westernpower

Our ref: DM# 10095513 v1

30 November 2012

Mr Lyndon Rowe
Chairman
Economic Regulation Authority
Level 4, Albert Facey House
469-489 Wellington Street
PERTH WA 6000

Dear Lyndon

Third Allowable Revenue Proposal - System Management

I am pleased to provide you with System Management (Markets)'s Third Allowable Revenue proposal as required in clause 2.13.23(a) of the Wholesale Electricity Market Amending Rules (1 November 2012).

The Third Allowable Revenue proposal covers the period from 1 July 2013 to 30 June 2016 and is required to be submitted to the Economic Regulation Authority by 30 November 2012.

In preparing this proposal System Management (Markets) has been careful to ensure that it has only included the costs of it providing the service described in clause 2.23.1 and performing its functions and obligations under the Wholesale Electricity Market Amending Rules (1 November 2012).

The following documents comprise our submission:

1. A printed copy of the proposal and supporting documents.
    - The *Allowable Revenue and Forecast Capital Expenditure Application* document specifies the allowable revenue and forecast capital expenditure for system operation services, including all of System Management (Markets) functions and obligations under the Rules.
    - The *Allowable Revenue Information* document outlines System Management (Markets)'s allowable revenue proposal for the period. It provides the context, rationale and justification for System Management (Markets)'s Allowable Revenue proposal, and should be read in conjunction with the associated Allowable Revenue document.
2. An electronic version of the proposal and supporting documents for your publication.
3. An electronic version of the supporting revenue model.
4. An electronic version of the documents that are referenced in the Allowable Revenue Information Document Index.

363 Wellington Street Perth WA 6000
GPO Box L921 Perth WA 6842
enquiry@westernpower.com.au

T 13 10 87 | F (08) 9225 2660
TTY 1800 13 13 51 | TIS 13 14 50
westernpower.com.au

Electricity Networks Corporation
ABN 18 540 492 861

The *allowable revenue information* document is structured in a number of parts comprising:

- Executive Summary
- Part A – Background and Context
- Part B – Expenditure Proposal
- Part C – Allowable Revenue
- Appendices

We look forward to working with the Economic Regulation Authority and its consultants over the coming months to ensure an efficient and effective process.

I invite you to contact Western Power's Mr Michael Harris who will manage correspondence on this proposal between System Management (Markets) and the Authority. Mr Harris' email address is michael.harris@westernpower.com.au and he can be reached by phone on (08) 9326 6677. If Mr Harris is unavailable please contact Ms Sally McMahon. Ms McMahon can be reached by phone on (08) 9326 7139.

System Management appreciates the Economic Regulation Authority's attention to this matter and we look forward to your response.

If you wish to discuss this proposal further I invite you to contact myself on 9325 5097.

Yours sincerely

Cameron Parrotte
GENERAL MANAGER
SYSTEM MANAGEMENT

System Management allowable revenue and forecast capital expenditure application

1 July 2013 – 30 June 2016

November 2012

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1 Introduction

1.1 Purpose of this document

1.1.1 This proposal for the *allowable revenue* and *forecast capital expenditure* of *System Management* is lodged by Western Power on 30 November 2012 for approval by the *Economic Regulation Authority* in accordance with the processes and criteria set out in the Wholesale Electricity Market Rules, herein referred to as the "***Rules***". Henceforth this document is referred to as the "***allowable revenue application***".

1.1.2 This *allowable revenue application* specifies the *allowable revenue* and *forecast capital expenditure* for system operation services, including all of *System Management's* functions and obligations under the *Rules.*

1.2 Definitions and interpretation

1.2.1 In sections 1 to 5 of this *allowable revenue application*, where a word or phrase is italicised it has the definition given to that word or phrase as described in this *allowable revenue application* or section 11 of the *Rules*, unless the context requires otherwise.

1.3 Review period

1.3.1 This *allowable revenue application* is for the *review period* 1 July 2013 to 30 June 2016.

1.4 Composition of this allowable revenue application

1.4.1 This *allowable revenue application* comprises this document together with detailed information supporting this *allowable revenue application* in the document titled "Allowable Revenue Information for 1 July 2013 to 30 June 2016".

2 Allowable revenue

2.1 Overview of allowable revenue

2.1.1 The calculation of *System Management's allowable revenue* has been undertaken in accordance with the building block method, as contained in the revenue model.

2.2 Opening capital base value

2.2.1 The table below shows the derivation of the capital base value as at 30 June 2013.

Table 1: Derivation of System Management capital base ($000 real as at 30 June 2013)

Financial year ending:	30 June 2010	30 June 2011	30 June 2012	30 June 2013
Opening capital base value		1,287.9	907.2	7,758.5
plus capital expenditure		825.4	7,552.4	6,868.7
less depreciation		-1,206.1	-701.1	-2,401.1
Closing capital base value	**1,287.9**	**907.2**	**7,758.5**	**12,226.1**

2.2.2 The *capital base* value as at 30 June 2013 reflects a forecast of inflation of 3.0% for the year ending 30 June 2013. To ensure that *System Management* is remunerated only for actual inflation, the opening *capital base* at the commencement of the next *review period* will be adjusted and the *allowable revenue* in the next *review period* will be adjusted as follows:

a) the capital base value at the commencement of the next *review period* will also be adjusted for any difference between the actual inflation (using the *CPI*) and the forecast inflation for the 2012/13 year that was used to establish the opening capital base value at 30 June 2013 (the "**2012/13 inflation forecast error**"); and

b) an adjustment to the *allowable revenue* in the next *review period* will be made to compensate *System Management* (or users) for the revenue foregone (or additional revenue recovered) by *System Management* over this *review period* in respect of the *2012/13 inflation forecast error*.

2.2.3 For the avoidance of doubt:

a) under the arrangements set out in section 2.2.2 of this *allowable revenue application* the *allowable revenue* for this *review period* will not be adjusted for the *2012/13 inflation forecast error*;

b) the intended effect of the arrangements set out in section 2.2.2 of this *allowable revenue application* is to hold *System Management* and users financially neutral in the event that there is a *2012/13 inflation forecast error* by taking account of:

i. the effects of actual inflation; and

ii. the time value of money as reflected by *System Management's weighted average cost of capital* specified in section 2.4 of this *allowable revenue application*

and

c) adjustments made pursuant to section 2.2.2 of this *allowable revenue application* will have the effect of ensuring that the total revenue recovered by *System Management* over this *review period* and subsequent *review periods* will be equivalent in present value terms to the amount that would be recovered if there were no *2012/13 inflation forecast error*.

2.3 Depreciation

2.3.1 The depreciation provision contained in the *allowable revenue* for each year of this *review period* is calculated using:

a) the straight line depreciation method;

b) the existing economic life for assets that comprise the capital base value as at 30 June 2013; and

c) for capital expenditure forecast for this *review period* the economic lives for each group of assets *as* set out in the following table:

Table 2: Asset groupings and economic lives for depreciation purposes

Asset group	Economic Life (years) for depreciation purposes
IT	4 years
SMARTS	4 years

2.3.2 *System Management* is not proposing any accelerated depreciation in this *review period*.

2.3.3 The depreciation of the opening capital base at the commencement of the next *review period* will be determined based on a straight line basis using the forecast capital expenditure over this *review period* and the economic lives detailed in section 2.3.1.

2.4 Weighted average cost of capital

2.4.1 The weighted average cost of capital for *System Management* is 6.66% real post-tax.

2.5 Allowable revenue for system operation services

2.5.1 The *allowable revenue* for system operation services for each financial year t, adjusted for the revenue correction factor and the expenditure correction factors, is determined by the annual aggregate revenue (AAR_t) for *System Management* as described in sections 2.5.5 to 2.5.12.

2.5.2 The operation of the revenue correction factor, K_t, as described in sections 2.5.6 and 2.5.7 of this *allowable revenue application* will ensure that the AAR in financial year t is adjusted for any shortfall or over-recovery of actual revenue compared to the AAR in preceding years.

2.5.3 For the purposes of this *allowable revenue application, System Management's* actual revenue in financial year t is revenue earned via s*ystem operation fees* in relation to the provision of system operation services in financial year t.

2.5.4 The operation of the expenditure correction factors, C_t and O_t, as described in sections 2.5.8 and 2.5.11 of this *allowable revenue application* will ensure that the differences between forecast and actual expenditures are reflected in the AAR for *System Management* as required by section 2.23.7 of the *Rules*.

2.5.5 For this *review period*, the annual aggregate revenue AAR_t is determined as follows:

$$AAR_t = AR_t + K_t + C_t + O_t$$

where:

AR_t is the dollar amount for the financial year t calculated from the dollar amounts (expressed in 30 June 2013 prices) set out in the table below.

Table 3: System operation services revenues to be used for calculating ARt ($000 real as at 30 June 2013)

Financial year ending:	30 June 2014	30 June 2015	30 June 2016
AR_t	11,880.2	14,182.7	16,960.8

K_t is the revenue correction factor (expressed in 30 June 2013 prices) calculated in accordance with sections 2.5.6 and 2.5.7 of this *allowable revenue application*.

C_t is the capital expenditure correction factor (expressed in 30 June 2013 prices) calculated in accordance with sections 2.5.8 and 2.5.9 of this *allowable revenue application*.

O_t is the operating cost correction factor (expressed in 30 June 2013 prices) calculated in accordance with sections 2.5.8 and 2.5.9 of this *allowable revenue application*.

For the purpose of calculating AAR_t in nominal terms in each financial year CPI adjustments will be effected by using published *CPI* data relating to the most recent December quarter compared to the December quarter in the previous year.

2.5.6 For financial years ending on 30 June 2014 to 30 June 2016:

$$K_{2013/14} = 0$$

$$K_{2014/15} = (FR_{2012/13} - R_{2012/13}) * (1+WACC_{\text{post-tax real}})^2 + (AAR_{2013/14} - FR_{2013/14}) * (1+WACC_{\text{post-tax real}})$$

$$K_{2015/16} = (FR_{2013/14} - R_{2013/14}) * (1+WACC_{\text{post-tax real}})^2 + (AAR_{2014/15} - FR_{2014/15}) * (1+WACC_{\text{post-tax real}})$$

where:

$\mathbf{FR_{2012/13}}$ is $9,766,970 (real as at 30 June 2013)

$\mathbf{FR_t}$ is the forecast revenue for *System Management* in the financial year t as calculated in the financial year t-2.

$\mathbf{R_t}$ is the actual revenue for *System Management* in the financial year t as defined in accordance with section 2.5.3 of this *allowable revenue application*.

$\mathbf{AAR_t}$ is the annual aggregate revenue for *System Management* in the financial year t.

$\mathbf{FR_t}$ is the forecast revenue for *System Management* in the financial year t.

$\mathbf{WACC_{post\text{-}tax\ real}}$ is the *weighted average cost of capital* as detailed in section 2.4.1 of this *allowable revenue application*.

2.5.7 The revenue correction factor, K_t, will also apply:

a) in the first year of the next *review period* to adjust for any difference between annual aggregate revenue and forecast revenue, in relation to the financial year ending on 30 June 2016 and for any difference between forecast revenue and actual revenue, in relation to the financial year ending on 30 June 2015; and

b) in the second year of the next *review period* to adjust for any difference between forecast revenue and actual revenue, in relation to the financial year ending on 30 June 2016.

2.5.8 For financial years ending on 30 June 2014 to 30 June 2016:

$$C_{2013/14} = 0$$

$$C_{2014/15} = (AC_{2012/13} - FC_{2012/13}) * WACC_{post\text{-}tax\ real} * (1+WACC_{post\text{-}tax\ real}) + (AC_{2012/13} - FC_{2012/13}) * WACC_{post\text{-}tax\ real} + (FC_{2013/14} - CE_{2013/14}) * WACC_{post\text{-}tax\ real}$$

$$C_{2015/16} = (AC_{2013/14} - FC_{2013/14}) * WACC_{post\text{-}tax\ real} * (1+WACC_{post\text{-}tax\ real}) + (AC_{2012/13} - FC_{2012/13}) * WACC_{post\text{-}tax\ real} + (AC_{2013/14} - CE_{2013/14}) * WACC_{post\text{-}tax\ real} + (AC_{2014/15} - CE_{2014/15}) * WACC_{post\text{-}tax\ real}$$

where:

$\mathbf{FC_{2012/13}}$ is $6,868,699 (real as at 30 June 2013)

$\mathbf{FC_t}$ is the forecast capital expenditure for *System Management* in the financial year t as calculated in the financial year t.

$\mathbf{CE_t}$ is the dollar amount for the financial year t calculated from the dollar amounts (expressed in 30 June 2013 prices) set out in the table below.

Table 4: System management capital expenditure to be used for calculating CEt ($000 real as at 30 June 2013)

Financial year ending:	30 June 2014	30 June 2015	30 June 2016
CE_t	2,426.9	1,768.9	1,074.8

$\mathbf{AC_t}$ is the actual capital expenditure for *System Management* in the financial year t.

$WACC_{post\text{-}tax\ real}$ is the *weighted average cost of capital* as detailed in section 2.4.1 of this *allowable revenue application*.

2.5.9 The capital expenditure correction factor, C_t, will also apply

a) in the first year of the next *review period* to adjust for any difference in the return on building block component due to differences between $CE_{2015/16}$ and forecast capital expenditure, in relation to the financial year ending on 30 June 2016 and for any difference in the return on building block component due to differences between forecast capital expenditure and actual capital expenditure, in relation to the financial year ending on 30 June 2015; and

b) in the second year of the next review period to adjust for any difference in the return on building block component due to differences between forecast capital expenditure and actual capital expenditure, in relation to the financial year ending on 30 June 2016

2.5.10 For financial years ending on 30 June 2014 to 30 June 2016:

$$O_{2013/14} = 0$$

$$O_{2014/15} = (AO_{2012/13} - FO_{2012/13}) * (1 + WACC_{post\text{-}tax\ real})^2 + (FO_{2013/14} - OE_{2013/14}) * (1 + WACC_{post\text{-}tax\ real})$$

$$O_{2015/16} = (AO_{2013/14} - FO_{2013/14}) * (1 + WACC_{post\text{-}tax\ real})^2 + (FO_{2014/15} - OE_{2014/15}) * (1 + WACC_{post\text{-}tax\ real})$$

where:

$FO_{2012/13}$ is $8,349,671 (real as at 30 June 2013)

FO_t is the forecast operating expenditure for *System Management* in the financial year t as calculated in the financial year t.

OE_t is the dollar amount for the financial year t calculated from the dollar amounts (expressed in 30 June 2013 prices) set out in the table below.

Table 5: System management operating expenditure to be used for calculating OEt ($000 real as at 30 June 2013)

Financial year ending:	30 June 2014	30 June 2015	30 June 2016
OE_t	8,269.6	8,609.3	8,669.8

AO_t is the actual operating expenditure for *System Management* in the financial year t.

$WACC_{post\text{-}tax\ real}$ is the *weighted average cost of capital* as detailed in section 2.4.1 of this *allowable revenue application*.

2.5.11 The cost correction factor, O_t, will also apply:

a) in the first year of the next *review period* to adjust for any difference between $OE_{2015/16}$ and forecast operating expenditure, in relation to the financial year ending on 30 June 2016 and for any difference between forecast operating expenditure and actual operating expenditure, in relation to the financial year ending on 30 June 2015; and

b) in the second year of the next *review period* to adjust for any difference between forecast operating expenditure and actual operating expenditure, in relation to the financial year ending on 30 June 2016.

2.5.12 The intended effect of the arrangements set out in sections 2.5.6 to 2.5.11 of this allowable revenue application is to hold System Management and users financially neutral for any differences between forecasts and actuals, as required by section 2.23.7 of the *Rules,* by taking account of:

a) the effects of actual inflation; and

b) the time value of money as reflected by System Management's weighted average cost of capital specified in section 2.4 of this allowable revenue application

3 Forecast Capital Expenditure

3.1.1 The *forecast capital expenditure* for system operation services for this *review period* (expressed in 30 June 2013 prices) is set out in the table below.

Table 6: Forecast capital expenditure for system operation services ($000 real as at 30 June 2013)

Financial year ending:	30 June 2014	30 June 2015	30 June 2016
Forecast capital expenditure	2,426.9	1,768.9	1,074.8

4 Annual budget proposal

4.1.1 Pursuant to section 2.23.5 of the *Rules*, by 30 April each year *System Management* will provide a copy of the budget proposal for the next financial year, as described in section 4.1.2, to the *IMO*.

4.1.2 The content of the budget proposal will include:

a) the calculation of the allowable revenue for system operation services for the next financial year as specified in section 2.5 this *allowable revenue application;*

b) information supporting how *System Management* derived the elements of the calculation of the allowable revenue for system operation services; and

c) a revised forecast of the capital expenditure for system operation services for the next financial year.

5 Allowable revenue reassessment

5.1.1 Pursuant to sections 2.23.8 and 2.23.8A of the *Rules*, *System Management* will apply to the *Economic Regulation Authority* to reassess the *allowable revenue* in the circumstances where:

For financial year ending on 30 June 2014:

$$1.15 \times \sum_{t=2013/14}^{2015/16} AR_t < AAR_{2013/14} + AR_{2014/15} + AR_{2015/16}$$

For financial year ending on 30 June 2015:

$$1.15 \times \sum_{t=2013/14}^{2015/16} AR_t < FR_{2013/14} + AAR_{2014/15} + AR_{2015/16}$$

For financial year ending on 30 June 2016:

$$1.15 \times \sum_{t=2013/14}^{2015/16} AR_t < R_{2013/14} + FR_{2014/15} + AAR_{2015/16}$$

where:

AR_t is the dollar amount for the financial year t calculated from the dollar amounts set out in Table 3 (expressed in 30 June 2013 prices).

AAR_t is the dollar amount for the financial year t calculated in accordance with section 2.5.5 of this *allowable revenue application* (expressed in 30 June 2013 prices).

FR_t is the forecast revenue for *System Management* in the financial year t (expressed in 30 June 2013 prices).

R_t is the actual revenue for *System Management* in the financial year t as defined in accordance with section 2.5.3 of this *allowable revenue application* (expressed in 30 June 2013 prices).

Allowable Revenue Information for 1 July 2013 to 30 June 2016

November 2012

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Executive Summary

This document outlines System Management (Markets)'s allowable revenue proposal for the third allowable revenue period (known as AR3), which covers 1 July 2013 to 30 June 2016. It provides the context, rationale and justification for System Management (Markets)'s allowable revenue proposal, and should be read in conjunction with the associated Allowable Revenue document, which provides summary financial information.

System Management (Markets) is the ringfenced business entity within Western Power. It is responsible for the provision of system operation services under Part 9 of the *Electricity Industry Act 2004,* which established the Wholesale Electricity Market (WEM).

System Management (Markets)'s primary responsibilities are to:

1. **support the secure and reliable operation of the South West Interconnected System (SWIS).** This requires System Management (Markets) to ensure that electricity demand and supply are in balance for every minute of every day of the year
2. **support the operation of the WEM.** System Management (Markets) must comply with its obligations within the Market Rules. These obligations encompass System Management (Markets)'s role in forecasting demand, dispatching supply through the market participants that generate electricity and receive payment through the market, and providing information to the Independent Market Operator (IMO)

The AR2 period (1 July 2010 to 30 June 2013) saw a significant change in the way System Management (Markets) fulfils these responsibilities. In December 2010, the Independent Market Operator (IMO), as part of the Market Evolution Program (MEP), announced the introduction of the Competitive Balancing[1] and Load Following[2] (CBLF) market in Western Australia.

The purpose of the CBLF market is to increase competition in the WEM by allowing market participants to bid for generation dispatch in near-real time and allow participants other than Verve Energy to provide balancing and load following services.

The objectives of the new market are to:

- enable utilisation of lower cost generation plant instead of only Verve for adjusting the generation to the actual load
- allow independent Power Producers (IPPs) to change bidding behaviour (i.e. reducing price offers) due to the availability of closer to real-time information
- enable lower market prices due to the ability to return lower cost IPPs from outage during a trading day
- avoid cycling of plant and thereby reducing maintenance and life expectancy costs on generation plant and reducing plant failure risk
- enable IPPs to smooth out infeasible[3] dispatch schedules thus reducing plant wear and system frequency excursions

The Market Rule change that gave effect to the new markets was implemented in March 2012, with the new market commencing on 1 July 2012.

[1] Balancing refers to the movement of balancing generators to follow the forecast system load trend, forecast changes in output trend of intermittent generators (e.g. windfarm output).

[2] Load following (or frequency keeping) is the ancillary service whereby assigned generators constantly change their output to compensate for random changes in system load, fluctuations in intermittent generation output, and unscheduled movements of scheduled generators and thus has the effect of regulating system frequency.

[3] The previous one shot, day in advance market often produced resource plans with large step changes. A resource plan outlines the MWHr output for each IPP facility for each trading interval in the market trading day.

To make the CBLF market a reality, System Management (Markets) was required to make substantial changes to its operations and the technology that underpins them. The IT systems and manual processes that had been in place since Western Power's disaggregation in 2006 could not support real-time bidding and competitive balancing. Therefore System Management (Markets), in consultation with the IMO, the ERA and market participants, scoped and implemented a new IT system called SMARTS (System Management Automated Real Time Systems).

SMARTS is an IT-based tool, specially designed to facilitate real-time balancing in the Wholesale Energy Market. The new system is significantly more complex than that used previously[4] as it is designed to fulfil the considerable increase in System Management (Markets)'s requirements that has resulted from the CBLF market. Table 1 summarises the key impacts to System Management (Markets)'s operations.

Table 1: Increase in System Management (Markets)'s operations arising from the introduction of the CBLF market

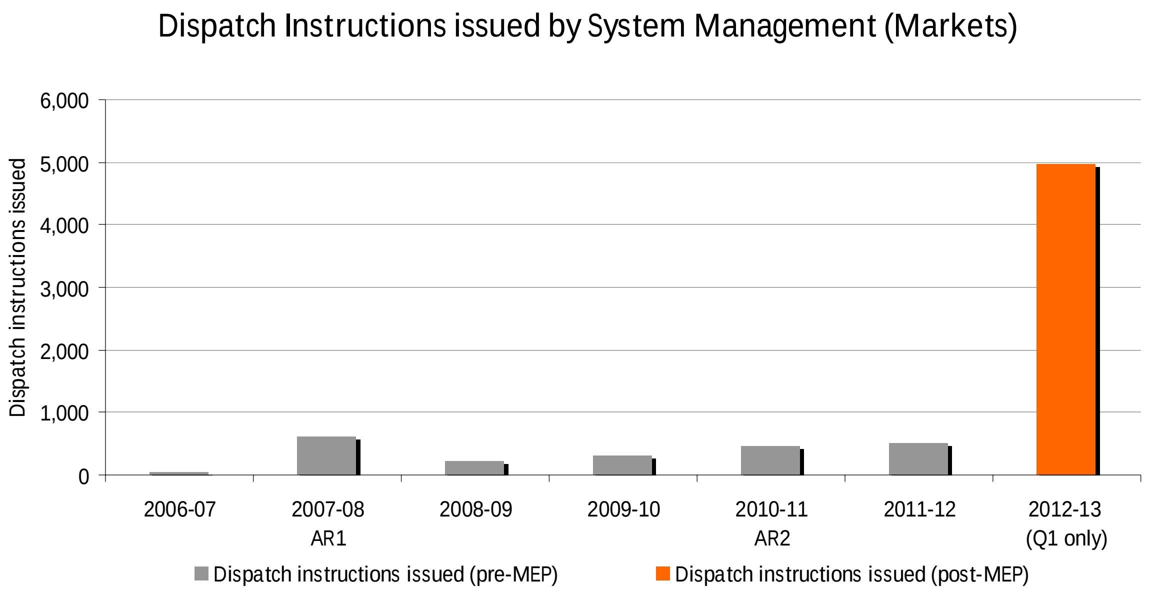
Impact area	Operations pre-CBLF	Operations post-CBLF
Rule Obligations	57 obligations	74 obligations[5]
Forecasting	2 forecasts issued daily (day ahead).	48 forecasts issued daily (5 minutes to a day ahead).
Planning & Scheduling	Market closure = 22 Hours. 18.5 - 42.5 hour time horizon. Once per day: • receive resource plan data • review load forecast • create Verve Energy dispatch plan and gas nomination	Balancing gate closure[6] = 2 hours. 2 – 42.5 hour time horizon. Pre dispatch security assessment. Ex-ante dispatch advisories[7] on constraint. 48 times per day: • receive resource plan data • review load forecast • create Verve Energy dispatch plan and gas nomination • receive updated balancing merit order[8] Once per day: • Full pre-dispatch plan for all facilities
Dispatch Instructions/ Dispatch Advisories	37 dispatch instructions per month by phone. 8 dispatch advisories per month (ex-post).	1,600 dispatch instructions per month. 15 dispatch advisories per month (ex-ante and real time).
Dispatch	• Controller, supported by comparative historic (similar day) forecast and SCADA system data.	• Creation and support of automated dispatch systems. Controller monitors and intervenes as necessary.

[4] The System Management Markets Information Technology System.
[5] Western Power maintains a legislative obligations register. Obligations in the register are typically defined from several individual Market Rules.
[6] For the purposes of this submission a balancing gate closure is the point in time immediately before the commencement of a trading interval before which a market participant must ensure they have made their balancing submission.
[7] For the purposes of this submission an ex-ante dispatch advisory is a communication issued by System Management (Markets) advising that an event has occurred (or is likely to occur) that will require dispatch of facilities out of merit.
[8] For the purposes of this submission a balancing merit order is the ordered list of balancing facilities and associated quantities determined by the IMO from the balancing submissions for each market participant's balancing facilities.

Impact area	Operations pre-CBLF	Operations post-CBLF
	• Manage non-scheduled generation, forced outages and commissioning test manually • Dispatch Verve Energy plant to plan • Manually monitor compliance to resource plan[9] • Issue dispatch instructions to independent power producer as required • Control of Verve Energy via automatic generator control load following ancillary service	• Mixed manual/auto management of real time operations • Continuous security assessment • Issue dispatch advisories in real time on forced outage • All balancing facilities dispatched automatically • Automated monitoring of dispatch compliance • Commission automated balancing control availability for most facilities • Commission automatic generation control for all load following ancillary service providers
Systems	Predominantly stand alone systems maintained and supported at branch level by subject matter experts	Integrated business systems supported centrally under full change control with full offsite disaster recovery facilities
Support rosters	Weekday coverage 7am – 4pm and 3 hours/day on weekends	7 day coverage 6am-8pm

SMARTS is being released in three stages, the first of which occurred in July 2012. Stage one sees SMARTS supporting the transition from the day-ahead to the new real-time CBLF market. Further releases are scheduled for December 2012 and mid 2013, by which time the new system will fully support the requirements of the CBLF market. These further releases are targeted for System Management (Markets)'s compliance with the Market Rules.

Since the start of the CBLF market System Management (Markets) has experienced a significant increase in the number of dispatch instructions issued. From an average of 36 a month prior to CBLF, dispatch instructions now average more than 1,600 a month. Figure 1 shows the total dispatch instructions issued by financial year, and the first quarter of 2012/13.



[9] For the purpose of this submission the resource plan data is a schedule for all facilities of the output of its facilities in MWh and other data for each trading interval in the trading day.

Figure 1: Total Dispatch Instructions Issued

Capital expenditure on the SMARTS system during AR2 is forecast to be $13.352 million. Due to the timing of the CBLF announcement by the IMO, SMARTS expenditure was not forecast in the November 2009 allowable revenue submission for the AR2 period and therefore not provided for in the allowable revenue.

Western Power's Board agreed that the SMARTS investment would be funded by Western Power, with System Management (Markets) repaying these funds, plus financing charges, over the four year capital asset amortisation period. Consistent with section 2.23.12 of the Market Rules, System Management (Markets) proposes capital expenditure on the SMARTS investment is recovered through the depreciation and amortisation of the assets during the AR3 period. This will enable System Management to repay the SMARTS funding and ensure that market participants will pay for the SMARTS investment rather than Western Power's network connected customers.

System Management (Markets) expects SMARTS will provide the platform for further business system improvements during the AR3 period to support the CBLF market and other obligations arising from the Market Evolution Program.

As a result, the recovery of SMARTS expenditure during AR2 and the proposed expenditure to further support the CBLF market during AR3 forms the largest component of the allowable revenue increase required during the AR3 period.

Investment proposal

System Management (Markets) has four investment objectives over AR3:

- **meeting market stakeholder requirements for performance and value** – to meet market objectives while investing efficiently during AR3 so that the services required by market stakeholders are provided at the lowest cost
- **compliance** – to invest efficiently to enable System Management (Markets) and market stakeholders to achieve compliance with the Market Rules and operating procedures
- **supporting market enhancements** – to invest efficiently to support changes to the Market Rules and act as a partner in the development of the market
- **improving process efficiency** – to invest efficiently to improve processes and systems that will lead to a lower cost of service for market participants over time

During AR3 System Management (Markets) will:

1. **consolidate support for the Market Evolution Program** – by ensuring System Management (Markets) has adequate staff to service the increased market trading hours and transactions and enhancing SMARTS to provide greater security and reliability
2. **improve specific systems and processes** - through targeted initiatives aimed at improving governance, and improving efficiencies and risks in key information systems
3. **support the development of the Market** – by being responsive to further enhancements planned by the IMO for the AR3 period
4. **continue to provide efficient system operation services** – in compliance with the Market Rules

The total investment required to deliver these objectives is $25.549 million operating expenditure and $5.271 million capital expenditure.

The following sections outline why this investment is required, and provide a breakdown of cost components.

Consolidating support for the Market Evolution Program

During AR3, System Management (Markets) will spend $3.723 million in operating costs and invest $0.821 million of capital to enable System Management (Markets) to effectively support the new CBLF market and the operation of SMARTS. The investment is required to ensure System Management (Markets) is compliant with Market Rules at the lowest practicably sustainable cost.

The Market Evolution Program has added complexity to System Management (Markets)'s operations by:

- significantly increasing the volume of transactions
- increasing monitoring requirements
- increasing obligations

System Management (Markets) has implemented a level of automation within SMARTS, and balanced this with a need for some labour increases in order to:

- monitor the additional transactions associated with a 30-minute, rather than day-ahead market
- extend System Management (Markets)'s hours of operation to meet market requirements
- enable an appropriate level of operator oversight, particularly where systems support complex decision-making within short timeframes

Initial increases in staffing will be offset by a reduction as the CBLF market moves from a transition stage to full production. Staffing requirements for the support of IT systems will be rationalised, and a number of contractor positions converted to permanent employees.

Operating expenditure for supporting the Market Evolution Program comprises:

- **$1.213 million** – to provide adequate staff to support the increased trading hours and higher numbers of transactions
- **$0.727 million** – to ensure SMARTS has sufficient technical support
- **$1.783 million** - for the maintenance of SMARTS infrastructure and software licences

Capital expenditure for supporting the Market Evolution Program comprises:

- **$0.480 million** for undertaking a security assessment of SMARTS and establishing an enhanced test environment. This will improve the robustness and reliability of SMARTS and help ensure that System Management (Markets) is adequately positioned to implement further developments in this system as changes occur to the Market Rules
- **$0.341 million** to enhance the interface which provides data to the IMO on a regular basis. This will provide a greater assurance that the information provided by System Management (Markets) is accurate and reliable and will provide a better service for participants by enabling any errors to be more effectively identified and resolved

These investments will benefit market participants by ensuring System Management (Markets) has adequate resources to support the CBLF market and achieve its Market obligations. It will also ensure the information systems that support these markets function reliably and securely.

Improved systems and processes

During AR3, System Management (Markets) will spend $3.351 million in operating costs and invest $2.325 million of capital to enable it to maintain and improve its governance procedures, address inefficiencies and risks in key information systems, and provide for shared costs.

System Management (Markets) will further invest in information systems and processes by migrating some disparate applications to the SMARTS environment. Rather than a wholesale upgrade of System Management (Markets)'s IT environment, these investments will target:

- current processes which are not fully compliant with the WEM
- systems requiring a high level of manual intervention, which are likely to significantly impair System Management (Markets) ability to support the developments planned for the market by the IMO

Operating expenditure for improving System Management (Markets)'s systems and processes comprises the following:

- **$2.919 million** – in business support costs for services provided by the broader Western Power business to System Management (Markets), which were excluded from Western Power's AA3 submission. System Management (Markets) continues to derive efficiencies by operating as a ringfenced business entity within Western Power. The allocation of these costs will ensure that they are incurred by market participants rather than Western Power's network connected customers.
- **$0.432 million** – to provide support for System Management (Markets)'s delivery program by engaging a program manager and cost controller. The cost for the program manager role will be split 50% to operational expenditure (focusing on the development of estimates and business cases for market rule changes) and 50% to capital expenditure (to support project managers and the implementation of project governance on capital projects). An allowance for project managers' time has been incorporated in the costs for each capital project.

Capital expenditure for IT systems comprises the following:

- **$0.316 million** – to implement a lodgement and approval system for market facility commissioning plans[10]. This will replace the largely manual process that has existed since the market commenced in 2006. The new lodgement and approval system will reduce inefficiencies and decrease the risk of errors in the process, particularly where participants lodge late changes to commissioning plans.

  This initiative will benefit market participants by enabling System Management (Markets) to process commissioning plans more reliably. It will also reduce the risk of confusion about whether a planned outage has been approved for commissioning to avoid an unnecessary forced outage[11]. Commissioning data will also be more readily available to participants.
- **$0.658 million** – to modify System Management (Markets)'s customer portal. This will enable participants to manage their own user logins and to view, validate, report and download transacted data between themselves and System Management (Markets).

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[10] In the context of this submission, a commissioning test plan defines the commissioning test requirements for a generator (either new, or having undergone significant maintenance) to prove its ability to operate at different levels of output and reliability. Commissioning test plans need to be agreed between System Management (Markets) and a market participant prior to commissioning.

[11] A forced outage is an outage of a facility or item of equipment on the list of equipment subject to outage planning that was not approved by System Management (Markets). Refer Clause 3.21.1 of the Market Rules.

This will also benefit participants by removing the delays which occur through the current manual process conducted by System Management (Markets).

- **$0.506 million** – for a joint initiative with the IMO to improve the technology used to exchange data between System Management (Markets) and the IMO. This will address reliability issues experienced with the current technology, and help ensure that data are provided within the required timeframes.
- **$0.376 million** – for disaster recovery measures to enable the Market to continue to function in the event of the East Perth Control Centre being unavailable.
- **$0.469 million** – in capitalised costs to provide support for System Management (Markets)'s delivery program (as noted under operational expenditure above).

Undertaking these investments will ensure the growing volume of data transactions will no longer be managed by manual processes, reducing the risk of human error and inaccurate data transmission. Appointing a program manager for the delivery of these investments will provide sufficient oversight and governance to help ensure project execution is within scope and in budget.

Supporting market development

During AR3, System Management (Markets) expects to invest $2.125 million of capital to support the enhancements planned for the market.

In its forthcoming Market Rules Evolution Plan 2013-2016[12] the IMO has identified a number of potential market enhancements, which it is seeking to implement over the AR3 period. At time of writing the details of the IMO's plan have not yet been crystallised, with the scope of initiatives available at a high level only.

Outcomes of the Market Rules Evolution Plan 2013-16 will almost certainly require System Management (Markets) to make changes to processes and systems during the AR3 period to maintain compliance with the Market Rules. System Management (Markets) proposes that the allowable revenue includes an amount to cover the potential costs associated with Market Rules changes.

Table 2 provides a summary of System Management (Markets)'s preliminary assessment of each proposed rule change and the associated costs. Estimates are based on a +/-50% confidence level.

Table 2: Cost estimate for rule changes identified in the Market Rules Evolution Plan ($000 real at 30 June 2013)

Proposed Initiative	Key Impacts	Cost estimate ($000 real +/-50%)		
		Low case (-50%)	High case (+50%)	Most likely
Outage Management Phase 1 (Information Transparency)	New systems to automate manual processes, new data interfaces and additional resources to manage data transparency and quality.	372	1,115	743
Outage Management Phase 2 (IMO Initiated Process Initiatives)	Changes to improve efficiency and effectiveness of existing business processes and systems.	245	734	489

[12] The Market Rules Evolution Plan is the IMO's plan to continue development of the market to the next stages beyond those of the Market Evolution Plan.

Proposed Initiative	Key Impacts	Cost estimate ($000 real +/-50%)		
		Low case (-50%)	High case (+50%)	Most likely
Improvements to Balancing	Changes to a number of processes and at least 3 existing systems.	46	139	93
30 Minute Gate Closure	Change from 120 minute ahead to 30 minute market gate closure requiring changes to timing of automated system security and monitoring applications and integration of these with dispatch processes.	80	239	159
Emissions Intensity Index	Changes to SCADA configurations and additional data interfaces.	32	95	63
Spinning Reserve Market	New systems to support a new component in the ancillary service market	288	865	577
Total		**1,062**	**3,187**	**2,125**

System Management (Markets) proposes that $2.125 million is included in the allowable revenue to account for these potential market changes. System Management (Markets) explored the option of not including these costs in the allowable revenue proposal and utilising the decared market project mechanism to provide for the expenditure.

However, though the costs for these proposed intitiatives are not yet certain, the IMO and market participants have indicated that they expect these projects to be delivered during the AR3 period. System Management (Markets) therefore considers it would be more efficient and desirable for market participants if an amount is included in the allowable revenue to enable these projects to commence. Using the declared market project approach may delay these projects unneccessarily and result in the initiatives not being delivered within the required time frames. System Management (Markets) has only included projects which are justifiable, achievable and determined from engagement with the IMO and market participants.

The revenue impact of including this $2.125 million investment in the submission is $0.621 million. This will impact market fees by 0.8%.

During the AR3 period System Management (Markets) will undertake a substantially more detailed determination of the scope of the rule changes. This will include an assessment of how it will meet these obligations and the development of final cost estimates once the scope for each rule change is finalised by the IMO. Any variation from the allocated amount will be adjusted through the in-period budget mechanism and if the changes exceed the revenue allowance then alternative approvals will be sought.

Provision of system operation services

System Management (Markets) will continue to provide ‘business as usual’ system operation services as required by the Market Rules. System Management (Markets) will require operating expenditure of $18.474 million to provide these services during the AR3 period.

What it will cost

System Management (Markets)'s required revenue for the period is $43.024 million. This is an 80%[13] increase compared with AR2.

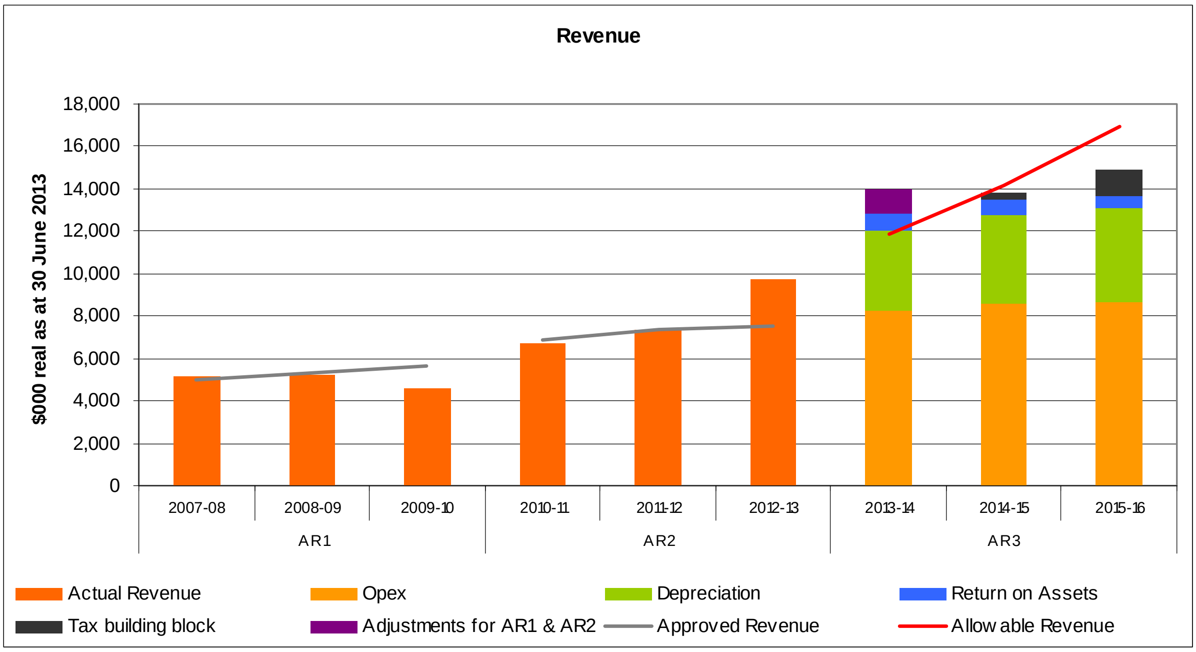

Figure 2: Required revenue for AR3

The key driver for this revenue increase is the recovery of costs associated with the implementation of SMARTS and the ongoing investment required to support the CBLF market during the period. Figure 3 shows the components that make up the AR3 allowable revenue. During AR3, $14.926 million of revenue is associated with supporting the CBLF market, including the recovery of SMARTS expenditure incurred during 2011/12 and 2012/13. This is represented by the 'Supporting MEP' bar on the waterfall chart below (Figure 3).

This chart shows that the core revenue components that comprise the AR3 revenue base are similar to those incurred during the AR2 period. The increase in revenue above the AR2 levels is mainly driven by the addition of the 'Supporting MEP', 'WACC' and 'Business Support' components, which are largely required as a result of the SMARTS investment and allocation of shared costs during AR3.

[13] This percentage increase is based on the estimate for the year to 30 June 2013.

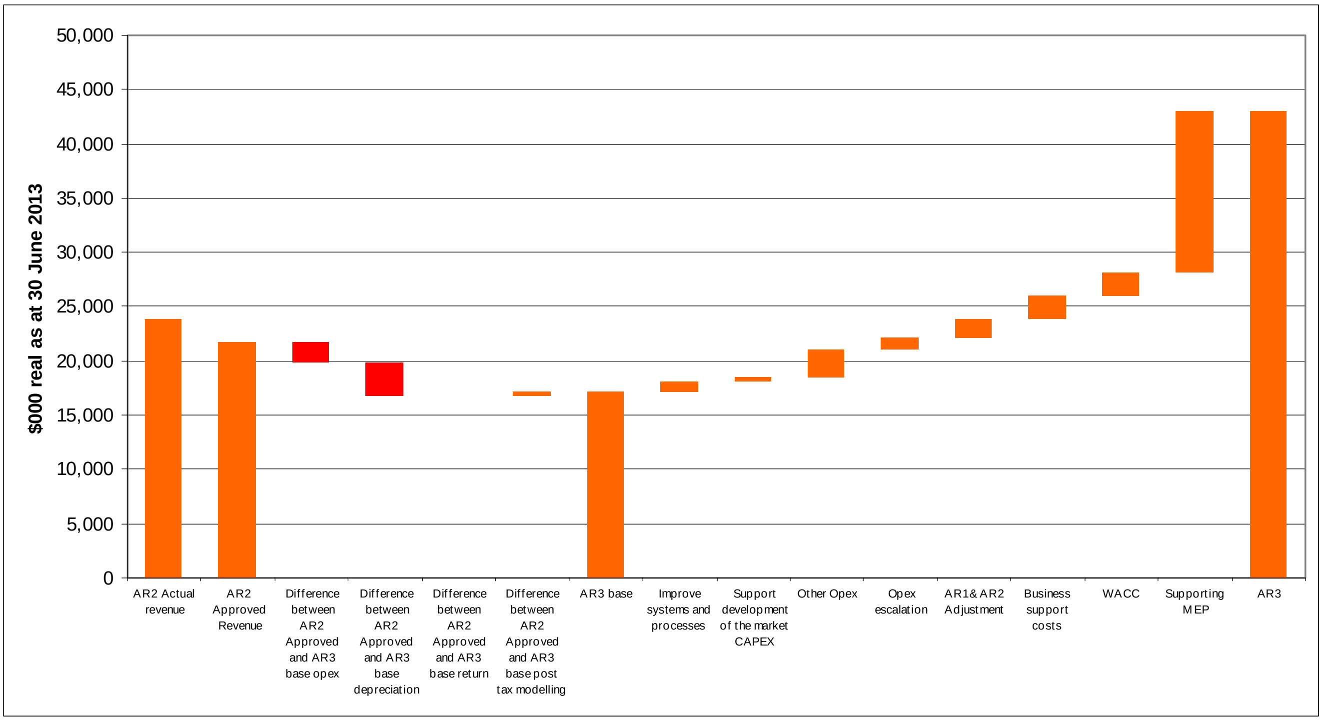

Figure 3: Revenue components for AR3 allowable revenue

Forecast operating expenditure

System Management (Markets) will require operating expenditure of $25.549 million for the AR3 period.

This is a 27% increase on the forecast expenditure at the end of the AR2 period ($20.082 million) and around 42% higher than allowed to System Management (Markets) in its AR2 submission ($17.984 million). This step change in operating costs is primarily due to the increased costs of operating the new CBLF market.

