs counter to the policy intent and expectations of AMI, reflected in the revised Order's minimum specifications, that all load (regardless of whether it relates to particular appliances) be charged at a rate which reflects its underlying cost to the network, which is possible through a single element meter and a single time of use tariff. The arguments submitted by PC and SPA indicate that they do not believe that customers will appropriately respond to full cost reflective tariffs in this regard. While the AER has no particular view about the extent of customer responsiveness to time of use tariffs, this is ultimately an empirical question and has been the subject of some debate in relation to previous cost-benefit analysis undertaken by the Commonwealth and jurisdictions on smart meter rollouts.

The AER also highlights that the arguments by the DNSPs rest heavily on the assumption that customers would simply refuse to allow direct load control under a single tariff arrangement, as anticipated under the AMI functional specifications and single element meters. Whether or not customers find this situation more favourable than current arrangements depends entirely on the particular tariffs offered, which is at the discretion of the DNSPs. The AER expects that DNSPs will eventually implement time of use pricing across their customer bases resulting in cost reflective pricing, however notes that alternative (non-price) methods exist to encourage more efficient network utilisation, which appears to be a policy goal of AMI.

The AER notes that SPA indicated to the AER in meetings that it intends to transfer controlled load tariffs to time-of-use tariffs in future. This means that SPA will utilise the two-element meters to control loads as currently, however, customers' tariffs will more accurately reflect the time of use of the controlled load, which in some cases is during peak times, for example the afternoon boost on slab heating. The AER anticipates that the approval of two-element meters will not prevent PC and SPA from improving pricing signals for controlled loads through time of use tariffs.

The AER considers that the information provided by PC, which is supported by Integral Energy, on balance substantiates that there would be a net benefit for customers by allowing the DNSPs to maintain firmer direct load control arrangements. The AER considers it to be a plausible argument that in the transition to time of use pricing, some customers may be resistant or not responsive to more cost reflective network tariffs, either due to unfavourable price impacts or through the dilution of network price signals at the retail level. That said, there are considerable uncertainties in the DNSPs' assumptions regarding the counterfactual situation which will influence the impact or size of any network augmentation that may otherwise be required. Overall, the AER considers that when taking all factors into account, a net benefit is likely to arise given the relatively low incremental cost of installing the second element in the meters for affected customers and that only the affected customers would be charged the higher meter cost. The AER will reconsider this issue for the second AMI budget period when more information on customer responses is available.

3.3.6 Contract and non-contract costs and tests

This section deals with a number of issues surrounding the DNSPs' proposed contract and non-contract costs and the AER's application of the associated tests in the revised Order.

3.3.6.1 Non-contract costs

CUAC stated its concerns regarding the significant level of expenditure in the initial AMI budget applications which had not yet been subject to a competitive tender process, and noted the negative impacts that delaying contracts may have on customers, who are paying upfront for AMI yet may be denied access to more suitable tariffs for some time. CUAC also recommended that the AER should closely review the competitive tendering processes of the DNSPs to ensure that their proposed expenditure is appropriate.[100]

The AER notes CUAC's concerns regarding the level of non-contract costs as a proportion of total budget costs proposed by the DNSPs. In the DNSPs' initial AMI budgets, non-contract costs made up the following proportions of their total proposed budgets for 2009–11:

- CitiPower – 60 per cent
- Powercor – 50 per cent
- Jemena and United Energy Distribution (combined) – 65 per cent
- SP AusNet – 94 per cent.

Where proposed costs were non-contract costs, the AER applied the expenditure incurred and commercial standard tests to those costs, as required by the revised Order and detailed in the draft determination. The revised Order also provided for DNSPs to resubmit budget applications for the 2009–11 budget period reflecting contracts that had been signed subsequent to their initial AMI budget applications, until 31 August 2009.[101]

3.3.6.2 CitiPower and Powercor—signed contracts since February 2009

CP's and PC's revised budget applications stated that the DNSPs had revised their budget non-contract cost forecasts where contracts had been signed subsequent to their initial budget applications, and the executed contract costs are lower than those originally forecast. As a result of these changes, CP and PC made minor adjustments to their capex to opex ratio. In addition, overall program costs changed due to changes in the exchange rate, as a number of CP and PC's AMI vendors are located outside of Australia.[102] Overall, the impact of executed contracts being lower than forecast, changes in capitalisation policy and changes in the exchange rate was a decrease in total budget costs of \$12.4 million for CP and \$24.1 million for PC.[103]

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[100] Consumer Utilities Advocacy Centre, *Submission on AER draft determination Victorian advanced metering infrastructure review 2009-11 AMI budget and charges applications (July 2009),* 11 September 2009, pp. 8-9.

[101] Revised Order, clause 5B3.

[102] CitiPower, *Revised Budget Application*, 31 August 2009, pp. 1-2, and Powercor, *Revised Budget Application*, 31 August 2009, pp. 1-2.

[103] CitiPower, *Revised Budget Application*, 31 August 2009, confidential budget templates, and Powercor, *Revised Budget Application*, 31 August 2009, confidential budget templates.

CP and PC indicated that the categories of budget expenditure to which the changes relates are:

- meter supply
- communications supply
- field installation costs.[104]

The AER requested copies of the signed contracts in order to examine them under the contract cost test. The contracts were executed according to the procurement policies implemented by CHED Services, which were reviewed by the AER prior to the draft determination. As noted in the draft determination, CHED Services engaged both Portland Group and Deloitte Touche Tohmatsu to review the procurement processes, including the request for proposal process.[105] The additional signed contracts provided to the AER as part of CP's and PC's revised budget application complied with these processes, which the draft determination identified as reasonable. The services covered by the contracts were bundled appropriately, and contracts incorporated efficiency targets for vendors. From the documentation provided, the AER did not establish that the AMI tender processes conducted by CP and PC leading up to the additional signed contracts were not competitive, and therefore did not establish that costs associated with these signed contracts are not prudent.

3.3.6.3 SP AusNet—contract costs

In its revised budget application, SPA provided further information regarding contracts that were signed prior to 27 February 2009 (contract costs, as defined in the revised Order), which the AER rejected under the contract cost test in the draft determination.[106] SPA provided signed contracts, quotes and purchase orders for goods and services supplied for metering activities. The AER considered the information provided by SPA, and requested further details on the contract costs.[107] In providing further information, SPA identified a discrepancy between its revised submitted budget templates and its actual signed contract costs. As a result, SPA proposed to increase its total contract cost budget proposal for 2009–11 by $25 018.[108] The AER has reviewed this discrepancy and considers it is reasonable, and the proposed costs are reflective of actual signed contracts. SPA's revised budget templates submitted on 13 October 2009 reflects this change.

The AER reconsidered these contracts under the contract cost test, in light of its considerations on SPA's general AMI procurement processes and independent assessments of these processes, which was detailed in the draft determination.[109] The services covered by the contracts appear to be bundled reasonably. After reviewing the documentation provided, the AER did not establish that the contracts provided by

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104 CitiPower, *Revised Budget Application*, 31 August 2009, pp. 1-2, and Powercor, *Revised Budget Application*, 31 August 2009, pp. 1-2.

105 AER, *draft determination*, p. 32.

106 Ibid., p. 92-3.

107 AER, Questions on the revised budget proposal and submissions, 18 September 2009.

108 SPA, *SP AusNet response to AER questions of 18 September 2009*, 6 October 2009, contract cost reconciliation spreadsheet.

109 AER, *draft determination*, p. 92-3.

SPA as part of its revised budget application were not let in accordance with a competitive tender process. Accordingly, the AER has revised its draft determination relating to $16.3 million of SPA's contract costs which were rejected under the contract cost test. As these costs were then assessed and approved under the non-contract cost tests, as detailed in the draft determination, this revision results in no change to SPA's approved AMI budget.[110]

3.3.6.4 Delaying contracts

While the AER notes that customers are paying upfront for costs, and notes CUAC's concerns regarding the potential costs to customers if DNSPs delay their rollouts, it also notes the scope of the mandated AMI rollout program and its impact on the DNSPs' operations. In any capital and operating expenditure project of this magnitude, a reasonable commercial business may expect some delays in the event of unforeseen circumstances. However, the AER notes that the revised Order requires the DNSPs to meet a specified rollout schedule, reproduced in section 1.2 above, and that failure to meet this schedule may result in a DNSP being in breach of its distribution license, of which penalties may apply.

3.3.6.5 AER application of revised Order tests

DPI's concerns over the AER's application of the contract cost test relate to its view that the AER has taken a narrow interpretation of contract costs, and that it should have considered the DNSPs' conduct with suppliers prior to the formal signing of contracts as sufficient to enable the costs to be considered as effective contract costs for the purposes of the revised Order. DPI considered this interpretation would have enabled the AER to determine the appropriate costs for contracts (although unsigned) which it established were not competitively tendered, rather than considering them under the tests for non-contract costs, being the expenditure incurred and commercial standard tests.

Clause 5C.11 of the revised Order states:

> 5C.11 In this clause:
>
> 'Contract cost' means expenditure incurred pursuant to a contract entered into:
>
> (a) prior to the day on which a distributor made its initial AMI budget period budget application or subsequent AMI budget period budget application (as the case may be); or
>
> (b) if a revised initial AMI budget period budget application has been made by the distributor pursuant to clause 5B.3, prior to the day on which that application was made, but does not include expenditure incurred pursuant to a variation of that contract where that variation is entered into or takes effect after that day.
>
> Note: The competitive tender process need not be conducted by the distributor, nor need the contract be one that the distributor has entered into.

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110 AER, *draft determination*, p. 92, pp. 27-105.

Hence the revised Order defines contract costs as those being pursuant to a contract entered into prior to or on 27 February 2009. As outlined above, the AER reconsidered some of the non-contract costs proposed in CP's and PC's initial AMI budget proposals in light of their revised budget applications and on the information available to it, was unable to establish that these costs were not competitively tendered.

Clause 5C.3 of the revised Order states:

> 5C.3 For the purposes of clause 5C.2(b), expenditure is prudent and must be approved:
>
> (a) where that expenditure is a contract cost, unless the Commission establishes that the contract was not let in accordance with a competitive tender process; or
>
> (b) where that expenditure:
>
> > (i) is not a contract cost; or
> >
> > (ii) is a contract cost and the Commission establishes that the contract was not let in accordance with a competitive tender process,
> >
> > unless the Commission establishes that:
> >
> > (iii) it is more likely than not that the expenditure will not be incurred; or
> >
> > (iv) the expenditure will be incurred but incurring the expenditure involves a substantial departure from the commercial standard that a reasonable business would exercise in the circumstances.

This means that where the AER establishes that proposed contract costs were not let in accordance with a competitive tender process, costs must be approved unless the AER can establish that the costs do not meet the expenditure incurred or commercial standard tests. The AER does not have discretion to determine an appropriate level of expenditure for contract costs that fail the contract cost test, unless such costs also fail either the expenditure incurred or commercial standard tests.

DPI also submitted that the draft determination provided insufficient evidence to indicate whether the AER has sufficiently assessed non-contract costs under the expenditure incurred and commercial standard tests. Pages 37 to 44, 62 to 74 and 97 to 104 of the draft determination outline the AER's assessment of each DNSP's proposed non-contract costs under the expenditure incurred and commercial standard tests. Furthermore, the AER applied both the expenditure incurred and commercial standard tests to all proposed non-contract costs and contract costs that it established were not competitively tendered.

In applying the expenditure incurred test, the AER's approach was to firstly examine whether the proposed costs were in the process of being tendered (future contract costs). Costs that were close to being pursuant to a signed contract via a competitive tender process were considered likely to be incurred.[111] The AER also had regard to the method by which non-contract costs were estimated. Where costs were estimated based on competitive tendering outcomes (although final contracts were not yet signed), the AER considered the costs likely to be incurred. The AER's consultant, Energeia, considered whether the proposed non-contract costs were reflective of existing work practices and cost structures, and therefore whether the costs were likely to be incurred.[112] The AER considered advice from its consultant and other industry stakeholders, including DPI, in applying the expenditure incurred test.[113]

The draft determination noted that in not incurring the proposed costs, the DNSPs face a degree of risk in terms of not meeting their AMI rollout obligations.[114] The AER considered that there was a reasonable incentive placed upon the DNSPs to incur their rollout costs rather than retain their budget allocations, as failure to meet the rollout obligations would result in a potential breach of their distribution licences, as outlined above. However, the AER did establish that certain costs were unlikely to be incurred by the DNSPs, including costs for customer response trials, self insurance and equity raising costs.

In conducting the commercial standard test, the AER had regard to the factors outlined in clause 5I.8 of the revised Order:

> 5I.8 For the purposes of making a determination pursuant to paragraph 5I.7(b), the Commission shall take into account and give fundamental weight to:
>
> (a) the circumstances of the distributor;
>
> (b) if the distributor did not directly incur the expenditure, the circumstances of the person that did incur it; and
>
> (c) if the distributor did not directly manage the expenditure, the circumstances of the person that did manage it,
>
> at the time the commitment was made to incur or manage (as the case may be) the expenditure excess including:
>
> (d) the information available at that time;
>
> (e) the nature of the provision, installation, maintenance and operation of advanced metering infrastructure and associated services and systems;
>
> (f) the nature of the rollout obligation;
>
> (g) the state of the technology relevant to the provision, installation, maintenance and operation of advanced metering infrastructure and associated services and systems;

[111] AER, *draft determination*, p. 62.
[112] Ibid., p. 97.
[113] Ibid., p. 37.
[114] Ibid., p. 63.

> (h) the risks inherent in a project of the type involving the provision, installation, maintenance and operation of advanced metering infrastructure and associated services and systems;
>
> (i) the market conditions relevant to the provision, installation, maintenance and operation of advanced metering infrastructure and associated services and systems; and
>
> (j) any metering regulatory obligation or requirement.

The AER's general approach in applying the commercial standard test was to examine each proposed cost category. In addition to the considerations listed in clause 5I.8, the AER also considered:

- the basis on which costs were estimated, for example whether based on an average of competitive tender outcomes or shortlisted vendor quotes[115]
- whether the DNSP had engaged an independent probity auditor to examine the basis of cost estimation[116]
- whether the DNSP had selected the lowest cost option, and if not, whether the long term costs associated with the decision would offset any higher implementation costs of particular technologies[117]
- risk management techniques, including leveraging existing systems where possible, selecting 'off-the-shelf' solutions from well-recognised providers, adopting future proofing techniques[118]
- whether the DNSP had left open the opportunity for multi-vendor provision of meters and AMI technology, which would encourage a competitive contract pricing once the rollout has commenced[119]
- the basis of the decision to incur the proposed costs, including research and investigation of different procurement options as well as any regulatory obligations.[120]

The AER considers it has conducted a thorough assessment of the DNSPs' proposed non-contract costs under the expenditure incurred and commercial standard tests, which is outlined in the draft determination. The onus of proof under the revised Order's tests is placed upon the AER, which creates an incentive for the DNSPs to withhold information. In spite of this, the AER has received a significant volume of high quality information from the DNSPs, which enabled it to determine that the majority of costs were both within scope and prudent, as per the revised Order. The AER sent out and received responses to over 25 information requests relating to the DNSPs' proposed budgets during its review. Energeia's report indicated that it had

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115 Ibid., p. 38.
116 Ibid., p. 38.
117 Ibid., p. 101.
118 Ibid., p. 42 and p. 70.
119 Ibid., p. 39.
120 Ibid., p. 42 and p. 99.

received and reviewed approximately 1500 pages of information regarding the DNSPs' AMI budget proposals.[121] The AER estimates that it reviewed over five times this volume of information in considering the DNSPs' proposed budget costs.

3.3.7 SP AusNet's proposed load contactors

SPA's revised submitted budget stated that in removing its proposed costs for direct load control contactor relays in the draft determination ($6.1 million), the AER had mistakenly also removed costs for load contactors on its proposed single and two-element meters. SPA submitted that the AER needed to reinstate these costs to enable it to maintain its existing load control arrangements.[122] SPA's revised submitted budget included costs for these load contactors.

The draft determination set out the AER's views regarding SPA's proposed load control contactor with relay. The AER maintains its view that the relay itself is above minimum specifications and therefore outside scope as defined by the revised Order. However, the AER agrees that the load contactors (without relay) are within scope as they are listed within the minimum specifications.[123] The AER agrees to reinstate the associated costs for load contactors which were removed for the draft determination. This decision results in a $2.5 million increase in SPA's AMI capex budget from that which was approved in the draft determination, however, no change from SPA's revised submitted budget.

3.4 AER conclusion – AMI budgets

Following its consideration of revised budget applications, further information provided and issues raised in submissions, the AER makes the following amendments to the DNSPs' budgets which were approved in the draft determination:

3.4.1 CitiPower

The AER rejects CP's revised submitted budget for the following cost categories, having established that:

- related party margins paid to CHED Services are outside scope as defined by the revised Order.

The new budget the AER has determined to approve for CitiPower is set out in Table 3.1.

[121] Energeia, *Review of Victorian Distribution Network Service Provider's Advanced Metering Infrastructure Budget Applications 2009-11*, July 2009, p. 15.
[122] SPA, *Advanced Metering Infrastructure Revised Budget Application*, 28 August 2009, p. 6-7.
[123] Department of Primary Industries (Victoria), *Advanced metering infrastructure – Minimum AMI functionality Specification (Victoria)*, September 2008, clause 3.1.

Table 3.1: AER determination- budget for CitiPower ($'000s, real 2008)

	2009	2010	2011
CP revised proposed capex	23,461	37,732	39,613
CP revised proposed opex	14,230	10,718	11,318
CP proposed related party margins	1,437	1,626	1,663
AER determination – CP capex	23,005	36,553	38,456
AER determination – CP opex	13,249	10,271	10,811

Source: CitiPower, *Revised Budget Application*, 31 August 2009, budget templates (confidential).
Note: Totals may not add due to rounding.

3.4.2 Powercor

The AER rejects PC's revised submitted budget for the following cost categories, having established that:

- related party margins paid to CHED Services are outside scope as defined by the revised Order.

The new budget the AER has determined to approve for Powercor is set out in Table 3.2.

Table 3.2: AER determination- budget for Powercor ($'000s, real 2008)

	2009	2010	2011
PC revised proposed capex	40,815	88,421	103,071
PC revised proposed opex	29,915	21,743	24,768
PC proposed related party margins	3,386	3,895	3,975
AER determination – PC capex	39,737	85,470	100,201
AER determination – PC opex	27,606	20,799	23,663

Source: Powercor, *Revised Budget Application*, 31 August 2009, budget templates (confidential).
Note: Totals may not add due to rounding.

3.4.3 Jemena

The AER rejects JEN's revised submitted budget for the following cost categories, having established that:

- related party margins paid to AAM are outside scope as defined by the revised Order.

The new budget the AER has determined to approve for JEN is set out in Table 3.3.

Table 3.3: AER determination- budget for JEN ($'000s, real 2008)

	2009	2010	2011
JEN revised proposed capex	54,607	31,940	34,044
JEN revised proposed opex	4,116	9,408	14,867
JEN proposed related party margins	3,324	2,340	2,769
AER determination – JEN capex	51,516	30,132	32,117
AER determination – JEN opex	3,883	8,876	14,026

Source: JEN, *Advance Infrastructure Roll out Budget Application from Jemena Energy Networks (VIC) Ltd*, 27 February 2009, budget templates (confidential) and AER analysis.

Note: Totals may not add due to rounding.

3.4.4 United Energy Distribution

The AER rejects UED's revised submitted budget for the following reasons, having established that:

- related party margins paid to AAM are outside scope as defined by the revised Order.

The new budget the AER has determined to approve for JEN is set out in Table 3.4.

Table 3.4: AER determination- budget for UED ($'000s, real 2008)

	2009	2010	2011
UED revised proposed capex	65,403	51,373	69,780
UED revised proposed opex	7,615	14,533	21,842
UED proposed related party margins	4,133	3,730	5,186
AER determination – UED capex	61,701	48,465	65,831
AER determination – UED opex	7,184	13,710	20,606

Source: UED, *AMI Budget Application 2009-11 to the Australian Energy Regulator*, 27 February 2009, budget templates (confidential), and AER analysis.

Note: Totals may not add due to rounding.

3.4.5 SP AusNet

The AER accepts SPA's revised submitted budget. The budget the AER has determined to approve for SPA is set out in Table 3.5.

Table 3.5: AER determination—budget for SPA ($'000s, real 2008)

	2009	2010	2011
AER determination – SPA capex	67,901	50,896	102,441
AER determination – SPA opex	30,757	30,463	29,655

Source: SPA, *Revised budget templates*, 13 October 2009.
Note: Totals may not add due to rounding.

3.5 AER determination – AMI budgets

The AER approves the total opex and capex set out in Tables 3.1 to 3.5.

4 AMI revenue requirement

This section assesses the DNSPs' proposed costs for 2009 to 2011 under a building block approach which includes actual costs and revenues for 2006–08 and forecasts for 2009–11. Forecast costs are based on the expenditures assessed by the AER in section 2. The conversion of costs into metering charges is discussed in section 5.

In response to the draft determination, the DNSPs provided a joint submission in relation to the Debt Risk Premium (DRP). CP, JEN and PC proposed revisions to actual costs and revenues for 2006-08, as a result of their resubmission of regulatory accounts information which was independently audited.

This section discusses:

- further details of the revised applications for each DNSP
- the AER's re-assessment of this new information
- the AER's final determination on the DNSPs' revenue requirements.

4.1 Amended applications

The DNSPs provided amended revenue requirement and amended charges applications in response to the draft determination.

Tables 4.1 to 4.5 show the resulting revenue requirements by DNSP. These can be compared to Tables 2.6, 2.8, 2.10, 2.12, and 2.14 above from the draft determination.

CP's amended proposed revenue requirements are shown in Table 4.1. CP applied a nominal after tax WACC of 10.01 per cent, which included a DRP of 4.84 per cent. Additionally, CP adopted the data on IMRO and pre-start date AMI actual costs and revenues for 2006-08 from their regulatory accounts that was independently re-audited.

Table 4.1: CP revised proposed revenue requirements ($'000s, nominal)

	2009	2010	2011
Return on capital	3,358	5,322	8,557
Depreciation	3,755	7,593	10,543
Operating & maintenance costs	14,230	10,718	11,318
Tax liability	0	0	0
Offset of costs and revenues 2006–08	7,892	N/A	N/A
Total revenue requirement	29,234	23,633	30,417

Source: CP, *AMI Audit Reports and Charges Applications*, 21 September 2009.

