Amended access arrangement information for the Western Power Network

Appendices

Response to the Economic Regulation Authority's 29 March 2012 draft decision

Date: 29 May 2012

westernpower

DM 9341642

Document Control

Document Status & Control

Status Date	29 May 2012
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Status	Final

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Appendix A. Revenue model summary

Output Summary

29 May 2012

Key metrics

WACC 6.39% Post-tax

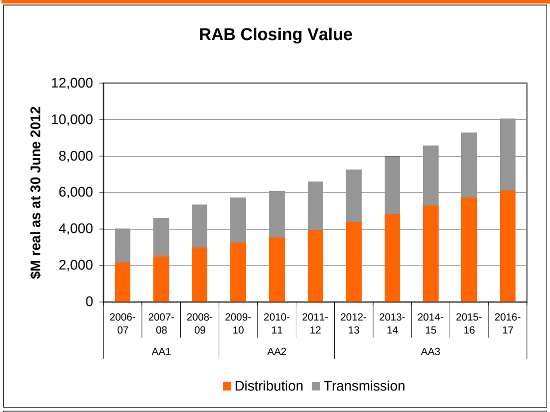
Expenditures	$M Real30/06/2012	$M Nominal
Equity raising costs	35.8	36.9
Ex-post writedown ris	64.1	-
Total Capex	5,997.1	6,507.7
Total Opex	2,655.8	2,880.2
Total Expenditure	**8,652.9**	**9,387.9**
Total Contributions	**872.8**	**944.9**
TEC	**906.9**	**982.1**
Deferred revenue	**516.7**	559.5
Total Revenue	**9,136.0**	**9,952.1**

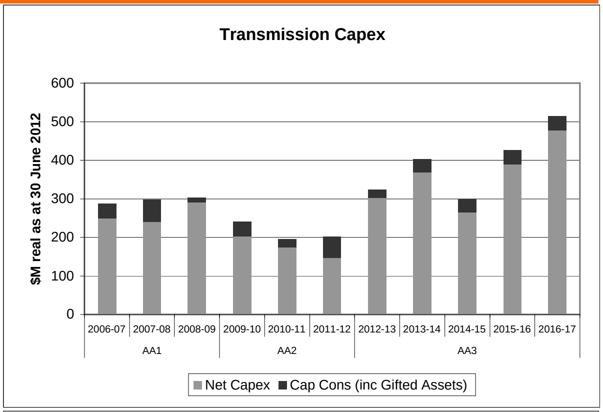
	2012-13	2013-14	2014-15	2015-16	2016-17
Price Path (annual change in tariff)					
Distribution	13.4%	13.4%	13.4%	13.4%	13.4%
Transmission	1.6%	1.6%	1.6%	1.6%	1.6%
Bundled	8.2%	10.0%	11.0%	11.1%	11.1%
Revenue Cap ($M real as at 30 June 2012)					
Distribution	989.6	1,138.6	1,313.0	1,538.1	1,801.4
Transmission	435.7	445.6	467.7	492.9	513.4
Total Revenue	1,425.3	1,584.2	1,780.7	2,031.1	2,314.7
Energy (GWh)					
Distribution Sales	14,402	14,627	14,847	15,331	15,831
Transmission Network	18,638	19,030	19,488	20,077	20,589

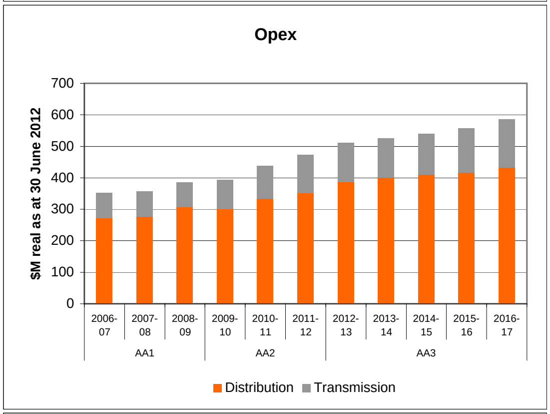
AA2 Deferred Revenue Recovery Period (years)

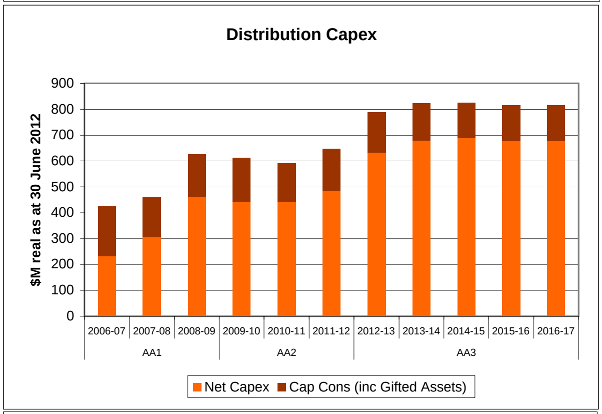
Distribution	10
Transmission	10

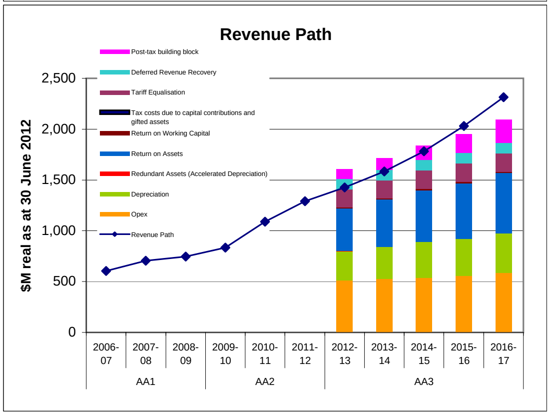
Charts

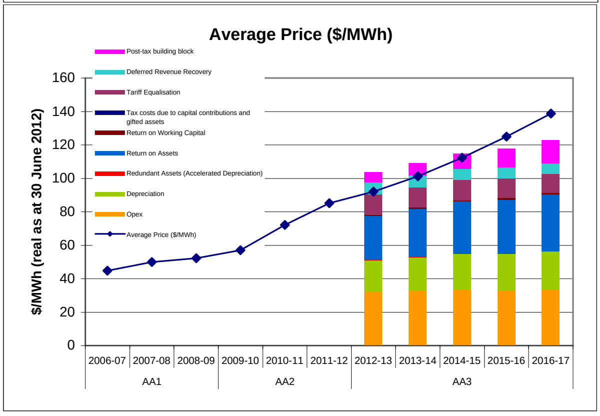












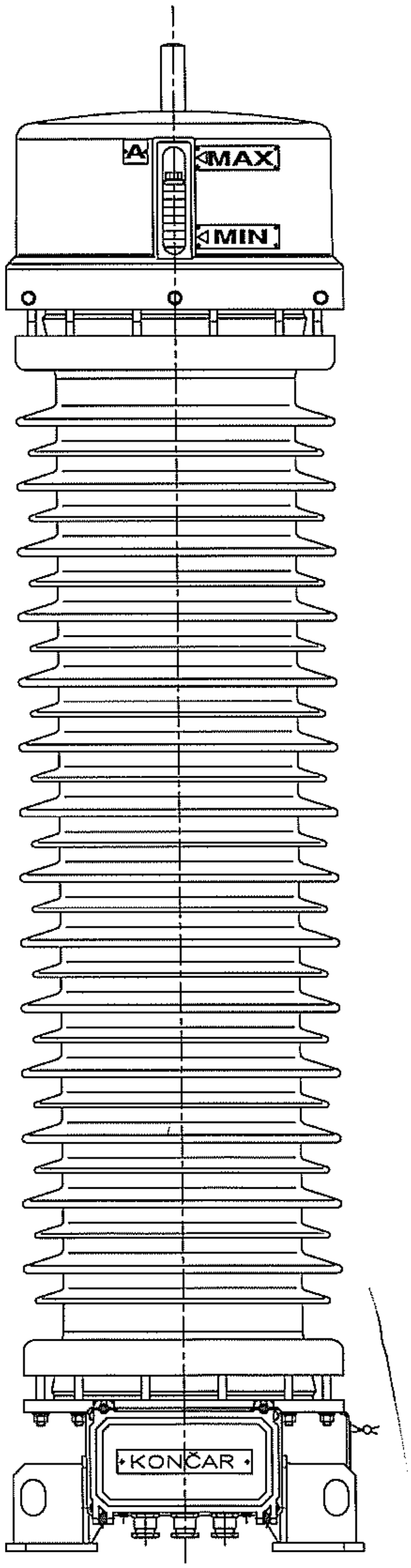
Appendix B. Koncar - Voltage instrument transformers - instructions for use and maintenance

pg 27

6.3.3.1

KONČAR

Končar - Instrument transformers, Inc.



VOLTAGE INSTRUMENT TRANSFORMERS TYPE

VPU – 145

INSTRUCTION FOR USE AND MAINTENANCE

UPTU-113/2E

M54869

04.2007.

CONTENTS

1. FIELD OF APPLICATION

These instructions apply to oil immersed voltage transformers type VPU-72,5 to VPU-420.

2. DESCRIPTION OF TRANSFORMER

The inductive voltage transformers are used to separate the protection and metering devices from high voltages and to transform the line voltage to be measured to the level suitable for measuring and protective devices, with defined accuracy.

The voltage transformers are designed and produced in compliance with IEC-60044-2 or some other international and national standards.

Core

For VPU transformer type, the core is of open bar-type, made of cold rolled, grain oriented magnetic steel (M4-0.27).

Secondary winding

The secondary winding is placed on the transformer core limb. The winding is made of electrolytic copper, insulated with thermal class F double insulating varnish. The winding is dimensioned in such as manner that it can withstand short and long-lasting thermal and mechanical loading.

Primary winding

The high voltage winding is placed on the insulating cylinder. The winding is made of electrolytic copper, insulated with thermal class F insulation. The winding is dimensioned in such as manner that it can withstand short and long-lasting thermal and mechanical loading.

Insulation

The insulation between the primary winding and the grounded parts of the transformer is made of high quality insulating paper, grade P5318 / DIN 6740, dried and impregnated with transformer oil under high vacuum. The capacitor effect of conductive screens inserted into the main insulation favourably influences on the distribution of impulse and A.C. voltages in the windings and insulation. The consequence is the uniform loading of the insulation, which makes these transformers resistant to atmospheric impulse voltages, and optimally loads the insulation in normal operating conditions.

Insulators

The insulators are made of high quality electro-grade porcelain, cylindrically shaped, brown glazed. If required, other glaze colours can be supplied. The insulators can be made of composite material, with silicon shed and are of grey color.

The creepage distance is chosen according to the ambient pollution or customer requirements.

Housing

The transformer housing is made of welded steel plates. The high quality anticorrosive protection is obtained by hot dip galvanising in accordance with ISO-1461/73. The hot dip galvanised surface is additionally protected by paint, of colour RAL-7001. Upon request, other colour can be obtained.

Terminals

The primary terminal is made of hot tinned cooper or aluminium alloy. The shape of the terminal is cylindrical or flat. The secondary terminals are made of stainless steel size M8, and are placed in the secondary terminal box together with the secondary winding earthing terminals.

Oil

The transformers are filled with high quality transformer oil of mineral origin, inhibited to improve its resistance to aging. The oil is degassed and dried in high vacuum, so that residual water content is 10 microgram per gram. In this way the maximum dielectric properties are obtained. The transformer oil used for instrument transformers is guaranteed to be free of polychlorinated biphenyls or terphenyls (PCB, PCT).

Dilatation

The transformer is hermetically sealed, without possibility of contact between transformer oil and ambient air. The high quality metallic bellows made of stainless steel is used for the compensation of the temperature dilatation of oil. Since there is no contact of oil with atmosphere, the insulating properties are maximally preserved.

3. SUPPLY AND TRANSPORT CONDITIONS

The transformers are delivered complete, filled with oil and tested in compliance with the standard stipulated in the contract.

Transformers type VPU for voltage levels 72,5 kV up to 170 kV are packed in upright position in wooden cases or crates. They are transported in upright position and they should not inclined by more than 20°.

Transformers type VPU-245 and VPU-420 are packed in horizontal position in wooden cases or crates.

4. INSPECTION OF TRANSFORMER BEFORE ERECTION

Before erection, the transformer is unpacked and inspected.

If any damage is noticed (cracked or damaged insulator, oil leakage, damaged metal parts, bent connections etc), the transformer should not be installed in the plant, but the factory or its authorised service shop should be informed about it.

The contact telephone is +385-1-379-4112 and fax +385-1-379-4040,
e-mail: info@koncar-mjt.hr

The transformer should be transported to the place of installation in original packing. It is necessary to unpack transformer from the wooden package and to erect it to the supporting structure by the means of ropes. The ropes should be fixed by hooks on the appropriate places on the transformer tank. The steel ropes for lifting should be of diameter 10 mm. Further care should be taken to avoid mechanical damage of insulator, HV terminals, bellows cover or transformer overturning.

The transformer should be secured from overturning by means of sling as shown on the drawing enclosed.

Please do the visual check of position of bellows in bellows screen and compare it with other transformers. The position of bellows of all transformers should be the same. Difference should not be more than ±10 mm.

Before erection of transformer on support structure, check tightness of lower insulator flange screws using tightening torque 45 Nm. Tighten the screws in pair on opposite sides, two times around entire flange.

5. TRANSFORMER CONNECTION

The transformer, put on the appropriate place, should be fixed to the portal with adequate bolts and earthed. The earthing connection should be carried out according to the regulations for plants with voltages above 1 kV. Anticorrosive protection of the connections and conductors may not be damaged.

Recommended tightening torque for the different bolt dimension used:

Bolt dimensions	Recommended tightening torque (Nm)
M8	20; 10*
M10	47
M12	81
M16	197

* Value valid only for secondary terminals in the secondary terminal box

The primary conductors are connected by means of corresponding links to the primary terminal. The connection has to be mechanically and galvanically correct. The primary connections, after fastening, should be protected with suitable means against galvanic currents.

The secondary terminals on voltage transformers are connected in accordance with local and general regulations. After that the secondary resistance should be checked and the insulation resistance should be measured.

One terminal of each secondary winding should be earthed.

Only one end of the three windings forming open delta connection may be earthed.

The secondary circuits can be protected by fuses. Special attention should be paid to the contact resistance of the fuses connected to the secondary terminals of accuracy class 0.2, so that it does not disturb the accuracy class.

Terminal marked with **tgδ** placed in secondary terminal box **must be always connected to terminal marked N and with earthing terminal.** It may be disconnected only during measuring of tg delta and insulation resistance.

6. STORAGE

Transformers are stored in vertical or horizontal position (depending on voltage level), with packing. It is recommended to store the transformer in dry and ventilated storehouse. Lifetime of original wooden package is six (6) months on open air and 18 months in dry ventilated place. Actual lifetime in dry ventilated place can be longer, depending on climatic conditions. Evaluation of package condition should be made on site.

In case the transformers are stored for longer time than package lifetime, or there is other reason for storage outside of the package, they must be unpacked and set in upright position. In that case, transformers must be secured against overturning.

Wooden package can be stored separately and reused.

If the transformer is transported to a longer distance (more than several hundreds meters) it must be packed again. Make sure that only sound wood is used for packing.

7. MAINTENANCE AND CHECKING

Within the frame of transformer maintenance works, the user can and must carry out any works found necessary during annual overhaul or during maintenance works, which do not require opening of the transformer.

No opening of transformer or oil drainage or topping up during guarantee period is allowed. This is not recommendable even after the guarantee period, and the user can do it at his own cost and risk.

Basically, the transformer is maintenance free, but some checks are recommended:

a) during the inspection of the switchgear, especially after disturbances in the network (short circuits, atmospheric discharges etc.):

- position of dilatation bellows

The position of the dilatation bellows is in the function of ambient temperature and transformer voltage, with constant secondary burden. At maximum ambient air temperature and voltage of 1.2 Un, the bellows can be in the highest position, and at minimum ambient temperature and transformer open circuit condition, the bellows will be in the lowest position.

A higher position of the bellows compared with other transformers in the switchgear can indicate a transformer fault.

- check the transformer for mechanical damages

b) during annual overhaul

- everything under a)

- the condition of terminals (contacts)

- the quality of earthing

- cleaning the transformer external surface

In addition to regular transformer supervision and maintenance, after 10 years of operation, the following tests are recommended:

- measuring of insulation dielectric dissipation factor tgδ

- measuring of insulation resistance

These tests shall be repeated in the fifteenth year, and then once in every five years.

Measurement of tgδ on field is performed according to the enclosed instruction (Enclosure No. 3). Test voltage for this measurement is **2 kV**.

Oil sampling is performed according to the instructions enclosed. No refilling of oil is required nor allowed because transformer is filled with 2 litres extra oil. This quantity is enough for 12 oil samplings if each sampling requires 150 ml of oil. If the dissolved gas analysis of oil indicates the damage of the insulation and local temperature rise, the manufacturer should be consulted.

List of checks for combined instrument transformers

Check	When to check			
	2-3 times per year	Once per year	Within first 10 years of service	After 10 years of service and every 5 years afterwards
Bellows level	☺	☺	☺	☺
Oil leakage	☺	☺	☺	☺
Electric connections		☺	☺	☺
Insulation resistance			☺	☺
Insulation tanδ measurement			☺	☺
Dissolved gas analysis			☺	☺

In case that user, because of internal regulations, must perform dissolved gas analysis before 10 years of service, manufacturer should be informed.

For evaluation of transformer insulation based on DGA, use following table of limit values for gases dissolved in oil:

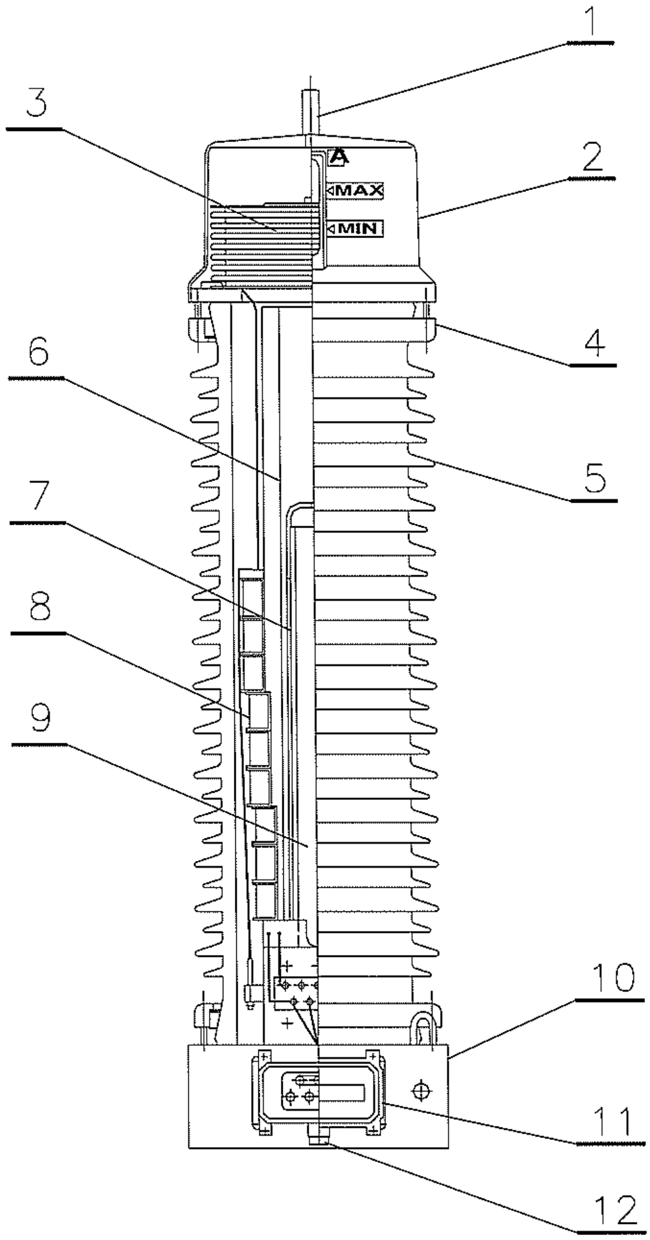
DGA limit values table

Gas [ppm]	YEARS IN SERVICE		
	0-3	3-15	≥15
H2	100	250	500
CH4	10	30	80
C2H6	10	40	50
C2H2	10	15	20
C2H4	10	40	50
CO	300	500	700
CO2	900	1500	3000

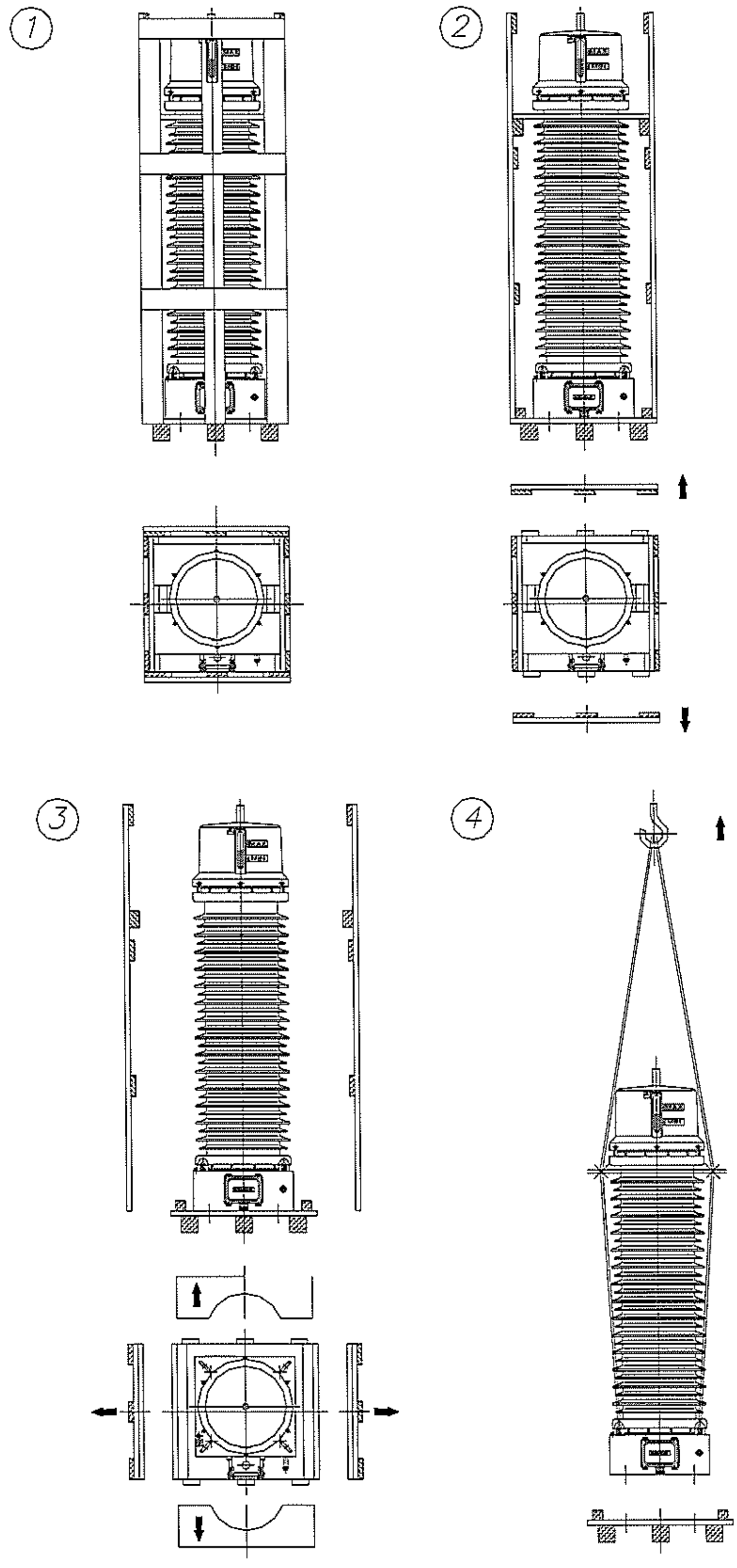
In some cases gases can appear because of chemical reaction between different materials. Appearance of hydrogen (H2) alone, without other hydrocarbons (CH_4, C_2H_2,C_2H_4 i C_2H_6) is a sure indication of chemical gas generation. **In that case hydrogen concentration should be neglected regardless of its value.** Practice has shown that in that case hydrogen concentration starts decreasing after 10 years regardless of whether transformer is in service or not.
Because of great risk of incorrect evaluation of insulation state, **shortened DGA** based on detection of only hydrogen, without checking other hydrocarbons, is not recommended. **Only complete dissolved gas analysis gives correct evaluation of insulation condition.**

Enclosure No. 1. *→ Transformer section drawing*

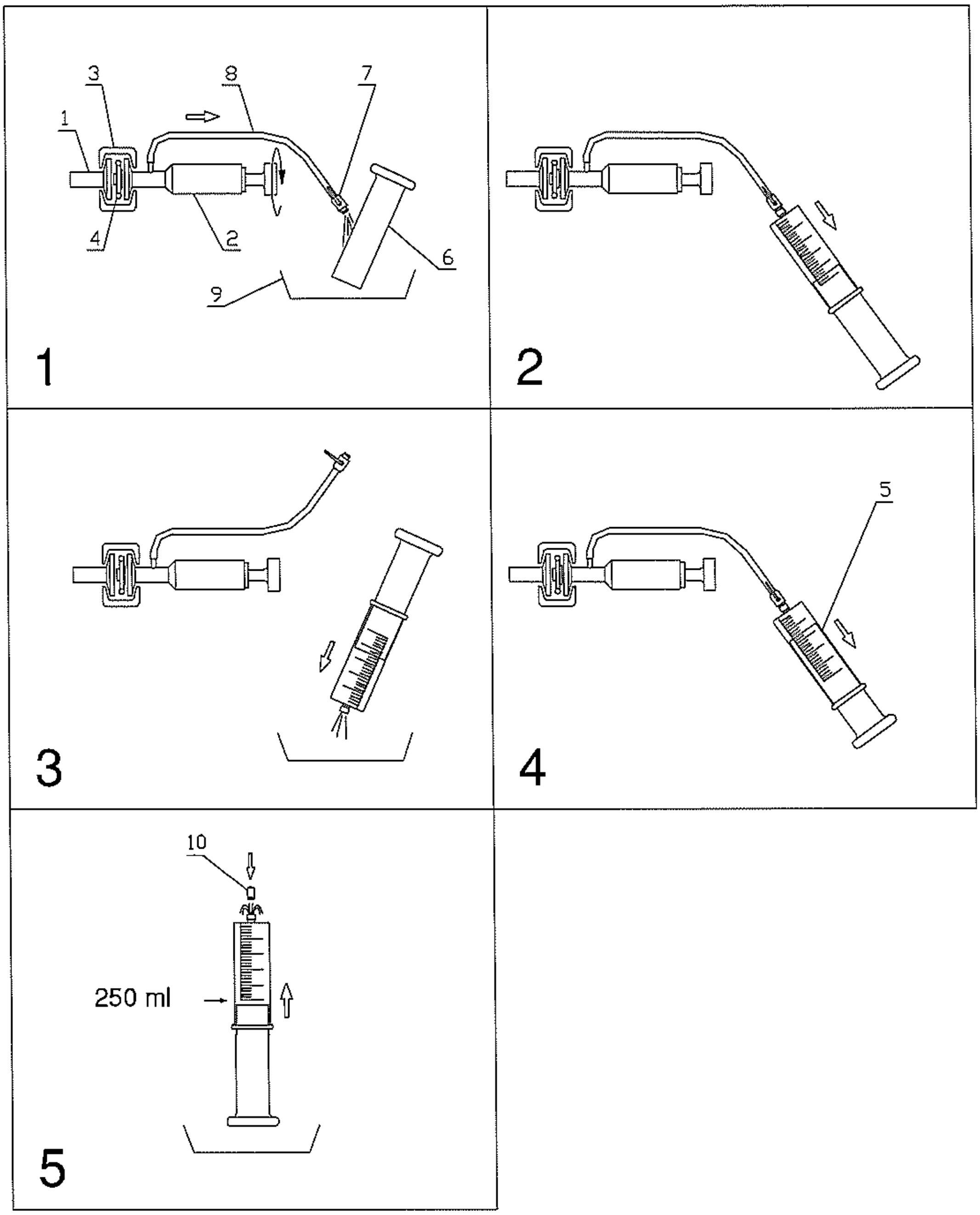
1. primary terminal
2. bellow's gard
3. metallic bellow
4. flange
5. insulator
6. HV insulation
7. secondary winding
8. primary winding
9. core
10. housing
11. secondary terminal box
12. cable gland



Enclosure No. 2. *→ Unpacking of voltage transformer*



Enclosure No. 3. *→ sampling of oil by syringe*



1. DRAIN PLUG ON INSTRUMENT TRANSFORMER
2. SAMPLING DEVICE
3. CLAMPING RING
4. ADAPTING CENTERING RING
5. GLASS SYRINGE
6. PLUNGER
7. ONE-WAY STOPCOCK
8. IMPERMEABLE OIL-PROOF PLASTIC TUBING
9. WASTE VESSEL
10. METAL FEMALE LUER PLUG

Shell Diala Oil GX

High performance insulating oil

Shell Diala GX is a top-tier inhibited insulating oil manufactured from specially refined high naphthenic feedstock. It offers very high oxidation stability, good dielectric strength, gas absorbing behaviour and excellent low temperature properties without the use of pour point depressants.