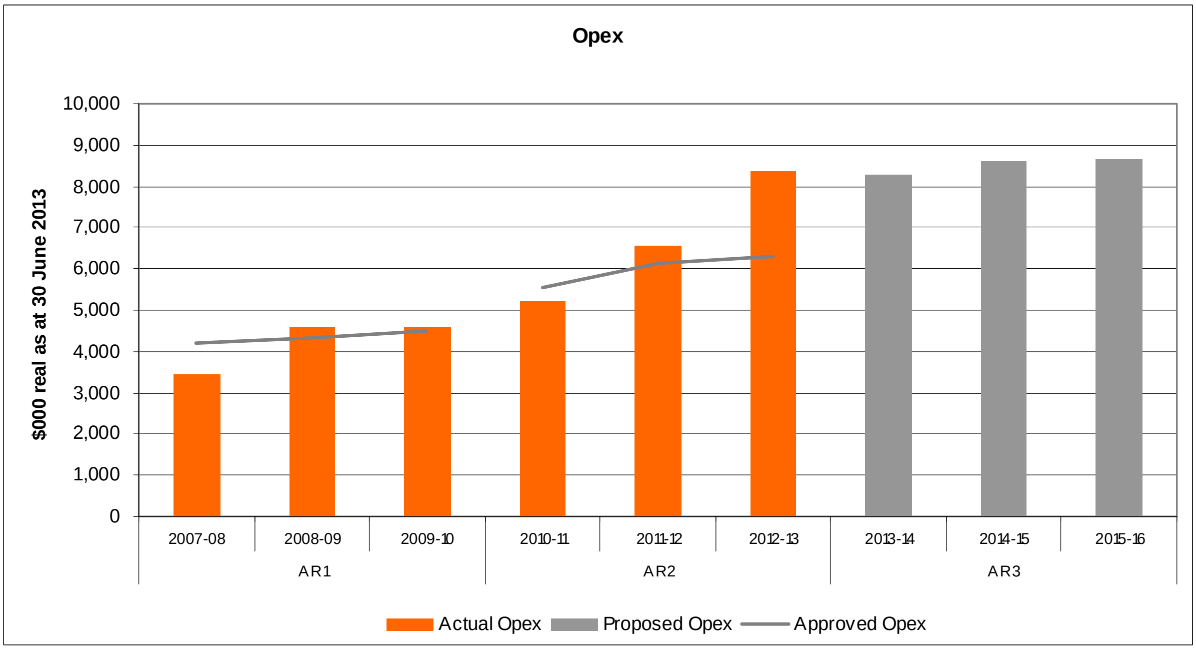

Figure 4: Forecast Operating Expenditure for AR3

Forecast capital expenditure

System Management (Markets) will require capital expenditure of $5.271 million for the AR3 period. This is 56% more than that approved for the AR2 period.

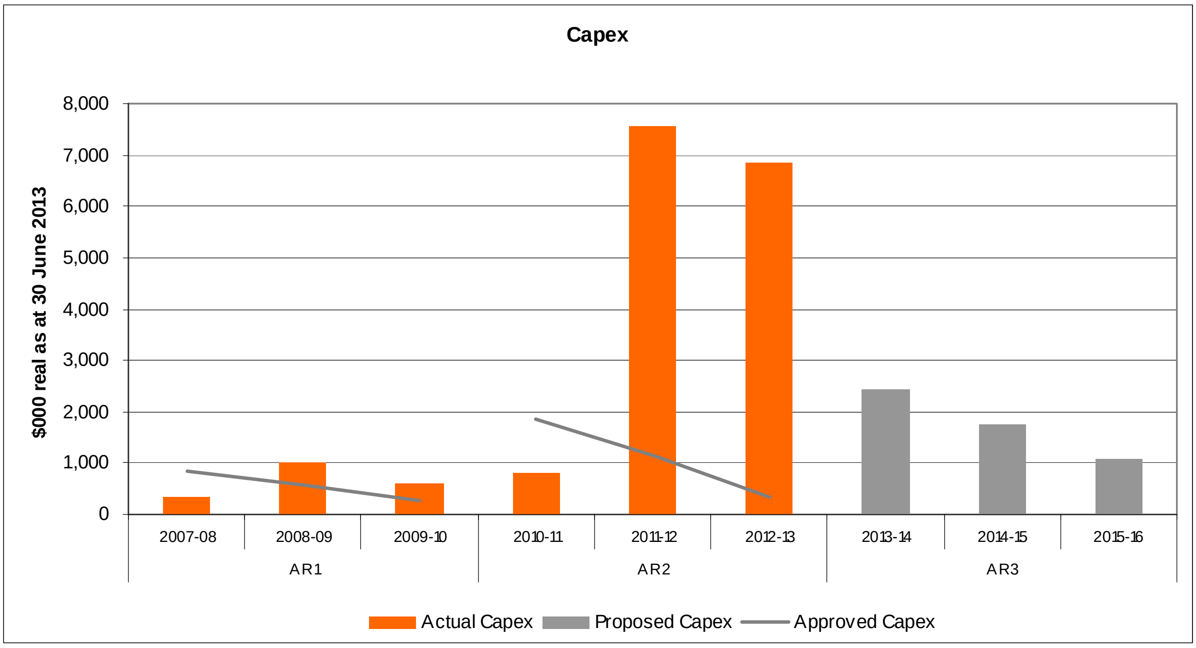

Figure 5: Forecast Capital Expenditure for AR3

Return on investment

The rate of return on investment is a critical determinant of System Management (Markets)'s revenue. The rate of return is applied to the projected capital base at the beginning of each year for the purpose of determining the return on the projected capital base. An appropriate weighted average cost of capital (WACC) ensures that the cost of capital required to provide regulated services is recovered.

To assist in the estimation of the return on investment, System Management (Markets) sought expert advice from KPMG. KPMG considered that the application of a WACC is consistent with the Market Rules and noted that a WACC is applied by the broader Western Power business. Therefore, a WACC of 6.66% real post-tax has been applied to System Management (Markets) capital base in accordance with expert advice provided by KPMG.

Market fees

System Management (Markets) has estimated the average price path to be an annual increase of 17.1% + CPI for each year of the AR3 period. This estimate is indicative only. The IMO determines the actual fee rate to be levied in any year based on System Management (Markets)'s annual budget proposal.

Table 3 details the forecast nominal fee rate and forecast % change.

Table 3: Forecast System Management (Markets) fee rate ($/MWh Nominal)

	2012/13	2013/14	2014/15	2015/16
Forecast fee rate	0.276	0.331	0.397	0.477
% change		20%	20%	20%

The actual fee rate levied in AR3 may differ from this estimate due to:

- revised sent-out energy forecasts in future Statement of Opportunities
- adjustments to the allowable revenue due to differences in operating and capital expenditure and actual revenue earned by System Management (Markets); and
- actual inflation

Conclusion

System Management (Markets)'s allowable revenue for the AR3 period is required to ensure it can continue to support the Market Evolution Program and deliver benefits and support competition to the Wholesale Electricty Market.

The step increase in revenue compared to the AR2 period is predominantly driven by the investment that was required to enable the CBLF market to commence. The investment in SMARTS only included costs that would be incurred by a prudent provider of system operations services and can be recovered in accordance with 2.23.12 of the Market Rules.

The SMARTS IT system is significantly more complex than System Management (Markets)'s previous systems and requires greater maintenance and support overheads. However, it is expected that SMARTS will provide a platform for further system improvements, increased automation and efficiencies over the medium-to-long term.

System Management (Markets) considers that this allowable revenue submission meets the requirements of section 2.23 of the Market Rules and can be approved by the ERA.

PART A: BACKGROUND AND CONTEXT

1 Introduction

This is System Management (Markets)'s third allowable revenue proposal to the Economic Regulation Authority (ERA). The third review period (referred to as AR3) covers the three-year period 1 July 2013 to 30 June 2016. For the purposes of this document, the first two review periods – 1 July 2007 to 30 June 2010 and 1 July 2010 to 30 June 2013 – are referred to as AR1 and AR2 respectively.

This Allowable Revenue Information document provides context, rationale and justification for System Management (Markets)'s allowable revenue proposal and should be read in conjunction with the associated allowable revenue document[14]. Collectively, these two documents comprise System Management (Markets)'s allowable revenue submission to the ERA.

The Wholesale Electricity Market (WEM) rules (the Market Rules) require System Management (Markets) to seek approval for its allowable revenue for each review period from the ERA, by 30 November of the year prior to the start of the review period.

1.1 Submission structure

This document comprises three parts:

- Part A – Background and context. This section includes an overview of System Management (Markets) and challenges for the AR3 period. It provides details of governance, planning and delivery processes, and performance during AR2.
- Part B – Expenditure proposal. This section details and justifies proposed capital and operating expenditure requirements during AR3. It discusses the methodology used to develop the investment proposal for AR3.
- Part C – Revenue. This section details the proposed revenue for AR3. It includes calculation of the value of the capital base, rate of return on investment and depreciation.

The allowable revenue information also includes a range of appendices containing supporting information where relevant.

1.1.1 Explanatory notes

All monetary amounts presented in this document are expressed in real 30 June 2013 dollars and apply to 1 July to 30 June financial years unless otherwise stated. Some tables may not add due to rounding.

[14] *System Management allowable revenue and forecast capital expenditure application*, Western Power, November 2012.

2 Overview of System Management (Markets)

This chapter provides contextual information to explain System Management (Markets)'s business operations. This information is provided as background to later sections of this document.

2.1 System Management (Markets) in the context of Western Power

It is important to differentiate between System Management and System Management (Markets):

- System Management is the division of Western Power that has the function of operating the South West Interconnected System (SWIS) in a secure and reliable manner.
- In the context of this Allowable Revenue proposal System Management (Markets) is the participant referred to as "a system management participant" in Part 9 of the Electricity Industry Act (2004).
- Part 9 of the *Electricity Industry Act (2004)* established the WEM. Western Power's obligations under Part 9 of the Act commenced with the establishment of the WEM on 21 September 2006.
- The **Electricity Industry (Wholesale Electricity Market) Regulations 2004** Part 2 regulation 13 states that the Market Rules are to confer on an entity the function of operating the SWIS in a secure and reliable manner. The entity on which the function mentioned in subregulation (1) is conferred is referred to in the regulations as **System Management.** The function referred to in subregulation (1) is a system management function for the purposes of the definition of “system management participant” in section 126(1) of the Act.
- Clause 2.2.1 of the Market Rules states that Western Power, acting through the segregated business unit known as System Management, has the function of operating the SWIS in a secure and reliable manner for the purposes of regulation 13(1) of the Regulations.
- System Management (Markets) sits within the System Management Division and is responsible under the Market Rules clause 2.23.1(a) for the provision of system operation services under the Wholesale Electricity Market Rules.

System Management (Markets) operates within a ringfence that was established under Chapter 13 of the Electricity Networks Access Code *(2004)* (the “ENAC”). The intention of the ringfence is twofold. Firstly System Management (Markets) must ensure that the broader Western Power business, as owner of the Western Power Network, is treated on an arms-length basis. Secondly, Western Power must ensure that there is appropriate cost allocation between System Management (Markets) and the broader Western Power business.

2.2 System Management (Markets)'s services and responsibilities

System Management (Markets) provides system operation services to the WEM. It has a fundamental role to:

- support the secure and reliable operation of the SWIS
- support the operation of the WEM

System Management (Markets) also works cooperatively with participants to assist them to understand and comply with their compliance responsibilities.

System Management (Markets)'s responsibilities under the Market Rules are[15]:

- operating the SWIS in a secure and reliable manner
- to procure adequate ancillary services where the Electricity Generation Corporation cannot meet the Ancillary Service Requirements
- to assist the Independent Market Operator (IMO) in the processing of applications for participation and for the registration, de-registration and transfer of facilities
- to develop market procedures, and amendments and replacements for them, where required by the Market Rules
- to release information required to be released by the Market Rules
- to monitor rule participants' compliance with Market Rules relating to dispatch, power system security and power system reliability
- to carry out any other functions or responsibilities conferred, and perform any obligations imposed, on it under the Market Rules

To meet these responsibilities, System Management (Markets) is required to provide the following functions:

- recognise transient or designed network constraints in the dispatch of generating facilities
- perform dispatch in accordance with a balancing merit order provided by the IMO
- coordinate and schedule plant outages ensuring that sufficient capacity is available and can be delivered via the SWIS network to meet electricity demand under all but extreme circumstances
- coordinate and manage the process of commissioning new facilities in a manner that is equitable and does not impact unduly on consumers, or other market participants
- maintain computer systems for participants to enter data necessary for its performance of the above services
- create and maintain a list of all equipment across the SWIS which has the potential to impact on a WEM related transfer of electricity
- procure and dispatch a range of services necessary to support stable network operations
- support the reserve capacity mechanism by conducting tests of facilities that receive capacity payments from the market when requested by IMO
- monitor the compliance of WEM participants with the rules and provide reports to the IMO
- receive data from the IMO, and in turn, send a range of real or near real time data back to the IMO
- send supervisory control and data acquisition (SCADA) data to the IMO to allow for the settlement of WEM facilties that do not have revenue quality metering installations

In addition to the above, System Management (Markets) is obliged to create and maintain a range of plans setting out how it will respond to system emergencies such as its response to under frequency events, its procedures to restart the system from a black state and how it

[15] System Management's obligations are detailed in section 2.2 of the Market Rules

will manage islanding and fuel contingencies such as those which have had a major impact on system security over the past few years.

2.3 System Management Non Trading Participant (SMNTP)

System Management (Markets) has two market participant registrations under the Market Rules:

1. **SM** – System Management
2. **SMNTP** – System Management Non Trading Participant

The costs and revenue associated with the System Management Non Trading Participant (SMNTP) are subject to separate approvals processes from the allowable revenue determination process. They are not included within this allowable revenue submission.

However, Western Power's regulatory financial statements include the costs and revenue for SMNTP within the System Management (Markets) category, therefore it is appropriate to include a short discussion of SMNTP here.

SMNTP effectively acts as an intermediary between Simoca and the IMO. Using low frequency initiated load rejection, Simcoa provides a spinning reserve service to the market. System Management (Markets) pays Simcoa for this service and then recovers this cost directly from the IMO through the SMNTP.

The SMNTP costs are approximately $2.5 million per year.

During the AR3 period the costs and revenue associated with Simcoa's load rejection service will continue to be governed outside of the allowable revenue and are not included in this submission.

3 Approach to preparing this submission

This chapter discusses System Management (Markets)'s key considerations when developing this allowable revenue submission. These include compliance with the Market Rules, stakeholder feedback and performance during the AR2 period.

3.1 Market Rules compliance

This allowable revenue submission meets the requirements of Section 2.23 of the Market Rules and aligns with the WEM objectives[16].

For the purpose of this submission, where the Market Rules refer to 'System Management', this should be taken to be referring to System Management (Markets).

3.1.1 Specific guidelines within the Market Rules

The Market Rules provide guidelines on what should be taken into account by the ERA in determining System Management (Markets)'s allowable revenue (clause 2.23.12).

1. the Allowable Revenue must be sufficient to cover the forward looking costs of providing the services described in clause 2.23.1 and performing its functions and obligations under these Market Rules in accordance with the following principles:
   a) recurring expenditure requirements and payments are recovered in the year of the expenditure
   b) capital expenditures are to be recovered through the depreciation and amortisation of the assets acquired by the capital expenditure in a manner that is consistent with generally accepted accounting principles
   c) costs incurred by System Management that are related to market establishment, as designated by the Minister, are to be recovered over a period determined by the Minister from Energy Market Commencement
   d) notwithstanding paragraphs (i), (ii) and (iii), expenditure incurred, and depreciation and amortisation charged, in relation to any Declared Market Project are to be recovered over the period determined for that Declared Market Project.
2. the Allowable Revenue must include only costs which would be incurred by a prudent provider of the services described in clause 2.23.1, acting efficiently, in accordance with good electricity industry practice, seeking to achieve the lowest practicably sustainable cost of delivering the services described in clause 2.23.1 in accordance with these Market Rules, while effectively promoting the Wholesale Market Objectives; and
3. where possible, the Economic Regulation Authority should benchmark the Allowable Revenue against the costs of providing similar services in other jurisdictions.

How these guidelines have been addressed

1. System Management (Markets) is applying the building blocks method in AR3, consistent with section 2.23.12(a) of the Market Rules, as recurring expenditure costs and depreciation form part of the revenue calculation. The buildings block method is detailed in Section 8.

[16] The WEM objectives are provided in Appendix A.

Although the Market Rules are not as prescriptive as either the Electricity Networks Access Code or Guidelines for Access Arrangement Information[17] in their requirements for the content of the relevant regulatory submissions, the principles of section 2.23.12(a) and 2.23.12(b) provide an important guide for preparing and reviewing forecast expenditure within an allowable revenue submission.

All forecast expenditure and elements of the revenue building blocks used to calculate the allowable revenue have been developed with close consideration of these clauses.

Where the Market Rules do not provide specific guidance on elements of this allowable revenue submission, such as calculation of the capital base, return on investment and depreciation, System Management (Markets) has given regard firstly, to the Market Rules objectives and secondly, to the approach adopted by Western Power in its recently revised Access Arrangement Submission for the period 2012-2017.

2. The Market Objectives seek efficient, safe and reliable production and supply of electricity and related services in the SWIS, and the minimisation of the long term costs of electricity. The primary function of System Management (Markets) in the Regulations[18] is to operate the SWIS in a secure and reliable manner. To help achieve these objectives System Management (Markets) is seeking to minimise the cost of its services to the WEM. It believes that this AR3 proposal clearly demonstrates that the revenue derived from the market during the AR3 period represents a prudent, economically efficient approach to meeting its obligations in the Market Rules, providing its functions in the Regulations and contributing to ensuring that the Market Objectives are achieved.
3. System Management (Markets) had previously considered how benchmarking of its costs might be carried out. After consultation with various electricity industry organisations nationally it became clear that each organisation had its own unique role, accountabilities, stakeholders, industry structures, and legal requirements. There is insufficient similarity between any of the organisations consulted and System Management (Markets) to enable a representative comparison of costs.

3.2 Engagement with Stakeholders

Particular focus has been given to working more closely with the IMO and market participants to ensure System Management (Markets)'s expenditure proposal will support the enhancements planned for the market during the AR3 period. Engagement has included:

- generator forums and Market Advisory Committee (MAC) meetings, where System Management (Markets) has worked with participants to ensure there is a common understanding of recent changes to the market, and the support required to roll out new systems as required.
- meetings with participants and the IMO to review the planned market enhancements.
- providing feedback to the IMO on the proposed rule changes associated with enhancements to the market. System Management (Markets) has focused on

[17] Economic Regulation Authority, Guidelines for Access Arrangement Information, 6 December 2010, available from: http://www.erawa.com.au/cproot/9113/2/20101206%20D47095%20Electricity%20Networks%20Access%20Code%202004%20-%20Guidelines%20for%20AAI%20(Version%202).PDF

[18] Refer to Regulation 13(1) in Part 2 of the Electricity Industry (Wholesale Electricity Market) Regulations 2004, available from: http://www.slp.wa.gov.au/pco/prod/FileStore.nsf/Documents/MRDocument:23752P/$FILE/ElecityIndusWhsaleElecityMarktRegs2004-01-g0-00.pdf?OpenElement

ensuring that proposed enhancements to the market also address any operational inefficiencies which the current Market Rules impose on System Management (Markets).

These engagements with stakeholders have enabled System Management (Markets) to understand its stakeholders' needs and manage expectations in the context of rapid evolution of the Market Rules, processes and procedures.

4 Performance & expenditure during the AR2 period

This chapter sets out how System Management (Markets) has performed over the first two years of the AR2 period (2010/11 & 2011/12) and forecasts performance for the last year of AR2 (2012/13). It summarises the key outcomes for customers in terms of service and the investment undertaken to achieve these outcomes.

This chapter also highlights a number of improvements that System Management (Markets) has made to its planning and delivery arrangements.

4.1 Key messages

- System Management (Markets) has met its obligations to provide system operation services, including effectively manage system frequency and all aspects of system security and reliability as required by the Market Rules.
- The Market Evolution Program (MEP) was announced during the first year of the AR2 period. This was in response to a change to the Market Rules, which resulted in a number of new obligations. These changes implemented the Competitive Balancing[19] and Load Following[20] (CBLF) markets, which required considerable changes to System Management (Markets)'s operations
- System Management (Markets) responded to this challenge by:
  - focusing resources to support the MEP
  - deferring planned investments in existing systems to avoid re-work once the new systems required to support MEP were deployed
- System Management (Markets) commenced delivery of the System Management Automated Real Time Systems (SMARTS) program in May 2011, in preparation for the commencement of the Competitive Balancing and Load Following (CBLF) markets in July 2012.
- Capital expenditure was $15.247 million[21] compared to an original AR2 forecast of $3.370 million. This was almost entirely due to the SMARTS implementation, which was not foreseen in the 2009 AR2 submission.
- Operational expenditure was $20.082 million[22] compared to a forecast of $17.984 million. This was due to the implementation of SMARTS.

4.2 Operational performance during AR2

Key aspects of operational performance during AR2 include:

- system frequency management
- dispatch performance

[19] Balancing refers to the movement of generators to follow the system load, forecast changes in output of intermittent generators (e.g. windfarm output) trend and movements of scheduled generators.
[20] Load following, or frequency keeping, is the ancillary service whereby assigned generators constantly change their output to compensate for random load changes, fluctuation in intermittent generator output and unscheduled movements of scheduled generators to achieve regulation of system frequency.
[21] Forecast to end 2012/13.
[22] Forecast to end 2012/13.

- outage scheduling
- compliance and rule changes

4.2.1 System frequency

System Management (Markets) has a responsibility to control system frequency[23] by ensuring that system demand and supply are in balance. The standard, which is defined in the approved Ancillary Services Report (refer Clause 3.11.13 of the Market Rules), requires system frequency to be maintained between 49.8 and 50.2 MHz for 99.9% of the time.

During AR2 System Management (Markets) has continued to meet this standard, maintaining system frequency within the required range (of 49.8 and 50.2 MHz) 99.91% of the time for both 2010/11, and 2011/12. Data for 2012/13 is not currently available.

4.2.2 Dispatch performance

System Management (Markets) provides quarterly reports to the IMO on the effectiveness of the market in relation to the dispatch process. System Management (Markets) issues dispatch instructions to generators advising them of when and how much power should be supplied to the system. The timely and accurate issuing of these instructions is essential in ensuring the balance between demand and supply, and in the effective operation of the market.

During AR2, System Management (Markets) supported a significant increase in the number of dispatch instructions issued. These have increased from an average of 36 dispatch instructions per month (since market inception) to over 1,600 dispatch instructions per month in the first 3 months of the CBLF market. Figure 6 shows the total dispatch instructions issued by financial year, and the first quarter of 2012/13.

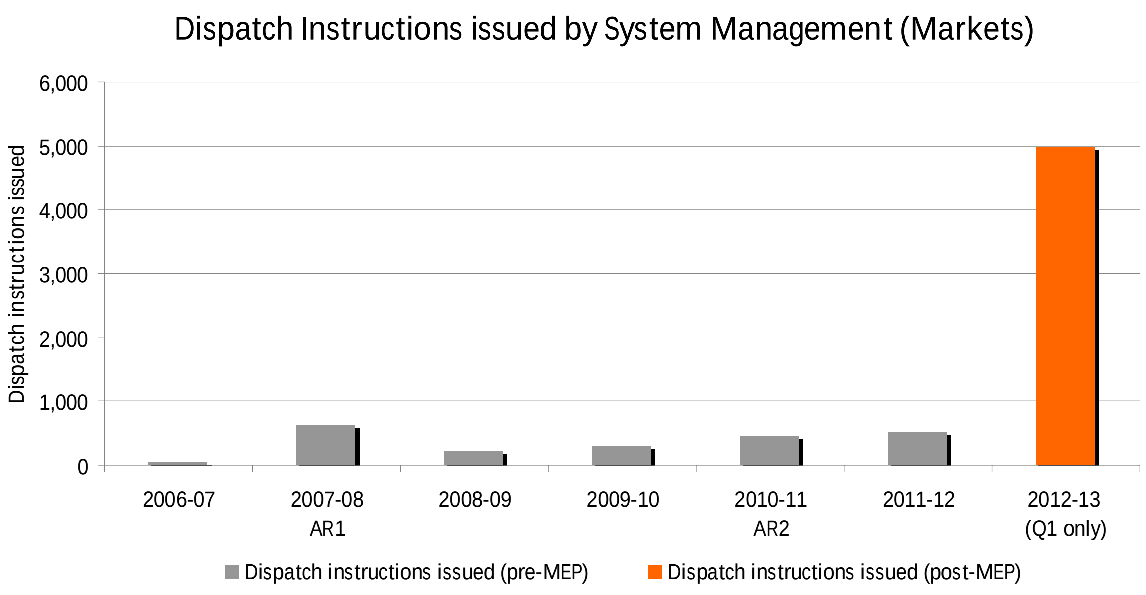

Figure 6: Total Dispatch Instructions Issued

[23] System frequency is a continuously changing variable that is determined by the balance between system demand and total generation. If demand is greater than generation, the frequency falls while if generation is greater than demand, the frequency rises. Maintaining system frequency at, or very close to 50Hz is essential for the consistent and reliable performance of electrical devices such as lighting, motors, transformers, and so on.

4.2.3 Outage scheduling

System Management (Markets) is responsible for planning outages of generation and network equipment. The outage scheduling criteria ensures all market participants are treated equitably and are able to schedule routine maintenance whilst enabling System Management (Markets) to ensure power system security and reliability standards are maintained.

Since the start of the market, the number of power providers has increased and the network itself has become more complex. As a result, the outage scheduling process has become significantly more challenging as System Management (Markets) seeks to balance compliance with the scheduling criteria and the quality and reliability of the electricity supply.

During AR2, an independent review was undertaken of outage planning functions. This found that System Management (Markets) had been impartial in its implementation of the outage planning function and also noted that the volume of outage requests was increasing over time.[24]

4.2.4 Compliance and rule changes

Throughout the AR2 period, System Management (Markets) has sought to identify any areas of non-compliance in operations and to work with stakeholders to resolve compliance issues.

An independent audit of System Management (Markets)'s compliance with the Market Rules noted that 'with limited exceptions, System Management (Markets) has complied with its obligations under the Market Rules'[25], and recognised the increased focus on identifying and dealing with compliance incidents.

Figure 7 shows the increase in the number of non-compliance events reported to the IMO from July 2009 to the end of August 2012.

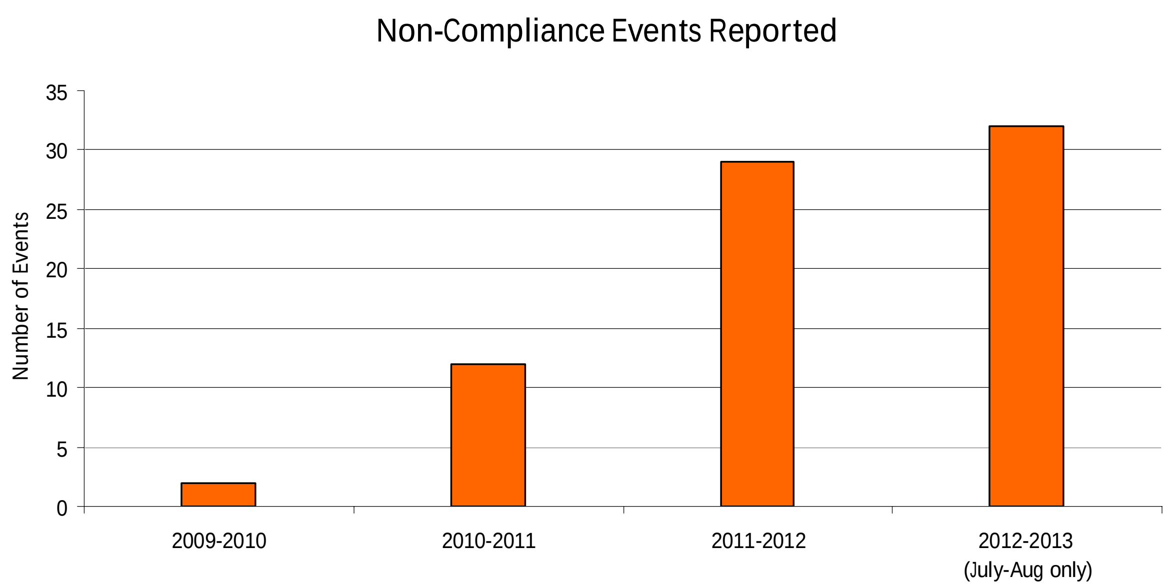

Figure 7: System Management (Markets) Non-Compliance Events From July 2009 to August 2012

[24] Independent Market Operator - Compliance of System Management With the Market Rules and Market Procedures. 20 September 2011. PA Consulting Group. Available from: http://www.imowa.com.au/f189,1613071/Audit_3.pdf

[25] Independent Market Operator - Compliance of System Management With the Market Rules and Market Procedures. 20 September 2011. PA Consulting Group. Available from: http://www.imowa.com.au/f189,1613071/Audit_3.pdf

Note that compliance performance is also dependent on the volume and nature of Market Rule changes. During AR2 there were 35 Market Rule changes[26], compared to 105 changes during the AR1 period. However the single rule change that implemented the Market Evolution Program (and consequently the CBLF market) resulted in 17 new compliance obligations and changes to a further 20 existing obligations[27].

4.3 SMARTS delivery performance

In December 2010 the IMO announced the implementation of the Market Evolution Program, with an initial ‘go-live’ date of 1 April 2012[28]. The program sought to introduce several improvements to the market, including the implementation of the competitive balancing and load following (CBLF) markets that would allow generators to bid for dispatch in near real-time.

The introduction of the CBLF market is the most fundamental change to System Management (Markets)’s operating environment since commencement of the WEM in 2006. In February 2011 System Management (Markets) undertook a study into the requirements of the CBLF market and understand the impact on System Management (Markets)’s systems, processes and resourcing requirements. The study found that to make competitive balancing and load following a reality, System Management (Markets) would require significant upgrade of its existing IT systems and manual processes.

Responding to the challenge, in May 2011 System Management launched its System Management Automated Real Time Systems (SMARTS) program[29]. The SMARTS program would deliver the IT systems, procedures and processes required to meet System Management (Markets)’s new obligations and enable the market to realise the opportunities CBLF will present.

System Management (Markets) worked with the IMO and key stakeholders to scope and develop the new system. The IMO developed the Market Rule changes associated with CBLF in tandem with the SMARTS development and issued a revised ‘go-live’ date of 1 July 2012. The Market Rules were finalised in February 2012 and market procedures finalised in June 2012.

The timing of the introduction of the CBLF meant that the November 2009 allowable revenue submission for the AR2 period did not include expenditure for SMARTS. As a result, the original investment proposal for AR2 was re-analysed and resources were re-allocated to delivery of SMARTS instead. In many cases the projects outlined in the 2009 AR2 submission were either postponed or revised so that they could be accommodated as part of the SMARTS solution in the future. For example, the dispatch decision support simulator and wind forecasting tools that were proposed for the AR2 period will now be delivered as part of SMARTS.

While SMARTS has been designed so that it is a scalable solution, expenditure in the AR2 period has been limited to only deliver the functionality immediately required to support the introduction of the CBLF market and allow full compliance with obligations by mid 2013. Critically, the timing requirements for the new market meant that there was insufficient time prior to the go-live date to be able to use the approval options[30] under the WEM Rules to

[26] This is the total number of new or amended Market Rules during AR2 to the end of August 2012.
[27] Western Power maintains a legislative obligations register. Obligations in the register are typically defined from several individual Market Rules, and each obligation is assessed in accordance with Western Power's Corporate Risk assessment criteria. Those obligations assigned an extreme or high residual risk rating are defined as significant legislative obligations and are the prime focus of System Management (Markets)’s compliance management activities.
[28] Further details can be found at http://imowa.com.au/RC_2011_10
[29] This program was originally termed System Management’s Market Evolution Program (MEP) and later renamed the System Management Automated Real Time System (SMARTS).
[30] System Management (Markets)’s preference was to engage further with the ERA and IMO to gain prior approval of the MEP as a Declared Market Project and to seek redetermination of the AR2 on

seek upfront approval of SMARTS costs from the ERA. As per section 2.23.12(a)ii of the Market Rules, System Management (Markets) proposes an amount is included in the AR3 allowable revenue to recover the SMARTS capital expenditure through the depreciation and amortisation of assets in a manner that is consistent with generally accepted accounting principles[31].

As the MEP was not a declared market project System Management (Markets) has commenced recovery for a limited amount of the costs associated with SMARTS as part of its 2012/13 budget submission which has been accepted by the IMO as being consistent with the AR2 determination. The balance of costs associated with the CBLF market and the SMARTS software and hardware are included in this allowable revenue submission for recovery during the AR3 period.

Figure 8 provides a summary of the MEP development timeline.

this basis. This would have ensured up-front recovery of the SMARTS investment by Western Power. However, this approach would have resulted in a significant delay in the introduction of the CBLF market and a deferral of the benefits sought by market participants. The ERA have since initiated a Market Rule change (RC_2011_02) which would require System Management (Markets) to obtain ERA approval prior to implementing a SMARTS sized project in the future.

[31] Paragraph 2.23.12(a)ii, Wholesale Electricity Market Regulations 2004.

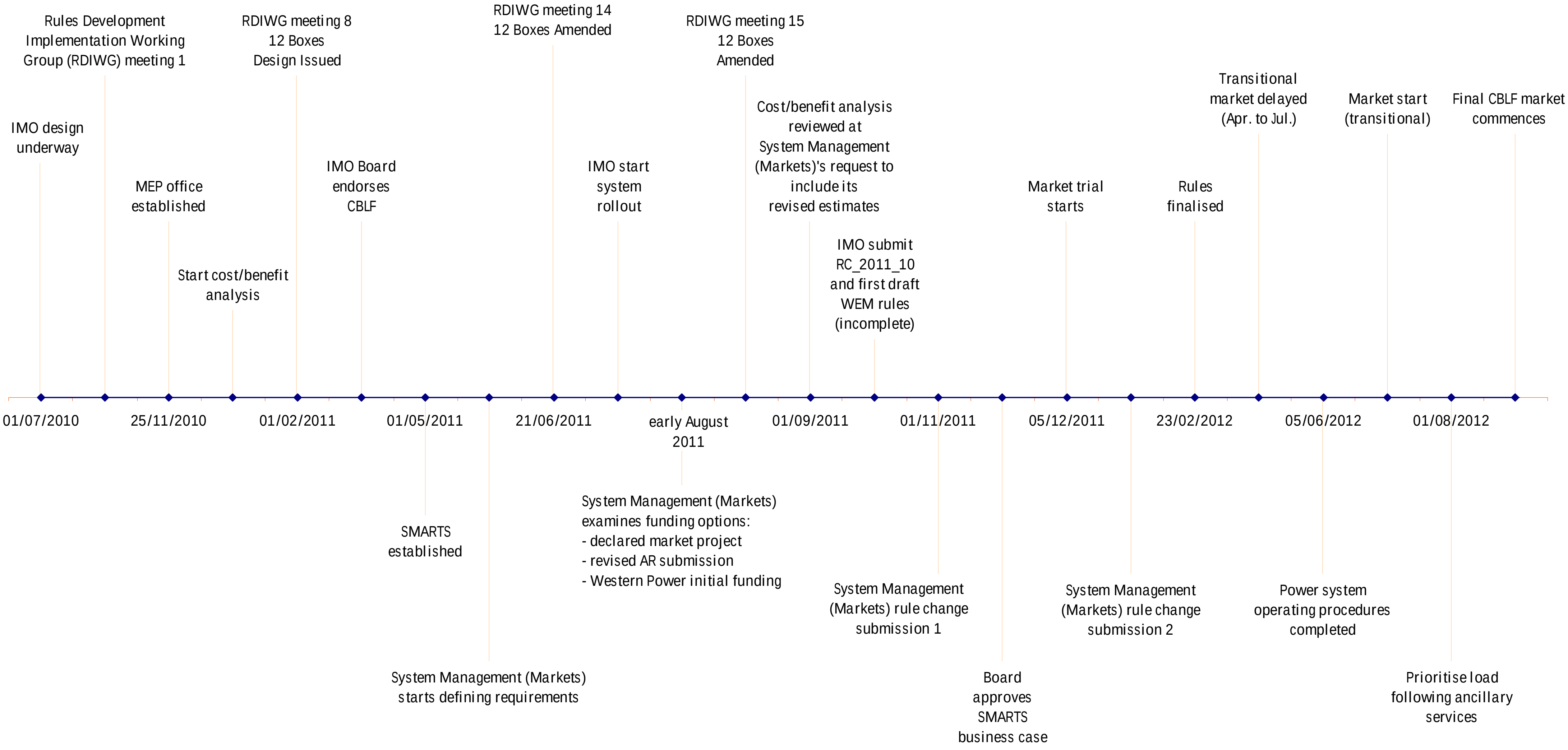

Figure 8: MEP development timeline

4.3.1 Project initiation and scoping

The industry proposed a two-phased approach to the introduction of the CBLF market, as follows:

1. a transitional market which would operate with simpler processes and some automation, commencing in April 2012 (this date was later revised to July 2012)
2. a full market, with the implementation of all required system and process changes, scheduled for December 2012

Adopting a phased approach is common practice for large IT projects where new systems are being introduced and/or must be integrated with existing business infrastructure.

4.3.2 Delivery

In 2011/12, System Management (Markets) focused on the policy, procedure and system solution development required to meet the requirements of the Transitional Market 'go live'. A significant amount of effort (resources, financial commitments and time) was made in this period, much of which was incurred between the business case approval in November 2011 and the IMO formally approving the final WEM rules in February 2012. The program has made significant progress towards achieving the intended objectives and outcomes for the new balancing market needs. The SMARTS program deliverables comprised the following key components:

- load forecasting
- wind forecasting
- dispatch planning/ scheduling
- dispatch execution/ monitoring
- communications
- infrastructure
- data layer and database

Further details of the scope of these deliverables are provided in Appendix E.

Details of performance against each program deliverable are provided in Appendix F. In summary:

- The program has made significant progress towards achieving the intended objectives and outcomes
- System Management (Markets) has been servicing the CBLF market in close to real time since July 1 2012, enabling market-based pricing, balancing and load following generation services
- Changes were made to the scope and schedule of some deliverables where it was considered prudent and efficient to do so. Key drivers for this included the need to:
    - meet obligations that had changed as the final rules were published
    - meet requirements that had reduced in scope as participants' needs became clearer
    - manage the deployment of complex functionality through a staged implementation approach

Table 4 provides a summary of expenditure compared to the budget developed for the business case. This is based on a revised scope for some deliverables as outlined in Appendix F.

Table 4: SMARTS Actual Expenditure ($000 real as at 30 June 2013)

Program Component	2011/12 Actual	2012/13 Forecast	Total Forecast
Load forecasting	307	92	399
Wind forecasting	69	126	194
Dispatch execution/ monitoring	24	1,217	1,241
Dispatch planning/ scheduling	769	93	862
Infrastructure	802	492	1,293
Data layer and database	2,415	2,509	4,924
Program Management	1,931	722	2,653
Change management	73	229	302
Process & procedures	21	639	661
Reporting	-	300	300
Initial Scoping	522	-	522
Total Capex	**6,932**	**6,420**	**13,352**

4.4 Expenditure during AR2

Based on actual expenditure during 2010/11 & 2011/12, and forecast expenditure for 2012/13, System Management (Markets) will have invested $15.247 million in capital and incurred $20.082 million in operating costs to provide system operation services for the AR2 period.

AR2 expenditure is significantly greater than provided for in the AR2 allowable revenue determination. This is predominantly due to the MEP and SMARTS expenditure described earlier in section 4.3.

Table 7 shows a breakdown of AR2 expenditure compared to forecast.

Table 5: Actual expenditure for AR2 compared to regulatory approved expenditure ($000 real as at 30 June 2013)

Expenditure type	2010/11	2011/12	2012/13 (Forecast)	Total
AR2 forecast capital expenditure	**1,860**	**1,160**	**350**	**3,370**
Actual capital expenditure excluding SMARTS	825	620	449	1,895
Actual capital expenditure on SMARTS	-	6,932	6,420	13,352
AR2 total capital expenditure	**825**	**7,552**	**6,869**	**15,247**
Capital expenditure variance	(1,035)	6,393	6,519	11,877
AR2 Forecast operating expenditure	**5,558**	**6,126**	**6,300**	**17,984**

Expenditure type	2010/11	2011/12	2012/13 (Forecast)	Total
Actual operating expenditure excluding MEP and SMARTS	4,777	5,395	7,438	17,610
Actual operating expenditure on MEP and SMARTS	419	1,142	912	2,473
AR2 total operating expenditure	**5,196**	**6,537**	**8,350**	**20,082**
Operating and maintenance costs variance	(362)	410	2,050	2,098

4.4.1 Capital investment

The AR2 allowable revenue determination approved forecast capital expenditure of $3.370 million. The proposed capex provided for the delivery of six key capital projects defined in the November 2009 submission. Table 6 shows the forecast capital expenditure for AR2.

Table 6: AR2 forecast capital expenditure ($000 real as at 30 June 2013)

Capital project	2010/11	2011/12	2012/13
Augmentation of existing IT systems			
SMMITS: Reporting tool	313	103	100
SMMITS: PASA redevelopment	427	0	0
SMMITS: Market rule driven system changes	261	258	250
New IT systems			
Wind farm forecasting tool	313	0	0
Dispatch decision support system	547	0	0
Dispatch training simulator	0	799	0
Total forecast capital expenditure	**1,860**	**1,160**	**350**

In 2010/11 and 2011/12, System Management (Markets) invested $8.378 million in capital expenditure compared to a forecast $3.020 million. In 2012/13 System Management (Markets) expects to invest $6.869 million in capital compared to a forecast of $0.350 million. Figure 9 provides a comparison of actual expenditure with the forecast for the AR2 period.

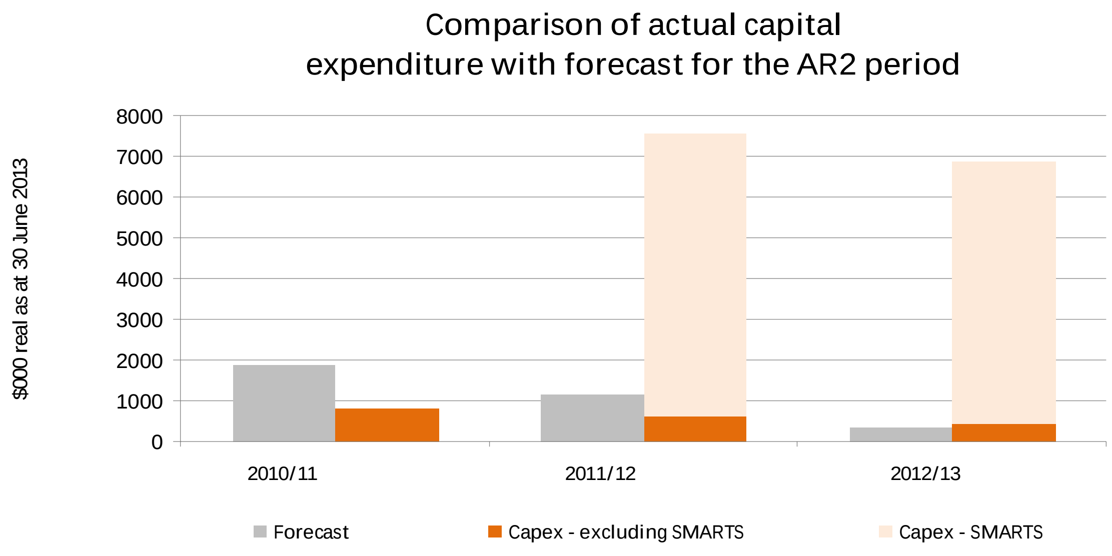

Figure 9: Comparison of actual capital expenditure with the forecast for the AR2 period

Once the MEP announcement was made and the IT requirements scoped, it became clear that the introduction of SMARTS would provide a new system which would impact a number of existing applications, including the the System Management Markets Information Technology System (SMMITS) database, wind forecasting tools, and the dispatch decision support simulator. As a result the originally proposed investment in these systems was either cancelled or postponed so that SMARTS could be prioritised.

During AR2 System Management (Markets) will complete three of the six capital projects originally forecast. In addition to SMARTS it will also deliver two other projects that were not forecast in the AR2 submission. Table 7 sets out the actual expenditure by project.

Table 7: AR2 actual capital expenditure ($000 real as at 30 June 2013)

	2010/11	2011/12	2012/13 (Forecast)
Augmentation of existing IT systems			
SMMITS: Reporting tool	0	0	0
SMMITS: PASA redevelopment	0	0	0
SMMITS: Market rule driven system changes	0	0	0
New IT systems			
Wind farm forecasting tool	0	19	0
Dispatch decision support simulator	250	375	0
Dispatch training simulator	391	129	449
Other capital expenditure not forecast in the AR2 submission[32]			
SMARTS	0	6,932	6,420
SMMITS other developments	108	97	0
Western Energy dispatch tool	76	0	0
Total actual capital expenditure	**825**	**7,553**	**6,869**

[32] expenditure that was committed during AR2, but not included in the AR2 submission

The following sections outline System Management (Markets)'s performance against the following three areas:

- augmentation of existing IT systems
- new IT systems
- other capital expenditure

4.4.1.1 Augmentation of existing IT systems

During AR2, System Management (Markets) did not incur any expenditure on the investments in this category. As previously noted, this was a direct result of the decision to defer projects due to the implementation of SMARTS.

Table 8: AR2 augmentation of existing IT systems capital expenditure – actual compared to forecast ($000 real as at 30 June 2013)

	Forecast	Actual[33]	$ variance	% variance
SMMITS: PASA redevelopment	427	0	-427	-100%
SMMITS: Reporting tool	516	0	-516	-100%
SMMITS: Market rule driven system changes	768	0	-768	-100%
Total capital expenditure	**1,711**	**0**	**-1,711**	**-100%**

PASA redevelopment

This project was deferred with no expenditure having been incurred.

Prior to AR2 System Management (Markets) developed a scope for the redevelopment of its Projected Assessment of System Adequacy (PASA) tools. The design required the development of an application within the SMMITS database to enable the exchange of data with other applications. As the high level design for SMARTS was developed it became apparent that the redeveloped PASA application would need to interface with the SMARTS database. It was not considered prudent to persist with re-developing the PASA tools until the new SMARTS database was in production and the requirements for integrating it could be assessed.

PASA was identified as a potential project for AR3. However, it is not included in the AR3 investment program as it is deemed a lower priority (as compared to other investments).