JEN undertook a complete re-audit of its regulatory accounts for the period 2006, 2007 and 2008, which it provided to the AER on 30 September 2009.[124] This data was requested by the AER to ensure it had appropriate information on 2006-08 actual costs and revenues for IMRO and pre-start date AMI activities. The breakdown of this data impacted JEN's claimed efficiency carryover mechanism (ECM) and therefore its proposed revenue requirement, in Table 4.2.

The re-audited data in JEN's amended charges application generated proposed charges for 2010 and 2011 that were the same as those originally proposed to the AER on 1 June 2009.

Table 4.2: JEN proposed revenue requirements ($'000s, nominal)

	2009	2010	2011
Return on capital	6,710	8,874	10,885
Depreciation	7,007	13,767	17,089
Operating & maintenance costs	4,116	9,408	14,867
Tax liability	0	0	0
Offset of costs and revenues 2006–08	7,610	N/A	N/A
Total revenue requirement	25,443	32,050	42,841

Source: JEN, *AMI Charges Model 2010-11 Draft Determination Amended for Restated Regulatory Accounts*, 30 September 2009.

The re-audited regulatory accounts used by PC resulted in an increase in their revenue requirements and higher charges compared to the draft determination. PC's revised submission is shown in Table 4.3 below.

Table4.3: PC proposed revenue requirements ($'000s, nominal)

	2009	2010	2011
Return on capital	6,204	10,636	19,074
Depreciation	7,135	14,588	21,497
Operating & maintenance costs	29,915	21,743	24,768
Tax liability	0	0	0
Offset of costs and revenues 2006–08	27,810	N/A	N/A
Total revenue requirement	71,063	46,967	65,338

Source: PC, *AMI Audit Reports and Charges Applications*, 21 September 2009.

[124] JEN, *AMI Charges Model 2010-11 Draft Determination Amended for Restated Regulatory Accounts*, 30 September 2009.

SPA's submission to the draft determination reflects its amended budget application 2009-11, together with the allocation of provisions. In its original charges application on 1 June 2009, SPA allocated all provisions to indirect overheads. However, its submission to the draft determination allocated the movement in labour cost provisions to meter data services. This was on the basis that employee entitlements and the unfunded shortfall in the defined benefits superannuation scheme is for permanent employees who perform meter data services and not for individuals who are included in the indirect overheads costs category.[125] The AER requested that these provisions be allocated to all cost categories that have labour cost components. SPA subsequently provided the AER with a template which allocated these provisions to standard metering maintenance, meter data services and indirect overheads. SPA did not allocate provisions to pre-start date AMI costs, as those individuals engaged on the AMI project are not direct employees of SPA, rather independent contractors. SPA's proposed revenue requirements are shown in Table 4.4.

Table 4.4: SPA proposed revenue requirements ($'000s, nominal)

	2009	2010	2011
Return on capital	8,004	11,242	17,316
Depreciation	9,465	18,415	24,477
Operating & maintenance costs	30,757	30,463	29,655
Tax liability	0	0	0
Offset of costs and revenues 2006–08	-6,198	N/A	N/A
Total revenue requirement	42,029	60,120	71,449

Source: SPA, *SP AusNet - updated AMI pricing and budget templates*, 13 October 2009.

The only area that UED contended in its submission to the draft determination was the use of a higher DRP (see section 4.2.1). The resulting proposed revenue requirements are shown in Table 4.5 below.

125 SPA, *Advanced Metering Infrastructure, SP AusNet Response to Draft Decision*, 11 September, p5.

Table 4.5: UED proposed revenue requirements ($'000s, nominal)

	2009	2010	2011
Return on capital	9,516	12,297	16,652
Depreciation	10,083	18,927	24,091
Operating & maintenance costs	7,615	14,533	21,842
Tax liability	0	0	0
Offset of costs and revenues 2006–08	-5,873	N/A	N/A
Total revenue requirement	21,340	45,757	62,585

Source: UED, *AMI 2010-11 Charges Model Response to DD*, 24 September 2009.

4.2 Additional information submitted by the DNSPs

4.2.1 Combined submission by DNSPs on Debt Risk Premium

The DNSPs provided a joint submission on the DRP, which included a report from the Competition Economics Group (CEG).[126] In their report the DNSPs maintain that a DRP of 4.84 per cent, based on a corporate bond issue by Tabcorp in April 2009, is appropriate and supported by other evidence regarding corporate bond yields. The DNSPs argue that the 3.09 per cent adopted by the AER in the draft determination was inappropriate and the AER's method of estimation (which utilised information from Bloomberg's fair yield curves) did not meet the requirements of the revised Order, which they note are:

- It must be determined using 'observed annualised Australian benchmark corporate bond rate for corporate bonds'
- The bonds must have a BBB+ credit rating
- The bonds must have a maturity of 10 years and
- Measurement must occur between 17 November 2008 and 5 December 2008.

The DNSPs contend that, due to the global financial crisis, there is no measure of the DRP that meets all four of these requirements. Accordingly, they submit that the AER must take into account all relevant information in determining the DRP.

The CEG report examined the accuracy of Bloomberg fair yield curves before, during and after the AMI averaging period. The CEG report also provides alternative proxies for the benchmark 10 year BBB+ bond (including the Tabcorp issue) and a comparison of the Bloomberg and CBASpectrum methodologies.

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126 Victorian Electricity Distribution Businesses, AER draft determination on 2009-2011 AMI budget and charges applications: Joint submission by the Victorian DNSPs on the debt risk premium, 11 September 2009, Tom Hird, CEG, *Estimating the cost of 10 year BBB+ debt during the period 17 November to 5 December 2008,* September 2009.

4.2.2 Amended historic information

JEN provided amended historical information for 2006, 2007 and 2008. Deloitte undertook the review of JEN's 2005-06 regulatory accounts, extracting detailed metering costs information for metering data services (MDS) and operating and maintenance costs as previously reported in the regulatory accounts dated 24 October 2006.[127] Audits were undertaken by KPMG for information relating to the period 31 July 2006 to 31 December 2007 and the year ending 31 December 2008.[128]

CP and PC amended their regulatory accounts information for IMRO costs and revenues and pre-start date AMI costs for the years 2006, 2007 and 2008, which was audited by Deloitte.

4.2.3 Provisions and capitalisation policy

In response to the draft determination, SPA advised that the movement in provisions were adjusted against metering data services, as provisions relate specifically to this item of expenditure.[129] A template was provided to the AER outlining the relevant cost allocation.

CP and PC submitted that because their forecast of AMI capital expenditure for 2009-11 had fallen from that originally proposed in February 2009, operating and maintenance costs made up a larger portion of the overall AMI budget expenditure for 2009-11 (conversely capital expenditure therefore made up a smaller proportion). With project management (overhead) costs remaining unchanged, both DNSPs therefore allocated a larger portion of these fixed costs to operating and maintenance expenditure and therefore a smaller proportion to capital expenditure.[130] This did not impact on the AMI charges proposed by both DNSPs.

4.3 Other Submissions

The AER did not receive submissions from parties other than DNSPs to the draft determination on the revenue requirements. There were, however, issues raised in relation to the draft determination charges, which are discussed in sections 5.2 and 5.3 below.

4.4 AER considerations and conclusions

This section outlines the AER's analysis and conclusions with respect to:

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[127] Deloitte, *Independent Auditor's Report to the Directors of CitiPower Pty*, 18 September 2009, p. 3 and Deloitte, *Independent Auditor's Report to the Directors of Powercor Ltd*, 29 September 2009, p1.

[128] KPMG, *Independent audit report to the directors of Jemena electricity networks (Vic) Ltd (formally Alinta AE Ltd) and the Australian Energy Regulator on the electricity regulatory accounting statements for the period 1 July 2006 to 31 December 2007*, 28 September 2009. KPMG, *Independent audit report to the directors of Jemena electricity networks (Vic) Ltd) and the Australian Energy Regulator on the electricity regulatory accounting statements for the year ended 31 December 2008*, 28 September 2009.

[129] SPA, *Advanced Metering Infrastructure SP AusNet Response to Draft Decision*, 11 September 2009. p.5

[130] CP, *Advanced Metering Infrastructure Draft Decision*, 31 August 2009, p 2.
PC, *Advanced Metering Infrastructure Draft Decision*, 31 August 2009, p 2.

- The DNSPs' proposed debt risk premium
- Historic information sourced from regulatory accounting statements
- SPA's movements in provisions
- The metering asset base
- Depreciation
- Benchmark corporate tax allowance
- Offset of costs and revenue for 2006-08

4.4.1 Debt risk premium

The AER's full considerations and conclusions regarding the DNSPs' proposed DRP are outlined in appendix A of this final determination.

In summary, the AER rejects the proposed DRP of 4.84 per cent based on the Tabcorp issue. The AER considers the DNSPs' misinterpretation and application of the terms in clause 6.5.2(e) led to the proposal of the Tabcorp issue as an alternative mechanism. However, the AER considers that sole reliance on the extrapolation of the Tabcorp issue is not robust enough in determining the DRP and it was not sufficiently established that the Tabcorp bond reflects the benchmark corporate bond. Accordingly, the Tabcorp bond does not satisfy the requirements of the revised Order.

The AER acknowledges the variety of supporting information presented by the DNSPs and CEG, however, the AER considers that most of the yield data are not appropriate comparators as they are not reflective of bonds issued by an Australian benchmark efficient DNSP.

The AER considers that arguments over the methodologies used by Bloomberg and CBASpectrum rely on incomplete information and do not provide any grounds to support or discredit one data source over the other. The AER has maintained its approach to testing fair yield curve data against information relevant to the benchmark corporate bond. Following this assessment for the relevant period, the AER concludes that the use of an average of Bloomberg and CBASpectrum's fair value curve provides the best prediction of observed yields for the purposes of determining the yield on the benchmark BBB+ 10 year corporate bond, as required by the revised Order, including clause 6.5.2(e) of the NER. This results in a DRP of 4.00 per cent.

It should be noted that conducting assessments for different periods may result in different outcomes in relation to the most appropriate data series that should be used. In previous determinations, this led to Bloomberg being selected by the AER, whereas on this occasion an average of Bloomberg and CBA Spectrum was seen as appropriate. The AER's full considerations are at appendix A.

The DNSPs did not contend any other WACC parameters as used in the draft determination. Accordingly, the AER's final determination on the WACC for the initial AMI period is set out in Table 4.6.

Table 4.6: AER final determination on WACC parameters for AMI period 1 January 2009 to 31 December 2013, per cent.

WACC Parameters	DNSPs' submission to draft determination	Final determination
Gearing (debt to equity ratio)	60	60
10 year risk free rate (nominal)	4.63	4.63
Market risk premium	6.00	6.00
Equity beta	1.00	1.00
Cost of equity	10.63	10.63
Cost of Debt (BBB+)[131]	9.60	8.76
Debt risk premium	4.84	4.00
Debt raising cost	0.125	0.125
Nominal Vanilla WACC	10.01	9.51

Source: JEN, CP, PC, SPA, and UED, *AER draft determination on 2009-2011 AMI budget and charges applications; Joint submission by the Victorian DNSPs on the debt risk premium,* 11 September 2009.

The AER has determined revenue requirements and charges using the WACC derived from the parameters in Table 4.6. Note that the WACC used for making the time value of money adjustments for the offset of cost and revenues 2006-08 is determined as per the EDPR 2006–10.

4.4.2 Use of historic information

In the draft determination, the AER did not accept CP, JEN and PC's un-audited adjustments to 2006-08 actual costs and revenues as they differed from regulatory accounting statements already provided for those years.

Clauses 4.1(k)(i) and 5D.6 of the revised Order states that audited regulatory account statements are the basis for accepting 2006–08 revenues and cost respectively. Therefore, in its draft determination, the AER:

- only accepted adjustments to 2006–08 costs and revenues that were consistent with UED's audited regulatory accounting statements. With respect to the initial charges application, this resulted in minor adjustments to UED's capital expenditure, which in turn affected the building block revenues associated with capital expenditure and depreciation

- did not accept the revisions proposed by the other DNSPs and instead used the information as it appeared in the already provided regulatory accounting statements.

[131] Includes debt raising costs of 0.125 per cent.

CitiPower and Powercor

In the draft determination, the AER did not accept CP or PC's written explanations outlining un-audited amendments to the regulatory accounts for 2006-08 that they proposed.

In response to the draft determination and following meetings with AER staff to clarify regulatory accounts information already provided, CP and PC engaged Deloitte to undertake a re-audit of the IMRO costs and pre-start date AMI costs in CP and PC's spreadsheets. These spreadsheets contained Schedules after adjustments and schedules before adjustments for IMRO related costs and pre-start date AMI costs, which were queried by the AER in the draft determination.

Deloitte's audit opinion attested to the amended regulatory accounts information provided by CP and PC such that:

- information was correctly extracted from audited regulatory accounts
- the nature of the costs included in pre-start date AMI costs tables in the schedules provided to the AER are consistent with activities within scope of the revised Order
- costs reported in the Efficiency Carry-over Mechanism rows of the charges template under the heading O&M Expenditure in the IMRO – Data Inputs tables in the 'Schedule Before Adjustments' provided to the AER was consistent with clause 5D.4(c) of the revised Order
- the adjustments made to the regulatory accounting statements, reflected in the IMRO and pre-start date AMI costs shown in adjustments template and notes provided to the AER, are consistent with the scope of AMI activities set out in the revised Order
- statements made by CP and PC in the notes to the adjustment schedule are factually correct
- information included in the IMRO – Data Inputs and pre-start date AMI costs tables in the schedules after adjustment has been correctly extracted from the schedules before adjustments and the adjustments schedule.[132]

The AER has accepted the re-audited information on IMRO and pre-start date AMI costs provided by CP and PC, which form part of the 'prescribed metering offset' revenue item, on the grounds that it meets the revised Order's requirements for audited regulatory accounting information to be used by the AER when determining the prescribed metering offset as part of each DNSPs' revenue requirement.

[132] Deloitte, *Op. cit.*, p. 3.

The AER notes that CP and PC's capitalisation policy has no impact on the NPV calculated in the revenue requirements and therefore no impact on AMI charges. It has no impact on historic costs as the capitalisation policy only affect forecast 2009-11 expenditure. Rather, it results in a timing difference, with CP and PC receiving cost recovery for overheads associated with operating and maintenance expenditure earlier in the period rather than later as part of capital expenditure. Therefore, no amendments were made by the AER to the capitalisation policy.

Jemena

In the draft determination, the AER made adjustments to JEN's revenue requirements (and therefore AMI charges) to correct for discrepancies between regulatory accounts provided at the time and the AMI charges application made on 1 June 2009.

In response to the draft determination, JEN provided the AER on 30 September 2009 with updated regulatory accounting information for 2006, 2007 and 2008 to justify its metering cost allocations.

The AER has considered all the information provided by JEN in the re-audited regulatory accounting statements and considers that it complies with clauses 4.1(k) and 5D.6 the revised Order.. Data from these statements was therefore used by the AER in setting JEN's offset of costs and revenues, its total revenue requirement and AMI charges in this final determination.

The impact of accepting JEN historic information is to increase the metering asset base and depreciation, such that the overall revenue requirements is increased by $21.6 million over 2009-11 compared to the draft determination.

4.4.3 SP AusNet's movement in provisions

In the draft determination, the AER offset a movement in provisions against metering maintenance and operating expenditure. In regards to provisions for 2006-08, the AER derived a different figure for movements in provisions than that in SPA's charges application, and allocated these costs to indirect overheads. In their submission, SPA agreed with the approach adopted by the AER, however, they claimed that provisions should be allocated against meter data services, and not indirect overheads based on the labour component.[133]

Previously SPA advised that movements in provisions mainly relate to indirect overheads, specifically for asbestos.[134] However, in response to the draft determination, SPA claimed that following a review of provisions, in 2007 and 2008, the balance of the movement in provisions for those years related to employee entitlements and an unfunded shortfall in its defined benefits superannuation scheme. That scheme was for employees performing metering data services only and not for the costs relating to individuals who are included in the indirect overheads cost category.

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[133] SPA, *Response to Draft Decision*, op. cit., p.5.
[134] SPA, Email to AER, *SP AusNet - AMI Data 2006-08 - AER Questions*, 16 June 2009.

Furthermore, SPA did not allocate provisions to pre-start AMI costs. This implied that SPA contracted out all its AMI related activities for 2006-08 to external parties. The AER queried this with SPA, who advised that no direct SPA employees were working on AMI during the period 2006-08. Equally, no direct employees have been engaged on the AMI program since that date; all are independent contractors, sometimes engaged through a labour hire company.

The AER requested that these provisions be allocated to all costs categories that have labour cost components.

In response, SPA allocated provisions against meter data services, standard meter maintenance and indirect overheads[135] – in contrast to only indirect overheads as per its 1 June 2009 initial AMI charges application. The AER accepted this explanation and SPA's allocation of provisions relating to AMI.

4.4.4 Metering asset base

The metering asset bases for each DNSP are shown in Tables 4.7 to 4.11, all of which have increased from that in the draft determination.

The DNSPs submissions to the draft determination noted the amendments made to regulatory accounting statements for capital expenditure associated with IMRO and pre-start date AMI activities. They submitted that this data reflected their expenditure of metering activities during 2006-08, in accordance the revised Order.

As shown in Tables 4.7 to 4.11, the metering assets base is driven by capex for IMRO, pre-start AMI capex, the budget period 2009-11 capex approved by the AER in this final determination and depreciation, for each DNSP. This data reflects their submissions to the draft determination.

The key area driving CP's higher metering asset base compared to the draft determination is data presented in re-audited regulatory accounts for 2006-08 IMRO and pre-start date capex. This was not accepted by the AER in the draft determination because at the time, it was un-audited and did not reflect the most recent regulatory accounts provided to the AER at that stage.

CP subsequently engaged independent auditors Deloitte to conform the data in a re-audit of the regulatory accounts.

[135] SPA, email to AER, *AMI Provisions Allocation for Final Determination*, 7 October 2009.

Table 4.7: CP submitted metering asset base, 2006–11 ($'000s, real 2008)

	2006	2007	2008	2009	2010	2011
Opening metering asset base	0	4,494	6,265	7,888	35,945	65,360
Pre start date AMI capital costs	N/A	N/A	N/A	9,436	N/A	N/A
Capital expenditure	4,698	2,259	2,276	23,461	37,732	39,613
Depreciation	204	488	652	4,840	8,316	11,530
Disposals	0	0	0	0	0	0
Closing metering asset base	4,494	6,265	7,888	35,945	65,360	93,444

Source: CP, *AMI Audit Reports and Charges Applications*, 21 September 2009.
Note: Capital expenditure is net of customer contributions.
Pre-start AMI capital costs include a WACC adjustment for the time value of money.

The metering asset base proposed by JEN, compared to the draft determination, reflects the data presented in re-audited regulatory accounts for 2006-08 IMRO and pre-start date capex. This data was not accepted by the AER in the draft determination because at the time, it was un-audited and did not reflect the most recent regulatory accounts provided to the AER at that stage.

JEN subsequently engaged independent auditors Deloitte and KPMG to confirm the data in a re-audit of the regulatory accounts. Table 4.8 below shows JEN's submission to the draft determination on the metering asset base.

Table 4.8: JEN submitted metering asset base, 2006–11 ($'000s, real 2008)

	2006	2007	2008	2009	2010	2011
Opening metering asset base	0	5,507	9,280	13,076	75,934	92,980
Pre start date AMI capital costs	N/A	N/A	N/A	17,452	N/A	N/A
Capital expenditure	5,592	4,000	4,136	54,607	31,940	34,044
Depreciation	86	227	340	9,201	14,895	17,997
Disposals	0	0	0	0	0	0
Closing metering asset base	5,507	9,280	13,076	75,934	92,980	109,027

Source: JEN, *AMI Charges Model 2010-11 Draft Determination Amended for Restated Regulatory Accounts*, 30 September 2009.
Note: Capital expenditure is net of customer contributions.
Pre-start AMI capital costs include a WACC adjustment for the time value of money.

Driving PC's higher proposed metering asset base compared to the draft determination is the data presented in re-audited regulatory accounts for 2006-08 IMRO and pre-start date capex. This was not accepted by the AER in the draft determination because at the time, it was un-audited and did not reflect the most recent regulatory accounts provided to the AER at that stage.

PC subsequently engaged independent auditors Deloitte to conform the data in a re-audit of the regulatory accounts.

Table 4.9: PC submitted metering asset base, 2006–11 ($'000s, real 2008)

	2006	2007	2008	2009	2010	2011
Opening metering asset base	0	7,562	13,951	18,070	65,054	137,400
Pre start date AMI capital costs	N/A	N/A	N/A	15,301	N/A	N/A
Capital expenditure	7,903	7,382	5,648	40,815	88,421	103,071
Depreciation	340	993	1,530	9,131	16,076	23,885
Disposals	0	0	0	0	0	0
Closing metering asset base	7,562	13,951	18,070	65,054	137,400	216,586

Source: PC, *AMI Audit Reports and Charges Applications*, 21 September 2009.
Note: Capital expenditure is net of customer contributions.
Pre-start AMI capital costs include a WACC adjustment for the time value of money.

The main difference between SPA's metering asset base in the draft determination and that proposed in Table 4.10, is the reduction in capex associated with an amended budget application 2009-11 and a lower depreciation allowance, which increases the size of the closing metering asset base.

Table 4.10: SPA submitted metering asset base, 2006–11 ($'000s, real 2008)

	2006	2007	2008	2009	2010	2011
Opening metering asset base	0	7,584	13,698	21,039	91,431	122,553
Pre start date AMI capital costs	N/A	N/A	N/A	14,520	N/A	N/A
Capital expenditure	7,967	7,109	8,847	67,901	50,896	102,441
Depreciation	383	995	1,506	12,029	19,774	26,177
Disposals	0	0	0	0	0	0
Closing metering asset base	7,584	13,698	21,039	91,431	122,553	198,817

Source: SPA, *SP AusNet - updated AMI pricing and budget templates*, 13 October 2009.
Note: Capital expenditure is net of customer contributions.
Pre-start AMI capital costs include a WACC adjustment for the time value of money.

UED's proposed metering asset base in Table 4.11 is identical to that of the AER's draft determination.

Table 4.11: UED submitted metering asset base, 2006–11 ($'000s, real 2008)

	2006	2007	2008	2009	2010	2011
Opening metering asset base	0	6,367	11,230	14,312	101,595	132,467
Pre start date AMI capital costs	N/A	N/A	N/A	35,066	N/A	N/A
Capital expenditure	6,733	5,890	4,633	65,403	51,373	69,780
Depreciation	366	1,026	1,552	13,186	20,501	25,673
Disposals	0	0	0	0	0	0
Closing metering asset base	6,367	11,230	14,312	101,595	132,467	176,574

Source: UED, *AMI 2010-11 Charges Model Response to DD*, 24 September 2009.
Note: Capital expenditure is net of customer contributions.
Pre-start AMI capital costs include a WACC adjustment for the time value of money.