Applications

- ***Industrial transformers***
  Electrical insulating oil for transformers and switch-gears.
  Grid and Industrial transformers up to maximum load.
- ***Electrical equipment***
  Components like rectifiers, circuit breakers, switch-gears.

Advice on applications not covered in this leaflet may be obtained from your Shell Representative.

Performance Features and Advantages

- ***Gas absorbing properties***
  Diala GX is providing gas absorbing performance in transformers running under very high voltage and electrical stress. That makes it particular suitable in biggest power plant transformers of any size and load.
- ***Excellent oxidation stability***
  Diala GX is offering inherent resistance to oil degradation. A proven anti-oxidant inhibitor enables outstanding product life.
  It is designed to perform as fill-for-life oil filling in transformers.
- ***Very good dielectric strength***
  It clearly exceeds the requirements from all major specifications.
- ***Very good low temperature properties***
  The high naphthenic nature of the feedstock of Diala GX provides a superior low temperature performance without adding any additives.
- ***Very good heat transfer characteristics***
  The very good fluidity of the oil is securing a proper heat transfer inside the transformer even from lowest starting temperatures on.

Specification and Approvals

Shell Diala GX meets the following specifications:

DIN 57370-1	
VDE 0370 Part 1	Class A
IEC 296	Class IIA
BS 148-98	Class IIA

Storage precautions

The critical electrical properties of Shell Diala GX are easily compromised by trace contamination with foreign material. Typically encountered contaminants include moisture, particles, fibers and surfactants. Therefore, it is imperative that electrical insulating oils be kept clean and dry.
It is strongly recommended that storage containers be dedicated for electrical service and include air-tight seals. It is further recommended that electrical insulating oils be stored indoors in climate-controlled environments.

Health and Safety

Guidance on Health and Safety are available on the appropriate Material Safety Data Sheet which can be obtained from your Shell representative.

Shell Diala GX is free of polychlorinated byphenyls (PCB).

Protect the environment
Take used oil to an authorized collection point. Do not discharge into drains, soil or water.

Typical Physical Characteristics

Diala GX			Shell Diala GX
Appearance		DIN 57370	bright and clear
Density		ISO 3675	
at 15°C	kg/m^3		889
at 20°C	kg/m^3		886
Kinematic viscosity		DIN 51562-1	
at 20°C	mm^2/s		19
at -30°C	mm^2/s		1100
Flashpoint P.M.	°C	ISO 2719 / ASTM D93	136
Pourpoint	°C	ISO 3016	-60
Neutralisation value	mg KOH/g	DIN 51558-2	<0,03
Corrosive sulphur		DIN 51353	non-corrosive
Breakdown voltage		DIN EN 60156 / IEC 156	
(after treatment)	kV		>60
Dielectric dissipation factor at 90°C		DIN 57370 / IEC 247	
(after treatment)			0,001
Oxidation stability			
Baader (28 d/110°C)		DIN 51554	
Saponification value	mg KOH/g		0,1
Sludge content	%m		0,02
Dielectric dissipation factor at 90°C			0,01
Gassing tendency	mm^3/min	IEC 628 A	-10

These characteristics are typical of current production. Whilst future production will conform to Shell's specification, variations in these characteristics may occur.

KONČAR-INSTRUMENT TRANSFORMERS Inc.
Josipa Mokrovića 10
HR-10090 ZAGREB, CROATIA

EXPLOSION PREVENTION BY OVERPRESSURE SWITCH

Introduction

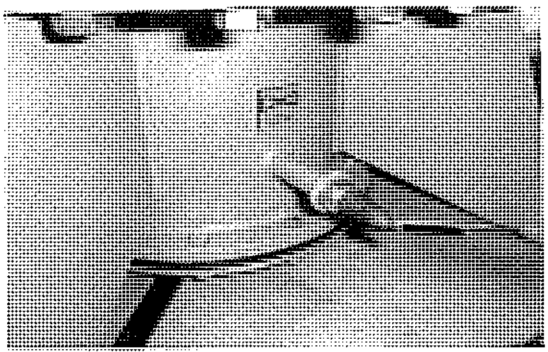
The main target is preventing explosion and unplaned black-out of energy due of internal failure of instrunent transformer in service.

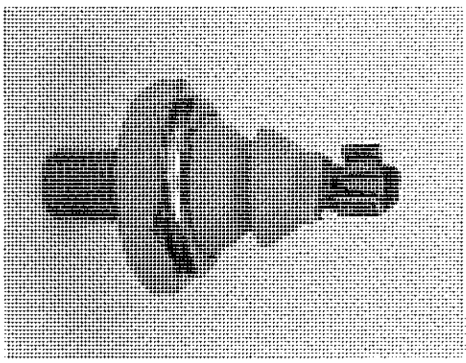
A phenomenon of aging of oil impregnated insulation is of the main importance. Cable paper insulation material P 5318 according to DIN 6740 density of 994 kg/m^3 has characteristic of slow degradation, resulting increasing of tgδ, partial discharge and gassing.

Any failure occurred in insulation or on windings results gassing and rising of bellow. When bellow rise to maximum position, bellow protector blocs it and internal pressure start to rise. It rises until generated force broke fasteners of below protector. After that bellow will rice until it broke and oil will be sprayed around. That will finally result in explosion of transformer.

This process is very slow and can last for months, even years.
Instrument transformers made by Končar are made of such quality of insulation material and are suitable for online monitoring by overpressure switch.

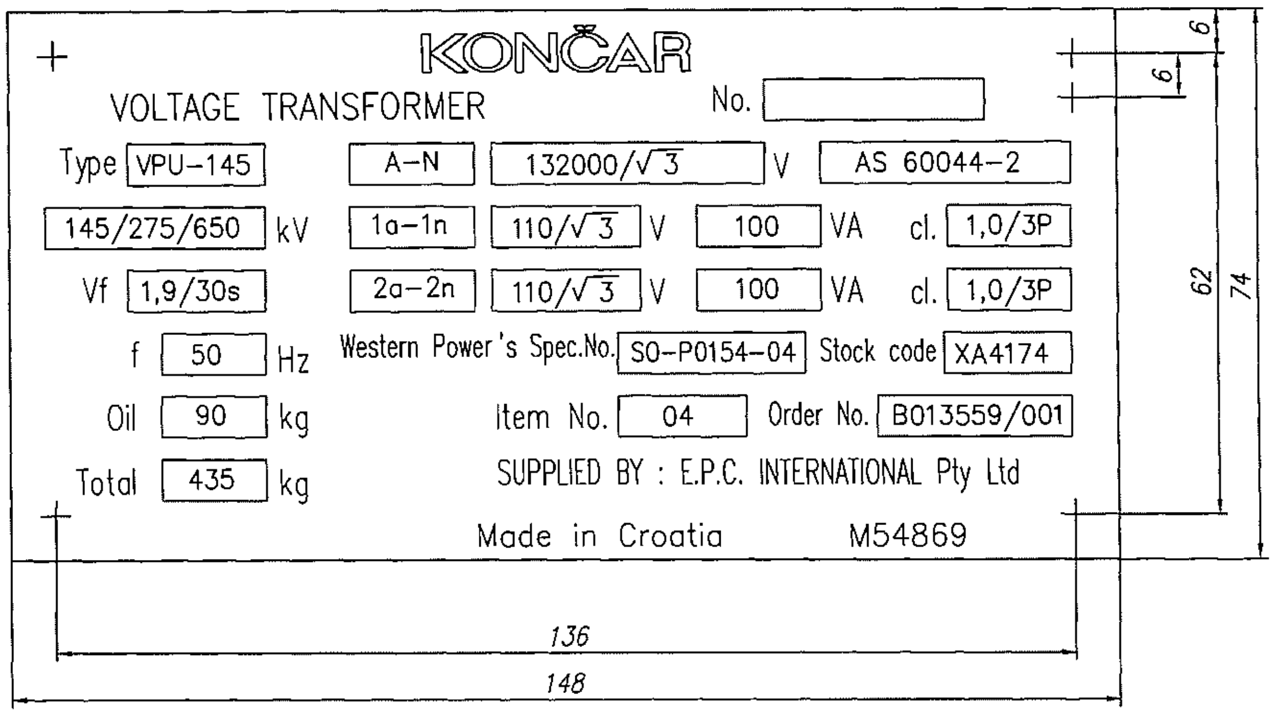
Composite material bellow protector of current transformers type AGU, APU and combined transformers type VAU withstand pressure up to 1.3 bars. Bellow protector of voltage transformers type VPU is made of casted aluminium and withstand pressure up to 5 bars.
Overpressure switch with operation pressure between 0.8 and 1.2 bars will indicate abnormal condition log time before blowing of bellow. Operator has enough time to locate failure transformer and organize replacement without unplanned black-out.
Normal position of switch is open, one end grounded. On one signal can be connected in parallel indicators of all instrument transformers in one bay, line or busbar in substation.
Overpressure switch is screwed on draining valve instead of screw.





Technical data of switch:
- operation pressure: 0.8 to 1.2 bars
- normal position of contact open
- operation voltage: up to 110V DC (+ 10%)
- power 5 VA
- working temperature: -50 to 140°C
- maximum operation pressure: 6 bars
- electric contact made of brass silver coated
- protective cap made of silicon rubber

1	2	3	4	5

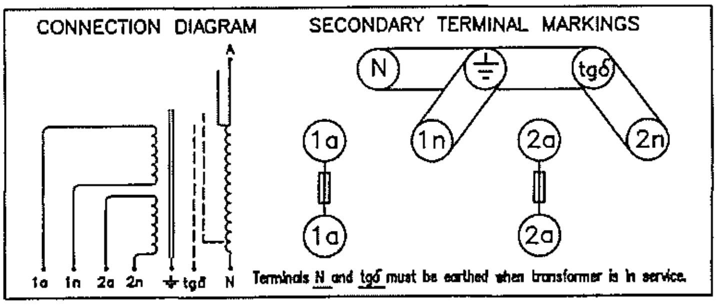


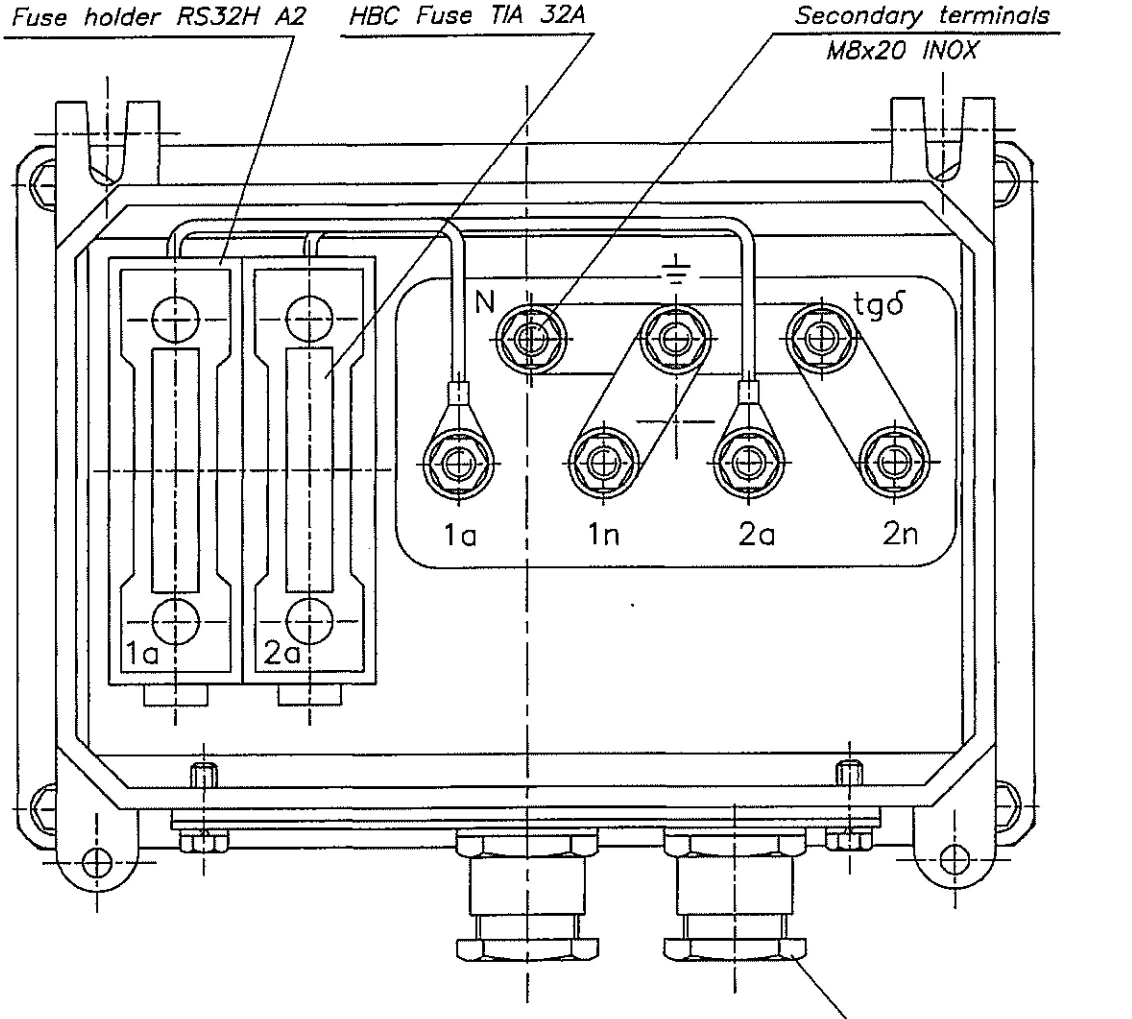
NOTE : – Produce the plate by engraving .
– Colour of surface high gray and black text and lines .

WESTERN POWER INFORMATION
Drawing No : SS1-4-8-210-19
Specification No : SO-P0154-04
Specification Item No : 04
Stock code : XA4174

(Project) –	(Toleronce) DIN 7168 m	(Machining)		(Scale)	(Mass) 0,02
				(Material-No.) ABS 1,5 mm	
(Notes)	Date	Designed by	ing.Brkić	Name plate	
	09.02.2007.	Approved by	ing.Štimac		
	KONČAR Končar - Instrument transformers, Inc.			M67547	Sheet No. 1 of sheets 1
				Replacement for:	Replaced with:

OB-222/1





WESTERN POWER INFORMATION
Drawing No : SS1-4-8-210-3
Specification No : SO-P1054-04
Specification Item No : 04
Stock code : XA4174

(Project) –	(Tolerance) HRN M.A1.410.Srednji DIN 7168 m	(Machining)	(Scale)	(Mass) –
			(Material-No.) –	

(Notes)
(01) 22.07.2005.
(02) 02.05.2007.

Date	Designed by	ing.Brkić
14.06.2005.	Approved by	ing.Ubrekić

Secondary terminal box VPU-145

KONČAR
Končar - Instrument transformers, Inc.

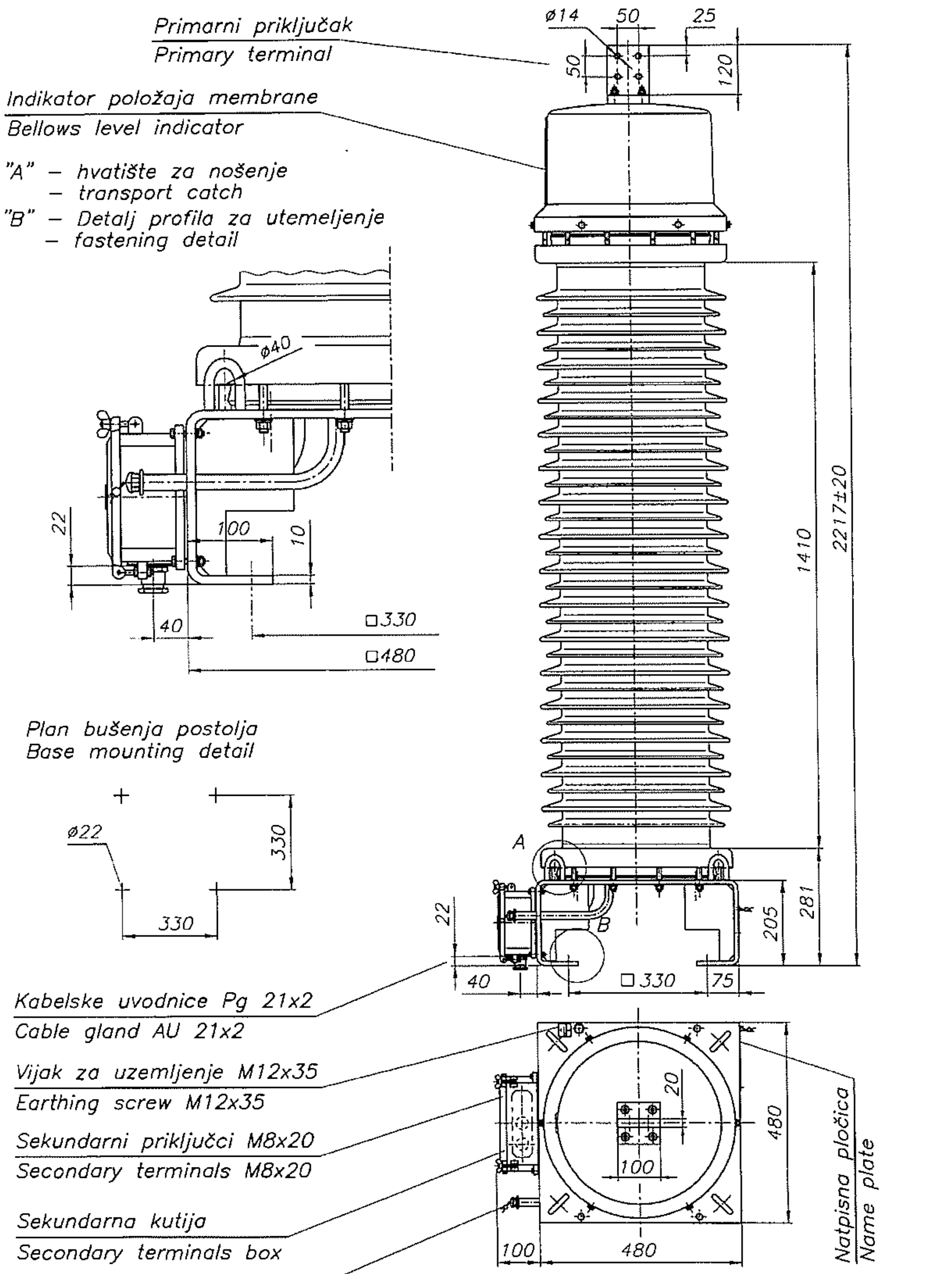
(02) M55613

Sheet No. 1 of sheets 1

Replacement for: | Replaced with:

OB-222/1E

KONČAR MJERNI TRANSFORMATORI	NAPONSKI TRANSFORMATOR VOLTAGE TRANSFORMER VPU−145	M52747



Masa:
Mass: 435 kg

Rev. (01) 22.07.2005.

WESTERN POWER INFORMATION
Drawing No : SS1−4−8−210−1
Specification No : SO−P0154−04
Specification Item No : 04
Stock code : XA4174

Datum	Izradio	Odobrio
07.02.2005.	ing Brkić	ing Ubrekić

OB−700/1	INSTRUMENT TRANSFORMERS Inc.

Appendix C. Scale escalation model

Driver analysis

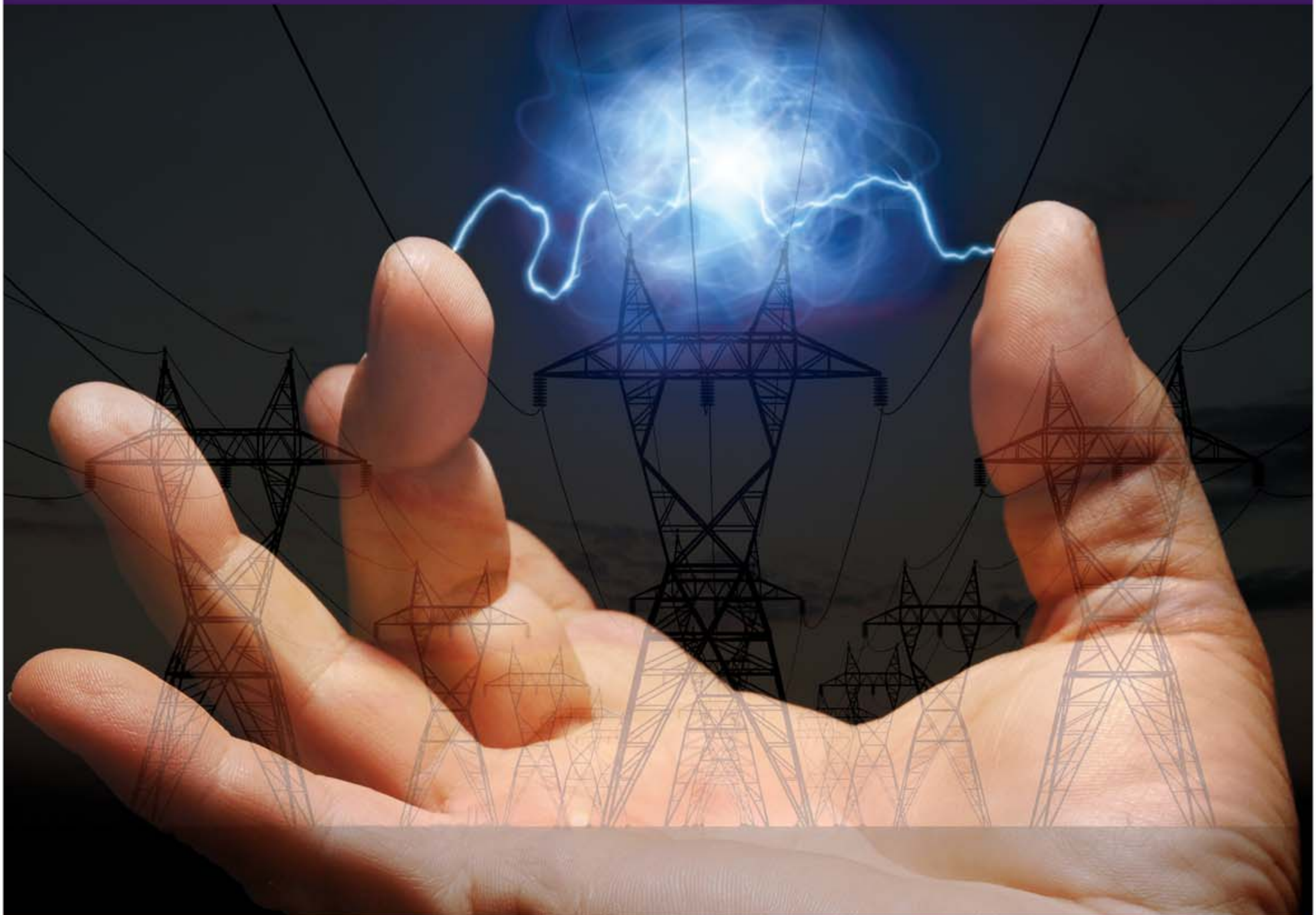
			06/07 Act	07/08 Act	08/09 Act	09/10 Act	10/11 Act	11/12 AWP	12/13 AA3	13/14 AA3	14/15 AA3	15/16 AA3	16/17 AA3
Raw data													
	Transmission	kms of line length	7,292	7,441	7,414	7,333	7,333	7,333	7,619	7,856	7,856	7,892	7,985
	Distribution	kms of line length	87,667	87,667	87,667	88,623	89,412	90,639	91,798	92,886	94,049	95,240	96,512
	Total	kms of line length	94,959	95,108	95,081	95,956	96,745	97,972	99,417	100,742	101,905	103,132	104,497
	Distribution	number of transformers	60,961	61,961	62,603	63,448	64,471	66,591	68,568	70,491	72,508	74,652	76,869
	Transmission	capacity	6,076	6,827	7,040	7,470	7,602	7,734	7,932	8,031	8,620	9,082	10,218
		Customer numbers	914,274	937,104	958,667	978,930	1,001,743	1,031,948	1,058,632	1,086,379	1,115,234	1,145,241	1,176,448
% change													
	Transmission	kms of line length		**2.04%**	**-0.36%**	**-1.09%**	**0.00%**	**0.00%**	**3.90%**	**3.11%**	**0.00%**	**0.46%**	**1.18%**
	Distribution	kms of line length				**1.09%**	**0.89%**	**1.37%**	**1.28%**	**1.19%**	**1.25%**	**1.27%**	**1.33%**
	Total	kms of line length		**0.16%**	**-0.03%**	**0.92%**	**0.82%**	**1.27%**	**1.48%**	**1.33%**	**1.15%**	**1.20%**	**1.32%**
	Distribution	number of transformers		**1.64%**	**1.04%**	**1.35%**	**1.61%**	**3.29%**	**2.97%**	**2.80%**	**2.86%**	**2.96%**	**2.97%**
	Transmission	capacity		**12.36%**	**3.12%**	**6.11%**	**1.77%**	**1.74%**	**2.56%**	**1.25%**	**7.33%**	**5.36%**	**12.51%**
		Network growth		**4.72%**	**1.38%**	**2.79%**	**1.40%**	**2.10%**	**2.33%**	**1.80%**	**3.78%**	**3.17%**	**5.60%**
		Customer numbers		**2.50%**	**2.30%**	**2.11%**	**2.33%**	**3.02%**	**2.59%**	**2.62%**	**2.66%**	**2.69%**	**2.72%**
Raw data													
	Transmission	K1-K4	35	32	33	28	40	43	36	37	38	39	40
		Operations	14	21	18	18	18	23	20	20	21	21	22
		non-recurrent	-	-	-	0	3	10	11	6	9	11	16
		Total transmission (less NRCS)	49	53	51	47	61	76	67	63	67	71	78
	Distribution	K1-K4	169	171	180	169	185	216	175	180	185	181	186
		Operations	20	15	19	20	21	26	21	22	22	23	23
		Customer related	29	31	35	39	36	39	34	35	36	37	38
		non-recurrent	-	-	-	5	8	9	10	11	12	13	14
% change													
	Transmission	K1-K4		**-8.76%**	**3.78%**	**-13.79%**	**42.62%**	**6.31%**	**-16.79%**	**2.68%**	**2.68%**	**2.68%**	**2.68%**
		Operations		**47.47%**	**-16.08%**	**1.95%**	**0.51%**	**26.32%**	**-15.55%**	**2.68%**	**2.68%**	**2.68%**	**2.68%**
		non-recurrent		**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	**486.75%**	**280.70%**	**15.18%**	**-48.95%**	**49.24%**	**25.41%**	**52.18%**
		Total distribution (less NRCS)		**7.79%**	**-4.22%**	**-7.37%**	**30.40%**	**23.81%**	**-12.29%**	**-6.07%**	**6.97%**	**5.60%**	**10.23%**
	Distribution	K1-K4		**1.15%**	**4.98%**	**-5.97%**	**9.45%**	**16.49%**	**-18.84%**	**2.68%**	**2.68%**	**-2.03%**	**2.68%**
		Operations		**-26.50%**	**30.39%**	**7.80%**	**2.79%**	**21.38%**	**-17.56%**	**2.68%**	**2.68%**	**2.68%**	**2.68%**
		Customer related		**7.35%**	**12.62%**	**12.65%**	**-9.11%**	**9.39%**	**-13.28%**	**2.99%**	**3.29%**	**2.96%**	**3.02%**
		non-recurrent		**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	**58.54%**	**21.21%**	**7.51%**	**8.15%**	**6.15%**	**10.22%**	**7.94%**

Appendix D. SKM MMA – Review of Western Power's Energy and Maximum Demand Forecasting Methodologies and Forecasts

REVIEW OF WESTERN POWER'S ENERGY AND MAXIMUM DEMAND FORECASTING METHODOLOGIES AND FORECASTS

Final Report

2 March 2012



achieve outstanding client success

SINCLAIR KNIGHT MERZ

SKM

Contents

1. Executive Overview

Overview

SKM MMA has reviewed Western Power's energy and customer number forecasting approach, methodology and forecasts. SKM MMA has previously also reviewed the Western Power maximum demand forecasting methodology and, for this assignment, has reviewed updates to the maximum demand methodology and forecasts.