Reporting tool

This project was originally scoped to provide a suite of reports from the SMMITS database. However, as the SMARTS program commenced it became clear that:

- the reporting application would need to access information from the SMARTS database (since this would now store some of the key data System Management (Markets) sought to report on)
- SMARTS is likely to become the preferred platform for any new or enhanced applications

[33] Includes a forecast of capital expenditure for 2012/13

Therefore System Management (Markets) considered it prudent to build the reporting functionality on the SMARTS database, and to defer this project until the SMARTS rollout was complete (limited reporting functionality will be delivered in 2012/13). An initiative to deliver reporting functionality from SMARTS is included in this AR3 submission.

Market rule driven system changes

The AR2 allowable revenue included an amount to cover change to IT systems in response to unforeseen Market Rule changes. The costs relating to the Market Rule change relating to the CBLF market have been treated as a discrete program, with costs recorded separately. No other costs have been recorded in this cost category.

4.4.1.2 New IT systems

During AR2, System Management (Markets) will spend $1.613 million, 3% less than forecast on new IT systems (excluding SMARTS). A breakdown is provided in Table 9.

Table 9: AR2 new IT system capital expenditure – actual compared to forecast ($000 real as at 30 June 2013)

	Forecast	Actual[34]	$ variance	% variance
Wind forecasting tool	313	19	-294	-94%
Dispatch decision support simulator	547	625	78	14%
Dispatch training simulator	799	970	170	21%
Total capital expenditure	**1,659**	**1,613**	**-45**	**-3%**

Wind forecasting tool

In the AR2 submission System Management (Markets) proposed to implement a wind forecasting system similar to that used by the Australian Energy Market Operator (AEMO). However, the project was placed on hold as it became clear that the new rules for the CBLF market may not require System Management (Markets) to develop more accurate wind forecasts.

Enhancements have now been delivered to wind forecasting tools as part of the SMARTS program, however this is a significantly reduced scope from the original investment proposal for AR2. Further details are provided in Appendix F.

Dispatch Decision Support Simulator (DDSS)

A key focus of implementing a DDSS was to improve the consistency and transparency of real time dispatch decisions. System Management (Markets) commenced work on this project, including the procurement of software and the development of a preliminary model for supporting dispatch decisions. At this stage the SWIS generator and network modelling was substantially complete, the data interfaces were specified and the model could be run to achieve results of reasonable quality.

The DDSS project was well advanced by the time the Market Evolution Program was announced by the IMO. The preliminary rules for the CBLF market made it clear that the dispatch process would change significantly, moving to greater reliance on automated pre-dispatch and real time dispatch decision making and execution. Requirements for DDSS

[34] Includes a forecast of capital expenditure for 2012/13

were therefore substantially re-scoped and work continued under two streams of the SMARTS program (dispatch planning and dispatch execution).

Capital expenditure on DDSS was $0.078 million greater than forecast in the AR2 submission. The capital forecast provided in the AR2 submission ($0.547 million) was based on a high level estimate of costs, assuming a 50-50 split between capital and operating expenditure. The subsequent tender process for DDSS led to a revised capital forecast of $0.672 million, offset by lower than forecast operating expenditure.

Dispatch Training Simulator

During AR2, System Management (Markets) invested in a computer based dispatch training simulator (DTS) to provide black start[35] training capability for its controllers.

The DTS project commenced in November 2010 and the simulator was deployed into its site acceptance testing environment in the system operations control room in September 2012. Costs incurred were higher than forecast (a variance of $0.171 million). The main reason for this was that the initial estimate for the solution did not include an allowance for factory or site acceptance testing. Once a more detailed estimate for project completion was prepared it became clear that this testing would be required in order to ensure that the solution would meet System Management (Markets)'s needs prior to its acceptance, and final payment being made to the vendor.

4.4.1.3 Other capital expenditure

System Management (Markets) will spend $13.633 million undertaking capital investment that was not forecast in for the AR2 period. The majority of this expenditure (97%) relates to the implementation of the SMARTS program and implementation of changes necessary to support the MEP.

Table 10: Other IT system capital expenditure – actual compared to forecast ($000 real as at 30 June 2013)

	Forecast	Actual[36]
SMMITS other developments	0	206
Western Energy dispatch tool	0	76
SMARTS	0	13,352
Total capital expenditure	**0**	**13,633**

SMMITS other developments

The electronic log book is a software application developed to support the real time market dispatching process and collect relevant data for audit and compliance purposes. It was completed in AR1, and deployed for use in May 2010. However, following deployment a number of issues were identified which required remedial work. System Management (Markets) invested $0.165 million to address high priority issues that had been identified in order to ensure the application could be used effectively. Additional expenditure included enhancements to risk management functionality.

[35] The term 'black start' refers to the process used to rebuild the electricity network from a 'black' or de-energised state. Black start requires the progressive energising of sub-networks using generators that have auxillary equipment that allows them to self start (ie without needing to draw energy from the network). These sub-networks are gradually expanded and synchronised with each other until the whole network has been rejoined and energised.

[36] Includes a forecast of capital expenditure for 2012/13

Western Energy dispatch tool

During AR2 System Management (Markets) invested $0.076 million to enable it to remotely control the Western Energy Kwinana facility (an unmanned site) so it could be used in the event of a black start. This was undertaken to improve security of the system, and with the intention of rolling out this capability to the broader market. However, as initial proposals were developed to progress the implementation of a competitive balancing market, System Management (Markets) deferred any further deployment of the remote control services as it considered that there was a strong risk that they would conflict with the outcomes sought for the CBLF market.

The project was successful and the remote control functions were in operation until July 2012, at which point the agreements with Western Energy were terminated in preparation for the commencement of the CBLF market. Importantly, this project secured the cornerstone technologies on which the automatic generator control and automated balancing control communications required by the CBLF market are being implemented by System Management (Markets).

4.4.2 Operating expenditure

The AR2 allowable revenue determination approved operating expenditure of $17.984 million. System Management will incur operating costs of $20.082 million during the period. Figure 10 provides a comparison of actual expenditure with the forecast for the AR2 period.

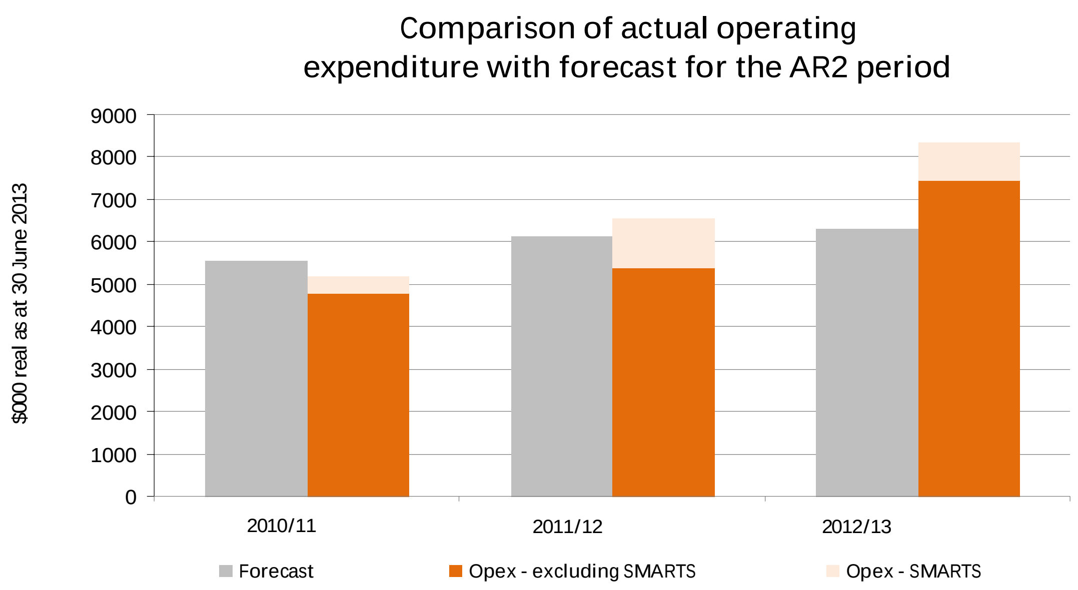

Figure 10: Comparison of actual operating expenditure with the forecast for the AR2 period

Table 11 summarises the variances between forecast expenditure for AR2 and that approved in the AR2 submission.

Table 11: Operating expenditure for AR2 – actual compared to forecast ($000 real as at 30 June 2013)

Category	10/11		11/12		12/13		Total AR2	
	Forecast	Actual	Forecast	Actual	Forecast	Actual (Forecast)	Forecast	Actual [37]
Labour (permanent employees)	3,847	3,591	3,994	3,744	4,149	4,119	11,990	11,453
Functional costs, comprising:								
• Contractors	208	558	247	677	270	1,111	726	2,346
• Austraclear	5	5	5	8	5	9	15	22
• Consultants	208	68	206	169	200	270	614	507
• Audit/review	31	43	31	0	30	50	92	93
• Travel and staff development	52	30	52	9	50	60	154	99
• Other	1	10	1	16	1	72	3	98
• Operating materials	0	0	0	0	0	0	0	0
Legal costs	391	190	397	137	400	200	1,187	526
Business support costs	0	0	0	0	0	916	0	916
IT operating expenditure	464	282	482	410	497	177	1,443	869
Insurance costs	0	0	0	0	0	0	0	0
Allowed operating expenditure to support capital expenditure spend, comprising:								
• Wind forecasting tool	125	0	124	79	120	0	369	79
• Dispatch decision support simulator	175	0	180	121	183	60	538	181
• Dispatch training simulator	0	0	309	0	321	321	630	321
• PASA redevelopment	0	0	0	0	0	0	0	0
• Interest expenses	50	0	99	25	74	74	223	99
• MEP and SMARTS	0	419	0	1,142	0	912	0	2,473
Total	**5,558**	**5,196**	**6,126**	**6,537**	**6,300**	**8,350**	**17,984**	**20,082**

Details of the key variances are provided below.

[37] Includes a forecast of operating expenditure for 2012/13

Labour (permanent employees)

Labour costs were less than the AR2 forecasts primarily due to the deferral of projects, or re-scoping as part of the SMARTS program.

Functional costs

Additional costs were incurred for additional resources engaged as contractors to support the implementation of the MEP and to provide backfill during the delivery of SMARTS. A breakdown of changes to staffing levels during 2012/13 is provided in Appendix D.

Legal costs

Legal costs were below the approved budget. During AR2 System Management (Markets) sought to limit engagement of legal resources, and strengthen its focus on working more closely with stakeholders to provide direction to the scoping and implementation of Market Rule changes.

Business support costs, IT operating costs and insurance

System Management (Markets) utilises a number of business support services from Western Power, including finance, regulation and sustainability, information technology and human resources. In order to account for the cost of these services, Western Power has allocated an amount to System Management (Markets) beginning in 2012/13. Western Power's Ringfencing Standard is provided in Appendix B.

During the AR2 period IT operating costs are below the approved AR2 budget. This is due to:

- the focus on SMARTS which required both a reallocation of resources and deferrment of other projects
- a reduction in charges for IT services in 2012/13 as these are now provided for within the Cost Sharing Methodology

Insurance costs were incurred by Western Power in the first two years of AR2, but not charged to System Management (Markets). This issue has been addressed by including insurance within System Management (Markets)'s shared costs from 2012/13 onwards.

Operating expenditure to support capital expenditure

This section provides a summary in relation to operating expenditure for the capital investments outlined in Section 4.4.1.1 and 4.4.1.2.

- **Wind forecasting tool** - significant underspend as the project was initially delayed as alternative solutions were investigated. The solution was then substantially de-scoped as obligations for the CBLF market were clarified. SKM was engaged to investigate options and develop a specification, at a cost of $0.079 million, which was incurred in the final two years of the AR2
- **Dispatch decision support simulator** – significant underspend as obligations for the dispatch process changed with the implementation of CBLF.
- **Dispatch training simulator** – significant underspend as this project was delayed through the requirement for the supplier to address issues found during the factory acceptance testing. Operating expenses for this project included additional staff to operate and maintain the system. Due to delays in delivery of the system System Management (Markets) has deferred recruitment of these staff.

- **PASA redevelopment** – this project did not incur any operating costs as it was deferred.

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PART B: EXPENDITURE PROPOSAL

5 Business drivers and investment objectives

This chapter outlines the key business drivers for System Management (Markets). It describes how these have informed System Management (Markets)'s investment objectives for AR3 and why this is an efficient approach, which will deliver benefits for market participants.

5.1 Key messages

- System Management (Markets) functions are defined in the Market Rules and Market Procedures
- Changes to the market requirements drive changes to System Management (Markets)'s processes, procedures and IT systems
- The implementation of enhancements to the market is a major driver for the business, and it is essential that System Management (Markets) is well positioned to support them.
- The increased number and diversity of power providers is a key business driver.

5.2 System Management (Markets) key drivers

As the operator of the SWIS and provider of supporting services to the WEM System Management (Markets)'s functions are defined in the Market Rules and Market Procedures. To enable it to meet its market obligations System Management (Markets) utilises its assets (market IT systems, business processes and procedures).

For System Management (Markets) the most significant business driver comes from the changes to the Market Rules. Many of these changes require System Management (Markets) to make significant changes to its IT systems, business processes and procedures.

Further investment drivers are the need to ensure IT systems and processes keep pace with the increasing complexities of the market, and the increased market activity as the volume and diversity of market participants increases.

These drivers are discussed in the following sections.

5.2.1 Enhancements to the wholesale electricity market

Since inception of the WEM in 2006, around 140[38] rule changes have been implemented. These have focused on refining existing requirements to provide clarity on stakeholders' obligations, and to enable the market to operate efficiently. For each rule change System Management (Markets) must consider:

- required changes to processes, and the Power System Operating Procedures (which define how System Management (Markets)'s processes align with its obligations)
- required changes to systems
- monitoring of compliance, to ensure rule changes are embedded so they become 'business as usual'

[38] To the end of August 2012.

Prior to the AR2 period, System Management (Markets) managed this process as part of its normal operations, as only a relatively small number of rule changes have had significant impacts on processes and systems.

The introduction of the Market Evolution Program in 2010 has resulted in major structural changes to the market, particularly the introduction of competitive balancing and load following. The single rule change which implemented the CBLF market effectively changed the market from trading on a day-ahead basis, to trading every 30 minutes.

System Management (Markets) has been working closely with the IMO and market participants to understand the further enhancements planned for the market during AR3. A number of these will implement significant structural changes, which will drive corresponding changes to operations.

5.2.2 Supporting effective and accountable system operations

As the WEM matures, System Management (Markets)'s operations need to occur closer to real time and be supported by systems which deliver efficiencies.

Prior to AR2, System Management (Markets) has operated using IT systems which were broadly in place since the start of the WEM.

The changes which occurred as a result of MEP required new systems, as the existing systems relied extensively on manual processes and were not scalable to support the closer to real time market. In scoping SMARTS System Management (Markets) was careful to strike a balance between investing in systems which would automate the key processes to deliver efficiencies, and the need to enable a level of expert user monitoring and intervention.

For AR3, System Management (Markets) recognises that the further developments planned for the market will require further investment in technology. System Management (Markets) will consider the scalability of existing applications, and the extent to which any new functionalities arising from market changes can be migrated to the SMARTS environment.

System Management (Markets) will:

- invest in enhancements to existing systems to improve market process efficiency and reduce compliance risk
- incrementally develop IT systems in response to specific rule changes, and as far as possible building on investment in SMARTS

And <u>not</u>:

- make a significant up-front investment to undertake a wholesale upgrade of IT systems

This approach will incur costs associated with specific market rule changes. It will enable market participants to assess the costs of rule changes against the benefits they will deliver.

5.2.3 Market diversity

Since the inception of the WEM, the number and diversity of participants in the market has increased. The increase in the number and diversity of power providers requires:

- a higher level of coordination in planning, scheduling and monitoring functions,
- System Management (Markets) to provide more accurate load forecasting (so participants can better align their bidding to supply with demand)
- System Management (Markets) to maintain communications and system control capabilities with an increased number of facilities

These changes are the main driver for System Management (Markets) to provide more robust systems, which enable participants to exchange data with (such as outage submissions and commissioning plans); and for System Management (Markets) to provide greater transparency so participants can be assured that System Management (Markets) is compliant and equitable in its decision making.

Figure 11 shows the increasing diversity in generation sources since the inception of the WEM.

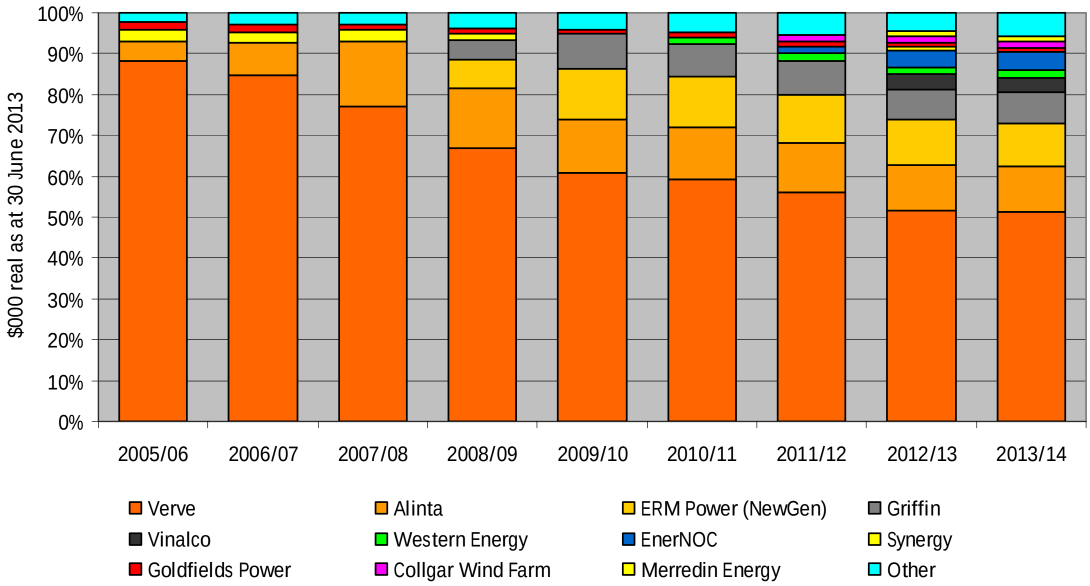

Figure 11: Changes to Generation Sources Since Inception of the WEM[39]

5.3 Investment objectives

System Management (Markets)'s investment objectives articulate the outcomes it is seeking to achieve through its investments in AR3. These are shown in Figure 12.

[39] Source: Data provided to System Management (Markets) by the IMO. Also appears in the Statement of Opportunities 2012, p28.

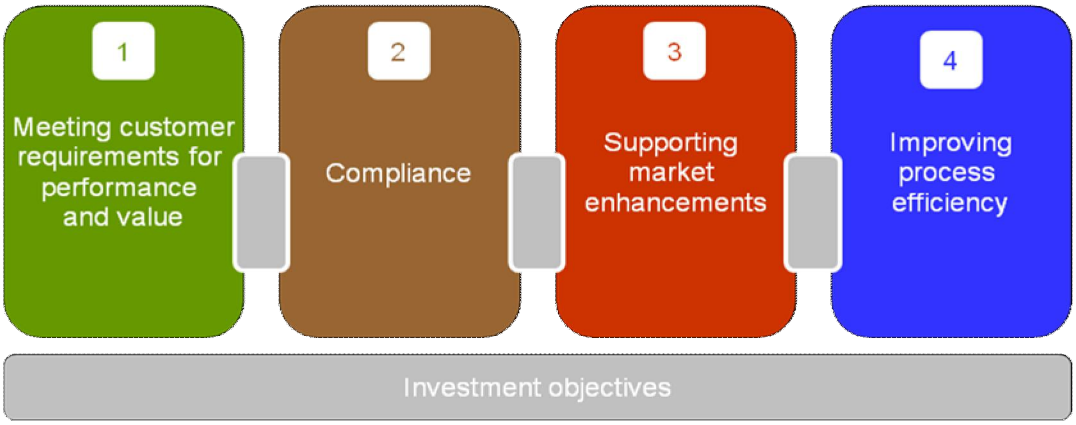

Figure 12: System Management (Markets) investment objectives

The investment objectives mean:

- **Meeting customer requirements for performance and value** – System Management (Markets) invests efficiently to enable it to provide the services required by its stakeholders at the quality level demanded, but being mindful to minimise the cost to market participants
- **Compliance** – System Management (Markets) invests efficiently to ensure that it is compliant with the Market Rules and operating procedures
- **Supporting market enhancements** – System Management (Markets) invests efficiently to support changes to the Market Rules and act as a partner in the development of the market
- **Improving process efficiency** – System Management (Markets) invests efficiently to improve processes and systems that will lead to a lower cost of service for market participants

5.4 Investment governance

System Management (Markets) applies a consistent approach to managing projects using the Improvement Portfolio Governance Model (IPGM)[40], which is particularly suited to projects that deliver new or enhanced IT systems.

The IPGM is a framework for managing non-AWP projects within Western Power's Improvement Portfolio whilst applying an appropriate level of governance to ensure ongoing strategic alignment of initiatives.

The IPGM is based on industry best practice project management methodologies and is strongly aligned with other standards already in use at Western Power such as the Works Program Governance Model.

The lifecycle of any project which forms part of the IPGM follows key inputs, outputs and approvals at the end of each stage. The IPGM provides for flexibility based on the scale and complexity of the program or project being considered.

The IPGM comprises a seven phase model as shown in Figure 13. Specific sub processes, actions and decisions are required during each phase. Between each phase there is a control 'gate', with a set of mandatory milestones, deliverables and approvals that must be in place before the project or program can move to the next phase.

[40] Document reference DM 9386323.

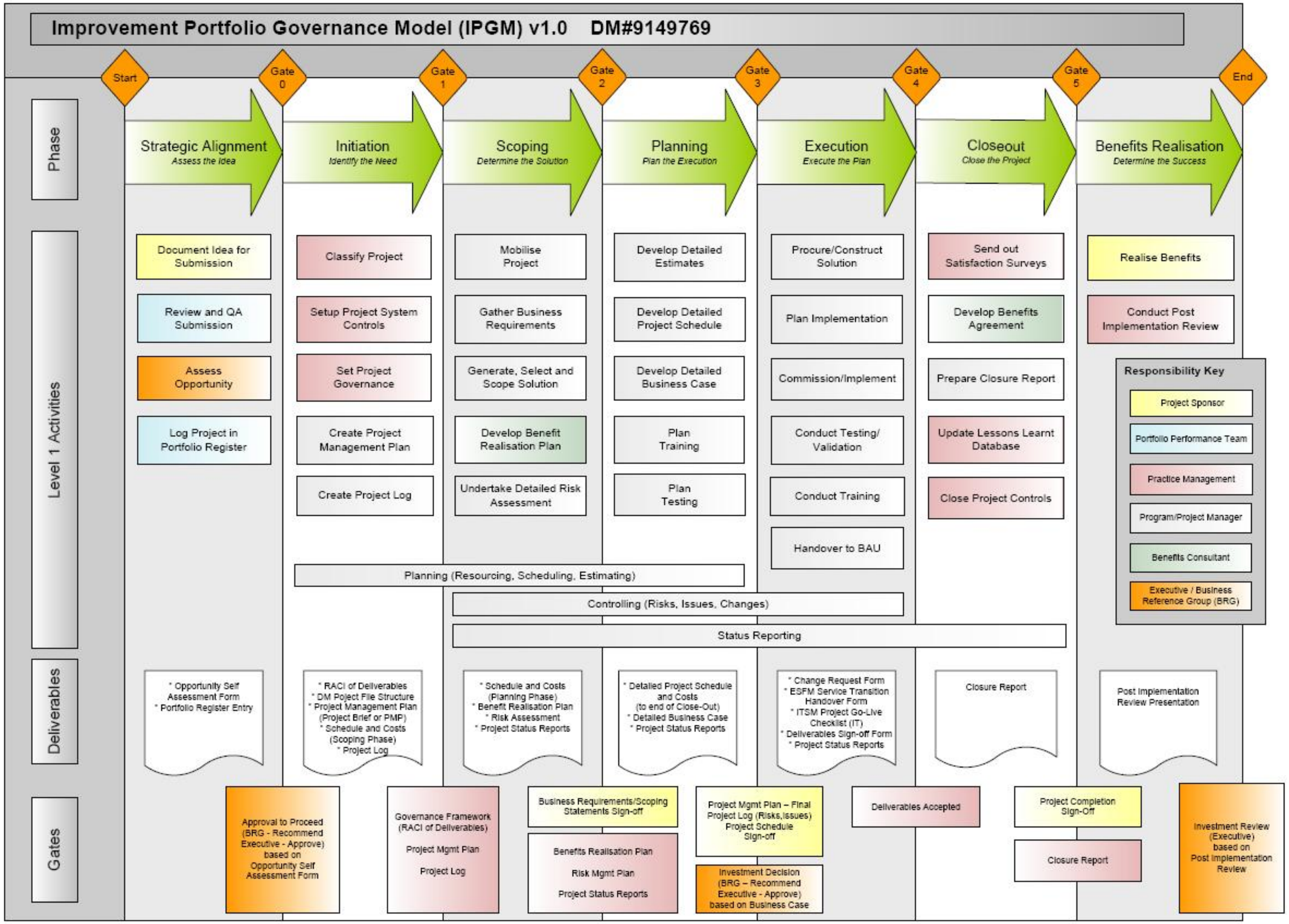

Figure 13: Improvement Portfolio Governance Model

The control gates ensure investment options and assessments are undertaken at the appropriate time and that they support regulatory requirements. This includes the need to confirm that capital investments satisfy appropriate investment tests in all phases[41].

5.4.1 Investment delivery

System Management (Markets) will utilise a project management office to oversee investment delivery. This will ensure there is an effective focus on the delivery of projects to meet market requirements, while maintaining effective engagement at the executive level.

Figure 13 shows an overview of the project delivery structure.

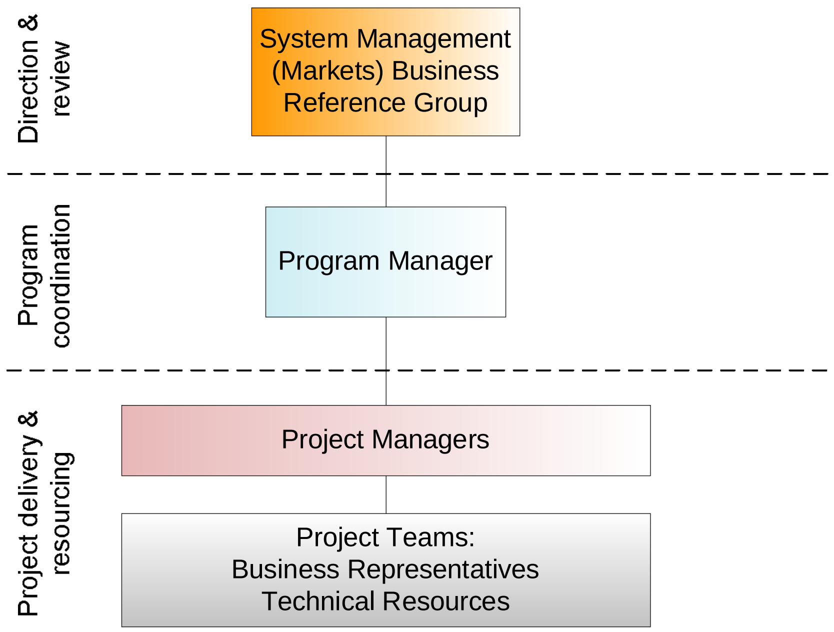

Figure 14: System Management (Markets) Project Delivery Structure for AR3

5.4.2 Business case process

Application of the IPGM, combined with the business case and associated change control disciplines will ensure that all investment decisions are monitored and controlled in an efficient and transparent manner. In preparing the capital investment program for this submission, business cases have been assessed as follows:

- an initial opportunity management assessment was undertaken (in line with gate 0 of the IPGM). Projects were assessed in non-financial terms (strategic alignment, business impact, and risk) and a financial assessment (considering overall net benefit).
- projects which passed this initial assessment then proceeded to the next stage, which assessed options, defined a clearer scope and assessed cost components.

[41] Document reference (DM 9386323).

This information was assembled as a preliminary business case. Whilst a business case is not required until gate 3 of the IPGM, this approach was taken to ensure that a more robust assessment was applied prior to the inclusion of projects in the capital investment program for this submission.

- the business cases were then assessed to confirm whether each initiative met investment objectives.

At the start of AR3, each project will commence at gate 1, and as each project proceeds to gate 2, a revised business case will be prepared for consideration by System Management (Markets)'s business reference group.

6 Operating expenditure

This chapter sets out the operating expenditure System Management (Markets) requires to provide system operation services during AR3. It also:

- describes how System Management (Markets) has forecast AR3 operating expenditure
- details the activities and disaggregated forecasts for key cost categories
- describes the basis of changes in operating costs, and outlines how cost increases have been offset by efficiency measures.

6.1 Key messages

- During AR3, System Management (Markets)'s operating expenditure will total $25.548 million, compared to a forecast expenditure at the end of the AR2 period of $20.082 million. The increase is primarily driven by:
  - increased labour costs to support the MEP's CBLF market and support new systems (SMARTS and DTS)
  - the inclusion of shared costs for services provided by the broader Western Power business, now properly recovered through System Management (Markets) charges
- the MEP has added complexity to System Management (Markets)'s operations, increasing the volume of transactions, monitoring and reporting requirements
- while there is a level of automation within SMARTS, this is balanced with a need for some labour increases in order to:
  - monitor the additional transactions associated with a 30-minute market (i.e. run 48 times per day), rather than day-ahead market
  - extend hours of operation to meet market requirements
  - ensure System Management (Markets) has an appropriate level of user input in line with the complexity of decision-making required.

6.2 Forecasting methods

System Management (Markets) has forecast operating expenditure using fit-for-purpose methods for each of the three cost types:

1. recurrent costs
2. non-recurrent costs
3. business support costs

The forecasting methods used reflect the differing cost drivers of each cost type over the three-year forecasting period.

To forecast the **recurrent costs** operating expenditure forecast, System Management has taken the efficient base year, identified the required cost adjustments (step changes related to changes in functions and requirements) and escalated these costs according to the drivers of the costs (predominantly market changes impacting business processes, procedures and systems and the labour costs to make the necessary changes).

For **non-recurrent costs** and **business support costs** System Management (Markets) has developed bottom-up forecasts to take into consideration the nature of the works program and the effect of factors other than scale.

6.2.1 Recurrent costs

Recurrent operating expenditure is forecast using a base year roll-forward method. This method is appropriate as System Management (Markets)'s operating expenditure mainly comprises recurrent costs, which are typically stable over time once growth in the operations of System Management (Markets) has been accounted for. This method is also the accepted standard used by regulated Australian distribution and transmission network businesses for forecasting recurrent operating costs under the National Electricity Rules.[42]

Recurrent network operating expenditure forecasts are based on System Management (Markets)'s actual 2011/12 costs. These costs are the most up to date information available on which to determine the efficient recurrent cost base. They constitute a relevant cost base against which forecasts of operating expenditure for AR3 can be assessed consistent with the ERA's considerations in its AR2 determination.

In forecasting recurrent operating expenditure System Management (Markets) has:

- used actual 2011/12 costs as the efficient base year to develop the AR3 forecasts
- removed non-recurring 2011/12 costs that are not expected to continue into AR3
- adjusted for relevant step changes related to known future changes in practices, functions, obligations and operating environment that affect the scope for recurrent works as identified through the 2012/13 budget process and review of future requirements
- applied input cost escalation to adjust for movements in the market price of labour.

Efficient base year

The costs incurred during 2011/12 reflect an efficient recurrent cost base because:

- 2011/12 was the latest completed financial year in the AR2 period
- operating activities were planned and carried out in accordance with good electricity practice, whilst seeking to achieve the lowest practicably sustainable costs
- following 2011/12 System Management (Market)'s operations have changed significantly

[42] See for example:

- Final decision Victorian electricity distribution network service providers distribution determination 2011-2015, AER, October 2010.
- Final decision South Australia distribution determination 2010–11 to 2014–15, AER, May 2010.
- Final decision Queensland distribution determination 2010–11 to 2014–15, AER, May 2010.
- Final decision Australian Capital Territory distribution determination 2009–10 to 2013–14, AER, 28 April 2009.
- Final decision New South Wales distribution determination 2008–09 to 2012–13, AER, 28 April 2009.

- the costs associated with the SMARTS program could be readily backed out of the cost base
- other capital investments (DDSS and DTS) focussed on enhancements to the existing IT environment, and represented 'business as usual' projects for System Management (Markets).

Cost adjustments

System Management (Markets) has adjusted for step changes related to known future changes in practices, functions, obligations and operating environment. These are costs that were incurred in the base year (2011/12) that will not be incurred in the AR3 period (negative step changes) and costs that will be incurred in the AR3 period that were not incurred in the base year (positive step changes).

The recurrent cost base setting process involves examining actual 2011/12 costs to identify recurrent and step changes in operating activities. This is primarily through the 2012/13 budget setting process and includes activities that are expected to impact future costs as well.

System Management (Markets) has identified specific changes that will affect operating expenditure requirements in the AR3 period (relative to 2011/12). These include:

- changes in obligations due to the implementation of the MEP
- changes in operating environment and practices due to the forecast capital investment program over AR3

These factors have given rise to two forms of required forecast adjustment:

- step changes to the 2011/12 base year to account for known changes in recurrent costs between 2011/12 and 2012/13 and those expected in the AR3 period; and
- one-off adjustment in costs for short-term variances in recurrent activities.

Adjustments to actual 2011/12 base year are set out in Table 12. This provides a description of the step change cost items along with a brief explanation of the reason for the change. The dominant step change is in labour operating costs amounting to $1.212 million.

Table 12: Recurrent cost adjustments ($000 real as at June 2013)

Category and cost activity	Value per year ($ '000's real at 30 June 2013)	Year	Nature of adjustment	Description
Labour	149	2012/13	+ recurrent	Resourcing to support the extended operating hours and increased transactions associated with the CBLF market.
	165	2012/13	+ recurrent	Support and maintenance to ensure the new DTS software application remains current and staff receive the required training.
	154	2013/14	+ recurrent	A transition of a contractor role to a permanent employee role (which provides a cost saving in functional costs).

Category and cost activity	Value per year ($ '000's real at 30 June 2013)	Year	Nature of adjustment	Description
	608	2013/14	+ recurrent	Resourcing to support SMARTS on an ongoing basis. A transition of contractor roles to permanent employee roles (which provides a cost saving in functional costs).
	136	2013/14	+ recurrent	Resourcing to enable the delivery of the capital investment program and implementation of governance improvements (program manager role).
	96	2013/14	+ recurrent	Tranisitioning-in of trainees due to planned retirements in the Control Room.
	-96	2015/16	+ recurrent	Adjustment to remove the above allowance (following the transition-in of trainees).
Total labour step changes	**1,212**			
Functional	446	2012/13	+ recurrent	Resourcing to support the additional functions which are required for the CBLF market (contractors). Backfill of one role during the delivery of SMARTS to provide sufficient support for day to day operations.
	104	2012/13	+ recurrent	Independent advice and additional resourcing to manage the delivery of the AR3 submission.
	49	2012/13	+ recurrent	Costs for an audit of the application of the Ringfencing Standard to enable any opportunities for improvement to be identified and acted upon.
	51	2012/13	+ recurrent	Adjustment of staff development and travel costs to a sustainable level. This follows a reduced spend in the 2011/12 base year (due to staff commitments to the SMARTS program).
	20	2012/13	+ recurrent	Summary of minor increases to the 'other' cost category.
	59	2013/14	+ recurrent	Costs for an audit of the processes and calculations conducted within market systems to confirm compliance with the Market rules. This will enable targeted action to be taken to address any key areas of non-compliance.

Category and cost activity	Value per year ($ '000's real at 30 June 2013)	Year	Nature of adjustment	Description
	-361	2013/14	- recurrent	A reduction in resourcing as the CBLF market move to a full production phase, and conversion of contractor roles to permanent employee roles (to provide a cost saving).
	-379	2013/14	- recurrent	Conversion of contractor roles to permanent employees (to deliver cost savings). An increased allocation for a staff member moving off the SMARTS program (which resulted in a number of system support tasks being delayed).
	-104	2013/14	- recurrent	Reduction in consultant costs to 11/12 level of expenditure (following increase to assist in the development of the AR3 submission).
	164	2014/15	+ recurrent	Costs associated with the preparation of the Allowable Revenue 4 submission to provide adequate resourcing, support and advice.
Total functional step changes	48			
Legal	63	2012/13	+ recurrent	Increased legal costs to support the enhancements planned for the Market and determine impacts on existing obligations. Note that legal costs will still be substantially lower than approved in AR2 due to a change in to System Management (Markets)'s approach to compliance.
Insurance	386	2012/13	+ recurrent	A portion of Western Power's insurance costs allocated to System Management (Markets). This will ensure that market participants incur these costs rather than Western Power's network connected customers.
Business support	557	2012/13	+ recurrent	Business support services provided by Western Power to System Management (Markets). This will ensure that market participants incur these costs rather than Western Power's network connected customers.
	-9	2013/14	- recurrent	Adjustment to business support services provided by Western Power to be consistent with AA3 submission.

Category and cost activity	Value per year ($ '000's real at 30 June 2013)	Year	Nature of adjustment	Description
	12	2014/15	+ recurrent	Adjustment as noted above.
	29	2015/16	+ recurrent	Adjustment as noted above.
Total business support step changes	589			
IT	-233	2012/13	- recurrent	Reduced costs for IT services provided by Western Power (as these are incorporated in the overall business support costs).
	594	2013/14	+ recurrent	Costs to maintain the software licences and infrastructure for SMARTS.
	321	2013/14	+ recurrent	DTS costs
Total IT step changes	**682**			
Wind farm forecasting tool	**-79**	2012/13	- recurrent	Expenditure reduced to zero.
Dispatch dispatch decision support simulator	-61	2012/13	- recurrent	Expenditure moved to SMARTS due to DDSS project closure.
	-60	2013/14	- recurrent	Expenditure reduced to zero.
Total dispatch decision support simulator step changes	**-121**			
Dispatch training simulator	321	2012/13	+ recurrent	Ongoing license costs.
	-321	2013/14	- recurrent	Expenditure reduced to zero, due to reclassification to IT operating costs in AR3.
Total dispatch training simulator step changes	**0**			
MEP/ SMARTS	-230	2012/13	- recurrent	Reduction in costs previously associated with the implementation of MEP.
	-912	2013/14	- recurrent	Removal of costs which have been re-allocated to labour, functional and IT.
Total MEP/ SMARTS step changes	**-1,142**			
Total positive step changes	**4,388**			
Total negative step changes	**-2,751**			
Total step changes	**1,637**			

A detailed breakdown of these adjustments is provided in Appendix D.

Figure 15 shows the operating expenditure step changes over AR3

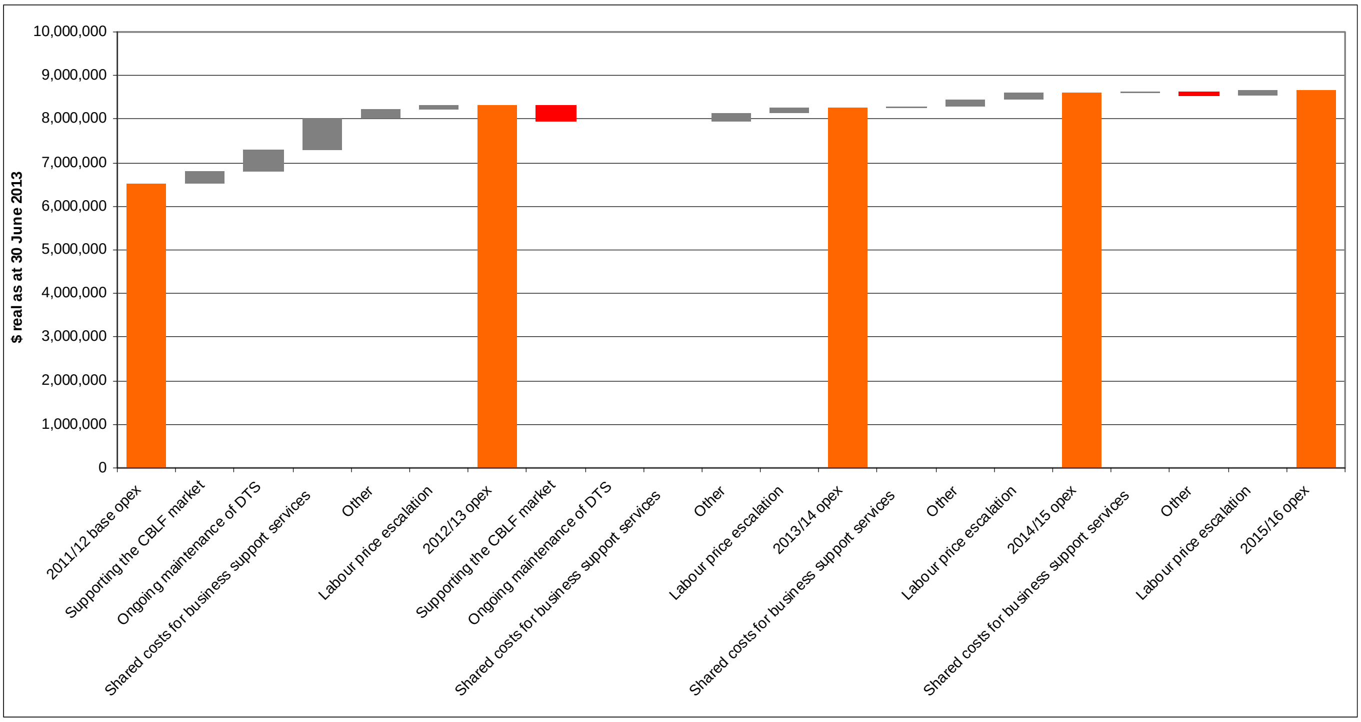

Figure 15: Operating expenditure step changes

In summary:

- System Management (Markets) will incur additional costs to enable it to support the introduction of the CBLF market. These include: additional staff to support the market and extended hours of operation; additional staff to support the SMARTS system; and additional costs to maintain the software licences and hardware for SMARTS
- System Management (Markets) will continue to incur costs for the additional staff required to support the ongoing maintenance of the DTS which was implemented during AR2
- System Management (Markets) will continue to incur shared costs which are charged by Western Power for the business support services it provides.

6.2.1.1 Benefits associated with operating expenditure costs

Ensuring compliance with Market Rule obligations

It is essential for System Management (Markets) to meet its compliance obligations under the Market Rules. Compliance provides market participants with the confidence that they can achieve the best economic outcomes that the market design can produce. With the significant increase in the volume of market transactions associated with the CBLF market, System Management (Markets) has had to improve its compliance monitoring and management systems and to increase the numbers of staff engaged in compliance management processes. System Management (Markets)'s improvements to compliance management was recently noted in the IMO's 2012 audit as required by section 2.14.6 of the

Market Rules. The audit report also indicated that System Management (Markets) should undertake further improvements in support of the CBLF market.

Error rate reduction

It is vital for smooth operation of the WEM and confidence of market participants that operational errors occur rarely. Achieving this requires reliable and fit for purpose business processes, procedures and systems. Whilst there is increased automation with the SMARTS system there is an overarching need for surveillance and oversight by System Management (Markets) to ensure that systems and processes are operating correctly. Consequently it is necessary to increase staffing levels in some operational areas.

Improved service to market participants

In the past the WEM design has focused market participant attention to mainly normal (weekday) business hours. To realise cost efficiency System Management (Markets) has maintained staffing levels that primarily service these hours with out of hours service being provided on a needs-only basis using callout or chance availability of staff. The focus of the current CBLF market covers more hours of the day and market participant activity is now required 7 days per week. Consequently operational expenditure forecasts include a number of changes to staffing levels and working patterns that are aimed at providing the hours of service necessary for the CBLF market.

Realising efficiencies

The increased operating costs will be partially offset by:

- a small reduction in staffing levels as the CBLF market move from the transitional stage to a full production phase, with more automation provided by SMARTS
- labour cost increases to support Market systems will be minimised by transitioning the staff who currently support SMITTS to SMARTS support roles (effectively reducing the number of staff required to support SMMITS)
- the conversion of a number of contractor roles to full time employees.

System Management (Markets) continues to derive efficiencies by operating as a ringfenced business entity within Western Power. It is able to access Western Power's corporate services, systems and processes for the same per-FTE cost as incurred by Western Power. This provides significant efficiencies of scale and avoids the costs which would otherwise be incurred if System Management (Markets) was required to establish and maintain separate corporate functions in its own right.

6.2.2 Non-recurrent costs

System Management (Markets) has not identified any non-recurrent costs that need to be included in operating expenditure forecasts for the AR3 period.

6.2.3 Adjusting for forecast movements in the market price of labour

System Management (Markets) has incorporated the forecast movements in the market price of labour costs into expenditure forecasts. System Management (Markets) has not adjusted for movements in materials. This is because System Management (Markets) primarily invests capital in SCADA and communications infrastructure and IT. While these are classified as materials, the cost of these products is expected to increase in line with inflation. Consequently, System Management (Markets) has not applied escalation above inflation to materials costs.

Labour escalation accounts for 4.5% of total operating expenditure across AR3. Table 13 provides the impact of input cost escalation in real terms on operating expenditure over AR3.

Table 13: Impact of input cost escalation on operating expenditure[43]

$ 000 real at 30 June 2013	2012/13	2013/14	2014/15	2015/16
Labour escalation	89	230	393	521

System Management (Markets) has applied expert labour forecasts from Macromonitor[44] commissioned by Western Power for its recent access arrangement submission and accepted by the ERA in the final decision to escalate the forecast labour costs. These escalation factors were developed specifically for the Western Australian electricity, gas, water and waste (EGWW)[45] sector and the associated conditions, characteristics and constraints are similarly applicable to System Management (Markets) given the use of the same labour market.