AER final determination on metering asset base

Clause 5D.2 of the revised Order requires the AER to determine the metering asset base for each DNSP.

In determining the metering asset base for each DNSP, as noted in section 4.4, for the years 2006, 2007 and 2008, the AER used data from JEN, CP and PC's restated regulatory accounting statements in relation to pre-start date AMI capex, as required by clauses 4.1(k)(i) and 5D.6 the revised Order. The data used for SPA and UED was the same as for the draft determination.

Further, the initial AMI budget period 2009-11 applications, for forecast capex that the AER has approved in this final determination, also impacts the metering asset.

Having determined the above parameters, Tables 4.12 to 4.16 shows the AER's final determination on the metering asset base for all DNSPs.

Table 4.12: AER final determination on CP’s metering asset base, 2006–11 ($’000s, real 2008)

	2006	2007	2008	2009	2010	2011
Opening metering asset base	0	4,494	6,265	7,888	35,522	63,881
Pre start date AMI capital costs	N/A	N/A	N/A	9,436	N/A	N/A
Capital expenditure	4,698	2,259	2,276	23,005	36,553	38,456
Depreciation	204	488	652	4,807	8,194	11,311
Disposals	0	0	0	0	0	0
Closing metering asset base	4,494	6,265	7,888	35,522	63,881	91,027

Note: Capital expenditure is net of customer contributions.
Pre-start AMI capital costs include a WACC adjustment for the time value of money.

Table 4.13: AER final determination on JEN’s metering asset base, 2006–11 ($’000s, real 2008)

	2006	2007	2008	2009	2010	2011
Opening metering asset base	0	5,507	9,280	13,076	73,062	88,841
Pre start date AMI capital costs	N/A	N/A	N/A	17,452	N/A	N/A
Capital expenditure	5,592	4,000	4,136	51,516	30,132	32,117
Depreciation	86	227	340	8,982	14,353	17,280
Disposals	0	0	0	0	0	0
Closing metering asset base	5,507	9,280	13,076	73,062	88,841	103,678

Note: Capital expenditure is net of customer contributions.
Pre-start AMI capital costs include a WACC adjustment for the time value of money.

Table 4.14: AER final determination on PC's metering asset base, 2006–11 ($'000s, real 2008)

	2006	2007	2008	2009	2010	2011
Opening metering asset base	0	7,562	13,951	18,070	64,058	133,742
Pre start date AMI capital costs	N/A	N/A	N/A	15,301	N/A	N/A
Capital expenditure	7,903	7,382	5,648	39,737	85,470	100,201
Depreciation	340	993	1,530	9,051	15,785	23,355
Disposals	0	0	0	0	0	0
Closing metering asset base	7,562	13,951	18,070	64,058	133,742	210,588

Note: Capital expenditure is net of customer contributions.
Pre-start AMI capital costs include a WACC adjustment for the time value of money.

Table 4.15: AER final determination on SPA's metering asset base, 2006–11 ($'000s, real 2008)

	2006	2007	2008	2009	2010	2011
Opening metering asset base	0	7,584	13,698	21,039	91,431	122,553
Pre start date AMI capital costs	N/A	N/A	N/A	14,520	N/A	N/A
Capital expenditure	7,967	7,109	8,847	67,901	50,896	102,441
Depreciation	383	995	1,506	12,029	19,774	26,177
Disposals	0	0	0	0	0	0
Closing metering asset base	7,584	13,698	21,039	91,431	122,553	198,817

Note: Capital expenditure is net of customer contributions.
Pre-start AMI capital costs include a WACC adjustment for the time value of money.

Table 4.16: AER final determination on UED's metering assets base, 2006–11 ($'000s, real 2008)

	2006	2007	2008	2009	2010	2011
Opening metering asset base	0	6,367	11,230	14,312	98,158	126,801
Pre start date AMI capital costs	N/A	N/A	N/A	35,066	N/A	N/A
Capital expenditure	6,733	5,890	4,633	61,701	48,465	65,831
Depreciation	366	1,026	1,552	12,921	19,821	24,698
Disposals	0	0	0	0	0	0
Closing metering asset base	6,367	11,230	14,312	98,158	126,801	167,934

Note: Capital expenditure is net of customer contributions.
Pre-start AMI capital costs include a WACC adjustment for the time value of money.

4.4.5 Depreciation

Regulatory depreciation is a component of the revenue requirement for regulated services and represents the annual rate at which accumulated capital is returned to investors. It is a function of the metering asset base and the period over which the assets are depreciated.

The revised Order stipulates that actual depreciation should be used for the period 1 January 2006 to 31 December 2008. [136]

Clause 4.1(g) of the revised Order also stipulates the asset life for remotely read meters and measurement transformers is 15 years, and for telecommunications and information technology assets is 7 years, over the 2009–11 period. The AER's framework and approach, consistent with revised Order, also permits DNSPs to accelerate depreciation of accumulation meters and manually read interval meters over 2010-13, such that their value is zero by 31 December 2013.

The DNSPs' charges submitted in response to the draft determination adopted the depreciation methodology and lives as set out in Clause 4.1(g) of the revised Order.

The AER has therefore accepted the DNSPs' proposed depreciation methodology and standard lives.

4.4.6 Benchmark allowance for corporate income tax

Clause 4.1(b)(iv) of the revised Order provides that a benchmark allowance for corporate income tax is one of the required building blocks. Clause 4.1(f) requires the benchmarking of parameters used in the calculation of tax liabilities, including tax depreciation methods and rates, the debt to equity ratio, the return on debt and the value of imputation credits.

[136] This is depreciation associated with actual capital expenditure for these years, as per data sourced from the DNSPs' regulatory accounts.

In accordance with clause 4.1(e)(ii), the AER carried forward the tax losses of the DNSPs associated with metering during 2006–08.

For the purposes of clause 4.1(f), the AER benchmarked declining balance depreciation as the tax depreciation method, with the rate set at 37.50 per cent for meters and transformers where unit cost is less than $1 000 and 6 per cent for meters and transformers where unit cost is greater than $1 000, 40 per cent for IT assets, 21.43 per cent for communications and 17.65 per cent for other.[137] The value of debt as a proportion of equity and debt was 60 per cent, the nominal cost of debt was 10.39 per cent in 2009 and 7.84 per cent for 2010 and 2011. The value of imputation credits was 0.65.

The AER included tax calculations in the charges model provided to the DNSPs. In their 1 June 2009 charges applications, and in amended charges submitted in response to the draft determination, the DNSPs did not alter these calculations. The AER therefore has accepted the methodology and tax depreciation rates proposed by the DNSPs in their charges applications. The value of the tax liability building block proposed by each DNSP was zero and remains unchanged as a result of the AER's final determination given the persistence of tax losses.

4.4.7 Offset of costs and revenues 2006-08

Clauses 5D.4(a) to 5D.4(g) of the revised Order require the AER to determine additional expenditure relating to the prescribed metering offset, DUOS tax liability, efficiency carryover for 2006–08 and pre-start date AMI costs.

In their submissions to the draft determination, the DNSPs proposed net offsets that are outlined in Tables 4.17 to 4.21 which are impacted by their re-audited regulatory accounting statement information for historic costs and revenues over the period. This in turn affected the ECM calculations.

Discussions of the main areas of contention from the draft determination are noted in sections 4.4.7.1 to 4.4.7.4 below.

[137] These rates and the methodology are consistent with ESCV, *Electricity Distribution Price Review 2006–10—Final Decision*, October 2006.

Table 4.17: CP revised proposed offset of costs and revenues 2006–08, ($'000s, nominal)

	2006	2007	2008	2009	2010	2011	2012	2013
Prescribed metering offset	-985	-3,443	-5,481	N/A	N/A	N/A	N/A	N/A
Duos tax offset	0	449	822	775	525	N/A	N/A	N/A
Efficiency carryover	291	1,385	1,122	1,178	1,208	1,239	921	-336
AMI O&M costs	490	3,375	4,430	N/A	N/A	N/A	N/A	N/A
Total	-204	1,767	892	1,953	1,733	1,239	921	-336
WACC time value of money adjustment factor	1.34	1.21	1.13	1.00	0.91	0.83	0.75	0.68
Total Offset	N/A	N/A	N/A	**7,892**	N/A	N/A	N/A	N/A

Source: CP, *AMI Audit Reports and Charges Applications*, 21 September 2009.
N/A = Not applicable.

Table 4.18: JEN revised proposed offset of costs and revenues 2006–08, ($'000s, nominal)

	2006	2007	2008	2009	2010	2011	2012	2013
Prescribed metering offset	-967	-508	-1,048	N/A	N/A	N/A	N/A	N/A
Duos tax offset	118	455	531	558	418	N/A	N/A	N/A
Efficiency carryover	1,514	1,425	1,263	1,326	1,360	1,395	-385	-219
AMI O&M costs	0	0	0	N/A	N/A	N/A	N/A	N/A
Total	665	1,372	747	1,884	1,778	1,395	-385	-219
WACC time value of money adjustment factor	1.34	1.21	1.13	1.00	0.91	0.83	0.75	0.68
Total Offset	N/A	N/A	N/A	**7,610**	N/A	N/A	N/A	N/A

Source: JEN, *AMI Charges Model 2010-11 Draft Determination Amended for Restated Regulatory Accounts*, 30 September 2009..
N/A = Not applicable.

Table 4.19: PC revised proposed offset of costs and revenues 2006–08, ($'000s, nominal)

	2006	2007	2008	2009	2010	2011	2012	2013
Prescribed metering offset	-6,619	-9,927	-14,653	N/A	N/A	N/A	N/A	N/A
Duos tax offset	0	832	1,918	2,486	2,271	N/A	N/A	N/A
Efficiency carryover	5,125	5,652	5,783	6,071	6,226	6,386	404	30
AMI O&M costs	1,529	5,858	9,571	N/A	N/A	N/A	N/A	N/A
Total	35	2,414	2,619	8,556	8,497	6,386	404	30
WACC time value of money adjustment factor	1.34	1.21	1.13	1.00	0.91	0.83	0.75	0.68
Total Offset	N/A	N/A	N/A	**27,810**	N/A	N/A	N/A	N/A

Source: PC, *AMI Audit Reports and Charges Applications*, 21 September 2009.
N/A = Not applicable.

Table 4.20: SPA revised proposed offset of costs and revenues 2006–08, ($'000s, nominal)

	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**212**	**2013**
Prescribed metering offset	-6,397	-10,053	-12,563	N/A	N/A	N/A	N/A	N/A
Duos tax offset	350	445	1,172	1,821	1,773	N/A	N/A	N/A
Efficiency carryover	1,222	2,392	1,221	1,282	1,315	1,348	-83	-1,412
AMI O&M costs	1,028	3,360	8,008	N/A	N/A	N/A	N/A	N/A
Total	-3,797	-3,855	-2,162	3,102	3,087	1,348	-83	-1,412
WACC time value of money adjustment	1.34	1.21	1.13	1.00	0.91	0.83	0.75	0.68

factor								
Total Offset	N/A	N/A	N/A	-6,198	N/A	N/A	N/A	N/A

Source: SPA, *SP AusNet - updated AMI pricing and budget templates*, 13 October 2009.
N/A = Not applicable.

Table 4.21: UED revised proposed offset of costs and revenues 2006–08, ($'000s, nominal)

	2006	2007	2008	2009	2010	2011	212	2013
Prescribed metering offset	-2,572	-3,166	-4,243	N/A	N/A	N/A	N/A	N/A
Duos tax offset	0	268	986	1,527	1,433	N/A	N/A	N/A
Efficiency carryover	-318	107	-56	-59	-60	-62	318	-192
AMI O&M costs	0	990	1,010	N/A	N/A	N/A	N/A	N/A
Total	-2,890	-1,801	-2,304	1,468	1,373	-62	318	-192
WACC time value of money adjustment factor	1.34	1.21	1.13	1.00	0.91	0.83	0.75	0.68
Total Offset	N/A	N/A	N/A	**-5,873**	N/A	N/A	N/A	N/A

Source: UED, *AMI 2010-11 Charges Model Response to DD*, 24 September 2009.
N/A = Not applicable.

4.4.7.1 Prescribed metering offset

Clause 5D.4(a) requires the AER to determine additional expenditure included in the building block costs incurred for prescribed metering services under the Current Price Determination from 1 January 2006 to the start date. It states:

> the building block costs incurred offset by the revenue earned by a DNSP in respect of prescribed metering services (not being metering services to unmetered supply points to which clause 6 applies) under the Current Price Determination during the period from 1 January 2006 until the Start Date. For the purposes of this clause 5D.4(a), the weighted average cost of capital in the Current Price Determination shall be applied, adjusted for inflation.

This means that the DNSP's revenue requirement will be adjusted by an amount which reflects any over or under-recovery of revenue in relation to metering services provided between 1 January 2006 and 31 December 2008.

The AER's adjustments to SPA's provisions discussed in section 4.4.3 and the independent re-audits of regulatory accounting statements undertaken for CP, JEN and PC were accepted by the AER because the audited statements satisfied the requirements of the revised Order.

4.4.7.2 DUOS tax liability

Clause 5D.4(b) of the revised Order require the AER to make an adjustment for

> the amount by which the 'building block taxation liability was reduced as a result of the consolidation undertaken by the Commission of the taxation for both 'regulated by price cap and metering' for the period 1 January 2006 to 31 December 2010 as referred to at page 399 of the current Price Determination (Volume 1).

The charges model automatically calculates the DUOS tax liability based on benchmark assumptions contained in the current price determination as noted in clause 5D.4(b). The DNSPs did not amend these calculations or assumptions when proposing their amended AMI charges in response to the draft determination.

The AER has therefore accepted the DUOS tax liability proposed by each DNSP, which are consistent with the revised Order.

4.4.7.3 Efficiency carryover arising from current price determination

Clause 5D.4(c) of the revised Order requires the AER to consider the ECM from the ESCV's manually read IMRO that was suspended in 2006. The AER is to reflect the ECM amounts when determining charges for 2010 and 2011. This requirement will be met by summing the efficiency carryover amounts for 2009 to 2013, adjusted to reflect the time value of money, and incorporating this amount in 2010 charges.

The AER calculated ECM amounts for actual opex from 2006 to 2008 consistent with the approach in the current price determination, while reflecting the requirements of the clauses 4.1(k)(i) and 5D.6 of the revised Order to use historical data from audited regulatory accounts which CP, JEN and PC resubmitted in response to the draft determination.

The re-audited regulatory accounts provided the breakdown and independent audit sign off for:

- Maintenance costs – meter data services – IT related
- Operating costs - metering data services
- Customer service operating costs associated with meter replacement.

The DNSPs' charges applications were consistent with these re-audited regulatory accounting statements and are therefore accepted by the AER.

As a result, the adjustments made by the AER to CP, JEN's and PC's efficiency carryover mechanism in the draft determination have been revised, taking into account the re-audited data from regulatory accounting statements.

The AER's final determination on the ECM amounts for each DNSP is detailed in Tables 4.22 to 4.26 below. Relative to the draft determination, JEN's Efficiency carryover has increased by $21 million, while the impacts for CP and PC were marginal.

4.4.7.4 AMI pre-start date O&M expenditure

DNSPs are able to recover pre-start date (1 January 2006 to 31 December 2008) AMI costs incurred under clause 5D.4 of the revised Order.

Clauses 5D.4(d) to 5D.4(g) of the revised Order require the AER to make an adjustment for pre-start date AMI expenditure. These mainly relate to project management cost; costs associated with undertaking technology trials and customer response trials at the direction of DPI; installation and commissioning of information technology systems to support remote meter reading; project management; and interest rate and exchange rate hedging costs.

The DNSPs did not respond to the draft determination on these issues. The exception was CP and PC, whose auditors signed off on re-audited regulatory accounts that affirmed the quantum of project management costs allocated to pre-start date AMI activities (which were identical to those in CP and PC's original AMI charges application in June 2009). The AER used this new data when determining the offset for CP and PC.

None of the DNSPs applied for interest rate hedging or exchange rate hedging costs under clause 5D.4(g) of the revised Order.

4.4.7.5 WACC adjustment for the time value of money

The revised Order permits the DNSPs to receive the time value of money for 2006–08 expenditure when calculating the offset of revenues and costs for 2006-08. The DNSPs accepted time value of money adjustment in the draft determination. Therefore, that adjustment is affirmed in this final determination.

The value of this adjustment in terms of the building block cost is shown in Tables 3.28 to 3.32 below. The actual value reflects the AER's final determination on 2006-08 AMI costs and revenues in this determination.

AER final determination on offset of costs and revenues 2006–08

The AER's final determination on the offset of costs and revenues 2006-08 for each DNSP, applied as a building block component in 2009, is shown in Tables 4.22 to 4.26.

The determination for each DNSP differs to those proposed in Tables 4.17 to 4.21 due to the WACC of 9.51 per cent per cent adopted by the AER, the adjustments to provisions made by SPA and the impact of the time value of money adjustment for the years 2009-13.

Table 4.22: CP final determination offset of costs and revenues 2006–08, ($'000s, nominal)

	2006	2007	2008	2009	2010	2011	2012	2013
Prescribed metering offset	-985	-3,443	-5,481	N/A	N/A	N/A	N/A	N/A
Duos tax offset	0	449	822	775	525	N/A	N/A	N/A
Efficiency carryover	291	1,385	1,122	1,178	1,208	1,239	921	-336
AMI O&M costs	490	3,375	4,430	N/A	N/A	N/A	N/A	N/A
Total	-204	1,767	892	1,953	1,733	1,239	921	-336
WACC time value of money adjustment factor	1.33	1.21	1.12	1.00	0.91	0.83	0.76	0.70
Total Offset	N/A	N/A	N/A	7,901	N/A	N/A	N/A	N/A

N/A = Not applicable.

Table 4.23: JEN final determination offset of costs and revenues 2006–08, ($'000s, nominal)

	2006	2007	2008	2009	2010	2011	2012	2013
Prescribed metering offset	-967	-508	-1,048	N/A	N/A	N/A	N/A	N/A
Duos tax offset	118	455	531	558	418	N/A	N/A	N/A
Efficiency carryover	1,514	1,425	1,263	1,326	1,360	1,395	-385	-219
AMI O&M costs	0	0	0	N/A	N/A	N/A	N/A	N/A
Total	665	1,372	747	1,884	1,778	1,395	-385	-219
WACC time value of money adjustment factor	1.33	1.21	1.12	1.00	0.91	0.83	0.76	0.70
Total Offset	N/A	N/A	N/A	7,605	N/A	N/A	N/A	N/A

N/A = Not applicable.

Table 4.24: PC final determination offset of costs and revenues 2006–08, ($'000s, nominal)

	2006	2007	2008	2009	2010	2011	2012	2013
Prescribed metering offset	-6,619	-9,927	-14,653	N/A	N/A	N/A	N/A	N/A
Duos tax offset	0	832	1,918	2,486	2,271	N/A	N/A	N/A
Efficiency carryover	5,125	5,652	5,783	6,071	6,226	6,386	404	30
AMI O&M costs	1,529	5,858	9,571	N/A	N/A	N/A	N/A	N/A
Total	35	2,414	2,619	8,556	8,497	6,386	404	30
WACC time value of money adjustment factor	1.33	1.21	1.12	1.00	0.91	0.83	0.76	0.70
Total Offset	N/A	N/A	N/A	27,871	N/A	N/A	N/A	N/A

N/A = Not applicable.

Table 4.25: SPA final determination offset of costs and revenues 2006–08, ($'000s, nominal)

	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**212**	**2013**
Prescribed metering offset	-6,397	-10,053	-12,563	N/A	N/A	N/A	N/A	N/A
Duos tax offset	350	445	1,172	1,821	1,773	N/A	N/A	N/A
Efficiency carryover	1,222	2,392	1,221	1,282	1,315	1,348	-83	-1,412
AMI O&M costs	1,028	3,360	8,008	N/A	N/A	N/A	N/A	N/A
Total	-3,797	-3,855	-2,162	3,102	3,087	1,348	-83	-1,412
WACC time value of money adjustment factor	1.33	1.21	1.12	1.00	0.91	0.83	0.76	0.70
Total Offset	N/A	N/A	N/A	-6,137	N/A	N/A	N/A	N/A

N/A = Not applicable.

Table 4.26: UED final determination offset of costs and revenues 2006–08, ($'000s, nominal)

	2006	2007	2008	2009	2010	2011	212	2013
Prescribed metering offset	-2,572	-3,166	-4,243	N/A	N/A	N/A	N/A	N/A
Duos tax offset	0	268	986	1,527	1,433	N/A	N/A	N/A
Efficiency carryover	-318	107	-56	-59	-60	-62	318	-192
AMI O&M costs	0	990	1,010	N/A	N/A	N/A	N/A	N/A
Total	-2,890	-1,801	-2,304	1,468	1,373	-62	318	-192
WACC time value of money adjustment factor	1.33	1.21	1.12	1.00	0.91	0.83	0.76	0.70
Total Offset	N/A	N/A	N/A	-5,827	N/A	N/A	N/A	N/A

N/A = Not applicable.

The total offsets as noted in the above tables are a component of the overall final determination building block revenues, outlined in the next section.

4.5 AER Determination – revenue requirements

The AER's final determination on the DNSPs' revenue requirements is summarised in Tables 4.27 to 4.31 below.

These revenues will be used to derive the AMI charges by each DNSP for the period 2010 and 2011. Chapter 5 discusses the DNSPs' submissions to the draft determination on the charges applications and the AER's final determination in relation to those charges.

The final determination on DNSPs' revenue requirements reflects a WACC of 9.51 per cent, incorporating a DRP of 4.00 per cent, together with information from the re-audited regulatory accounting statements for JEN, CP and PC. The revenues also reflect the final determination on initial AMI budget applications 2009-11, outlined in Tables 3.1 to 3.5 above.

The final determination on CP's revenue requirements reflects a WACC of 9.51 per cent adopted by the AER, which affected the return on capital and the offset of costs and revenues for 2006-08, determined in section 4.4.7 and shown in Table 4.22 above, together with the budget approved by the AER. As a consequence, these revenues are $2.8 million lower than those in the draft determination.

Table 4.27: CP final determination revenue requirements ($'000s, nominal)

	2009	2010	2011
Return on capital	3,195	4,959	7,927
Depreciation	3,730	7,487	10,355
Operating & maintenance costs	13,249	10,271	10,811
Tax liability	0	0	0
Offset of costs and revenues 2006–08	7,901	N/A	N/A
Total revenue requirement	28,075	22,717	29,092

N/A = Not applicable.