Energy and customer number forecasts

Our review of the energy and customer number forecasts against criteria we consider suitable for demand forecasting is summarised in Table 1-1.

- **Table 1-1 Assessment of Western Power's approach and methodology against criteria**

Criterion	Assessment
Logical and suitable for the task	We consider the approach and methodology to be logical and suitable and the key drivers selected to be appropriate.
Account of history and key drivers	The methodology inherently takes into account the history of key drivers and how this is expected to change in the future. We consider the key drivers selected to be appropriate to the situation, although we have recommended some relatively minor changes to variables used.
Forecast assumptions	Assumptions based on credible sources, mainly the state Government budget, are transparently derived, documented and current.
Modelling	The models generally result in reasonable to good fits. Inputs are generally well considered, although we have recommended a number of relatively minor changes in this area. There is very little requirement for judgements to be exercised.
Unbiased application	Our detailed review of methodology application has found no evidence of bias in the forecasting.
Documentation	The methodology and application are generally well documented, although we have identified a small number of areas where this could be improved.
Forecasting effort	Commensurate with end use.
Transparent and repeatable	The model inputs and outputs are all available for review and replication.

Overall, we consider the Western Power customer number and energy forecasting methodology to be well considered and sound with key drivers being suitably selected and generally well characterised. Although we have in the body of the report made many recommendations which we consider could help improve the forecasting methodology and forecasts over time, we generally consider the methodology and its application to be commensurate with good forecasting practice.

Maximum demand forecasting methodology and forecasts

Overall, we consider the Western Power maximum demand forecasting methodology to be well considered and sound. Although we have in the body of the report made a small number of recommendations which we consider could help improve the forecasting methodology and forecasts over time, we consider the methodology and its application to be commensurate with good forecasting practice.

2. Executive Summary

2.1. The assignment and review process

Demand forecasts are important to Western Power for operational, planning and regulatory reasons. Western Power has commissioned SKM MMA to:

- Review the updates it has made to its maximum demand forecasts following the Western Power AA3 submission. SKM had previously reviewed the Western Power maximum demand forecasting methodology and forecasts in 2010.
- Review at a higher level the customer number and energy forecasting approach, methodology and forecasts it has recently developed to ensure that they are appropriate for both internal and regulatory purposes.
- Over the month of February 2012 SKM MMA has reviewed the Western Power methodology and forecasts. Western Power has provided full access to models, data and personnel. SKM MMA has relied on the information provided. The forecasts reviewed have been those covering the period from 2011-12 to 2016-17. For the review of energy forecasts we have focused on the residential (RT1) and business tariffs.

2.2. Energy and customer number approach, methodology and forecasts

2.2.1. Approach

Western Power has forecast on a monthly basis at the tariff level using the following five-step approach:

1) Derive monthly historical data: consumption, customer numbers (and demand where appropriate) for each tariff
2) Adjust the data historically to ensure that movements between tariffs and other anomalies are captured
3) Explore key explanatory variables which can help explain changes in consumption
4) Derive an econometric relationship between consumption and the key explanatory variables through multiple regression analysis
5) Forecast using assumptions of key drivers derived from credible sources.

The approach taken to forecasting depends heavily on the requirements of the forecast, key drivers and data availability. Given the importance of weather and specific tariff characteristics and the availability of 6.5 years of reliable network data we consider the above forecasting approach taken by Western Power to represent good practice. The main concern we have relates to the monthly analysis based on billing data which is not collected within the same timeframe, however, we consider that Western Power has handled this reasonably.

SKM MMA considers the use of well founded and applied econometric modelling to be good practice for utility forecasting. Such econometric forecasting is currently becoming the norm for energy forecasting in Australia, largely displacing the trend and appliance based analysis of the past[1]. We consider econometric forecasting to represent good forecasting practice in this area as it provides transparency and allows for changing circumstances if the underlying key drivers have been well considered. Where econometric modelling has not

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[1] We note that we still consider there to be scope for well considered adjustments or alternative approaches to be used based on specific policy or appliance related circumstances.

been useful, or where other approaches such as discussions with the largest customers are considered more appropriate, then these other approaches have been applied.

SKM MMA has concluded that the overall approach taken by Western Power is reasonable and, if the methodology is also sound and properly applied, is likely to result in good forecasting practice being followed.

2.2.2. Methodology

We have carried out a detailed review of the methodology applied and consider that:

- The key drivers considered, being weather, price, income and PV installation are reasonable and are similar to those used by utilities elsewhere and do not obviously omit any key drivers which can be readily captured.
- The explanatory variables which represent these factors are generally well considered. We have, however recommended that Western Power use cooling and heating degree days for its weather variables, rather than a function of average monthly temperature and that, for the RT1 tariff for residential customers it should use GSP per capita rather than GSP as the measure of income. We do not consider these to be major changes to the methodology.
- We have reviewed the history used for these variables. While we have recommended a number of changes which we believe will improve the forecasts, we again consider none of these to be major in its own right.
- We consider the multi regression methodology to be well applied. The regressions generally have reasonable goodness of fit and the variables are only included if they are statistically significant and the coefficients make sense.
- The assumptions made about movement of the key drivers over the forecast period are derived from credible and reliable sources and generally appear timely and realistic. Again, while we have made a number of recommendations in this area, none are considered fundamental.

Overall, SKM MMA considers the approach taken by Western Power to be well conceived and the methodology well considered, well applied and generally commensurate with good forecasting practice. We have, in the main report, made a number of recommendations in terms of variables, history and assumptions which are not fundamental to the methodology but which will, we believe, improve the accuracy of the forecasts.

2.2.3. Review of the Western Power forecasts and of the potential impact of recommended changes

SKM MMA has, in the main report, recommended a number of changes to the Western Power forecast methodology. While none of the changes recommended are fundamental in nature, and most are expected to have relatively minor impact on the forecasts, in combination they may be more material.

Taken over the entire network, the changes recommended by SKM MMA have very little impact on the Western Power forecasts. There are, however, some larger movements within specific customer sectors, notably in the residential class, where SKM MMA forecasts are higher and in the small business class where they are lower.

Overall, we consider the Western Power energy and customer number forecasting methodology to be well considered and sound with key drivers being suitably selected and generally well characterised. Although we have in the body of the report (and consolidated below) made many recommendations which we consider could help improve the forecasting methodology and forecasts over time, we generally consider the methodology and its application to be commensurate with good forecasting practice.

2.3. Maximum Demand

SKM MMA has reviewed Western Power's Maximum Demand (MD) forecasting methodology and outcomes for 2011. This follows a similar review of the MD forecasts conducted in 2010, the Executive Summary of which is copied below.

2.3.1. SKM MMA 2010 Review of Western Power's MD Forecasts - Executive Summary

In preparation for Western Power's submission to the Economic Regulation Authority (ERA) for the proposed revisions to the access arrangement (for period AA3), Sinclair Knight Merz through its new division SKM MMA, has been commissioned to provide an independent review of Western Power's demand forecasting methodology and forecasts for the electricity supply in the SWIS to assure stakeholders that the results, method and input assumptions are robust.

SKM MMA generally concludes that the forecasting methodology adopted by Western Power is comparable with good industry practice throughout Australia.

SKM MMA's key findings can be summarised:

- The suite of forecasting software (ForeSite) used by Western Power is perhaps the best integrated demand forecasting package that SKM MMA has reviewed;
- The process and practices used in accessing and processing input data are well established and technically sound;
- The treatment of load transfers and block loads (historical and forecast) is consistent with good industry practice;
- The calculation of trends in historic data and the forecast of future demands using regression analysis is technically sound;
- The forecasts produced by Western Power are robust and repeatable;
- Western Power does not explicitly weather correct the historic data. This is a key difference between the Western Power approach and typical industry practice;
- Western Power does not develop an econometric top-down demand forecast. Western Power has made a decision to utilise the IMO econometric forecast for comparison purposes;
- Western Power does prepare an alternate high economic growth scenario demand forecast but this is based on the same underlying growth trend as the base forecast, but with more optimistic assumptions regarding future block load development;
- Western Power's assessment of new block loads over the forecast period is more conservative (lower) than the IMO, resulting in a lower demand forecast than that included in the IMO's Statement of Opportunities;
- The adjustment of the 50 POE forecast to provide a 10 POE forecast is based on a statistical analysis of the historic series and calculation of a Prediction Interval. This is another key difference between the Western Power approach and typical industry practice which normally uses temperature correction to estimate the demand under a 10 POE temperature condition.

These findings are discussed in more detail in the body of this (2010) report.

SKM MMA has some remaining concern with Western Power's decision not to explicitly correct for weather on two grounds:

- The assumption that in the historical figures any abnormal days are distributed evenly across the history – this may indeed be the current situation over recent years, but it is clear that a congregation of abnormal days can skew the trend curve – impacting 50 POE as well as 10 POE forecasts;
- The assumption that temperature dependence is reasonably constant (therefore represented in the historical series) – work done by SKM MMA suggests that the sensitivity of demand to temperature (MW/degree) appears to be changing – therefore the historic series may not capture future sensitivity.

Subject to this qualification, SKM MMA believes that the methodology adopted by Western Power and the forecasts produced are technically sound, conservative and generally in line with good industry practice.

2.3.2. Review of 2011 forecast updates

As the Western Power methodology and forecasts had been reviewed in 2010, the focus of the current review has been on:

- Updates and modifications to the methodology since the 2010 SKM MMA study
- Application of the methodology to the most recently available data.

Western Power has identified the following changes to MD forecasting methodology:

a) Taking explicit account of the impact of photovoltaic (PV) installations on MD
b) Revising Block Loads and the way in which they are assessed
c) Additional statistical testing of the trend line analyses described in section 7.2.3
d) Removing double counting of Cottesloe

Western Power has also noted the following consequences of incorporating 2011 data in its analysis:

a) A change in the MD growth rate (Trending Change)
b) Lower initial value in 2012
c) Lower POE adjustment (gap between 50 POE and 10POE)

SKM MMA has reviewed the changes to both methodology and forecast outcomes and has found them to be generally appropriate and suitably applied. Recommended changes to the approach resulting from a small number of exceptions are reported in the body of the report and in the consolidated list of recommendations provided below.

2.4. Consolidated list of recommendations

We have consolidated below the recommendations from the main body of the report. In order to assist with implementation we have divided them into recommendations related to the customer numner and energy forecasts and maximum demand forecasts.

While we consider all our recommendations worth pursuing, the importance and expected timing differ. In Table 2-1 below we also provide an indication of the expected materiality of the recommendations and the recommended timing.

We have generally assessed materiality of different forecast parameters or assumptions by examining the impact this has on cumulative volumes forecast over the period 2011-12 to 2016-17. We have in our assessment considered an impact of 2% on cumulative volumes (often in the RT1 tariff) to be material. We note, however, that the recommendations relevant to the customer numbers and energy forecasts will generally have low revenue materiality under the AA3 revenue cap regulatory regime. We have divided timing into recommendations that should be pursued during AA3 (whether because of materiality or ease of implementation) and those which can be implemented in AA4.

Table 2-1 Consolidated list of recommendations

No	Recommendation	Materiality	Implementation
	Customer numbers and energy		
1	We recommend that Western Power reconcile the information in the reports and spreadsheets used for analysis.	<2% on RT1	AA3
2	We recommend that Western Power use data from the BOM instead of its composite weather index. Using the BOM data has resulted in a slight improvement in the R^2 value for the RT1 tariff and a reduction in forecast RT1 consumption of about 1.3% over the period 2012 to 2017.	<2% on RT1	AA3
3	We recommend that Western Power consider using CDD and HDD rather than T and T^2 for its weather variables. The HDD and CDD variables are easier to assess and more intuitively explain the impact of hot and cold weather. Our initial modelling has suggested that the impact of this plus the move to BOM weather is relatively low (+1.6% on RT1), however, this can be easily implemented.	<2% on RT1	AA3
4	We recommend that Western Power consider using GSP/capita as an explanatory variable for the residential sector rather than GSP. Our initial analysis suggests that using GSP per capita results in an R^2 which is similar to that found with GSP alone and has a slightly lower outcome (-1.3% on RT1). As we consider GSP/capita to be a better measure of residential income we recommend that this be monitored over the longer term. This has a medium priority.	<2% on RT1	AA4
5	We recommend that Western Power should use the most recent GSP data available. Such data is now available for the 2010-11 year. Our initial analysis suggests that using the later GSP data results in an R^2 which is similar to that found with the earlier GSP and has a higher outcome (+1.9% on RT1).	(almost 2% on RT1)	AA3
6	We recommend that Western Power continue to use the price dummy parameter for modelling the residential market, but monitor the summer and winter response over time to ensure that this does not change.	<2% on RT1	AA4
7	We recommend that Western Power use the Perth CPI index for conversion of nominal to real prices. For the RT1 tariff this is estimated to have an impact of +1.1% on volumes. While a relatively low impact overall, we consider this to have a high priority as it can be easily implemented.	<2% on RT1	AA3
8	We recommend that Western Power use the first band of prices within the L1 tariff for its analysis and forecasting of RT2 and RT4 prices. While this is expected to have a relatively low impact, it may make a difference when carbon price is included as an absolute (not percentage) cost increase.	Expect <2% on RT1	AA4
9	We recommend that Western Power use published contestable prices as appropriate for its business customers RT5 to RT8 in the short to medium term. In the longer term we recommend that Western Power try to get a better picture of costs to contestable customers either from retailers or from building up costs using a building block approach.	Expect <2%	AA3,AA4
10	We recommend that Western Power re-run the RT1 tariff model with the changes previously recommended and then remove the PV variable (and	Expect <2%	AA3

No	Recommendation	Materiality	Implementation
	any others) if they do not meet at least a 10% level of significance. We estimate this will only have a relatively small effect on the R2 and an incremental impact of about +1% on volumes over the period.		
11	We recommend that Western Power continue to monitor the level of PV installations and update the RT1 model if this variable again becomes significant.	Expect <2%	AA4
12	If the PV explanatory variable is found not to be significant and is excluded from the model we recommend that Western Power consider post-modelling adjustment to take account of expected PV impact on consumption as discussed in the text.	Expect <2%	AA4
13	We recommend that Western Power forecast customer number growth based on population growth forecasts, rather than GSP forecasts. The material impact of this is likely to be low.	Expect <2%	AA3
14	We recommend that Western Power forecast weather based on the history of the BOM weather station, rather than the composite index it has devised. The impact of the combination of the change to history, and forecasts as well as a move to HDD and CDD is an increase of 1.6% in the RT1 forecasts.	<2%	AA3
15	We also recommend that, over the longer term Western Power assess whether a combination of weather stations is likely to be more representative of consumption in the SWIS as a whole and also whether the history of CDDs and HDDs at the Perth Airport BOM have changed sufficiently over time to require the average over a more recent period to be used.	Expect <2%	AA4
16	We consider that Western Power's use of the WA GSP forecasts contained in the state Government's 2011-12 budget forecasts to be reasonable, as would be the use of the NIEIR forecasts used in the 2011 Statement of Opportunities or even a more recent credible forecast. However, if the state Government's forecast is to be used than it should actually be the forecast, including a 4.5% growth in 2011-12 with extrapolation only for the final years as required. We note that the use of alternative GSP forecasts is likely to have a material impact on a number of tariff forecasts.	<2%	AA3
17	We consider that Western Power's assessment of the pass-through cost of carbon to be reasonable, however, we consider it should have GST added to it to ensure it is consistent with other prices used in modelling . This is easily manageable in the modelling and will have a slightly negative impact on volumes.	<2%	AA3
18	We recommend that the CPI assumptions used in modelling be the same as those in the 2011-12 budget paper, with the value in the last year extended for a further two years. This will have a small positive impact on modelled volumes.	<2%	AA3
19	We recommend that the reason for difference between the PV assumptions used in the maximum demand analysis and in the energy analysis be explained and documented.	<2%	AA3
20	We recommend that Western Power confirm that the timings and loads for large new customers are consistent between the latest maximum demand and energy forecasts.	?	AA3
21	We recommend that Western Power ensure that there is full documentation regarding forecast assumptions for this class of customer and that this is reviewed by the forecasting team. In addition, we consider that the basis for the load factor assumed for the new loads should be provided.	?	AA4
	Maximum demand update		
22	We recommend that the PV peak reduction estimates used in the AA3 forecast be aligned with the most recently prepared estimates.	Expect <2%	AA3
23	We recommend that Western Power allocates PV MD reductions to substations.	<2% if 22 implemented	AA4

No	Recommendation	Materiality	Implementation
24	We recommend that Western Power carefully guides and monitors the application of its new block load criteria framework and maintains a register to allow the accuracy of forecasts resulting from its use to be assessed over time.	?	AA4
25	We recommend that Western Power implements an improved methodology for forecasting maximum demand in substations with weak trends as soon as practicable.	<2%	AA4
26	We recommend that Western Power adjusts historical MDs upwards for the estimated PV impacts. Allocation to substations should be consistent with the allocation of system PV forecasts to substations	<2%	AA4

3. Introduction

3.1. Western Power network

On 31 March 2006, the Western Power Corporation was restructured into four separate corporations: Western Power responsible for the transmission and distribution network in the south west interconnected system (SWIS); Verve Energy responsible for energy generation in the SWIS; Synergy responsible for electricity retail in the SWIS and Horizon Power responsible for the generation, transport and sale of electricity outside the SWIS.

Western Power owns and operates the Western Power Network, the major transmission and distribution network in Western Australia which extends from Albany in the south to Kalbarri in the north and to Kalgoorlie in the east, covering almost 95% of the state's population.

The network serves over 1 million customers and supplied about 16,700 GWh of energy in 2010-11.

3.2. Economic regulation of Western Power's network

The Western Power transmission and distribution network is regulated economically under the Electricity Network Code (Code) by the Economic Regulation Authority (ERA) through network Access Arrangements (AA). The current Western Power second Access Arrangement (AA2) expires at the end of June 2012. On 30 September 2011, Western Power submitted proposed changes to its access arrangements to cover the third access arrangement period (AA3) which is expected to cover the five-year period from 1 July 2012 to 30 June 2017. ERA is expected to release its draft decision in March 2012 and its final decision later in 2012.

The form of regulatory control proposed for the AA3 period (as for AA2) is revenue cap. Under a revenue cap control the key demand forecast inputs are spatial maximum demand which relate to capital expenditure forecasts,Any divergence in revenue due to consumption differences is recovered in subsequent years through an "unders and overs" k-factor mechanism. As a result, Western Power has invested considerable effort in developing its spatial maximum demand methodology, having the methodology reviewed and comparing the overall global outcome with macro forecasts prepared by IMO and NIEIR. SKM carried out a review of the Western Power MD forecasting methodology in 2010 and this review was included as Appendix S within the Access Arrangement information provided for AA3[2].

Under a revenue cap regulatory control, forecasts of energy consumption and customer numbers, while relevant, have relatively little material impact. As a result, Western Power has not until recently invested significantly in developing its energy and customer number forecast methodologies. The energy and customer number forecasts for Western Power's AA3 regulatory proposal were derived by Deloitte Touche Tohmatsu (Deloitte) and provided as Appendix T within the Access Arrangement information provided for AA3[3].

3.3. Use of demand forecasts

Demand forecasts are important to a utility for both operational and regulatory reasons. Spatial and global maximum demand forecasts are vital in network planning. Customer numbers and energy forecasts at a

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2 SKM MMA report to Western Power, "Review of Western Power's Demand Forecasts for the AA3 Period (2012/13 to 2016/17)", 11 November 2010 provided as Appendix S to the Western Power AA3 Regulatory Proposal available at http://www.erawa.com.au/3/1181/48/_western_powers_proposed_revised_access_arrangemen.pm

3 Deloitte report to Western Power, "Energy and customer number forecasts for the AA3 Period (2012/13 to 2016/17)", 18 August 2011 provided as Appendix T to the Western Power AA3 Regulatory Proposal available at http://www.erawa.com.au/3/1181/48/_western_powers_proposed_revised_access_arrangemen.pm

suitably disaggregated level and for short and long time frames are important for budgetary and planning purposes.

Western Power may also contemplate moving to a price cap form of control for its next regulatory period[4]. For its own budgetary purposes and in order to consider a price cap form of control, Western Power must be confident that the forecast methodologies it adopts are sufficiently well developed to both produce accurate results and also be credible to both internal management and the regulator.

3.4. New energy and customer number forecasts and updated maximum demand forecasts

Western Power has now developed its own methodology and prepared its own forecasts for energy and customer numbers for the AA3 proposal and also for internal use. In addition, the maximum demand forecasts have now been updated to take into account the most recent data, including actual results for summer 2010-11.

Western Power proposes to use both the updated maximum demand forecasts and its own energy and customer number forecasts in both its AA3 regulatory submission and internally.

3.5. Review by SKM MMA

Western Power has commissioned SKM MMA to:

- Review the updates it has made to its maximum demand forecasts following the Western Power AA3 submission
- Review at a higher level the customer number and energy forecasts to ensure that they are appropriate for both internal and regulatory purposes.

SKM MMA is a strategic consulting centre of excellence within SKM formed after the acquisition of McLennan Magasanik Associates (MMA) by SKM in August 2010. The SKM MMA team is well experienced in the review of relevant demand forecasts, having:

- Reviewed a large number of demand forecasts for regulators across electricity, gas and water sectors – meaning that SKM MMA has experienced a number of approaches and methodologies.
- Worked more recently for a number of network service providers (NSPs) in developing their demand forecasting methodologies and forecasts.
- Worked for Western Power in the review of spatial forecast methodologies in 2010.

3.6. Layout of the report

The report is set out as follows:

- Section 4 lists the tariffs reviewed, review process undertaken and the criteria we have used to assess the forecasting methodology.
- The review of approach and detailed review of methodology are provided in Section 5.
- Section 6 assesses the Western Power energy forecasts and provides indicative outcomes if the SKM MMA recommendations were applied. It also provides a brief comparison with the Deloittes and IMO forecasts and assesses the Western Power methodology against the criteria previously listed.

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4 According to Deloitte Western Power contemplated a weighted average price cap form of regulatory control however, decided against it because of uncertainty about achievable levels of accuracy in forecasting customer numbers and average energy. Deloitte report to Western Power, "Energy and customer number forecasts for the AA3 Period (2012/13 to 2016/17)", 18 August 2011 provided as Appendix T to the Western Power AA3 Regulatory Proposal, page 8, available at http://www.erawa.com.au/3/1181/48/_western_powers_proposed_revised_access_arrangemen.pm

- The updates to the maximum demand since the last SKM MMA review are provided in Section 7.
- Appendix A provides further details of analysis carried out on individual tariffs.

3.7. Further notes and caveats

We note that we have interspersed recommendations throughout the report. These are also consolidated at the end of the Executive Summary and divided between "essential" and "desirable" and according to whether the recommendations are to be implemented over the short or medium to longer term..

We have generally carried out most of our analysis and impact assessment on the RT1 tariff. This is the most complicated and serves best to illustrate the impacts.

We have been asked to assess the materiality of our recommendations and have done so in two ways. Firstly we have carried out our own regression analysis where appropriate to attempt to measure the impact of some individual recommendations. In addition, we have indicated where some recommendations are intended for the medium and longer, rather than shorter term. In order to assess the cumulative impact of the recommendations, we have provided indicative SKM MMA forecasts. However, we stress these are indicative and for guidance only. Western Power should reproduce the impacts if it wishes to validate them.

We have generally assessed materiality of different forecast parameters or assumptions by examining the impact this has on cumulative volumes forecast over the period 2011-12 to 2016-17. We have arbitrarily assessed an impact of 2% on cumulative volumes to be material. We note, however, that the recommendations relevant to the customer numbers and energy forecasts will generally have low revenue materiality under the AA3 revenue cap regulatory regime.

We have relied on information provided by Western Power. We have not checked the original data or audited the forecasts.

We have reviewed only the Central case forecasts. This is the forecast which is generally used.

4. Tariffs reviewed, process undertaken and criteria used

4.1. Tariffs reviewed

The tariffs under which customers at Western Power are supplied as well as the number of customers served and the energy consumption and percentage of total energy supply are provided in Table 4-1. The customer numbers are sourced from the Western Power Energy and Customer Numbers forecast[5] . The energy usage has been sourced from the Western Power spreadsheet[6].