In determining the appropriate labour escalation forecasts, Macromonitor developed weighted average forecasts for EGWW labour hired through enterprise bargaining requirements[46], individual contracts and awards. The geographic isolation of Western Australia's labour market and the unique labour constraints affecting this market result in labour escalation rates that exceed the rest of Australia. Table 17 shows Macromonitor's labour escalation forecast.

Table 14: Labour escalation factors[47]

	2012/13	2013/14	2014/15	2015/16
Labour	1.5%	2.2%	2.4%	2.0%

6.3 Operating expenditure forecast

System Management (Markets) will require $25.549 million of operating expenditure for the AR3 period. A breakdown is provided in Table 15.

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[43] Note that these impacts are indicative, as escalation necessarily compounds and when viewed at this disaggregated level is affected by the ordering in which escalation is applied.
[44] *Forecasts of Labour Costs – Electricity, Gas, Water and Waste Services Sector, Western Australia, Report prepared for Western Power*, Macromonitor, July 2011.
[45] Using the Australian Bureau of Statistics industry classification.
[46] Western Power +CEPU Union collective agreement which operates until October 2013
[47] Economic Regulation Authority, Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network, 5 September 2012, Table 43.

Table 15: Operating expenditure by category ($000 real as at June 2013)

	2013/14	2014/15	2015/16	Total AR3
Labour Costs	5,240	5,366	5,369	15,975
Functional Costs	791	984	1,003	2,778
Legal Costs	200	200	200	600
Insurance Costs	386	386	386	1,159
Business Support	560	581	619	1,760
IT Support	1,092	1,092	1,092	3,277
Total operating expenditure	**8,270**	**8,609**	**8,670**	**25,549**

This expenditure will enable System Management (Markets) to directly respond to its key drivers and support delivery of its investment program. It will:

1. **Assist in consolidating support for the Market Evolution Program** – by providing an increase in staff to service the increased market trading hours and increased transaction volumes associated with the CBLF market.
2. **Assist in improving key systems, reducing market compliance risk** and **supporting the development of the market** – by providing adequate resources to enable the effective management and delivery of capital investments, and the significant changes planned by the IMO.

During AR2 much of the originally proposed investment program was deferred, in part due to insufficient resources to deliver it in parallel with delivering SMARTS.

During AR3 the IMO plans further enhancements to the market. It is important that System Management (Markets) has sufficient available resources to respond to these challenges and remain compliant with the Market Rules as changes are introduced.

7 Capital expenditure

This chapter provides an overview of:

- the forecast capital expenditure over the 2013/14 to 2015/16 review period
- the activities, key drivers and the detailed forecasts for capital investment related to the key regulatory cost categories
- the methodology used to develop the forecasts and how they comply with the relevant sections of the Market Rules.

7.1 Key messages

- The investment program will:
  - embed the transition to the SMARTS platform by providing greater security and a more robust test environment
  - improve specific systems and processes through targeted initiatives aimed at improving efficiency and reducing risk
  - support the development of the market by positioning System Management (Markets) to support the enhancements planned for the AR3 period by the IMO
- System Management (Markets) has utilised Western Power's IPGM methodology to assess its proposed investments and developed preliminary business cases for each[48]. These will be further refined as each project commences. Consistent with section 2.23.10 of the Market Rules, System Management (Markets) finances all approved capital expenditure via Western Power's Statement of Corporate Intent. Western Power will require full recovery of capital costs and costs of capital over the asset lifetime expectations.
- System Management (Markets) has engaged with the IMO to gain a basic understanding of the proposed rule changes for the AR3 period and is able to include an allocation of funding to support these initiatives through this submission.

7.2 Overview of the investment proposal

During AR3, System Management (Markets) will invest $5.271 million in capital to deliver system operation services. These services include those necessary for System Management (Markets) to support the CBLF market.

Capital investment will be made across three categories, as follows:

1. consolidating support for the MEP
2. improving internal processes and systems
3. supporting market development

Figure 16 shows the relative value of investments to be made in each category.

[48] Business cases have been prepared for the projects proposed in our investment program. System Management (Markets) has not developed business cases for the funding sought for rule changes within the IMO's Market Rules Evolution Program as these proposed changes are not sufficiently scoped at this stage.

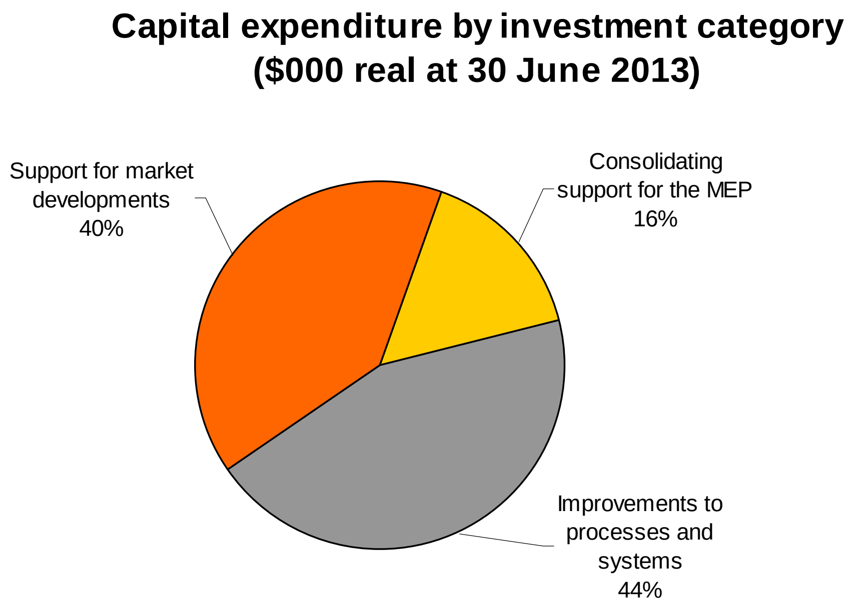

Figure 16: Capital expenditure by investment category

A breakdown of the individual projects within each category is provided in Table 16 below.

Table 16: Capital expenditure by year by investment category ($000 real at 30 June 2013)

Investment Proposal by Category	2013/14	2014/15	2015/16	Total AR3	% of gross capital
Consolidating support for the MEP, comprising:					
• SMARTS security assessment	149	0	0	149	
• SMARTS test environment	216	115	0	330	
• IMO outbound data	168	174	0	341	
Sub total	**532**	**288**	**0**	**821**	**16%**
Improving internal processes and systems, comprising:					
• Lodgement and approval for commissioning	232	84	0	316	
• Customer portal user management phase 1	85	0	0	85	
• Customer portal user management phase 2	0	282	291	573	
• FTP replacement	251	206	50	506	
• Disaster recovery	376	0	0	376	
• Capitalised labour	151	156	161	469	
Sub total	**1,094**	**729**	**502**	**2,325**	**44%**

Investment Proposal by Category	2013/14	2014/15	2015/16	Total AR3	% of gross capital
Support for market development, comprising:					
• Outage management phase 1	469	274	0	743	
• Outage management phase 2	107	144	238	489	
• Improvements to balancing	46	47	0	93	
• 30 minute gate closure	0	159	0	159	
• Emissions intensity index	63	0	0	63	
• Spinning reserve market	115	127	334	577	
Sub total	**800**	**752**	**572**	**2,125**	**40%**
Total capital expenditure	**2,427**	**1,769**	**1,075**	**5,271**	**100%**

Details of the capital investment program are provided in the following sections.

7.2.1 Consolidating support for the MEP

SMARTS was implemented pursuant to a change to the Market Rules. The projects described below are considered necessary to comply with the Market Rules.

Enhancing SMARTS security

System Management (Markets) will undertake a security assessment of SMARTS and its environment. This is a standard procedure for all systems managed by the SCADA branch and is used to determine the risks associated with malicious attacks on key production systems. The assessment will deliver a security report which identifies recommended steps to be taken (where appropriate) to enhance system security.

The recommended security measures may require additional investment, however as the scope and cost of the measures is not currently known this additional cost has not been included in this submission.

Enhancements to the SMARTS environment

System Management (Markets) will establish an integrated test environment for SMARTS that connects the existing test environment for the system with the SCADA test environment. This will mirror the way the production systems operate. This initiative will reduce the risk of issues occurring as system enhancements are migrated to the production environment, and will assist with user training.

These investments are targeted to improve the robustness and reliability of SMARTS and help ensure System Management (Markets) is adequately positioned to implement further developments in this system as changes occur to the Market Rules.

IMO outbound data

In implementing SMARTS an interface was established to provide essential market, performance and compliance related data to the IMO. This interface is automated and supplies data on a regular basis throughout each trading day. Since deployment of the transitional CBLF market there have been issues reported by the IMO and participants in relation to errors in the data being provided.

To address this issue, System Management (Markets) will implement enhancements to the existing data interface. This will enable staff to undertake quality assurance checks on the data, and to more easily locate the source of any errors reported by participants or the IMO. This will provide a greater assurance that the information provided by System Management (Markets) is accurate and reliable and will provide a better service for participants by enabling any errors to be more effectively identified and resolved.

7.2.2 Improving internal processes and systems

System Management (Markets) has a key role to play in managing and maintaining the security of the SWIS. As the WEM continues to mature, the role of System Operator will continue to become more complex. To ensure that the market is fully supported, and there is transparency in System Management (Markets)'s decision making and regulatory compliance, investment is required in improving business processes and the information systems that support them.

Historically, System Management (Markets) has invested in incremental enhancements to its systems, which comprised a suite of largely disparate applications, custom-developed spreadsheets and a number of processes requiring manual inputs. To comply with the requirements of the CBLF market, System Management (Markets) needed to implement systems and processes that would support closer to real-time market transactions. This meant that an information systems environment was required which would be able to manage a significantly higher number of transactions than required for the previous WEM, without the need for the same level of user intervention, or the re-entry of data from one system to another.

The implementation of SMARTS, therefore represents a step change in System Management (Markets)'s IT environment. In developing the scope for SMARTS, System Management (Markets):

- focused on delivering the core functionality required to enable the CBLF market
- sought to establish a sound information systems environment which would support further developments and complexities in the market
- deferred additional investment in information systems until SMARTS was in place. These included the PASA and monitoring and reporting projects originally proposed for the AR2 period.

Reliance on manual systems is no longer practical or efficient. In order for systems to support repeatable and defensible decision making, they need a level of automation, and integration with each other (so each system is relying on common sources of information). During AR3 System Management (Markets) will address some key issues in existing systems in order to:

- mitigate the risks of errors in the commissioning process
- enable System Management (Markets) to create reports from SMARTS in order to better understand compliance and operational efficiency, and to enable market participants to access key data related to their facilities

These investments do not represent a wholesale upgrade of the information systems environment. Instead, they are a targeted response to ensure System Management (Markets) is compliant with the Market Rules and is effectively positioned to support the planned developments for the market published by the IMO.

Enhancing the commissioning process

The commissioning process ensures a participant's commissioning plans are compliant and do not adversely impact power system security.

System Management (Markets) currently uses a manual process to record, review and approve the commissioning plans and schedules submitted by market participants. These plans are submitted as a spreadsheet, often with revised versions being submitted closer to the commissioning date.

The current process leads to a number of issues associated with version control, the management of emails (notifying participants of approvals) and the creation of data for use in other processes (including forecasting, PASA, and the publishing of data to the IMO).

System Management (Markets) seeks to address these issues by implementing a lodgement and approval system for commissioning plans. This system will be implemented within the SMARTS environment and leverage the customer portal. It will:

- reduce the reliance on spreadsheets for recording and tracking commissioning plans
- automate parts of the commissioning plan acceptance, analysis, approval, revision and reporting process to improve efficiency
- enable data to be made more readily available to participants (e.g. approval status of commissioning and outage plans), and to other systems used by System Management (Markets)
- reduce the risk of errors being made by ensuring that the most current version of each commissioning plan is used

This investment is required in order to:

- reduce the risk of delays to the commissioning process
- mitigate the risk of commercial impacts for market participants due to delays in commissioning

Improved user management for the customer portal

This project is separated into 2 phases as follows.

Phase 1 - System Management (Markets) provides access to a range of data for each market participant through a customer portal. This includes notifications of outages, submission of commissioning plans and compliance monitoring. The portal is a customised web site which supports the requirements under the Market Rules for System Management (Markets) and participants to provide each other with specific information on an ongoing basis.

As the data exchanged via the portal is specific to each participant, it provides secure access via named user logins and passwords. However, each participant has a number of logins to the portal, with varying levels of functionality depending on user roles, which are managed by System Management (Markets). The method of granting participants access is manual and has the potential for errors and delays.

During AR3, System Management (Markets) will resolve this issue by modifying the customer portal to enable participants to manage the user logins for their own staff. This will allow participants to take responsibility for their own user changes, and will allow System Management (Markets) to add data to the customer portal and further increase its use by participants.

Phase 2 - As part of the process of improving efficiency in the management of data exchange between System Management (Markets), the IMO and participants, System

Management (Markets) needs to provide a means for users and market operators to review and validate data being transacted across the interfaces. Phase 2 of the customer portal is designed to provide this review and validation capability by enhancing the customer portal implemented in phase 1.

This investment is required in order to:

- enable System Management (Markets) to respond to requests for information from market participants and the IMO in a timely fashion
- avoid the need for an additional resource to be recruited to manage the increased requirement for information which has resulted from the Market Evolution Program
- avoid addressing this shortfall in accessible information by developing ad-hoc software applications to extract information from the SMARTS database. While this approach would address specific information requirements it would be inefficient, difficult to maintain and not scalable to cope with changes to SMARTS resulting from enhancements to the market

These projects will enable System Management (Markets) to realise efficiencies in current processes. These efficiency gains are estimated at less than one full time equivalent (FTE) staff member for each project and consequently will not result in a direct reduction in staffing levels. These investments will however, enable staff to focus more time to providing responsive and reliable support for market participants, and less time supporting manual processes.

FTP replacement

Since the start of the WEM in 2006, data communications between System Management (Markets) and the IMO have relied on the file transfer protocol (FTP) technology. However, this technology has not proved to be reliable, resulting in disruptions and delays in the transfer of essential Market, performance and compliance related data, in turn leading to potential breaches of the Rules.

System Management (Markets) will work with the IMO to resolve this issue by upgrading the data transfer interface to a more up to date technology (eg web services). This technology is more reliable than FTP, provides greater flexibility, and builds upon the web services interface implemented as part of SMARTS.

This initiative will benefit participants by improving the reliability of the data provided to the IMO, and help ensure that data are provided within the required timeframes.

The IMO have informed System Management (Markets) of their intention to upgrade the IMO interfaces to web services technology during the AR3 period. For this to deliver benefits for participants it is important that System Management (Markets) also upgrades its interfaces so that the systems managed by both parties are able to communicate using the same protocol.

Disaster recovery

Following the implementation of the CBLF market, System Management (Markets)'s IT systems are now more embedded in the operation of the SWIS. As SMARTS is completed in 2012/13, it will provide an increased level of automation of the functions performed by System Management (Markets) in the dispatch of power generation and the overall management of the SWIS. This change means that SMARTS is a critical system for the operation of the Market, and needs to be supported by appropriate disaster recovery mechanisms. The current Business Continuity Plan developed by System Management (Markets) may not provide for sufficiently rapid recovery of Market systems. However, a provision has been made for the SCADA systems through maintenance of a remote facility which can be used to operate the SWIS in the event of the East Perth Control Centre being unavailable.

System Management (Markets) will update the Business Continuity Plan for its Market systems, and invest in additional hardware at the existing remote facility to enable the Market to continue to function in the event of the East Perth Control Centre being unavailable.

This will benefit participants by providing a greater certainty that the Market will continue to operate in the event of a disaster, and reassurance that System Management (Markets) is taking appropriate steps to mitigate the impacts of such an event.

7.2.3 Supporting market development

System Management (Markets) is required to make changes to processes and systems as rule changes occur in order to maintain compliance with the Market Rules. In its forthcoming Market Rules Evolution Plan 2013-2016, the IMO has identified a number of potential market enhancements, which it is seeking to implement over the AR3 period. At time of writing the details of the IMO's plan have not yet been crystallised, with the scope of initiatives available at a high level only.

System Management (Markets) has assessed what will be required to support the proposed changes, and identify the potential investment involved.

Table 17 provides an overview of the proposed rule changes, with an estimation of the costs associated with each initiative. System Management (Markets) proposes that an amount of funding consistent with the 'most likely' case is provided for in the allowable revenue to cover these potential costs.

As further information about each initiative becomes available, System Management (Markets) will review and potentially re-scope its investments as required, with any variation from the allowable revenue determination addressed using the in-period budget cycle.

Table 17: Cost allocation for rule changes identified in the Market Rules Evolution Plan ($000 real at 30 June 2013)

Proposed Initiative	Key Impacts	Cost Allocation ($000 +/-50%)		
		Low case (-50%)	High case (+50%)	Most likely
Outage Management Phase 1 (Information Transparency)	New systems to automate manual processes, new data interfaces and additional resources to manage data quality	372	1,115	743
Outage Management Phase 2 (IMO Initiated Process Initiatives)	Changes to existing business processes and systems	245	734	489
Improvements to Balancing	Changes to a number of processes and at least 3 existing systems	46	139	93
30 Minute Gate Closure	Implementation of automated system security and monitoring applications and integration of these with dispatch processes.	80	239	159

Proposed Initiative	Key Impacts	Cost Allocation ($000 +/-50%)		
		Low case (-50%)	High case (+50%)	Most likely
Emissions Intensity Index	Changes to SCADA configurations and additional data interfaces	32	95	63
Spinning Reserve Market	New systems to support a new market	288	865	577
Settlement Simplification	As insufficient detail is available System Management (Markets) has not assessed the impacts of this proposed change.	-	-	-
Total		**1,062**	**3,187**	**2,125**

System Management (Markets) proposes that $2.125 million is included in the allowable revenue to account for these potential market changes. System Management (Markets) explored the option of not including these costs in the allowable revenue proposal and utilising the decared market project mechanism to provide for the expenditure.

However, though the costs for these proposed intitiatives are not yet certain, the IMO and market participants have indicated that they expect these projects to be delivered during the AR3 period. System Management (Markets) therefore considers it would be more efficient and desirable for customers if an amount is included in the allowable revenue to enable these projects to commence. Using the declared market project approach may delay these projects unneccessarily and result in the initiatives not being delivered within the required time frames. System Management (Markets) has only included projects which are justifiable, achievable and determined from engagement with the IMO and market participants.

The revenue impact of including this $2.125 million investment in the submission is $0.621 million. This will impact market fees by 0.8%.

During the AR3 period System Management (Markets) will undertake a substantially more detailed determination of the scope of the rule changes, including an assessment of how System Management (Markets) will meet these obligations and final cost estimates when the scope for each rule change is finalised by the IMO. Any variation from the allocated amount will be adjusted for through the in-period budget mechanism and if the changes exceed the revenue allowance then alternative approvals will be sought.

A summary of the initiatives in the Market Rules Evolution Plan is provided below.

Outage Management Phase 1

This rule change is being progressed and is likely to be finalised in late 2012[49]. System Management (Markets) has undertaken some initial scoping to assess impacts, which are likely to require the creation of systems to automate previously manual processes as well as data interfaces to supply data to the IMO for publication. The increase in data volume is substantial and will require data quality to be managed more rigorously as any data quality issues will have the potential to more significantly impact market outcomes. As a result additional resourcing to manage validation and to commence investigations may also be necessary.

[49] This is Rule Change 2012_11 which addresses the '5 Year Review of the Outage Planning Process' report (www.imowa.com.au/5yearoutageplanningreview/).

Outage Management Phase 2

System Management (Markets) and market participants have identified a number of issues with the current outage planning process. These have been brought to the attention of the IMO in MAC meetings over the course of the past 12 months, and through feedback provided in the 5 year Outage Planning Review.

The IMO has deferred consideration of any of these until after implementation of Phase 1 to determine if the situation has improved or deteriorated. Therefore, this package of potential rule changes is unlikely to proceed before late 2013 or early 2014. Its impact on System Management (Markets) is likely to be significantly less than that of Phase 1, and focus on changes to business processes and existing systems.

Improvements to Balancing

The IMO intends to continue fine tuning the new balancing market following the introduction of competitive balancing. A range of consequential amendments have been identified including removal of the resource plan concept and a review of provisions which confer obligations on System Management (Markets) and Verve Energy that are different than those which apply to other generators. The impact on System Management (Markets) may be significant, including a need to amend program logic in the Real Time Dispatch Engine, Dispatch Planning Tool and PASA as well as a review of a number of fundamental dispatch planning processes that are currently performed manually.

30 Minute Gate Closure

Gate Closure refers to the time when the last submissions must be made to the IMO by participants in the competitive balancing market. On the 5 December 2012, gate closure will move from 6 hours to 2 hours. The IMO has flagged its intention to further close the gap between gate closure and real time to 30 minutes. The decision places increased emphasis on the need for development of automated system security and monitoring systems and integration of these with dispatch processes. However, it will improve the ability of market participants to respond to events that impact on system conditions.

Emissions Intensity Index

The IMO has published a discussion paper regarding the publication of an emissions intensity index for the WEM. The index will be based, at least in part, on production data that will be drawn from the SCADA systems. Design decisions as this project is implemented are likely to have some impacts on SCADA configurations, but may also required additional data interfaces.

Spinning Reserve Market

Following the implementation of CBLF, the IMO has identified the introduction of a similar market for the procurement of spinning reserve services through the SWIS. Currently spinning reserve is procured solely through Verve Energy. Implementation effort is likely to be of a similar magnitude to that required for CBLF. However, additional systems to perform a dynamic assessment of spinning reserve requirements and signal these to market are likely to be required.

An indicative implementation plan is provided in Figure 17 (note that the timelines for projects associated with Market Rule changes are based on preliminary estimates only).

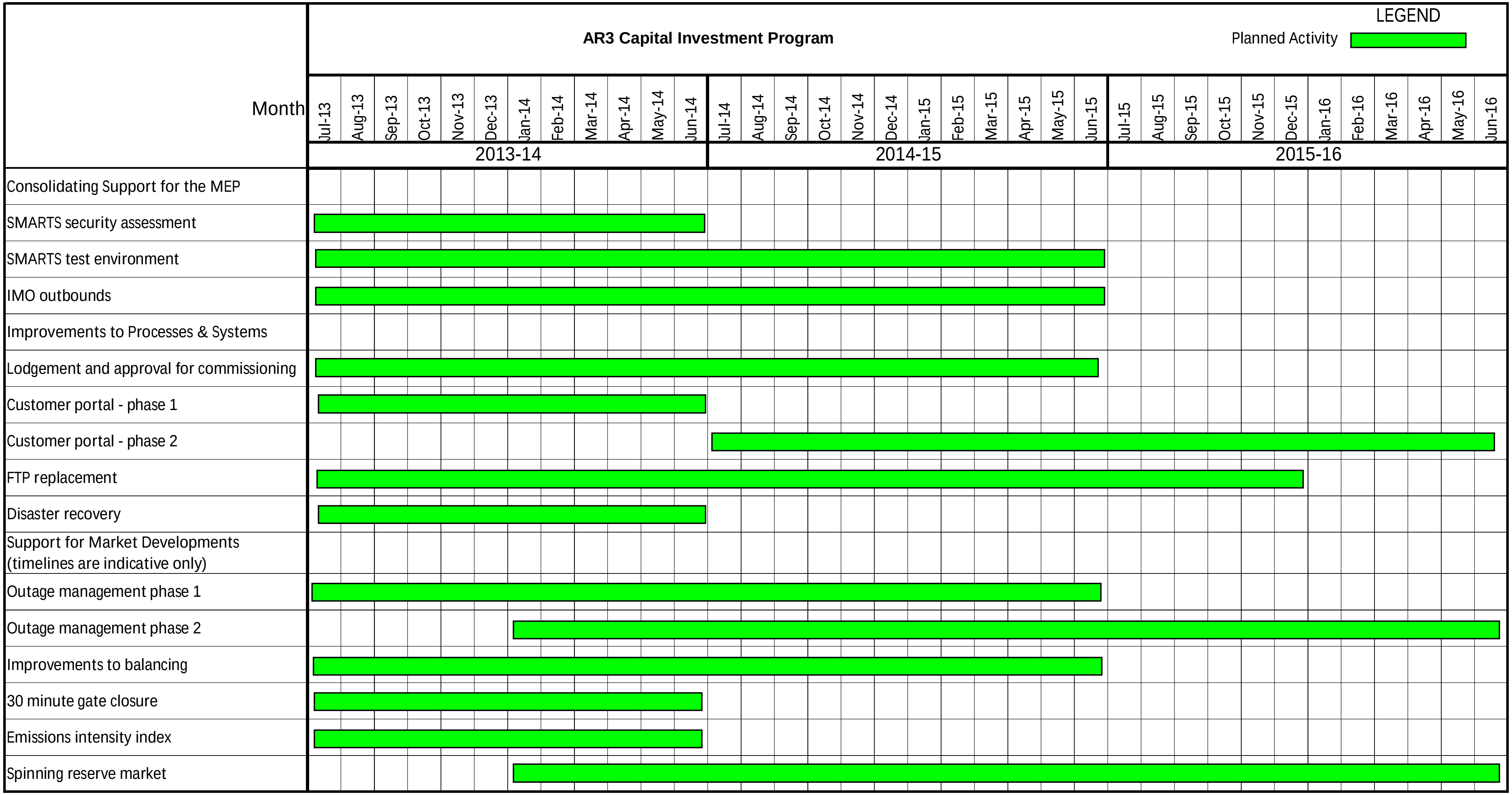

Figure 17: Indicative AR3 Capital Investment Program

7.3 Forecasting methodology

This section describes the methodology and approach used to forecast System Management (Markets)'s capital investment requirements for the AR3 period.

A two stage process has been used:

1. determine the works required to be undertaken in the period
2. estimate the cost of the required works

The two stages are discussed in the following sections.

7.3.1 Determining the AR3 capital works program

System Management (Markets) has forecast the cost of many projects for AR3 using a project specific estimation method which involves the following steps:

a) determining the issue or need

b) developing options to address the need

c) costing those options; and

d) selecting the lowest sustainable cost option

If options analysis is not feasible for projects, for example where they are in the very early stages of development, typical options that have addressed similar issues in the past are selected and costed.

7.3.2 Estimating the AR3 capital works program

Project cost estimates have been applied to the individual projects identified for AR3. Project specific estimations have been built up by using individual cost estimates for each item within a project based on a 'building blocks' approach.

System Management (Markets) has developed a set of cost 'building blocks' for estimating the cost of projects identified in the AR3 capital works program. They are based on common elements such as IT analysts, planning engineers, software materials and fixed price contracts. The cost building blocks draw from the most relevant cost; either the historical or current contracted cost of a standard design or labour type. These provide a pool of itemised costs suitable for consolidation to form whole of project costs. This ensures the application of consistent cost rates[50] to different cost types.

The approach also ensures that the correct escalation rates are applied as necessary. For example, it ensures that fixed price contracts are not escalated, materials costs attract only inflation and the labour costs are escalated in line with the forecast movements in market prices.

[50] The labour costs rates applied are taken from the Resource Type and Labour Rate Governance Manual (DM 8908099).

7.3.3 Adjusting for forecast movements in the market price of labour

System Management (Markets) has escalated the labour component of the forecast capital expenditure for forecast real growth in the market price of labour. Section 6.2.3 of this document provides an overview of the labour cost escalation factors and method of application. As noted previously, materials have not been escalated above inflation.

Table 18 provides the impact of forecast movements in labour input costs for capital expenditure over the AR3 period.

Table 18: Impact of forecast movements in labour costs on capital expenditure

$000 real at 30 June 2013	2013/14	2014/15	2015/16	AR3 total
Labour escalation[1]	43	103	92	237

7.4 Capital raising and recovery

Consistent with section 2.23.10 of the Market Rules, System Management (Markets)'s capital expenditure is financed via Western Power's Statement of Corporate Intent. Before System Management (Markets) commences a market project, approval of the capital expenditure is required from the relevant Western Power Delegated Financial Authority. This requires System Management (Markets) to demonstrate that it can fully recover the capital cost and the costs of capital for the project, which requires a number of key criteria to be met:

- The ERA must approve the capital expenditure for each project either through its AR3 determination or as a result of a re-determination of the AR3 proposal.
- The IPGM requires that the scope of the project be clearly defined and gate 3 estimates (with 10% accuracy) be completed.
- Confirmation of the project scope depends on the market requirements being firmed up through the rule change process and the procedure change process.
- If the gate 3 estimate of capital expenditure of a project would result in a forecast revenue recovery 10% greater than the approved AR3 revenue then System Management (Markets) will seek approval of a Declared Market Project from the IMO.
- If the IMO approve a Declared Market Project then System Management (Markets) will seek a re-determination of the AR3 proposal incorporating the Declared Market Project.
- Approval of the AR3 re-determination must be received.

Western Power requires full recovery of the capital cost and the cost of providing the capital within the life cycle of completion of the capital project.

System Management (Markets) recognises that submitting a revised AR3 proposal will take significant time and resources thus adding to the cost of project implementation and this may delay benefits being realised by participants. To minimise the likelihood of this occuring System Management (Markets) has worked with the IMO and market participants and only included projects in this proposal which are justifiable and achievable.

7.5 Capital expenditure items not yet included

There are a number of potential enhancements to the market which have been identified by the IMO but are not included in the Market Rules Evolution Plan.

System Management (Markets) has not included an allowance for these rule changes in its forecast expenditure for AR3, but acknowledges that should the market development priorities change, these initiatives could significantly impact operations and expenditure requirements.

Should these initiatives proceed, System Management (Markets) will seek funding to support them as declared market projects.

These potential initiatives include:

- **Reserve capacity**

  Changes will be made to the reserve capacity mechanism as a result of the deliberations of the Reserve Capacity Mechanism Working Group. This group is tasked with implementation of a range of recommendations made by the Lantau Group in a report prepared for the IMO "Review of RCM: Issues and Recommendations" (available to download from the IMO website). Implications on System Management (Markets) business from this work cannot be estimated at this point.

- **Constrained network access**

  The move to constrained network access will require optimisation of market generation offers having regard to the network constraints. This impacts directly on the dispatch decisions to be made by System Management (Markets). In the fullest development of the concept a full nodal network pricing model could be implemented. This would require significant investment in systems and control process and resources. The ERA publication "2010 Annual Wholesale Electricity Market Report for the Minister for Energy" discusses the potential for a move towards Constrained Network Access.

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PART C: ALLOWABLE REVENUE

8 Method for calculating revenue

This chapter provides information on the approach to calculating the allowable revenue for the AR3 period, including an overview of the building blocks methodology. The actual revenue calculation can be found in Section 11.

8.1 Key messages

- System Management (Markets) has applied the building blocks methodology to determine target revenue for AR3.
- The building blocks method is commonly used by regulated business and economic regulators to determine ‘target or ‘allowable revenue.
- The building blocks method is consistent with the principles of section 2.23.12(a) of the Market Rules.

8.2 Use of ‘building blocks’ method

System Management (Markets) has applied the building blocks method to determine the allowable revenue for AR3.

The building blocks method is consistent with the principles detailed in section 2.23.12(a) of the Market Rules, as recurring expenditure costs and depreciation form part of the revenue calculation.

System Management (Markets) has determined the allowable revenue on a post-tax basis with an end of year timing assumption. A detailed revenue model has been prepared to support this submission. A copy of the model will be made available to the ERA.

Figure 18 outlines the key building block elements that determine the allowable revenue for AR3.

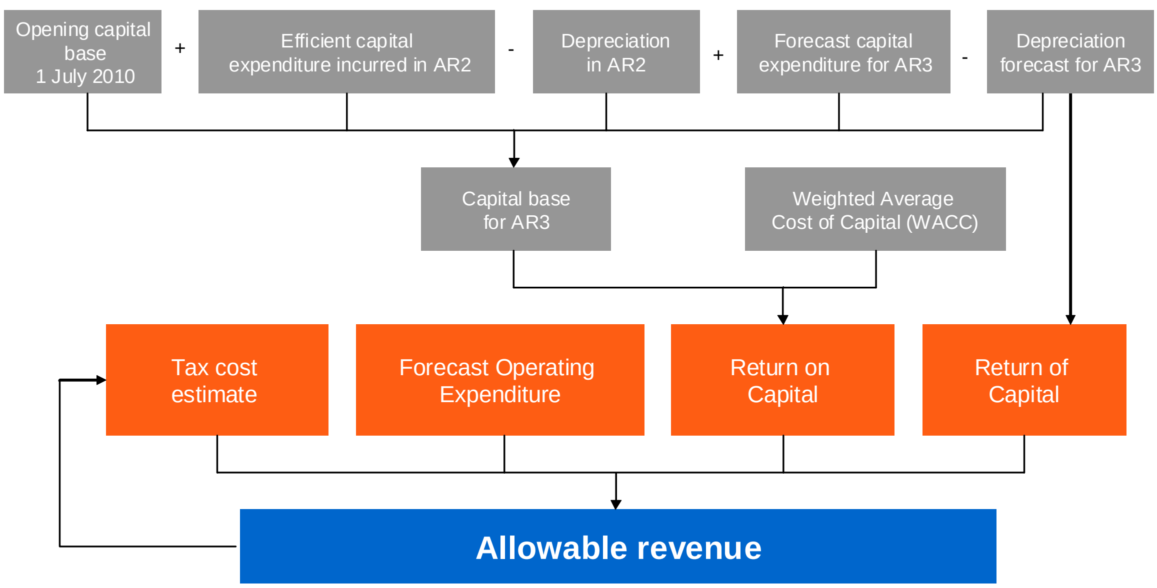

Figure 18: Revenue building blocks

Each building block is discussed in further detail elsewhere in this document. Table 19 provides cross-references to the relevant section where each block is discussed.

Table 19: Cross reference to discussion of individual revenue building blocks

Revenue building block	Relevant section of this document
Tax cost estimate	Section 8.4
Forecast operating expenditure	Section 6
Return on capital	Section 10
Return of capital	Section 9.3.1

8.3 Revenue modelling

The revenue model implements the building block method to calculate the allowable revenue. A copy of the revenue model calculations and outputs is provided in Appendix G.

The following formula represents how the allowable revenue for providing system operation services is calculated:

$$\mathbf{AR_t = r.RAB_{t,open} + Dep_t + O\&M_t + Tax_t - Imputation\ Credits_t}$$

where:

AR_t = allowable revenue for providing system operation services in year t.

r = WACC (in real post-tax terms)

$RAB_{t,open}$ = opening value of the capital base (which takes into account forecast capital expenditure over AR3)

Dep_t = depreciation in year t (which takes into account forecast capital expenditure over AR3)

$O\&M_t$ = forecast of operating and maintenance costs for year t

Tax_t = estimate of tax costs for year t

$Imputation\ Credits_t$ = estimate of the value of the imputation credits to investors for year t

The revenue model incorporates the following high level assumptions:

- revenue modelling occurs on a real post-tax basis
- all expenses are modelled on an as-incurred basis
- end of year timing for modelling revenues and expenses in real terms
- the estimate of tax costs is calculated based on:
  - all calculations of the tax costs occur in nominal dollar terms. The tax is then converted into real dollar terms for inclusion in the building block calculation
  - the interest cost is based on:
    - the opening debt balance for each year of the AR3 period is based on 60% (being the benchmark gearing assumed in the WACC) of the nominal opening value of the capital base

  - o the interest rate applied to the opening debt balances is based on the nominal cost of debt that is consistent with the WACC calculation

- tax depreciation is calculated from:
  - o System Management (Markets)'s tax asset base roll forward over the AR3 period, based on the remaining life of the opening tax asset base and the tax lives of the various capital assets. This reflects that tax depreciation is generally based on a much shorter tax life or calculated in a different way
- any estimated tax losses are carried forward.

8.4 Modelling System Management (Markets) tax asset base

Adopting a post tax revenue modelling assumption requires System Management (Markets) to determine a tax asset base.

Western Power engaged Ernst & Young to determine the most appropriate and reliable information to use as a starting tax asset base for AA3. As part of this work Ernst & Young determined a value for System Management (Markets) tax asset base as at 30 June 2012 as shown in Table 20.

Table 20: Tax asset base as at 30 June 2012

$	Tax asset base ($000 nominal)
System Management (Markets)	112

Ernst & Young calculated the opening tax asset base at 30 June 2012 from:

- Western Power's fixed asset register as at 1 April 2006
- additions and disposals for 1 April 2006 – 30 June 2006 and the financial years 2006/07, 2007/08, 2008/09, 2009/10, 2010/11 and 2011/12
- depreciation based on effective lives for depreciation purposes using the prime cost method.

Adopting the same methodology used for Western Power's AA3 process ensures that there is no double counting or missing value.

For the last year of the AR2 period and the AR3 period System Management (Markets) has rolled forward the value of the tax asset base by:

- adding all capital expenditure on an as incurred basis
- deducting the depreciation based on the applicable effective tax lives calculated on:
  - a straight-line basis for the initial tax asset base
  - the diminishing value method for subsequent additions to the tax asset base in the last year of the AR2 period and the AR3 period

It should be noted that no capital contributions are included in the tax asset base.

Western Power determines the life to use for tax depreciation purposes from the Commissioner of Taxation's effective lives. System Management (Markets) has adopted a four-year tax life as its assets are primarily IT assets.

9 Capital base

The building blocks method requires a capital base to be established. This chapter describes the method for rolling forward the System Management (Markets) capital base and calculating its closing value for AR2. It also includes forecasts of the capital base for each year of the AR3 period and considers:

- forecasts of capital investment
- forecasts of capital contributions
- inflation assumptions
- depreciation
- economic lives of assets
- calculation of opening capital base for AR4

9.1 Key messages

- The building blocks method requires an opening and closing capital base to be established.
- System Management (Markets) has established the capital base value as at 30 June 2013 using the roll-forward method.
- System Management (Markets) rolls forward the capital base over AR3 based on its forecast of capital expenditure. This capital base is used in determining the allowable revenue for AR3.
- System Management (Markets) has adopted the straight-line depreciation method for the all of its investment.
- System Management (Markets) has amended the asset lives for AR3 IT assets to four years.
- No asset disposals are forecast over the AR3 period.

Table 21 shows the forecast opening and closing capital base values.

Table 21: Opening and closing AR3 capital base

Capital base	Forecast opening value for AR3 at 1 July 2013 ($ 000 real at 30 June 2013)	Forecast closing value for AR3 at 30 June 2016 ($ 000 real at 30 June 2013)
System Management (Markets)	12,226	5,288

9.2 Establishing the opening capital base

Detailed calculations of the capital base over AR2 are included in the revenue model attached at Appendix G.

System Management (Markets) has forecast the opening capital base value at 1 July 2013 using the roll-forward method by:

- rolling forward the capital base value at the commencement of AR1 (as System Management (Markets) have not previously determined a capital base)
- adding all new capital investment incurred or forecast to be incurred[51] during AR1 and AR2
- applying the consumer price index (weighted average of eight capital cities) to the rolled-forward capital base value
- deducting the depreciation applicable to the actual capital expenditure based on a 2.5 year life for IT assets and a 4 year life for SMARTS[52]

When forecasting the opening capital base value at 1 July 2013 System Management (Markets) has applied Western Power's Ringfencing Standard (see Appendix B) and the Cost Sharing Methodology, to ensure that the opening capital base reflects capital expenditure incurred by System Management (Markets).

The initial capital base at 30 June 2007 is $2.153 million (real as at 30 June 2013).

The initial capital base value at the commencement of AR1 was $1.825 million (nominal).[53] This initial capital base value was determined from the written-down value of the $2.500 million (nominal) of market establishment costs approved by the Minister for Energy in System Management's 2006/07 budget.[54]

In the AR1 determination the ERA accepted that these costs were designated as market establishment costs by the Minister.[55] This initial investment was fully depreciated over AR1 and AR2 and no longer contributes towards the opening capital base value at 1 July 2013.

Table 22 lists the actual and forecast capital expenditure undertaken during AR1 and AR2.

Table 22: Capital expenditure to be added to the capital base

Asset Group	Capital expenditure ($ 000 real as at 30 June 2013)					
	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13 (Forecast)
Market establishment	0	0	0	0	0	0
IT	337	1,027	617	825	620	449
SMARTS	0	0	0	0	6,932	6,420

[51] The capital expenditure that is forecast to be incurred during 2012/13 has been used to determine the capital base. An adjustment for any variance between actual and forecast capital expenditure will be made during AR3, as discussed in section 12.3 of this document.
[52] System Management (Markets) has received expert advice on the expected life of SMARTS. Based on this advice System Management (Markets) has adopted a four year life for the SMARTS investment that occurred in AR2.
[53] System Management Allowable Revenue Application 1 July 2010 to 30 June 2013, 30 November 2009, pg 21-22
[54] Economic Regulation Authority, Allowable Revenue Determination – System Management, 30 March 2007, para 53
[55] Ibid.

Asset Group	Capital expenditure ($ 000 real as at 30 June 2013)					
	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13 (Forecast)
Total	**337**	**1,027**	**617**	**825**	**7,552**	**6,869**

The actual capital expenditure over AR1 has previously been considered by the ERA in the AR2 determination.[56] This investment was fully depreciated over a 2.5 year life over AR1 and AR2 and no longer contributes towards the opening capital base value at 1 July 2013.

Actual capital expenditure over AR2 is discussed in detail in section 4.4.1.

Table 23 details the calculation of the capital base value at 30 June 2013.

Table 23: Derivation of capital base at 30 June 2013

($ 000 real as at 30 June 2013)	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13 (Forecast)
Opening capital base value		2,153	1,833	1,930	1,288	907	7,759
Plus capital expenditure		337	1,027	617	825	7,552	6,869
Less depreciation		-657	-930	-1,259	-1,206	-701	-2,401
Closing capital base value	**2,153**	**1,833**	**1,930**	**1,288**	**907**	**7,759**	**12,226**

Actual capital investment for 2012/13 was not available at the time of writing this proposal. Therefore the opening capital base has been calculated using forecast capital expenditure for 2012/13.[57]

System Management (Markets) has applied the consumer price index (weighted average of eight capital cities) to determine the rolled-forward capital base value. Table 24 shows the inflation values applied when determining the rolled-forward capital base value to 30 June 2013.

Table 24: Inflation values applied when determining 30 June 2013 capital base

Financial year ending:	30 June 2007	30 June 2008	30 June 2009	30 June 2010	30 June 2011	30 June 2012	30 June 2013 (Forecast)
June CPI	157.5	164.6	167.0	172.1	178.3	180.4	
Inflation	2.07%	4.51%	1.46%	3.05%	3.60%	1.18%	3.00%

The inflation values use actual CPI data published by the Australian Bureau of Statistics for the June quarter, where available. Where Australian Bureau of Statistics data is not

56 Economic Regulation Authority, Allowable Revenue Determination – System Management, 31 March 2010, para 36 & 86

57 To ensure System Management (Markets) and market participants are held financially neutral in the event of a variation between forecast and actual capital expenditure, Market Rule 2.23.7 requires adjustments to the revenue during the AR3 to correct for this variation.

available, System Management (Markets) has used forecast CPI data from the Reserve Bank of Australia's Statement on Monetary Policy.

Actual inflation for 2012/13 was not available at the time of writing this proposal. Therefore the opening capital base has been calculated using forecast inflation for 2012/13.

To ensure Western Power and customers are held financially neutral in the event of a variation between forecast and actual inflation, System Management (Markets) proposes that the capital base at the commencement of the next review period (AR4) be adjusted to correct for this variation.

An adjustment will also be made to the allowable revenue for AR4 to compensate System Management (Markets) (or customers) for any revenue foregone (or additional revenue recovered) as a result of a variation from forecast in 2012/13.

The allowable revenue for AR3 will not be adjusted for any differences between the 2012/13 forecast and actual inflation.

9.3 Capital base value over AR3

Forecast capital expenditure is included in the calculation of the closing AR3 capital base (30 June 2016).

Table 25 provides an overview of the forecast capital base values for each year of AR3.

Table 25: Assessment of capital base over AR3

($ 000 real at 30 June 2013)	2012/13	2013/14	2014/15	2015/16
Opening capital base value		12,226	10,890	8,534
Plus capital expenditure		2,429	1,769	1,142
Less depreciation		-3,766	-4,125	-4,387
Closing capital base value	**12,226**	**10,890**	**8,534**	**5,288**

9.3.1 Depreciation over AR3

System Management (Markets) has used the straight-line approach over the life of the asset to determine the depreciation[58].

For capital expenditure made during the AR1 and AR2 periods any depreciation during AR3 is based on the economic life that applied at the time the capital expenditure was incurred. This was generally 2.5 yrs (20% in the first year, and 40% in the subsequent 2 years).

Western Power's accounting policy allows for it to depreciate assets based on the expected life of the asset.[59] Based on expert advice and practices in other jurisdictions, System Management (Markets) has determined that the useful life of the SMARTS platform is four years. System Management (Markets) considers that four years is the appropriate timeframe

[58] The depreciation component of the calculation of allowable revenue as provided for in section 2.23.12 (a) of the Market Rules, will differ from the depreciation charge that appears in the statutory financial accounts, or in Western Power's tax return due to different asset lives adopted and different valuation methods of the capital base values.

[59] This decision has been made applying AASB 116 which states that the depreciable amount of an asset shall be allocated on a systematic basis over its useful life. The estimation of the useful life is a matter of judgement based on the experience of the entity with similar assets, giving consideration to such things as expected usage, technical or commercial obsolescence arsing from changes or improvements to production or from a change in market demand.

given changing technologies and the continued evolution of the Market Rules over time. Other investments over AR3 are of a similar nature to the SMARTS program and therefore a four-year life will be adopted to determine the depreciation for all AR3 capital expenditure.

Table 26: Economic life for depreciation purposes

Asset Group	Economic Life
IT	4 years
SMARTS	4 years

9.3.2 Asset disposals over AR3

System Management (Markets) has not forecast any asset disposals over the AR3 period. System Management (Markets) will adjust the capital base for actual asset disposals that occur over the AR3 period when setting the capital base for the AR4 period. System Management (Markets) will continue to value the asset disposals based on the gross asset sales proceeds.