The final determination on JEN's revenues requirements was impacted by the WACC of 9.51 per cent adopted by the AER, which affected the return on capital and the offset of costs and revenues 2006-08 in determined section 4.4.7 and shown in Table 4.23 above. An increase in the revenue requirement of $43.3 million from the draft determination resulted.

Table 4.28: JEN final determination revenue requirements ($'000s, nominal)

	2009	2010	2011
Return on capital	6,262	8,078	9,851
Depreciation	6,849	13,278	16,428
Operating & maintenance costs	3,883	8,876	14,026
Tax liability	0	0	0
Offset of costs and revenues 2006–08	7,605	N/A	N/A
Total revenue requirement	24,600	30,232	40,305

. N/A = Not applicable.

The final determination on PC's revenue requirements reflects a WACC of 9.51 per cent adopted by the AER, which affected the return on capital and the offset of costs and revenues for 2006-08, determined in section 4.4.7 and shown in Table 4.24 above. These revenues are $8.7 million lower than those in the draft determination.

Table 4.29: PC final determination revenue requirements ($'000s, nominal)

	2009	2010	2011
Return on capital	5,890	9,869	17,619
Depreciation	7,075	14,337	21,045
Operating & maintenance costs	27,606	20,799	23,663
Tax liability	0	0	0
Offset of costs and revenues 2006–08	27,871	N/A	N/A
Total revenue requirement	68,442	45,005	62,327

N/A = Not applicable.

SPA's final determination revenue requirements reflects a WACC of 9.51 per cent adopted by the AER, which affected the return on capital and the offset of costs and revenues for 2006-08, determined in section 4.4.7 and shown in Table 4.25. SPA's draft determination revenue requirement was therefore increased by $8.2 million, to that shown in Table 4.30 below.

Table 4.30: SPA final determination revenue requirements ($'000s, nominal)

	2009	2010	2011
Return on capital	7,677	10,676	16,444
Depreciation	9,465	18,415	24,477
Operating & maintenance costs	30,757	30,463	29,655
Tax liability	0	0	0
Offset of costs and revenues 2006–08	-6,137	N/A	N/A
Total revenue requirement	41,762	59,554	70,577

N/A = Not applicable.

The final determination on UED's revenue requirements reflects a WACC of 9.51 per cent adopted by the AER, which affected the return on capital and the offset of costs and revenues for 2006-08, determined in section 4.4.7 and shown in Table 4.26 above. Revenues are $3.6 million less than those in the draft determination due to the elimination of related party margins from UED's budget expenditure.

Table 4.31: UED final determination revenue requirements ($'000s, nominal)

	2009	2010	2011
Return on capital	8,919	11,224	15,081
Depreciation	9,890	18,319	23,211
Operating & maintenance costs	7,184	13,710	20,606
Tax liability	0	0	0
Offset of costs and revenues 2006–08	-5,827	N/A	N/A
Total revenue requirement	20,165	43,252	58,898

N/A = Not applicable.

5 AMI charges

The DNSPs' AMI charges 2010 and 2011 recover the costs of meter provision and meter data services as a single charge. In the current regulatory period, separate charges are calculated and applied for each of these services. Charges are either on a per meter basis, or a per NMI basis, depending on DNSPs' approaches and current charging practices.

Regulated metering charges for 2010 and 2011 are required by clause 5A.1(b) of the revised Order. Charges for 2009 are those approved by the ESCV in November 2008.[138]

This section assesses the proposed charges that result from the revenue requirements determined in section 4, stakeholders' comments in relation to charges and sets out the AER's responses and final determination on those charges.

5.1 DNSPs' revised submitted charges and further information submitted

The DNSPs amended charges applications, submitted in response to the draft determination are shown in Tables 5.1 to 5.10 along with the proposed amended revenue requirement.

The DNSPs maintained the same charging structure as their original charges application submissions on 1 June 2009. JEN noted that it had incorrectly proposed charges per NMI in its original 1 June 2009 proposal, rather than by meter. Its amended charges application corrected this, and proposed charges on a per meter basis. All DNSPs' initial AMI charges 2010–11 are addressed in turn below.

Table 5.1 contains CP's proposed recovery of AMI costs over 2010–11, where an under–recovery of $7.1 million occurs in 2010. This results in the increase in proposed charges for 2011 shown in Table 5.2.

The amended proposed charges adopted by CP are higher than those in the draft determination, reflecting the use of re-audited regulatory accounting information and the proposed WACC of 10.01 per cent, adopted by all DNSPs in their submissions to the draft determination.

For a customer receiving a single phase single element AMI meter, the charge proposed by CP, shown in Table 5.2, is the same in 2010 as the draft determination; however, it is $7.12 higher in 2011, to recoup the $7.1 million of revenue under recovery occurring in the previous year.

[138] Essential Services Commission of Victoria, *Electricity Tariffs 2009*, http://www.esc.vic.gov.au/public/Energy/Regulation+and+Compliance/Decisions+and+Determinations/Electricity+tariffs+2009/Electricity+Tariffs+2009.htm, accessed on 15 October 2009.

Table 5.1: CP revised proposed AMI cost recovery 2010–11 ($'000s, nominal)

	2009	2010	2011
Total costs	29,234	23,633	30,417
Total revenues	12,701	33,484	39,588
Discount factor	0.94	0.86	0.78
NPV proposed over (under) recovery		-7,141	0

Source: CP, *AMI Audit Reports and Charges Applications*, 21 September 2009.

Table 5.2: CP revised proposed AMI charges, per annum, per NMI ($, nominal)

	2010	2011
Single phase	$104.79	$120.12
Three phase direct connected	$136.98	$162.30
Three phase CT connected	$172.99	$201.87

Source: CP, CP, *AMI Audit Reports and Charges Applications*, 21 September 2009.

Table 5.3 shows JEN's proposed recovery of AMI costs over 2010–11, with an under recovery of $5.5 million proposed in 2010 and $5.6 million in 2011. Proposed charges resulting from this are shown in Table 5.4; 2010 charges for customers on a single phase meter have increased from those in the draft determination by $66.84 and by $6.18 in 2011. This is due to the AER adopting JEN's re-audited regulatory accounting statements information on IMRO and pre-start date AMI costs (see sections 4.1 and 4.2), which increased JEN's allowed revenue requirement.

For its customers, JEN has mitigated this price impact, in part, by adopting under recovery of metering revenues in both 2010 and 2011.

Table 5.3: JEN revised proposed AMI cost recovery 2010–11 ($’000s, nominal)

	2009	2010	2011
Total costs	25,443	32,050	42,841
Total revenues	11,049	41,402	42,738
Discount factor	0.94	0.86	0.78
NPV proposed over (under) recovery		-5,553	-5,634

Source: JEN, *AMI Charges Model 2010-11 Draft Determination Amended for Restated Regulatory Accounts*, 30 September 2009.

Table 5.4: JEN revised proposed AMI charges, per annum, per meter ($, nominal)

	2010	2011
Single phase single element	$134.63	$136.70
Single phase single element with contactor	$134.63	$136.70
Three phase direct connected	$165.46	$167.99
Three phase CT connected	$183.95	$186.77

Source: JEN, *AMI Charges Model 2010-11 Draft Determination Amended for Restated Regulatory Accounts*, 30 September 2009.

Table 5.5 shows PC’s proposed recovery of AMI costs over 2010–11, with an under recovery of $16.5 million in 2010. This results in higher charges for 2011, shown in Table 5.6, as PC seeks to recoup the foregone revenue. These proposed charges are the same as originally proposed by PC in its charges application on 1 June 2009.

The impact on customers receiving a single phase single element meter in PC’s geographic area is that proposed charges are identical to those in the draft determination for 2010 but $5.51 higher in 2011.

Table 5.5: PC revised proposed AMI cost recovery 2010–11 ($’000s, nominal)

	2009	2010	2011
Total costs	71,063	46,967	65,338
Total revenues	32,715	69,853	86,570
Discount factor	0.94	0.86	0.78
NPV proposed over (under) recovery		-16,533	0

Source: PC, *AMI Audit Reports and Charges Applications*, 21 September 2009.

Table 5.6: PC revised proposed AMI charges, per annum, per NMI ($, nominal)

	2010	2011
Single phase	$96.67	$116.98
Three phase direct connected	$127.50	$158.47
Three phase CT connected	$168.94	$209.09

Source: PC, *AMI Audit Reports and Charges Applications*, 21 September 2009.

SPA’s proposed recovery of AMI costs over 2010–11 in shown in Table 5.7, where a marginal under recovery of $2 000 is applied for in both 2010 and 2011.

SPA’s single phase single element meter customers would pay $16.06 and $2.75 more in 2010 and 2011, respectively, under their proposal than the draft determination charges.

Table 5.7: SPA revised proposed AMI cost recovery 2010–11 ($’000s, nominal)

	2009	2010	2011
Total costs	42,029	60,120	71,449
Total revenues	38,250	64,275	71,449
Discount factor	0.94	0.86	0.78
NPV proposed over (under) recovery		-2	-2

Source: SPA, *SP AusNet - updated AMI pricing and budget templates*, 13 October 2009.

Table 5.8: SPA revised proposed charges, per annum, per meter ($, nominal)

	2010	2011
Single phase single element 1 contactor	87.29	94.99
Single phase, two–element 2 contactors (2 load controls)	100.29	109.15
Multi phase, one contactor (1 load control)	121.16	131.86
Multi phase, two contactor (2 load controls)	134.41	146.28
Multi phase CT connected	173.07	188.35

Source: SPA, *SP AusNet - updated AMI pricing and budget templates*, 13 October 2009.

In its submission to the draft determination, UED proposed recovery of AMI costs over 2010–11 in shown in Table 5.9, where an under recovery of $1.8 million is adopted in 2010 and $3.2 million for 2011. The resulting AMI charges for each year in Table 5.10 show a jump in charges, mitigated to some extend by the under recovery in 2011.

Despite UED using a proposed WACC of 10.01 per cent, compared to the draft determination's 8.96 per cent, the proposed charges in Table 5.10 are identical to those of the draft determination. This is because UED now proposes to under recover metering revenues in 2010 and 2011, whereas its initial charges application on 1 June 2009 adopted revenue neutrality. This reduces the AMI price shock for its customers in the early years of the meter rollout.

Table 5.9: UED revised proposed AMI cost recovery 2010–11 ($, nominal)

	2009	2010	2011
Total costs	21,340	45,757	62,585
Total revenues	18,182	47,128	60,838
Discount factor	0.94	0.86	0.78
NPV proposed over (under) recovery		-1,802	-3,162

Source: UED, *AMI 2010-11 Charges Model Response to DD*, 24 September 2009.

Table 5.10: UED revised proposed AMI charges, per annum, per NMI ($, nominal)

	2010	2011
Single phase single element	$71.80	$92.12
Single phase single element with contactor	$73.30	$94.02
Three phase direct connected	$81.01	$103.89
Three phase CT connected	$86.40	$110.82

Source: UED, *AMI 2010-11 Charges Model Response to DD*, 24 September 2009.

5.2 Submissions on the draft determination

5.2.1 Consumer Utilities Advocacy Centre

CUAC was concerned that the draft determination implied the AER did not have the ability to enforce charges.[139] CUAC sought clarity that metering charges would be enforced and regulated by the AER, representing the charges to be paid by consumers in 2010–11.

CUAC also sought further explanation from the AER on how the true-up mechanism, for charges from 2009 to 2015 would work.

5.2.2 Origin Energy

Origin Energy stated that although a single AMI charge per AMI meter type generates price simplicity, as proposed by distributors, there was still merit in separating the meter data charge from the meter provisions charge.[140] Two separate charges per AMI meter type would therefore be provided to retailers under such an approach. This would deliver further cost transparency and assist with alternative competitive metering contracts to customers in the future. Separation of charges would also assist with the establishment of DNSPs' exit and restoration fees in the future.

5.2.3 St Vincent de Paul

In its submission to the draft determination, St Vincent de Paul (SVDP)[141] noted that Victorian households will experience significant price increases as a result of the AMI rollout. Low consumption households would face proportionally higher electricity costs. SVDP suggested the AER mitigate this impact in the final determination by requiring DNSPs to allocate a larger proportion of the AMI costs to high consumption households. This would in turn reduce the price impact on low consuming households of the rollout.

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[139] Consumer Action Law Centre, *Draft Decision – Victorian advanced metering infrastructure review 2009-11 AMI budget and charges applications*, 11 September 2009, pp.3, 5.

[140] Origin, *Victorian Advanced Metering Infrastructure Review 2009-11 AMI budget and charges applications – Draft Determination*, p. 2.

[141] St Vincent de Paul Society, *Customer Protections and Smart Meters: Issues for Victoria*, August 2009 p. 42.

5.3 AER considerations

5.3.1 AER enforcement of charges

The AER confirms that its determination on the initial AMI charges, and the subsequent true up of charges, will be the regulated and enforced. Compliance with, including determinations made under, the revised Order is a condition of each of the DNSPs' licences.[142] The AER is responsible for the enforcement of such licences.[143]

Clause 11A.1 of the revised Order requires DNSPs to make retailers aware of these charges by 30 November 2009.

The charges in the draft determination were a signal only of the likely movement in metering charges. However, the final determination will be the charges approved by the AER and to commence from 1 January 2009.

In regards to the true-up mechanism, the revised Order provides an example of how this will operate:

1. Charges for 2009 are set by reference to the metering charges already set by the Current Price Determination for that year.

2. In 2009 there will be the setting of initial charges to apply for 2010 and 2011, based on an Approved Budget for 2009–2011 and actual expenditure and revenues for 2006–2008.

3. In 2010 the initial charges for 2011 will be revised to take account of actual expenditure and revenues known for 2009 and revised forecasts for 2010–2011.

4. This process is repeated by the setting, in 2011, of charges to apply for the years 2012–2015 based on actual expenditure and revenues known to 2010, revised forecasts for 2011 and an Approved Budget for 2012–2015.

5. Then in 2012 the initial charges for 2013 will be revised to take account of actual expenditure and revenues known to 2011 and revised forecasts for the period to 2015. This process of revising charges is then repeated for 2014 and 2015 to take account of actual expenditure and revenues for 2012 and 2013 as they become known. Then a charge is to be applied in the years 2016 and 2017 to take account of actual expenditure and revenues for 2014 and 2015 as they too become known.

6. The charges will be designed so that the net present value of building block costs incurred to date must always equal the net present value of revenues incurred to date unless a distributor decides (and the Commission agrees) for a particular year that it will not recover its full building block costs in which case un-recovered expenditure will be carried over to a later year. In setting charges actual expenditure is to be used (to the extent such is allowed under the Order) along with actual revenue or if actual figures are not available then a distributor's most recent forecasts are used.

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[142] *Electricity Industry Act 2000* (Vic) s 46C.
[143] *National Electricity (Victoria) Act 2005* (Vic) s 25.

The AER will implement this mechanism as described above, based on actual costs and revenue data, beginning in 2009, reported in audited regulatory accounts. Much like annual network tariff approvals, this is a largely a mechanical process, ensuring that actual reported AMI costs and revenues are verified and adopted for setting charges. This will not involve draft and final determinations, or stakeholder consultation and engagement.

5.3.2 Charges for meter provision and meter data provision

Clause 4.1(n) of the revised Order sets out the requirements on the AER to establish charges which may differ in respect of:

(i) single phase single element meter

(ii) single phase single element meter with contactor

(iii) single phase two-element meter with contactor

(iv) three phase direct connected meter

(v) three phase direct connected meter with contactor

(vi) three phase current transformer connected meter and

(vii) any other customer or metering class proposed by the distributor and approved by the regulator

The charges may not differ depending on whether the meter is an accumulation meter, a manually read meter or a remote read meter.

The revised Order does not permit the AER to require DNSPs to set a separate charge for meter data services and meter provision. Origin agreed that a combined meter data services and meter provision charge met the objective of simplicity.

The AER’s framework and approach paper set out three pricing principles, one of which was simplicity of charges, such that charges were easily understood by market participants.

The AER notes DNSPs are derogated as the sole providers of AMI metering services until 31 December 2013. Following that date, other meter providers may enter the market and offer customers an alternative competitive metering service, such as a new meter with an accompanying new (unregulated) meter provision charge.

Given the derogation and the pricing principles applied by DNSPs in compliance with the AMI framework and approach, the AER will not seek a separation of charges into meter provision and meter data services.

However, when metering becomes contestable from 2014, the AER will review this issue to determine if separate DNSP charges for meter data services and meter provision are necessary to ensure contestability in the market is maximised.

In respect of DNSPs’ proposed exit and restoration fees, the AER will review these when proposed by DNSPs as part of a fees application.

5.3.3 Smoothing of charges

The charges from the draft determination were arbitrarily scaled by the AER to ensure that they recovered only the revenue requirements that were established in the draft determination. That is, if the DNSPs' initial AMI charges in 2010 and, or, 2011 resulted in an over recovery of the draft determination revenues, the AER would reduce charges in the affected year(s) to ensure that the net present value (NPV) of revenue and costs were equal for one or both years.

CUAC was also concerned that metering charges should be further smoothed over the regulatory period, given the significant increase that AMI charges represent over 2009 meter charges. The AER notes that the revised Order permits it to only accept DNSP charges where NPV of revenue and NPV of costs are equal, or where there is an under recovery of costs. The revised Order does not allow the AER to further smooth prices.

The AER notes that under clause 4.1(p) of the revised Order it may approve the under recovery of charges. However, if it chooses not to do so, it must approve charges that meet clause 4.1(o), which require the NPV of total cost incurred by the DNSP for metering services to equal the NPV of revenue earned by the DNSP between 2009 and 2011.

In responding to the draft determination, consumer groups, including CUAC, CALC, and SVDP were concerned that metering charges should be further smoothed over the regulatory period, given the significant increase that AMI charges represent over existing 2009 meter charges.

AER staff requested clarity from the consumer groups on the AER's approach to price smoothing. In response, SVDP advised that they supported any proposal that minimises price shock within any one year period as a result of the rollout of AMI meters. [144] They also supported the approach of DNSPs to under recover revenues where possible and the AER's approach to approve this, given limitations of the revised Order. CUAC expressed the same view.[145]

In its submission, EWOV acknowledged that DNSPs will recover their entire revenue requirement over the AMI rollout period and that any pricing adjustment is only a timing issue. [146] They supported AER's approach, adopted in the draft determination, to smooth out price rises for customers by accepting DNSP under recovery when proposed.

However, they were concerned that many customers might struggle with the higher AMI charges, based on EWOV payment plans implemented for customer experiencing hardship in 2008-09. The AER notes these concerns, however, they are not a consideration for the determination of charges. They are more appropriately assessed in the customer framework under the NERR, to which EWOV can submit.

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[144] St Vincent de Paul, email to AER, *AMI Charges - customer views*, 12 October 2009.

[145] Consumer Utilities Advocacy Centre, email to AER, *AMI Charges - customer views*, 13 October 2009.

[146] Energy and Water Ombudsman (Victoria), email to AER, *AMI Charges - customer views*, 13 October 2009

CALC noted that there was limited opportunity for the AER to smooth price increases, noting the substantial increase in metering costs between those applying in 2009 and proposed in 2010 and 2011. They noted that it would be more beneficial to customers if the price shock between 2009 and 2010 could be reduced, or mitigated.[147]

In this final determination, the AER has reduced charges in 2010 and 2011 where DNSPs' initial AMI charges 2010-11 over recovered the final determination revenue requirements. This occurred because the AER did not accept the amended budgets 2009-11 for related party margins and the DNSPs' proposed WACC of 10.01 per cent. The AER determined a WACC of 9.51 per cent, which was used to set final determination revenue requirements and charges.

5.3.4 Allocation of charges

The metering price control established by the ESCV during the current price determination allocated the costs of meter charges equally among all households, irrespective of their energy usage. The meter supply cost is a fixed cost component of DNSPs service provision and is required in order for customers to receive supply to their premises. Equally, under the AMI rollout, the same applies. SVDP contended meter charges should be based on customer usage patterns.

Distribution use of system tariffs, based on 30 minute usage data from interval meters, will be utilised by the DNSPs to send pricing signals to customers that encourage efficient energy consumption, rewarding changes in usage patterns. This may occur through peak, shoulder and off-peak tariffs, or time of use pricing structures.

The AER notes that the revised Order permits the DNSPs to propose metering charges that recover their costs of service provision. The AER established a set of pricing principles in the framework and approach that DNSPs had to take into account when proposing AMI charges.

The DNSPs did not propose a pricing structure dependent upon electricity consumption profiles. As noted above, distribution tariffs will be set on the basis of energy usage, likely including the time of day to which usage relates.

The AER therefore will not require the DNSPs to set their metering charges on the basis of customer usage patterns. Such a pricing approach is not mentioned in the revised Order.

5.4 AER conclusion

5.4.1 Assessment of charges - CitiPower

CP proposed to under recover revenues by $7.1 million in NPV terms in 2010. The effect of this is to lower charges in 2010 but requires offsetting increases in charges to apply in 2011. This pricing methodology accords with clause 4.1(p) of the revised

[147] Consumer Action Law Centre, email to AER, *AMI Charges - customer views*, 13 October 2009.

Order and therefore is approved. The AER has accepted CP's proposed charges for 2010.

CP's revenues were reduced by $3.4 million as a result of final determination with CP's amended initial charges application impacted by:

- the adoption of data in the re-audited regulatory accounting statements submitted in response to the AER's draft determination and

- the AER's WACC of 9.51 per cent for this final determination compared to 8.96 per cent in the draft determination and the 10.01 per cent proposed by CP.

The AER has therefore reduced 2011 charges to align with final determination revenues in NPV terms. As a result, for most customers, charges in 2011 are 9.7 per cent below those proposed by CP.

Having made the appropriate amendments to the revenue requirements as discussed above, the AER's final determination for CP's charges is set out in Table 5.11 below.

Table 5.11: AER final determination—CP AMI charges, per annum, per NMI ($, nominal)

	2010	**2011**
Single phase	104.79	108.43
Three phase direct connected	136.98	146.51
Three phase CT connected	172.99	182.23

In relation to the cost of service provision pricing principle, CP's cost of service provision is as per the costs incurred in 2006–08 and forecast costs for 2009–11, as provided in their budget application. The AER has assessed these, made amendments where necessary and set out the draft determination charges. The charges for serving the class of customers proposed appear to reflect the costs of serving those customer classes. The final determination charges therefore comply with the cost of service provision principle.

In respect of cost allocation, the AER assessed CP's allocations, such as for meter data services, to arrive at the final determination. Meter provision costs included metering capital expenditure on meters, communications, meter maintenance and operating costs attributable to customer service costs. Meter data serviced costs comprised capital expended on IT and communications, costs for meter data management meter reading, backhaul and communication operations.