- **Table 4-1 Tariffs reviewed, customer numbers and energy used in 2010-11**

Tariff	Description	Customer numbers	Energy usage, GWh	% of energy usage
RT1	Anytime Energy (Residential)	851,000	5,265	31.5%
RT2	Anytime Energy (Business)	85,022	1,673	10.0%
RT3	Time of Use Energy (Residential)	19,889	185	1.1%
RT4	Time of Use Energy (Business)	12,024	2,082	12.4%
RT5	High Voltage Metered Demand	122	348	2.1%
RT6	Low Voltage Metered Demand	1,333	1,213	7.2%
RT7	High Voltage Contract Maximum Demand	255	3,005	18.0%
RT8	Low Voltage Contract Maximum Demand	62	245	1.5%
RT9	Street lighting		113	0.7%
RT10	Un-Metered Supplies		34	0.2%
TRT1	Transmission Supply	33	2,569	15.4%
	Total	**969,740**	**16,731**	**100%**

We note that there are appear to be some relatively minor discrepancies between the energy and customer numbers provided in the spreadsheet and those provided in the document[7]. We have used the information in the spreadsheet in our analysis. We note that these should be reconciled in the final documentation.

- **Recommendation 1: We recommend that Western Power reconcile the information in the reports and spreadsheets used for analysis.**

We have focused on the important tariffs in terms of energy consumption and customer numbers: RT1, RT2, RT4, RT6, RT7 and TRT1. In terms of customer numbers we have focused on RT1.

4.2. Process undertaken

The review of both the energy and customer number forecasts and the updated maximum demand forecasts has been undertaken during the month of February 2012. Documentation related to the forecast methodologies were initially provided. These were followed by spreadsheets containing the information on which the forecasts

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5 Western Power System Forecasting: Energy and Customer Numbers: Energy Forecast 11/12 – 16/17 dated October 2011

6 Western Power spreadsheet: Forecasting Transfer and Storage for SKM MMA.xls provided on 7 February 2012

7 For example, Table 3 in the document has annual consumption for RT1 at 5293 GWh while in the spreadsheet it is 5265 GWh.

were based together with the methodologies and some documentation relating to key aspects of methodology, including the Photovoltaic forecast[8].

Meetings with Western Power were held on 13 and 14 February, 2012 to discuss the methodology and key issues in detail. There were a number of questions raised by SKM MMA and further information has been provided in response to these questions.

SKM MMA has reviewed the methodologies used by Western Power and undertook replication of the Western Power energy and customer number forecasts based on the historical information provided.

The review has assessed whether the customer numbers and energy forecasting methodologies appear reasonable and, where appropriate, highlights issues and makes suggestions and recommendations on how to improve the methodology or the input assumptions..

We note that while we have reviewed the methodology and forecasts we have not audited the forecasts. We have also relied on the historical information provided by Western Power.

4.3. Criteria used in the assessment

We have assessed the energy and customer number forecasts against criteria we have developed in a number of reviews of demand forecasts for the Australian Energy Regulator (AER). We quote below a relevant section of a report to the AER which we consider relevant.

"*While it must be recognised that demand forecasts will never be perfect, MMA considers the following to form the required underpinnings of a good forecasting methodology:*

- *the basis of forecasting should be logical and appropriate to the situation and nature of the specific electricity market and item being forecast. It should be at a suitable level of disaggregation, both functional and geographical*
- *it should review history and recent trends and explain if, why and by how much the future should be different to the recent past*
- *it should review, recognise and reflect the underlying key drivers and expected changes to these from previous history and balance historical trend against expected changes in key drivers*
- *it should be based on reasonable assumptions using the best information available at the time. It should take into account current demand and economic conditions and reasonable prospects for future market development. The basis or sources of material assumptions, and of material changes to assumptions, should be documented. Sources used should be recognised in their fields and the information should be used as intended. Significant assumptions which are sensitive to timing should be updated close to the time of the forecast being finalised.*
- *modelling should be accurate, use appropriate inputs, be validated where possible and be applied consistently, both in terms of information used and the items forecast . There should be limited scope for judgement inputs and, where applied, the reasons should be documented.*
- *the methodology should be applied in an unbiased manner*
- *the meth*odology should be well documented

[8] Western Power document WE-7976363v5 photovoltaic, "Photovoltaic (PV) forecast" 20 January 2012

- the forecasting effort should be commensurate with the importance of the forecasts.

Western Power has used the following criteria in its internal review of these forecasts. According to Western Power, forecasts should:

- be accurate and unbiased
- be transparent and repeatable
- incorporate all key drivers
- withstand scrutiny of models and assumptions
- use the most recent input information
- incorporate weather variability.
- We consider the two sets of criteria to be complementary.

5. Review of energy and customer number approach and methodology

5.1. Approach taken

The approach taken by Western Power has five key components

1) Derive monthly historical data: consumption, customer numbers (and demand where appropriate) for each tariff
2) Adjust the data historically to ensure that movements between tariffs and other anomalies are captured
3) Explore key explanatory variables which can help explain changes in consumption
4) Derive an econometric relationship between consumption and the key explanatory variables through multiple regression analysis
5) Forecast using assumptions of key drivers derived from credible sources.

SKM MMA generally considers this to be a well-considered approach. Analysis at the tariff level is considered good practice so long as sufficient data exists, the drivers at that level can be reasonably assessed and any movement between tariffs, which could distort the analysis are adjusted for[9].

Utilities have generally applied one of three distinct approaches to forecasting consumption, trend analysis, appliance based and econometric modelling as well as combinations of these. Trend analysis assumes that key drivers will stay relatively unchanged over time. Over the past several years it has become clear that several of the drivers of energy consumption are in fact changing. Concerns about greenhouse gas warming and government policies to reduce energy consumption, together with significantly increased prices have, in much of eastern Australia turned around the previous trend of increasing average residential usage per customer, with residential average usage per customer now either flat or declining. Usage by business customers appears to have also changed, especially in areas where manufacturing is struggling against the high Australian dollar and rising costs. As a result, a simple trend-based analysis no longer appears realistic.

Appliance-based modelling recognises that, at the residential level, consumption is through specific appliances. If sufficient information is available about the penetration and usage of such appliances, and how these are changing over time or under different policies then overall residential usage can be modelled. Unfortunately, such an approach relies on a great deal of data – which is expensive to generate and may change quickly, meaning that the modelling becomes increasingly assumption driven and difficult to validate. In addition, the appliance approach is not readily transferrable to the non-residential sector and the modelling of behavioural impacts, such as increasing price, are extremely difficult to accurately allocate to appliances. This has resulted in hybrid models such as appliance-based with incrementally modelled impacts using price elasticity of demand. Such models are messy and risk double-counting changes in trends.

As a result of the changing key drivers, utilities are moving towards econometric modelling of energy consumption. Such econometric modelling has the advantage of being derived from existing consumption data as well as key explanatory variables which can be observed and forecast. It is, therefore, a relatively transparent approach. Further, it carries out the analysis of simultaneous changes to key drivers, rather than assuming each takes place in isolation. Two key drawbacks of this methodology, if rigorously applied, are that

9 We note that Western Power has also carried out some supplementary analysis, for example energy usage by new homes versus existing homes.

it can require a significant amount of data and that new key drivers may take some time to become sufficiently robust[10] to include in regression equations. Western Power has generally not included explanatory variables in its analysis unless they have been shown to be statistically significant and the coefficient derived have generally been of the right sign and expected order of magnitude.

We conclude that the overall approach taken by Western Power is reasonable and, if methodologically sound and properly applied, is likely to result in good forecasting practice being followed.

5.2. Methodology and application

5.2.1. Monthly historical usage on a tariff basis

The amount of reliable data available to Western Power for modelling is restricted to information from around the break-up of Western Power Corporation in 2006. Western Power has access to only six years of data since disaggregation. Data before disaggregation is stored in a legacy system called IRIS. System incompatibilities have meant that merging the historical IRIS data and the available current data is cumbersome.

In order to provide data on a short-term basis for internal usage and to allow the historical effects of weather to be captured by the model, Western Power has modelled information on a monthly basis. While we consider it reasonable to model on a monthly basis, a key drawback is the lack of monthly data available at the residential level and for several of the small business tariffs, which only have meter readings every two months. This means that it is impossible to accurately state the usage of such a customer over a shorter period – say the month of August.

Western Power has tackled this issue by extracting the billing data from its data warehouse and pro-rating it daily over the billing period. This has allowed it to allocate a daily usage to each customer over the year. The sum of the daily allocated consumptions in any day is, therefore, the amount of usage estimated for the month.

While such an approach will inevitably lead to some loss of accuracy it is difficult to conceive of a better methodology until time of use or interval metering is available for the residential market. Some utilities attempt to weather correct by using daily supply data and establishing a correlation between weather (using for example cooling degree days (CDD) or heating degree days (HDD)), and daily consumption. This allows the response to weather of the utility as a whole to be measured. It is then difficult, however, to allocate between tariffs and arbitrary factors are often used[11]. Other utilities have attempted to overcome such issues by using a "degree day" billing factor to multiply usage by.

While recognising that the estimates used by Western Power are not ideal, we consider them reasonable to use for these tariffs and these forecasts in the absence of a better data source. While there will doubtless be some inaccuracies arising from the use of such data we do not expect it to be biased in any way and, based on overall results, consider that it is likely to represent these tariffs reasonably well.

We do, however, consider that an overall check needs to be made to ensure that the weather impact overall is not over or under-stated by this method. Such a check would see the modelled weather impact of the markets combined, assessed against the weather impact for the network as a whole.

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10 That is, statistically significant and with meaningful coefficients.

11 While some utilities have recently used detailed load studies by customer class to do this, we understand that such studies have not been carried out by Western Power.

- **Recommendation 1: We recommend that Western Power attempt to check the weather impact of the modelling against that for the system as a whole. We consider this to have a medium priority, to be carried out over the next year or two.**

For customers billed monthly or those who have meters capable of reading more frequently we expect the data to be more accurate.

5.2.2. Data adjustment

Western Power has adjusted the historical data to remove the effect of movement between customer tariffs and assumed that, apart from movements to time of use tariffs, there will be no further movements in time.

We consider such adjustments to be good practice.

5.2.3. Key explanatory variables

5.2.3.1. Explanatory factors

Western Power has assessed that the following factors are likely to influence monthly consumption on a tariff basis:

- The number of days in the month. Western Power has regressed average daily consumption (ie the total estimated consumption averaged over the number of days in the month) against the other factors. We consider it reasonable to assume that days per month will influence consumption. Although the number of working days in the month will also influence consumption, we do not consider that this needs to be included.
- Weather. As for many utilities, both hot and cold weather influence consumption in the Western Power network.
- Income, as measured by Gross State Product (GSP)
- Price
- Photovoltaic (PV) penetration.

We consider the independent variables chosen to be likely to explain much of the variation of consumption over time. Weather is well known to affect consumption on a daily basis. Income is also generally acknowledged to affect consumption at both residential and business levels. There has been significant anecdotal reporting to suggest that significant price increases in the recent past have had an impact on consumption, with the estimated price elasticity of demand in the literature ranging from about -0.1 to -0.7.

Western Power has also assessed that the strong uptake of photovoltaics in recent years is likely to also impact on consumption as well as maximum demand. We also consider this to be a reasonable potential variable to explore. We have, for other utilities, also recommended PV uptake as an explanatory variable and have postulated that it may act as a proxy for the rapid increase in recent years of other "energy efficiency" effects related to concerns about the environment, government policy and water restrictions.

We consider the range of explanatory variables explored by Western Power to be reasonable.

5.2.3.2. Variables selected

Variables selected as representative of the above factors need to:

- Be representative of the underlying factor

- Have a credible history
- Be credibly forecast.

These requirements rule out a number of potential explanatory variables.

5.2.3.2.1. Weather

To assess the impact of weather, Western Power has used two temperature variables, T and T^2, where T is the average daily temperature in any given month, to try to capture this sensitivity to both hot and cold weather. While we consider the outcome of using these measures to be reasonable, we have two relatively minor issues about the methodology:

- Western Power has primarily used its East Perth weather station as the source of reliable weather data. While we do not have any concerns about this as such, the weather data available from the East Perth station only go back to early 2007 – meaning that the East Perth station not only does not cover the entire period of the regression analysis (January 2006 to end June 2011) but it does not have sufficient data to allow reasonable longer-term monthly averages to be derived. In order to extend its weather history, Western Power has relied on weather history dating back to 1985 from the Bureau of Meteorology's (BOM) Perth Airport station (number 9021). It has corrected for the different location by applying a constant factor to the Perth Airport monthly data[12]. We do not consider it to be good forecasting practice to use composite data when adequate data from the BOM station exists. We have no reason to believe that the weather at the East Perth station better represents weather for the network as a whole than does weather at Perth Airport.

- **Recommendation 2: We recommend that Western Power use data from the BOM instead of its composite weather index. Using the BOM data has resulted in a slight improvement in the R^2 value for the RT1 tariff and a reduction in forecast RT1 consumption of about 1.3% over the period 2012 to 2017. While we consider that this has a relatively low materiality (less than 2% impact) we consider that it can be easily undertaken.**

We consider that Western Power should also consider the use of the more conventional measures – heating degree days (HDD) and cooling degree days (CDD) instead of the T and T^2 variables. We have carried out some analysis of the impact of using these alternative variables, with the threshold set at 18 degrees C with the BOM station data and found that, for RT1, the combination resulted in a similar R^2 to the Western Power modelling but a slightly higher volume (1.6% increase). We have, in addition, evaluated whether the HDD or CDD coefficient is changing over time through use of a DD times index interaction variable but have not found this to be significant.

- **Recommendation 3 We recommend that Western Power consider using CDD and HDD rather than T and T^2 for its weather variables. The HDD and CDD variables are easier to assess and more intuitively explain the impact of hot and cold weather. Our initial modelling has suggested that the impact of this plus the move to BOM weather is relatively low (+1.6% on RT1), however, this can be easily implemented.**

5.2.3.2.2. Economic output or income

GSP is a commonly used as a measure of state or regional income by utilities across Australia for non-residential consumption forecast, less frequently for the residential sector. For non-residential consumption

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12 Western Power has divided the BOM data by a factor of 0.87 to convert the BOM data to an East Perth equivalent in its composite index. The factor was derived by averaging the monthly average temperatures at the BOM and East Perth stations over the four years where data for both have existed. The ratios for the period, November to March, actually averaged about 0.9 while those for the remaining period averaged less than 0.7.

GSP is generally considered to be an appropriate measure of state income. While it would be useful to try using other measures of income, such as sectoral or geographical product, for example manufacturing product or gross regional product for the Western Power network region, such measures often lack reliability and are often forecast by relatively few, if any, credible sources. Although GSP also suffers from perceptions of poor reliability, being subject to frequent revisions, it is collated by a credible, independent source, the Australian Bureau of Statistics, and is forecast by a number of credible sources, including Government. We have for some other utilities, also found strong correlations with other measures, such as labour hours worked, for utilities with a strong manufacturing base. While Western Power might assess such a measure, they are not routinely forecast and GSP alone appears to result in reasonable outcomes.

For the residential sector we consider it more appropriate to regress against income on a per capita or per household basis. Real household disposable income (HDI) is ideal for such analysis, historically and we understand that Western Power has experimented with this variable. The difficulty is obtaining credible forecasts of HDI over the forecast period. In the absence of credible forecasts of this parameter, it is not considered to be a suitable candidate for use as a forecasting variable.

Another measure of income potentially suitable for the residential sector is GSP/capita and we consider that this is likely to provide a better measure of income per customer than is GSP alone. We recommend that this variable be assessed for the residential sector.

- **Recommendation 4: We recommend that Western Power consider using GSP/capita as an explanatory variable for the residential sector rather than GSP. Our initial analysis suggests that using GSP per capita results in an R^2 which is similar to that found with GSP alone and has a slightly lower outcome (-1.3% on RT1). As we consider GSP/capita to be a better measure of residential income we recommend that this be monitored over the longer term. This has a medium priority.**

We note that Western Power has used the 2009-10 history of GSP, which includes a forecast for 2010-11. The 2010-11 GSP data are now available from the ABS (Category 5220) and we have used these in our analysis. As these are the latest available, and include some revisions to earlier data, we recommend that these should be used by Western Power rather than the earlier GSP data.

- **Recommendation 5: We recommend that Western Power should use the most recent GSP data available. Such data is now available for the 2010-11 year. Our initial analysis suggests that using the later GSP data results in an R^2 which is similar to that found with the earlier GSP and has a higher outcome (+1.9% on RT1). As we consider GSP/capita to be a better measure of residential income we recommend that this be monitored over the longer term. This has a medium priority.**

5.2.3.2.3. Price

Western Power uses real price as an explanatory variable for consumption in several of its tariffs. As there is a well established theoretical relationship between price and demand, we consider this to be appropriate[13]. A strong feature of the Western Power methodology is that it calculates the price elasticity of demand applicable to each tariff through regression analysis, rather than assuming an elasticity, as is often the case.

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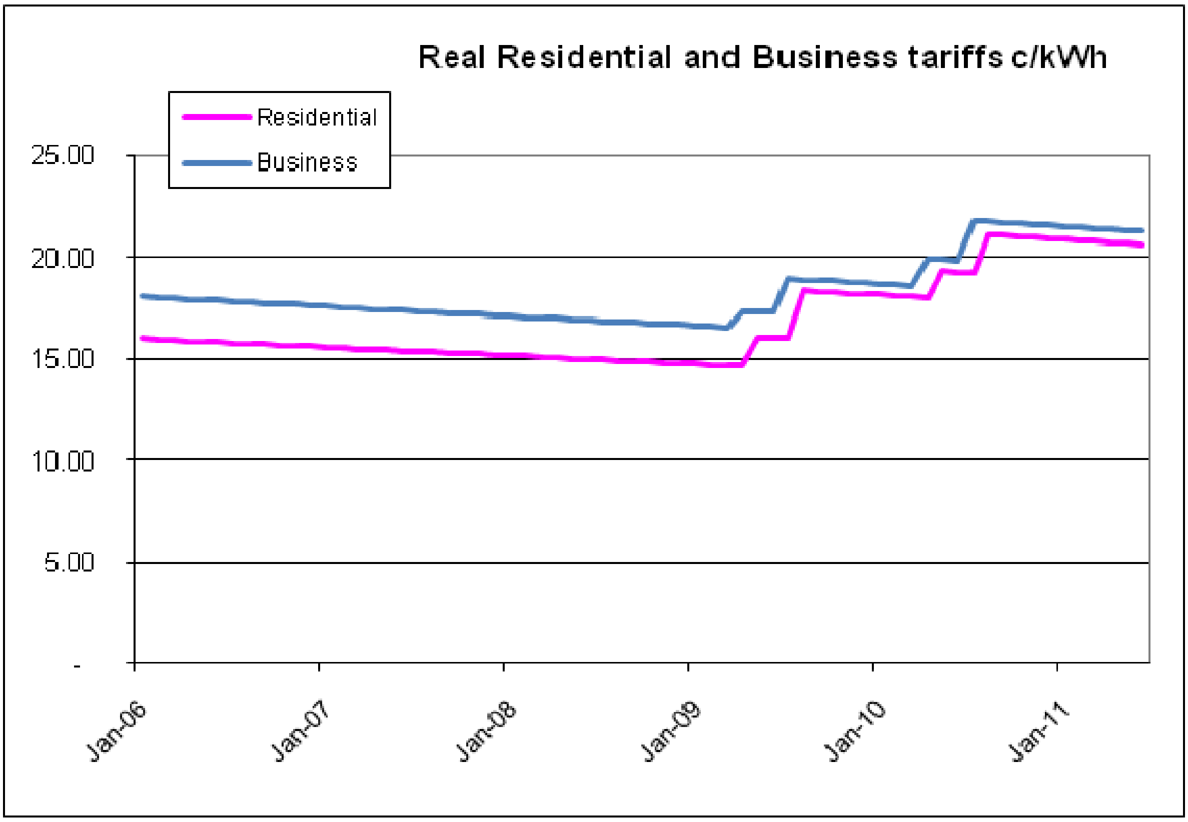
[13] Most studies have assessed electricity demand to be relatively inelastic to price, with price elasticity of demand ranging from -0.1 to -0.7. Fan and Hyndman in "The price elasticity of electricity demand in South Australia" available at robjhyndman.com/papers/Elasticity2010.pdf have calculated a price elasticity of demand in South Australia of about -0.4.

The Western Australian state government publishes prices for a number of retail tariffs in Western Australia[14]. Western Power has used energy prices published in the gazette for the non-contestable residential (A1) tariff and the second energy band[15] of the non-contestable small business L1 tariff to calculate nominal historical prices for residential and all business customers. We note that these include GST. Conversion to real prices was done by deflating historical values using an estimated annual CPI of 2.75% pa, applied uniformly.

Real prices for the A1 and L1 tariffs in cents/kWh as calculated by Western Power are provided in Figure 5-1. They show declining real prices for the early part of the analysis period, as prices were held constant in nominal terms, and then rapidly increasing real prices from 2009. This reflects the Office of Energy's assessment that very significant price increases were required to achieve cost-reflectivity[16].

- **Figure 5-1 Electricity prices for residential and business customers in $Jan2011 terms, c/kWh**



Source: Western Power real tariff prices spreadsheet we_n8484783_v2

Western Power analysis suggests that, for the residential tariff, the price elasticity of demand is about -0.1, but that price response is much higher in winter than in summer. A similar finding was made by Fan and Hyndman for South Australia, who speculated that this might be due to more comfort control choice being available in winter (eg putting on more clothes, using a gas heater[17]) than in summer.

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14 Available at http://www.slp.wa.gov.au/legislation/statutes.nsf/main_mrtitle_1378_currencies.html

15 For consumption of more than 1650 kWh/d.

16 Office of Energy report to the Minister of Energy, "Electricity retail market review: Final recommendations report: review of electricity tariff arrangements", January 2009,

17 Although we note that gas prices are also increasing in real terms in WA.

In its residential modelling, Western Power has, separated out winter and summer months price impacts by using a price dummy which sees a price response only in winter. While we consider the above explanation to be plausible, we consider the case for inclusion of the dummy for medium and longer-term forecasts to be unclear, with the explanatory power of the regressions equation (as measured by R^2) being very similar with and without the price dummy. In the longer-term we would expect that the price of electricity will have an impact on appliance selection which will affect both winter and summer, although, as many residents in the SWIS have a choice between electric and gas for space heating and hot water, the possibility that the impact will be greater in winter than summer, remains. The impact of the price dummy (when multiplied by the price) on modelling is assessed as being material, being of the order of 3% in volume terms over the next six years.

On balance, we consider that the use of the price-dummy combination for residential customers currently appears warranted, but that this should be monitored over time to assess whether the difference between summer and winter responses changes[18].

- **Recommendation 6: We recommend that Western Power continue to use the price dummy parameter for modelling the residential market, but monitor the summer and winter response over time to ensure that this does not change.**

The Western Power modelling for business tariffs does not include a price dummy.

Western Power has converted its tariffs from nominal to real terms by using an estimated average historical consumer price index of 2.75% pa. It is not clear why Western Power has used a flat historical inflation assumption rather than using the available Perth CPI index, which shows an average inflation rate of 3.3% pa over the period of analysis, January 2006 to June 2011. We recommend that the actual Perth CPI index numbers be used, rather than the Western Power assumption.

- **Recommendation 7: We recommend that Western Power use the Perth CPI index for conversion of nominal to real prices. For the RT1 tariff this is estimated to have an impact of +1.1% on volumes. While a relatively low impact overall, we consider this to have a high priority as it can be easily implemented.**

Customers in the SWIS who consume less than 50 MWh per year are not currently contestable and must be supplied by Synergy. All customers in the SWIS who use more than 50 MWh are currently contestable, meaning they can elect to be supplied by a retailer other than Synergy. Customers who consume between 50 MWh and 160 MWh per year may choose between paying the relevant prescribed capped tariffs or selecting a retailer.

Almost all residential consumers are currently non-contestable and the prescribed tariffs are applicable to them. We consider that Western Power has appropriately used the prescribed A1 energy price as the price for the residential customers[19].

However, Western Power has also used the second energy band (> 1650 kWh/day) of the prescribed L1 tariff as its pricing for all non-residential customers. We have two concerns with this:

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18 We have also assessed the net residuals by month in Appendix A to see whether the price dummy results in over-forecasting demand in summer. This appears to not be the case with some of the summer months being over-forecast and some under-forecast, as is the case for winter months.

19 Although there is generally debate as to whether average or marginal prices should be used, we consider the use of the marginal energy price to be reasonable.

- Firstly, for the RT2 customers who average 20 MWh per year consumption and the RT4 customers who average 180 MWh per year consumption, the first band (<1650 kWh/day) is probably a better choice of the marginal price. We recommend that Western Power use the first band of prices within the L1 tariff for its analysis and forecasting of RT2 and RT4 prices.

- **Recommendation 8: We recommend that Western Power use the first band of prices within the L1 tariff for its analysis and forecasting of RT2 and RT4 prices. While this is expected to have a relatively low impact, it may make a difference when carbon price is included as an absolute (not percentage) cost increase.**

- Secondly, since all customers of size greater than 50 MWh/year are contestable, it is more likely that the larger customers, at least, will be paying prices different to the prescribed non-contestable tariffs.

It is very difficult to know exactly what prices are being paid by the larger contestable business customers. We have modelled price impacts using the published S1 and T1 contestable tariffs where considered appropriate. We have found that this generally has little impact on the goodness of fit and can increase or decrease the expected consumption over the next six years by up to 3%.

We have discussed with Western Power two possible alternatives for assessing prices to contestable business customers:

- Ask a retailer whether it will, in confidence, provide an index of prices for representative customer sizes
- Build up a contestable price proxy by using a building block approach, such as has been used in the analysis of cost-reflectivity of existing tariffs[20].

In either case, such information is likely to take some time and effort to generate. In the meantime, Western Power has a choice of not using price as an explanatory variable, continuing to use the second price band or using the published contestable electricity tariff most likely to represent the tariff faced by particular customers. We recommend the latter option for the short to medium term while a better picture of contestable tariffs is being developed.

- **Recommendation 9: We recommend that Western Power use published contestable prices as appropriate for its business customers RT5 to RT8 in the short to medium term. In the longer term we recommend that Western Power try to get a better picture of costs to contestable customers either from retailers or from building up costs using a building block approach.**

5.2.3.2.4. Photovoltaic installed

Western Power has used the capacity of installed PV as an explanatory variable for consumption in the RT1 tariff. The rationale for the inclusion of PV MW as an explanatory variable is that each unit of PV installed is expected to displace energy consumption, a significant proportion within this tariff.

According to Western Power information, the amount of PV installed has increased exponentially over the past four years as illustrated in Figure 5-2, driven by a combination of federal and state government policies and incentives as well as reducing PV costs. Between December 2007 and June 2011 the amount of installed PV increased from essentially zero to almost 150 MW.