9.3.3 Equity raising costs

System Management (Markets) has included equity raising costs in its revenue modelling for AR3. This has been done in recognition that equity raising costs are a legitimate expense for a benchmark firm where external equity funding is the least-cost option. Through benchmark cash flow modelling System Management (Markets) is able to demonstrate that cheaper sources of funding, such as retained earnings, are insufficient to fully fund its capital expenditure program, whilst complying with the benchmark financing assumptions. Therefore it is appropriate to incorporate equity raising costs into the capital base in AR3.

System Management (Markets) has applied the same cash flow modelling method from the ERA's Final Decision for Western Power to calculate its equity raising cost proposal for AA3. System Management (Markets) has determined that the useful life of the SMARTS platform is four years and proposes that, consistent with the ERA's methodology, 25% of dividends should be assumed to return to the business through a dividend reinvestment plan at a cost of 1%. Any further requirement for equity is assumed to come from seasoned equity offerings, at a cost of 3%. In keeping with the Australian Competition Tribunal's April 2011 Decision on the value of imputation credits, a 70% payout of imputation credits is assumed.

The required equity raising costs have been calculated in accordance with the methodology set out above in the post-tax revenue model (Appendix G). System Management Market's benchmark equity raising costs for AR3 are presented in Table 27.

Table 27: Equity raising costs to be amortised in the capital base ($ 000 real as at 30 June 2013)

	2013-14	2014-15	2015-16	Total
Equity raising costs	2	0	67	**70**

9.4 Treatment of depreciation in establishing the opening capital base for AR4

System Management (Markets) will establish the capital base at the commencement of AR4 using the forecast depreciation over AR3, as detailed in Section 10. Using forecast depreciation ensures that the capital base at the start of AR4 reflects the depreciation recovered through the allowable revenue. This is consistent with the financial capital maintenance[60] principle. Using forecast depreciation ensures that System Management (Markets)'s allowable revenue, over time, will recover all depreciation relating to actual capital expenditure.

[60] Also known as NPV=0

10 Return on investment

The rate of return on investment is a determinant of System Management (Markets)'s revenue. The rate of return is applied to the projected capital base at the beginning of each year for the purpose of determining the return on the projected capital base. The return on investment forms part of the building blocks from which total revenue is calculated.

This chapter details the calculation of System Management (Markets) proposed rate of return on its capital base during the AA3 period. It explains the methods and assumptions applied to derive the proposed allowance by calculating the weighted average cost of capital (WACC).

10.1 Key messages

- System Management (Markets) has calculated the real post-tax WACC using a formulation – including the Capital Asset Pricing Model (CAPM) – which is consistent with the approach accepted by the ERA in AA3 and access arrangement determinations for other regulated businesses.
- It is important for System Management (Markets) to earn a return on investment to allow it to attract sufficient funds to invest in its systems. The cost of accessing capital should be paid for by System Management (Markets)'s customers and not Western Power's access connection customers.
- To assist in the estimation of the WACC, expert advice was sought on the WACC and its constituent parameters from KPMG.

10.2 Why is a WACC appropriate for System Management (Markets)

An appropriate cost of capital ensures that a regulated business recovers the opportunity cost of capital employed to provide regulated services. Earning a return on investment is generally accepted regulatory practice. The Allen Consulting Group's November 2007 report[61] to the IMO clearly articulates the need for a cost of capital in a regulated environment:

> *In setting regulated prices, the challenge for the regulator is to ensure that the prices are sufficient for the regulated business to be able to recover all its costs (operating and maintenance, and depreciation), as well as earn an appropriate return on existing and new capital invested in the relevant asset.*
>
> *One of the regulator's objectives in setting efficient prices is to ensure that investment funds continue to be drawn into the regulated industry, so that the services that are valued by customers continue to be provided. Another objective, however, is to ensure that customers pay the lowest price commensurate with the ongoing provision of the service and an efficient level of new investment. The logical reconciliation of these objectives is for the pricing regime to create the expectation that investors will receive a return equal to the cost of capital associated with the activities.*

Therefore, it is clear that in establishing an appropriate cost of capital, the equity portion of the WACC is as much a legitimate cost as the debt portion. The WACC should be recovered from System Management (Markets) customers that receive the services provided from the

[61] The Allen Consulting Group, Review of the Weighted Average Cost of Capital for the Purposes of Determining the Maximum Reserve Capacity Price, November 2007, Available from: http://www.imowa.com.au/f345,53574/ACG_Final_Report_IMO01_FINAL_221107.pdf

capital investment. If it is not, these costs are recovered from Western Australian tax payers and may also reduce Western Power's ability to attract the necessary funds required to provide services.

To assist in the estimation of the WACC, System Management (Markets) sought expert advice on the WACC and its constituent parameters from KPMG. A copy of KPMG's report is provided in Appendix H.

10.3 Benchmark or actual WACC

In accordance with regulatory precedent, System Management (Markets) has applied a benchmark cost of capital rather than an actual cost of capital in its estimation of the WACC. The rationale in applying a benchmark approach is that it aligns more closely with the legislative framework applied to System Management (Markets), in terms of costs being incurred on an efficent basis[62]. As stated in the KPMG report:

"*A benchmark ensures that any cost of capital included within the allowable revenue for System Management Markets will contribute to ensuring the recovery of only those costs incurred by an efficient prudent provider. This is more the case than with an 'actual' cost of capital which may include inefficiencies or distort electricity market price signals*[63]*.*"

System Management (Markets)'s approach is also consistent with the ERA's recent decision for the broader Western Power business as part of AA3. The ERA considered the implications of adopting an actual estimate of Western Power's debt costs and determined that it is appropriate to adopt the benchmark approach.

10.4 Approach to estimating the WACC

In estimating the WACC System Management (Markets) has sought and relied on expert advice from KPMG. Given the current economic climate, System Management (Markets) has had particular regard to recent developments in global capital markets – most notably the ongoing high level of volatility in the wake of the global financial crisis and the ongoing uncertainty surrounding sovereign debt in Europe and the United States. System Management (Markets) has also examined recent Australian regulatory WACC decisions by both the ERA and AER.

In light of the ERA's recent regulatory decisions, System Management (Markets) has adopted a real post-tax formulation of the WACC. This approach is identical to the one approved by the ERA for Western Power in AA3. It is considered that this formulation meets the Market Rules requirements.

The post-tax real WACC formulation is as follows:

$$\mathbf{WACC_{real\ post\text{-}tax} = [(1 + WACC_{nominal\ post\text{-}tax}) \,/\, (1 + \pi_e)] - 1}$$

where:

$$\mathbf{WACC_{nominal\ post\text{-}tax} = R_e * E/V + R_d * D/V}$$

$\mathbf{R_e}$ is the nominal post-tax expected rate of return on equity – the cost of equity

$\mathbf{R_d}$ is the nominal pre-tax expected rate of return on debt – the cost of debt

E/V is the proportion of equity in the total financing (which comprises equity and debt)

D/V is the proportion of debt in the total financing

[62] For example, section 122(2) of the *Electricity Industry Act 2004*

[63] Page 16, Western Power System Management Weighted Average Cost of Capital, KPMG, October 2012,

π_e is expected inflation

Under this approach, the cost of equity, (R_e), is determined using the Capital Asset Pricing Model (CAPM) as follows[64]:

$$R_e = R_f + \beta.MRP$$

where

R_f is the risk free rate

β is a measure of the systematic risk of Western Power, relative to the market and

MRP is the market risk premium

The cost of debt (R_d) is estimated as the risk free rate (R_f) plus a debt risk premium (DRP). The cost of debt also includes an additional allowance for debt issuance costs.

The WACC formulation set out above is comprised of a number of constituent parameters, some of which cannot be measured directly and many of which are subject to estimation error. Ultimately however, a single 'point estimate' of the WACC is required for use in the revenue building blocks formula, to calculate target revenue.

The following sections explain the basis for the values for each WACC parameter.

10.4.1 Nominal risk free rate

The risk free rate is the basic building block of both the cost of equity and the cost of debt. Its value is impacted by various factors, the most significant of which include the averaging period and term adopted.

10.4.1.1 Averaging period

Most regulators aim to set the risk free rate as close as possible to the start of the regulatory control period. However, this approach is questionable during periods of extreme market volatility. The Australian Competition Tribunal (ACT) acknowledged this in allowing Energy Australia to adopt a sampling period prior to the onset of the global financial crisis (GFC)[65].

KPMG's expert advice suggests that current market financial conditions could be classified as abnormal. Furthermore, in its recent Statement on Monetary Policy the RBA noted that "Low appetite for risk has seen long-term interest rates faced by highly rated sovereigns, including Australia, remain at exceptionally low levels[66]".Therefore, KPMG recommends that an averaging period of 20 days that is closest to the regulatory control period prior to the emergence of the marked increase in European sovereign debt risk that commenced in 2011.

System Management (Markets) has adopted KPMG's advice with the adoption of a 20 business day averaging period for the risk free rate and debt risk premium commencing on 14 June 2011 and ending on 11 July 2011.

[64] The CAPM is widely used for this purpose, and its use is contemplated by clause 6.66(b) of the Access Code. The CAPM was applied to determine Western Power's cost of equity for AA2.
[65] Application by EnergyAustralia and Others (No 2) [2009] ACompT9
[66] Reserve Bank of Australia, Statement by Glenn Stevens, Govenor: Monetary Policy Decision, 2 October 2012

10.4.1.2 Term of risk free rate

System Management (Markets) has adopted the yield on ten-year Commonwealth bonds as a proxy for the nominal risk free rate. It is noted that the ERA in its most recent decision[67] (AA3) adopted a five year term. However, it is considered that the ERA erred in its reasoning. In particular:

- the ERA erred in finding that current debt profiles for Australian rated utilities indicate that the appropriate term of debt for the sample of securities is approximately five years. Correctly analysed, the debt profiles relied upon by the ERA show the appropriate term of debt is ten years.
- the ERA erred in finding that Standard & Poors presented data showing more than 50% of debt financing by Australian rated businesses is with terms to maturity of less than five years. The Standard & Poors data represents the remaining term to maturity, not the term at issuance.
- the ERA erred in finding that Australian businesses have not preferred to raise long term debt. The evidence shows Australian businesses have preferred to raise long term debt.
- the ERA erred in finding that (on the assumption that the term of the risk free rate is required to be consistent with the term of the cost of debt raised by Australian rated companies), the five year term is appropriate (paragraph 1393). The evidence presented shows Australian businesses have preferred to raise long term debt.
- the ERA's reliance on the yields on five year CGS for the purposes of estimating the risk free rate is contrary to the weight of regulatory decisions which estimate the risk free rate using the yields on ten-year CGS.

KPMG's expert advice also considers that there is insufficient justification to depart from the use a ten year term[68].

Based on this methodology and the proposed averaging period, System Management (Markets) proposes a nominal risk free rate of 5.15%.

10.4.2 Capital structure

Capital structure refers to the mix of debt and equity used to finance an asset or business. The WACC formulation produces an estimate of the cost of capital of an asset that is funded by a mix of equity and debt financing. The contribution made by the respective costs of equity and debt to the WACC must be weighted in proportion to the mix of these two funding sources in the capital structure. Therefore, one of the WACC parameters that must be specified is the capital structure.

Accordingly, System Management (Markets) proposes to adopt a benchmark capital structure of 60% debt to total assets for AR3. This is consistent with KPMG's expert advice and regulatory precedent.

10.4.3 Market risk premium

The market risk premium (MRP) is the expected return over the risk free rate that investors require to invest in a well-diversified portfolio of assets. It represents the risk premium that investors expect to earn for bearing systematic or non-diversifiable risk.

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[67] ERA, Western Power's Proposed Revised Access Arrangement for the Western Power Network: Final Decision, September 2012

[68] Western Power System Management Weighted Average Cost of Capital, KPMG, October 2012,

System Management (Markets) has adopted an MRP of 6% based on regulatory precedent and KPMG's expert advice. It is noted that this is substantially different to the MRP proposed by the broader Western Power business as part of AA3 (7.75%). The difference is attributable to the fact that System Management (Markets) has adopted a pre-GFC risk free rate, whereas the risk free rate used for AA3 was based on spot rates significantly impacted by unusual conditions in the market.

10.4.4 Value of imputation credits (gamma)

The value of gamma is the value of franking credits distributed to shareholders. Gamma is the product of two components, the distribution ratio (F) and utilisation rate or 'theta' (θ). The distribution ratio represents the proportion of franking credits that are distributed to shareholders by attaching them to dividends and theta is the value of each franking credit.

This is represented by the following formula:

$$\gamma = F \times \theta$$

In estimating the value of imputation credits System Management Market has had regard to recent regulatory decisions, the ACT decision on Energex Limited and the advice of its consultant KPMG.

In October 2010 the ACT found that there was substantial evidence to suggest that the AER had made a material error of fact and exercised its discretion incorrectly in the calculation of both the distribution ratio and utilisation rate. Subsequently, both of the components of gamma were reviewed by experts, the AER and the ACT. These findings have resulted in revisions to the calculation of the distribution ratio and utilisation rate, which now provide for a gamma of 0.25.[69]

Following the ACT's decision, Australian regulators have consistently applied an estimate of 0.25 for the value of gamma. In June 2011 the AER delivered its Final Decision for Envestra and APT Allgas, in which it stated:

> *There is no new evidence currently before the AER that would cause it to depart from the findings of the Tribunal in respect of gamma.*[70]

System Management (Markets) therefore proposes a value for gamma of 0.25 (being the product of the distribution ratio of 70% and the utilisation rate of 35%).

10.4.5 Debt margin

The debt margin reflects the risk margin on debt that is over and above the risk free rate. It is composed of two elements:

- the debt risk premium (which is the additional return required by investors above the risk free rate for providing debt finance to a firm with a particular credit rating)
- the cost of issuing debt

The total allowance for the cost of debt (R_d) is calculated by adding the debt margin to the risk free rate.

Explanations of the basis of the assumed benchmark credit rating, the debt risk premium range and the allowance for the cost of issuing debt are set out below.

[69] *Application by Energex Limited (Gamma) (no 5) [2011] ACompT 9*, 12 May 2011.
[70] Page 57, *Final Decision Envestra, Access arrangement proposals*, AER, June 2011.

10.4.5.1 Benchmark credit rating

For regulated energy businesses, Australian regulators have typically adopted a target credit rating of BBB+. However, due to a limited number of credit ratings for Australian energy firms in the Australian financial market, most Australian regulators tend to combine the credit rating of BBB/BBB+ as the benchmark credit rating. In its final decision for AA3, the ERA adopted a credit rating using an average of A-, BBB+ and BBB rated firms. System Management (Markets) has a number of concerns with this approach:

- the ERA included government-backed firms within the sample, which masks the true credit risk of these organisations
- the ERA was selective in excluding some firms with low credit ratings (such as ATCO Gas, Envestra and Dampier to Bunbury Natural Gas Pipeline)
- it is inconsistent with the credit rating provided for every other business regulated by the ERA
- it is unique in an Australian regulatory context.

Therefore, System Management (Markets) considers there is insufficient evidence to move away from a BBB+ credit rating. Therefore, System Management (Markets) has adopted a credit rating of BBB+.

10.4.5.2 Debt risk premium

The debt risk premium is the additional return over the risk free rate required by investors to hold debt that is not risk free. The purpose of including the debt risk premium within the expected cost of debt is to compensate a regulated firm for the benchmark cost of capital.

System Management (Markets) notes that the ERA applied its bond yield methodology to the broader Western Power business in AA3. However, expert advice provided by Competition Economists Group (CEG) suggests that the bond yield approach was not sufficiently developed or sophisticated enough to replace the expertise provided in Bloomberg's fair value estimates.

System Management (Markets) proposes to use Bloomberg fair value curves (FVC) to determine the debt risk premium. This is consistent with advice from KPMG and the approach of businesses regulated by the AER. A ten year term has been adopted to be consistent with the term used for the risk free rate.

To estimate the debt risk premium over a ten-year period it is necessary to extrapolate the Bloomberg BBB seven-year curve out to ten years. A universally accepted extrapolation method does not exist. In recent regulatory decisions the AER has adopted the method of adding the spread of Bloomberg's AAA rated estimates from seven to ten years, as averaged over the last 20 trading days to 22 June 2010, when these estimates were last available[71].

In the past the AER has also supported the use of Bloomberg's Commonwealth Government Securities as a proxy for Bloomberg AAA rated bonds[72]. Extrapolating the Bloomberg seven-year BBB fair yield curve using the spread between seven and ten-year Commonwealth Government Securities yields provides a reasonable method for extrapolating the Bloomberg BBB fair yield curve to ten years[73].

The debt risk premium is based on:

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[71] AER 2011, *Envestra Access arrangement proposal for the Qld gas network*, Final Decision.
[72] AER 2010, *AER draft approach for measuring the debt risk premium for the Victorian Electricity Distribution Determinations*, 27 September 2010.
[73] Western Power, *Submission to the ERA Discussion Paper – Estimating the Debt Risk Premium*, January 2011.

- the average annualised Australian Bloomberg BBB seven-year FVC over 5 March 2012 to 30 March 2012 of 7.63%; *less*
- the average annualised seven-year CGS yield over 5 March 2012 to 30 March 2012; *plus*
- a range of 0.00% to 0.36% to adjust the estimate to a ten year term.

Using the value at the lower end of the range provides a debt risk premium of 3.67%.

It is noted that the sampling period differs from that used for the risk free rate. KPMG's expert advice is that this is not an issue because the decline in yields on both risk free and corporate bonds would be broadly similar.

10.4.5.3 Debt issuance costs

Debt issuance or establishment costs represent the transaction costs associated with raising debt capital. In accordance with the methodology established by the Allen Consulting Group[74], the debt margin includes an allowance of 12.5 basis points per year for debt establishment costs. This is consistent with KPMG's expert advice, the ERA's approach in AA3 and in its other recent decisions for WA Gas Networks and the Dampier to Bunbury Pipeline.

10.4.5.4 Debt margin

Based on the debt risk premium and debt issuance cost estimates set out above, System Management (Markets) proposes a debt margin of 3.80%.

10.4.6 Expected inflation

Expected inflation is used to convert the nominal WACC into a real WACC.

Most Australian regulators use the geometric mean of RBA inflation forecasts to estimate the expected inflation rate. A commonly used method prior to this was applying the Fisher equation to yield differentials between nominal and real Commonwealth Government Securities. This method fell out of favour during the GFC as liquidity declined in these bond markets.

In its final decision for AA3, the ERA reverted back to this method. KPMG's expert advice suggests that there is insufficient evidence to justify departing from using the RBA's inflation forecasts due to the uncertainty in the economic environment. Therefore, System Management (Markets) has used the RBA's inflation forecasts.

KPMG has estimated the annual rate of inflation based on the geometric mean over a ten-year period of 2.52%.

10.4.7 Equity beta

The equity beta represents the volatility of the business' returns relative to the market.

As an unlisted entity, the equity beta for System Management (Markets) is not directly observable and must be estimated with reference to proxies. KPMG considers that using electricity transmission and distribution businesses as comparators for the non-market components of the WACC is reasonable. In making its assessment, KPMG also considered

[74] ACG, *Debt and equity raising transaction costs*, December 2004, pp. 27-53.

analysis undertaken for the Commission for Energy Regulation in Ireland., which comfirms this approach.

In terms of an appropriate equity beta for electricity transmission and distribution businesses, most Australian regulators have adopted a value of 0.80. While the ERA used 0.65 for Western Power, 0.80 was considered within the reasonable range. It should also be noted that the analysis underpinning the 0.65 had high standard errors and was unreliable. Therefore, 0.80 is a reasonable estimate for beta.

10.5 Rate of return

The point estimate for the WACC of 6.66% real post-tax has been determined using the input parameters set out in Table 28.

Table 28: Pre-tax real WACC parameter estimates

Parameter	Basis of estimate	Point estimate
Nominal risk free rate*	This is the effective annual nominal yield on 10 year Government bonds using an averaging period of 14 June 2011 to 11 July 2011.	5.15%
Inflation forecast*	This is a 10 year forecast estimated from the inflation forecasts published by the Reserve Bank of Australia (RBA) and the long term inflation target of the RBA. The approach is consistent with that applied recently by other Australian regulators.	2.52%
Real risk free rate	This value has been calculated from the nominal risk free rate and inflation forecasts set out above.	2.57%
Equity beta	This range is based on regulatory precedent and expert advice from KPMG.	0.80
Market risk premium (MRP)	This range is based on regulatory precedent and expert advice from KPMG.	6.00%
Capital structure (debt to total value)	This value is consistent with regulatory decisions around Australia. Prevailing market evidence does not provide a compelling case to justify a departure from this benchmark.	60.00%
Debt margin*	The range of values reflects the yields on the 7 year BBB Bloomberg fair value yield curve, extrapolated to 10 years. The estimate reflects average yields over a 20 trading day period to 30 March 2012. The estimate also includes an allowance of 12.5 basis points per year for debt establishment costs.	3.80%
Value of imputation credits (gamma)	This value is consistent with the decision of the Australian Competition Tribunal made in May 2011 and the subsequent decisions of the ERA.	25.00%
Real post-tax WACC	Output of above parameters	6.66%

System Management (Markets) proposal is based on a thorough and robust analysis of the individual parameter values that must be combined to form a reasonable estimate of the WACC. The proposal satisfies the requirements of the Market Rules, including the Market Rules objective set out in section 1.2.

11 Allowable revenue

This chapter details System Management (Markets)'s revenue for the AR3 period.

11.1 Key messages

- The allowable revenue over AR3 is $43.024 million
- The allowable revenue includes a smoothing adjustment to reduce the volatility of prices.

11.2 Adjustments for AR1 & AR2

System Management (Markets) has incorporated an adjustment into the 2013/14 allowable revenue calculation to reflect any differences between actuals and forecasts over AR1 & AR2 that have not already been accounted for through the annual budget submissions. The adjustment to the 2013/14 allowable revenue calculation is determined through a cash flow analysis of the revenues and expenditures over AR1 & AR2, taking into account the initial capital base and the closing capital base.

The purpose of the adjustment for AR1 and AR2 is to keep System Management (Markets) financially neutral for differences over AR1 and AR2 as a result of differences between:

- actual operating expenditure in 2011/12 and the operating expenditure provided for in the AR2 submission
- forecast operating expenditure for 2012/13 and the operating expenditure provided for in the AR2 submission
- actual capital expenditure in 2011/12 and the capital expenditure provided for in the AR2 submission
- forecast capital expenditure for 2012/13 and the capital expenditure is provided for in the AR2 submission
- actual revenue earned by System Management (Markets) in 2011/12 and the revenue provided for in the 2011/12 budget letter
- forecast revenue to be earned by System Management (Markets) in 2012/13 and the revenue provided for in the 2012/13 budget letter
- any other adjustment due to actual revenue and actual expenses over the AR1 and AR2 period that may not have been corrected for previously.

11.3 Allowable revenue

System Management (Markets) has calculated allowable revenue by applying the building blocks method. This section brings together the building blocks of the allowable revenue. Table 29 presents the AR3 allowable revenue.

Table 29: Composition of allowable revenue

($ 000 real at 30 June 2013)	2013/14	2014/15	2015/16	Present value
Operating expenditure	8,270	8,609	8,670	22,466

($ 000 real at 30 June 2013)	2013/14	2014/15	2015/16	Present value
Plus depreciation	3,766	4,125	4,387	10,772
Plus return on investment	814	725	568	1,870
Plus tax payable	0	544	1,674	1,857
Less value of imputation credits	0	-136	-418	-464
Forward-looking costs	**12,850**	**13,867**	**14,881**	**36,500**
Plus adjustments for AR1 & AR2	1,154	0	0	1,082
Allowable revenue (unsmoothed)	**14,004**	**13,867**	**14,881**	**37,582**

Further detail of the modelling is set out in Appendix G.

11.4 Forecast average price path

System Management (Markets) has translated the unsmoothed allowable revenue into a forecast average price path and smoothed allowable revenue. This forecast price path is indicative only. The IMO will determine the actual fee rate to be levied in any year based on System Management (Markets)'s annual budget proposal.

The forecast price path is determined by smoothing the revenue over the review period whilst retaining the net present value of the total allowable revenue. The smoothed revenue in any year may not reflect the underlying building block components of that year, however the total value of revenue is retained over AR3 in present value terms. This smoothed revenue profile may be affected by the following:

- updated forecast energy consumption throughout AR3
- adjustments due to differences between actual and forecast expenditure, and actual revenue and allowable revenue
- actual inflation

It is normal regulatory practice to adjust the building blocks revenue to enable a more predictable (and less volatile) price path by smoothing the revenue. Smoothing is required because the allowable revenue calculated through the building block methodology may result in the revenue moving up or down throughout the period.

System Management (Markets) proposes smoothing the allowable revenue based on a price path of equal increases in the System Management (Markets) fee rate over the AR3 period. The forecast fee rate and forecast % change are detailed in Table 30.

Table 30: Forecast System Management (Markets) fee rate ($/MWh Real)

	2012/13	2013/14	2014/15	2015/16
Forecast fee rate	0.276	0.323	0.378	0.443
% change (real)		17%	17%	17%

These forecast System Management (Markets) fee rates will collect revenue equivalent, in net present value terms, to the allowable revenue for AR3 from Table 29. Western Power adopted the IMO's method to determine the fee rate[75] to then calculate the smoothed revenue based on these forecast System Management (Markets) fee rates:

- apply the sent-out energy forecasts in the IMO's 2012 Statement of Opportunities (SOO)
- adopt the IMO's calculation of an average (generation) loss factor of 1.006931712 (average for the 2010/11 Reserve Capacity Year) to loss-adjust the SOO sent-out figure to the Muja reference node
- double the resultant loss adjusted energy forecast as the fees applies equally across market generators and market customers.

Table 31 details the resulting smoothed allowable revenue for AR3:

Table 31: Smoothed allowable revenue

($000 real at 30 June 2013)	2013/14	2014/15	2015/16	Present Value
Smoothed allowable revenue	11,880	14,183	16,961	37,582
% change in revenue (real)	22%	19%	20%	

Smoothing is undertaken to reduce the volatility of prices.

[75] Further information on the IMO's approach to calculating the fee rate is detailed on the IMO website: http://www.imowa.com.au/fees_charges

12 Annual Budget Proposal

This chapter details Western Power's approach to the annual budget proposal throughout the AR3 period.

12.1 Key messages

- The annual budget proposal includes adjustments to the allowable revenue to compensate System Management (Markets) for differences beween actual expenditure and forecast expenditures and actual revenue and allowable revenue.
- System Management (Markets) will seek reassessment of the allowable revenue if it is likely that the revenue recovered over AR3 will be 15% greater than the AR3 allowable revenue or if there is a significant unforeseen event.

12.2 Budget proposal content

Each year System Management (Markets) will submit a budget proposal to the IMO by 30 April, as required by section 2.23.5 of the Market Rules.

The content of the budget proposal will include:

- the calculation of the allowable revenue for system operation services for the next financial year using the formulas explained in the section 12.3 below
- information supporting how System Management (Markets) derived the elements of the calculation of the allowable revenue for system operation services
- a revised forecast of the capital expenditure for system operation services for the next financial year.

12.3 Adjustments to annual allowable revenue

System Management (Markets)'s budget proposal will determine the revenue for the next financial year by making adjustments due to differences between actual and forecast expenditure, and actual revenue and allowable revenue.

System Management (Markets) determines the revenue for the next financial year through the application of the following formula:

$$\mathbf{AAR_t = AR_t + K_t + C_t + O_t}$$

The allowable revenue application sets out the detailed formula for each element of above formula. The purpose of the adjustments is to keep System Management (Markets) financially neutral for differences between actuals and forecasts. In summary:

- $\mathbf{AR_t}$ is the smoothed allowable revenue determined from the building blocks method as set out in Section 8
- $\mathbf{K_t}$ is the adjustment due to differences in the revenue provided for in previous budget proposals and the actual revenue earnt by System Management (Markets), including allowances for the time value of money
- $\mathbf{C_t}$ is the adjustment due to differences in the actual capital expenditure and the capital expenditure forecasts in this allowable revenue application, including allowances for the time value of money

- **O_t** is the adjustment due to differences in the actual operating expenditure and the operating expenditure forecasts in this allowable revenue application, including allowances for the time value of money

12.4 Reassessment of the allowable revenue

System Management (Markets) will apply to the ERA to re-assess the allowable revenue if it becomes likely that the anticipated actual revenue recovered over AR3 will be 15% greater than the sum of the smoothed allowable revenues set out in Section 11.4. This is a requirement of section 2.23.8 of the Market Rules. The allowable revenue application sets out the detailed formula that applies if this threshold is been exceeded.

Allowable Revenue Information Document Index

The following documents are referenced in this Allowable Revenue Information document.

Document Title	Reference / Comment
Improvement Portfolio Governance Model (IPGM)	Refer to document DM 9386323
Resource Type and Labour Rate Governance Manual	Refer to document DM 8908099v14
Competitive Balancing and Load Following rule change	Refer to URL http://imowa.com.au/RC_2011_10
Electricity Networks Access Code 2004 Guidelines for Access Arrangement Information	Refer to URL http://www.erawa.com.au/cproot/9113/2/20101206%20D47095%20Electricity%20Networks%20Access%20Code%202004%20-%20Guidelines%20for%20AAI%20(Version%202).PDF
Annual Compliance Audit	Refer to URL http://www.imowa.com.au/f189,1613071/Audit_3.pdf
Review of the Weighted Average Cost of Capital for the Purposes of Determining the Maximum Reserve Capacity Price	Refer to URL http://www.imowa.com.au/f345,53574/ACG_Final_Report_IMO01_FINAL_221107.pdf
Fees and Charges	http://www.imowa.com.au/fees_charges
Electricity Industry (Wholesale Electricity Market) Regulations 2004	http://www.slp.wa.gov.au/pco/prod/FileStore.nsf/Documents/MRDocument:23752P/$FILE/ElecityIndusWhsaleElecityMarktRegs2004-01-g0-00.pdf?OpenElement

List of Figures

List of Tables

Glossary

The following table shows a list of abbreviations and acronyms used throughout this document.

Abbreviation / Acronym	Definition
AA1	Access Arrangement for the first period, 2006/07 to 2008/09
AA2	Access Arrangement for the second period, 2009/10 to 2011/12
AA3	Access Arrangement for the third period, 2012/13 to 2016/17
AAI	Guidelines to the Access Arrangement Information, published by the ERA in December 2010.
Access Code	Electricity Networks Access Code 2004
ACT	Australian Competition Tribunal
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGC	Automatic Generator Control
AR2	The submission for the second regulatory period which is from 1 July 2010 to 30 June 2013
AR3	The allowable revenue submission for the third regulatory period which is from 1 July 2013 to 30 June 2016.
AR4	Review period to follow AR3 (2017/18 – 2020/21)
AWP	Approved Works Program
BRG	Business Reference Group
CAPM	Capital Asset Pricing Model
CBLF	Competitive Balancing and Load Following
CEG	Competition Economists Group
CRAM	Cost Revenue Allocation Model
DA	Dispatch Advisory / Advisories
DDSS	Dispatch Decision Support Simulator
DNSP	Distribution Network Service Provider
DTS	Dispatch Training Simulator
DI	Dispatch Instruction
EGWW	Electricity, Gas, Water and Waste
ELB	Electronic Log Book
ENAC	Electricity Networks Access Code (2004)
ENC	Electricity Networks Corporation
ERA	Economic Regulation Authority
FTE	Full Time Equivalent
FTP	File Transfer Protocol

Abbreviation / Acronym	Definition
FVC	Fair Value Curves (based on Bloomberg)
GFC	Global Financial Crisis
IMO	Independent Market Operator
IPGM	Investment Portfolio Governance Model
IPP	Independent Power Producer (Non-Verve)
LFAS	Load Following Ancillary Service
MAC	Market Advisory Committee
MEP	Market Evolution Program (developed between Dec 2010 and July 2012)
MRP	Market Risk Premium
MW	Megawatts
Metrix IDR	Software solution by System Management (Markets) for SWIS load (produced by Itron)
ODS	Operational Data Store
PADP	Performance Appraisal Development Plan. (Known as STRIVE from 1 July 2012.)
PASA	Projected Assessment of System Adequacy
PSOP	Power System Operating Procedures
RBA	Reserve Bank of Australia
SM	System Management
SMARTS	System Management Automated Real Time Systems
SMMITS	System Management Markets Information Technology System
SMNTP	System Management Non Trading Participant
SCADA	Supervisory Control and Data Acquisition
SOO	Statement of Opportunities
STEM	Short-Term Energy Market
SWIN	South West Interconnected Network - the electrical network comprised of the transmission equipment, the distribution equipment and other associated electrical network equipment.
SWIS	South West Interconnected System – the SWIS includes the South West Interconnected Network, the generation plant and other associated system equipment.
Technical Rules	'Technical Rules' are the Technical Rules for the network proposed by the SWIS network service provider (Western Power) and approved by the Economic Regulation Authority under chapter 12 of the Access Code. 23 December 2011.
WACC	Weighted Average Cost of Capital
WEM	Wholesale Electricity Market

Abbreviation / Acronym	Definition
WPN	The Western Power Network is the portion of the SWIN that is owned by Western Power. The Western Power Network incorporates the integrated transmission and distribution networks.

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Appendix A. WEM Objectives

The objectives of the WEM (as indicated in Part 9 of the Electricity Industry Act [2004] and the Market Rules) are:

- to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system
- to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors
- to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions
- to minimise the long-term cost of electricity supplied to customers from the South West interconnected system
- to encourage the taking of measures to manage the amount of electricity used and when it is used.

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Appendix B. Ringfencing Standard

Purpose

The purpose of this standard is to:

1. define the requirements under which the ringfencing of System Management (Markets) from the remainder of ENC can be administered
2. provide for the monitoring and reporting on the effectiveness of ENC's compliance with its obligations under Chapter 13 of the ENAC
3. Outline what is required for Western Power to comply with:
   a. its obligations under clauses the WEM Rules, including the non-disclosure of confidential information
   b. the spirit of WEM Rule 2.2.1, "The Electricity Networks Corporation, acting through the ringfenced business unit known as System Management, has function of operating SWIS in a secure and reliable manner".

Definitions

Access Arrangement Information (AAI) – it is generally defined in the Electricity Networks Access Code; with regard to Western Power it is the information submitted by Western Power to the ERA, in relation to the access Arrangement, but is not strictly part of the Access Arrangement.

Allowable Revenue determination – the process established under clause 2.23 of the WEM Rules by which the revenue that System Management (Markets) is allowed to recover from the Independent Market Operator is determined by the ERA.

Electricity Network Access Code (ENAC) – prescribes a framework for access to electricity distribution and transmission networks in Western Australia.

Electricity Networks Corporation (ENC) – The financial entity that is comprised of the ringfenced entities System Management (Markets) and Western Power Networks (WPN).

Independent Market Operator (IMO) – oversees access arrangements/rules under the Electricity Networks Access Code.

PADP – Performance Appraisal Development Plan (Known as STRIVE from 1 July 2012.)

System Management (Markets) - is a ringfenced business unit within Western Power established under section 13 of the Electricity Industry (Wholesale Electricity Market) Regulations 2004. System Management (Markets) is a separate regulated entity from the Western Power Networks. System Management (Markets)'s role includes scheduling generator, transmission and certain distribution outages, power system operation and other functions related to the WEM.

SWIS – South West Interconnected System. The SWIS covers the interconnected transmission and distribution systems, generating works and associated works.

Wholesale Electricity Market (WEM) – A market where competing generators offer their electricity output to retailers, established under Part 8 of the Electricity Industry Act 2004.

Wholesale Electricity Market Rules (WEM Rules) – The WEM rules cover the roles and functions of the IMO and System Management (Markets) and govern the WEM.

Western Power Networks (WPN) – the part of an integrated provider's business and functions which are responsible for the operation and maintenance of a covered network and the provision of covered services by means of the covered network. WPN is a separate regulated entity from System Management (Markets).

Scope

The Standard provides clarity and guidance on ENC's compliance with its ringfencing obligations. In addition, the Standard provides the ERA and WEM stakeholders with assurance on ENC's compliance with its ringfencing obligations.

The Standard facilitates the management and disclosure of conflicts of interest, elimination of cross subsidy where the benefits of doing so outweigh the costs and strikes an appropriate balance between independence and cost efficiency.

<u>Chart of Accounts and Financial Reporting Structures:</u>

ENC shall maintain a chart of accounts that enables the overall statutory financial statements to be disaggregated into the appropriate regulated financial statements for both System Management (Markets) and WPN.

<u>Cost of Funding and Cash flow Management:</u>

Interest shall be appropriately allocated between the separately regulated financial statements, subject to an assessment of materiality.

<u>Shared Cost Allocation</u>

The allocation of shared costs shall be consistent with the Cost and Revenue Allocation Method document for the relevant year.

<u>Conflicts of Interest and Management of Employees</u>

PADPs shall provide clear documentation that sets out criteria for accountabilities and performance in instances where employees undertake activities that overlap between the two regulated entities (WPN & System Management [Markets]). Potential conflicts of interest will be identified within PADPs.

Employees shall be required to highlight potential conflicts of interest and the prevailing ENC grievance process used to resolve any ongoing concerns.

<u>Delegated Financial Authorities and Business Case Sign Off</u>

The ENC delegated financial authorities and business case policies and procedures will apply across the whole of ENC and are relevant in both regulated environments. Decisions which concurrently affect both WPN and System Management (Markets) should be highlighted as such with a supplementary document to clarify the impact and resolution for both regulated entities.

<u>Jointly Forecasting</u>

ENC shall develop, implement, maintain and endorse processes for the treatment of jointly forecasting costs for regulatory submissions in order to manage the risk that costs could inadvertently be included in, or excluded from both submissions.

<u>Professional Advice</u>

The separately regulated entities of WPN and System Management (Markets) shall retain separate professional advisors where the benefits of doing so (in terms of avoiding a potential for conflict of interest) outweigh the cost.

<u>Training and Monitoring</u>

ENC shall educate all personnel who are identified as having a conflict of interest within the corporation regarding compliance with its ringfencing obligations.

System Management (Markets) shall ensure an independent compliance audit is undertaken at least annually to assess compliance with its ringfencing obligations.

Reporting

Any breach of this Standard must be reported in accordance with the Legislative & Regulatory Compliance Framework.

Procedures Manual

ENC will produce and maintain workplace procedures that outline its ringfencing obligations. The procedures will be the principal method by which ENC will manage compliance with these arrangements. The contents of the procedures will be reviewed at least annually or earlier if deemed appropriate.

Materiality

The materiality of a cost will be determined by applying a test to be outlined in the Procedures.

All ENC formal leaders, employees, contractors, alliance partners and subcontractors are responsible for adhering to the requirements of this standard.

The Managing Director (or CEO) and the executive management team are accountable to Western Power’s Board for the development and implementation of this standard.

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Appendix C. Key Challenges for AR3

The key challenges facing System Management (Markets) over AR3 are summarised as follows.

- System Management (Markets) is experiencing significant changes to its business through the implementation of the MEP.
  - Whilst the SMARTS program is being implemented in mid 2012, there are likely to be ongoing ‘refinements’ to this market, resulting in an ongoing program of change, potentially extending throughout the 2013 calendar year and beyond.
  - System Management (Markets) is working closely with the IMO to understand the next phase of its Market Rules evolution and to incorporate its impacts into the program of work for the AR3 period.
- There are likely to be further changes to System Management (Markets)’s operations through the ongoing development and maturing of the WEM. These are expected to include:
  - A move to nearer real-time trading
  - Expansion of the market to encompass spinning reserve, and possibly load rejection and system restart markets
  - A decreased reliance on portfolio generation owned by Verve Energy
  - An increasing number of intermittent generation sources, and an increasing portfolio of demand side management
  - Increasing number and complexity of constraints on the SWIN
  - Changes to outage management
  - An increased focus on regulatory assurance, and our ability to demonstrate transparency, performance and compliance.
- The ongoing development of the WEM is expected to lead to an increase in the complexity of System Management (Markets)’s operations, including:
  - A need to leverage technology to support rapid decision making which is dependable, repeatable and defensible
  - A move to systems which support more rule-based decision-making (rather than manual intervention)
  - A need to manage the risk of ‘change overload’ through the provision of more formal process management and support
  - A need to demonstrate regulatory compliance in line with new or amended Market Rules
  - An increase level of interest in decisions made by System Management (Markets) which impact consumers and service providers’ costs
  - Potential increases in System Management (Markets)’s operating expenditure.
- It is anticipated that electricity prices will rise (due to a number of factors). This is likely to result in increased pressure on System Management (Markets) to justify its costs, and demonstrate efficiency and ‘value for money’.

These challenges have been specifically considered in the development of the investment objectives outlined Section 5 of this submission.

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Appendix D. Step Changes in Operating Costs

D.1 Permanent employees and contractors

Details of the step changes in FTEs (for both permanent employees and contractors) are provided in Table 32. This table shows step changes for each of the following investment areas:

- **Support for the MEP** – which provides the necessary resources to support the operation of the CBLF market
- **Dispatch training** – which supports essential training for staff on the new DTS application so that dispatch processes are effective and in line with the requirements of the Market
- **Market systems support** – which helps ensure that SMARTS is effectively supported so that the CBLF market can operate with minimal disruption or down time
- **Governance improvements** – to enable effective project delivery in line with an improved governance framework
- **Succession planning** – to provide an effective handover to new staff as existing staff retire, and help ensure minimal disruption to the essential functions performed by the Control Room.

Further details of the changes in staffing requirements are provided in the following sections. Explanations of the need for these step changes are provided in Section 6.

Table 32: Changes in Full Time Equivalent Staff (FTEs) by Investment Area

Investment Area	**Step increase in FTEs**			
Section	**2012/13**	**2013/14**	**2014/15**	**2015/16**
Permanent Employees				
Support for MEP				
Market Operations Planning	**1.00**			
System Operations Control Engineering	**0.25**			
System Operations Planning		**1.00**		
Sub total	1.25	1.00	0.00	0.00
Dispatch training				
SCADA Branch	**1.00**			
System Operations Control Engineering	**0.10**			
Sub total	1.10	0.00	0.00	0.00
Market systems support				
SCADA Branch		**4.50**		
Sub total	0.00	4.50	0.00	0.00
Governance improvements				

Investment Area	Step increase in FTEs			
Section	**2012/13**	**2013/14**	**2014/15**	**2015/16**
Market Strategic Development		1.00		
Sub total	0.00	1.00	0.00	0.00
Succession planning				
System Operations and Control		0.50		-0.50
Sub total	0.00	0.50	0.00	-0.50
Total increase in permanent employees	**2.35**	**7.00**	**0.00**	**-0.50**
Contractors				
Support for MEP				
System Operations Planning	2.00	-1.50		
Market Operations Planning	1.00	-1.00		
Sub total	3.00	-2.50	0.00	0.00
Market systems support				
SCADA		-3.00		
System Operations Planning		0.30		
Sub total	0.00	-2.70	0.00	0.00
Total increase in contractors	**3.00**	**-5.20**	**0.00**	**0.00**
Total Step Change	**5.35**	**1.80**	**0.00**	**-0.50**

D.1.1 Support for MEP

System Management (Markets) will incur additional labour costs due to changes in operations as a result of the MEP. Many of these resources have been engaged during 2012/13 to support the increased workload associated with the implementation of CBLF and the transition into operations necessary to support the changes.

System Management (Markets) has implemented a level of automation within SMARTS, however this needs to be balanced with some labour increases to manage the additional transactions and complexities of the CBLF market, comprising 20 significant rule changes and seventeen new obligations, including:

- security constrained pre-dispatch planning
- real-time dispatch of balancing facilities
- Verve energy's portfolio generators
- facilities providing load following ancillary services

To manage these changes to obligations, step changes in labour costs during 2012/13 will comprise:

- 1 additional FTE within the Market Operations Planning section to support the extended operating hours during both weekdays and over weekends. This is also required to support the additional volume of data supplied to the IMO and market participants with the operation of the CBLF market[76]. This resource will be required to monitor, validate and manage this information on an ongoing basis.

- An increase in the allocation of engineering analysts in the System Operations Control Engineering section to a higher percentage of their role. This represents an increase of 0.25 FTEs and is required to support the management of the increased transactions associated with the CBLF market.
- An increase of 2 FTEs (engaged as contractors) in the System Operations Planning section. This is required to support the additional functions which are required for CBLF, including additional dispatch functions and the capture of data used for settlements and investigations.
- An increase of 1 FTE (engaged as a contractor) within the Market Operations Planning section to provide backfill whilst the Manager, Market Operations managed the delivery of the SMARTS program.

Step changes in labour costs during AR3 will comprise:

- A reduction of 1.5 FTEs (contractors) in the System Operations Planning section as one existing contractor role is transitioned to part time role, and one contractor role is moved to a permanent employee role. This net reduction of 0.5 FTEs will be made as the CBLF market move from the transitional stage (reliant on more manual processes) to a full production phase, with more automation provided by SMARTS.
- A decrease of 1 FTE (contractor) within the Market Operations Planning section as backfill for the delivery of the SMARTS program manager role will no longer be required.

D.1.2 Dispatch training

Additional staff will be required to support the new dispatch training function which will be enabled through the Dispatch Training Simulator (DTS) project. These labour costs were approved in the AR2 submission, but were not incurred in the 2011/12 base year as the project was delayed.

Step changes in labour costs during 2012/13 will comprise:

- An additional staff member (1 FTE) in the SCADA Branch to provide technical support to maintain the new DTS software application. This staff member will be required to maintain and rebuild the models and training scenarios used by DTS, which change as changes are made to the SWIS (such as additional lines, transformers, generators and loads). For the DTS to be effective, it is essential that it is maintained to mirror the current state of the SWIS.
- An allocation of additional market support time for engineering analysts in the System Operations Control Engineering section to undertake training using the DTS on an ongoing basis. This will represent an allocation of 0.1 FTEs.

[76] Prior to the introduction of CBLF the data flows principally comprised of changes to the Dispatch Merit Order, Standing Data and Outages on a daily basis. With the introduction of CBLF this information has the potential to change every 30 minutes, resulting in a significant increase to data flows to the IMO and participants. This can impact on settlements and requires a greater scrutiny by System Management (Markets).