CP split costs equally between meter provision and meter data services for 2006–08 costs, trails costs, project management and overheads.

CP consolidated and simplified its metering charging structure into single phase, three phase direct connected and three phase current transformer. The split between single phase non-off peak and single phase off-peak, was deemed redundant under AMI. Further, CP has consolidated the meter reading and meter provision charge into one charge, thereby applying a one tariff per meter approach. CP will continue its practice of levying meter service charges on a per NMI basis.

The AER considers these approaches to metering tariffs are consistent and compliant with the pricing principles in the AER's framework and approach paper.

As per clause 4.1(k) of the revised Order, the AER accepts CP's actual AMI metering revenues for 2009 and accepts that the forecasts are based on the most recent forecast quantities as per clause 4.1(l) of the revised Order.

5.4.2 Assessment of charges - Jemena

JEN chose to under recover revenues by $5.5 million in NPV terms in 2010 and $5.6 million in 2011. The effect of this is to lower charges across all meter types for both years. This pricing methodology is consistent with clause 4.1(p) of the revised Order and therefore is approved.

The AER, however, reduced JEN's revenues by $5.2 million as a result of final determination. Their amended initial charges application was impacted by:

- the adoption of data in the re-audited regulatory accounting statements submitted in response to the AER's draft determination and
- the AER's WACC of 9.51 per cent for this final determination compared to 8.96 per cent in the draft determination and the 10.01 per cent proposed by JEN.

The AER has therefore accepted 2010 and 2011 charges proposed by JEN, as even after allowing for the above adjustments, those charges still under recover allowed revenues in both years.

Having made the appropriate amendments to the revenue requirements as discussed above, the AER's final determination for JEN's charges is set out in Table 5.12 below

Table 5.12:AER final determination—JEN AMI charges per annum, per meter ($, nominal)

	2010	2011
Single phase single element	134.63	136.70
Single phase single element with contactor	134.63	136.70
Three phase direct connected	165.46	167.99
Three phase CT connected	183.95	186.77

In relation to the cost of service provision pricing principle, JEN's cost of service provision is driven primary by the capital costs of meters. The charges for serving the class of customers proposed appear to reflect the costs of serving those customer classes. The final determination charges therefore comply with the cost of service provision principle.

In respect of cost allocation the AER assessed JEN's allocations throughout its review such as for meter data services in the draft determination. The AER established that JEN included costs only for metering services and not costs incurred or revenues received as part of its distribution use of system revenue requirement provided under the current price determination. No shared costs were included in JEN's proposed revenue.

Metering charges were simplified by amalgamating the meter reading and meter provision charge into a single charge, set according to meter type, JEN proposed a similar metering tariff for off-peak and non-off peak single phase customers on the basis that these meters have the same functionality in measuring electricity consumption.

The AER considers these approaches to metering tariffs are consistent and compliant with the pricing principles in the AER's framework and approach paper and clause 4.1(n) of the revised Order.

As per clause 4.1(k) of the revised Order, the AER accepts JEN's actual AMI metering revenues for 2009 and accepts that the forecasts are based on the most recent forecast quantities as per clause 4.1(l) of the revised Order.

5.4.3 Assessment of charges - Powercor

PC chose to under recover revenues by $16.5 million in NPV terms in 2010. The effect of this is to lower charges in 2010 but requires offsetting increases in charges to apply in 2011. This pricing methodology is consistent with clause 4.1(p) of the revised Order and therefore is approved.

PC's revenues were reduced by $7.6 million as a result of final determination, with PC's amended initial charges application impacted by:

- the adoption of data in the re-audited regulatory accounting statements submitted in response to the AER's draft determination and
- the AER's WACC of 9.51 per cent for this final determination compared to 8.96 per cent in the draft determination and the 10.01 per cent proposed by PC.

The AER has therefore reduced 2011 charges to align with final determination revenues in NPV terms. As a result, for most customers, charges in 2011 are 9.9 per cent below those proposed.

Having made the appropriate amendments to the revenue requirements as discussed above, the AER's final determination for CP's charges is set out in Table 5.13 below.

Table 5.13: AER final determination—PC AMI charges, per annum, per NMI ($, nominal)

	2010	2011
Single phase	96.67	105.35
Three phase direct connected	127.50	142.71
Three phase CT connected	168.94	188.29

In relation to the cost of service provision pricing principle, PC's cost of service provision is as per the costs incurred in 2006–08 and forecast costs for 2009–11, as provided in their budget application. The charges for serving the class of customers proposed therefore appear to reflect the costs of serving those customer classes. The final determination charges therefore comply with the cost of service provision principle.

In respect of cost allocation, the AER assessed PC's allocations throughout its review as detailed in this final determination. Meter provision costs included metering capital expenditure on meters, communications, meter maintenance and operating costs attributable to customer service costs. Meter data serviced costs comprised capital expended on IT and communications, costs for meter data management meter reading, backhaul and communication operations.

PC split costs equally between meter provision and meter data services for 2006–08 costs, trails costs, project management and overheads.

PC consolidated and simplified its metering charging structure into single phase, three phase direct connected and three phase current transformer. The split between single phase non-off peak and single phase off-peak, was deemed redundant under AMI. Further, PC has consolidated the meter reading and meter provision charge into one charge, thereby applying a one tariff per meter approach. The AER notes that it has approved two–element meters proposed as part of PC's budget application, and single element and two–element meter customers will pay the consolidated single phase metering charge. PC will continue its practice of levying meter service charges on a per NMI basis.

The AER considers these approaches to metering tariffs are consistent and compliant with the pricing principles from the AER's framework and approach paper.

As per clause 4.1(k) of the revised Order, the AER accepts PC's actual AMI metering revenues for 2009 and accepts that the forecasts are based on the most recent forecast quantities as per clause 4.1(l) of the revised Order.

5.4.4 Assessment of charges – SP AusNet

SPA chose to under recover revenues by $2 000 in NPV terms in 2010 and 2011. This pricing methodology is consistent with clause 4.1(p) of the revised Order and therefore is approved.

SPA's revenues were altered by $1.7 million as a result of final determination.

The AER has reduced charges in 2010 and 2011 to align with final determination revenues in NPV terms. As a result, for most customers, charges in 2010 are 1.4 per cent below those proposed, while in 2011 they are 1.2 per cent lower than proposed by SPA.

Having made the appropriate amendments to the revenue requirements as discussed above, the AER's final determination for SPA's charges is set out in Table 5.14 below

Table 5.14: AER final determination—SPA AMI charges, per annum, per meter ($, nominal)

	2010	2011
Single phase single element 1 contactor (1 load control)	86.10	93.83
Single phase, two–element 2 contactors (2 load controls)	98.93	107.81
Multi phase, one contactor (1 load control)	119.51	130.25
Multi phase, two contactor (2 load controls)	132.58	144.49
Multi phase CT connected	170.71	186.05

In relation to the cost of service provision pricing principle, SPA's costs are driven primary by the capital costs associated with the AMI rollout SPA developed its metering tariffs on the basis of its expenditure forecasts and assumed total metering revenue for 2009, and forecast customer numbers. The charges for serving the class of customers proposed appear to reflect the costs of serving those customer classes. The final determination charges therefore comply with the cost of service provision principle.

In respect of cost allocation, the AER assessed SPA's allocations throughout its review, as detailed in this final determination. The AER established that SPA included costs only for metering services and not costs incurred or revenues received as part of its distribution use of system revenue requirement provided under the current price determination.

Metering charges were simplified by consolidating the meter reading and meter provision charge into one charge, thereby applying a one tariff per meter approach.

The AER considers these approaches to metering tariffs are consistent and compliant with the pricing principles in the AER's framework and approach paper.

As per clause 4.1(k) of the revised Order, the AER accepts SPA's actual AMI metering revenues for 2009 and accepts that the forecasts are based on the most recent forecast quantities as per clause 4.1 (l) of the revised Order.

5.4.5 Assessment of charges - UED

The proposed AMI charges for 2010 and 2011 submitted by UED are identical to the charges from the AER's draft determination and are therefore accepted as being final determination charges.

However, the AER amended UED's budget application 2009-11 to remove the impact of related party margins. Therefore, UED's proposed charges were reduced to meet the final determination on its revenue requirement.

The effect was a reduction in charges for customers receiving a single phase single element meter of 3.6 per cent in 2010 and 3.2 per cent in 2011.

Table 5.15: AER final determination—UED AMI charges, per annum, per NMI ($, nominal)

	2010	**2011**
Single phase single element	69.21	89.18
Single phase single element with contactor	70.65	91.03
Three phase direct connected	78.08	100.58
Three phase CT connected	83.27	107.28

The final determination charges are the same as those proposed by UED in its submission to the draft determination.

In relation to the cost of service provision pricing principle, UED's cost of service provision is driven primary by the capital costs of meters.

In respect of cost allocation, the AER assessed UED's allocations throughout its review, as detailed in this final determination. The AER established that UED included costs only for metering services and not costs incurred or revenues received as part of its distribution use of system revenue requirement provided under the current price determination. No shared costs were included in UED's proposed revenue. The charges for serving the class of customers proposed appear to reflect the costs of serving those customer classes. The final determination charges therefore comply with the cost of service provision principle.

Metering charges were simplified by amalgamating the meter reading and meter provision charge into a single charge, set according to meter type as per clause 4.1(n) of the revised Order.

The AER considers these approaches to metering tariffs are consistent and compliant with the pricing principles from the AER's framework and approach paper.

As per clause 4.1(k) of the revised Order, the AER accepts UED's actual AMI metering revenues for 2009 and accepts that the forecasts are based on the most recent forecast quantities as per clause 4.1 (l) of the revised Order.

5.4.6 General conclusions on AMI charges

The charge for AMI services in this final determination will be the charges levied by DNSPs on metering customers for the respective meter type. These will be the maximum charges permissible for 2010-11.

The AER concludes that the charges proposed meet the pricing principles set out in the AER's framework and approach paper and the draft determination, and that DNSPs will not be required to separately show meter data services and meter provision charges to customers or retailers.

The charges in this final determination have been smoothed in the same manner as in the draft determination, such that NPV neutrality is achieved, or under recovery occurs when that was proposed by a DNSP. The AER has assessed each element of the regulatory proposals and the amended proposals without any preconceived notion about what might be regarded as acceptable price increases.

In respect of the true-up mechanism for 2011 and subsequent charges, the AER will apply the true-up mechanism provided in the note to clause 4.1(p) of the revised Order.

5.5 AER determination

The AMI charges for 2010-11 contained in the final determination Tables 5.11 to 5.15 are the regulated charges that will apply in those years.

The AER has determined that these initial AMI charges meet the pricing principles as noted in the framework and approach, the draft determination and this final determination. DNSPs will not be required to separate the charges into those relating to meter data services and meter provision.

These charges will be the maximum regulated charges applying from 1 January 2010. During that year, the initial 2011 charges in this determination will be revised, to take account of actual expenditure and revenues known for 2009 (as reported in regulatory accounting statements to be provided to the AER in April 2010) and revised (budget) forecasts for 2010-2011.

6 Other issues raised in submissions

This section outlines and provides the AER's consideration of submissions on the following issues that are indirectly related to the AER's determination on the DNSPs' initial AMI budgets and charges:

- billing and customer information
- cost allocation
- realisation and pass through of AMI benefits
- use of AMI infrastructure to provide unregulated services
- other issues, such as customer hardship and direct load control information.

These issues relate to the AMI rollout generally and are considered in turn below.

6.1 Billing and customer information

6.1.1 Submissions

Submissions from CALC, CUAC, Origin Energy and SVDP raised issues relating to the content of customers' bills and information provided to customers by DNSPs and retailers.

6.1.1.1 Consumer Action Law Centre

CALC stated that the AER should recommend that DNSPs fully and adequately communicate their rollout plan to their customer base, via their websites and directly, including information on the timeframes for meter installations, communications networks, time of use tariffs and access to full meter functionality.

CALC also stated that, at a minimum, retailers should be required to clearly explain the composition of the metering costs to consumers, through including metering charges separately on customers' bills or providing a clear breakdown for each component charge as a percentage of the total bill.[148]

6.1.1.2 Consumer Utilities Advocacy Centre

CUAC's submission recommended that the AER initiate action to ensure customers' energy bills separately record the charges associated with metering charges commencing on 1 January 2010. Specifically, CUAC stated that the AER should recommend that the ESCV make amendments to the *Energy Retail Code* to provide for itemisation of charges on customers' bills.[149]

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[148] Consumer Action Law Centre, *Draft Decision – Victorian advanced metering infrastructure review 2009-11 AMI budget and charges applications*, 11 September 2009, pp. 2-3.

[149] Consumer Utilities Advocacy Centre, *Submission on AER draft determination Victorian advanced metering infrastructure review 2009-11 AMI budget and charges applications (July 2009)*, 11 September 2009, p. 15-16.

6.1.1.3 Origin Energy

Origin Energy submitted that the presentation of costs, including network charges, on customers' bills is a matter for retailers. It noted that customers can identify the costs of metering charges as this information is publicly available, and that the metering charges will be available from the AER's final determination. Origin Energy stated its view that Victorian customers have a significant visibility of costs related to electricity metering, as compared to other jurisdictions in the NEM.[150]

6.1.1.4 St Vincent de Paul

SVDP's submission raised a comprehensive number of issues relating to customers' bills and information provided to customers about the AMI rollout. A number of these issues and recommendations are made to other government agencies and regulatory bodies. The relevant recommendations made which request action by the AER or on which the AER considers it should comment include:

- via a change in the proposed National Energy Retail Rules (NERR), the AER should be required to develop a separate guideline for bills and information on bills to be applied to smart meter enabled dynamic pricing contracts[151]

- that the AER should undertake a review into customer access to data processing checks and meter tests under AMI, with the aim of developing guidelines for transitional and ongoing arrangements[152]

- that the AER should develop a comprehensive one-stop shop website for consumer information on energy and that the NERR ensures that retailers and DNSPs inform customers about the website as appropriate[153]

- that AMI rollout costs should be a line item on customers' electricity bills.[154]

6.1.2 AER considerations

6.1.2.1 Metering costs as a line item on customers' bills

The AER agrees that separately identified metering costs would increase transparency, help to provide a benchmark should metering services become competitive in the future, and assist customers in understanding their bills such that they may be better able to respond to time of use pricing.

The contents of customers' retail bills are to be regulated by the new NERR, which are currently under development by the Ministerial Council on Energy's Retail Policy Working Group and for which a second exposure draft is expected to be released in December 2009.

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150 Origin Energy, *Victorian advanced metering infrastructure review 2009-11 AMI budget and charges application - Draft Determination*, 10 September 2009, pp. 1-2.
151 St Vincent de Paul, *Customer Protections and Smart Meters – Issues for Victoria*, August 2009, p. 25.
152 Ibid., p. 29.
153 Ibid., p. 39.
154 Ibid., p. 43.

The first exposure draft of the NERR was released on 30 April 2009. Currently, the provisions for the contents of customers' bills are contained in Division 4, section 214 of the proposed NERR. As noted by SVDP, Division 10, section 239 of the proposed National Energy Retail Law (NERL) states that the AER may develop AER Pricing Information Guidelines which specify the manner and form which standing offer and market prices are to be presented to customers. Their prescribed purpose is to allow comparison of retail price offers, and in doing so to inform a customer's choice of retail energy contract. These guidelines do not extend to the breakdown of network charges, including metering costs, within a retail energy price. However, as noted within Origin Energy's submission, while not included as a separate line item on customers' bills, metering charges are publicly available from the regulator's (ESCV, and in the future, the AER) website.[155]

6.1.2.2 Communication of rollout information to customers

The AER notes CALC's submission that DNSPs should be required to fully and adequately communicate their rollout plan to their customers, via their websites and directly, including information on the timeframes for meter installations, communications networks, time of use tariffs and access to full meter functionality.

The issues surrounding the communication with customers relating to the rollout has been considered by DPI and the AMI Industry Steering Committee. As part of this process, DPI has prepared a standard letter which will be sent to customers outlining the rollout, which will accompany various other public information initiatives. The DNSPs will also be sending a letter to their customers informing them of the rollout plans.

As noted in section 6.1.2.1, the contents of bills are specified by the NERR, for which the AER is the enforcement body. These provisions are still under development, and interested parties will have the opportunity to provide comments on a second exposure draft of the NERR later this year. The NERL will include a procedure for making amendments to the NERR after it commences.

6.1.2.3 Customer access to data processing and meter tests

Meter testing is a technical requirement which is regulated under rule S7.3 of the NER. The Australian Energy Market Operator (AEMO) has responsibility for reviewing rule S7.3 on a five yearly basis to ensure it accords with equipment performance and industry standards.[156] The AER does not have a role in technical regulation, however, it notes that SVDP's suggestion for improving customer access to meter testing information may increase customers' assurance of billing accuracy. The way in which such information is made available may be best considered in the context of the NERR.

6.1.2.4 AER 'one-stop-shop' website for retail customers

As part of adopting the functions proposed in the first exposure draft of the NERL (expected to be in January 2011), the AER is planning to develop a website to provide

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155 Origin Energy, *Victorian advanced metering infrastructure review 2009-11 AMI budget and charges application - Draft Determination,* 10 September 2009, p. 1.

156 NER, schedule 7.3.1(d).

useful information to consumers on their rights and obligations in dealings with energy businesses, including answers to frequently asked questions about energy retail and distribution. The AER is open to suggestions from stakeholders as to the form and content this information may take, and will consult on these issues via the National Customer Consultative Group.

6.2 Pass through of benefits

6.2.1 Submissions

6.2.1.1 Consumer Action Law Centre

CALC submitted that within the rollout period, it anticipates benefits to accrue to DNSPs, which should be passed through to customers during the next distribution price review, commencing in November 2009. It noted that the AER will need to pay careful attention to the possibility of double-dipping for cost recovery between the AMI cost recovery and the broader distribution price review.[157]

6.2.1.2 Consumer Utilities Advocacy Centre

CUAC stated that while costs for the AMI rollout are being funded by customers up front, the benefits are expected to accrue over the long term, and the AER must be pro-active and ensure that benefits are delivered to consumers in a timely manner. It recommended that benefits, including operational cost savings, should be accounted for and passed to consumers at least on an annual basis, and monitored and reported to the Victorian Government by the AER. It recommended that the AER consider the anticipated future cost savings resulting from AMI, and the impact of improved price signals on proposed network augmentation plans in the context of the next and future Victorian distribution price reviews.[158]

CUAC also requested that the AER acknowledge the importance of customer education, tariff reassignments and the need for transparency in billing in ensuring that the advertised benefits of the AMI rollout can be achieved.[159]

6.2.1.3 Department of Primary Industries Victoria

DPI's submission requested that the AER should note that the benefits arising to DNSPs from the AMI rollout will require careful consideration in the 2011–15 distribution price review.[160]

6.2.1.4 St Vincent de Paul

SVDP submitted that as the AMI costs are being incurred by customers upfront, there is a risk to them that if benefits are not accrued and monitored by the AER, the cost savings AMI is expected to bring may not be realised by customers. SVDP also

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[157] Consumer Action Law Centre, *Draft Decision – Victorian advanced metering infrastructure review 2009-11 AMI budget and charges applications*, 11 September 2009, p. 3.

[158] Consumer Utilities Advocacy Centre, *Submission on AER draft determination Victorian advanced metering infrastructure review 2009-11 AMI budget and charges applications (July 2009)*, 11 September 2009, pp. 13-14.

[159] Ibid., p. 17.

[160] Department of Primary Industries Victoria, *Draft determination Victorian advanced metering infrastructure review 2009-11 AMI budget and charges applications*, 2 October 2009.

recommended that the AER should provide an annual public assessment report to the Victorian Government on the status of the AMI benefits. It also recommended that the five year regulatory period framework should be adjusted to allow benefits of AMI to be passed through to customers annually.

SVDP also recommended that the AER review excluded services charges in light of AMI to assess the impact AMI may have on these charges.

6.2.2 AER considerations

The AER notes stakeholders' concerns that the costs of the AMI rollout will be incurred by customers up front, while any benefits of the rollout will be realised over a longer period of time. The AER agrees that the pass through of AMI benefits will be an issue for close consideration in future distribution price reviews, in particular the 2011–15 distribution price review which commences in late 2009.

The AER's role in regard to the Victorian AMI rollout is specified in the revised Order. Aside from making this determination and the determination for the second budget period (2012–15), if it receives a charges revision application from a DNSP for any year, the AER must then make a revised charges determination for that year. Clause 5I of the revised Order sets out the AER's role with regards to making revised charges determinations.

Clause 5I provides that for the initial budget period 2009–11, if the AER receives a charges revision application from a DNSP, the AER must determine charges based on actual capex and opex which is:

- supported by an audit report
- for activities within scope, and
- up to 120 per cent of the approved budget (being the budget approved in this determination) for that year.[161]

In this circumstance, activities are deemed to be within scope if the charges revision application is supported by an audit report that certifies that the expenditure is for activities within scope and has been incurred. Should the AER establish that any capex or opex is not within scope, then that amount shall be removed from the DNSP's budget and will not be recovered from customers.

During the AER's review, the DNSPs identified the following areas where potential benefits may be expected from the AMI rollout:

- reduced special meter reading requests
- reduced costs associated with reconnection and disconnection requests
- reduced metering maintenance, due to meter replacement with new meters

[161] Revised Order, clause 5I.2(a).

- reduced costs of customer pricing trials.[162]

In relation to the costs faced by customers for reconnection, disconnection and special meter reading, the AER anticipates that AMI will facilitate lower charges for these services, which are currently classed as excluded services. The AER will review the DNSPs' excluded service charges as part of the 2011–15 distribution price review.