According to Western Power's regression analysis for the RT1 tariff, each kW of installed PV capacity is associated with 7.145 kWh of energy reduction per day[21] which, according to Western Power, is in line with

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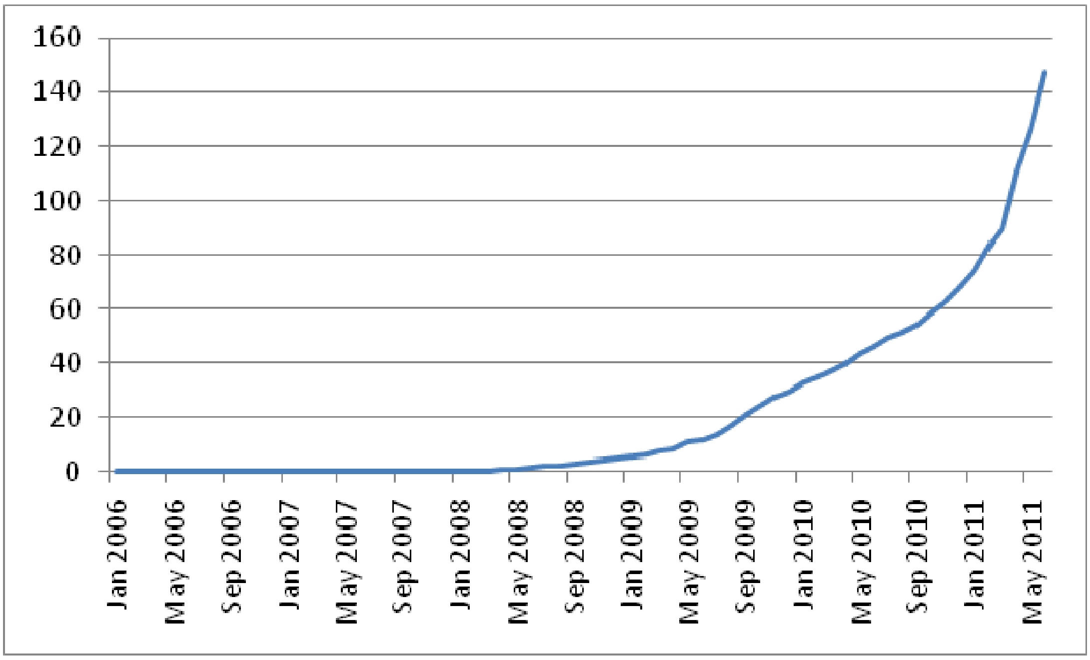
20 See, for example, Frontier Economics report to office of Energy, "Electricity retail market review – electricity tariffs", January 2009.

21 Western Power System Forecasting: Energy and Customer Numbers: Energy Forecast 11/12 – 16/17 dated October 2011 page 25.

expectations. However, this value appears much higher than expected based on the modelled PV output expectations as described in Western Power's PV forecast document[22], especially when it is considered that not all the PV capacity installed is residential.

It may well be that the PV variable is catching a number of other environmental and energy efficiency variables which have also increased significantly over the past several years, such as the increased use of water efficient showerheads and reduced electric hot water systems in new homes. This is not necessarily a bad outcome in forecasting terms if the trend of these other factors follows the expected trend of installed PV.

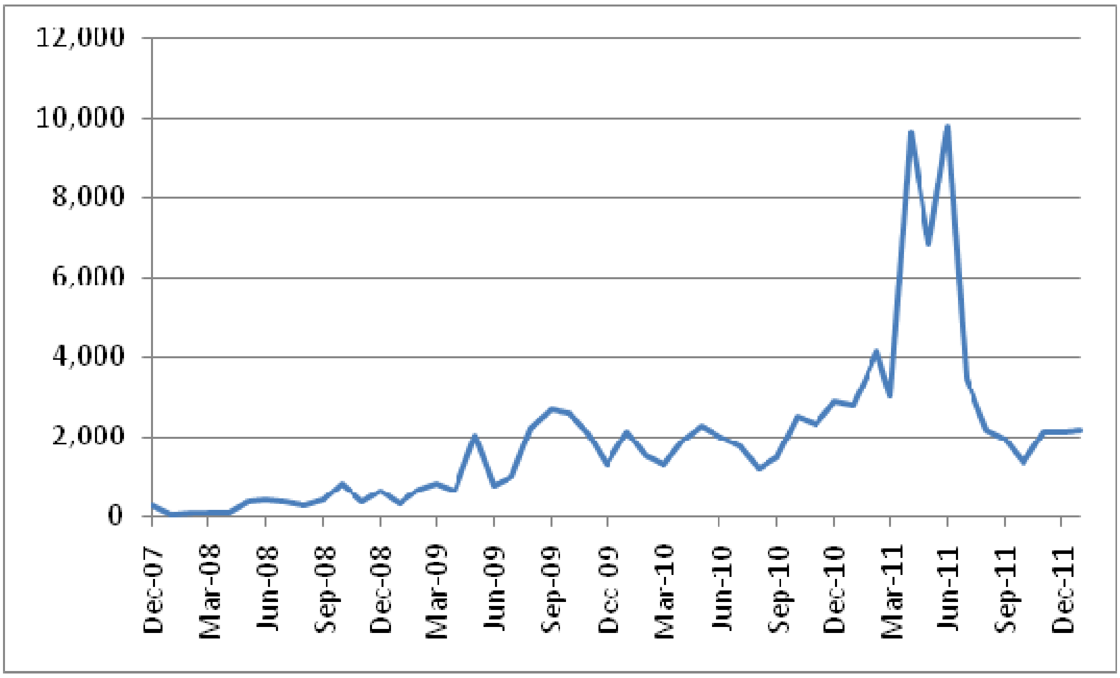
- **Figure 5-2 Installed Photovoltaics, MW**



Source: Western Power Forecasting Transfer and Storage for SKMMMA spreadsheet

22 See Western Power Photovoltaic (PV) Forecast dated 20 January 2012 pages 14 and 34.

- **Figure 5-3 Photovoltaic applications per month**



Source: Western Power PV applications per month.xls

We have found in most of our analysis of the RT1 tariff that the PV variables tend to become not significant (even at the p = 0.1 level) after the changes to the weather, CPI, GSP etc are incorporated into the model. If this is so then we consider that the PV variable should be removed from the model.

However, we consider the PV variable likely to become a good explanatory variable over time and recommend that it be monitored for possible inclusion in future if it again reaches the required level of significance.

- **Recommendation 10: We recommend that Western Power re-run the RT1 tariff model with the changes previously recommended and then remove the PV variable (and any others) if they do not meet at least a 10% level of significance. We estimate this will only have a relatively small effect on the R2 and an incremental impact of about +1% on volumes over the period.**
- **Recommendation 11: We recommend that Western Power continue to monitor the level of PV installations and update the RT1 model if this variable again becomes significant.**

We agree with Western Power that significantly increasing levels of PV installation is likely to reduce consumption, especially in the RT1 tariff. If PV is excluded from the econometric model because of lack of significance, then Western Power should consider adjusting the RT1 tariff forecasts by a suitable amount to account for the increased PV. The appropriate amount can be calculated by:

- Estimating the amount of PV capacity which has been residential and which will be residential
- Estimating the average amount of generation each day. This appears to be about 4.85 kWh/kW/day according to the Western Power PV forecasts [23]
- Adding back historically the amount estimated to have been generated over the period 2006 to 2011 – although allocating generation by month may be difficult.

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[23] Western Power Photovoltaic (PV) Forecast dated 20 January 2012 pages 14 and 34.

  - Re-running the RT1 regression with the adjusted quantities and without PV as an explanatory variable
  - Subtracting future quantities based on the installed residential MW.
- **Recommendation 12: If the PV explanatory variable is found not to be significant and is excluded from the model we recommend that Western Power consider post-modelling adjustment to take account of expected PV impact on consumption as discussed in the text.**

5.2.3.2.5. Customer numbers against GSP

Western Power forecasts customer numbers in many of the tariffs by using GSP as the explanatory variable. We consider that for the residential tariff, RT1, population growth is likely to better explain customer number growth in the SWIS than is GSP.

Both regressions result in high R^2. Both result in similar outcomes.

While the two are related, we consider that customer number growth in future is likely to be more strongly linked to population growth than it is to GSP. As a result we recommend that Western Power forecast residential customer number growth based on population forecasts for the RT1 tariff. However, we consider that GSP will better correlate with small business customer number changes as is usually used by Western Power.

- **Recommendation 13: We recommend that Western Power forecast customer number growth based on population growth forecasts, rather than GSP forecasts. The material impact of this is likely to be low.**

5.2.3.2.6. Using average daily usage per customer as the dependant RT1 variable

Western Power has modelled RT1 consumption with daily usage as the independent variable. In the residential sector it is common to model average usage per customer. This is then multiplied by customer numbers to derive forecast residential consumption.

We have, for the RT1 tariff, modelled average daily usage per customer as the independent variable. The "goodness of fit" in all cases is a little worse than it is for the corresponding daily usage model (R^2 of about 0.84 and 0.9 respectively). It is not immediately clear why this should be the case. Average usage per customer outcomes also tend to be a little lower.

Intuitively we consider the separate modelling of daily usage per customer and customer number growth to better reflect what is happening in the market, and it could be further considered. However, the higher R^2 value for daily usage suggests that it better explains the tariff outcomes to date.

5.2.3.2.7. Other possible key drivers

We consider that the key drivers assessed and variations discussed within this report cover all the main drivers which could realistically be expected to be meaningful to the analysis at the moment.

We have discussed with Western Power other possible key drivers which might be included within future analysis, including drivers associated with energy efficiency (apart from PV), employment numbers and hours worked, gas price and proportions of single to multi residential customers. We currently do not consider there to be a compelling case to include these.

In addition, we consider that some emerging trends warrant future consideration, including the potential increase in consumption related to electric vehicles. However, we do not see this having a significant influence over the next several years.

There is an expectation that replacement electric storage hot water will be banned or limited within the next few years. If this is the case Western Power may need to model this as an add-on to its econometric modelling.

5.2.3.2.8. Conclusion with regard to independent variables

We consider the variables considered by Western Power to generally be suitable for the econometric modelling undertaken. However, we have suggested a change for the variables modelling weather impact from T and T^2 to the more generally used CDD and HDD and that GSP per capita should be used for RT1 and RT3.

While we consider that Western Power has generally selected and used historical data well, we have made a number of recommendations with regard to:

- Changing the historical weather used from the composite used by Western Power to the BOM data measured at Perth Airport.
- Using price histories which are more in line with the tariffs for some of the business tariffs
- Using actual CPI history rather than an assumed CPI to convert prices from nominal to real
- Using the latest GSP history

While each of these is likely to have a minor impact on its own, in combination they may be material to the forecasts.

We consider that the Western Power variables used are likely to cover all the currently foreseeable key drivers operating over the forecast period apart possibly from the banning of electric storage hot water which should be monitored.

5.2.4. Multiple regression analysis

Western Power carries out multiple regression analysis against the appropriate explanatory variables including an index (or trend) variable if no other variable is significant. Western Power also assesses the robustness of the coefficients and has carried out other tests, such as for collinearity where appropriate.

We have also been advised that Western Power has tested transforming and lagging some variables without improvement in the outcomes.

We have carried out a few basic tests on the RT1 tariff modelling. These are described in Appendix A. As discussed there, the plot of residuals showed no obvious trend and, while our analysis of net forecasting errors by month showed some months to have relatively high errors, this did not indicate a change of model or variables apart possibly from the recommended move to using the BOM data exclusively rather than the composite index.

We consider Western Power's regression modelling to be commensurate with good forecasting practice.

5.2.5. Forecast assumptions

In order to use its model for forecasting purposes, Western Power has had to make assumptions about changes to the key variables in the future. The source of these assumptions and the assumptions themselves are listed in Table 5-1.

Table 5-1 Sources and assumptions for independent variables

	Source	Assumption
Weather	Composite 27 year history from the Perth Airport BOM station and Western Power's East Perth station	Average monthly temperatures from the composite index over the past 27 years.
GSP	WA State Budget forecasts 2011-12	Assumed 4% growth pa from 2011-12
Prices	WA State Budget papers. Federal government modelling of carbon price impacts	Assumed the nominal price increases included in the budget paper. Assumed that Western Power would experience the average modelled price increase per MWh
CPI		Assumed CPI would continue at 2.75% pa
PV	Variation to PV Forecast	Assumed 1500 new applications/month @2.4 MW each
Population		Not required

The key assumptions are discussed below.

5.2.5.1. Weather

As described in 5.2.3.2.1, Western Power has used its composite index to derive future average temperatures by month. As discussed previously, we can see no reason why the composite index should be used rather than the consistent history from the BOM station.

Similarly, we consider that the weather assumptions (CDD and HDD) used for the forecasts should be those derived from the available long-term history from the BOM station. The impact of this change is likely to be material.

- **Recommendation 14: We recommend that Western Power forecast weather based on the history of the BOM weather station, rather than the composite index it has devised. The impact of the combination of the change to history, and forecasts as well as a move to HDD and CDD is an increase of 1.6% in the RT1 forecasts.**
- **Recommendation 15: We also recommend that, over the longer term Western Power assess whether a combination of weather stations is likely to be more representative of consumption in the SWIS as a whole and also whether the history of CDDs and HDDs at the Perth Airport BOM, which are illustrated in Appendix A and show a reduction in HDD/day and increase in CDD/day over time, have changed sufficiently over time to require the average over a more recent period to be used.**

5.2.5.2. GSP

Western Power has used the WA 2011-12 Budget Forecasts[24] as the basis of its economic and pricing forecasts. The budget paper forecast WA GSP growth of 4.5% in 2011-12, followed by three years of 4% growth.

This forecast, and that of the National Institute of Economic and Industrial Research (NIEIR) as described in the WA IMO 2011 statement of Opportunities[25] are presented in Table 5-2.

- **Table 5-2 WA Budget and NIEIR forecasts of growth in GSP**

	WA Budget	NIEIR Expected case
2012	4.5%	5.0%
2013	4.00%	3.70%
2014	4.00%	2.00%
2015	4.00%	2.10%
2016		3.60%
2017		4.90%

Western Power has assumed that growth will be 4% flat throughout the period, based on the Government budget forecasts and extrapolating for the last two years to 2017. The NIEIR forecast over the period to 2017 is for growth averaging 3.5% pa.

Both the WA Government and NIEIR are credible forecasters. We consider that either, or a more recent credible GSP forecast can be used. However, if the State Government forecast is to be used then it should be that forecast, rather than a flat assumption of 4% pa.

24 Western Australian 2011-12 Budget Paper 3, Economic and fiscal outlook, presented May 2011, page 3.
25 WA Independent Market Operator, "Statement of Opportunities" June 2011.

- **Recommendation 16: We consider that Western Power's use of the WA GSP forecasts contained in the state Government's 2011-12 budget forecasts to be reasonable, as would be the use of the NIEIR forecasts used in the 2011 Statement of Opportunities or even a more recent credible forecast. However, if the state Government's forecast is to be used than it should actually be the forecast, including a 4.5% growth in 2011-12 with extrapolation only for the final years as required. We note that the use of alternative GSP forecasts is likely to have a material impact on a number of tariff forecasts.**

5.2.5.3. Retail prices

Tariff increases

Western Power has used the assumed non-contestable glide path for the A1 and L1 tariffs contained in the WA 2011-12 Budget Forecasts[26] as the basis of its tariff price increases. These assumed price increases, as well as those for the contestable S1 and T1 tariffs that we have used in our analysis are provided in Table 5-3.

- **Table 5-3 WA Budget glide path assumptions about tariff price increases**

	2011-12	2012-13	2013-14	2014-15
Non-contestable A1	5%	12%	12%	5%
Non-contestable L1	5%	12%	12%	5%
Contestable S1	3.90%	1%	5.60%	3.90%
Contestable T1	5.10%	0.70%	5.50%	5.10%

According to the budget papers, the price increases in 2010-11 were not sufficient to bring prices to a cost-reflective basis and would continue not to be cost-reflective after the glide path assumed. The assumed glide path did not include the cost of carbon and there was a risk due to significant network tariff increases[27].

We consider it reasonable for Western Power to use the most authoritative source available, the state Government, to estimate likely tariff changes over time. Western Power has assumed 5% pa increases for the A1 and L1 tariffs in the years 2015-16 and 2016-17 on which the budget papers are silent and we consider this reasonable. We have, however, used the average of the four years increases in our modelling of the S1 and T1 tariffs.

Carbon price

Western Power has added to the above electricity tariffs the expected impact of the carbon price. It has derived the price impact from the Federal Treasury's carbon price modelling, using the real carbon prices for the Strong Growth Low Pollution (SGLP) core scenario multiplied by the average Australian CO_2-e intensity of generation. According to Western Power's calculation, this results in a price increase of about 1.5 c/kWh in 2012-13 increasing to 1.95 c/kWh by 2017[28].

We consider it reasonable to use the Treasury modelling results. These assume the average Australian carbon CO_2-e intensity of generation of 0.822 kg CO_2-e /kWh in 2013 and less than full pass-through. The SWIS average intensity according to the NGERS Technical Guidelines in July 2011 was a little lower than this at 0.8

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26 Western Australian 2011-12 Budget Paper 3, Economic and fiscal outlook, presented May 2011, Table 8.1.
27 Western Australian 2011-12 Budget Paper 3, Economic and fiscal outlook, presented May 2011, page 285.
28 The assumption appears to be that competitive forces will mean that the full cost of the carbon price, $23/t in 2013 will not be passed through in full.

kg CO_2-e /kWh. From this perspective the price impact may be a little over-stated, by of the order of 0.05 c/kWh in 2013.

However, the Treasury modelling was carried out in $2010. This means that, in today's dollars the costs are likely to be higher by some 0.05-0.1 c/kWh. In addition, we understand that this price does not include GST. If this is included, to remain consistent with the other prices modelled by Western Power it will add about 0.15 c/kWh to the price. Finally, the average emission intensity of Australian generation is assumed to reduce quickly. It is not clear that this will also happen in Western Australia.

Overall, given the uncertainty, we expect that the carbon price modelled by Western Power to be a reasonable estimate – although we recommend that the GST be included in order to make it consistent with the other tariffs used.

- **Recommendation 17: We consider that Western Power's assessment of the pass-through cost of carbon to be reasonable, however, we consider it should have GST added to it to ensure it is consistent with other prices used in modelling This is easily manageable in the modelling and will have a slightly negative impact on volumes.**

5.2.5.4. CPI

In calculating future price increases, Western Power has assumed that the inflation rate for the state will be 2.75% pa. However, the Western Australian budget has assumed that inflation will be 3% in 2011-12, followed by 3.25% pa for the following three years. In order to be consistent with the assumptions made in the budget papers about tariff pricing we recommend that the CPI assumptions used in these papers be used by Western Power.

- **Recommendation 18: We recommend that the CPI assumptions used in modelling be the same as those in the 2011-12 budget paper, with the value in the last year extended for a further two years. This will have a small positive impact on modelled volumes.**

5.2.5.5. PV installed

As can be seen in Figure 5-4, Western Power is forecasting that the capacity of photovoltaics installed will continue to grow strongly, although linearly rather than exponentially. This is because of the impact of the significantly reduced subsidies from July 2011, which saw an immediate strong reduction in the amount of PV applications from about 9,000 per month to 1,500-2,000 per month. Whilst historically the application levels are at about 2,000 per month, it is anticipated that the level will reduce further due to the watered down state based feed-in-tariffs and the reducution of solar credits multiplier in July 2012 and again in July 2013[29]. In future, the impact of carbon pricing may yet see an increase in the level of application.

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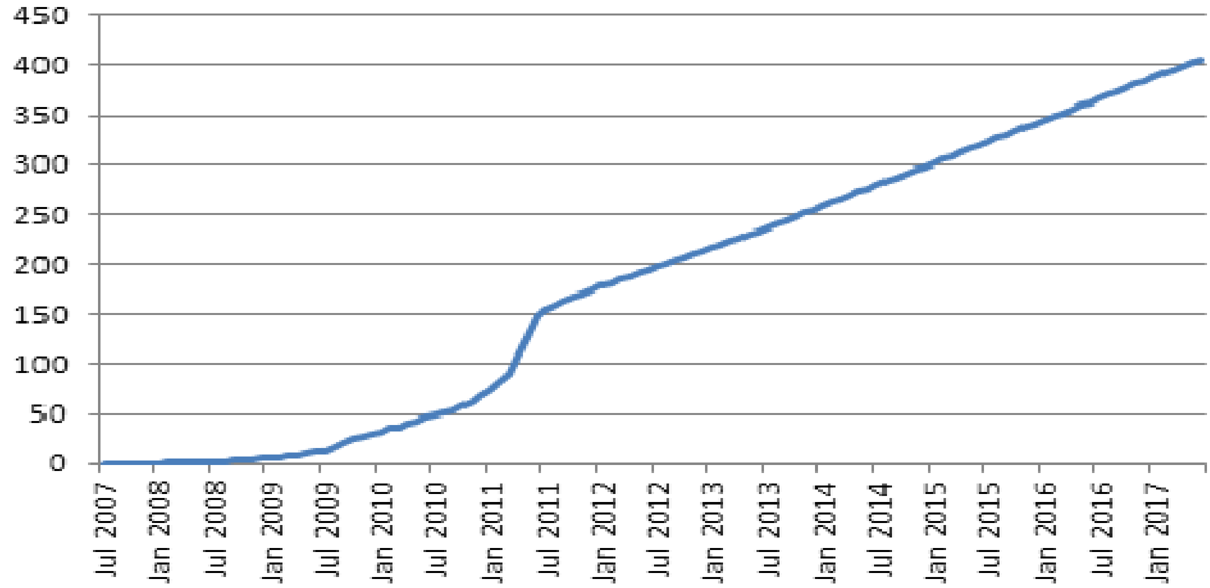
[29] Refer also to the PV analysis in Section **Error! Reference source not found.**

- **Figure 5-4 Forecast installed Photovoltaics, MW**



Source: Western Power Forecasting Transfer and Storage for SKMMMA spreadsheet

In its modelling, Western Power has assumed that over most of the period installations will equal 1500 per month and that the average size of the installation will increase from the current 2.2 kW to 2.4 kW from July 2013.

These assumptions appear reasonable and are consistent with independent SKM MMA modelling of PV installations in WA. SKM MMA numbers were slightly higher.

They do not, however, appear to be consistent with the assumed outputs from the maximum demand analysis, with monthly applications there assumed to be 2000 per month with, we understand, similar capacity assumptions. The two need to be reconciled in any documentation – with either the assumptions being the same or an explanation provided about the cause of the discrepancy.

- **Recommendation 19: We recommend that the reason for difference between the PV assumptions used in the maximum demand analysis and in the energy analysis be explained and documented.**

5.2.5.6. Discussions with large customers

Western Power has based its forecast of the transmission connected large customers, TRT1, on the basis of detailed discussions with large customers and analysis of potential new projects. We understand that the forecasts have also included large new customers who have been included within the Central case of the Western Power maximum demand forecasting (see Section 7). It should be confirmed that this is still the case and that the timings assumed in the energy and latest maximum demand forecasts are still consistent.

- **Recommendation 20: We recommend that Western Power confirm that the timings and loads for large new customers are consistent between the latest maximum demand and energy forecasts.**

There are currently about 33 such very large customers, each consuming on average, about 80 GWh. Such customers represent large lumpy loads and we consider it good practice to base forecasts on extensive discussions and objective assessments about new loads, as are currently applied to block loads (see Section 7.5.2). We note, however, that such discussions should be detailed, fully documented and subject to some scrutiny.

In addition, Western Power has assumed that the load factor for new customers is 0.8 but has not provided any support for this assumption. Such supporting data might be available from load factors from existing customers or from detailed discussions with new customers.

In conclusion, we consider it reasonable that this class of large lumpy customers should be forecast through a deep understanding of the loads involved and detailed discussions, which are likely to be best carried out by account managers not within the forecasting team. We have not seen or reviewed any of the Western Power discussions, nor have we reviewed any of the detailed assumptions about this tariff. We recommend, however, that the discussions on which the forecasts are based should be fully documented and reviewed by the forecasting team and that the 0.8 load factor assumption for new loads should be reviewed.

- **Recommendation 21: We recommend that Western Power ensures that there is full documentation regarding forecast assumptions for this class of customer and that this is reviewed by the forecasting team. In addition, we consider that the basis for the load factor assumed for the new loads should be provided.**

5.3. Conclusion regarding approach and methodology

We have in this chapter outlined the approach taken by Western Power and carried out a detailed review of the methodology applied.

Western Power has forecast on a monthly basis at the tariff level using the following five-step approach:

1) Derive monthly historical data: consumption, customer numbers (and demand where appropriate) for each tariff
2) Adjust the data historically to ensure that movements between tariffs and other anomalies are captured
3) Explore key explanatory variables which can help explain changes in consumption
4) Derive an econometric relationship between consumption and the key explanatory variables through multiple regression analysis
5) Forecast using assumptions of key drivers derived from credible sources.

The approach taken to forecasting depends heavily on the requirements of the forecast, key drivers and data availability. Given the importance of weather and specific tariff characteristics and the availability of 6.5 years of reliable data we consider the above forecasting approach taken by Western Power to represent good practice. The main concern we have relates to the monthly analysis based on billing data which is not collected on the same timeframe, however, we consider that Western Power has handled this reasonably.

We consider the use of well founded and applied econometric modelling to be good practice for utility forecasting. Such econometric forecasting is currently becoming the norm for energy forecasting in Australia, largely displacing the trend and appliance based analysis of the past[30]. We consider econometric forecasting to represent good forecasting practice in this area as it provides transparency and allows for changing

[30] We note that we still consider there to be scope for well considered adjustments or alternative approaches to be used based on specific policy or appliance related circumstances.

circumstances if the underlying key drivers have been well considered. Where econometric modelling has not been useful, or where other approaches such as discussions with the largest customers are considered more appropriate, then these other approaches have been applied.

We have concluded that the overall approach taken by Western Power is reasonable and, if methodologically sound and properly applied, is likely to result in good forecasting practice being followed.

We have carried out a detailed review of the methodology applied and consider that:

- The key drivers considered, being weather, price, income, PV penetration are reasonable, are similar to those used by utilities elsewhere and do not obviously omit any key drivers which can be readily captured.
- The explanatory variables which represent these factors are generally well considered. We have, however recommended that Western Power use cooling and heating degree days for its weather variables, rather than a function of average monthly temperature and that, for the RT1 tariff for residential customers it should use GSP per capita rather than GSP as the measure of income. We do not consider these to be major changes to the methodology.
- We have reviewed the history used for these variables. While we have recommended a number of changes which we believe will improve the forecasts, we again consider none of these to be major in its own right.
- We consider the multi regression methodology to be well applied. The regressions generally have reasonable goodness of fit and the variables are only included if they are statistically significant and the coefficients make sense.
- The assumptions made about movement of the key drivers over the forecast period are derived from credible and reliable sources and generally appear timely and realistic. Again, while we have made a number of recommendations in this area, none are considered fundamental.

Overall, SKM MMA considers the approach taken by Western Power to be well conceived and the methodology well considered and applied and generally commensurate with good forecasting practice. We have made a number of recommendations in terms of variables, history and assumptions which are not fundamental to the methodology but which will, we believe, improve the accuracy of the forecasts.

6. Review of central energy forecasts and comparison against other forecasts

6.1. Introduction

We have in the previous chapter reviewed in detail the approach and methodology applied by Western Power and we have concluded that these are commensurate with good forecasting practice. We have, however, made a number of recommendations, some applicable to the short and others to the longer term, which we consider would improve the accuracy of the forecasts.

This chapter provides an overview of our considerations for each tariff. Our detailed analysis is available in Appendix A. It concludes by examining the history and the Western Power forecasts at the residential, business and network levels against indicative[31] SKM MMA forecasts where we have applied most of our recommendations and some external forecasts.

6.2. Overview of the Western Power forecasts and of the potential impact of changes

An overview of the Western Power forecasts, the changes we have recommended and the indicative changes by tariff where these are been reviewed are provided in Table 6-1.