D.1.3 Market systems support

During AR3, additional staff will be required to provide support and maintenance for SMARTS. This increase reflects the significantly increased support requirement for this new system, which must be sufficiently reliable to support the operation of the CBLF market with minimal disruptions and down time. Support staff will be required to:

- Monitor and maintain the system
- Support its software, models and infrastructure
- Assist staff with the familiarisation and the transition to self sufficiency.

This will result in a net increase of 1.8 FTEs to support SMARTS in AR3. Labour cost increases will be minimised by transitioning the staff who currently support SMITTS to SMARTS support roles, as the requirement for staff to support SMMITS will reduce as some of its functionality is replaced by SMARTS.

Step changes in labour costs during AR3 will comprise:

- An increase of 2 FTEs in the SCADA Branch for a system administrator and a web developer to provide support for SMARTS on an ongoing basis. Two support staff are required to ensure that there is constant support coverage for the system (for example if one resource is taken ill or on planned leave) and that the CBLF market can continue to operate effectively.
- An increase of 0.3 FTEs in System Operations Planning as an existing staff member moves off the SMARTS program to a market systems model support role. This staff member's role was not backfilled and this has resulted in a number of system support tasks being delayed, with resulting adverse impacts to System Management (Markets)'s operations.
- A decrease in the number of business analysts allocated to support tasks (0.5 FTEs) resulting from a reduced support requirement for SMMITS. This 0.5 FTE will be utilised in the capital program to provide essential technical input to capital projects.
- Cost savings will also result from converting 3 contractor roles (business analysts who previously supported SMMITS) to permanent employees.

D.1.4 Governance improvements

It is essential that System Management (Markets) has appropriate resourcing to enable the delivery of its capital investment program and to implement improvements in its governance processes. Without appropriate resourcing System Management (Markets) will be unable to support the enhancements planned for the Market in a timely fashion, or able to effectively ensure that these investments are made in the most cost efficient manner.

During AR3 System Management (Markets) will appoint a program manager to oversee the delivery of the capital investment program, and the implementation of the IPGM framework across all capital projects. Costs for this role will be split as follows:

- 50% to operational expenditure - focusing on the development of estimates and business cases for market rule changes, and the implementation of governance processes
- 50% to capital expenditure - to support project managers and provide oversight of effective project governance on capital projects.

A part time (0.5 FTE) project cost controller/scheduler will be appointed to support the Program Manager and project managers in the monitoring and reporting of project costs and schedules. This approach is more cost effective than assigning administrative tasks related to cost and schedule control to project managers and the Program Manager.

D.1.5 Succession planning

During AR3, at least two senior system operations controllers will reach retirement age. This staffs performs a vital role in operating the Control Room to support the realtime operation of the power system and the dispatch of generation and ancillary services in the WEM.

The senior system operations controllers possess a range of specialty skills gained through many years of experience. Transitioning-in trainee staff must be managed carefully to ensure that trainees have a suitable level of experience and knowledge to perform this essential role.

To ensure an effective transition-in process System Management (Markets) will appoint two trainees to work in parallel with the existing controllers for a six month period. This equates to an additional 0.5 FTE across the first 2 years in AR3, and then reverting back to normal levels.

D.2 Functional costs

Step changes in functional costs during 2012/13 will comprise:

- An increase in travel and staff development costs to a more sustainable level. During 2011/12 System Management (Markets) underspent on travel and staff development. This was mainly due to project delivery commitments which limited the time available for training and staff development. These levels are not sustainable during AR3 as they do not reflect the investment required to provide effective staff development on an ongoing basis.
- Increased consultancy costs to obtain independent advice and assistance in managing the delivery of the AR3 submission. A more rigorous approach was applied to the development of the AR3 submission. Assistance was required to provide additional resourcing which was not available from within System Management (Markets).
- Additional consultancy costs to audit System Management (Markets)’s compliance with the Ringfencing Standard. An audit will be undertaken annually to enable System Management (Markets) to assess compliance against the Standard and identify any opportunities for improvement.

Step changes in functional costs during AR3 will comprise:

- A reduction in consultancy costs in 2013/14 to remove the increase associated with the development of the AR3 submission.
- An increase in consultancy costs for advisory services to assist in the preparation of the AR4 submission. This cost will be minimised by following a similar methodology to the development of the AR3 submission, and by maximising the use of internal resources.
- Additional consultancy costs for an audit of the processes and calculations conducted within System Management (Markets)'s market systems to confirm compliance with the Market Rules. This will provide an independent assessment of the level of compliance and enable targeted action to be taken to address any key areas of non-compliance.

D.3 Legal costs

Reduced legal costs were incurred in the 2011/12 base year due to the focus on the delivery of SMARTS. As this expenditure is not sustainable during AR3, System Management (Markets) has applied a limited increase to the 2011/12 base year expenditure. In making this adjustment, consideration has been made of the enhancements planned for the Market and the requirement for legal advice to be sought in relation to some potentially significant changes to the Market Rules.

D.4 Business support costs

As noted in Section 4 System Management (Markets) will continue to incur business support costs which are charged by WPN for business support services, including finance, regulation and sustainability, information technology and human resources. Business support costs will be incurred from 2012/13. As these costs were not incurred during the 2011/12 base year they have been included as a positive step change. This will be partially offset by a reduction in IT operating costs (which were previously charged as a separate item for IT services provided by WPN).

D.5 SMARTS infrastructure and software licences

Additional costs will be incurred to maintain the infrastructure and software licences for SMARTS. This investment is required to ensure that the hardware and software remains current, and can therefore be effectively supported on an ongoing basis. This approach mitigates the risk of IT systems being unsupported by vendors (meaning that system errors can remain unresolved) and avoids the potentially substantial costs associated with a major system upgrade from a legacy system.

A breakdown of these costs is provided in Table 33.

Table 33: Step increase in software maintenance and infrastructure costs from the 2011/12 base year ($000 nominal at June 2013)

Item	Increase ($000)
Hosting & Technology Management	50
Software License Renewals	483
Hardware Maintenance	41
Consumables	20
Total step increase	**594**

Appendix E. Scope of SMARTS Deliverables

The following table provides a summary of the scope of the SMARTS deliverables, as compared to our systems' capabilities prior to the implementation of the system.

Table 34: Requirements for System Changes Identified in the SMARTS Business Case

System	Prior Capability	Requirement Identified for CBLF
Load Forecasting (develops a forecast of system load to be met by generation largely by weather inputs but modified by actual loads).	Primarily day ahead forecasting tool (Metrix IDR) although used as a reference in real time (adjusted by actual loads).	Enhance existing Metrix tool for 5min through to day ahead accuracy. BOM data feed changes required.
Wind Forecasting (develops forecast of windfarm outputs largely by weather inputs but modified by actual output).	Primarily day ahead forecasting tool (inhouse spreadsheet) although used as a reference in real time.	Purchase /implement new wind forecasting tool for 5min through to day ahead accuracy.
Dispatch Planning / Scheduling (undertakes pre-dispatch planning to determine if any security constraints and optimise plan, manages Verve portfolio, develops dispatch advisories to inform market of security constraints).	Variety of tools (spreadsheets, SCADA, Java-ELB, SMMITS2) enables commitment / decommitment of Verve plant and identifies need for IPPs. Limited constraint analysis using external tools.	New Dispatch Planning Tool for planning & scheduling market facilities introduced, with ability to undertake generation planning and scheduling for 4-48hrs out, and conduct initial security assessments during the scheduling day for the trading day. Generation of security constraint violations and Dispatch Advisories.
Dispatch Execution / Monitoring (real time and close to real time security assessment and determination of generator dispatch instructions (DIs) to resolve security constraints, recording of outcomes).	Variety of tools (spreadsheets, SCADA, Java-ELB, SMMITS2) identifies need to dispatch plant (generally Verve). Enables controllers to monitor plant against dispatched levels and manually take action as required. Constraint analysis performed manually using external tools, interpreted and then manual dispatch to resolve.	New Dispatch Engine to undertake the real time security assessments and automatically generate Dispatch Instructions (DIs) to generators around the constraints. Monitors compliance to DIs and real time load/outages and takes rectifying action. High availability with "fail over" site.
Communications (interfaces and communications between SM and generators and SM-IMO).	Dispatch done by telephone and formalised by ELB generated emails. System security advisories (rare) generated in ELB. Transfers with IMO are through a simple process not suited to near real-time transfers.	New Dispatch Interface (sends DIs, receives confirmation, plant availability). IMO-SM interfaces enhanced to enable greater and more common data exchange, including security information and Dispatch Advisories.
Infrastructure (Various hardware, storage and network assets).	Single points of failure as not real time systems. Limited backup.	Duplicated, robust hardware and networks purchased. For efficiency co-location with main/backup SCADA proposed.

System	Prior Capability	Requirement Identified for CBLF
Data Layer and database (the custom SMMITS2 database and related repositories as well as various application specific databases).	Variety of different systems and platforms used with limited integration.	Central, integrated database that is optimised for near real-time processing with a separate 'duplicated' reporting database and refurbished existing applications.

Appendix F. SMARTS Delivery

This appendix provides additional detail around how SMARTS has been delivered.

F.1 Load forecasting

System Management (Markets)’s load forecasting system used a commercial off-the-shelf solution which used a regression model suitable for providing an accurate forecast for the following day. This model considered a range of factors such as weather, day of the week, seasonal effects and so on.

This was sufficient as the trading mechanisms of the market were based on the day ahead Short Term Energy Market (STEM). System Management (Markets) previously published a load forecast twice a day.

As part of the changes being considered for the CBLF market System Management (Markets) recognised that the load forecast would be critical to achieving the outcomes sought by the changes to the market and would need to be published much more frequently. System Management (Markets) anticipated that the forecast should be updatable more frequently and should use more complex modelling which considers both external factors (as used in the existing system) and the trend of actual load and supply measured in real time. The initial rules, however did not make the details of these requirements clear.

The final rules for CBLF (published in February 2012) were in line with System Management (Markets)’s expectations and confirmed that load forecasts would need to:

- be published frequently (once every half hour)
- take into account actual trends of load and supply measured in real time.

This is important for the effective operation of the CBLF market because the forecast will define the quantities which participants will bid to supply, and therefore provides for more informed bidding and pricing.

The scope of this deliverable aligned with the original scope defined for the business case, and provided:

- Enhancements to System Management (Markets)’s existing solution to provide automated forecasts to the IMO every half hour.
- Revised forecasts to System Management (Markets)’s planners and system controllers every 5 minutes, with 5 minute granularity. System Management (Markets) delivered this functionality to provide accurate data for the management of system security, and to provide better information for intra-interval dispatch if security margins were critically reduced. Additionally, this functionality had a limited impact on the costs of the system’s configuration.
- Functionality which enables monitoring and manual intervention by an operator to allow for changes to be made to the forecast if required. This may be as a result of, for example, a reduction in a large mining load that could be anticipated ahead of time.

System Management (Markets) delivered load forecasting as a production system in July 2012. Some remedial corrections were then applied during August and September to resolve an issue related to the system’s alignment with weather forecast data.

In summary:

- System Management (Markets) has delivered a fit for purpose load forecasting solution which meets its compliance obligations under the new rules, and supports the market outcomes sought by their introduction.
- System Management (Markets) achieved this by enhancing an existing application and avoiding the need to implement a new system as the preliminary CBLF rule changes indicated that this would not be necessary.
- This solution was delivered in production to support the transitional market in July 2012.
- The solution was delivered within the scope and budget of the original business case.

F.2 Wind forecasting

System Management (Markets)'s wind forecasting tool comprised a custom-developed spreadsheet which provided an estimate of the output of the four largest wind farms on the system. These forecasts were used to inform System Management (Markets)'s dispatch of the Verve portfolio throughout the trading day (so that Verve outputs would be reduced). The forecasts provided half hour estimates which were used as a guide by System Management (Markets)'s planners and controllers.

In planning its investments for the AR2 period System Management (Markets) identified a growing need for a more sophisticated wind forecasting tool. As more wind farms were being commissioned, it was clear that the supply from these providers would become a more significant source of power, and would therefore require more accurate forecasting.

In defining the scope and cost estimates for SMARTS System Management (Markets) assumed that the new rules would require it to provide improved wind forecasts to the market. At the stage System Management (Markets) developed the SMARTS business case the draft new rules did not define System Management (Markets)'s wind forecasting requirements, but did imply that System Management (Markets) would need to define the volumes required from windfarms (which would require it to publish forecasts).

System Management (Markets) undertook preliminary work to define requirements and procure a more sophisticated wind forecasting tool. However, System Management (Markets) has deferred procurement of this system as the new rules required wind farm operators to provide their own forecasts, and a means of updating these forecasts each half hour.

Whilst the rules provide System Management (Markets) with the option to replace the participant derived forecasts with its own, it is of the view that this would only be necessary if System Management (Markets) considered that the participant's forecast was not sufficiently accurate. However, System Management (Markets) considered it likely that wind farm operators would be able to provide more accurate forecasts about their own specific plants then a generalised forecasting methodology used by it. This would need to be monitored and assessed as the CBLF market went live.

System Management (Markets) is currently gathering forecast data provided by wind farm operators to determine their accuracy. System Management (Markets) will make an assessment of the accuracy of these forecasts and monitor their reliability as it develops a representative set of data.

Given the uncertainty going forward in relation to wind forecasting requirements System Management (Markets) adopted a simplified solution for providing wind forecasts. This delivered enhancements to its existing wind forecasting tool to:

- Improve forecasting accuracy by incorporating real time measurement of windfarm output and linking this to an error correction algorithm within the tool
- Enable a level of automation by creating forecasts on a 5 minute basis, and transferring them to the Operational Data Store (ODS). This enables the forecasts to be accessed by other applications within SMARTS. It also provides the ability for System Management (Markets) to provide the forecasts to the IMO in the event that the IMO considers that the System Management (Markets) generated forecast should be used in place of a forecast provided by a wind farm operator.

System Management (Markets) delivered the enhanced wind forecasting tool in September 2012.

In summary:

- System Management (Markets) has assessed its needs for a more sophisticated wind forecasting solution and identified that there are a number of systems available which broadly meet requirements.
- System Management (Markets) has deferred this investment as it does not believe that this is necessary or justifiable. System Management (Markets) will continue to monitor this requirement in line with its obligations and the accuracy and reliability of the forecasts provided by wind farm operators.
- System Management (Markets) has delivered a fit for purpose, and cost effective option to meet the requirements of the new Market Rules. This enables it to provide a forecast to the IMO if it considers that this needs to be used in place of forecasts provided by wind farm operators. It has avoided the implementation of a new system which had the potential to duplicate similar investments made by wind farm operators.

F.3 Dispatch planning/ scheduling

Prior to the introduction of the CBLF market, System Management (Markets) used a variety of tools for dispatch planning. Whilst these were effective for the STEM outcomes and resource plans, they required interpretation and intervention by experienced staff, which had the potential to lead to decisions that, whilst maintaining security were not always consistent between staff members. System Management (Markets) sought to address this issue during AR2 by investing in a new system to support consistent dispatch decision making (DDSS).

The preliminary rules for CBLF made it clear that the dispatch planning process would become more complex, and this would require a more automated solution. System Management (Markets) considered that the solution used for the DDSS application would be suitable (after modification) for deployment as a new, more automated dispatch planning tool, and the same software package could also be used to deliver the dispatch execution function (outlined in the following section).

The business case assumption, which was reasonable in light of the information available during the scoping of SMARTS, was that the planning tool would have a horizon of 4- 48 hours with the real time engine looking at shorter timeframes. While modelling the dispatch it became apparent that even though gate closure was set to 2 hours (6 hours transitional) the 30 minute delivery of the balancing merit order meant it was more appropriate to run the planning tool for each half hour. This represented a significant increase in the complexity of the dispatch planning tool which was not contemplated in the original SMARTS business case. A summary of these changes is provided in Table 35 below.

Table 35: Key Changes to the Dispatch Planning Process with the Introduction of CBLF

Requirements under the STEM	Business Case Assumptions for planning requirements	Final requirements for CBLF
Dispatch plan created for the following day.	Dispatch plan created for 4-48 hours ahead	Dispatch plan created for the following 30 minutes to the end of the Balancing Horizon.
Market Dispatch plan only updated due to significant changes.	Dispatch plan updated 4 times a day.	Dispatch plan updated every 30 minutes.

A key focus for System Management (Markets) was to support the deployment of the transitional CBLF market in July 2012. The additional scope required to provide an effective dispatch planning tool, however meant that the solution would not be ready within this timeframe.

In order to meet its obligations to support the transitional CBLF market System Management (Markets) developed a contingency dispatch tool which was deployed in July 2012. This had the benefit of supporting the transitional market, and enabling a better understanding of the complexities which would need to be built into the dispatch planning solution.

System Management (Markets) has delivered the dispatch planning tool into the SMARTS production environment in late August 2012 and realised some efficiencies by using a single instance of the software solution for the tool (whereas the SMARTS business case assumed that two separate installations would be necessary).

In summary:

- System Management (Markets) has incurred additional costs due to the added complexity in the dispatch planning process and model which was contained in the final design for the CBLF market.
- This additional investment provided a more appropriate long term solution to meet the final requirements for the CBLF market in support of the Market Rules, both for the transitional market and the full market (scheduled to ‘go live’ in December 2012).
- System Management (Markets) has realised some efficiencies by using a single instance of the software solution for the dispatch planning tool.

System Management (Markets) will create the capability to issue dispatch advisories resulting from constratints identified in the pre-dispatch plan.

F.4 Dispatch execution/ monitoring

Prior to the introduction of the CBLF market, the dispatching of generators was undertaken in line with a pre-defined resource plan. Verve Energy was the sole provider of balancing energy and load following, with instructions being provided via phone, or by dispatching generator units directly, where these units could be controlled by System Management (Markets) through the SCADA network.

With the introduction of CBLF, the overall dispatch process has become more complex. This includes both dispatch planning (as outlined in the previous section) and dispatch execution. The issues which affected the scope of the dispatch planning project, also applied to the dispatch execution project. This included the publication of more extensive dispatch advisories in real time than was considered in the business case.

As the Market Rules evolved it became clear that the amount of changes during course of a trading day could be significantly higher than first thought, as the final rules enable providers to change their contract position every half hour. The key impacts of this are a potentially significant increase in:

- the volume of dispatch instructions
- the amount of monitoring System Management (Markets) is required to undertake (to ensure that each balancing facility is complying with each dispatch instruction).

The finalised CBLF rules also impacted market participants. System Management (Markets) received feedback from participants indicating that:

- they would not be ready to receive automated dispatch instructions electronically, and would need to develop their own system interfaces to receive them
- their preference was to receive these instructions via System Management (Markets)'s SCADA network (as opposed to relying on a network owned by a third party).

These changes required System Management (Markets) to develop more complex dispatch execution options, and change its plans for deployment, as follows:

- System Management (Markets) delivered the contingency dispatch tool to enable deployment of the transitional CBLF market in July 2012. Whilst this has supported the transitional market, it does not allow the auditing of dispatch instruction calculations, or automate the provision of dispatch advisories to the market as required under the Market Rules.
- System Management (Markets) will deliver the full version of the dispatch execution tool in December 2012. This will provide dispatch instructions to market participants via its SCADA network, and integrate with the SMARTS dispatch planning solution. A limited set of dispatch advisories will also be provided at this stage.

In summary:

- System Management (Markets) has incurred additional costs due to the added complexity in the dispatch planning process and the associated project delays this caused.
- System Management (Markets) has made a limited additional investment to meet its obligations to support the transitional market.
- System Management (Markets) has modified its approach to issuing dispatch instructions and dispatch advisories in order to provide a practical solution which meets the needs of market participants.

F.5 Communications

The SMARTS business case recognised that the new market would require improved communications with market participants. In particular:

- the number of transfers to and from the IMO would increase
- the timing of those transfers would become much closer to real time
- all balancing facilities would need to accept electronic dispatches.

In order to issue time-critical information securely and reliably, it was clear that an appropriate communications framework would be required.

The original scope of this framework included:

- a dedicated business-to-business network supplied by a third party provider (for dispatch instructions to be submitted)
- a portal for use by participants (to access specific data on an as-needed basis)
- an enhanced network connection between the IMO and System Management (Markets) to cope with the increased volume of data to be transmitted.

Whilst the rules were finalised by February 2012 the associated market procedure detailing file transfers was not published by the IMO until the 1st July 2012. As communication requirements became clearer, a number of changes were made to the original scope and/or schedule:

- System Management (Markets) has determined that it would be more efficient for most participants to use the existing SCADA network for issuing dispatch instructions due to its reliability, and in order to avoid the additional costs required to establish a third party business-to-business network.
- Participants provided feedback that they would not be ready to receive automated dispatch instructions electronically, and would need time to develop their own system interfaces to receive them. This required System Management (Markets) to delay delivery of this functionality so that participants can assess their ability to receive these instructions.
- System Management (Markets) initially assumed it would need to fully redevelop its web portal to provide real time information to smaller participants as well as historical information to all participants. Consultation with participants has indicated that it may be more cost effective to increase the amount and frequency of information to the IMO as most participants have already established communications with the IMO.
- System Management (Markets) will continue to work with the IMO to provide as much data to the market as possible to allow transparency and will only provide direct communication to participants for real time events and transfer of data.

System Management (Markets) has delivered the SMARTS communication framework as follows:

- Deployment of an interface to the IMO (including applications to exchange data which are automated from SMARTS) by July 2012.
- Deployment of an automatic generator control (AGC) interface for participants competing in the load following service (this enables System Management (Markets) to remotely control generator units), scheduled for December 2012.
- Development of a business-to-business data specification to enable participants to assess the changes required to their systems to receive dispatch instructions electronically, published to participants in November 2012.

In summary:

- Due to late advice on the requirements for communications and the added complexity of the dispatch execution process System Management (Markets) has re-considered the original scope and schedule for this project.
- System Management (Markets) has consulted with market participants and the IMO to determine practical and efficient solutions which will meet stakeholders' requirements and support the outcomes sought by the introduction of CBLF.

- System Management (Markets) has reduced the scope of items and deferred expenditure in order to more clearly define the requirements for this solution.

F.6 Infrastructure

The SMARTS business case recognised that System Management (Markets) would require new infrastructure to deploy SMARTS. System Management (Markets) has established several development environments to cater for multi-vendor applications. System Management (Markets) has also enhanced its test and production environments for SMARTS. This allows it to deploy the system from the transitional market to the full CBLF market in December smoothly.

The new environments have been incorporated in the SCADA network at the East Perth Control Centre, providing better security and monitoring. This included single site recovering. By December 2012 the ODS will be replicated at Southern Terminal (the backup SCADA site) to allow for multi-site access. Additional failover capability will be implemented post December 2012 to allow full duplication of the essential SMARTS applications from the current backup control room located at Head Office.

During user acceptance testing System Management (Markets) identified a need to integrate the SMARTS test environment with its full SCADA test environment. This requirement was not included in the SMARTS business case as the initial focus was on delivery of the system, and this was not seen as critical for the system's initial release. This investment is outlined in the capital investment proposal for AR3.

In summary:

- System Management (Markets) has delivered the required infrastructure to allow the start of the transitional market in July 2012
- Locating SMARTS within the SCADA network allows for 24 x 7 monitoring of the system
- System Management (Markets) is adding replication and redundancy capability as appropriate including the ability to run the full market from the alternative site at Head Office.

F.7 Data layer and database

The SMARTS business case recognised the need for System Management (Markets) to provide an integrated solution to support the increased transactions and automation required to enable the CBLF market. A key component of this was the development of a new database which could hold all of the operational data required to operate the market. An important consideration was the ability to keep historical records in the data layer so they could be accessed for monitoring and compliance purposes.

By comparison, System Management (Markets)'s existing database (SMMITS) only keeps a snapshot of the latest registration record. It should be noted that SMARTS does not fully replace SMMITS, as it delivers different functionality for outage planning that is not within scope of CBLF.

In developing the data layer, System Management (Markets) has focussed on enabling SMARTS to be a scalable solution, in recognition that the market will continue to mature and this will require ongoing changes to its systems. This was a primary consideration in deploying SMARTS using a services-oriented architecture, and developing the ODS database as a single source of truth for current and historical data.

System Management (Markets) delivered the ODS database, and SMARTS data layer into production in July 2012. However, these components will not be fully utilised until the full versions of the dispatch planning and execution systems are deployed to the market in December 2012. Until this has been achieved the SMMITS database will be retained. As a result the refurbishment of existing applications will be conducted in 2013.

In summary:

- System Management (Markets) has deployed a service orientated integration layer and new Operational Data Store to enable better auditing and error recording within the SMARTS data layer and database.

Figure 19 provides an overview of the actual delivery schedule for SMARTS and forecast for 2012/13.

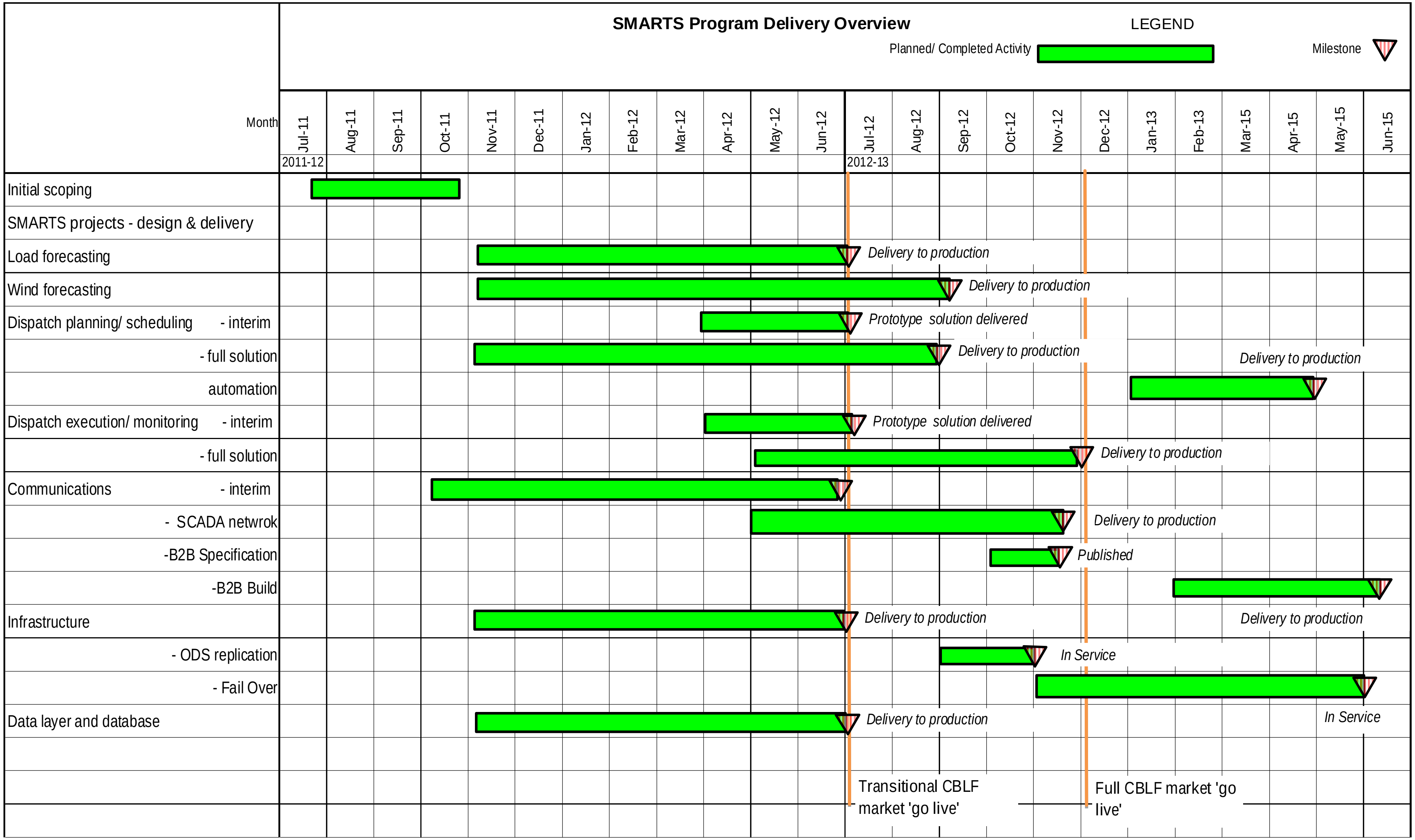

Figure 19: SMARTS Program Schedule Delivery Timeline

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Appendix G. Revenue Model Summary

Output Summary

30 November 2012

Key metrics

WACC 6.66% Post-tax

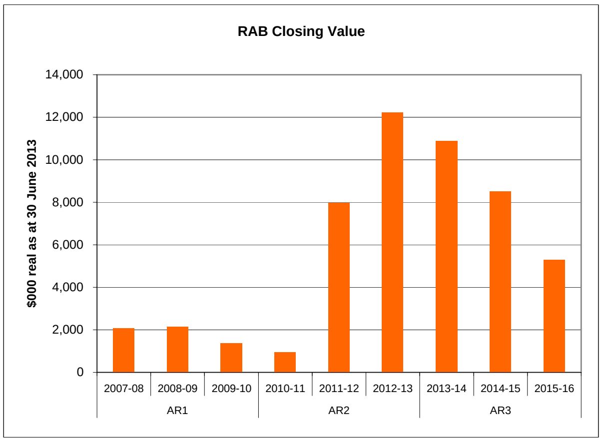
	2013-14	2014-15	2015-16	AR3 Total
Total Expenditure ($000 real as at 30 June 2013)				
Equity Raising Costs	2.5	0.0	67.4	**69.8**
Capex	2,426.9	1,768.9	1,074.8	**5,270.6**
Opex	8,269.6	8,609.3	8,669.8	**25,548.7**
Total	10,696.5	10,378.2	9,744.6	**30,819.3**
Total Expenditure ($000 nominal)				
Equity Raising Costs	2.5	0.0	72.5	**75.1**
Capex	2,487.6	1,858.4	1,157.5	**5,503.5**
Opex	8,476.4	9,045.2	9,336.4	**26,857.9**
Total	10,963.9	10,903.6	10,493.9	**32,361.4**

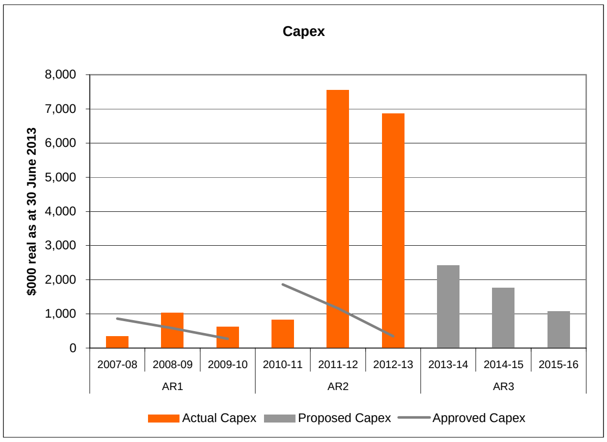
Revenue Smoothed

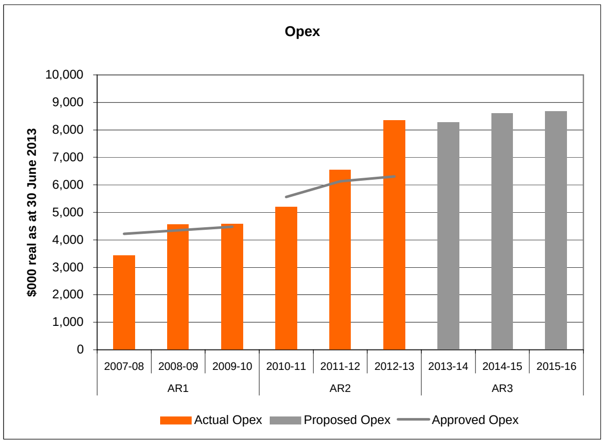
	2012-13	2013-14	2014-15	2015-16	AR3 Total
Allowable Revenue ($000 real as at 30 June 2013)					
Revenue	9,767.0	11,880.2	14,182.7	16,960.8	**43,023.8**
% change		22%	19%	20%	
Allowable Revenue ($000 nominal)					
Revenue	9,767.0	12,177.2	14,900.7	18,265.0	**45,342.9**
% change		25%	22%	23%	

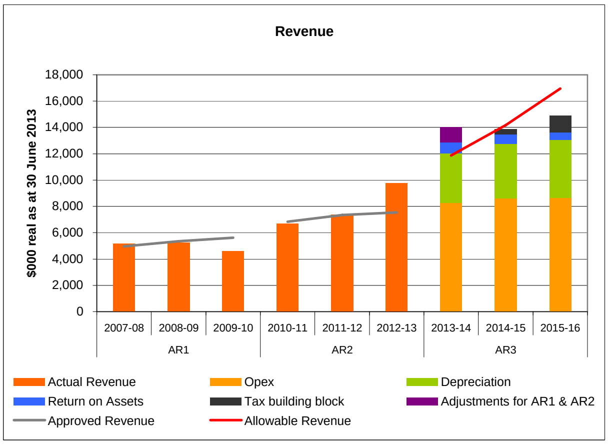
Expected System Management Fee Rate ($/MWh nominal)					**% AR3 increase**
Fee Rate	0.276	0.331	0.397	0.477	
% change		20%	20%	20%	73%

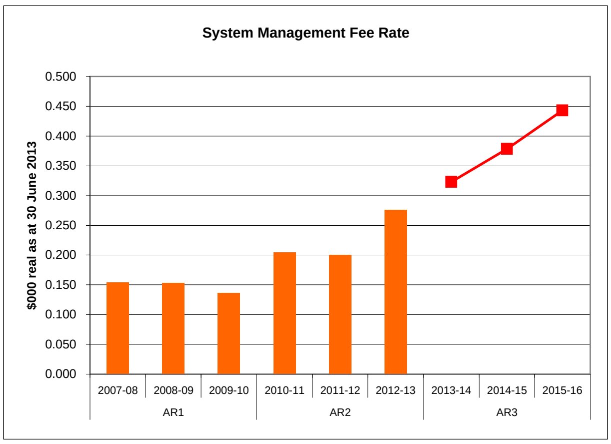
Charts











Appendix H. WACC Report

Western Power System Management

Weighted Average Cost of Capital AR3 submission

October 2012
This report contains 60 pages
WP System Management WACC

Contents

1 Introduction

1.1 Background

Following the reform of Western Australia's electricity supply industry, Western Power Corporation, the former vertically integrated supply business, was restructured. Its successor entity, Electricity Networks Corporation (Western Power), now operates and maintains the South West Interconnected System (SWIS). Its services principally comprise:

- Transmission and distribution services; and
- System operation functions, in turn comprising system management and ancillary services.

Clause 2.2 of the Wholesale Electricity Market Rules (Market Rules) requires Western Power to provide system management services through a segregated business unit.

Western Power is a monopoly provider of both sets of services and accordingly the tariffs it may charge and revenues it may recover from customers and other market participants are regulated.

Tariffs and revenues are regulated under two different regulatory regimes, albeit both are administered by the Economic Regulatory Authority of Western Australia (ERA):

- Transmission and distribution services are access regulated under the Electricity Networks Access Code; and
- The revenues that System Management is allowed to recover from market participants for System Management and Ancillary Services are regulated under the Market Rules.

Clause 2.23.3 of the Market Rules requires the ERA to determine amounts of Allowable Revenue for System Management to provide system operation services for a three year 'review period'.

System operation services for this purpose comprise:

- Operating the SWIS in a secure and reliable manner;
- Assisting the Independent Market Operator (IMO) in processing applications for participation and for the registration, deregistration and transfer of facilities;
- Developing Market Procedures, and amendments and replacements for them, where required by the Market Rules;
- Releasing information required to be released by the Market Rules;
- Monitoring Rule Participants' compliance with Market Rules relating to dispatch and Power System Security and Power System Reliability; and
- Carrying out any other functions or responsibilities conferred, and perform any obligations imposed, on it under the Market Rules.

The current three year review period expires on 30 June 2013.

The matters that the ERA must consider are set out in clause 2.23 of the Market Rules.

For the avoidance of doubt, the following terms are used throughout this report:

- 'Western Power Networks' refers to the business unit that provides transmission and distribution services;
- 'System Management Markets' is used to refer to the business unit within Western Power that provides system operation functions; and
- 'Western Power' refers to the monopoly provider of both sets of services, or the 'parent' company.

1.2 The purpose of this report

The sole purpose of this report is to provide independent evidence that may assist the Economic Regulation Authority of Western Australia (ERA) and any relevant appellate body to consider System Management Markets' proposed allowable revenue application for System Management Markets for the period 2013/14 to 2015/16, in accordance with the scope of work provided to us by System Management Markets on 22 June 2012. The scope of work is appended to this report at Appendix A. This report has been written to comply with the Federal Court's "*Practice Note CM 7 Expert Witnesses in proceedings in the Federal Court of Australia*" (1 August 2011).

1.3 Compliance with the Federal Court's Practice Note CM 7

1.3.1 The expert

The author of this report is:

Keith Lockey
KPMG
147 Collins Street
Melbourne VIC 3000

1.3.2 Assistance

Keith Lockey has relied on his colleagues, Nicki Hutley and Justine Bond in preparing this report.

1.3.3 Acknowledgement

Keith Lockey has read, understood and complied with the Federal Court's Practice Note CM 7 "Expert Witnesses in proceedings in the Federal Court of Australia" (1 August 2011).

1.3.4 Training and experience

Keith Lockey's qualifications and relevant experience are set out in his CV attached at Appendix A. CVs for Nicki Hutley and Justine Bond are also attached at Appendix B.

1.3.5 The questions the expert has been asked to consider

Western Power, through the ring fenced System Management Markets business unit, provides system operation services to the wholesale electricity market in accordance with the Market Rules. The allowable revenue is revised on a periodic basis, in accordance with the Market Rules, and is submitted to the ERA for approval.

System Management Markets has requested an expert report that will satisfy Federal Court Guidelines, regarding parameters associated with the determination of System Management Markets' Weighted Average Cost of Capital (WACC) for the next review period (AR3) – 2013/14 to 2015/16. The WACC will be used to determine the return on investment for AR3.

System Management Markets has requested that the expert report should respond to the following issues:

1) What are the appropriate values for the WACC parameters for System Management Markets under the Capital Asset Pricing Model (CAPM) including:
   - Risk free rate;
   - Inflation rate;
   - Gearing (debt and equity proportions);
   - Cost of debt;
   - Market risk premium;
   - Equity beta;
   - Corporate tax rate; and
   - Gamma.

   Does section 61(2) of the *Electricity Corporations Act 2005* impact on the values of the WACC parameters?
2) Does adopting a benchmark cost of capital achieve the objectives of the market, satisfy the Market Rules and satisfy section 61(2) of the *Electricity Corporations Act 2005*. If not, what alternative should be adopted?
3) Whether, under section 2.23.7 of the Market Rules, a revenue adjustment should be provided for during AR3 for differences between the cost of debt and equity within the WACC and the resulting actual costs and gearing level. If a revenue adjustment is required, what methodology should be used for arriving at a revenue adjustment?

1.3.6 The documents and material the expert has been asked to consider

The expert has been asked by System Management Markets to consider sources of information including but not limited to:

- Relevant legislation, including section 61(2) of the *Electricity Corporations Act 2005* and the Market Rules;
- Recent AER and ERA determinations and associated expert reports relied upon by the regulators and submitted by network service providers;
- Actual business practice and stock exchange information; and
- Decisions of and submissions made to both the Australian Competition Tribunal (ACT) and the Western Australian Energy Disputes Arbitrator.

1.3.7 Factual Findings

To complete this task, the expert has:

- In section 2 of this report described the approach taken to responding to the questions set out by System Management Markets in its Scope of Work;
- In section 3 of this report considered whether adopting a benchmark cost of capital achieves the objectives of the market, satisfies market rules and satisfies section 61(2) of the *Electricity Corporations Act 2005*.
- In section 4 of this report assessed the appropriate parameters for a System Management Markets cost of capital under the CAPM.
- In section 5 of this report considered whether clause 2.23.7 of the Market Rules requires that a revenue adjustment be made for differences between the cost of debt and equity within the WACC and the resulting actual costs and gearing level.

Sections 3 to 5 of this report set out the factual findings and assumptions on which the expert's opinion is based.

1.3.8 The expert's opinions

In accordance with Guideline 2.1 (f), the expert has set out below his opinions relevant to the response to the Scope of Work.

Each of these opinions is based wholly or substantially on the expert's specialised knowledge and that of his colleagues specified in section 1.3.2 of this report.

In the expert's opinion:

- Adopting a benchmark cost of capital as part of determining the allowable revenue for System Management Markets achieves the objectives of the market, satisfies the Market Rules and satisfies section 61(2) of the *Electricity Corporations Act 2005*.

- Estimating the appropriate values for WACC parameters under CAPM results in a real post-tax vanilla WACC for System Management Markets of 6.59%.
- A revenue adjustment under clause 2.23.7 of the Market Rules should not be provided for during AR3, for differences between the cost of debt and equity within the WACC and the resulting actual costs and gearing level.

1.3.9 The reasons for the expert's opinions

The reasons for the expert's opinions are as follows.

Adopting a benchmark cost of capital

The wholesale market objectives, Market Rules and *Electricity Corporations Act 2005* set out various requirements and objectives relating to the determination of allowable revenue for System Management Markets.

These include:

- To promote the economically efficient, safe and reliable production and supply of electricity and electricity related services;
- To minimise the long-term cost of electricity;
- That allowable revenue must be sufficient to cover the forward looking costs of providing the relevant services; and
- That allowable revenue must include only costs that would be incurred by a prudent provider of the services, acting efficiently, seeking to achieve the lowest practically sustainable cost of delivering the services.

Section 3 of this report sets out our findings that adopting a benchmark cost of capital achieves the objectives of the market, satisfies Market Rules and satisfies section 61(2) of the *Electricity Corporations Act 2005*.

Including a rate of return in regulated revenue streams is generally accepted regulatory practice. An appropriate rate of return ensures that a regulated business recovers the opportunity cost of capital employed to provide regulated services. There is strong domestic and international regulatory precedent for the inclusion of a cost of capital for energy and other regulated businesses, including in Western Australia for distribution and transmission networks. The requirement to include a cost of capital for distribution and transmission networks, both in Western Australia and elsewhere in Australia, is more explicit in the relevant legislative instruments. However, the Market Rules and *Electricity Corporations Act 2005* do not prohibit the inclusion of a cost of capital in the calculation of allowable revenue for System Management Markets. Rather, both simply require that allowable revenue covers the cost of providing the services in question.

The key determinant of whether a cost of capital should be included in the determination of allowable revenue therefore appears to be whether this would be included within the definition of what the cost is of performing the System

Management Markets function. We conclude that a cost of capital should be included within the definition of "cost" on the basis that:

- A cost of capital is an unavoidable cost associated with the capital expenditure necessary to ensure "...*the efficient, safe and reliable production and supply of electricity and electricity related services*."[1]
- The sustainability of the electricity industry depends on the ability of service providers to ensure long-term supply, which in turn necessitates the recovery of at least efficient cost in order to "...*minimise the long-term cost of electricity supplied*..."[2]
- A cost of capital is a forward-looking cost of performing the System Management Markets function as required by the Market Rules.

We also conclude that a benchmark cost of capital rather than an actual cost of capital more appropriately meets the objectives of the market, satisfies Market Rules and satisfies section 61(2) of the *Electricity Corporations Act 2005*. The reason for this is that a benchmark cost of capital ensures that any cost of capital included within the allowable revenue for System Management Markets will contribute to ensuring the recovery of only those costs which would be incurred by an efficient prudent provider of the services in question. This is because a benchmark is generally more efficient than an 'actual' cost of capital as benchmark parameters are set on the basis of an efficient provider. A benchmark cost of capital removes any distortions that may exist within an 'actual' cost of capital (potentially) minimising the long-term cost of electricity and aims to ensure that System Management Markets acts prudently and efficiently in delivering regulated services.

Appropriate parameters of WACC

On the basis that a benchmark cost of capital is appropriate for inclusion, section 4 of this report assesses the appropriate parameters for a System Management Markets cost of capital under the CAPM.

Given the small size of the System Management Markets allowed revenue associated with this assessment, we do not calculate individual WACC parameters using market evidence (with the exception of the nominal risk free rate and inflation rate). Rather, we base our assessment on existing work including regulatory determinations, associated expert reports and decisions of the Australian Competition Tribunal.

We consider whether it is appropriate to estimate certain WACC parameters for System Management Markets using distribution and transmission businesses as comparators. The appropriateness of this depends largely on an assessment of whether there is a difference in systemic risk faced by these businesses compared to System Management Markets. There is some suggestion that variations in the nature of the activities undertaken by the businesses and the costs incurred imply that there may be a difference in systemic risk. However, on balance, the evidence is not

[1] Wholesale market objectives as set out in section 122(2) of the Electricity Industry Act 2004.
[2] Ibid.

sufficiently conclusive, and it is therefore reasonable to use WACC evidence gathered for distribution and transmission businesses for System Management Markets.

The table below summarises our proposed parameters for the WACC and the resulting real pre-tax vanilla WACC for System Management Markets.

Table 1: Benchmark cost of capital for System Management Markets

Parameter	Benchmark value
Nominal risk free rate	5.152%
Expected ``Inflation rate	2.52%
Gearing	60%
Risk margin	3.80%
Market risk premium	6.0%
Equity beta	0.8
Gamma	0.25
Nominal pre-tax cost of debt	8.95%
Nominal post-tax cost of equity	9.95%
Real post-tax vanilla WACC	*6.66%*

Our reasons for our estimations of each parameter are set out in more detail in section 4.