In considering the likely cost savings that the AMI rollout could have for DNSPs in the context of the 2011–15 distribution price review, the AER will have regard to the AMI cost benefit study completed in late 2005, co-funded by the Victorian Government, DNSPs and retailers.[163] The AER will also have regard to a national cost benefit study funded by the Ministerial Council on Energy.[164] These studies indicate the following areas of benefits stemming from an AMI rollout could be expected in the short to medium term:

- Remote routine daily reading—avoided cost of routine meter reading; avoided cost of validation and exception management for routine and special meter readings; reduced cost of management of keys to access meters at customers' premises; avoided cost of meter reading route management; avoided cost of special meter reads; avoided or reduced portable data entry costs; avoided cost of peel off metering

- Remote connect/disconnect—avoided cost of manual connections and disconnections; avoided revenue loss from electricity used at premises between move out and move in; avoided cost of installing pre-payment metering for customers requiring pre-payment tariffs; elimination of unknown customers

- Load management at meters through dedicated control circuit—avoided cost of current ripple control and time-switch based systems.[165]

In the longer term, the cost benefit studies indicate the following areas of benefits:

- Interval metering—avoided cost of new and replacement metering; avoided cost of import/export metering; reduced testing of meters; reduction in cost of load research; reduction in technical losses; reduction in costs of network planning and operation

- power factor improvement through use of reactive power (kVA) tariffs

- reduction in non-technical losses (i.e. electricity theft)

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162 CP and PC, Email to the AER - *Questions for CitiPower and Powercor Revised Budget Application*, 25 September 2009; UED, Email to the AER - *Questions for UED – AMI final determination*, 25 September 2009; and JEN, Email to the AER - *JEN response to AER AMI questions,* 30 September 2009; SPA, Email to the AER - *SP AusNet response to AER questions of 18 September 2009*, 6 October 2009, p. 11.

163 CRA International, *Advanced Interval Meter Communications Study*, 23 December 2005.

164 CRA International, *Cost benefit analysis of smart metering and direct load control-Network benefits and recurrent costs – Phase 2 Consultation Report*, 27 February 2008.

165 CRA International, *Cost benefit analysis of smart metering and direct load control-Network benefits and recurrent costs – Phase 2 Consultation Report*, 27 February 2008, pp. 12-13.

- Supply capacity control—ability to set demand limits for customers and defer augmentation capex; ability to set supply capacity-based tariffs; improved supply shortage recovery after major power system outages and supply shortfalls; avoided cost of supply capacity circuit breakers; avoided cost of replacing service fuses that have failed due to overload

- Quality of supply and other event recording—avoided cost of investigation of customer complaints about voltage related quality of supply; more detailed quality of supply for DNSPs to manage network planning and operations more effectively; reduction in end of line monitoring; reduction in cost of recording and reporting quality of supply metrics

- Meter loss of supply detection and outage detection—reduced cost for supply restoration; reduced calls to faults and emergency lines; avoided cost of investigation of customer complaints of loss of supply that turn out to be not a loss of supply; reduction in cost of recording and reporting minutes off supply to regulators; reduction in unserved energy.[166]

In addition, the Victorian cost benefit study identified cost savings for retailers in anticipating fewer calls associated with estimated bills, meter reader issues and delayed bills.[167]

The AER will be looking for the impact of the AMI rollout on DNSPs in the areas identified in the cost benefit studies, as well as generally looking for the impact of anticipated lower peak demand (due to time of use tariffs) on network planning and capex.

Any cost savings or reductions will be passed through to customers through lower network prices in the five yearly regulatory price determinations, as well as through lower metering charges.

After receiving stakeholder queries regarding the likely impact of AMI on customer charges beyond 2011, the AER asked the DNSPs to provide estimates of the 2012–15 AMI budgets. In response, the DNSPs stated that they are unable to estimate their likely future AMI budgets, as tendering processes for 2012–15 have not yet been completed.[168] SPA noted that such a large scale project with significant capital outlays being implemented over such a short time period, a bow-wave effect in customer charges is evident. Capex incurred to rollout AMI infrastructure results in rapid and large scale increases in the DNSPs' regulatory asset bases, which increases

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166 CRA International, *Cost benefit analysis of smart metering and direct load control-Network benefits and recurrent costs – Phase 2 Consultation Report*, 27 February 2008, pp. 12-13.

167 CRA International, *Advanced Interval Meter Communications Study*, 23 December 2005, p. 58. The AER notes these costs are likely to be offset in the short term by an increased number of calls associated with the AMI rollout, however considers that over time retailers could expect such cost savings.

168 CP and PC, Email to the AER - *Questions for CitiPower and Powercor Revised Budget Application*, 25 September 2009, p. 5; UED, Email to the AER - *Questions for UED – AMI final determination*, 25 September 2009, p. 3; and JEN, Email to the AER - *JEN response to AER AMI questions,* 30 September 2009, p. 3; SPA, Email to the AER - *SP AusNet response to AER questions of 18 September 2009*, 6 October 2009, p. 20.

their return on capital allowance in the regulatory building blocks. SPA pointed out that when the rollout is completed, the regulatory asset base will start to decline, as the growth in new connection meter costs and IT upgrades should be exceeded by depreciation, or return on capital.[169] This will result in a drop in customer metering charges, back to a level reflective of general maintenance costs.

An additional impact of such a large scale metering rollout is that when the meters and infrastructure reach the end of their useful lives (which is estimated to be in around 15 years time, or from 2025), a second full-scale replacement meter rollout is likely to be required. This will again result in significant capex being incurred over a short time frame, and a second bow-wave effect in customer charges, as the costs of replacing the infrastructure are recovered.

Compliance with the revised Order, including the rollout timetable in Schedule 1, is deemed to be a license condition for the Victorian DNSPs. Under the *National Electricity (Victoria) Act 2005* (Vic) the AER is responsible for the enforcement of license conditions in Victoria. The AER is therefore able to issue a provisional or final enforcement order, as provided for under the *Essential Services Commission Act 2001* (Vic), to enforce compliance with the revised Order. The AER will monitor the DNSPs' compliance with the revised Order as part of the annual true-up of prices and revenues. Further details on this annual process are provided in section 5.3.1 above.

6.3 SP AusNet's WiMAX solution

6.3.1 Submissions

CUAC's submission stated its concern that there is a potential for the bandwidth required for SPA's WiMAX solution to support unregulated services outside of AMI functionality and scope. CUAC recommended that the AER review SPA's use of WiMAX on an annual basis to prevent any unregulated services being provided by SPA or third parties using the WiMAX infrastructure paid for by electricity consumers. CUAC also submitted that the AER should ensure that any demonstrated lower opex associated with SPA's WiMAX solution is passed through to consumers in a timely manner.

SVDP also stated its concern regarding the future use of WiMAX bandwidth at the AER's public forum, held on 21 August 2009.[170]

6.3.2 AER considerations

The draft determination set out the AER's initial concerns that SPA's WiMAX communications solution may have been outside scope as defined in clause S2.8(iv) of the revised Order.[171] The draft determination noted that the AER had material to suggest that SPA had given significant weight to the potential for future unregulated benefits of WiMAX in considering its choice of an AMI communications solution. However, the draft determination noted that the AER did not establish that SPA was

[169] SPA, Email to the AER - *SP AusNet response to AER questions of 18 September 2009*, 6 October 2009, pp. 11-12.
[170] AER, *Minutes – AMI public forum*, 21 August 2009, p. 3. See www.aer.gov.au.
[171] AER, *draft determination*, p. 78.

using AMI technology to provide communications services beyond those in the minimum specifications, as required by clause S2.8(iv) of the revised Order. The AER noted that in order for SPA to provide additional unregulated services beyond those in the minimum specifications, it would need to undertake significant additional investment, the costs for which could not be passed through to electricity consumers.

The large bandwidth that forms part of SPA's WiMAX communication solution is needed for SPA to transmit its customers' data to its back-office systems and to market, as required by the AMI minimum functionality specifications. The AER understands that SPA will only need to utilise this large bandwidth for certain periods of the day, and that for the remaining time it is not required. The AER notes that there is the potential for this spare bandwidth to be used to provide other communications services in the times it is not being used to transmit electricity meter data, by either SPA or third parties. SVDP stated its view that as the spare bandwidth is to be paid for by electricity customers, should a DNSP use this bandwidth to provide additional services, any benefits it achieves from doing so should be shared with electricity customers.[172]

The AER acknowledges the concerns raised by SVDP regarding the potential for unregulated service provision. However, the revised Order does not permit the AER to consider the potential for unregulated communications service provision in the future as a basis for rejecting costs under the scope test. It is only when the DNSP is actually using AMI technology to provide communications services that the AMI technology could be established as being outside scope. As noted above, the AER considers this would require significant additional investment on SPA's behalf, which would not be recoverable via customers prices, unless the proposed expenditure met the capex and opex criteria in the NER and the AER accordingly approved it as part of a regulatory determination.

On a more general note, any spare capacity in the communications technologies installed during the AMI rollout could also be utilised by the DNSPs to provide smart grid applications and other network management services which could provide additional functions to electricity networks, retailers and customers over the long term. Such functions could include automated switching capabilities (i.e. a 'self-healing' network) with less frequent and shorter outages. The additional expenditure needed to facilitate such services would also be considered by the AER in future determination processes.

6.4 Other issues

6.4.1 Hardship policies

SVDP submitted that the National Energy Retail Law should include a requirement for the AER to develop national hardship policy guidelines and empower the AER to approve retailers' hardship policies according to these guidelines.[173] CALC's submission noted the significant price increases Victorian customers will face from January 2010, noting that these increases may place consumers in a position of

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172 AER, *Minutes – AMI public forum*, 21 August 2009, p. 3. See www.aer.gov.au.

173 St Vincent de Paul, *Customer Protections and Smart Meters – Issues for Victoria*, August 2009, pp. 58-59.

increased financial difficulties, especially if they already struggle with affordability issues.[174]

The AER notes the concerns raised regarding customer price increases. A national customer hardship policy framework is currently under consideration as part of the National Energy Retail Law, within Part 2, Division 9 and Part 10, Division 2. Part 10, Division 2 requires that the AER make an order determining national hardship indicators, to which the retailers' hardship policies must refer. Part 10, Division 2 of the current Law framework allows the AER to carry out compliance audits of retailers' hardship policies developed under Part 2 Division 9. Part 3 of the draft NERR provides further detail on the proposed customer hardship regime. The National Energy Retail Law and NERR are currently under consultation, and interested parties will have the opportunity to provide comments on a second exposure draft later this year.

6.4.2 Transparency and AER processes

CALC's and CUAC's submissions on the draft determination requested that the AER make public all the DNSPs' documents that it relied upon in making the draft determination, including all request for tender and proposal documents, procurement strategy documents, signed contracts, internal business cases and presentations made to AER staff, as well as further information provided in response to the AER's questions.[175] CUAC urged the AER to take a 'narrow view of confidentiality' on certified audited documents such as audit reports, regulatory accounts and other documents so that they could be published on the AER's website.[176] CALC also suggested that the AER develop a template for submissions to enable stakeholders to effectively compare DNSPs' proposals, in particular for the annual true-up process.

CUAC's submission requested that the AER:

- disclose the parties to any negotiations on the matters outlined in the draft determination following the publication of the DNSPs' revised budget applications, and acknowledge the negotiations in the final determination
- publish a summary of the revised initial AMI budget applications and consult with stakeholders on them prior to the final determination

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174 Consumer Action Law Centre, *Draft Decision – Victorian advanced metering infrastructure review 2009-11 AMI budget and charges applications*, 11 September 2009, p. 2.

175 Consumer Action Law Centre, *Draft Decision – Victorian advanced metering infrastructure review 2009-11 AMI budget and charges applications*, 11 September 2009, p. 1; and Consumer Utilities Advocacy Centre, *Submission on AER draft determination Victorian advanced metering infrastructure review 2009-11 AMI budget and charges applications (July 2009)*, 11 September 2009, pp. 4-5.

176 Consumer Utilities Advocacy Centre, *Submission on AER draft determination Victorian advanced metering infrastructure review 2009-11 AMI budget and charges applications (July 2009)*, 11 September 2009, p. 5.

- consult with stakeholders on any additional information submitted to the AER relating to the DNSPs' charges applications.[177]

Transparency is a key objective within the AER's regulatory processes. Consultation procedures set out in the NER require that the AER consults widely with the public, and specifies the minimum number of days between the publication of a draft determination and the closing dates for submissions. The revised Order provided that the AER could issue a timetable for its AMI draft determination and consultation process, provided that it allowed at least 30 business days for submissions on the draft determination, which it did.[178] While the revised Order did not require the AER to make a draft determination on the DNSPs' proposed charges for 2010–11, it did so anyway to provide information to customers on the likely charges and to inform a more meaningful consultation process on the draft determination. In addition, while it was not a requirement, the AER held a public forum on the draft determination to give stakeholders an opportunity to comment on and discuss the draft determination with AER staff.

The AER publishes all relevant non-confidential information on its website. It is the AER's policy that where a party claims confidentiality over information, it must support this claim with reasons and/or evidence of the confidential nature of the information.

During the AMI review process, the DNSPs were conducting highly sensitive negotiations with vendors for AMI contracts, some of which were in the final stages of negotiations. The AER considered that to publish information on unit prices, individual contract terms and conditions, tender proposals and procurement strategy documents could result in the parties to future contracts negotiating higher prices than would otherwise been the case, resulting in higher charges for consumers. Publishing certified audited regulatory accounts data and reports could also jeopardise negotiations on future contracts between DNSPs and third parties. However, where reasons for confidentiality claims were not immediately obvious, the AER requested DNSPs to justify the confidential nature of their documents.

The AER acknowledges stakeholders' concerns regarding the information supplied to the AER between draft and final determinations which could significantly alter its position on certain issues. However, as much of this information is also confidential, the AER is unable to disclose the nature of such negotiations. The final determination indicates areas where the AER sought additional information from the DNSPs and other parties, for example in the discussion on two-element meters in section 3.3.5. AER staff met with consumer representatives to discuss the issues raised in their submissions. The AER published the non-confidential areas of the DNSPs' revised submitted budget applications, as well as additional information on their charges applications, soon after they were received. The AER also published all submissions that were received on the draft determination, which should indicate the key areas of consideration for the final determination. In addition, as noted above AER staff

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177 Consumer Utilities Advocacy Centre, *Submission on AER draft determination Victorian advanced metering infrastructure review 2009-11 AMI budget and charges applications (July 2009)*, 11 September 2009, pp. 5-6

178 Revised Order, clause 10.

sought the views from consumer groups on the profile of charges across the initial AMI budget period.

The AER agrees with CALC that a standardised template for DNSP applications and submissions would provide greater transparency. The AER is working to ensure uniform regulatory proposals are submitted for the 2011–16 Victorian distribution review.

The AER considers that it has overseen a reasonably transparent review process in the lead up to this determination, and has taken care to ensure all issues raised are given proper consideration. The AER will consider its processes between making draft and final determinations, in addition to the requirements set out in the NER, in future reviews.

6.4.3 Substituted data

SVDP recommended that the AER reviews the guidelines in relation to substituted data in the AEMO Metrology Procedure, and that the AMI section of the NERR reflects the outcomes of this review. Furthermore, it recommended that the AER should develop a system wide reporting framework on the use of substituted data.[179]

The AER agrees with SVDP that the new AMI meters are likely to create some new challenges in terms of the use of substituted data. This relates to the fact that an infinitely larger volume of information will be collected and transmitted to market. Where there is a need for a DNSP to use substituted data during a critical peak pricing period, the substitution could make a material difference to energy costs, drawing customers' attention to the issue.

Clause 7.14.1 of the NER requires that AEMO must publish a metrology procedure to apply to metering installations and that it must revise the metrology procedure in accordance with the consultation procedures in the NER. The contents of the metrology procedure are also set out in clause 7.14.1 of the NER.

The AER does not have a role in reviewing AEMO procedures or guidelines. As required by the NER, AEMO consults with stakeholders on these procedures via its website, following a consultation process prescribed in the NER. It is open to stakeholders to approach AEMO in relation to the operation of these procedures at any time, and to propose amendments to those procedures under the NER. The AER's role in relation to these procedures is limited to monitoring and enforcing compliance with the relevant provisions of the NER.

6.4.4 Direct load control information

SVDP stated its view that retailers offering direct load control contracts to their customers should be subject to specific product requirements, which should specify maximum thresholds in relation to duration, frequency and scope of load control. It submitted that the AER should be requested to review direct load control product

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[179] St Vincent de Paul, *Customer Protections and Smart Meters – Issues for Victoria*, August 2009, p. 27.

requirements and that the AER's decision should be reflected in the NERR product requirement provisions.[180]

The AER considers that retailers' offers for direct load control contracts will be governed by the market for energy retail contracts. Customers will be able to select their retail contracts from a range of market offers, which must comply with the Retail Law and Rules. Where the duration, frequency and scope of load control offered as part of electricity contract market offers is undesirable, the AER expects that customers will elect not to sign such contracts. The AER considers that mandating such product requirements in the NERR is unnecessary, and may be inefficient, as it may discourage retailers' from offering such services where it would be efficient to do so.

[180] St Vincent de Paul, *Customer Protections and Smart Meters – Issues for Victoria*, August 2009, p. 27.

A. Appendix: Debt risk premium

This appendix outlines the AER's determination on the debt risk premium to apply in the calculation of the WACC for the initial AMI period, as discussed in section 4.4.1 of this final determination.

A.1 Regulatory requirements

Clause 4.1(i) of the revised Order requires the AER to use input parameters to calculate the Weighted Average Cost of Capital (WACC) for the initial AMI WACC period using market observables from the AMI averaging period and otherwise in accordance with the AER's Statement of Regulatory Intent (SORI) issued under 6.5.4 of the NER.[181]

'WACC' is defined in the revised Order as:

> benchmark weighted average cost of capital calculated in accordance with the formula set out in clause 6.5.2(b) of the National Electricity Rules.

Clause 6.5.2(b) of the NER states that the return on debt (k_d) is calculated as:

$$k_d = r_f + DRP$$

Where:

r_f is the nominal risk-free rate

DRP is the debt risk premium for the regulatory control period determined in accordance with clause 6.5.2 (e).

Clause 6.5.2(e) of the NER states that the DRP is:

> …the margin between the annualised nominal risk free rate and the observed annualised Australian benchmark corporate bond rate for corporate bonds which have a maturity equal to that used to derive the nominal risk free rate and a credit rating from a recognised credit agency.

Relevantly, the SORI dated 1 May 2009 determined a maturity of 10 years in relation to clause 6.5.2(d) for the nominal risk-free rate and a credit rating of BBB+ for the credit rating level.

A.2 Draft determination

In the draft determination, the AER rejected the DNSPs' proposed debt risk premium of 4.84 per cent, based on the Tabcorp floating 5 year BBB+ rated bond issue of April 2009 (Tabcorp issue). The AER noted that the Tabcorp issue did not meet the requirements of the revised Order, including the requirement to be measured from 17 November to 5 December 2008 (the AMI averaging period) and from a bond with a maturity of 10 years. The AER also considered that the benchmark corporate bond

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[181] AER, *Electricity transmission and distribution network service providers–Review of the weighted average cost of capital (WACC) parameters final decision*, 1 May 2009.

rate should be based on the observed yields of all bonds suitable for inclusion rather than a single bond.[182]

The AER considered concerns expressed in the DNSPs' proposal that the fair yields published by Bloomberg were below a variety of alternatives, namely:

- the CBASpectrum BBB+ fair yield curve
- the yield on BBB corporate bonds as published by the RBA
- US BBB/BBB+ corporate bonds swapped to Australian dollars
- selected bonds issued in the United States by Australian companies swapped to Australian dollars
- the Tabcorp bond issued in April 2009.

The AER tested the accuracy of the Bloomberg fair yield curve by comparing it against a sample of observable yields of corporate bonds with a fixed coupon rate issued in the Australian market. This demonstrated that the yields on the Snowy Hydro and Santos bonds, both of which are in the energy sector and rated BBB+, was consistent with the BBB fair yield curve published by Bloomberg.

The draft determination determined a benchmark debt risk premium of 3.09 per cent using Bloomberg estimates of fair yields during the AMI measurement period. The AER concluded that Bloomberg provided better estimates relevant to the benchmark corporate bond rate as required under the revised Order because it relies on more information than a single bond and was calculated for the required averaging period.[183]

A.3 DNSPs' submission

In response to the draft determination, the AER received a joint submission from the Victorian DNSPs dated 11 September 2009, which included a report by Tom Hird of Competition Economics Group (CEG) on estimating the cost of 10 year BBB+ debt during the AMI averaging period.

The DNSPs' submission argued that due in large part to the effects the global financial crisis (GFC), there is no measure of the DRP that meets all of the requirements of the revised Order, and therefore in making its determination the AER is required to have regard to all relevant evidence.[184] The DNSPs note that the draft determination DRP of 3.09 per cent, based on Bloomberg fair yield curves, cannot be supported after giving proper consideration to all the relevant considerations, and does not meet many of the requirements of the revised Order. In reaching this conclusion,

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182 AER, *draft determination*, pp. 119-120.

183 AER, *draft determination*, p. 123.

184 Victorian Electricity Distribution Businesses, *AER draft determination on 2009-2011 AMI budget and charges applications: Joint submission by the Victorian DNSPs on the debt risk premium*, 11 September 2009, p. 3.

the DNSPs outline their interpretation of 'observed' and 'benchmark' corporate bond as per requirements of the revised Order and clause 6.5.2(e) of the NER.

The DNSPs maintained that the Tabcorp floating rate bond issue of April 2009 (converted into an annualised fixed yield to maturity rate, and adjusted to reflect the yield that would have prevailed during the AMI average period) produces a reliable measure of the observed benchmark corporate bond rate. The DNSPs substantiate the reasonableness of their proposed DRP and the unreasonableness of the draft determination through a comparison of yields derived from a variety of alternative methods.

The CEG report examined the accuracy of Bloomberg fair yield curves before, during and after the AMI averaging period. The CEG report also provides alternative proxies for the benchmark 10 year BBB+ bond (including the Tabcorp issue) and a comparison of the Bloomberg and CBASpectrum methodologies.

Overall CEG concludes that placing sole reliance on the Bloomberg fair value curve does not comply with the requirements of the revised Order and is an unreliable and a downward biased proxy for a benchmark bond rate.[185] Through its analysis, CEG considers it examines more reliable alternative measures in its report which would result in a DRP at least a 1.5 per cent higher than the Bloomberg fair value curve.[186]

A.4 AER's considerations

The AER has considered the reports compiled by the DNSPs and CEG in relation to the requirements of the revised Order and subsequently the NER. In summary, the AER maintains that it is inappropriate to set the DRP with respect to the Tabcorp issue because doing so does not meet the requirements of the revised Order.

A key consideration in this regard relates to the DNSPs' interpretation of terms used in the phrase 'observed annualised Australian benchmark corporate bond rate for corporate bonds' of clause 6.5.2(e) of the NER, which the AER disagrees with.

The AER has also considered the detailed comparative analysis of bond yields presented by the DNSPs and CEG in the context of these requirements and considers that much of the data used is not relevant or otherwise persuasive with respect to the AER's determination.