- **Table 6-1 Summary of Western Power forecasts, recommended SKM MMA changes and indicative impact of these**

Tariff	Western Power Forecast Volumes, GWh (1)	Proposed changes (2)	SKM MMA indicative volumes, GWh (3)	Change, % (4)
RT1	33124	CPI[32], BOM[33], CDD[34], HDD, Remove PV if not signif, GSP/Capita, GSP[35]	35178	6%
RT2	10081	CPI, BOM, CDD, HDD, GSP	9859	-2%
RT3	1457	Not reviewed as largely same as RT1 apart from tariff movements	1457	0%
RT4	11599	As per RT2, L1b1[36]	11112	-4%
RT5	2689	CPI, BOM, CDD, GSP	2616	-3%
RT6	8694	CPI, BOM, CDD, GSP, S1[37], L1b2	8546	-2%
RT7	19214	CPI, BOM, CDD, HDD, GSP	19022	-1%
RT8	1415	CPI, BOM, CDD, HDD	1428	1%
RT9	773	Not reviewed as immaterial	773	0%
RT10	208	Not reviewed as immaterial	208	0%
TRT1	22421	Not reviewed as based on discussions	22421	0%
Total	111675		112620	1%

31 We stress that these forecasts are indicative only for purposes of assessment of materiality and not to be relied upon. They have not been checked and only represent our current best estimates.

32 Index price by CPI and use budget forecast for future periods

33 Use Perth Airport temperature data

34 Use CDD and HDD or alternatively CDD per day and HDD per day if complete temperature data is not available. Per day is a count of the days where data is available. It equals to days in month when no data is missing

35 Update to more recent GSP

36 L1b1 = L1 prices constructed using band 1 rates; L1b2 = L1 prices constructed using band 2 rates

37 S1 prices

Notes:

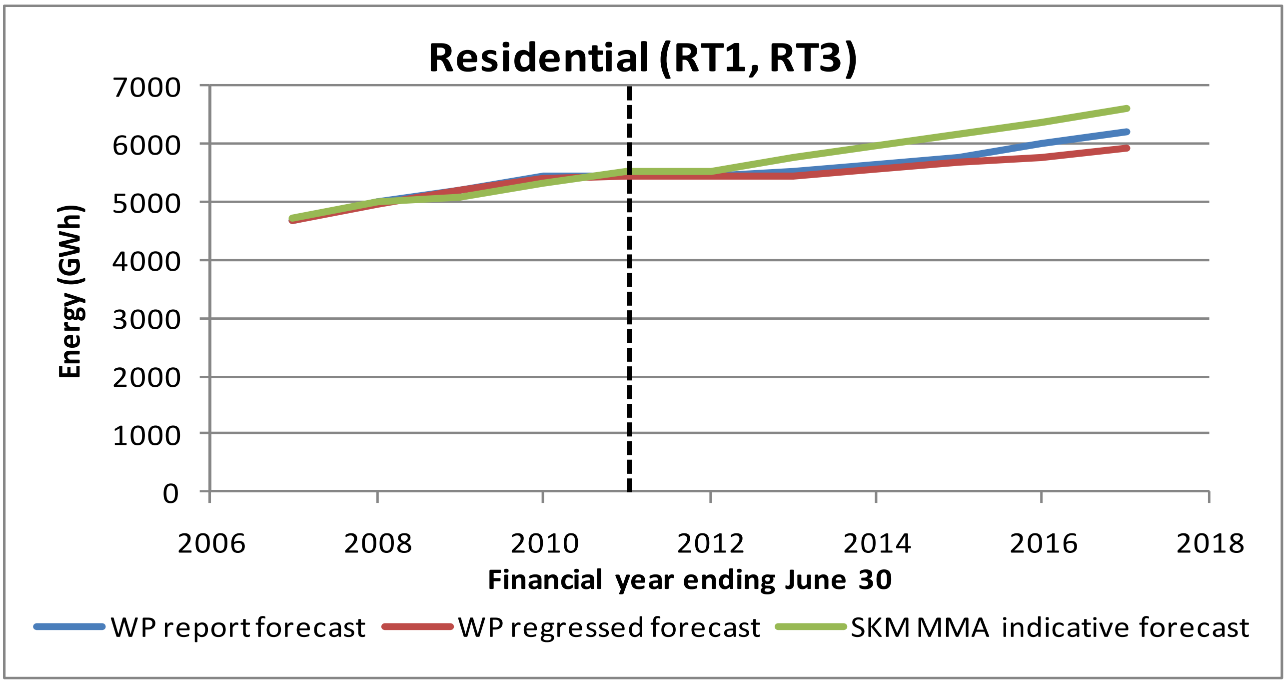
1) This is the summed forecast volumes over the years 2011-12 to 2016-17 in the Western Power energy and customer numbers report, not necessarily the volumes determined from regression analysis.
2) These are the changes we have recommended in the body of the report. Several tariffs have not been reviewed.
3) These are indicative volumes modelled after implementing the changes recommended. Note that several tariffs have not been reviewed.
4) SKM indicative forecasts divided by Western Power report forecasts -1.

Over the entire network the forecast volumes before and after implementing the changes proposed by SKM MMA are very similar – although we stress that some tariffs, including the large TRT1 tariff have not been reviewed.

However, there are some material differences in some categories, with the residential forecasts after the proposed changes being higher than forecast by Western Power and the business tariffs generally being lower.

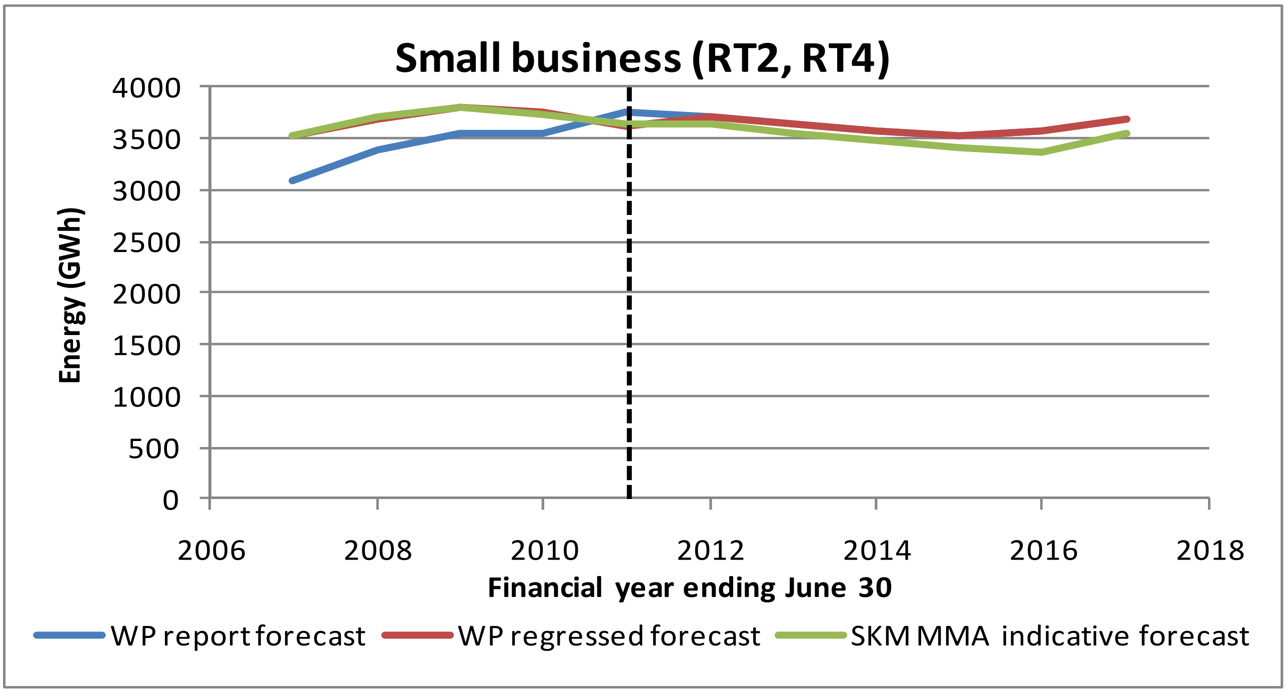
We illustrate the Western Power and indicative SKM MMA forecasts for residential, small, medium and large business[38] and the network as a whole in the following Figures.

- **Figure 6-1 Comparison of Western Power forecasts (report and model) and indicative SKM MMA residential forecasts, GWh**

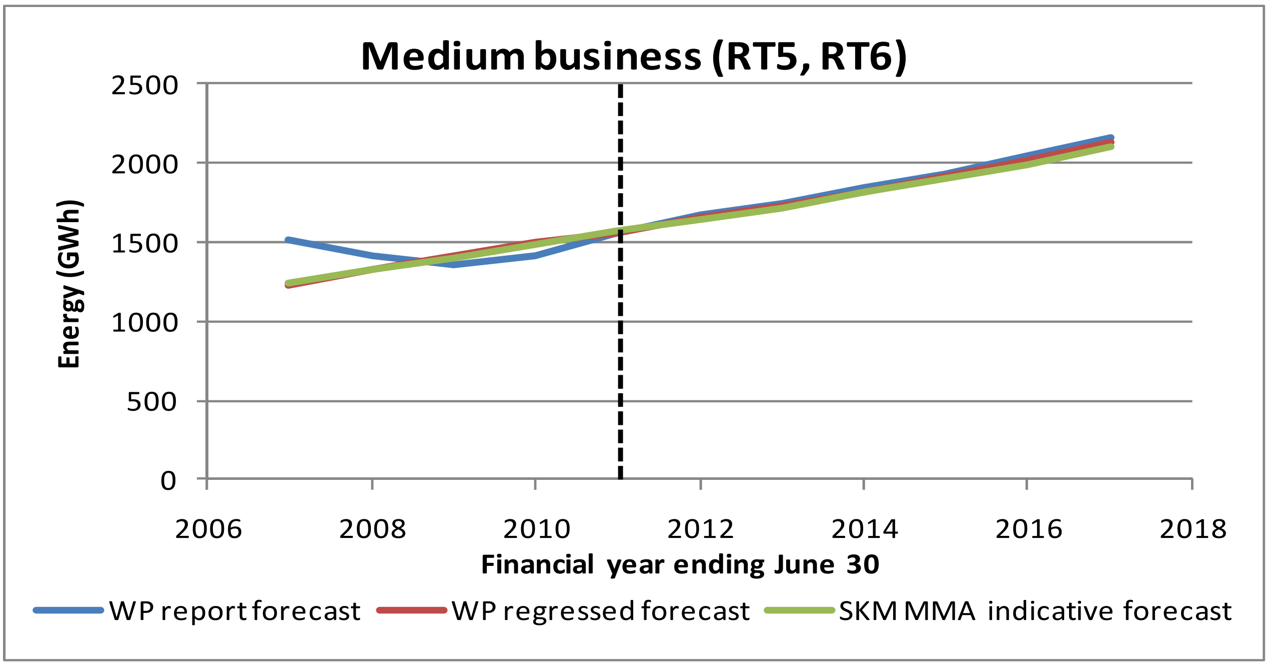


[38] We note that the definitions we have used may not accord with Western Power's definitions. The tariffs we have included are illustrated.

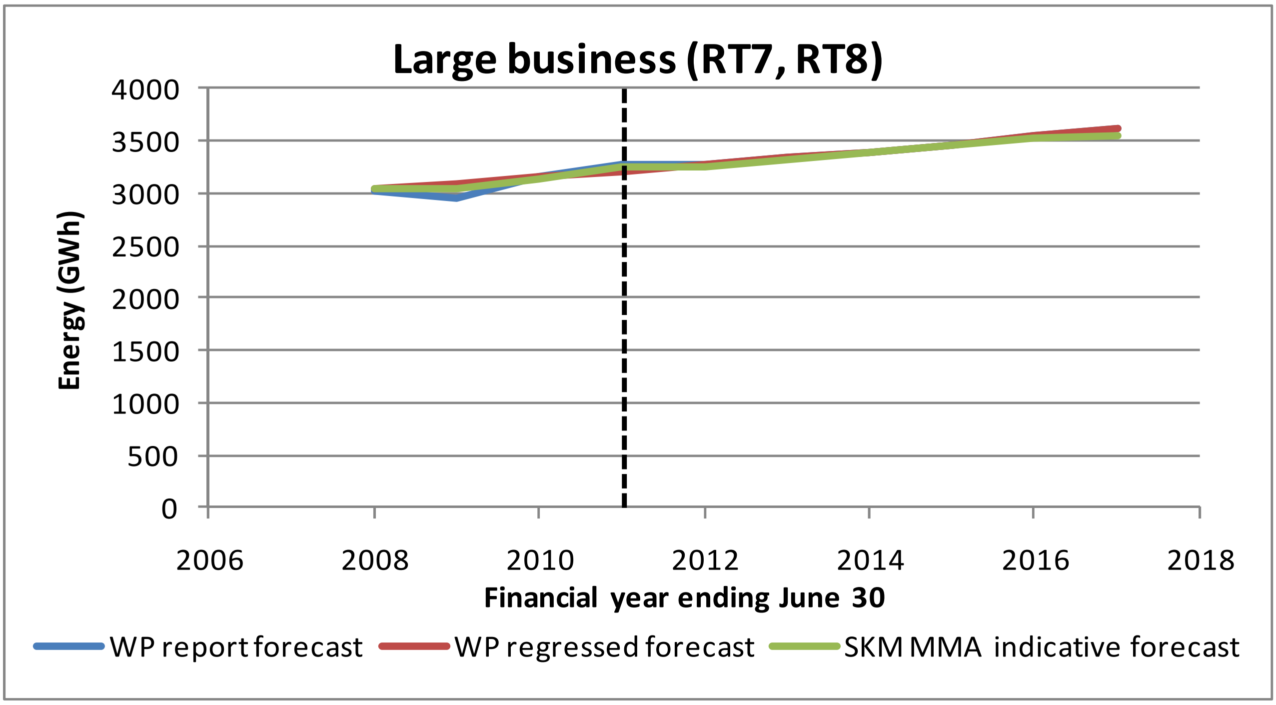
- **Figure 6-2 Comparison of Western Power forecasts (report and model) and indicative SKM MMA small business forecasts, GWh**



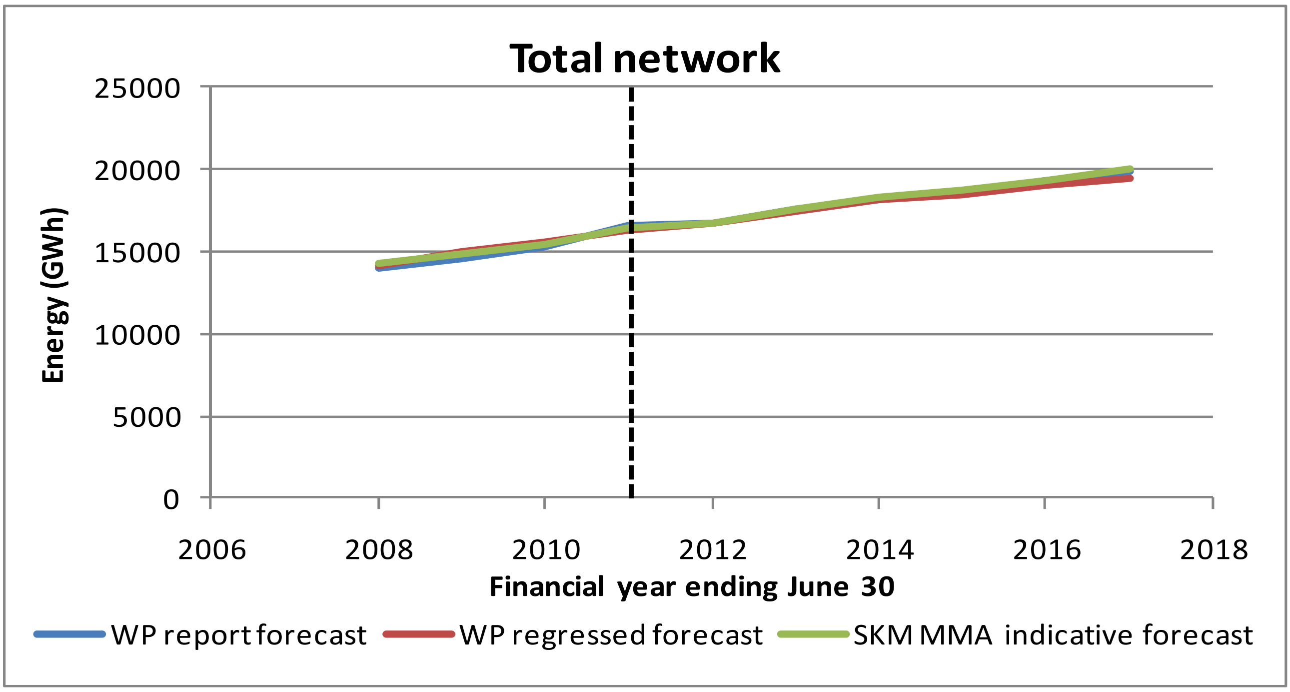
- **Figure 6-3 Comparison of Western Power forecasts (report and model) and indicative SKM MMA medium business forecasts, GWh**



- **Figure 6-4 Comparison of Western Power forecasts (report and model) and indicative SKM MMA large business forecasts, GWh**



- **Figure 6-5 Comparison of Western Power forecasts (report and model) and indicative SKM MMA network forecasts, GWh**

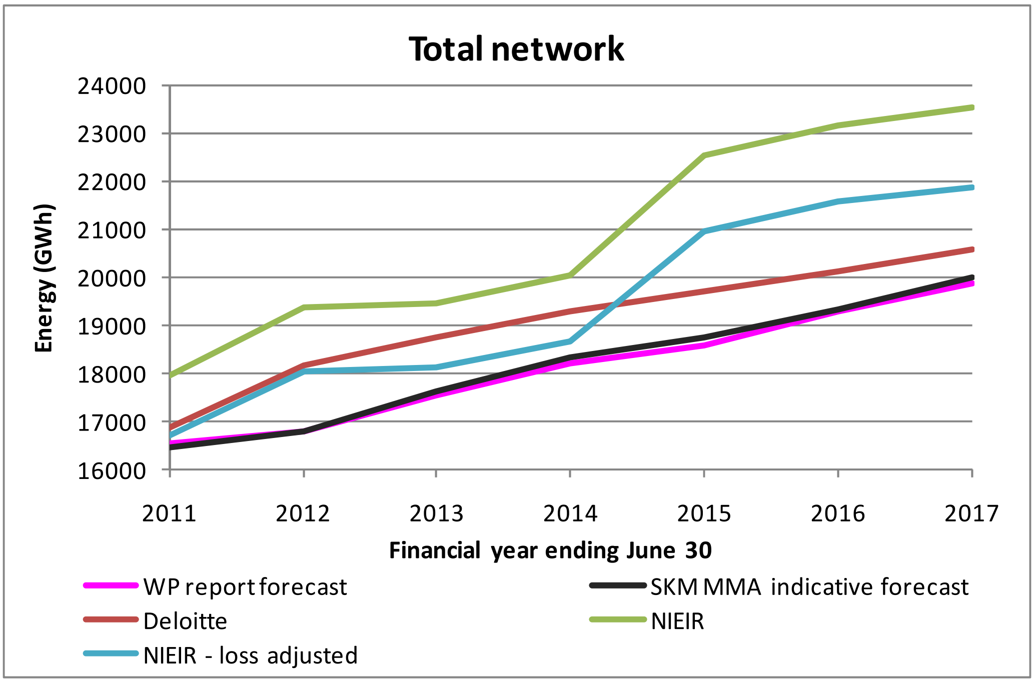


Taken over the entire network, the changes recommended by SKM MMA have very little impact on the Western Power forecasts, as can be seen in Figure 6-5. There are, however, some movements within specific customer sectors, notably in the residential class (Figure 6-1), where SKM MMA forecasts are higher and in the small business class (Figure 6-2) where they are lower.

6.3. Comparison against the Deloittes and IMO forecasts

Figure 6-6 compares Western Power's forecasts at network level against: SKM MMA's indicative forecast, Deloitte's 2010 forecast, the IMO 2011 energy forecasts and IMO's loss adjusted forecasts. IMO's loss adjusted forecast was obtained by factoring out distribution and transmission loss factors of 2.69% and 4.66%, respectively, as documented in Western Power's forecast report.

- **Figure 6-6 Comparison of forecasts – network, GWh**

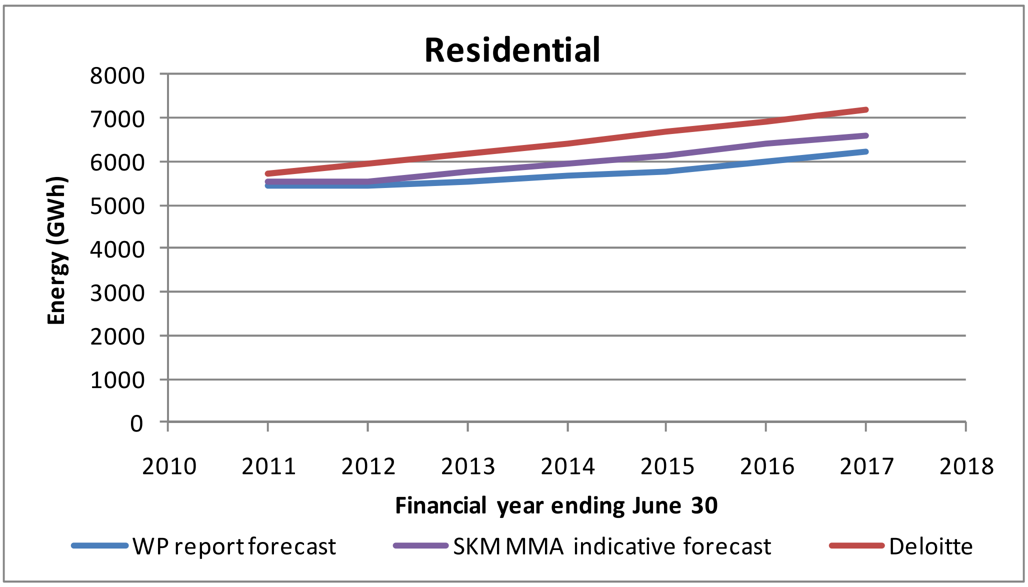


After adjusting for losses, it can be seen that the all forecasts start in proximity to each other. Western Power's forecast and SKM MMA's indicative forecasts are very similar. However, both the Deloittes and IMO forecasts appear to have a large block load applied in 2012, while this only builds up over time according to Western Power. By 2014 the Western Power forecast is similar to the IMO forecast. However, IMO appears to be forecasting another major block load in 2014 which does not appear to be included in the Western Power forecasts. It is difficult to provide any further comparison between the two as the IMO forecast is not disaggregated.

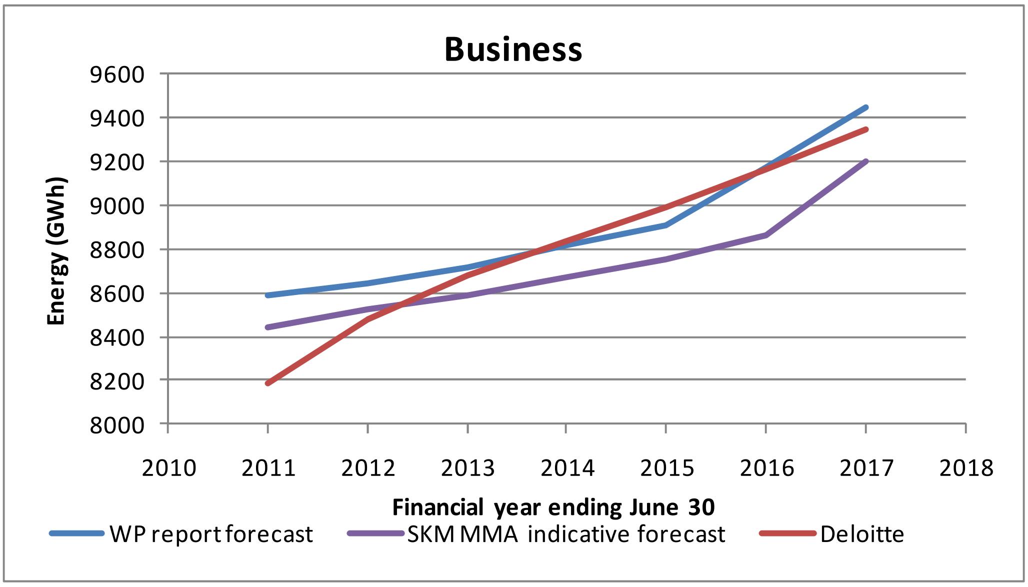
The Deloittes network forecasts are also significantly higher than Western Power's by 2012, again possibly due to block load assumptions. From there, the Deloitte's forecast remains consistently higher than the Western Powr forecasts.

Comparison of forecasts for the combined residential and combined business tariffs are shown in Figure 6-7 and Figure 6-8 respectively. SKM MMA's indicative energy forecast for the collective residential lies between Western Power's and Deloittes forecasts. The Western Power residential forecasts are lower for the residential sector than SKM MMA's forecasts for reasons discussed in the report. The reasons for the difference between the Deloittes forecasts and the other two are likely to be due to significantly different forecasting methodologies.

- **Figure 6-7 Comparison of forecasts – residential, GWh**



- **Figure 6-8 Comparison of forecasts – business, GWh**



For the collective business forecast, SKM MMA's indicative forecast is lower than Western Power's. The gap between the two is initially attributable to the difference in 2011 forecast numbers between Western Power's reported forecast and their forecast values resulting from their regression. It is not clear why there is such a difference, possibly a transfer between tariffs. The Deloittes forecasts are not dissimilar to the other two forecasts over the forecasting period.

Relatively little can be learned from comparing forecasts as they all have different methodologies. Overall the largest differences appear to be due to major block load assumptions. The Deloittes residential forecasts are somewhat higher than both the Western Power and SKM MMA indicative forecasts but the business forecasts are similar.

6.4. Assessment against criteria

We have evaluated the Western Power approach, methodology, application and forecasts against the criteria we have previously listed in Section 4.3. These evaluations are summarised below.

6.4.1. Basis of forecasting logical, appropriate to the situation and at a suitable level of disaggregation

Western Power has used an econometric approach based on regressing monthly consumption by tariff against key drivers including weather, real price, income or output and PV installations. We consider the approach and methodology to be logical and suitable and the key drivers selected to be appropriate.

6.4.2. Review of history and key drivers

The Western Power methodology inherently takes into account the history of key drivers and how this is expected to change in the future. We consider the key drivers selected to be appropriate to the situation, although we have recommended some relatively minor changes to variables used.

6.4.3. Forecast assumptions

Western Power has based its assumptions about how the drivers will change over time on credible sources, mainly the state Government budget. The assumptions are transparently derived and documented. The assumptions which require inputting into models are generally forecast by a number of credible sources and can be updated as required.

6.4.4. Modelling

The Western Power models generally result in reasonable to good fits. Inputs are generally well considered, although we have recommended a number of relatively minor changes in this area, including consistent use of the Perth Airport weather data and consistent use of state Government forecasts. There is very little requirement for judgements to be exercised.

6.4.5. Unbiased application

Our detailed review of methodology application has found no evidence of bias in the forecasting.

6.4.6. Well documented

The methodology and application are generally well documented although we have identified a couple of areas where this could be improved.