Adopting a revenue adjustment

Clause 2.23.7 of the Market Rules requires that:

> *"Where the revenue earned for a service...via System Operation Fees in the previous Financial Year is greater than or less than System Management's expenditure for that Financial Year, the current year's budget must take this into account by decreasing the budgeted revenue by the amount of the surplus or adding to the budgeted revenue the amount of any shortfall, as the case may be."*

Section 5 of this report considers whether this clause requires that a revenue adjustment be made for differences between the cost of debt and equity assumed within the WACC and the corresponding actual costs and gearing level, attributable to System Management Markets.

We conclude that a revenue adjustment should not be made on the basis that an actual WACC is not practically measurable for System Management Markets.

There are inherent difficulties in determining an actual WACC for System Management Markets. To observe an actual cost of capital for System Management Markets, it would be necessary to observe actual costs of both debt and equity for Western Power and to objectively determine a gearing structure for System Management Markets. However, it is not possible to observe an actual (as opposed to a benchmark) market cost of equity for Western Power because it is wholly owned by government and its equity is not traded. Further, where capital is allocated to System

Management Markets, it is not be possible to deterministically attribute this between debt and equity. We also find that in any event, the likely materiality of an adjustment between an 'actual' and benchmark WACC would seem unlikely to justify the costs of determining the exact scale of such an adjustment. This is because the size of System Management Markets' asset base is such that the likely outcome of an adjustment would:

- In the case of a downward adjustment, result in the costs of calculating a difference between actual and benchmark WACC, offsetting the consequential decrease in costs of capital; and
- In the case of a positive adjustment, the costs of calculating the difference could materially add to the cost increase to customers resulting from the adjustment.

The cost of making an adjustment appears to be sufficient to result in a likelihood of an adjustment mechanism providing a net dis-benefit for customers, regardless of whether individual adjustments were to increase or reduce System Management Markets' cost of capital.

It is unclear how the objectives of minimising the long-term cost of electricity would be served by applying a revenue adjustment under clause 2.23.7 such that an efficient benchmark WACC would be set aside and replaced by an estimate of actual WACC incurred by System Management Markets. We have previously concluded that setting a benchmark cost of capital fulfils the requirements of the Market Rules because it provides an efficiency incentive and a reasonable, forward-looking estimate of efficient costs over a regulatory period.

1.3.10 Closing statement

The statement required by paragraph 2.3 and the requirement of paragraph 2.1 (a) of the Guideline is set out at section 6 of this report.

2 Approach

This section of the report describes the approach taken to responding to the issues set out by System Management Markets in its scope of work.

2.1 Overall approach

As described in section 1.3.5, System Management Markets has requested expert advice on the WACC for System Management Markets with specific regard to three issues:

1) Assessment of appropriate values for WACC parameters under CAPM.
2) Whether adopting a benchmark cost of capital achieves the objectives of the market, satisfies the Market Rules and satisfies section 61(2) of the *Electricity Corporations Act 2005*. If not, what alternative should be adopted?
3) Whether, under section 2.23.7 of the Market Rules, a revenue adjustment should be provided for during AR3 for differences between the cost of debt and equity within the WACC and the resulting actual costs and gearing level. If a revenue adjustment is required, what methodology should be used for arriving at a revenue adjustment?

In addressing these issues, it seems first appropriate to address issue (2) – whether adopting a benchmark cost of capital achieves the objectives of the market and relevant legislation – before considering what the appropriate parameters of a cost of capital (benchmark or otherwise) might be.

The following approach to providing expert advice on the issues raised by System Management Markets in its scope of work was therefore adopted:

- Assessment of whether adopting a benchmark cost of capital would achieve the objectives of the market, satisfy Market Rules and satisfy section 61(2) of the *Electricity Corporations Act 2005*. If not, what alternatives should be adopted?
- If it is considered that a benchmark cost of capital would achieve the objectives of the market and satisfy relevant legislation, assessment of appropriate values for WACC parameters under CAPM.
- Assessment of whether a revenue adjustment should be provided for differences between the cost of debt and equity within the WACC and the resulting actual costs and gearing level. If a revenue adjustment is required, what methodology should be used for arriving at a revenue adjustment?

3 Benchmark cost of capital

This section of the report considers whether adopting a benchmark cost of capital achieves the objectives of the market, satisfies the Market Rules and satisfies section 61(2) of the *Electricity Corporations Act 2005*.

3.1 Background

3.1.1 Wholesale market objectives

The wholesale market objectives are set out in Section 122(2) of the *Electricity Industry Act 2004*[3] and clause 1.2.1 of the Market Rules. Specifically, the objectives of the market are:

(a) to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system;

(b) to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors;

(c) to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions;

(d) to minimise the long-term cost of electricity supplied to customers from the South West interconnected system; and

(e) to encourage the taking of measures to manage the amount of electricity used and when it is used.

The objectives relevant to the determination of allowable revenue for the purposes of this report are (a) and (d) which relate to the economically efficient supply and long-term cost of electricity.

3.1.2 Relevant legislation

Although a benchmark cost of capital has not been used for previous allowable revenue determinations, this does not necessarily mean that one should not be applied in future allowable revenue determinations. The relevant legislation, as set out below, does not appear to explicitly preclude the use of a benchmark cost of capital.

Clause 2.23 of the Market Rules is relevant. It requires the ERA to determine amounts of allowable revenue for System Management Markets to provide services defined in

[3] Western Australia Electricity Industry Act 2004 at: http://www.slp.wa.gov.au/pco/prod/FileStore.nsf/Documents/MRDocument:23313P/$FILE/ElecityIndusAct2004-02-h0-00.pdf?OpenElement

clause 2.23.1 of the Market Rules. The factors that the ERA must take into account in determining amounts of allowable revenue are set out in clause 2.23.12 which requires that:

- *"The allowable revenue must be sufficient to cover the forward looking costs of providing the relevant services..."*
- *"The allowable revenue must include only costs that would be incurred by a prudent provider of the services, acting efficiently, seeking to achieve the lowest practically sustainable cost of delivering the services in accordance with the Market Rules, while effectively promoting the Wholesale Market Objectives."*
- *"Where possible, the Authority should benchmark the allowable revenue against the costs of providing similar services in other jurisdictions."*

Section 61(2) of the *Electricity Corporations Act 2005* requires that System Management Markets is:

> *"...required to ensure, so far as practicable, that the reasonable cost of performing the function does not exceed the revenue from doing so."*

3.1.3 Previous allowable revenue determinations

The ERA has made two allowable revenue determinations to date – the first in March 2007 relating to the period 2007/08 – 2009/10 (AR1)[4] and the second in March 2012 relating to the period 2010/11 – 2012/13 (AR2). AR1 did not use a benchmark cost of capital to determine the revenue that System Management Markets is allowed to recover from its customers, while AR2 included a benchmark cost of debt (as a proxy for the cost of capital).

The AR1 determination based allowable revenue on an assessment of the forward-looking (forecast) expenditure amounts submitted by System Management Markets. The forecasts included labour costs, functional costs, legal costs, self-insurance costs and IT costs. No allowance was made for a return on capital nor was one proposed by System Management Markets.[5]

A similar approach was taken by the ERA for AR2.[6] However, the ERA noted that System Management Markets had not submitted any borrowing costs associated with

[4] Economic Regulation Authority of Western Australia, Allowable Revenue Determination – System Management, 30 March 2007 at: http://www.erawa.com.au/library/04_Decision%20Paper%20-%20SM.pdf

[5] Western Power, System Management Allowable Revenue Application, 30 November 2006 at: http://www.erawa.com.au/cproot/5059/2/System%20Management%20Submission%20-%20System%20Management%20Allowable%20Revenue%20Application%20-%2030%20November%202006.pdf

[6] Economic Regulation Authority of Western Australia, Allowable Revenue Determination – System Management, 31 March 2010 at: http://www.erawa.com.au/cproot/8459/2/20100415%20Allowable%20Revenue%20Determination%20-%20System%20Management%20-%20Reprinted%2014%20April%202010.pdf

its capital projects for the second review period, or in relation to those capital projects commenced in the first review period and for which depreciation was to be incurred in the second review period. The ERA therefore added an amount to the allowable revenue in respect of borrowing costs for capital expenditure in the second review period, for which the ERA required depreciation of IT capital expenditure over a period longer than one year. The cost of capital was calculated by the ERA based on an understanding that System Management Markets could potentially have access to debt funds from the Western Australian Treasury Corporation at a cost in the order of the 10-year Commonwealth Bond rate of 5.48 per cent plus 60 basis points.

3.1.4 Other approaches

Australian Energy Market Operator

The Australian Energy Market Operator (AEMO) operates the energy market and systems (and also delivers planning advice) in eastern and south-eastern Australia. AEMO operates on a cost-recovery basis and fully recovers its operating costs through fees paid by market participants. Under clause 2.11.1 of the National Electricity Rules (NER)[7], AEMO is required to determine the structure of participant fees and recover fees on the basis of budgeted revenue requirements. The rules applicable to the recovery of revenue are similar to that applied to System Management Markets in Western Australia. The NER requires AEMO to have regard to the national electricity objective[8] which is:

> *"To promote efficient investment in, and efficient operation and use of, electricity services for the long term interest of customers of electricity with respect to –*
>
> *(a) Price, quality, safety, reliability and security of supply of electricity; and*
>
> *(b) The reliability, safety and security of the national electricity system."*

The NER also sets out the basis on which participant fees should recover budgeted revenue requirements. With respect to capital costs, clause 2.11.1 states that:

> *"Capital expenditures...are recovered through the depreciation or amortisation of the assets acquired by the capital expenditure in a manner that is consistent with generally accepted accounting principles."*

In practice, AEMO has included interest expenses under the financing facility put in place to fund specific costs in its revenue requirement.[9]

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[7] National Electricity Rules, Version 50 at: http://www.aemc.gov.au/Electricity/National-Electricity-Rules/Current-Rules.html

[8] http://www.aemc.gov.au/Electricity/Electricity-Market.html

[9] *Australian Energy Market Operator*, Structure of Participant Fees in the National Electricity Market – Determination and Report, 21 March 2011 at: http://www.aemo.com.au/en/About-AEMO/Energy-Market-Registration/Current-Energy-Market-Budget-and-Fees/~/media/Files/Other/registration/0118-0008%20pdf.ashx

Independent Market Operator (Western Australia)

The Independent Market Operator (IMO) in Western Australia operates and develops the Wholesale Electricity Market (WEM) in the SWIS. Similar to System Management, under the Market Rules IMO must submit a proposal for allowable revenue to the ERA for approval for periods of three years duration.[10] The Market Rules[11] require the ERA to determine amounts of allowable revenue for IMO taking into account a number of factors, including:

- *"The allowable revenue must be sufficient to cover the forward looking costs of providing the relevant services..."*
- *"The allowable revenue must include only costs that would be incurred by a prudent provider of the services, acting efficiently, seeking to achieve the lowest practically sustainable cost of delivering the services in accordance with the Market Rules, while effectively promoting the Wholesale Market Objectives."*
- *"Where possible, the Authority should benchmark the allowable revenue against the costs of providing similar services in other jurisdictions."*

These are principally the same factors that apply to the determination of allowable revenue for System Management Markets. The ERA has included an allowance for interest costs in the calculation of the IMO's allowable revenue.

Separate to its position as a regulated business whose allowable revenue is determined by the ERA, the IMO is itself required to determine the Maximum Reserve Capacity Price (MRCP) for each Reserve Capacity Cycle, which is the maximum bid price that can be made in a Revenue Capacity Auction.[12]

The method for determining the MRCP is specified in the "*Market Procedure: Maximum Reserve Capacity Price*". The method must include a cost of capital, being an appropriate WACC for a theoretical power station on which the Reserve Capacity Price is based. The Market Procedure further specifies that among other things, the WACC shall use the Capital Asset Pricing Model as the basis for calculating the return to equity.

Distribution and transmission businesses

In Western Australia, Western Power operates and maintains the SWIS, providing both distribution and transmission services. Western Power is access regulated under the Electricity Networks Access Code[13], section 6.64, which requires that any access arrangement must set out a WACC. The cost of capital may either be based on a

[11] Clause 2.22.12 of the Market Rules.
[11] Clause 2.22.12 of the Market Rules.
[12] E.g. IMO, Final Report: Maximum Reserve Capacity Price for the 2014/15 Capacity Year, February 2012.
[13] Western Australia Electricity Networks Access Code 2004 at:
http://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Energy_Initiatives/Current_Electricity_Networks_Access_Code_2004.pdf

methodology published by the ERA, represent an effective means of achieving the code objective or be based on an accepted financial model such as the Capital Asset Pricing Model.

This is consistent with the approach taken by the AER for distribution and transmission businesses in eastern and south-eastern Australia. The NER[14] provide that the annual revenue requirement for distribution and transmission network service providers must be determined using a building block approach which includes a return on capital for that year. The NER are more precise regarding the form of the return of the cost of capital. Clauses 6.5.2 and 6A.6.2 define the rate of return as:

> *"...the cost of capital as measured by the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by the [network] business of the provider..."*

The NER also provides that the cost of capital must be calculated as a 'nominal vanilla' WACC, in accordance with a defined formula.

Single Electricity Market Operator – Ireland

The Single Electricity Market Operator (SEMO) in Ireland administers the Single Electricity Market (SEM). Its role is specified in the Trading and Settlement Code (TSC) as "...to facilitate the efficient, economic and coordinated operation, administration and development of the Single Electricity Market in a financially secure manner."[15] Under its Market Operator Licence, SEMO submits proposals on its allowed revenue and the charges required to recover this revenue to the Northern Ireland Authority for Utility Regulation and the Commission for Energy Regulation ('the Regulatory Authorities').

The revenue requirement for capital expenditure is now recovered via a revenue-cap approach after previously being subject to rate of return regulation. Despite the departure from rate of return regulation, the Regulatory Authority's decision on SEMO revenue and tariffs for 2010-2013 included a WACC. This was because SEMO still had capital expenditure items in the depreciation phase such that the prevailing regulatory asset base would continue to be depreciated according to the rules established in the previous price control.

The WACC included by the Regulatory Authorities was based on a blended WACC of SEMO's parent companies, Eirgrid and Soni.

3.2 Inclusion of a cost of capital

Including a rate of return in regulated revenue streams (regardless of the method through which the revenue is calculated and ultimately recovered) is generally

[14] National Electricity Rules, Version 50 at: http://www.aemc.gov.au/Electricity/National-Electricity-Rules/Current-Rules.html
[15] Section 1.3 of the Trading and Settlement Code in *Northern Ireland Authority for Utility Regulation and the Commission for Energy Regulation*, SEMO Revenue and Tariffs for October 2010-September 2013 – Decision Paper, 10 December 2010.

accepted regulatory practice.[16] An appropriate rate of return ensures that a regulated business recovers the opportunity cost of capital employed to provide regulated services. This is reflected in the inclusion of costs of capital in building block revenues as required by the NER in the National Electricity Market, as well as for Western Power Networks. There are also numerous domestic and international precedents for including a cost of capital in revenue allowances for energy and other regulated businesses.

The requirement to include a cost of capital in the access arrangements for distribution and transmission businesses, both in Western Australia and elsewhere in Australia, is more explicit in the relevant legislative instruments than those that apply to System Management Markets. However, the Market Rules and the *Electricity Corporations Act 2005* do not prohibit the inclusion of a cost of capital in the calculation of allowable revenue for System Management Markets. Rather, both simply require that allowable revenue covers the cost of providing the services in question.

The key determinant of whether a cost of capital should be included in the determination of allowable revenue appears to be whether this would be included within the definition of what the cost is of performing the System Management Markets function.

The *Electricity Industry Act 2004* sets out market objectives requiring the economically efficient supply of electricity and electricity-related services, as well as minimising the long-term cost of electricity supplied to customers. A cost of capital is an unavoidable cost associated with the capital expenditure necessary to ensure the "*...efficient, safe and reliable production and supply of electricity and electricity related services...*" The sustainability of the electricity industry depends on the ability of service providers to ensure long-term supply, which in turn necessitates the recovery of at least efficient cost in order to *"...minimise the long-term cost of electricity supplied..."*

Clause 2.23.12 of the Market Rules requires that allowable revenue must be sufficient to recover the forward looking costs of providing services. The cost of capital meets this criterion in that it is a forward looking cost that estimates the return on investment required to meet service obligations over the regulatory period. Further, the Market Rules suggest that, where possible, the ERA should benchmark against comparable jurisdictions. The National Electricity Law, NER and general regulatory precedent provide support for the inclusion of a cost of capital within the allowable revenue for System Management Markets.

Finally, the *Electricity Corporations Act 2005* provides for the recovery of the 'reasonable cost' of performing the System Management Markets function. As discussed above, inclusion of a cost of capital is undoubtedly part of this reasonable cost. The ERA has already recognised that there is an additional cost to System Management Markets of undertaking capital projects through the inclusion of borrowing costs in the AR2 allowable revenue determination.

It therefore seems reasonable to conclude that there can, and should, be a cost of capital included within the allowable revenue for System Management Markets. This

[16] See, for example: http://www.erg.eu.int/doc/publications/erg_07_05_pib_s_on_wacc.pdf

appears to be entirely consistent with the objectives of the market, the Market Rules and section 61(2) of the *Electricity Corporations Act 2005*. The next issue to address is whether this cost of capital should be 'actual' or benchmark.

3.3 Actual versus benchmark cost of capital

Historically, the ERA has included a cost of capital in the allowable revenue that is based on the assumption that System Management Markets could potentially access debt funds from the Western Australian Treasury Corporation. However, this assumes that System Management Markets is 100% debt-funded. This assumption is not substantiated by evidence.

A rate of return is intended to provide efficient price signals to market participants and customers, as well as to provide firms with an incentive for efficient investment in relevant infrastructure and services. This is typically achieved by setting a rate of return that investors in a regulated company could expect to earn in a competitive market (that is, a benchmark rate of return) rather than with reference to an 'actual' cost of capital. This is because the rate of return earned in a competitive market reflects the true opportunity cost of capital – setting a rate of return below the opportunity cost of capital could make investment unattractive to investors, while setting it too high would allow the regulated company to earn an excessive return ultimately impacting the long-term cost of the regulated service.

Setting a rate of return based on what System Management Markets could expect to earn in a competitive market also appears consistent with the objectives of the market, market rules and the *Electricity Corporations Act 2005*.

As set out in section 3.1, the wholesale market objectives relate to economically efficient supply and minimising the long-term cost of electricity. As discussed, in section 3.2, the inclusion of a cost of capital is consistent with these objectives. A benchmark cost of capital goes one step further. Setting the cost of capital based on a benchmark is generally more efficient than an 'actual' cost of capital as benchmark parameters are estimated on the basis of an efficient provider of the services in question. The use of a benchmark cost of capital demonstrates that the cost recovered is economically efficient and does not result in distorted price signals to the market. This also applies to the requirements of the Market Rules that "*...allowable revenue must include only costs that would be incurred by a prudent provider of the services, acting efficiently, seeking to achieve the lowest cost of delivering the services...*" Using a benchmark removes any distortions that may exist within an 'actual' cost of capital (potentially minimising the long-term cost of electricity) and aims to ensure that the System Management Markets acts prudently and efficiently in delivering its regulated services.

Building on our conclusion in section 3.2, it appears that using a benchmark cost of capital is consistent with the objectives of the market, the Market Rules and section 61(2) of the *Electricity Corporations Act 2005*. A benchmark ensures that any cost of capital included within the allowable revenue for System Management Markets will contribute to ensuring the recovery of only those costs incurred by an efficient prudent provider. This is more the case than with an 'actual' cost of capital which may include inefficiencies or distort electricity market price signals.

4 Benchmark cost of capital parameters

On the basis that a benchmark cost of capital achieves the objectives of the market, satisfies the Market Rules and satisfies section 61(2) of the *Electricity Corporations Act 2005*, this section of the report assesses the appropriate parameters for System Management Markets' cost of capital under the CAPM.

4.1 Approach

Our approach to estimating a benchmark cost of capital is based on deriving a WACC under the CAPM. This is consistent with the approach taken by the ERA for the Western Power network.[17] The WACC methodology is also the most widely accepted approach to calculating the cost of capital. It is understood by the finance community and industry and is consistent with the methodology used by many regulators, such as the AER. The same applies to the CAPM which, although not without acknowledged limitations, is also used by the AER. The CAPM is also referenced in the *Electricity Networks Access Code 2004* as "*...an accepted financial model.*"[18]

Given the small size of System Management Markets' allowed revenue associated with this assessment[19], we do not calculate individual WACC parameters using market evidence (with the exception of the nominal risk free rate and inflation rate). Rather, we use existing work including:

- Recent AER and ERA determinations and associated expert reports relied upon by the regulators and submitted by network service providers; and
- Decisions of and submissions made to, both the ACT and the Western Australian Energy Disputes Arbitrator.

For those parameters where market evidence is required, we refer to the specific information used in the relevant section of this report.

The primary reasons for this approach are to provide consistency with the principles underlying the cost of capital for Western Power Networks and to provide an appropriate balance between the benefits of determining a WACC with great precision and the costs of achieving that precision. The latter point has regard to the relatively small capital base of System Management Markets. Because of this, a marginal increase in precision may not deliver any discernable changes in allowed revenue.

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[17] Economic Regulation Authority of Western Australia, Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network, 29 March 2012.
[18] Section 66 of the Access Code.
[19] Approximately $12m.

4.2 Weighted average cost of capital

Based on the approach used by the ERA for Western Power Networks, the following formula is used to derive a post-tax 'vanilla' WACC for System Management Markets:

$$WACC_{vanilla} = E(R_e) \times \frac{E}{V} + E(R_d) \times \frac{D}{V}$$

Where:

- $E(R_e)$ is the post-tax expected rate of return on equity – the cost of equity;
- $E(R_{d)}$ is the pre-tax expected rate of return on debt – the cost of debt;
- $\frac{E}{V}$ is the proportion of equity in the total financing (which comprises equity and debt); and
- $\frac{D}{V}$ is the proportion of debt in the total financing.

The real post-tax WACC is obtained by removing expected inflation π_e from the nominal post-tax WACC.

$$WACC_{Real\,post-tax} = \frac{(1 + WACC_{Nominal\,post-tax})}{1 + \pi_e} - 1$$

This is also consistent with the approach taken by the AER which is required by the NER to calculate the cost of capital as a 'nominal vanilla' WACC.

4.2.1 The cost of equity

The cost of equity cannot easily be observed in the market, hence CAPM is used to estimate an appropriate cost of equity. The CAPM estimates the return on equity using three variables – the risk free rate, the market risk premium and the equity beta. It is calculated in accordance with the following formula:

$$E(R_e) = r_f + \beta_e \times MRP$$

Where:

- r_f is the risk free rate;
- β_e is the equity beta; and
- MRP is the market risk premium.

Each of these elements is discussed in more detail below.

4.2.1.1 Risk free rate

The risk free rate is the rate of return an investor receives from holding an asset with guaranteed payments. Where a risk free rate is calculated in nominal terms, it will compensate investors for the opportunity cost of not investing in the next best equivalent asset. This includes compensation for the time value of money, the expected cost of inflation and other possible premia for certain risks (for example, liquidity and inflation risk).

The risk free rate is used as a direct input into the CAPM to determine the required return on equity. It is also used as an input into the calculation of the required cost of debt.

Given that no asset is truly 'risk free', a proxy is used to determine the risk free rate. Common regulatory practice is to use government bonds. In Australia this generally refers to the yields from Commonwealth Government Securities (CGS).

The use of CGS as a proxy for the risk free rate has been subject to review amongst concerns that the CGS is no longer a true reflection of the risk-free rate due to an observed divergence between the yields on CGS and other 'risk-free' assets (such as State government bonds and Commonwealth Government guaranteed bank debt).[20] In its 'Electricity transmission and network service providers – review of the weighted average cost of capital (WACC) parameters'[21] ('2009 WACC Review'), the AER considered that there was no persuasive evidence to suggest that a more appropriate proxy for the risk free rate exists, or that the CGS yield exhibits any downward bias. As a result, CGS yields continue to be used by regulators such as the AER and ERA. This report therefore uses CGS yields to estimate the risk free rate for System Management Markets.

A further issue for consideration when estimating the risk free rate is the term used. In Australia, usual regulatory practice has been to average the yield on the indexed 10 year CGS for a specified period (such as 20 trading days) as close as feasible before the day a regulatory decision is made.

Again, this has been subject to review. In its 2009 WACC Review, the AER considered there to be persuasive evidence to move away from a 10 year term assumption to a term that matches the length of the regulatory period in question. However, the AER ultimately concluded that this could result in a shortening of debt on issue by a benchmark efficient regulated energy network business. Further, despite strong conceptual arguments for a term matching the regulatory period, the AER considered it reasonable and appropriate to adopt a cautious approach to avoid any increase in refinancing risk. As a result, a 10 year term assumption for the risk free rate continues to be adopted by the AER.

In its 2012 Final Decision on Proposed Revisions to the Access Arrangements for the Western Power Network ('Final Decision'), the ERA opted to adopt a term to maturity of five years.[22] This was based on a view that there should be consistency between the terms of the risk free rate and the debt premium. In previous decisions[23], the ERA concluded that there were strong grounds for matching the assumption of term to

[20] See, for example, AER 'Electricity transmission and network service providers – review of the weighted average cost of capital (WACC) parameters,' Final Decision, May 2009.
[21] Ibid.
[22] Economic Regulation Authority of Western Australia, Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network, 5 September 2012.
[23] ERA, 2011, Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline, October 2011.

maturity with the regulatory period as this better reflected the financing strategies of regulated businesses.

In its response to the ERA's Draft Decision, which adopted the same term to maturity, Western Power Networks raised a number of issues with the ERA's reasoning which are summarised in the table below.

Table 2: Issues with adopting an assumed term to maturity of five years[24]

ERA argument	Western Power Networks response
The ERA found that privately owned energy networks in Australia have 52.5% of total debt instruments with an average term of less than five years. The ERA also looked at a sample of government-owned energy networks in Australia which have approximately 44% of total debt instruments with an averaging term of less than five years.	The ERA is failing to appreciate that the term of debt data taken from company accounts is the remaining life of the debt – not the term of the debt at time of issue. When determining the cost of debt funding, businesses need to be funded for the interest rate they commit to when they issue debt. This is determined by the term of debt at the time of issue. Correctly interpreted, the evidence presented by the ERA is entirely consistent with a 10 year term of debt at issue.
Interest rate swaps are used by privately owned energy networks to exchange floating interest amounts for fixed interest amounts. Regulated businesses normally borrow floating rate debts and then fix the interest rate for the term of the reset period, which is usually five years, using interest rate swaps.	In relation to the use of interest rate swaps by regulated businesses, the ERA appears to believe that this practice means that businesses can be treated 'as if' they issued five year debt. This is wrong. Even if a business issued 10 year debt but used interest rate swaps in the way the ERA suggests, it must still pay a debt risk premium equal to the debt risk premium on 10 year debt. Using interest rate swaps in the manner described by the ERA only changes the profile of the (relatively risk free) swap rate component of debt. It does not alter the fact that a business which issues 10 year debt must pay a debt risk premium associated with 10 year debt. If the ERA did rely on the assumption that, as well as issuing 10 year debt, firms also immediately swapped their (risk free) interest rate exposure to the term of the regulatory period then one would have to, at a minimum, adopt the approach of the Queensland Competition Authority where the business is compensated for the cost of swap contracts.

[24] Taken from Western Power Networks, Response to the Economic Regulation Authority's 29 March 2012 draft decision. This table is based on work undertaken for Western Power Networks by CEG.

ERA argument	Western Power Networks response
The three year government bond future contracts are highly traded compared with the three year government bonds. The ERA considered that the shorter trading term is preferred by market participants over the longer trading term of 10 years.	The marginal differences in liquidity are trivial in the context of setting a regulatory WACC and do not provide a basis for choosing between different terms for the risk free rate for that purpose.

It has also been noted that the actual practice of Australian utilities is to issue debt of more than 10 years' duration.[25] On the whole, the ERA did not agree with the issues raised by Western Power Networks in its Final Decision. However, we do not consider that the ERA's Final Decision provides a compelling reason to depart from usual regulatory practice – such as that adopted by the AER – which is to use a term to maturity of 10 years. A 10 year term assumption is also consistent with broader financial market practice when applying the CAPM.

As a result, this report adopts a 10 year term assumption to estimate the risk free rate. Importantly, a shorter term to maturity would increase the allowed cost of raising debt that is used to calculate the debt risk premium. This is because the costs of raising debt must be amortised over a shorter time period. In IPART's review of the debt risk premium, costs of raising debt were increased from 12.5 basis points to 20 basis points to compensate for the decision to use a five year term assumption.

As noted above, CGS yields are normally measured based on a 20 day averaging period. While the averaging period is helpful in reducing the volatility in yields, if the WACC is being determined during a period of sustained market volatility and risk aversion by investors, then bond yields are likely to be trading at lower than typical, and therefore temporary levels. Such is the case currently as a consequence of global investor uncertainty and concerns over the sovereign debt crisis in Europe. Consequently, as at 1 October 2012 the 20 day average yield on 10-year CGS was 3.088%, which compares to the same estimated rate of 5.152% in July 2011, immediately prior to the marked increase in European sovereign debt risk.

Previously, regulators have aimed at setting the risk free rate whereby the averaging period commences as close as practically possible to the start of the regulatory control period. This approach has recently come into question for time periods impacted by sustained market volatility. Specifically, the ACT, in *Application by EnergyAustralia and Others (No 2) [2009] ACompT9*, agreed with the proposed approach of Energy Australia which was to choose an averaging period that 'is closest to the regulatory control period prior to the emergence of the marked acceleration of the global financial crisis in September 2008'.

Energy Australia proposed this approach on the basis that:

- The AER's specified averaging period for observing key financial data is highly likely to include data that has been impacted by this supervening critical event; and

[25] CEG in Western Power Networks. 'Response to the Economic Regulation Authority's 29 March 2012 draft decision'.

- An averaging period affected by the current abnormal financial market conditions will provide an estimate of the rate of return '… which is materially biased below the rate of return required by investors in a similar commercial business'.

KPMG contends that current financial market conditions, including the European sovereign debt crisis, could similarly be classified as 'abnormal'. That is, current global economic and financial factors have consequently been increasing the price of bonds, decreasing yields to historic lows.

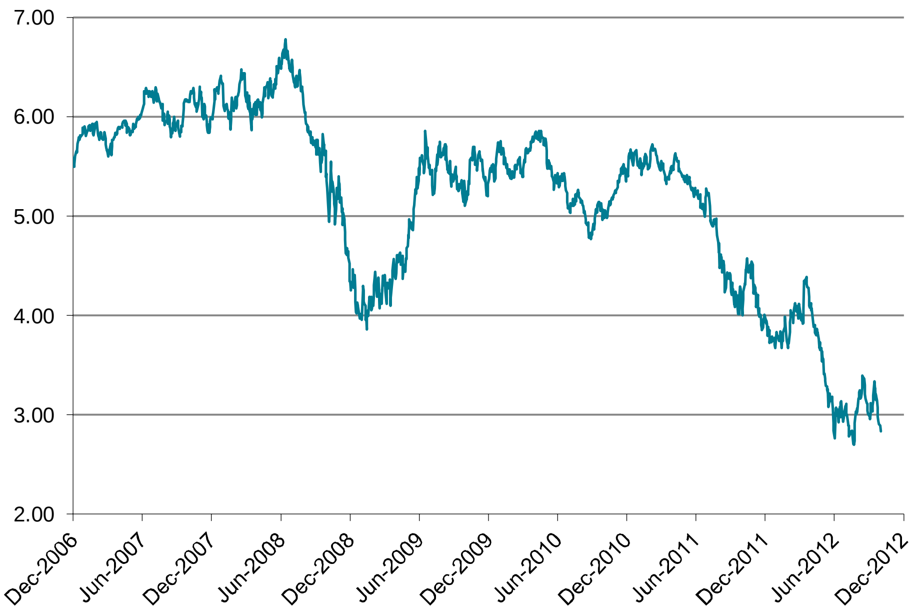
The Reserve Bank of Australia (RBA) has in its most recent statement on the October monetary policy decision, noted that "Low appetite for risk has seen long-term interest rates faced by highly rated sovereigns, including Australia, remain at exceptionally low levels"[26].

For the purposes of this report, we have adopted the methodology proposed by Energy Australia and accepted by the ACT to determine an appropriate risk free rate. That is, we have chosen an averaging period of 20 days that is closest to the regulatory control period prior to the emergence of the marked increase in European sovereign debt risk that commenced in 2011.

As shown in the following graph, we consider that the time period which appears to satisfy this criterion is 20 days between 14 June 2011 and 11 July 2011. That is, on 11 July 2011, 10 year bond yields were 5.10%, while on 12 July 2011, the yield had declined to 4.94% and have continued to fall.

[26] Reserve Bank of Australia, Statement by Glenn Stevens, Governor: Monetary Policy Decision, 2 October 2012

Figure 1: 10-year Commonwealth Government Securities (Yield to Maturity)



Source: Reserve Bank of Australia

Applying the ACT accepted methodology, a revised risk free rate of 5.152%[27] is therefore estimated for the benchmark cost of capital for System Management Markets.

4.2.1.2 Equity beta

The equity beta measures the standardised correlation between the returns on an individual risky asset or business with that of the overall market. That is, it represents the riskiness or volatility of the business' returns relative to the market.

Under CAPM, it is assumed that investors can diversify away business-specific risk and therefore only require compensation for bearing non-diversifiable or systemic risk (that is, risk associated with movements in the market as a whole).

An equity beta of one implies that the business' returns have the same level of systemic risk as the overall market. An equity beta of less than one implies that the business' returns are less sensitive to systemic risk, while an equity beta of more than one implies that the business' returns are more sensitive to systemic risk.

[27] Reserve Bank of Australia, RBA Statistical Tables - *Capital Market Yields – Government Bonds - Daily - F2*

As an unlisted entity, the equity beta for System Management Markets is not directly observable and must therefore be estimated with reference to proxies, that is, based on observed equity betas of comparable firms that are listed.

In its 2009 WACC Review, the AER changed its previously held position on the value of the equity beta for electricity distribution and transmission businesses from 1.0 to 0.8[28]. This was based on assessing empirical evidence from Australian data, which indicated a range of 0.44 to 0.68 for selected comparator companies, as well as the need to promote investment and maintain stability in the regulatory regime.

Importantly, the AER considered that an equity beta of 0.8 was necessary to achieve an outcome that is consistent with the NEO, in particular the need for the efficient investment in electricity services for the long-term interests of consumers of electricity, and revenue and pricing principles such as providing the service providers with a reasonable opportunity to recover at least efficient costs.

The AER considered that the non-diversifiable risk faced by network service providers was generally lower compared to the market, driven by relatively low elasticity of demand to price and by particular features of the regulatory regime in place (annual adjustment of prices, roll forward of the regulatory asset base and certain pass through provisions).

In its Draft Decision, the ERA considered that the value of the equity beta should be primarily based on capital market evidence and statistical estimates of beta values, where these are available for comparable businesses.[29] The ERA undertook a statistical analysis of a sample of Australian regulated infrastructure owners, based on the analysis undertaken for the AER 2009 WACC Review, and also took into account the equity beta range it determined for Western Power Networks' current access arrangement. As a result, the ERA concluded that its previous decision with regard to estimates of the equity beta ranging from 0.5 to 0.8 held and adopted a point estimate of 0.65.

A number of concerns were identified with the approach taken by the ERA[30]. Specifically:

- The sample size is small. The ERA Draft Decision is based entirely on a small set of Australian firms, whereas the AER included international comparators due to perceived limitations of the data obtained from the Australian market.
- There is a large degree of variation between the ERA's calculated values and the AER's values for specific companies. Variances of between 20 and 50 per cent suggest that the regulatory estimates of beta are unreliable.
- The results do not pass standard statistical reliability tests. The ERA makes no use of standard errors or confidence intervals other than to conclude that both sets of

[28] AER 'Electricity transmission and network service providers – review of the weighted average cost of capital (WACC) parameters,' Final Decision, May 2009.
[29] ERA Draft Decision, p.196.
[30] SFG in Western Power Networks, Response to the Economic Regulation Authority's 29 March 2012 draft decision.

regulatory estimates are so imprecise that it is statistically impossible to distinguish between them.

- No adjustment is made to correct for the demonstrated bias in beta estimates.

An independent assessment of the prescribed equity beta[31] also found flaws with the ERA's methodology and identified a number of reasons why the ERA should err on the side of caution in its assessment of beta. In its response to the Draft Decision, Western Power Networks also noted that, while the ERA used a similar style of analysis to the AER, the AER ultimately chose not to rely on its analysis on the basis that a value below 0.8 would be unlikely to result in efficient investment.[32] However, in its Final Decision, the ERA did not accept that any of the above concerns were relevant and maintained its point estimate of 0.65 for the equity beta.

The question of whether it is appropriate to use the equity beta applied to distribution and transmission businesses depends on an assessment of whether there is a difference in the systemic risk faced by these businesses compared to System Management Markets. Reasons for any differences are primarily due to the nature of activities undertaken by the businesses and the costs incurred. In the case of System Management Markets, a higher proportion of costs tend to be related to operating expenditure rather than capital expenditure as is the case with distribution and transmission businesses.

This issue was addressed by Europe Economics on behalf of the Commission for Energy Regulation (CER) in Ireland.[33] Europe Economics considered whether there was a case for a different cost of capital to be applied to the Transmission Service Operator (TSO) and Transmission Asset Owner (TAO). In this case, the TSO – Eirgrid – performs a role similar to System Management Markets in that it is responsible for the operation, development and maintenance of the electricity transmission system. As noted above, differences in systemic risk between the TSO and TAO arose due to the nature of the activities performed and the fact that the TSO faced a lower proportion of capital expenditure than the TAO. Europe Economics noted that "companies which have a higher gearing (i.e. fixed costs comprise a greater proportion of their cost base) will have higher systematic risk exposure, *ceteris paribus*."[34] As a result, Europe Economics considered that there may be a weak qualitative case for allowing a higher cost of capital to the TAO compared to the TSO. However, Europe Economics concluded that the evidence to support this was not sufficiently conclusive and that it was therefore reasonable to use the TAO as a comparator for the TSO.

As a result, we consider using electricity distribution and transmission businesses as comparators for non-market components of the WACC to be reasonable. Apart from the ERA, to the best of our knowledge no other Australian regulator to date has

[31] CEG in Western Power Networks, Response to the Economic Regulation Authority's 29 March 2012 draft decision.
[32] Western Power, Response to the Economic Regulation Authority's 29 March 2012 draft decision, May 2012.
[33] Europe Economics, Cost of Capital for Transmission Asset Owner (TAO), Transmission System Operator (TSO), Distribution System Operator (DSO), 16 June 2010.
[34] Ibid, p.68.

adopted an equity beta of less than 0.8 for a transmission or distribution business. This report therefore adopts an equity beta of 0.8 in estimating a benchmark cost of capital for System Management Markets. Historically, state based regulators have used equity betas in the range of 0.9-1.0 for distribution and transmission businesses. As stated above, the AER used an equity beta of 1.0 prior to its 2009 review of WACC and 0.8 thereafter.[35]

4.2.1.3 Market risk premium

The market risk premium is the expected return over the risk free rate that investors would require in order to invest in a well-diversified portfolio of risky assets. It represents the risk premium that investors can expect to earn for bearing only non-diversifiable or systemic risk.

Estimating a forward-looking market risk premium, commensurate with the current market, generally involves having regard to historical estimates on the basis that investors' forward-looking expectations will be based on past experience. Current regulatory practice in Australia is to estimate the market risk premium using historical data on equity premia.

In the past, Australian regulators consistently applied a market risk premium of 6 per cent. However, in its 2009 review of WACC parameters, the AER concluded that the market risk premium should be increased to 6.5 per cent on the basis of market conditions at the time. Nevertheless in its final decision on Envestra's access arrangement proposal for the South Australian gas network, released in February 2011, the AER used a market risk premium of 6 per cent. Other regulators, such as IPART and the Queensland Competition Authority, have also continued to use market risk premia of 6 per cent in regulatory decisions. In its Draft Decision, the ERA used a long term average to estimate the market risk premium for Western Power Networks and also concluded that 6 per cent was appropriate.

We are aware that Western Power Networks submitted that the market risk premium should lie in the range 6.5 to 8.5 per cent in its response to the Draft Decision, although this was not accepted by the ERA in its Final Decision. This is based on:

- Concerns with the averaging period used by the ERA to determine the historical market risk premium;
- Perceived limitations associated with the survey evidence also used by the ERA to determine the market risk premium;
- A view that the move by the AER from 6.5 to 6 per cent was made on the basis that the world economy had improved since May 2009, an assumption that Western Power Networks believes is incorrect; and
- Analysis undertaken by CEG relating to internal consistency between the market risk premium and risk free rate when estimating the overall return on equity.

[35] AER, *Electricity transmission and distribution network service providers – Review of the weighted average cost of capital (WACC) parameters,* May 2009, p 242.

We have followed generally accepted regulatory practice and adopted a market risk premium of 6 per cent to estimate the benchmark cost of capital for System Management Markets.

4.2.2 The cost of debt

The cost of debt is the return required by debt providers for lending to a business. It is estimated as the sum of the nominal risk free rate of return plus a debt risk premium in accordance with the following formula:

$$E(R_d) = r_f + DRP$$

Where:

- r_f is the risk free rate; and
- *DRP* is the debt risk premium.

The risk free rate is discussed in section 4.2.1.1. The remainder of this section therefore focuses on the debt risk premium.

4.2.2.1 Credit rating

The credit rating is an input into deriving the debt risk premium (see below). It is reflective of the assumed credit rating of an efficient provider of the services in question. As this is not directly observable, it is typically based on a benchmark comparator approach.

For regulated energy businesses, Australian regulators have tended to use a target credit rating of BBB+. However, due to a limited number of BBB+ credit ratings for Australian energy firms in the Australian financial market, regulators tend to combine the credit rating of BBB/BBB+ as the benchmark credit rating.

The AER reviewed the appropriateness of the BBB+ benchmark credit rating in its 2009 WACC Review. The AER considered that the most appropriate approaches to determining the benchmark credit rating were the modified best comparators approach and median analysis, which provided a range of credit ratings from BBB+ to A- respectively. However, the AER concluded that the weight of evidence did not support a deviation from the previously adopted credit rating of BBB+[36].

In its Draft Decision, the ERA determined a new benchmark credit rating for Western Power Networks of A- based on the median credit rating of a sample of companies used by the AER in its 2009 WACC Review. However, a number of deficiencies were identified with the approach taken by the ERA[37]. Specifically:

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[36] AER 'Electricity transmission and network service providers – review of the weighted average cost of capital (WACC) parameters,' Final Decision, May 2009.
[37] CEG. Western Power's proposed debt risk premium: a report for Western Power, May 2012.

- The ERA incorrectly assigned AGL a credit rating of A-, when it is rated by Standard and Poor's as BBB. When this error is accounted for, the median credit rating of the ERA's sample is adjusted to BBB.
- The ERA's sample included credit ratings of three regulated businesses which reflect support by Australian State Governments. These credit ratings cannot be considered to be 'stand alone' credit ratings as they are based on the businesses in question having support from the State. The inclusion of these businesses in the sample conflicts with the requirements of the Access Code which states that Western Power be provided an opportunity to recover revenue that meets forward-looking and efficient costs, including a return on investment commensurate with the commercial risks involved. It is reasonable to conclude that a similar approach should apply to System Management Markets given that the Market Rules also require that allowable revenue be sufficient to recover only forward looking costs, which are those that would be incurred by a prudent, efficient provider of the services.
- Inclusion of SPI PowerNet and SP AusNet effectively results in double-counting given that SPI PowerNet is a subsidiary of SP AusNet. Moreover, SP AusNet is ultimately owned by the Singapore Government meaning that the same questions over the appropriateness of its inclusion in the benchmark sample, as noted above, apply.
- The use of Synergy, an electricity retailer in Western Australia, as a guide is inappropriate due to the significant differences in risk profiles between retail and network businesses. Similarly, the risk profile between Synergy and System Management Markets is also significantly different.
- Taking the above into account, CEG[38] found that an adjusted ERA sample would result in a median credit rating of BBB. In its response to the Draft Decision, Western Power Networks proposed a revised credit rating of BBB+. This is consistent with accepted regulatory practice in Australia.

In its Final Decision, the ERA did not accept all the above arguments. However, it did acknowledge that applying a credit rating of A- would be a departure from the current regulatory practice as applied by the AER. The ERA also acknowledged the costs that may be incurred by energy businesses in obtaining higher credit ratings for their instruments. As a result, the ERA amended its approach in the Draft Decision to include all Australian corporate bonds with a credit rating of A-, BBB+ and BBB in the benchmark sample for its bond yield approach to estimate the debt risk premium.

We note that this still represents a significant departure from current regulatory practice and do not consider that there is sufficient evidence to support the approach taken by the ERA.

As discussed in section 4.2.1.2, we consider the use of electricity distribution and transmission businesses as comparators for System Management Markets to be appropriate in the context of non-market components of the WACC. Accordingly, it is

[38] Ibid.

reasonable to conclude that, as a business unit within Western Power, System Management Markets would have the same credit rating applied. As a result, this report uses a credit rating of BBB+ as an input into the debt risk premium.

4.2.2.2 Debt risk premium

The debt risk premium is the additional return over the risk free rate required by investors to hold debt that is not risk free (that is, where there is a risk of default). The purpose of including the debt risk premium within the expected cost of debt is to compensate a regulated firm for the benchmark cost of debt capital.

The debt risk premium is calculated by subtracting the risk free rate from the yield payable on a reference bond. The reference bond is determined by the benchmark credit rating (as discussed in section 4.2.2.1) and the term of the corporate bond used. Regulatory practice is to use the same term as that used for the risk free rate (as discussed in section 4.2.1.1). That is, the reference bond will be BBB+ rated and have a maturity of 10 years. The main issue surrounding the calculation of the debt risk premium is the selection of the fair value curve (which comprises a sample of reference bonds) used.