The AER also acknowledges the arguments submitted by the DNSPs and CEG in relation to the methodologies used by Bloomberg (and also CBASpectrum), and the subsequent reliability of their fair yield curve estimates. Many of these arguments have been considered by the AER in previous regulatory determinations. The AER's approach to setting the DRP for network service providers (including in the draft determination) has been and continues to be refined in light of the arguments presented during consultation and changing market circumstances. This approach has involved an assessment of the performance of Bloomberg fair yield estimates against

185 CEG, *Estimating the cost of 10 year BBB+ debt during the period 17 November to 5 December 2008*, p. 77.

186 Ibid., p. 77.

information relevant to the benchmark corporate bond, in particular those rated BBB+. The AER considers this approach is robust and more effective in determining the reliability of estimates provided by Bloomberg (and also CBASpectrum) given the difficulties in adequately assessing their underlying methodologies.

The remainder of this appendix addresses the specific arguments submitted by the DNSPs and CEG, and the AER's responses, under the following headings:

- Interpretation of regulatory requirements
- Criticism of Bloomberg fair yield curves
- Comparison of Bloomberg estimates with market data
- The DNSPs proposed measure of the debt risk premium
- AER's current approach to assessing measures of the DRP

A.4.1 Interpretation of regulatory requirements

Both the DNSPs and CEG summarise the regulatory framework for determining the DRP into four requirements:

- It must be determined using the 'observed annualised Australian benchmark corporate bond rate for corporate bonds' (see clause 6.5.2(e) of the NER and the definition of 'WACC' in the AMI OIC);
- The bonds must have a BBB+ credit rating (see the SORI, clause 6.5.2(e) of the NER, the definition of 'WACC' in the AMI OIC and clause 4.1(i)(i) of the AMI OIC);
- The bonds must have a maturity period of 10 years (see the SORI, clause 6.5.2(e) of the NER, the definition of 'WACC' in the AMI OIC and clause 4.1(i)(i) of the AMI OIC); and
- Measurement must occur between 17 November and 5 December 2008 (the AMI measurement period)(see clause 4.1(i)(i) of the AMI OIC).[187]

The AER notes that the DNSPs rely heavily upon their definition of key terms referred to above, in particular 'observed', 'benchmark' and 'BBB+'. They define these terms as follows:

> **The meaning of 'observed'**
>
> …that the common understand of the term 'observed' in the finance industry is that it refers to a number that can be produced from data that can be pointed to as being 'real' in the market. It is most likely to be used to refer to a traded price, and would not generally be understood as including an 'estimate'.
>
> …

187 Victorian Electricity Distribution Businesses, *AER draft determination on 2009-2011 AMI budget and charges applications: Joint submission by the Victorian DNSPs on the debt risk premium*, 11 September 2009, p. 8.

> In the case of corporate bond rates, the 'observed' data should therefore consist of actual trades, whether new issues or secondary market trades. Estimates or indicative prices that are prepared by banks or other people and that are not based on actual trades cannot be classed as 'observed'.
>
> …
>
> **The meaning of 'benchmark'**
>
> …that 'benchmark' in this context refers to a typical corporate bond rate. That interpretation is consistent with the ordinary meaning of the term 'benchmark'.
>
> The DNSPs also consider that the meaning of benchmark is coloured by the preceding use of 'observed'. The use of these terms together show that the debt risk premium is to be based on usual rates seen in the market.
>
> **The meaning of 'BBB+'**
>
> … the credit rating for the debt risk premium in the AMI determination must also be BBB+ from Standard and Poor's. [188]

Based on the requirements of the revised Order and these definitions, the DNSPs consider the Bloomberg BBB 8-year fair yield curve, extrapolated to ten years by the AER in the draft determination, is not compliant with the revised Order since it is not reflective of yields from bonds that are 'observed', of ten years maturity or of a BBB+ rating.

CEG also offers its interpretation of the terminology used in clause 6.5.2(e) of the NER:

> I interpret this to mean that it is the yield that would be paid on a typical BBB+ rated bond with a maturity of 10 years and that this typical yield must be assessed based on actual observations of yields in the corporate bond market. Specifically, observation from the bond market should have primacy over any preconceived conceptual notions of what the yield on a 10 year BBB+ bond should be absent those market observations.[189]
>
> …
>
> The specific meaning of the term 'benchmark' in economic regulation is consistent with the interpretation of the benchmark cost of debt to mean 'typical' cost of debt.[190]

The AER notes that the terms 'observed' and 'benchmark' are not defined in the NER or the revised Order. However, the AER does not agree with the interpretations offered by the DNSPs and CEG for the following reasons.

Regarding 'observed', neither annualised bond rates for Australian corporate bonds of 10 years maturity with a BBB+ rating nor a 'benchmark bond rate' is directly

188 Ibid., p. 8-10.
189 CEG, *Estimating the cost of 10 year BBB+ debt during the period 17 November to 5 December 2008*, September 2009, p. 3.
190 Ibid., p. 3.

observed in the market as suggested by the DNSPs. For this reason the AER considers the meaning of ‘observed’ in this context is not intended to mean directly observed but logically also captures a process of analysis or estimation as is required.

Regarding ‘benchmark’, the AER considers that the “benchmark corporate bond rate” connotes efficiency of performance and is not a bond rate that has ‘typical’ or ‘usual’ features. This interpretation accords with the use of the expression ‘benchmark’ as it appears elsewhere in Chapter 6 of the NER.

Regarding the rating of ‘BBB+’, the AER notes clause 6.5.2(e) of the NER is not prescriptive in naming a credit rating agency. Rather that the credit rating must be ‘from a recognised credit rating agency’.

The AER also notes that it has regarded the term ‘Australian’ as referring to corporate bonds issued in Australia by Australian privately owned businesses and not by government entities. This definition excludes bonds issued by Australian companies overseas and bonds issued by overseas companies in Australia. Further, the AER notes that to be consistent with risk free rate, these Australian corporate bonds should be estimated using a fixed coupon bond.

For these reasons the AER disagrees with the DNSPs’ contention that the method used in the draft determination, which was based on Bloomberg’s fair yield estimates, only meets one of the four requirements of the revised Order. As discussed in the following sections, the AER considers that Bloomberg fair yield estimates reflect observations relevant to the benchmark corporate bond, and that its extrapolation of fair yield data to a 10 year maturity does not result in any material error or bias.[191]

On this basis, the AER maintains that its approach in the draft determination is consistent with all four requirements of the revised Order.

A.4.2 Criticism of Bloomberg fair yield curves

The DNSPs submitted the following broad criticisms in relation to Bloomberg’s methodology, in the context of setting the DRP:

- The fair yield curves are based on estimates rather than actual market trades, reflecting a lack of underlying data, which undermines their reliability as a measure of yields on BBB+ 10 year bonds[192]

- Bloomberg’s recent decision to cease publishing an 8-year BBB fair yield curve appears to represent an acknowledgement that its curves are an unreliable indicator of the true value of longer term corporate bonds[193]

[191] CEG, *Nominal risk free rate, debt risk premium and debt and equity raising costs for EnergyAustralia*, June 2008, p. 4.

[192] Victorian Electricity Distribution Businesses, *AER draft determination on 2009-2011 AMI budget and charges applications: Joint submission by the Victorian DNSPs on the debt risk premium*, 11 September 2009, pp. 18- 21.

[193] Ibid., p. 21.

- The manner in which Bloomberg calculates its fair yield curves is not transparent, thus the AER cannot determine that its methodology will result in a reliable estimate of the DRP[194]

- The calculation of fair yield curves involves elements of discretion (including in the estimation of bond yields, exclusion of outliers and fitting curves). The exclusion of outliers cannot be justified[195]

- The rate at which a DNSP could issue a new bond in the market will be at a significant premium to the Bloomberg fair yield curves.[196]

The AER thoroughly rejects this final argument and notes it is substantiated by the fact that Bloomberg data represents secondary market prices, which in theory would tend to understate the yields on bonds issued in primary markets where the DNSPs would raise debt finance. The AER notes that the averaging period prescribed in the revised Order are likely to reflect market conditions at the peak of the GFC, thus setting the DRP on information from this period (regardless of the method used) would be at historically high levels. The AER is also aware of regulated entities issuing new debt at a significant discount to the DRP of 3.09 per cent set in the draft determination. For these reasons, the AER suggests that DNSPs have avoided presenting any evidence on their actual cost of debt in their submissions because this would reveal that the DRP set by the AER (using any of the measures available for the AMI averaging period) would result in a significant overcompensation of their cost of debt.

Many of the arguments presented by the DNSPs and CEG stem from the lack of observed trades relating to 10 year BBB+ bonds and the subsequent difficulties in estimating yields for such bonds. As stated earlier in section A.4.1, the DNSPs' also rely heavily on their interpretation of the term 'observed' which subsequently overstates the apparent shortcoming of using Bloomberg's data in setting the DRP under the revised Order. In particular, the AER does not consider it a flaw in Bloomberg's methodology that some of its information reflects estimates of yields, as well as the use of expert judgement, rather than a strict reliance on actual observed trades. While the AER notes that these features unfortunately detract from transparency, given the paucity of information and current market volatility (discussed below) the AER sees Bloomberg's practices as necessary and also advantageous when regarding the benchmark corporate bond.

The AER has previously, and continues to, place little weight on the arguments over the methods used by Bloomberg (and CBASpectrum) to generate fair value estimates, given that they both use proprietary methods which are not fully known, particularly to the DNSPs and CEG:

> I cannot express an opinion on the actual estimation techniques used by CBASpectrum to give effect to this concept as I do not have a full knowledge of them.

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[194] Ibid., pp. 22-23.
[195] Ibid., pp. 23-28
[196] Ibid., p. 28.

> I cannot express an opinion, at a conceptual or implementation level, of the Bloomberg methodology as I do not know what this is.[197]

In the absence of a full understanding of either method, many of the arguments presented are based on conjecture and do not form a sound basis on which to determine the reliability of Bloomberg's (or CBASpectrum's) fair value estimates.

In this context, the author of the CEG report notes that he has been critical of CBASpectrum in a previous report, where it was suggested that Bloomberg would produce more accurate estimates of the DRP. In this regard, CEG notes:

> A repeat of the 2005 methodology used by myself and Prof. Bruce Grundy to compare the accuracy of the Bloomberg and CBASpectrum fair value curves for long maturities would find that CBASpectrum was now significantly more accurate than Bloomberg.[198]

The AER considers that assessing the performance of the fair value estimates using market data, rather than considering the proprietary methodology used to derive them, is a more effective way to determine their reliability. The AER considers that such testing is not inconsistent with the views put forth by CEG in a number of reports currently before the AER.[199] The difference between the AER's and CEG's approaches and conclusions appears to stem from the choice of market data used to undertake this assessment and the prevailing market conditions. The AER's approach to testing the reliability of Bloomberg estimates, and issues arising out of current consultation processes, is addressed in section A.4.5 below. The AER has used and refined this general approach over several regulatory determinations and notes that this has resulted in Bloomberg proving to be more reflective of observed data at the time.

A final "methodology" argument of the DNSPs relates to the AER's use of the 8 year BBB rated Bloomberg fair yield plus the spread between the 8 and 10 year A rated Bloomberg fair yield. The DNSPs argue that this does not meet the requirement under the revised Order that the observed benchmark corporate bond must have a 10 year maturity.[200]

In the absence of published data from Bloomberg to this maturity date, and in the event the AER has determined Bloomberg estimates to be superior for the purposes of determining the DRP, the AER considers that extrapolation is conceptually reasonable. The use of the BBB fair yield curve would tend to overestimate the yields for the benchmark BBB+ bond as it is based on bonds that are rated below this benchmark. This would tend to offset any potential underestimation of yields resulting

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197 CEG, *Estimating the cost of 10 year BBB+ debt during the period 17 November to 5 December 2008,* September 2009, p. 61

198 Ibid., p. 61.

199 See CEG, *Estimating the cost of 10 year BBB+ debt: A report for ETSA, Ergon and Energex*, June 2009; CEG, *Estimating the cost of 10 year BBB+ debt during the period 17 November to 5 December 2008*, September 2009 and CEG, *Estimating the cost of 10 year BBB+ debt: A report for ActewAGL*, June 2009.

200 Victorian Electricity Distribution Businesses, *AER draft determination on 2009-2011 AMI budget and charges applications: Joint submission by the Victorian DNSPs on the debt risk premium*, 11 September 2009, p. 17.

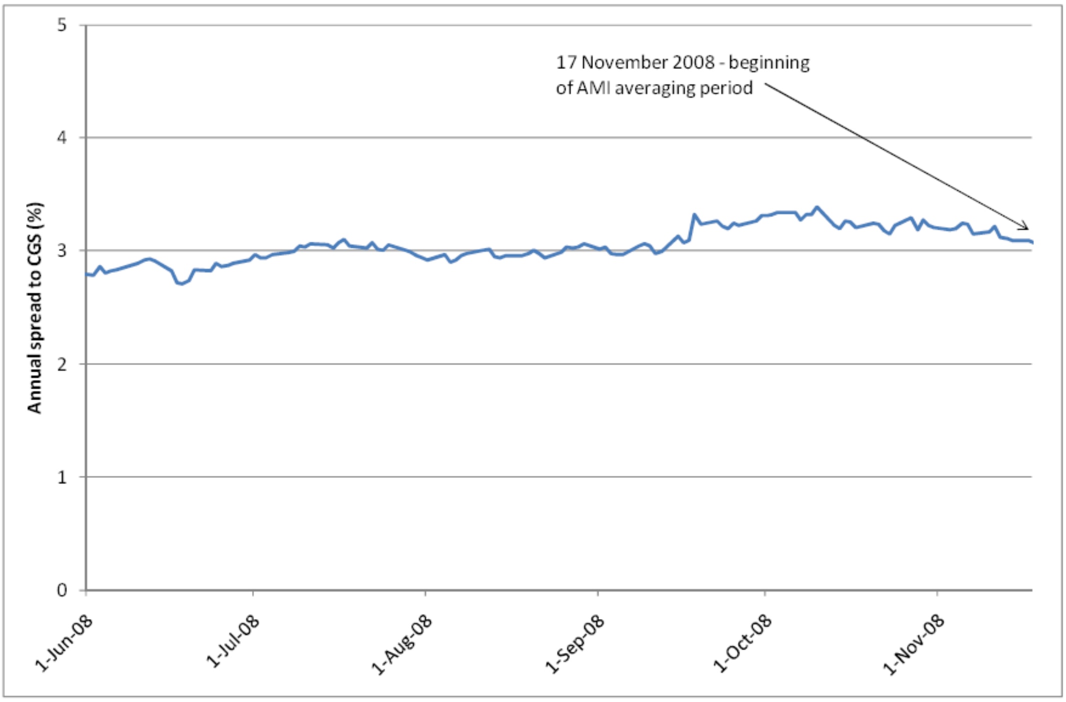
from the use of the spread on the A rated fair yield curve from 8 to 10 years. Furthermore, CEG has previously supported the AER's method of extrapolation:

> In our opinion this approach is reasonable and the AER has shown that it does not result in a material error or an obvious bias (at least when measured against recent history). [201]

A.4.3 Comparison of Bloomberg estimates with market data

CEG considered that Bloomberg estimates do not adequately capture the effect of the GFC in the lead up to the AMI averaging period, claiming that over September 2008, risk premiums for BBB+ rated debt should have increased markedly.[202] The DNSPs support this finding [203]. Figure A.1 below is reproduced from CEG's report to illustrate this argument.

Figure A.1: Bloomberg estimated spreads to CGS on 10 year BBB+ corporate bonds204



Source: Bloomberg, RBA

The AER considers CEG has selectively chosen a time period which serves to illustrate its point instead of considering all the available data. Figure A.2 below illustrates the DRP measured from Bloomberg, as well as CBASpectrum over the last 7 years. This illustrates the relative stability of the market leading to sharp increases

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[201] CEG, *Nominal risk free rate, debt risk premium and debt and equity raising costs for EnergyAustralia* June 2008, page 4. Also suggested by NERA: *NERA, Critique of Available Estimates of the Credit Spread on Corporate Bonds: A report for the ENA*, May 2005, p. 21.

[202] CEG, *Estimating the cost of 10 year BBB+ debt during the period 17 November to 5 December 2008,* September 2009, p. 18.

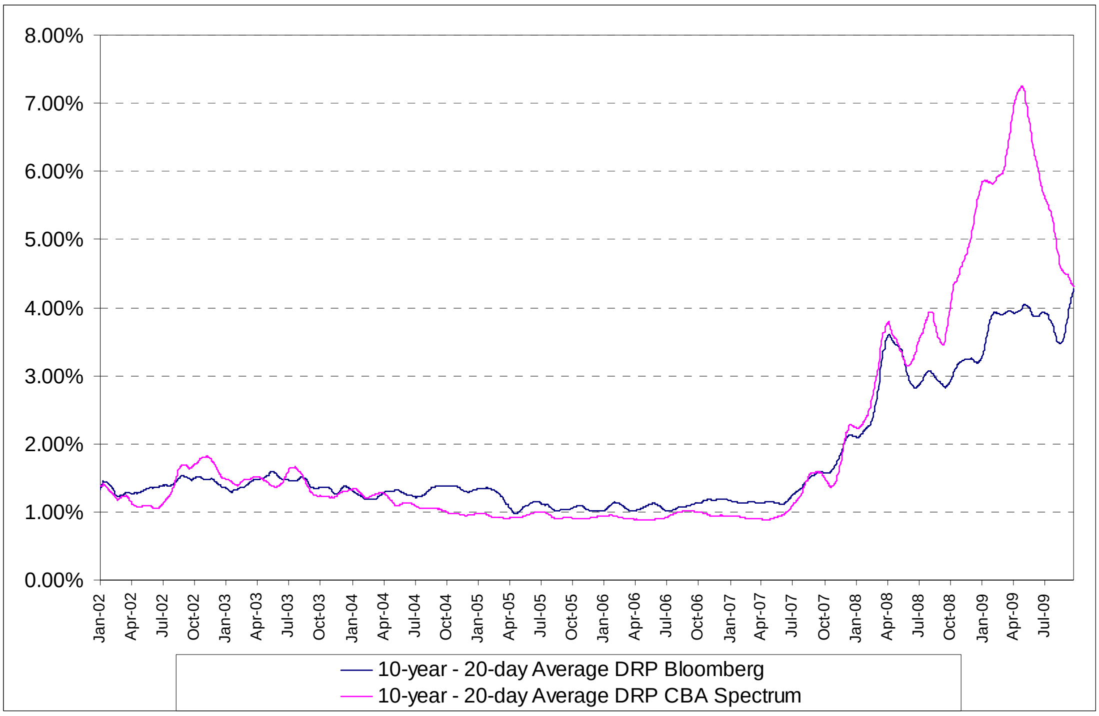
[203] Ibid., p.19.

[204] Ibid., p.19.

in spreads from late 2007 reflecting the market reaction to the causes of the GFC, rather than to the announcements regarding major lending institutions at the height of the GFC as assumed by CEG.[205]

The AER notes that the increase in the DRP measured using Bloomberg estimates was not as much as that using CBASpectrum estimates. This divergence highlights the inherent difficulties in estimating a fair yield for long dated bonds in the presence of significant market volatility. As a more general observation, the AER considers that the DRP of over 7 per cent derived from CBASpectrum supports its view that information derived from any data source during this period should be tested against appropriate market data rather than relied upon solely based on methodological considerations.

Figure A.2: BBB+ 20 Day average Debt Risk Premium



CEG also compared the accuracy of Bloomberg fair yield estimates (including the AER's extrapolation to 10 years) during the AMI averaging period with 600 bonds issued in Australian dollars but not issued by Commonwealth or State Governments, including bonds of various ratings and maturities. CEG concludes:

> During the AMI averaging period, the AER/Bloomberg BBB+ fair value curve clearly does not accurately predict/reflect the yield estimates for corporate bonds of BBB+ rating or higher for which yield estimates are available from a large number of sources. This is true at all maturities but is especially true for longer maturities (e.g. greater than 3.5 years)… In the case of BBB+ to AA- corporate bonds with a time to maturity of more than 3.5 years, all but one of the 19 issuers of these bonds attract a higher yield than the AER/Bloomberg BBB+ fair value curve. The differences are not trivial, with the average mean difference being 2.1%.

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[205] CEG, *Estimating the cost of 10 year BBB+ debt during the period 17 November to 5 December 2008*, September 2009,, p. 18.

To argue that the Bloomberg estimates are downward biased, and to support the reasonableness of their proposed use of the Tabcorp bond issue, the DNSPs draw on a range of other potential measures of the DRP which they consider are at least as, if not more, reliable than the AER's approach.[206] These other measures include yields from an AMP issue, CBASpectrum, RBA data, bonds issued by Australian companies in the US, other bonds issued in overseas markets, and a bond pricing envelope which draws on these and other data already considered. The DRP estimated by the DNSPs through these alternative measures, including those examined by CEG, are reproduced in Table A.1 below.

[206] Victorian Electricity Distribution Businesses, *AER draft determination on 2009-2011 AMI budget and charges applications: Joint submission by the Victorian DNSPs on the debt risk premium*, 11 September 2009, p. 36.

Table A.1: DNSPs’ alternative measures of the debt risk premium

DRP measure	Yield	Debt risk premium
Draft determination, based on Bloomberg fair yield curves	7.72%	3.09%
RBA (average of November and December 2008 BBB spreads for 1-5 year maturity)	9.11%	4.48%
AMP March 2009 A- bond issue	9.12%	4.49%
Secondary trades during the AMI measurement period of bonds issued by Australian corporates in the US market	9.24%	4.61%
CEG report: BBB+ mean (4 to 16 year fixed and floating rate observations)	9.43%	4.80%
Tabcorp April 2009 BBB+ bond issue	9.48%	4.84%
CEG report: BBB+ mean (4 to 16 year fixed rate observations)	9.55%	4.92%
CBASpectrum BBB+ 10 year fair yield curve	9.55%	4.92%
CEG report: BBB+ mean (all fixed rate observations)	9.71%	5.08%
CEG report: BBB+ to A- mean (4 to 16 year fixed and floating rate observations)	9.80%	5.17%
Overseas issues during the AMI measurement period: mean of A rated 10 year bonds	9.90%	5.27%
CEG report: BBB+ mean (all fixed and floating rate observations)	10.05%	5.42%
CEG report: BBB+ to A- mean (all fixed rate observations)	10.09%	5.46%
CEG report: BBB+ to A- mean (4 to 16 year fixed rate observations)	10.28%	5.65%
DNSPs' bond pricing envelope: raw average (8 to 11 years)	10.65%	6.02%
Bonds issued by Australian corporates in the US market (mean of all bonds)	10.98%	6.35%
Bonds issued by Australian corporates in the US market (mean of 10 year bonds)	11.18%	6.55%
Overseas issues during the AMI measurement period: mean of BBB rated 10 year bonds	11.26%	6.63%
DNSPs' bond pricing envelope: adjusted average (8 to 11 years)	11.32%	6.69%

Source: *Victorian Electricity Distribution Businesses, report, p. 57-58.*

From these other measures the DNSPs conclude:

- the DRP set in the draft determination is the lowest possible, with the next lowest result being 45 per cent higher, and several of the measures are more than double the AER's proposed DRP
- the DRP calculated based on the Tabcorp issue is lower than almost three-quarters of the other estimates but is much closer to the majority of the other results

- the Bloomberg fair yield curves are an unreliable estimate of the debt risk premium and significantly underestimate the observed corporate bond rate for BBB+ 10 year bonds. The use of the Bloomberg fair yield curves is inconsistent with all relevant supporting evidence, and they cannot reasonably be relied upon by the AER as the measure of the debt risk premium

- the DNSPs' proposed debt risk premium, which is based on the Tabcorp bond issue, is significantly more consistent with the weight of the supporting evidence.