6.4.7. Forecasting effort

The modelling and supporting documentation together with our discussions demonstrate that Western Power has spent a considerable amount of effort on developing its energy forecasting methodology.

6.4.8. Transparent and repeatable

The model inputs and outputs are all available for review and replication.

6.4.9. Overall assessment

We consider the Western Power customer number and energy forecasting methodology to be well considered and sound with key drivers being suitably selected and generally well characterised. Although we have in the body of the report made many recommendations which we consider could help improve the forecasting methodology and forecasts over time, we generally consider the methodology and its application to be commensurate with good forecasting practice.

7. Maximum Demand

7.1. Introduction

SKM MMA reviewed Western Power's Maximum Demand (MD) forecasting methodology and outcomes in 2010. The executive summary of the 2010 study report is reproduced in the executive summary of this report.

In view of the 2010 review, and the similar forecasting approach taken by Western Power in 2011, the focus of the current review is on:

- Updates and modifications to the methodology since the 2010 SKM MMA study
- Application of the methodology to the most recently available data.

An outline of Western Power's methodology is provided below.

7.2. Description of method

Western Power's MD forecasts are based on a bottom-up approach. Forecasting is undertaken at the substation level and higher level forecasts are calculated by aggregation, with allowance for load diversity. Western Power does not prepare a high level econometric forecast but a system level econometric forecast is produced by NIEIR and published by the IMO. A comparison of the Western Power and IMO MD forecasts is presented in Section 7.6.

For each substation a series of forecasts are produced:

- 50 POE[39] substation MD – a trend forecast underlying the 10 POE forecast
- 10 POE substation MD – used for planning network augmentation
- 50 POE substation MD at time of system peak – used to produce the 50 POE system peak forecast
- 10 POE substation MD at time of system peak - used to produce the 10 POE system peak forecast

The Western Power 50 POE system forecast is calculated by the summation of the individual substation 50 POE forecast demands at the time of system peak and the system peak forecasts are compared with the equivalent IMO forecasts.

7.2.1. Inputs

For each substation the historic annual demand is captured for both substation peak and time of system peak.

Block loads that may be included are collated by a central system. The decision on the inclusion of individual block loads is based on a guideline matrix relating to block load size, timing and how far through the development process the project is. Western Power has processes for estimating size, timing, diversity and power factor based on previous similar block load proposals.

For each load transfer between zone substations a size, date, power factor and growth rate are specified. The transfer and future growth is subtracted off the sending substation and added to the receiving substation. The total MVA added and subtracted net out to zero. It is assumed that the transfer has a diversity of 1 with both the sending and receiving substation.

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[39] 50 POE – implies 50% Probability of Exceedance

7.2.2. Forecast approach

An adjusted historic series, in MVA, is calculated for each substation. This adjusted series has had the effect of transfers being removed. For the majority of substations, around 95%, a linear trend is fit through this series[40]. The regression statistics from this fit are checked including the R squared, which should be greater than 0.5, and the MVA per year added due to trend growth.

The 50 POE forecast is produced using this trend and including the effect of block loads and transfers.

- A decision is made on whether a block load (or group of small block loads) is considered additional to underlying growth or not. Often a block load, such as a residential subdivision, may be considered to overlap with underlying growth in which case the block load is reduced to account for the overlap. For example, if a residential substation with 2 MVA growth per year has a 4 MVA block load subdivision added, the block load may be reduced to 2 MVA. This adjustment is documented when it occurs.
- Block loads are diversified. The diversity factor is based on an analysis of customer type peak day profiles against substation types or even the specific substation peak day profile..
- Transfers include an assumed growth rate based on the growth rate of the sending substation in that year. Transfers are assumed to have a diversity of 1 with both the sending and receiving substation. Transfers do not impact the calculation of the difference between the 10 and 50 POE forecasts.

The trend growth is forecast in MVA. Block loads and transfers are also added back in MVA. This is converted to MW using the average power factor of the most recent 5 years of history. The power factor can be adjusted if new capacitors are to be added.

The approach taken by Western Power of using historic trends and adjusting for block loads and transfers is generally considered by SKM MMA to constitute good industry practice.

7.2.3. Calculation of 10 POE relative to the 50 POE trend

Western Power has utilised a different approach to the typical industry practice for forecasting 10 POE demand.

The 50 POE forecast is based on the linear trend line through the historic data that has been adjusted for block loads and transfers as they occur.

The residuals to the linear trend fit through historical data can be used to calculate the Prediction Interval. The Prediction Interval is a statistical estimate of a range in which a future observation will fall. This is based on a Student T test.

The following formula is used by Western Power to calculate its 10POE forecast. Where the probability of Xn-1 1 falling in a given interval is then:

$$\Pr\left(\overline{X}_n - T_a S_n \sqrt{1+(1/n)} \le X_{n+1} \le \overline{X}_n + T_a S_n \sqrt{1+(1/n)}\right) = p$$

40 If there is three years or less of history for a substation then a manual fit is applied by the forecaster selecting an appropriate growth rate.

where T_a is the $100((1 + p)/2)^{th}$ percentile of Student's t-distribution with $n - 1$ degrees of freedom. Therefore the numbers are the endpoints of a 100p% prediction interval for Xn + 1 is

$$\overline{X}_n \pm T_a S_n \sqrt{1 + (1/n)}$$

Assumptions:

- Distribution of probabilities of exceedance is symmetrical and normal
- Historic data contains the same variability with respect to drivers and coincidence of factors that is likely to occur in the future. These drivers include (but are not limited to) temperature, day of week and time of season.
- 10 POE forecast should incorporate the "risk of uncertainty" e.g. if only a few data points are available then the Prediction Interval is larger.

The difference between 10 and 50 POE demand is calculated as a MW figure, not a ratio or percentage difference. The gap between the 10 and 50 POE forecasts increases gradually over time, though this is a function of increasing prediction uncertainty (variance) as the forecast time point moves away from the data time points, rather than increasing temperature sensitivity as in other approaches to 10 POE forecasting.

The system level 50 POE forecast is derived by summing the substation 50 POE demand at time of system peak forecasts. The 10 POE system forecast is then calculated by adding this 50 POE bottom-up trend and the variance in the linear fit to the system level historical data.

The impact of new transfers or block loads is not taken into account when calculating the gap between 10 and 50 POE. This would only be significant in the case where a large transfer in or out relative to the size of substation occurred.

7.3. Review structure

7.3.1. SKM MMA 2010 Review

SKM MMA reviewed Western Power's MD forecasting methodology and outcomes in 2010. The executive summary of this study is presented in Section 2.3.1 above. In summary, SKM MMA supported the approach and its implementation and made a number of suggestions for further refinement.

7.3.2. 2011 MD Forecast Review

In view of the above review, and the similar forecasting approach taken by Western Power in 2011 the focus of the current review is on:

- Updates and modifications to the methodology since the 2010 SKM MMA study
- Application of the methodology to the most recently available data

Under the first item Western Power has made the following changes:

- Taking explicit account of the impact of photovoltaic (PV) installations on MD
- Revising Block Loads and the way in which they are assessed

- Additional statistical testing of the trend line analyses described in section 7.2.3
- Removing double counting of Cottesloe

WP has also noted the following consequences of incorporating 2011 data in its analysis:

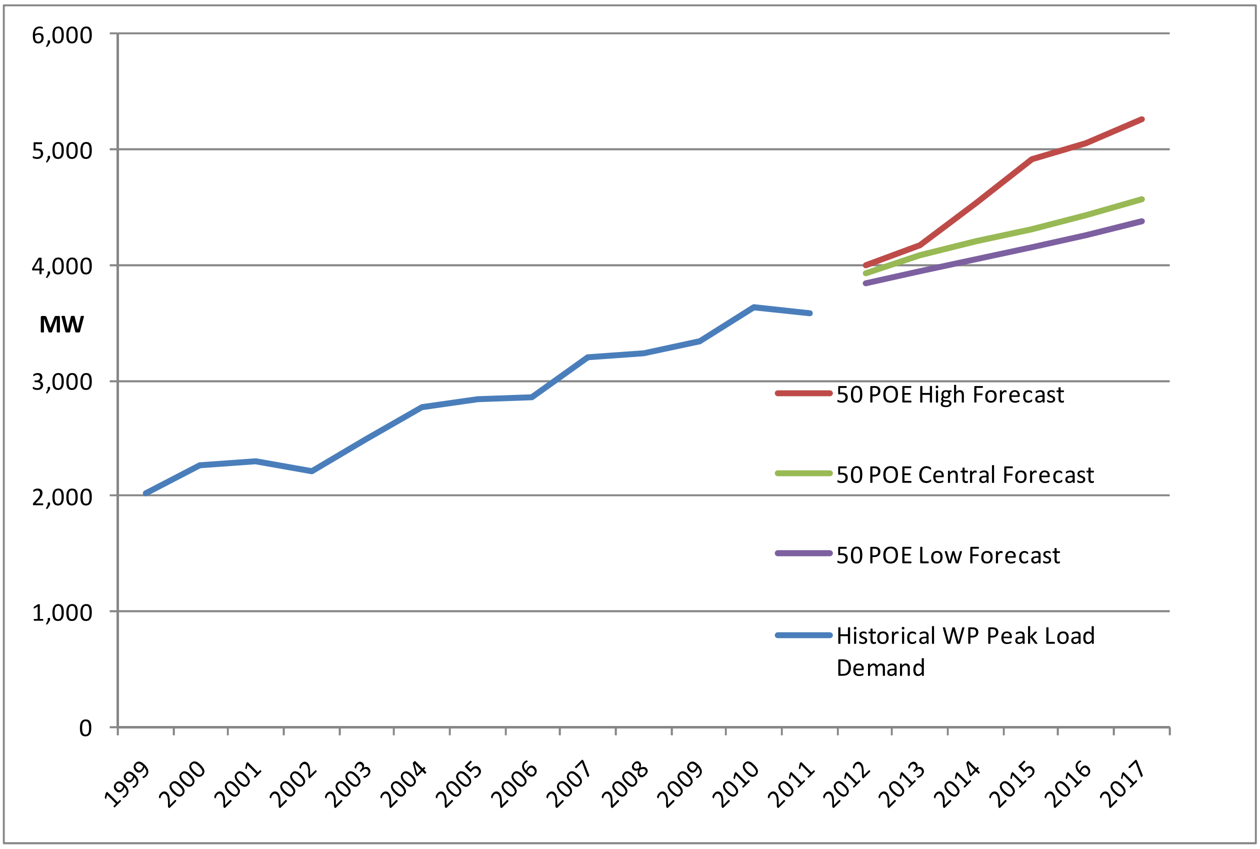
- A change in the MD growth rate (Trending Change)
- Lower initial value in 2012
- Lower POE adjustment (gap between 50 POE and 10 POE)
- Items a), b), c), e), f) and g) are addressed below.

7.4. Summary of Western Power MD forecasts

Figure 7-1 illustrates Western Power's 50 POE MD forecasts prior to adjustment for PVs, based on trend and block load analysis. The differences between High, Central and Low forecasts are accounted for by assumptions regarding major new block loads over 20 MW:

- In the Low forecast here are none
- In the Central forecast there are a small number up to 2014 that are more certain to proceed
- In the High forecast there are a larger number with lower probabilities of proceeding

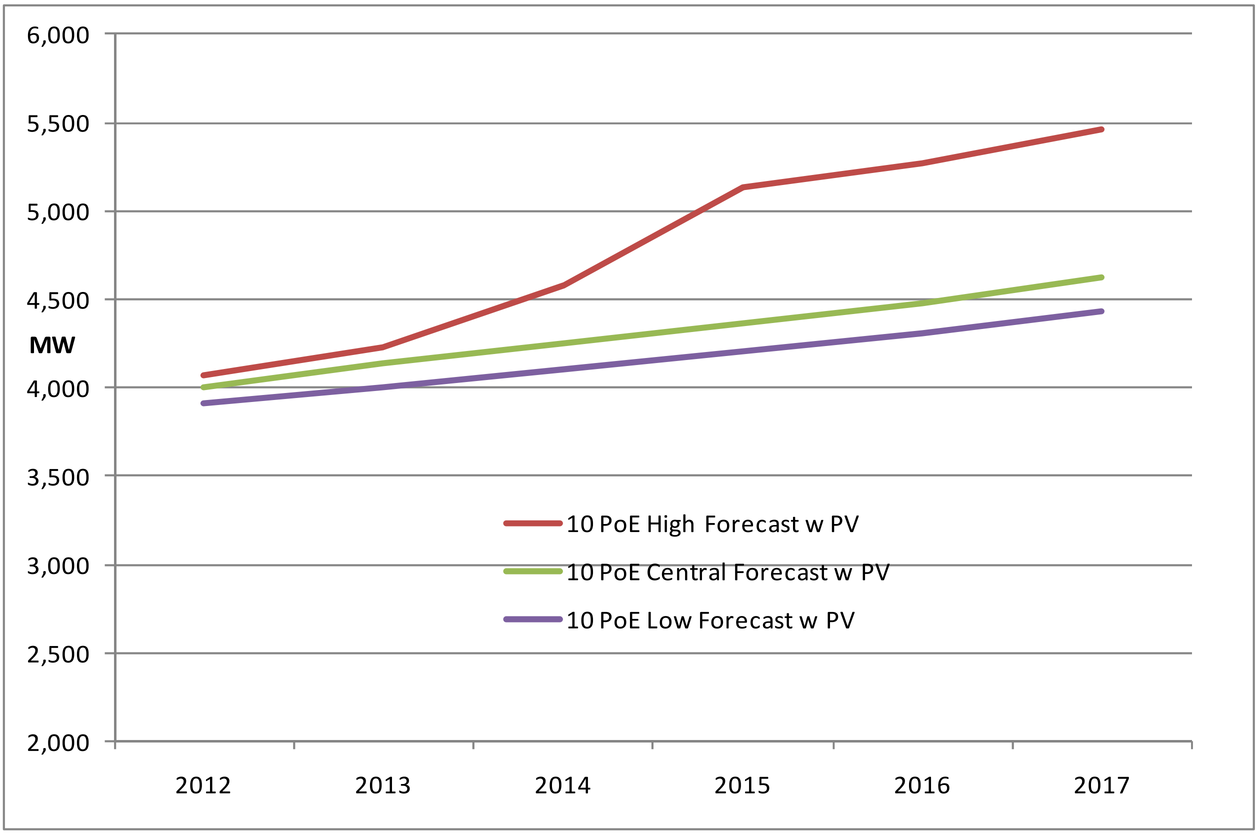
- **Figure 7-1 WP 50 POE forecasts prior to PV adjustment (MW)**



Source: Western Power spreadsheet, WE_n8541739 v2

Figure 7-2 illustrates Western Power's 10 POE forecasts calculated by adding the 10 POE adjustment to, and subtracting the PV adjustment from, the 50 POE figures (the same adjustments in all scenarios). The adjustments are discussed below. Our analyses focus on the Central scenario projections.

- **Figure 7-2 WP 10 POE Forecasts (MW)**



Source: Western Power spreadsheet, WE_n8541739 v2

7.5. Review of changes from 2010 to 2011

7.5.1. Photovoltaic impact

Western Power has prepared estimates of the number of PVs installed in premises connected to its network, their total capacity, energy generation and their impact on peak load[41]. The projected number of PVs and their aggregate capacity are presented in Table 7-1 – they are reasonably similar to the SKM MMA estimates in Table 7-2 and SKM MMA accepts them as fit for purpose for demand forecasting.

[41] Photovoltaic (PV) Forecast, Western Power 20 January 2012.

- **Table 7-1 WP PV Projections (Medium Case)**

	2012	2013	2014	2015	2016	2017
Units	107,414	132,244	157,074	181,904	206,734	231,564
Capacity (MW)	190	243	299	357	414	472

Source: Photovoltaic (PV) Forecast, Western Power 20 January 2012.

- **Table 7-2 SKM MMA PV Projections for the SWIS**

	2012	2013	2014	2015	2016	2017
Units	92,089	124,488	157,189	190,127	220,559	250,551
Capacity (MW)	143	202	263	324	383	443

Source: SKM MMA projections

The PV impact on MD depends on the relationship between the PV generation profile and the timing of peak demand. System peak demand without PVs typically occurs around 5 PM, at which time PVs are typically producing at 30% or less of capacity. This net demand reduction shifts the system peak back to 6 PM, by which time PVs are producing at 20% or less. This is reflected in the peak reduction figures produced in the Western Power report referred to above, reproduced below. However the peak reduction figure used in AA3 is equivalent to approximately 40% of PV capacity in 2012, which seems unrealistic (Table 7-3). We understand the AA3 figures pre-date the report and recommend that they be re-aligned with the report figures.

- **Recommendation 22: The PV peak reduction estimates used in the AA3 forecast should be aligned with the most recently prepared estimates.**

- **Table 7-3 PV Peak reduction estimates (MW)**

	2012	2013	2014	2015	2016	2017
Report	37	46	55	64	73	83
AA3	75	96	112	120	126	133

Source: Photovoltaic (PV) Forecast, Western Power 20 January 2012

We note that the PV peak reduction estimates are subtracted from the pre-adjustment forecasts depicted in Figure 7-1 which is valid provided that there is no PV impact on these forecasts. However this is not the case, since there is a PV impact embedded in the actual peak data over the last few years. Estimates of these PV impacts should be added back to the data prior to performing the analyses that lead to the pre-adjustment forecasts. Our estimates of the impact of this on the forecasts are presented in section 7.5.3.5.

Western Power has prepared the PV estimates on a system-wide basis and has not allocated them to substations. It is important that an allocation be made, so that the substation forecasts are correctly aligned with the system forecast, though we recognise the technical difficulties associated with this, which include different PV impacts on residential, commercial and industrial substations and changes in diversity factor due to changes in the relationships between substation and system peaks. If PV capacity in each substation zone is known, a suitable methodology may be to allocate set percentages of PV capacity in each substation eg 10% in residential and 40% in commercial and industrial, and normalise the result to the system-wide estimate. If substation PV capacity is not known, proportional allocation may be the only alternative. Undertaking this allocation will become more important over time, as PV penetration increases.

- **Recommendation 23: Western Power should allocate PV MD reductions to substations.**

7.5.2. Revising Block Loads

7.5.2.1. Block load criteria framework

Western Power has moved to incorporate a more systematic approach to its block load forecasting and weighting for incorporation in its maximum demand spatial forecasts. According to the information provided in a document[42] describing the updated methodology and the associated spreadsheet[43], the following approach is taken:

- Initially, both the expected load (in MVA) and the diversity factor are assessed. According to Western Power the expected load is often significantly lower than that provided by the proponent and is discounted. An appropriate diversity factor is then applied[44]. We understand that the final assumed load after discount and diversification is documented in the Topaz system.
- The stage of advancement of the project is defined, with a more certain project having a higher weighting than one for which little information is available as shown in Table 7-4.

- **Table 7-4 Summary of Western Power's project and economic criteria for block load analysis**

Factor	Criteria Range following "No Information"	Lowest Weighting	Highest Weighting
Project milestone	Conceptual Plan to Construction start	0%	13%
Project funding	Up to 20% to 100% Project funding	0%	16%
Dependency on other projects proceeding	High dependency, low chance to No dependency	0%	9%
Type of industry	Based on sector beta, varying from 1.4 to 1.1	4%	5%
Revenue stream	Unfavourable to guaranteed	0%	13%
Required in Service, i.e. years before load expected	1 year to 7 years	0%	9%

Western Power subsequently assesses the time it would take to meet internal Western Power requirements, including those related to works, funding and expected time taken or delay for planning and queuing. The two former factors appear to change the likelihood of the block load, while the latter changes only the expected time of implementation.

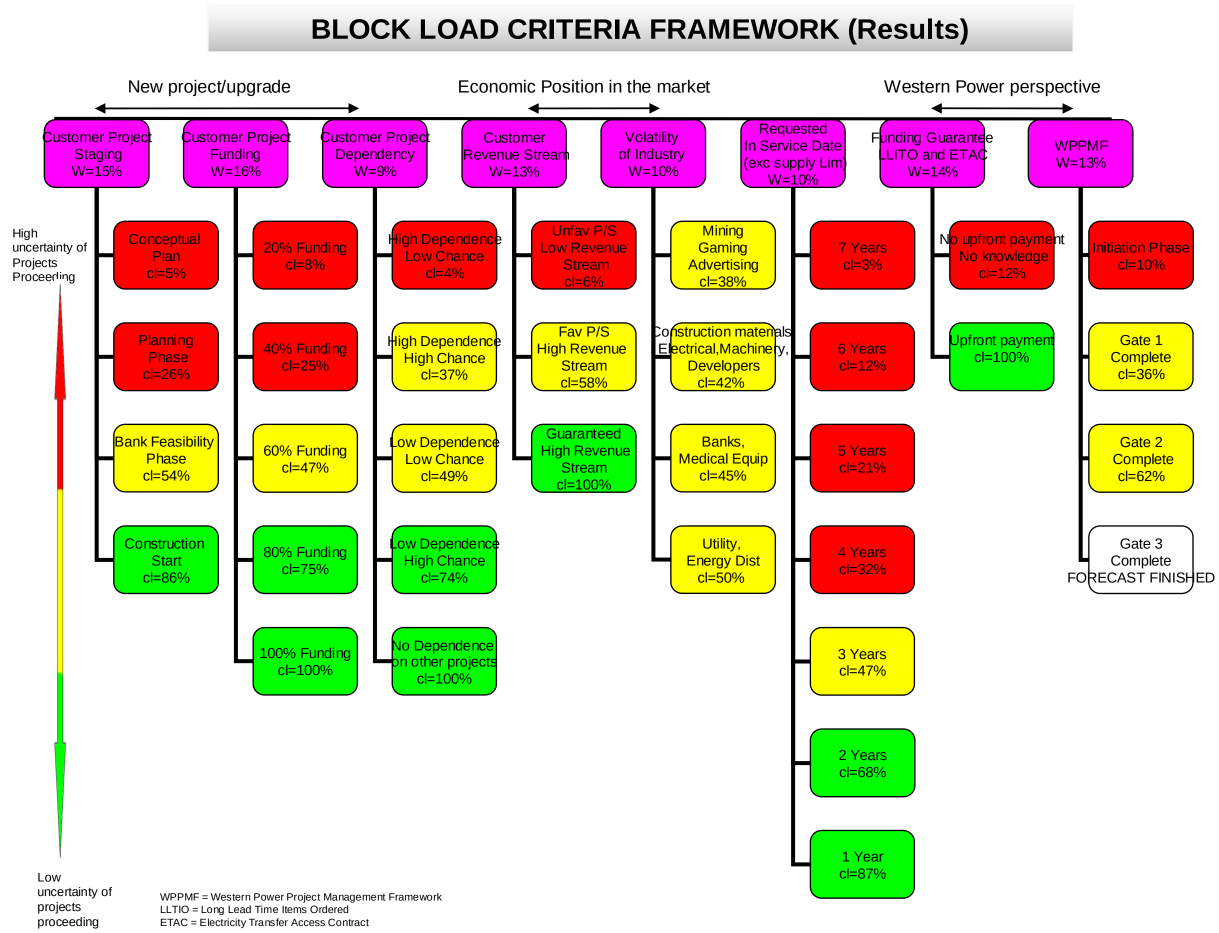
The approach and factor weightings are summarised in Figure 7-3.

42 Copy of WE_n8802499 BlockLoad_FinalShortKEMHv2

43 BLForecastingV1_Example from V1_SC

44 Documentation relating to calculation of diversity factors includes Copy of WE_n7375622_v2_Determination_of_diversity_factors_for_new_loads_on_the_SWIS and Copy of WE_n8944535_ v1_Determination_of_diversity_factors_for_ industrial _and_ mining _customers as well as spreadsheet Copy of WE_n7370268_v1a_Template_for_diversity_factor.

- **Figure 7-3 Western Power's block load criteria framework**



Source: Western Power Copy of WE_N8816684_V1_AppendiciesBLCPaperDM8813497.xls

Loads which have summed probability weightings from 0 to 32.9% are allocated to the High case, those which have weightings of 33% to 66% are allocated to the Central case and those with above 66% are allocated to the Low case (i.e. very likely to proceed). We understand that the loads allocated to each case are the proposed diversified loads rather than the probabilities multiplied by the diversified loads.

7.5.2.2. Assessment of the block load criteria framework

While utilities almost invariably include some block loads separately in forecasts, the methodology for inclusion varies. In some cases block loads are included according to the size and timing information proposed by the proponent. This often results in an optimistic assessment of the project eventuating, actual size of load and timing. In other cases, block loads are included according to a subjective assessment of the probability of the load and start date, with the basis of the judgement made being unclear.

We generally consider it good practice to systematise and objectify the block load decision making criteria as has been done by Western Power. In most cases the project-related criteria and the weightings selected appear reasonable and to reflect the level of uncertainty associated with projects eventuating[45].

Five areas of uncertainty remain:

- What the initial loads and diversity factors applied to the block load are. It has been documented by Western Power that the loads requested by industrial and mining proponents at an early stage are, on average, some 67% higher than the eventual loads although the difference shrinks significantly within a year of commencement.46 This suggests that the load requested at an early stage needs, in most cases, to be significantly discounted. In addition, the load needs to be diversified at the feeder, substation and system level, as appropriate, as described in a Western Power document47. It is unclear at this stage how the discounting and diversity factors have actually been applied.
- Whether the ranges selected are appropriate to each level of forecast. While this is difficult to ascertain without analysis of actual outcomes. After experimenting with the example spreadsheet provided by Western Power, we initially consider that the inclusion within the Central case of any outcomes lying between 33% and 66% probability appears reasonable if the intention is to estimate the probability of the load at between 33% and 66%. However, it is not clear that the Central case has in the past actually included projects which have as low a probability as 33%. A probability of 33% could, for example, be attached to projects which are only at the planning phase but expected to start within two years, are less than half funded, have low dependency and an expected favourable revenue stream. While we certainly do not discount the possibility of such projects having a reasonable chance of proceeding, we understand that these would not have been included within the Central case in the past.
- In order to operate effectively, such a framework needs to have suitable guidelines to use and users taught in its operations. Unless these exist, the users are likely to still make relatively arbitrary judgements.
- Whether the framework adequately handles timing issues. For example, the only delays built into the system appear to be those related to how long Western Power delays the project. However, our experience has been that projects are almost inevitably delayed beyond their expected completion date. This has also been the experience of Western Power48 – with delays of one to two years being common.
- Whether the load specified is to be included as a block load or as part of normal or organic growth. Western Power applies the principle that only discrete loads of a material size are included as block loads and then only if the block loads are of a size greater than organic growth. While we consider this to be a reasonable approach given available information, we would prefer a more structured approach in this regard.49
- Western Power will need to ensure that these uncertainties are minimised over time.

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45 We do have some minor quibbles, for example, the industry volatility component results in an outcome of between 4% or 5%, regardless of industry, not really reflecting any difference in industry volatility.

46 Copy of WE_n8944535_ v1_Determination_of_diversity_factors_for_ industrial _and_ mining _customers page 5.

47 Copy of WE_n7375622_v2_Determination_of_diversity_factors_for_new_loads_on_the_SWIS.

48 Copy of WE_n7375622_v2_Determination_of_diversity_factors_for_new_loads_on_the_SWIS page 32.

49 Western Power has stated that it generally does not have the block load history available to utilise the SKM MMA preferred approach: to historically subtract block loads over a threshold size from history when calculating growth and then add them and additional block loads over the threshold size back into forecasts.