The AER did not consider the calculation of the debt risk premium in its 2009 WACC Review, although it did consider the benchmark credit rating and appropriate term for the risk free rate. In recent regulatory decisions,[39] the AER adopted a hybrid approach to estimating the debt risk premium rather than relying, as it did previously, solely on the Bloomberg fair value curve. This was primarily because the AER had concerns about sole reliance on the Bloomberg fair value curve given that it has a period of seven years and must therefore be extrapolated to 10 years. However, this approach has been challenged. As recently as January 2012, the ACT has endorsed the reasonableness of using the Bloomberg fair value curve in determining the debt risk premium. In subsequent regulatory decisions, the AER has recognised Tribunal decisions and adopted the extrapolated Bloomberg fair value curve to estimate the debt risk premium.

In its Final Decision, the ERA chose to adopt a 'bond yield' approach to estimate the debt risk premium. This approach was developed by the ERA on the basis of concerns about the use of the extrapolated Bloomberg fair value curve, similar to those of the AER. The bond yield approach bases the debt risk premium on:

- A sample of bond yields of varying terms to maturity; and
- A sample excluding the Bloomberg yield curves.

The approach relies on bond yields observed directly from the Australian financial market.

[39] For example see: Australian Energy Regulator, Victorian electricity distribution network service providers Distribution Determination 2011-2015 (Final Decision), October 2012.

The appropriateness of the bond yield approach was reviewed by CEG on behalf of Western Power Networks.[40] CEG ultimately concluded that the bond yield approach was not sufficiently developed or sophisticated to replace the type of expertise provided in Bloomberg's fair value estimates.[41] Given the uncertainty associated with the use of the bond yield approach and the continued endorsement of the extrapolated Bloomberg fair value curve, this report uses the extrapolated Bloomberg fair value curve to estimate a benchmark cost of capital for System Management Markets. The debt risk premium for System Management Markets is based on:

- The average annualised Australian Bloomberg BBB seven-year fair value curve over 5 March 2012 to 30 March 2012 of 7.63 per cent; less
- The average annualised seven-year CGS yield over 5 March 2012 to 30 March 2012 of 3.97 per cent; plus
- A range of 0.00% to 0.36% being between 0 and 12 basis points per annum for three years which accounts for the range of values provided by the extrapolation methodology.

This results in a range of between 3.67 per cent and 4.03 per cent. Western Power used 3.67 per cent as a conservative estimate of the debt risk premium in its response to the ERA Draft Decision.

We acknowledge that we have not applied the same date values as that used for the risk free rate, which were selected as those which preceded a period of marked acceleration in bond yield decline. We do not consider this to have a material effect on the estimation as the debt risk premium is intended to calculate the additional return over the risk free rate required by investors – that is, the difference between the reference bond and the risk free rate. Yields on both have been affected by the decline in bond yields and we would therefore expect the change in the difference between the two to approach zero.

In addition to the calculation of the margin between corporate debt and the risk free rate, the debt risk premium may include debt raising costs. In its Final Decision for Western Power, the ERA determined that debt raising costs should be an additional 12.5 basis points, which is consistent with the values used by other regulators in Australia when using a ten year time to maturity.

Adding the cost of raising debt to the margin between corporate debt and the risk free rate of 3.67 percent, provides a debt risk premium of 3.80 per cent, consistent with the value used by Western Power and the lower end of the range recommended by CEG.

[40] CEG, Western Power's proposed debt risk premium, May 2012.
[41] CEG, Western Power's proposed debt risk premium, May 2012. Paragraph 223.

4.2.3 Other parameter values

4.2.3.1 Gearing

Gearing is defined as the ratio of the value of debt to total capital (that is, debt and equity). A business's' gearing, or capital structure, will have a significant bearing on the expected required return on debt and the expected required return on equity. For regulatory purposes, the benchmark gearing ratio is usually considered to be the capital structure of a benchmark efficient business. This is intended to provide companies with an incentive to manage the costs associated with debt and equity efficiently.

As the optimal level of gearing is not directly observable, an estimate is derived using an average of actual gearing level from a group of comparable firms.[42] Analysis undertaken by the AER and adopted by other regulators, including the ERA, suggests a gearing level of 60 per cent is appropriate. Western Power Networks proposed a gearing level of 60 per cent in its Access Arrangement information[43], which was accepted by the ERA on the basis that it is consistent with the approach taken in relation to the current Access Arrangement and the approach taken in the AER 2009 WACC Review, as well as being consistent with regulatory precedent and observed levels of gearing of Australian electricity and pipeline companies.[44]

As a result, this report uses a gearing level of 60 per cent to estimate a benchmark cost of capital for System Management Markets.

4.2.3.2 Value of imputation credits (gamma)

A full imputation tax system for companies has been adopted in Australia since 1 July 1987. Under the tax system of dividend imputation, a franking credit is received by Australian resident shareholders, when determining their personal income taxation liabilities, for corporate taxation paid at the company level. In a dividend imputation tax system, the proportion of company tax that can be fully rebated (credited) against personal tax liabilities may be best viewed as personal income tax collected at the company level. With the full tax imputation system in Australia, the company tax is effectively eliminated if all the franking values are used as credits against personal income tax liabilities.

The actual value of franking credits, represented in the WACC by the parameter 'gamma', depends on the proportion of:

- The franking credits that are created by the firm and that are distributed; and
- The value that the investor attaches to the credit, which depends on the investor's tax circumstances (that is, their marginal tax rate).

[42] AER, May 2009, Final Decision, Electricity transmission and distribution network service providers: review of the weighted average cost of capital (WACC) parameters.
[43] Western Power, September 2002, Access Arrangement Information for 1 July 2012 to 30 June 2017.
[44] ERA Draft Decision, p.161.

As these will differ across investors, the value of imputation credits may be between nil and full value (i.e. a gamma value between zero and one).

There has been and continues to be significant debate concerning the appropriate value to ascribe to imputation credits. Whilst a value of 50 per cent has been widely adopted by regulators in the past, the AER's 2009 WACC review marked a significant turning point by settling on a value of 65 per cent.

However, a number of electricity distribution businesses have sought to challenge the AER's position on this matter and appealed to the ACT. The appeal was successful and gamma was subsequently lowered. Since the ACT decision, the value of gamma used by regulators has been reduced. The following reviews since the ACT decision have used gammas of 0.25:

- ACT – Decision on Energex Limited (Gamma) May 2011[45];
- AER – Queensland Electricity Distribution 2010-11to 2014-15[46]; and
- ERAWA – Dampier to Bunbury gas transmission[47].

In its Final Decision for Western Power, the ERA also considered that a reasonable value of gamma was 0.25.

On the basis of the above, this report uses a gamma value of 0.25 for the purposes of estimating a benchmark cost of capital for System Management Markets.

4.2.3.3 Inflation

Regulators in Australia are increasingly using RBA inflation forecasts to estimate the expected inflation rate.

In its Draft Decision, the ERA calculated the expected inflation rate as the geometric mean of the RBA's inflation forecasts on the basis that this method is widely used by Australian regulators. The AER adopts this approach – using a simple average of the RBA's forecasts of short-term inflation and the mid-point of the RBA's inflation target for the remaining years in the forecast period. However, in its Final Decision, the ERA changed its approach to adopt an inflation rate derived from the Fisher equation using estimates of the nominal and real risk free rates of return. This was based on a view that, given the current economic environment, markets may have discounted the RBA's mid-point value and that the Fisher equation estimate more accurately reflected market expectations of inflation over the regulatory period. The ERA noted that deriving inflation estimates using the Fisher equation was a practice adopted by regulators – including the ERA and the AER – until 2008 when the Global Financial Crisis occurred and the market for Treasury indexed bonds experienced liquidity

[45] Australian Competition Tribunal, Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9 (12 May 2011).
[46] Australian Energy Regulator, Queensland Distribution Determination 2010-11 to 2014-15 – Final Decision, May 2010.
[47] Economic Regulatory Authority of Western Australia, Revised Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline, 22 December 2011.

issues. In its Final Decision, the ERA considered that the market for Treasury's indexed CGS bonds is sufficiently liquid to justify the re-introduction of the Fisher equation rather than calculating the expected inflation rate as the geometric mean of the RBA's inflation forecasts.

At this point, we do not consider that there is sufficient evidence to justify departing from using the RBA's inflation forecasts as a reasonable estimate of the expected inflation rate. This is due to continuing uncertainty over the economic environment on both a domestic and international basis, as well as whether the market is producing signals that could be considered efficient. We acknowledge that this approach may change in the future depending on economic and market outcomes. For the purposes of this report, we therefore estimate the expected inflation rate based on the geometric means of the RBA's inflation forecasts.

As discussed elsewhere in this report, a term of 10 years has been adopted for estimating parameters for the System Management Markets' cost of capital. Therefore the expected inflation rate is also estimated using a 10 year term to maturity. This results in an inflation rate of 2.52 per cent based on the RBA's August 2012 Statement on Monetary Policy.

4.3 Results

The table below sets out the proposed parameter values for the benchmark cost of capital for System Management Markets and the resulting cost of capital.

Table 3: Benchmark cost of capital for System Management Markets

Parameter	Benchmark value
Nominal risk free rate	5.152%
Expected Inflation rate	2.52%
Gearing	60%
Risk margin	3.80%
Market risk premium	6.0%
Equity beta	0.8
Gamma	0.25
Nominal pre-tax cost of debt	8. 95%
Nominal post-tax cost of equity	9.95%
Real post-tax vanilla WACC	*6.66%*

5 Adjustment for actual cost of capital

This section of the report considers whether clause 2.23.7 of the Market Rules requires that a revenue adjustment be made for differences between the cost of debt and equity within the WACC and the resulting actual costs and gearing level.

5.1 Background

Clause 2.23.7 of the Market Rules requires that:

> *"Where the revenue earned for a service...via System Operation Fees in the previous Financial Year is greater than or less than System Management's expenditure for that Financial Year, the current year's budget must take this into account by decreasing the budgeted revenue by the amount of the surplus or adding to the budgeted revenue the amount of any shortfall, as the case may be."*

The ERA is responsible for approving System Management Markets' annual allowable revenue on a forward-looking (three year) basis. It is our understanding that annual approval of System Management Markets' budget is given by the Minister for Energy who receives advice from the Independent Market Operator (IMO) regarding whether the budget is consistent with the allowable revenue approved by the ERA.[48]

Adjustments have been made to the annual budget for System Management Markets to account for variations between actual expenditure and allowable revenue. These adjustments have been lagged to account for timing differences between end of year reconciliation and setting charges for the following year. For example, the System Management Markets budget for 2011/12 included an adjustment for 2008/09 reconciliation.[49] It is not clear how the reconciliation is calculated or whether there is a separate approval process for ensuring that any (positive) adjustment relates to efficient expenditure by System Management Markets.

As discussed in previous sections of this report, System Management Markets has not previously included a return on capital in its Allowable Revenue submission. Consistent with the commonly accepted building block approach, we understand that System Management Markets intends to include a return on capital in its AR3 submission, where the return is determined by reference to a benchmark WACC. Our assessment of an appropriate benchmark cost of capital for System Management Markets is set out in section 4 of this report.

Therefore clause 2.23.7 of the Market Rules suggests that to the extent that System Management Markets' actual cost of capital or WACC may differ from that included in its Allowable Revenue for a given year, an adjustment should be made in subsequent years to reflect this variation. However, we note that there is no precedent for this type of adjustment (that is, between actual and benchmark WACC) in any other regulatory regime of which we are aware.

[48] For example see: http://www.westernpower.com.au/documents/aboutus/STATEMENTOFCORPORATEINTENT200708.pdf
[49] http://www.imowa.com.au/n191.html

This section of the report therefore considers, given the inclusion of a benchmark cost of capital in System Management Markets' allowable revenue determination:

- Whether determining an actual cost of capital for System Management Markets is justified on a cost-benefit basis; and
- Whether an actual cost of capital is practically measurable for System Management Markets.

5.2 Cost-benefit analysis of adjusting for an actual cost of capital

As a general principle, the costs of regulation should justify its benefits[50]. It therefore seems reasonable to question whether the cost, complication and uncertainty associated with adjusting System Management Markets' budgeted revenue for the difference between an actual WACC and benchmark WACC would be justified by benefits to consumers.

5.2.1 Materiality of adjustments

For regulatory purposes, a benchmark cost of capital is applied primarily on an 'efficient benchmark provider' basis. That is, certain parameters of the WACC (as described in section 4) are estimated according to what an efficient provider of the services in question would achieve rather than what a specific (or actual) provider might achieve over the period being considered. This is intended to provide regulated businesses with an additional efficiency incentive (over and above any others applied via the regulatory regime) with respect to their financing arrangements. As a result, absent any significant changes in the regulatory approach to determine parameters of the WACC, it would be reasonable to assume that any difference between benchmark and actual WACC over an Allowable Revenue period would have an expected value of zero. Further, any management decisions by System Management Markets during the Allowable Revenue period would not impact on the value of these parameters.

That said, some WACC parameters – the risk free rate, the debt margin and the inflation rate – may differ from what is estimated prior to commencement of the regulatory period. These changes are determined by market forces external to System Management Markets.

In any event, it is difficult to see how the difference between an 'actual' and a benchmark WACC for System Management Markets in AR3 would have a material impact in the market or on customers. For example, on the basis of illustrative assumptions that System Management Markets' capital base is of the order of $12m even a variation between an 'actual' and benchmark WACC of as much as say 0.5 per cent, would have an impact of only $60,000 per annum. In the context of total System Management Markets' Allowable Revenues which in AR2 for example, ranges from approximately $6.6m to $7.5m per annum, and total electricity retail revenues of

[50] For example, see Council of Australian Governments, Best Practice Regulation. A Guide for Ministerial Councils and National Standard Setting Bodies, October 2007, Principle 3.

approximately $2.67b[51] in the SWIS, a possible (and arguably hypothetical) under or over-recovery of $60,000 per annum from Western Power's total customer base of over one million[52] does not appear to be material, either in total or individually, equating to about 6 cents per customer per annum, on average.

5.2.2 Cost of calculation

Unlike other expenditure items, the actual WACC incurred by Western Power (whose share capital is not traded) and System Management Markets is neither of a transactional nature nor, being an economic cost, is it recorded in accounting records. Setting aside the intrinsic uncertainties explained at section 5.3, involved in determining the cost of capital of a business unit that is not a legal entity, an attempt to estimate the actual WACC of a business unit would require data gathering and computations such as those outlined at section 4. This would likely require System Management Markets to incur additional expenditure to determine any potential adjustment. Usual regulatory practice is to have work of this kind undertaken by an independent expert. On the basis of our experience as expert advisors, we would expect that the professional fee for an assessment cost of capital for a firm whose capital is not traded, would typically be in the region of $30,000 to $50,000. This is a material amount relative to the potential impact on System Management Markets' customers of any differences between an actual and benchmark WACC.

The costs of conducting an assessment of an 'actual' WACC are incurred regardless of whether the outcome results in an increase or decrease in revenue recovered from customers. Therefore, the adoption of an 'actual', rather than a benchmark, WACC will be intrinsically biased towards imposing additional costs on customers, unless a pre-judgement is made that the benchmark WACC initially used to set Allowable Revenue is systemically biased towards material overstatement. However, it is not clear how such a hypothetical pre-judgement could arise, since a benchmark WACC will necessarily be subject to the ERA's approval.

Furthermore, the example figures provided above suggest that for System Management Markets the costs of determining and evidencing an adjustment under clause 2.23.7 could at best largely negate any reduction and have the potential to significantly amplify any increase, in charges to customers arising from an underlying adjustment.

5.2.3 Summary

The above points suggest that the likely materiality of an adjustment between an 'actual' and benchmark WACC alongside the costs of determining the exact scale of such an adjustment would not justify an adjustment process in accordance with clause 2.23.7 of the Market Rules.

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[51] Synergy – Electricity Retail Corporation, Annual Report, 1 July 2010-30 June 2011 at: http://www.synergy.net.au/docs/Synergy_2010_-_11_Annual_Report.pdf
[52] http://www.westernpower.com.au/aboutus/aboutus.html#our_customers, July 2012

The likely outcome of any adjustment process would be:

- In the case of a downward adjustment, result in the costs of calculating a difference between actual and benchmark WACC, offsetting and potentially exceeding the consequential decrease in costs of capital; and
- In the case of a positive adjustment, the costs of calculating the difference could materially add to the cost increase to customers resulting from the adjustment.

The cost of making an adjustment appears to be sufficient to result in an likelihood of an adjustment mechanism providing a net dis-benefit for customers regardless of whether individual adjustments were to increase or reduce System Management Markets' cost of capital. Accordingly, the potential costs of an adjustment would not justify the potential benefits.

5.3 Measuring an actual cost of capital for System Management Markets

Leaving aside concerns that the costs of attempting to include a WACC adjustment in the revenue reconciliation may outweigh the potential benefits, consideration needs to be given to whether it is possible to measure an actual cost of capital for System Management Markets.

The requirements of clause 2.23.7 of the Market Rules would require measurement of System Management Markets' actual WACC on an annual basis.

System Management Markets is an organisational unit of Western Power. Therefore in order to determine an actual WACC for System Management Markets, it is necessary to:

- Measure the actual WACC of Western Power; and then
- Allocate that observed WACC to System Management Markets.

Each of these matters is considered below.

5.3.1 Measuring the actual WACC of Western Power

As described in section 4 of this report, WACC is the weighted average of a cost of debt and a cost of equity.

The cost of debt can in principle be observed where an amount of debt can be ascribed to a business and a corresponding interest cost similarly identified.

Because Western Power is a non-traded government owned organisation, it is not apparent how a market cost of equity could be observed. Rather, a cost of equity based on comparable organisations would need to provide a suitable proxy for Western Power in terms of how it would be viewed by financial markets. This would bring us back to calculating a benchmark cost of capital as described in section 4 and hence obviate the point of comparing an actual to a benchmark cost of capital.

5.3.2 Allocating WACC to System Management Markets

Even if it were possible to observe actual costs of equity and hence capital for Western Power, it is not clear how a gearing level and hence an actual WACC could be established for System Management Markets separately to that of Western Power.

The total capital invested in System Management Markets can be readily determined by reference to its capital base. However, it is not clear that there is a deterministic basis for allocating capital invested in System Management Markets between

- equity comprising:
  - shareholder equity (share capital, retained earnings after tax and other reserves); and
- debt.

Revenues and costs that make up retained earnings before interest, dividends and taxation can generally be allocated on the basis of accounting and causal cost allocation rules, since they represent the accumulation of trading profits and losses attributable to System Management Markets.

An allocation of debt and share capital to System Management Markets is required to provide a basis for an objective, reasoned basis of attribution of:

- Interest and dividends; and hence
- Taxation; and hence
- Retained earnings after tax.

We explain below why there is not a causal basis of determining how much share capital and debt necessarily attach to a business unit such as System Management Markets.

Share capital is necessarily issued by a legal entity as a whole, not business units within a legal entity. Also, unless the entirety of an entity's debt is issued on terms that have the effect of ring fencing it for purposes of specific business lines or services (for example, it is all secured on individually specified assets), which we understand is not the case for Western Power's approximately $5bn of debt, there is also not a general accounting basis or rationale to determine an objective, attribution of debt between business units.

Accordingly, equally valid, multiple alternative combinations of share capital and debt and hence retained earnings could be proposed for System Management Markets, but each would provide a different gearing ratio and hence cost of capital. (The range of possible permutations further increases where several differently priced sources of debt need to be attributed between business units.) The use of an assumed or benchmark gearing ratio to overcome this problem would be self defeating since it would negate an objective of comparing actual to benchmark costs.

Therefore, there is not a deterministic basis for:

- Allocating the components of capital, share capital, retained earnings and debt between business units; and hence
- Determining an actual cost of capital for System Management Markets.

The absence of capacity to accurately determine an actual cost of capital for System Management Markets (or any other business unit) means that an adjustment between benchmark and actual cost of capital under clause 2.23.7 of the Market Rules would not be meaningful.

Further support for this finding is provided by Australian regulatory accounting guidelines, which often do not require regulated businesses to report allocations between regulated and non-regulated business segments, of share capital, general purpose debt, interest, dividend payments and taxation actually incurred, because of the intrinsically arbitrary nature of such allocations. For example:

- The Australian Energy Regulator's (then ACCC) Draft Regulatory Reporting Guidelines for Gas Pipeline Service Providers, May 2004 states:

  "The following items do not need to be allocated to a Covered Pipeline, or any other part of Service Provider's business, in the Disaggregation Statements. If they are not allocated or otherwise attributed to any part of a Service Provider's business they should be recorded in the "Not Attributed" column of the Disaggregation Statements.

  - *Share capital;*
  - *Investment revenue;*
  - *Loan capital on long term borrowings;*
  - *Short term borrowings or overdrafts;*
  - *Cash or bank deposits;*
  - *Non-operating investments;*
  - *Interest payable on receivables;*
  - *All income tax, deferred tax on future income tax benefits, charges, credits, assets or liabilities; and*
  - *Goodwill"*[53]*;*

  KPMG worked closely with the ACCC to develop this guideline. To the best of KPMG's knowledge, the ACCC made these exclusions because it recognised that because of their arbitrary nature, any allocation of actual figures (and hence gearing ratios) would not provide meaningful information.

- The Office of the Regulator-General, Victoria's Electricity Industry Guideline No 3, "Regulatory Accounting Information Requirements" Issues 1 and 2, exclude such

[53] ACCC, Draft Regulatory Reporting Guidelines for Gas Pipeline Service Providers, May 2004, p 13-p 14.

items from disaggregation.[54] KPMG worked closely with the ESC to develop this guideline, which has provided a precedent for regulatory accounting and reporting requirements for electricity businesses throughout Australia. To the best of KPMG's knowledge, the ESC made these exclusions because any allocation of these items would be arbitrary and not provide meaningful information.

- For similar reasons, the Office of the Tasmanian Economic Regulator (OTER) does not require the allocation of equity, cash and tax items between business segments. (KPMG bases this statement on from having worked with OTER to develop reporting requirements for regulatory financial statements.) For example, see the templates that support Electricity Industry Guideline No 2.2[55], that are currently published on www.energyregulator.tas.gov.au. In particular, the regulator's website states:

  "In February 2011, the Australian Energy Regulator requested certain changes to the Accounting Ring-fencing Guideline to facilitate transfer of the economic regulation of distribution services provided by Aurora from the Tasmanian Economic Regulator to the Australian Energy Regulator (AER). The changes will enable Aurora to submit its pricing proposal in accordance with the AER's framework for the economic regulation of these services."

We also observe that the ERA's own "Guidelines for Access Arrangement Information" (December 2010):

- Specify principles for the causal allocation of all material *"revenue and cost items"* (paragraph 3.5, p. 7 and paragraph 4.3.2, p. 12), consistent with a requirement to allocate operating items and profits between business segments; but
- do not set out principles for the attribution of debt and equity and hence gearing ratios; and
- in other regards, also follows much of the precedent set by the Office of the Regulator-General, Victoria's Electricity Industry Guideline No 3, referred to above.

5.3.3 Summary

To observe an actual cost of capital for System Management Markets, it would be necessary to observe actual costs of both debt and equity for Western Power and to objectively determine a gearing structure for System Management Markets. However, it is not possible to observe a market cost of equity for Western Power.

Also, where an entity bears debt for the general purpose of funding its operations, the actual capital of an entity (such as Western Power) that is allocated to individual services or business segments (such as System Management Markets and its market operations) cannot be attributed between debt and equity on a deterministic basis.

[54] For example: See Office of the Regulator-General Electricity Industry Guideline No 3, Issue No 2, 14 November 1997, Appendix 1, Statement S200.
[55] Office of the Tasmanian Economic Regulator, Electricity Industry Guideline No 2.2 – Electricity Distribution Accounting Ring Fencing and Model Regulatory Accounts, Issue No 5, March 2011, Supporting Templates.

Because of these reasons an objective actual WACC for System Management Markets cannot determined .

5.4 Conclusion

It is unclear how the objectives of minimising the long-term cost of electricity supplied to customers from the SWIS would be served by applying clause 2.23.7 of the Market Rules such that an efficient benchmark WACC initially used to determine Allowable Revenue, would be set aside and replaced by a subjective estimate of "actual" WACC incurred by System Management Markets. The mechanics of determining an actual WACC for System Management Markets (should this be practically possible) would likely result in additional cost that would outweigh the benefit of any revenue adjustment.

Further, the Market Rules require that:

- *Allowable revenue must be sufficient to cover forward looking costs*
- *Allowable revenue must include only costs that would be incurred by a prudent provider of the services, acting efficiently, seeking to achieve the lowest practically sustainable cost of delivering the services in accordance with the Market Rules, while effectively promoting the Wholesale Market Objectives*
- *Where possible, the Authority should benchmark the allowable revenue against the costs of providing similar services in other jurisdictions.*

Arguably, setting a benchmark cost of capital fulfils the requirements of the Market Rules. A benchmark cost of capital is a commonly used regulatory tool applied to regulated businesses. This is because a benchmark cost of capital can provide a further efficiency incentive and because it provides a reasonable forward-looking estimate of efficient costs over a regulatory period.

An objective actual WACC for System Management Markets is not available to enable an adjustment under clause 2.23.7 of the Market Rules.

The above findings lead us to conclude that a revenue adjustment under clause 2.23.7 of the Market Rules should not be provided for during AR3, for differences between the cost of debt and equity within the WACC and the resulting actual costs and gearing level.

Consequently, we have not considered any methodology for arriving at such a revenue adjustment.

6 Expert's statement

I have read the Federal Court's "Practice Note CM 7 "Expert Witnesses in proceedings in the Federal Court of Australia" (1 August 2011) and prepared this report in a form consistent with Practice Note CM 7.

I have prepared this report for the purpose set out in section 1.2 of this report and it is not to be used for any other purpose without my prior written consent. Accordingly, KPMG accepts no responsibility in any way whatsoever for the use of this report for any purpose other than that for which it has been prepared.

I have made all inquiries that I believe are desirable and appropriate and that no matters of significance which I regard as relevant have, to my knowledge, been withheld from the material set out in this report.

Nothing in this report should be taken to imply that I have verified any information supplied to me, or have in any way carried out an audit of any information supplied to me other than as expressly stated in this report.

My opinion is based solely on the information set out in this report. If I amend any conclusion on further information, I will amend the report.

Keith Lockey

A Western Power scope of work

ANNEXURE 2 – SCOPE OF WORK

NAME OF PROJECT:

Expert advice regarding Weighted Average Cost of Capital (WACC) for System Management's allowable revenue application for the AR3 period (2013/14 to 2015/16)

LOCATION:

Head Office

BRANCH/DIVISION:

System Management

PURPOSE:

Western Power requires the services of a suitably skilled and experienced consultant to provide expert advice regarding parameters associated with the determination of System Management's WACC for the next review period (AR3) – 2013/14 to 2015/16. The WACC will be used to determine the return on investment for AR3. The WACC will need to be documented in an expert report that will be able to withstand scrutiny by Western Power, the Economic Regulation Authority (ERA) and other stakeholders.

BACKGROUND

Western Power, through the ringfenced System Management business, provides system operation services to the wholesale electricity market in accordance with the Market Rules. The allowable revenue is revised on a periodic basis, in accordance with the Market Rules, and is submitted to the ERA for approval. Western Power's proposal for the 2013/14 to 2015/16 period must be submitted by 30 November 2012.

Section 2.23.12 of the Market Rules details the principles that are to be applied in determining the Allowable Revenue. Western Power has not previously adopted the building blocks method to determine the allowable revenue and has never determined a value for the WACC for System Management. Historically, the allowable revenue has been determined as:

- For AR1 (2007/08 to 2009/10): **Opex** plus **depreciation**
- For AR2 (2010/11 to 2012/13): **Opex** plus **depreciation** plus **borrowing costs**

For AR3 (2013/14 to 2015/16) Western Power is proposing to adopt the conventional building blocks method (on a real pre-tax basis) to determine the allowable revenue. It is anticipated that the allowable revenue will be determined using the following formula:

Revenue$_t$ = **WACC**$_{\text{real pre-tax}}$ *** opening value of capital base$_t$**
plus **depreciation$_t$**
plus **opex$_t$**

WACC

The determination of the WACC and its associated parameters is required for the AR3 period (2013/14 through to 2015/16).

For AR3 Western Power will include an opening capital base (RAB) and detailed capital expenditure forecasts for the AR3 period. For the purposes of determining the building block revenue the WACC will be applied to the forecast value of the RAB.

The Market Rules do not provide any guidance on the calculation of a WACC for System Management. Broadly section 2.23.12 of the Market Rules provides for the allowable revenue to be sufficient to cover the forward looking costs of providing system management services.

At present the ERA has not published a preferred WACC methodology for System Management so the consultant shall have particular attention to:

- recent ERA determinations or determinations in other relevant jurisdictions, including decisions by the Australian Energy Regulator (AER) for the Australian Energy Market Operator.
- relevant legislation, including section 61 (2) of the Electricity Corporations Act 2005 and the Market Rules.

The consultant shall provide compelling arguments, with supportive evidence and analysis, for all relevant WACC parameters/estimates. It is expected that the consultant will provide advice that will have a reasonable likelihood of being accepted by the ERA.

The Economic Regulation Authority (ERA), or its consultant, will examine Western Power's WACC estimate which will also be subject to scrutiny during the public consultation phases of the approval process.

PROJECT SCOPE

Western Power requires the consultant to prepare an expert report which will satisfy the Federal Court Guidelines (see attachment) and responds to the following issues.

1. Assessment of appropriate values for WACC parameters under CAPM

We are seeking your opinion on the appropriate values for the WACC parameters for System Management under the CAPM including:

- Risk free rate
- Inflation rate
- Gearing (Debt and Equity proportions)
- Cost of debt
- Market risk premium
- Equity beta
- Corporate tax rate
- Gamma

In your opinion, does section 61 (2) of the Electricity Corporations Act 2005 impact on the values for the WACC parameters?

2. Adopting a benchmark WACC

In your opinion, does adopting a benchmark firm cost of capital achieve the objectives of the market, satisfy the Market Rules and satisfy section 61 (2) of the Electricity Corporations Act 2005? If not, what alternative should be adopted?

3. Cost true up

We are seeking your opinion on whether, under section 2.23.7 of the Market Rules, a revenue adjustment should be provided for during AR3 for differences between the cost of debt and equity within the WACC and the resulting actual costs and gearing level.

If a revenue adjustment is required, in your opinion, what methodology should be used for arriving at the revenue adjustment?

RESOURCES

The consultant will be expected to liaise closely with Western Power and review other Australian sources of information, including, but not limited to:

- relevant legislation including the Electricity Corporations Act 2005 and the Market Rules
- actual business practice and stock exchange information
- the work of other experts and academic research
- recent AER and ERA determinations and associated expert reports relied upon by the regulators and submitted by network service providers

- decisions of and submissions made to both the Australian Competition Tribunal and the Western Australian Energy Disputes Arbitrator

DELIVERABLE

At the completion of its task the expert will provide an independent expert report that includes the findings of the Project Scope outlined above. The reports will:

- be a stand alone document of a professional standard that can be submitted to and relied upon by the ERA for the purpose of assessing System Management's AR3 proposal
- be able to be made available to the public and be in an appropriate format to be accessible on the internet
- is prepared in accordance with the Federal Court Guidelines for Expert Witnesses set out in Attachment 1 and acknowledges that the expert has read the guidelines
- summarises the expert's experience and qualifications and attaches curriculum vitae
- identifies any person and their qualifications, who assists you in preparing the report or in carrying out any research or test for the purposes of the report
- summarises WP's instructions and attaches these terms of reference
- carefully sets out the facts that the expert has assumed in putting together the report and the basis for those assumptions

Any queries regarding this Request for Proposal should be directed to Hugh Smith 08 9326 6116 or James Wright 0421 052 364.

B Appendix - Curricula Vitae

Keith Lockey
Executive Director

Keith Lockey

Executive Director

KPMG
147 Collins Street
Melbourne VIC 3000

Function and Specialisation

Economics

Certifications & Professional Memberships

- BSc (Hons) (Environmental Sciences), University of Lancaster
- Institute of Chartered Accountants in England and Wales

Profile/Overview

Keith co-leads KPMG's economic and policy advisory group. He specialises in advising governments, utilities and other economically regulated industries on matters of industry reform, economic regulation and pricing and funding arrangements. He has worked almost exclusively in this area since 1995.

Experience

United Energy Distribution Electricity Distribution Price Review – Keith wrote an expert report to evidence the robustness of UED's 5 year expenditure forecasts and their consistency with National Electricity Rule objectives.

Horizon Power: Regulatory advice - Keith led a team that provided Horizon, a vertically integrated electricity business serving remote and rural Western Australia, with regulatory advice on emerging industry reform issues.

Western Power:Review of customer contributions policy - Keith worked with a small team to provide a review of the commercial and regulatory implications of Western Power's regulatory policy for its significant customer contributions income.

Regional Development Victoria: Electricity transmission pricing - Keith undertook a feasibility assessment of the opportunities and practical process for a potential investor in Victoria to gain access to prudent discounts on regulated transmission charges under different connection scenarios.

Korea Electric Power Corporation: Electricity industry disaggregation and reform in Korea. Keith led KPMG teams that:

- reviewed the draft pool rules for the Korean electricity market and advised the vertically integrated Korea Electric Power Corporation (KEPCO) on the practical implications for the disaggregation of distribution and retail businesses;
- advised on appropriate debt-to-equity ratios for disaggregated businesses; and
- assisted with development of a pool price risk management strategy ("vesting contracts") for KEPCO.

Northern Territory's Power and Water Corporation: Network revenue submission - Keith provided advice throughout the process leading to the 2004 network price review submission.

Assessment of potential for cross-subsidies in a vertically integrated energy utility - Keith undertook a study that reviewed the potential for economic cross- subsidies both within the utility and with other parties to assist with planning disaggregation options.

Independent Pricing and Regulatory Tribunal of NSW: Review of electricity industry regulatory model - Keith led a team that provided an independent review of the robustness of its electricity network pricing model.

Queensland Competition Authority – Water business price monitoring. Keith led a team that developed templates to collect financial information to assist the QCA with monitoring price and a financial model for analysing that information in accordance with building block principles.

Office of the Tasmanian Energy Regulatory: Redesign and simplification of regulatory accounting requirements – Keith reviewed Tasmania's regulatory accounting requirements for the electricity distribution industry. Keith led a team that consulted with the AER on its potential future requirements and significantly revised the regulatory accounting templates and accompanying text, to provide clarity and simplification.

Allgas: Assistance with compliance with regulatory accounting requirements - Keith helped this gas network operator to develop reporting procedures to help demonstrate compliance with regulatory accounting requirements.

Electricity Transmission Network Owners Forum (ETNOF): Transmission cost allocation guidelines 2007 - Keith reviewed draft Cost Allocation Guidelines published by the Australian Energy Regulator.

Transend Networks Ltd: AER Cost Allocation Methodology Manual (2007 and 2008) - Keith led a KPMG team that drafted a "Cost Allocation Methodology" required by the Australian Energy Regulator, to demonstrate the allocation of costs between different transmission services in accordance with the National Electricity Rules. KPMG also drafted an accompanying cost allocation and regulatory reporting procedures and process manual to assist Transend.

Transend Networks Ltd: Allocation of shared costs to unregulated business activities – Keith advised on the consistency of an allocation approach developed by Transend with good business practice and regulatory requirements.

Confidential client: Related party transactions - Keith was retained by a network business to advise on the business risks and regulatory implications of regulator requirements for related party disclosures that were inconsistent with Accounting Standards.

Queensland electricity network businesses: Electricity industry regulatory accounting guidelines - Keith was engaged by industry to critique the Queensland Competition Authority's Guidelines published as part of the 2005 Price Determination.

Electricity network: Electricity industry ring-fencing guidelines - Keith drafted an electricity utility with a submission on the jurisdictional regulator's draft guideline. He identified significant practical issues that also would not have assisted the regulator to achieve his objectives. As a consequence, the regulator significantly revised the guideline.

Independent Pricing and Regulatory Tribunal of NSW: Review of audit requirements for electricity industry price cap variables - Keith provided an independent critique of criticism of the audit regime for this form of regulatory data submission. Keith developed transparent reasoning that recommended changes to the audit regime to make it significantly more light-handed and consistent with Auditing Standards.

Independent Competition and Regulatory Commission, ACT: Licensed electricity, gas, water Australian Competition and Consumer Commission: Record Keeping Rules - Keith reviewed draft accounting separation rules (regulatory accounting requirements) for the postal industry drafted by the ACCC and provided a range of suggestions and advice to improve their workability.

Australian Competition and Consumer Commission: Accounting Ring Fencing Guidelines for Gas Transmission Businesses - Keith reviewed a jurisdictional regulator's guideline as a basis for accounting ring fencing for gas transmission pipeline service providers, under the Gas Code for the Commission. Keith was then engaged by the Commission to draft a guideline to allow service providers to meet the Commission's objective of demonstrating compliance with the National Gas Code, while following generally accepted accounting principles.

Independent Pricing and Regulatory Tribunal of NSW: Review of rail access dispute - Keith led a small team that advised the Tribunal on regulatory accounting issues that were central to the resolution of a dispute between a rail access provider and a rail access seeker.

Transgrid – Negotiated Services Pricing – Keith led a team that developed a model that enabled prices to be calculated on the basis of both standalone and incremental allocations of cost, in accordance with the National Electricity Rules.

Northern Territory Power and Water Corporation: Development of an industry based cost ring fencing guideline - Keith developed a "self-regulating" cost ring fencing guideline that was accepted by the Northern Territory Utilities Commission with a minimum of revision.

Electricity network businesses throughout Australia: Review of regulatory accounting submission - Keith has been engaged by different electricity networks to review regulatory accounts for compliance with regulatory requirements, prior to submission.

Australian Competition and Consumer Commission: Review of Electricity Transmission Business Co Regulatory Information Guidelines - Keith reviewed and provided constructive advice to the ACCC on proposed regulatory information guidelines to help it achieve its objectives in a practical, workable way aiming to minimise the information burden on business. Subsequently a small team led by Keith drafted revised Guidelines.

Office of Regulator-General, Victoria ("ORG"): Regulatory management secondment - Shortly after its establishment, Keith was seconded to the ORG for 15 months to: manage and implement the process of acquiring and analysing regulatory accounts from electricity distribution businesses. He also provided the ORG with day-to-day advice on regulatory financial and accounting issues.

Electricity businesses Electricity retailer gross margin benchmarking - Keith has undertaken a range of studies for retailers (and network businesses) to establish benchmarks of operating costs returns and margins.

Power and Water Authority: Assessment of cost allocations and the bases of CSO payments for electricity supply - Keith advised on appropriate responses to government guidelines on and a regulator's review of, these issues.

APA Group: Expert report on recoverability of contract termination payment, under the National Gas Rules – Keith authored an expert report to accompany an access arrangement revision to the regulator, explaining how an intangible accounting asset ranks as an asset eligible for inclusion in a regulatory asset base.

Legal advisors to Envestra and Multinet: Expert witness reports– support for a management fee claimed as a recoverable cost under the Gas Code - Keith has provided expert reports on the activities and costs incurred by related entities necessary to reference service delivery, and recharged by way of a management fee.

Legal advisors to electricity and gas network service providers - benchmarking of efficient distribution business costs - Keith has provided independent expert advice on issues of cost efficiency and allocation key to their access arrangement revisions and price review submissions.

Gas network business: Development of a cost allocation model for gas businesses - To assist a gas business gain regulatory approval for access arrangements, Keith led a KPMG team that developed and reported on, a cost allocation model.

Independent Pricing and Regulatory Tribunal New South Wales ("IPART"): Gas Access Arrangements - Keith helped analyse and assess a range of key pricing proposals included in a major pipeline operator's Access Arrangement proposals. This work included the development of a sophisticated financial model and an assessment of options for cost allocation. Keith also reviewed pricing and cost allocation models submitted by the pipeline operator.

Victorian Regional Channels Authority: Price review submissions - Keith managed the KPMG team that drafted the VCA's regulatory submission. Keith also provided assistance to the Melbourne Ports Corporation with its regulatory submission.

Confidential Client: Privatisation of SA Ports - Keith led a small team that provided confidential advice on prospective regulatory matters to a bidder.

Legal advisors to BHP Billiton (BHPB): Options for providing access to the Mt Newman railway - Keith reviewed the commercial and regulatory options for providing access.

Government of Queensland: Assessment of options for regulation of coal, rail and port assets – Keith led a KPMG team that advised Queensland Treasury on the regulatory frameworks and options for economically regulating a privatised coal-rail network and port assets.

Private rail operator: Regulated pricing model and asymmetric risk – Keith led a team that developed a model to assist the operator of an access regulated mining rail network and port assets, demonstrate the efficiency of its pricing proposals to the regulator. This included advice on pricing asymmetric risk.

Sydney Water Corporation (SWC) – development of access prices. Keith assisted SWC to develop access pricing principles for inclusion in a draft access arrangement.

Independent Pricing and Regulatory Tribunal of NSW ("IPART"): Bulk Water Pricing - Keith led a team that reviewed the business rules of financial models developed by IPART for bulk water pricing, and quality assured the models' implementation of those rules.

Nicki Hutley
Director

Nicki Hutley

Director

KPMG
10 Shelley Street
Sydney NSW 2000

Function and Specialisation

Economics

Certifications & Professional Memberships

- BEc (Hons) University of East Anglia (UK)
- Member, Companies and Securities Advisory Commission (1998-2000).
- Affiliate member, Institute of Chartered Accountants in Australia
- Member, Economics Society of Australia
- Member, Australian Business Economists

Profile/Overview

Nicki has more than 20 years' experience in the provision of financial and economic advice to markets, industry, peak bodies and Federal, State and Local Government. Over the past six years, Nicki has led numerous project teams undertaking consulting work for public and private sector clients across a broad spectrum of economic, industry and policy issues, including finance and infrastructure.

Experience

- Peer review of appropriate cost of capital for Tier 1 airport (confidential client).
- An assessment of financing options (including determination of an appropriate discount rate) for the development of new high care residential facilities for the aged for a Catholic Health Australia-led consortium.
- Engaged by the Queensland Competition Authority (QCA) to review the methodology and assumptions (including appropriateness of calculation of discount rate) used to determine infrastructure charges by Queensland councils. Reviews undertaken for Sunshine Coast, Moreton Bay and Brisbane City Councils (2008-2010).
- Assessment of potential competition for water supply in NSW (confidential client).
- Modelling the cost of choice in financial products for Virgin money Australia. Assessed the collective cost to individuals of failure to exercise lowest cost choice across a number of financial products including savings accounts and home mortgages.
- Developed a model to determine the relationship between unemployment and mortgage default rates and a framework for a cost-neutral mortgage assistance program for the unemployed for Genworth Financial. Presented findings to the government Caucus Economics Committee.

Justine Bond
Senior Manager

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KPMG
10 Shelley Street
Sydney NSW 2000

Function and Specialisation

Economics

Certifications & Professional Memberships

- Bachelor Economics, Australian National University
- Bachelor Arts, Australian National University
- Postgraduate Diploma in Applied Commerce, University of Melbourne

Profile/Overview

Justine is in economic regulation across a number of sectors including electricity, gas, telecommunications, post and transport.

Her experience includes:

- five years working with KPMG UK where she worked on economic regulation of the telecommunications, post, transport, water and energy sectors;
- working for Indepen Consultants where she provided advice and analysis for clients on telecommunications, broadcasting and other regulatory issues;
- being seconded to Ofcom to work on the Digital Dividend Review and to provide advice on competition issues;
- working for an electricity and gas distribution business in Australia, developing regulatory strategy, preparing price review submissions and responding to other regulatory issues; and
- working for the Australian Communications Authority (now ACMA) on a range of regulatory issues.

Experience

- Provided advice to a large utility company in Australia on the impact of different regulatory and commercial scenarios on shareholder value. This involved conducting client workshops to understand operations and evaluating likely scenarios based on the regulatory regime.
- Provided advice to a large water company in the UK on the impact of future changes in the regulatory regime and options for structuring the business going forward.
- Provided advice to a UK energy company on the regulatory regime for gas in Australia. The UK energy company was interested in expanding its operations in Australia but required a detailed understanding of the operation of the regulatory regime before undertaking investment. The advice included detail on how regulation would impact on commercial operations, the state of competition in the market, risks and opportunities and relevant stakeholders.
- Developed a regulatory impact framework for the selection of ex ante obligations in an emerging telecommunications market. This included applying the framework to markets were ex ante regulation was required based on an identification of market failures such as predatory and excessive pricing, and anti-competitive bundling.
- Provided advice to Ofcom as part of their review of the Financial Framework regarding the current and future efficiency of Openreach and its methodology for cost allocation. This advice was followed up for subsequent reviews.
- Provided advice to a national postal operator on their regulatory strategy for an upcoming price review process.
- Assisted a national postal operator with its input into a government review of the postal sector. This included undertaking analysis of actual financial performance compared to regulatory assumptions and providing advice on the approach to regulation taken in other comparable sectors.
- Assessed whether a ferry company was earning a fair return on the capital employed to provide transport services to provide input to a subsequent OFT investigation into prices charged by the ferry company.

Justine Bond
Senior Manager

- Supported the due diligence and bidder questions process associated with the sale of a large utility company in the United Kingdom. This included managing data room documents, responding to bidder questions with strict timeframes and reviewing due diligence documentation.

- Critiqued a model developed to calculate the costs and benefits of digital switchover in South Africa, identifying methodological and model errors, in order to support the policy and decision-making process in relation to digital switchover.

- Provided advice to Ofcom on the costs of digital switchover as an input to the valuation of Channel 3 and Channel 5 licences and the decision-making process relating to licence renewals. This work involved modelling the costs of converting sites from analogue to digital operation and evaluating whether these costs are greater or less than the revenue earned from the increased coverage.

- Project managed TXU Australia's 2006 Electricity Distribution Price Review submission, which encompassed drafting the submission, as well as contributing to the development of business strategy for the review; coordinated, drafted and reviewed TXU submissions on regulatory/economic issues; prepared TXU Networks annual price submissions for Electricity and Gas Distribution; and developed distribution tariff strategies.

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