- the DNSP's approach is a conservative measure and there would be grounds for justifying a higher debt risk premium than the Tabcorp rate of 4.84 per cent, but there is clearly no basis for adopting a debt risk premium of 3.09 per cent based on the Bloomberg fair yield curves.[207]

The AER has assessed these conclusions and the underlying data in light of the requirements of the revised Order. The AER notes that the DNSPs themselves give limited weight to many, if not most, of their alternative measures in the context of the requirements of the revised Order. They are simply presented as a range of possible yields which imply that the draft determination was unreasonable simply because it was the lowest of these possibilities.

As noted in the draft decision, the AER does not consider it appropriate to compare yields from bonds issued by Australian companies overseas as they do not fit the criteria of ‘observed annualised Australian benchmark corporate bond rate for corporate bonds’. As defined above, the AER considers the term ‘Australian’ in this reference refers to corporate bonds issued in Australia by Australian privately owned businesses and not by government entities. Further, the AER notes that to be consistent with risk-free rate, these Australian corporate bonds should be estimated using a fixed coupon bond. The AER also rejects comparisons of yields to the extent they reflect bonds issued by foreign issuers into the Australian domestic market and denominated in Australian dollars. These bonds are not valid comparators for the benchmark Australian corporate bond rate as they do not reflect many of the features required by the revised Order.

On a more fundamental point, the AER observes that the AMI averaging period (November/ December 2008) coincides with the peak of the GFC, thus any conclusions need to be drawn in light of the volatility and lack of liquidity in debt markets at the time, particularly for lower rated bonds.

The AER notes that the perceived underestimation of Bloomberg estimates in the AMI averaging period may not be unexpected. Due to the GFC, many companies have experienced negative effects relating to their perceived financial risks. Taking this into account, observers would note that the yields on some bonds change noticeably relative to others with the same credit rating reflecting the change in perceived risks associated with those bonds. The AER notes that CEG and the DNSPs have not acknowledged the impact of such bonds on their analysis where this is

[207] Victorian Electricity Distribution Businesses, *AER draft determination on 2009-2011 AMI budget and charges applications: Joint submission by the Victorian DNSPs on the debt risk premium*, 11 September 2009, p. 58.

clearly an issue (e.g. those issued by Sallie Mae and BBI[208]) and have instead criticised the AER for its exclusion of outliers on such grounds[209], casts doubt over the robustness of the comparative data they rely on.

The AER also considers that the actual cost of debt for DNSPs would be expected to be below the benchmark cost of debt at this time. Market participants would expect the financial risks faced by DNSPs to remain relatively steady during deteriorating market conditions due to the stable revenue streams offered by the regulated monopoly business, as well as guaranteed asset values through the RAB roll-forward mechanism.

In summary, the AER appreciates that CEG and the DNSPs have presented a wide variety of data for its consideration, particularly given the current lack of information relevant to determining the benchmark corporate bond yield, being that which relates to bonds that:

- are issued in Australia by Australian companies
- are rated BBB+
- have a fixed coupon
- have a maturity of 10 years.

However, in considering the totality of information presented by the DNSPs, the AER considers that many of the estimated yields do not reflect or closely approximate these requirements and has accordingly placed limited weight on them. Those that remain to be considered by the AER include yields derived from Bloomberg, CBASpectrum, the Tabcorp issue, and the measures reflecting BBB+ rated fixed coupon bonds issued in Australia by Australian companies.

A.4.4 The DNSPs' proposed measure of the debt risk premium

The DNSPs have reaffirmed their position from their June 2009 proposals for the use of the Tabcorp floating rate bond issue of 1 April 2009 as a basis to set the DRP. From this methodology the DNSPs propose a debt risk premium of 4.84 per cent.[210]

The DNSPs consider that whilst this approach does not satisfy all four requirements of the revised Order, the Tabcorp issue is the most recent actual 'observed' measure of an Australian corporate bond with a BBB+ rating and a more reliable predictor than the extrapolation of Bloomberg data used in the draft determination.[211]

CEG also investigated other potential measures of the DRP with regard to the AMI averaging period and provide alternative proxies for the benchmark 10 year BBB+

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[208] Victorian Electricity Distribution Businesses, *AER draft determination on 2009-2011 AMI budget and charges applications: Joint submission by the Victorian DNSPs on the debt risk premium*, 11 September 2009, p. 27, 37.
[209] Ibid., p. 26-28
[210] Ibid., p. 3.
[211] Ibid., p. 35.

rate. CEG proposes the following four methods to obtain a benchmark BBB+ corporate bond rate.

- the use of a published fair value estimates from CBASpectrum and Bloomberg to arrive at an estimate.
- the derivation of a bespoke estimate of the fair value of BBB+ bonds from Australian corporate bond yield estimates observed within the AMI averaging period.
- the use of observations of actual trades in Australia from outside the AMI averaging period and applying these as a basis for setting the benchmark rate within the AMI averaging period
- the use of observations of actual trades from outside Australia and applying these as a basis for setting the Australian benchmark rate within the averaging period.[212]

CEG's analysis concluded that the proxies in Table A.2 are more reliable benchmark corporate bond rate then the draft determination estimate of 3.09 per cent.[213]

Table A.2: Debt premiums based on alternative proxies for the benchmark rate for BBB+ 10 year bonds during the AMI averaging period

Proxy	Implied DRP
Average of RBA estimated spreads to CGS for 3 year BBB bonds (November to December)	4.60%
CBASpectrum 10 year BBB+	4.92%
Tabcorp/AMP actual trade observed debt premia*	5.16%
Average of estimated yields during AMI period	5.50%
Actual trades in the US and other markets (including during the AMI period)	5.86%

Source: CEG report, p. 59.
* No adjustment made to reflect AMI averaging period

On the use of the Tabcorp issue, CEG notes that:

> The Tabcorp bond is the best observation available of a traded BBB+ bond with a medium term maturity that is proximate to the AMI averaging period. Importantly, it is also an observation of the cost of debt to an *issuer* and therefore is desirable as a source of information on the benchmark rate[214]…

As per the draft determination, the AER does not consider that the recent Tabcorp issue should be solely relied upon in determining the DRP. As discussed above, the

[212] CEG, *Estimating the cost of 10 year BBB+ debt during the period 17 November to 5 December 2008,* September 2009,, p. 46.
[213] Ibid., p. 59.
[214] Ibid., p. 44.

DNSPs have overly relied on their interpretation of the term ‘observed’ referred to in clause 6.5.2(e) in arguing for the Tabcorp bond, evidently at the expense of the term ‘benchmark’. In this context, the DNSPs have not sufficiently established that the Tabcorp bond alone reflects the benchmark corporate bond required under the revised Order.

Regarding other features of the bond, the AER acknowledges the DNSPs’ proposed approach to converting the Tabcorp issue into an annualised fixed yield to a 10 year maturity, submitted to satisfy the requirements of the revised Order. The AER does not have any in-principle issues with extrapolating and converting the Tabcorp floating rate to a 10 year maturity. However, the AER considers that it is possible to satisfy the requirements in relation to the averaging period and maturity through using other measures of the DRP, which would be more robust than making ad hoc adjustments to the Tabcorp bond yield.

Similar to the reasoning outlined in section A.4.3 above, many of the other alternative measures put forward by the DNSPs and CEG do not meet the requirements of the revised Order.

A.4.5 AER’s approach to measuring the DRP

The AER notes that its task of determining the DRP has become more difficult due to the lack of liquidity in the market for 10 year BBB+ bonds, which has tended to result in a greater reliance on data published by Bloomberg and CBASpectrum. The lack of data for the purposes of determining yields on bonds with benchmark characteristics has also provided an opportunity for service providers to seek a DRP which may be higher than the ‘true’ benchmark cost of debt using a variety of information sources such as bonds with floating rates, non-BBB+ rated bonds and ‘kangaroo’ bonds which are addressed above. Compounding these issues, the revised Order requires the benchmark corporate bond yield to reflect information from a period which reflects the peak of the GFC and associated market volatility, and for a time when it was unlikely that any debt was actually issued.

Arguments regarding the robustness of methods employed by Bloomberg and CBA Spectrum, with respect to producing data for the DRP, have been raised and considered by the AER (as well as other regulators) over many review processes.[215] Regulated service providers, as well as their advisors, have argued for both Bloomberg and CBA Spectrum at varying times.[216] While more information has been obtained regarding the methodologies utilised by Bloomberg and CBASpectrum through the AER’s recent review processes, the AER acknowledges that they are not completely transparent to stakeholders and this is a factor subject to current consideration by the AER, ACCC and other regulators.[217] To this end, the AER is

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215 See for example: ESC, Electricity Distribution Price Review 2006-10, October 2005 Price Determination as amended in accordance with a decision of the Appeal Panel dated 17 February 2006, Final Decision Volume 1: Statement of Purpose and Reasons, October 2006, pp. 366-372; and AER, Directlink Joint Venturer’s application for conversion and revenue cap decision, 3 March 2006, pp. 17-18.

216 See for example: Directlink Joint Venturer’s, Submission in response to the AER’s draft decision of 8 November 2005, 9 December 2005, pp. 22-24.

217 IPART, Estimating the debt margin for the weighted average cost of capital, May 2009.

currently investigating other methodologies for testing and setting the DRP. At present the AER relies on the fact that Bloomberg and CBASpectrum are experienced market operators who use their knowledge and expert judgement in establishing best estimates.

In response to the proposals and arguments before it, and recognising the limitations in arguing over the methods employed, the AER's approach has been to test the robustness of estimates derived from both data sources against relevant market data.[218] This analysis has evolved to compare the fair market yields published by Bloomberg and CBASpectrum against observed yields on BBB+ rated bonds. From this analysis the best performing fair value estimates are utilised in determining the DRP for each particular AER decision. The AER notes that usually this process of analysis utilises the most up to date information in order to provide the best possible estimate or forecast in the circumstances, including with respect to the relevant averaging period. The AER also notes that this has tended to result in Bloomberg proving to be a more reliable estimate than alternatives proposed at the time, including the Tabcorp issue.

Consistent with the AER's previous analysis,[219] the assessment of providers of financial information has included a simple average of Bloomberg and CBASpectrum fair yield estimates in the analysis. The simple average has been included for consistency and will only be relied upon where it is found that neither Bloomberg nor CBASpectrum are a better predictor. In the circumstance where one provider of financial information is found to be a better predictor than the other, then the AER considers that service provider should be relied upon solely. As noted above, the AER will consider further refinements to its approach in setting the DRP in the future.

In this comparative analysis, the observed yields of a common sample of BBB+ rated bonds (with a maturity of at least 2 years) from different sources are compared with the fair value estimates based on Bloomberg, CBASpectrum and a simple average of both. The difference between the observed yields and the fair value estimates are compared using the weighted sum of squared errors, which can be defined as:

$$WSSE = \frac{1}{n}\sum_{i=1}^{n}\left\{\left[\sum_{j=1}^{t_i}\left(Observed_{i,j} - Fair_{i,j}\right)^2\right]\frac{1}{t_i}\right\}$$

Where:

- N is the number of bonds in the sample
- t_i is the number of observations for the i^{th} bond

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[218] See for example: AER, Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12, Draft determination, 8 December 2006, pp. 103-104; AER, Directlink Joint Venturers' application for conversion and revenue cap, Decision, 3 March 2006, pp. 211, 221; AER, New South Wales distribution determination 2009-10 to 2013-14 final decision, 28 April 2009, pp. 225-232.

[219] AER, *Final Decision, ACT DNSP*, 28 April, and AER, *Final Decision, NSW DNSPs,* 28 April 2009.

- $Observed_{i,j}$ is the j^{th} observed yield for the i^{th} bond, taken from either Bloomberg, CBASpectrum or UBS

- $Fair_{i,j}$ is the j^{th} fair yield for the i^{th} bond, taken from either Bloomberg, CBASpectrum.

Previously the AER allocated equal weight to all bonds in the sample. The weighted sum of squares allows for bonds with fewer observations to have less impact on the final calculation.

In order to conduct this analysis, the AER defines a population of bonds to observe and then selects a sample from this population. Ideally the population and sample of bonds would be the same. The AER, however, considers that some bonds from the population should be excluded if there is a valid reason. The population of bonds are BBB+ rated corporate bonds issued in Australia by Australian companies with observations available from Bloomberg, CBASpectrum and UBS over the averaging period. Based on these criteria, the population of bonds are as shown in Table A.3.

Table A.3: Population of BBB+ rated corporate bonds

Issuer	Maturity	ISIN
Bank of Queensland	2 December 2010	AU300BQ40434
Tabcorp*	13 October 2011	AU300TPP0010
Coles Myer	25 July 2012	AU300CML1014
Snowy Hydro	25 February 2013	AU000SHL0034
DB RReef	8 February 2011	AU3CB0016673

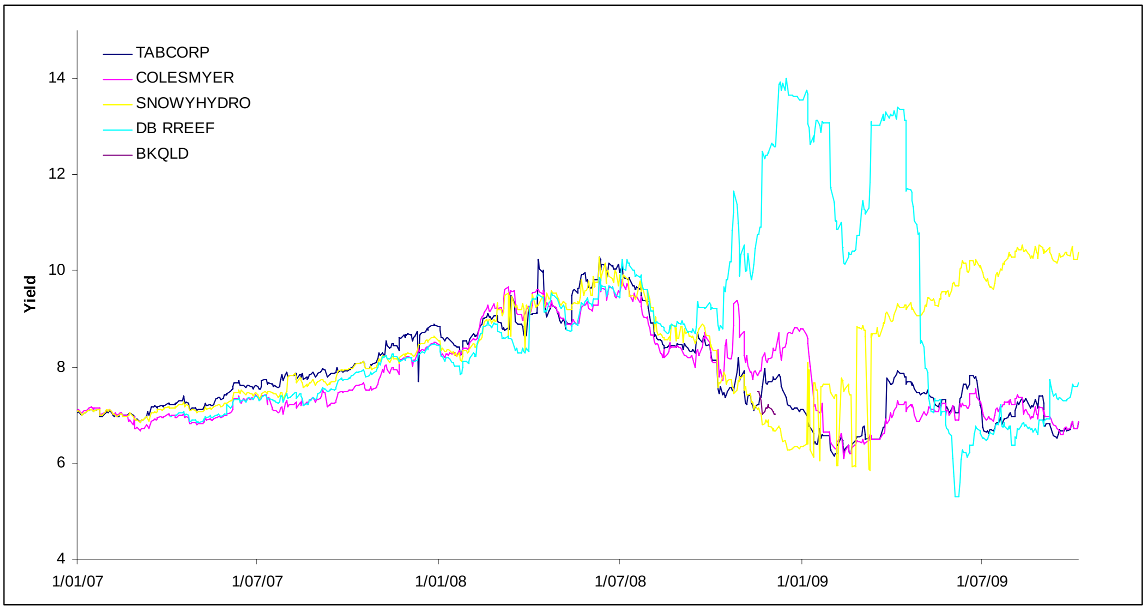
*NB: The Tabcorp corporate bond cited here is a different issue to that proposed by the Victorian DNSPs. This Tabcorp corporate bond has a fixed coupon and was issued prior to the AMI averaging period. No adjustment made to reflect AMI averaging period

Due to the requirement of bond observations required from all three data providers, Santos and Babcock and Brown Infrastructure has been ruled out due to no observations from Bloomberg during the AMI measurement period. Origin Energy was ruled out due to no observations available for this bond from CBASpectrum.

The AER considers that the observed yields on these bonds also reflect the credit rating perceived by market participants, not necessarily the credit rating assigned by ratings agencies. As set out in the SORI, these bonds are required to have a credit rating of BBB+. However, if the AER notes strong evidence to suggest a divergence between the market perceived credit ratings and assigned credit ratings then the bond should be excluded from the sample. This is done because where a bond is considered an outlier even though it has the assigned credit rating, its inclusion contaminates the sample and therefore is detrimental to the outcome of the process of analysis for ‘true’ BBB+ bonds.

Further, to the extent that a structural break in respect of the yield of a particular bond can be identified then this is strong support for a divergence between the market perceived and assigned credit rating. In such a case the yield on the bond would represent an outlier in the data set and would not represent the yield on the benchmark corporate bond. Figure A.3 shows the observed yields from a population of BBB+ bonds.

Figure A.3: **Observed yields for a population of BBB+ bonds (per cent)**



Souce: CBASpectrum.

The identification of a structural break must, initially, be made on the basis of an inspection of data. The period identified as a possible structural break for DB RReef bond occurs during the averaging period. In the period from 5 April 2007 to 13 October 2008 the average yield was 8.3 per cent. From 14 October 2008 to 7 May 2009 the average observed yield was 11.9 per cent. From 8 May to 6 October 2009 the average yield is 6.8 per cent.

The Chow test is commonly used to determine the existence of a structural break—it compares two time periods to determine if they have the same explanatory factors.[220] Based on a comparison of the average yields in these two periods, the Chow test supports the conclusion that these averages are not statistically the same.[221] This suggests that there has been a divergence between market perceived credit rating and assigned credit rating. As a result of this analysis, the AER considers that the DB RReef bond should be excluded from the sample of BBB+ rated bonds that is used in the comparison of fair value curves to observed yields.

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220 Chow, G. C., *Tests of Equality Between Sets of Coefficients in Two Linear Regressions*, Econometrica 28(3), July 1960.

221 More specifically, the Chow test statistic is distributed according to the F distribution and the null hypothesis is that the two averages are the same. Given this data set, the observed F is 2141—this is a p–value much smaller than 0.001. This leads to the rejection of the null hypothesis, at any reasonable level of significance, and the conclusion that the averages are statistically different.

Yields were observed for the bonds listed in Table A.4 over AMI measurement period. These yields were observed from Bloomberg, CBASpectrum and UBS.

Table A.4: Sample of BBB+ corporate bonds—observed yields and fair values during AMI measurement period (per cent)

Issuer	Average observed yield			Average fair value	
	Bloomberg	CBASpectrum	UBS	Bloomberg	CBASpectrum
Tabcorp	7.3	7.6	7.1	6.7	8
Coles Myer	7.9	8.1	8	6.8	8.3
Snowy Hydro	6.8	6.9	7.4	6.8	8.4
Bank of Queensland	6	7.2	6.2	6.4	7.6

The AER notes that these bonds mature within six years. Ideally, the sample would also include BBB+ bonds with longer maturity dates but there are no such bonds currently available in the market. The AER utilises the most information relevant to the benchmark corporate bond for its process of analysis which are BBB+ rated bonds with the longest maturity. The AER therefore utilises all appropriate BBB+ bonds with a maturity of at least two years. Given the restrictions of not having longer maturity dated bonds, the AER considers that this sample of bonds is the best possible in the current circumstances.

The observed yields were compared to the Bloomberg BBB fair value curve, the CBASpectrum BBB+ fair value curve and a simple average of the two curves using the weighted sum of squared errors. This comparison provided the results shown in Table A.5:

Table A.5: Fair value and observed yield analysis using weighted sum of squared errors during AMI measurement period

Fair value source	Observed yield source		
	Bloomberg	CBASpectrum	UBS
Bloomberg BBB	0.51	0.76	0.57
CBASpectrum BBB+	1.42	0.72	0.98
Simple average of Bloomberg and CBASpectrum	0.48	0.31	0.27

The AER considers that over the AMI measurement period, a simple average of Bloomberg and CBASpectrum's BBB+ fair value curve has performed best at matching observed yields for the sample of bonds when performance is measured using the weighted sum of squared errors. This is true whether the source of the observed bond yields was Bloomberg, CBASpectrum or UBS.

The AER notes that this result should not be interpreted as endorsing or criticising the methodologies used by CBASpectrum and Bloomberg to develop their fair value curves. The AER also highlights that its approach to testing the reliability of Bloomberg and CBASpectrum has been and continues to be refined in light of the arguments presented during consultation and changing market circumstances. In recognising the imperfections in this approach and the reliance on methods which are not fully transparent, the potential for an alternative, custom-built estimation approach is being considered by the AER, ACCC and other regulators and may be developed for consultation in the near future.

A.5 AER's conclusions

The AER acknowledges the arguments regarding the use of the Tabcorp issue (given adjustments) for determining the DRP. The AER considers the DNSPs' misinterpretation and application of the terms in clause 6.5.2(e) led to the proposal of the Tabcorp issue as an alternative mechanism. However, the AER considers that sole reliance on the extrapolation of the Tabcorp issue is not robust enough in determining the DRP and it was not sufficiently established that the Tabcorp bond reflects the benchmark corporate bond and therefore not satisfying the requirements of the revised Order.

The AER acknowledges the variety of supporting information presented by the DNSPs and CEG, however, the AER considers that most of the yield data are not appropriate comparators as they are not reflective of bonds issued by an Australian benchmark efficient DNSP.

The AER considers that arguments over the methodologies used by Bloomberg and CBASpectrum rely on incomplete information and do not provide any grounds to support or discredit one data source over the other. The AER has maintained its approach to testing fair yield curve data against information relevant to the benchmark corporate bond. Through this assessment the AER concludes that the use of a simple average of Bloomberg and CBASpectrum's fair value curve provides the best prediction of observed yields for the purposes of determining the yield on the benchmark BBB+ 10 year corporate bond, as required by the revised Order, including clause 6.5.2(e) of the NER.

The AER notes that the averaging period prescribed in the revised Order will capture market conditions reflective of the peak of the GFC, thus setting the DRP on information from this period (regardless of the method used) is likely to significantly overcompensate the DNSPs for their actual cost of debt.

For this final determination, the AER has determined the debt risk premium based on the average of Bloomberg (extrapolation) and CBASpectrums' fair value curves of 4.13 per cent in accordance with the requirements of the revised Order.[222]

[222] Including 12.5bp for debt raising costs as required by the revised Order.