7.5.2.3. Conclusions and recommendations

We consider the application of an objective block load criteria to be a step forward in the Western Power forecasting methodology and consistent with good forecasting practice in this area elsewhere. At first sight the screening criteria and weightings applied appear reasonable. However, in order to ensure that this is the case, Western Power will need to ensure that the framework is fully understood and used as intended and validate the framework methodology (and associated diversity factors applied) over time and refine these as required.

We recommend that Western Power:

- Establish clear guidelines in the use of the framework and provides training in its use
- Ensures that proper factors are applied by users of the framework to both discount initial load proposed (as appropriate) and to apply appropriate diversity at feeder, substation and system levels
- Maintain a register of each block load evaluated against the criteria, including the load and diversity factor assessed, screening outcomes and expected project start recorded at the time and track these against the eventual outcomes of block loads. Only by tracking these assessments can the actual results of the framework in evaluating block loads be evaluated and the framework refined if required.
- Maintain a register of historical block loads over a threshold size.

- **Recommendation 24 : Western Power should carefully guide and monitor the application of its new block load criteria framework and maintain a register to allow the accuracy of forecasts resulting from its use to be assessed over time.**

7.5.3. Additional statistical testing

SKM MMA's only material reservation about Western Power's MD forecasting methodology, expressed in the 2010 report, is that the trend analysis used to estimate the 10 POE correction assumes that the historical data has a constant variance. In our 2010 report we tested the system-wide data for changes in variance (heteroskedasticity) in the historical data but the tests were inconclusive. We recommended that Western Power test for heteroskedasticity in its future applications of the 10 POE / 50 POE gap methodology.

For the 2011 forecast, Western Power has therefore introduced a number of statistical tests in addition to the correlation tests already used. These tests are:

- Cook's distance – a test for outliers
- Durbin-Watson – a test for autocorrelation
- Whites test – a test for heteroskedasticity

Western Power has also employed HAC (Heteroskedasticity and Autocorrelation Consistent) regression methods and compared the 10 POE results with the Ordinary Least Squares approach.

Western Power has provided SKM MMA with sample output of the test results and HAC/OLS comparisons from four substations. The test results are negative for heteroskedasticity and the HAC and OLS 10 POE projections differ by less than 0.6% up to 2017. This supports continued use of the current methodology.

7.5.3.1. Changes due to the addition of 2011 data

To determine whether the scale of the impacts of the 2011 data reported by Western Power are reasonable, SKM MMA has estimated 10% and 50% POE MD projections for the system as a whole using data from 1999 to 2010 and from 1999 to 2011, using the same methodology as Western Power uses at the substation level, and compared them with Western Power's estimates of system total impacts. The SKM MMA projections are presented in Table 7-5. All values are prior to PV adjustment and there is no adjustment for new block loads.

- **Table 7-5 SKM MMA estimates of system MDs (MW)**

	2012	2013	2014	2015	2016	2017
50 POE 2010 data	3,817	3,958	4,098	4,239	4,379	4,520
50 POE 2011 data	3,788	3,925	4,063	4,200	4,337	4,475
10 POE 2010 data	3,985	4,131	4,279	4,426	4,575	4,723
10 POE 2011 data	3,944	4,086	4,229	4,372	4,515	4,659

Source: SKM MMA estimates

7.5.3.2. Change in the MD growth rate (Trending Change)

Western Power has noted that "Due to the lower 2011 peak load demand the overall underlying peak growth on the SWIS network has decreased by 3 MW per year". The SKM MMA estimates tabled above yield decreases in growth of 3.2 MW for 50 POE and 4.7 MW for 10 POE (Table 7-6), confirming the Western Power estimate.

- **Table 7-6 SKM MMA estimates of average MD growth (MW)**

	2010 data	2011 data	Decrease
Average 50 POE growth	140.5	137.4	3.2
Average 10 POE growth	147.4	142.7	4.7

Source: SKM MMA estimates

7.5.3.3. Lower initial value in 2012

WP reports a forecast reduction of 81 MW in 2012 due to the low system peak in 2011. This is in part due to the substations with weak trends, for which the starting point of the forecast is set at the current year's value rather than a trend value and consequently varies significantly from year to year. This reduction is not evident in the trend based SKM MMA estimates, which show reductions of 29 MW and 31 MW in the 2012 50 POE and 10 POE MDs respectively. Western Power is developing a methodology to improve the forecasting of these substations but has not provided details.

- **Recommendation 25: Western Power should implement an improved methodology for forecasting maximum demand in substations with weak trends as soon as practicable.**

7.5.3.4. Lower POE adjustment (gap between 10 POE and 50 POE)

The 2011 data has led to a reduction in the POE adjustment between 50 POE and 10 POE estimates, compared to the 2010 forecast. SKM MMA and Western Power estimates of this change are strongly aligned (Table 7-7). However we do not agree with Western Power's assertion that this occurs automatically – it is in part due to the low variance in the 2011 actual MD and if a higher variance MD had occurred, e.g. 3,500 MW instead of 3,581 MW, the POE adjustment gap would not have reduced.

- **Table 7-7 SKM MMA and Western Power estimates of changes to the POE adjustment**

	2012	2013	2014	2015	2016	2017
10 - 50 POE 2010 data	167	174	180	187	195	203
10 - 50 POE 2011 data	156	161	166	172	178	184
Reduction	11	13	14	16	17	19
WP estimate	9	10	12	13	15	16

7.5.3.5. Treatment of PV reduction in historical data

As noted in section 7.5.1, PVs almost certainly reduced the actual MD in 2011 and possibly in earlier years. To avoid double counting it is necessary to add back the PV contribution before undertaking the trend analyses and then subtracting the PV forecast. SKM MMA has estimated the impact of doing this by increasing the actual 2011 MD by 38 MW, which is consistent with the PV penetration in 2011 and with the PV MD reductions used in AA3 (Table 7-3), and then re-estimating the projections.

The results, shown in Table 7-8, show an increase of 12 MW in 50 POE in 2012, growing to 18 MW in 2017, and an increase of 9 MW in 10 POE in 2012, growing to 14 MW in 2017. The POE adjustment is reduced because the adjusted 2011 MD value has lower variance than the original. Although these impacts are marginal, they will grow in future forecasts and should be taken into account.

- **Recommendation 26: Western Power should adjust historical MDs upwards for the estimated PV impacts. Allocation to substations should be consistent with the allocation of system PV forecasts to substations**

- **Table 7-8 Impact of PV adjustment of 2011 data**

	2012	2013	2014	2015	2016	2017
50 POE 2011 data	3,788	3,925	4,063	4,200	4,337	4,475
50 POE PV adjusted	3,800	3,938	4,077	4,215	4,354	4,493
10 POE 2011 data	3,944	4,086	4,229	4,372	4,515	4,659
10 POE PV adjusted	3,953	4,096	4,240	4,384	4,528	4,673

7.6. Comparison with IMO 2011 Forecasts

The Independent Market Operator (IMO) publishes forecasts of sent out energy and maximum demand in its annual Statement of Opportunities (SOO) report. The forecasts are prepared by the National Institute for Economic and Industrial Research (NIEIR) using an econometric model plus separate consideration of large block loads. MD forecasts are based on weather sensitivity modelling, with different POE levels related directly to the relevant POE temperature conditions. SKM MMA's 2010 report to Western Power explored the differences between this approach to MD forecasting and Western Power's statistical variance approach and concluded that NIEIR overstated the 10-50 POE gap, possibly because it had overestimated the temperature sensitivity of load at high temperatures.

IMO's 2011 SOO expected scenario 10 POE and 50 POE MD forecasts are presented in Table 7-9.

- **Table 7-9 IMO 2011 SOO Expected scenario MD forecasts (MW)**

	2012	2013	2014	2015	2016	2017
10 POE	4,458	4,635	4,802	5,219	5,448	5,625
50 POE	4,181	4,340	4,487	4,889	5,104	5,264

To compare the forecasts to Western Power's central scenario forecasts it is necessary to allow for losses which are reflected in the differences between historical sent out values (IMO) and demand (Western Power). MD losses appear to be quite volatile, ranging between 4.5% and 10.4% (Table 7-10) - this may reflect real changes in losses due to changing supply-demand patterns or network efficiency, but may also reflect artificial factors such as timing differences between sent out and demand peaks. For the purpose of comparing IMO and Western Power forecasts we have assumed losses of 6.5%, which equals the 2011 value and the 11-year average but which is higher than the most recent 5-year average of 4.8%.

- **Table 7-10 Historical MD's (MW)**

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Sent out	2538	2473	2721	3004	3055	3008	3364	3392	3515	3766	3831
Demand	2299	2216	2491	2760	2834	2856	3201	3238	3342	3639	3581
Losses	239	257	230	244	221	152	163	154	173	127	250
Loss %	9.4%	10.4%	8.5%	8.1%	7.2%	5.0%	4.8%	4.5%	4.9%	3.4%	6.5%

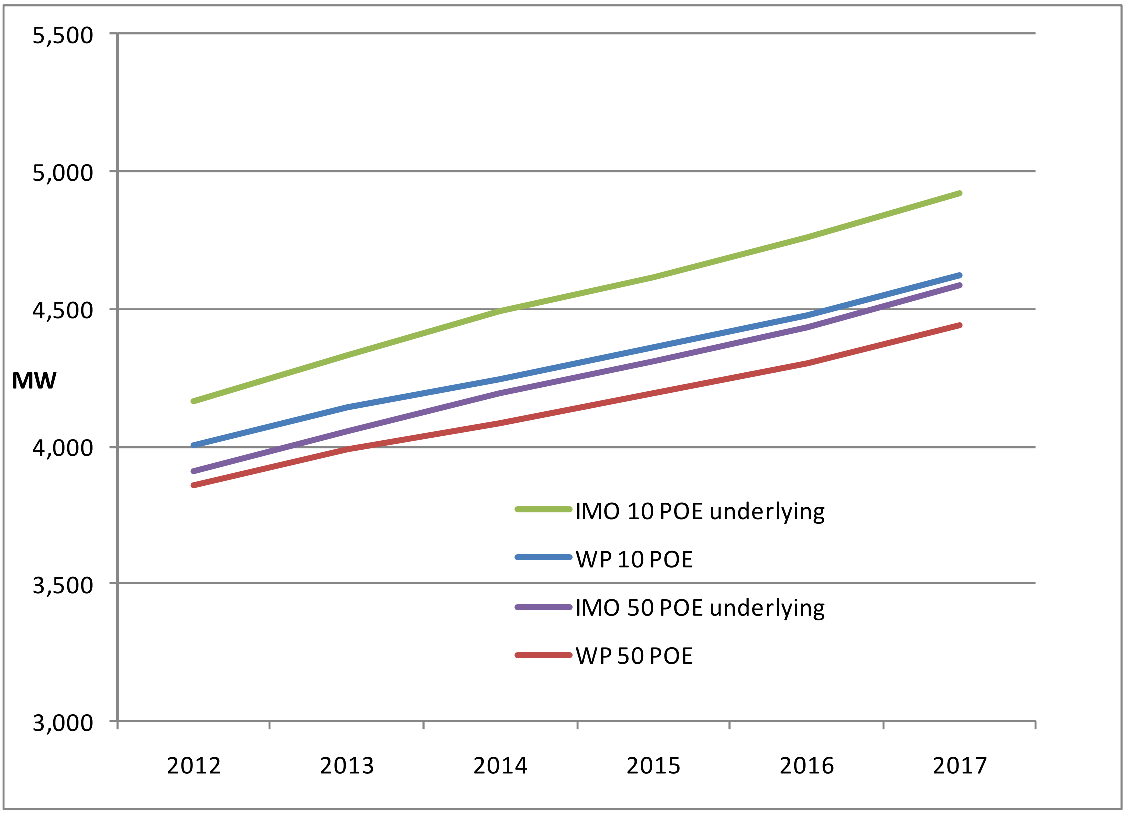
To compare underlying trends in the forecast it is also necessary to align assumptions regarding major block loads. The IMO expected scenario assumes significant new block loads from the Mid West energy project from 2015, which Western Power only includes in its high scenario. We have therefore subtracted these from the IMO projections (260 MW in 2015 and 335 MW in 2016 and 2017). The resulting "underlying" IMO MD projections are compared with the Western Power projections in Figure 7-4 and they are clearly similar, with differences ranging from 50 to 150 MW (3% by 2017 with IMO being higher) for 50 POE and 150 to 300 MW (7% by 2017 with IMO being higher) for 10 POE. If the IMO projections were also adjusted for PV impact, the 50 POE projections would be almost identical – it appears that the IMO projections are not adjusted for PV impact but this is not stated explicitly in the SOO report.

The 10-50 POE gap is considerably larger in the 2011 IMO forecasts than in the 2011 Western Power forecasts, as would be expected from the 2010 forecasts. However we note with interest that the IMO gap is 130-160 MW less than it was in the 2010 forecast.

- **Table 7-11 Comparison of IMO and Western Power 10-50 POE gaps (MW)**

	2012	2013	2014	2015	2016	2017
IMO (after losses)	259	276	294	308	322	337
WP	151	155	160	166	172	178

■ **Figure 7-4 IMO and Western Power expected scenario MD forecast comparison**



Appendix A Model evaluations

To verify energy and customer number forecasts, SKM MMA undertook to replicate the models contained in Western Power's (WP's) system forecasting document titled, "*Energy Forecast 11/12 – 16/17, Energy & Customer Numbers, October 2011*". Subsequently, a series of tests were applied to investigate if possible improvements could be achieved by using parameters that SKM MMA regards as more conducive to energy forecasting.

Whilst every effort has been made to analyse the models in reasonable detail, due to the limited time in which these studies were to be completed, tests were prioritised to address those areas that SKM MMA regarded as important to the forecasting methodology. Data used in replicating the models were supplied by Western Power, however, they were not verified against any independent and credible source. Therefore, results presented below are bound to any inherent discrepancies contained in the data supplied. This was the case with for temperature data which contained missing values in some early years.

A.1 Methodology

Table A-1 shows the list of network tariff whose energy forecast models were validated. The "Alternatives" column indicates where alternative data and/or SKM MMA parameters were substituted to model and compare alternative approaches.

- **Table A-1 Modelled network tariffs**

Tariff	Description	Tested	Alternatives
RT1	Anytime Energy (Residential) Exit Service	✓	✓
RT2	Anytime Energy (Business) Exit Service	✓	✓
RT3	Time of Use Energy (Residential) Exit Service	✓	✓
RT4	Time of Use Energy (Business) Exit Service	✓	✓
RT5	High Voltage Metered Demand Exit Service	✓	✓
RT6	Low Voltage Metered Demand Exit Service	✓	✓
RT7	High Voltage Contract Maximum Demand Exit Service	✓	✓
RT8	Low Voltage Contract Maximum Demand Exit Service	✓	✓
RT9	Street lighting Exit Service	✓	×
RT10	Un-Metered Supplies Exit Service	✓	×
RT11	Distribution Entry Service	×	×
RT12	Time of Use (Residential) Bidirectional Service	×	×
TRT1	Transmission Exit Service	×	×
TRT2	Transmission Entry Service	×	×

Steps taken to replicate the models are as follows:

- setup independent and dependent variables in EXCEL using supplied historical data
- replicate regression model using WP's parameters in EXCEL using the LINEST function
- use regression coefficients to backcast and forecast energy

- calculate residuals (backcast – actual)
- derived energy forecast totals for financial years 2011-12 to 2016-17
- derived a total energy forecasted over the period 2011-12 to 2016-17

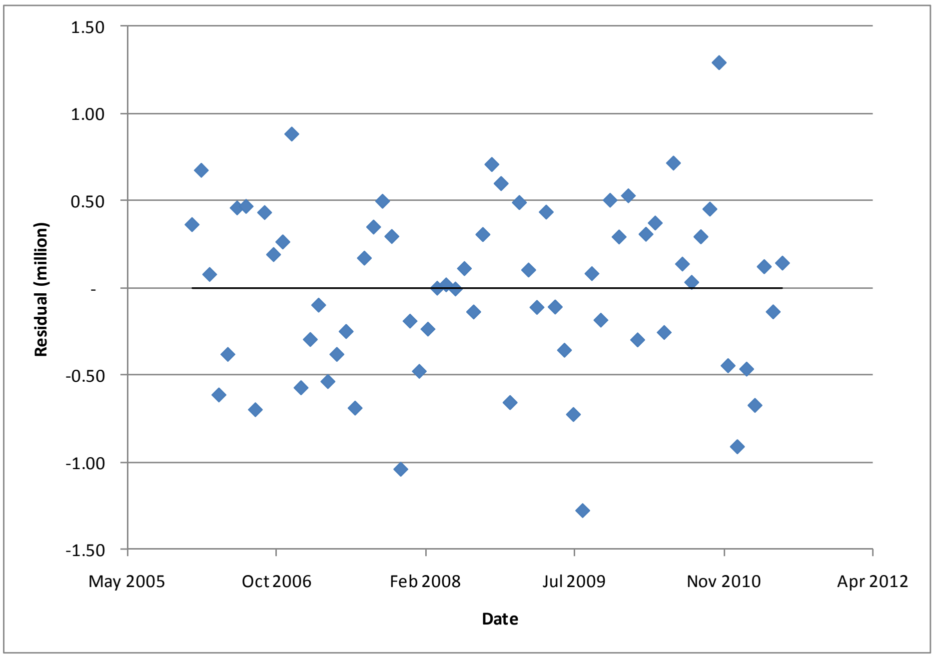
Steps taken to verify the models are as follows:

- compare residuals for reasonable even spread around or close to zero. Figure A-1 and Figure A-2 show the residuals for RT1 and RT2 respectively
- for tariffs RT1 and RT2, the net residual for all historical years by months were calculated to understand the models performance. Figure A-3 shows that the RT1 model on average understates August forecast and overstates September to November. For RT2, the residuals are larger in the months December to March (Figure A-4). Improvements to the model should look add reducing the differences
- annual forecast figures were also compared for a selection of tariff. The difference between the forecast numbers from WP's replicated model and WP's published numbers are summarised in the results section
- the coefficient of determination (R^2) from the regression was compared against WP's R^2 value. This is summarised in the results section
- the significance of input parameters to the regression model was evaluated using t-stat of 2. That is an input parameter was considered as not having any material impact to the model outcome if its t-stat was below "2"

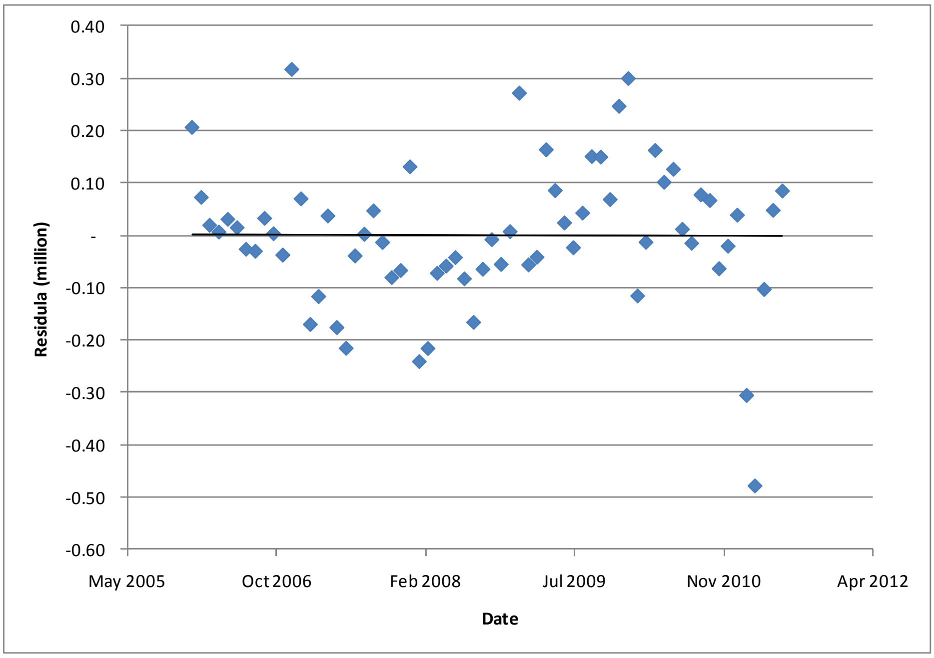
In addition to the model replication, alternative data to those used by WP were tested. The changes to the data include:

- use of the BOM temperature data captured at Perth Airport instead of the WP composite temperature. WP's model used a composite temperature that includes data measured at East Perth from January 2007 and onwards. Data prior to this was determined as a proxy using determined by calculating an average of the ratios between Perth Airport and East Perth data for the period January 2007 to March 2011, then multiplied by Perth Airport data prior to January 2007
- use of historical real prices determined by CPI instead of the 2.75% index used by WP. Future CPI was indexed by 2.75%. An alternative case used 3% CPI for 2011/12 and 3.25% for future years as per government budget papers
- use of 2010-11 GSP instead of the 2009-10 GSP used by WP

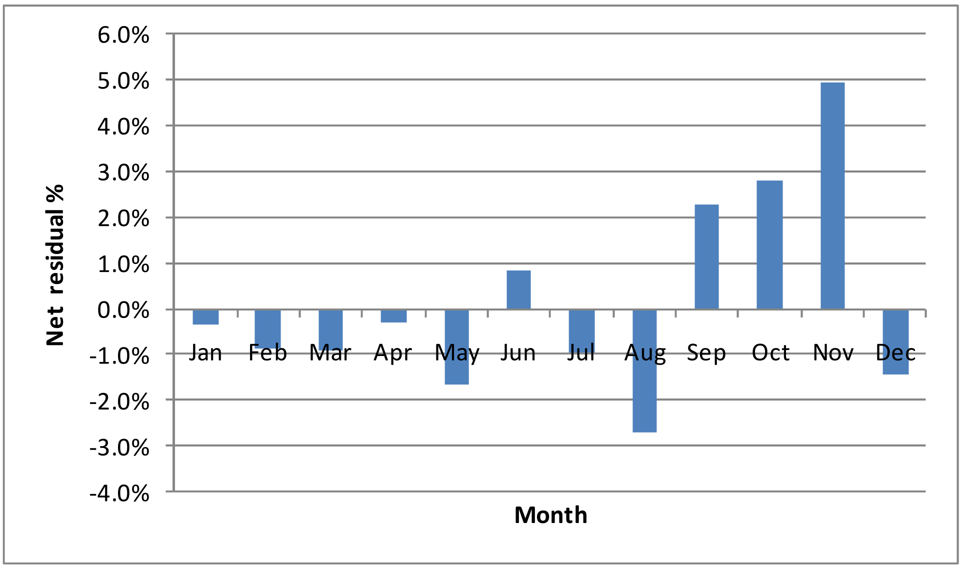
▪ Figure A-1 Residuals for tariff RT1



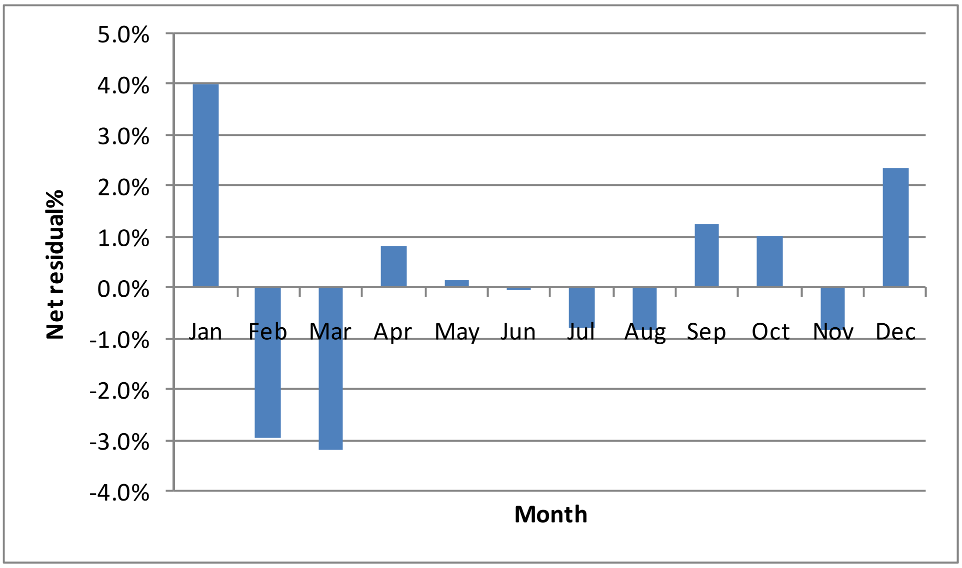
▪ Figure A-2 Residuals for tariff RT2



- **Figure A-3 Monthly net residual for tariff RT1 (% difference relative to actual)**



- **Figure A-4 Monthly net residual for tariff RT2 (% difference relative to actual)**



Further tests attempted to introduce and replace WPs input parameters with SKM MMA's suggestions. These parameters include:

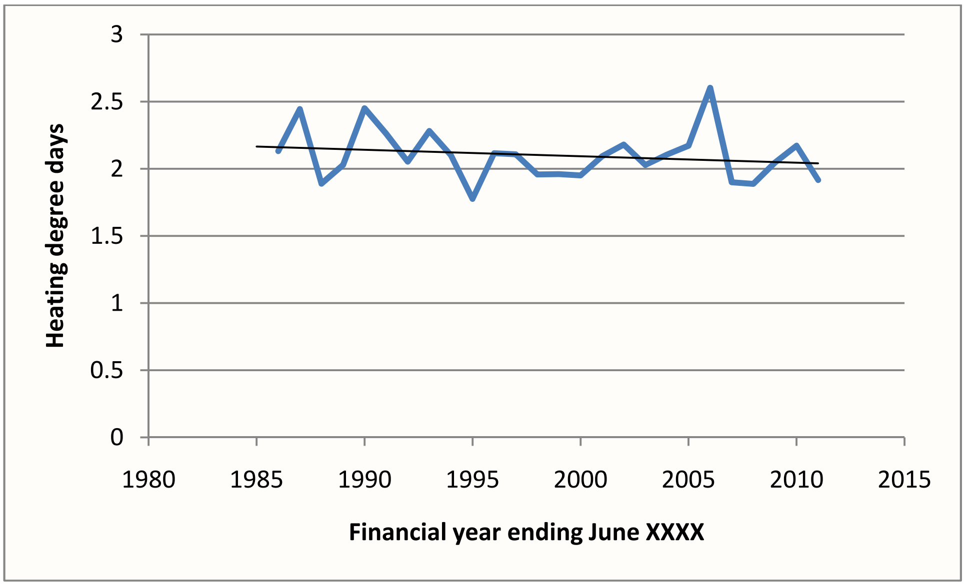
- replacing monthly temperature data (T) and T^2 with monthly values for Heating Degree Days (HDD) and Cooling Degree Days (CDD) (Table A-2). Although this is recommended, HDD and CDD values could not be used due to missing data in some years.
- To overcome the missing data, HDD and CDD values were divided by the number of data points per month in the repective year to get HDD/day and CDD/day. Figure A-5 and Figure A-6 shows the trends for HDD/day and CDD/day respectively. These were used to backcast the models.
- To forecast, monthly values for HDD/day and CDD/day were derived by averaging the historical HDD/day and CDD/day data for each month in a year.

- GSP/Capita was used in the alternative models for residential tariffs (RT1 and RT3).

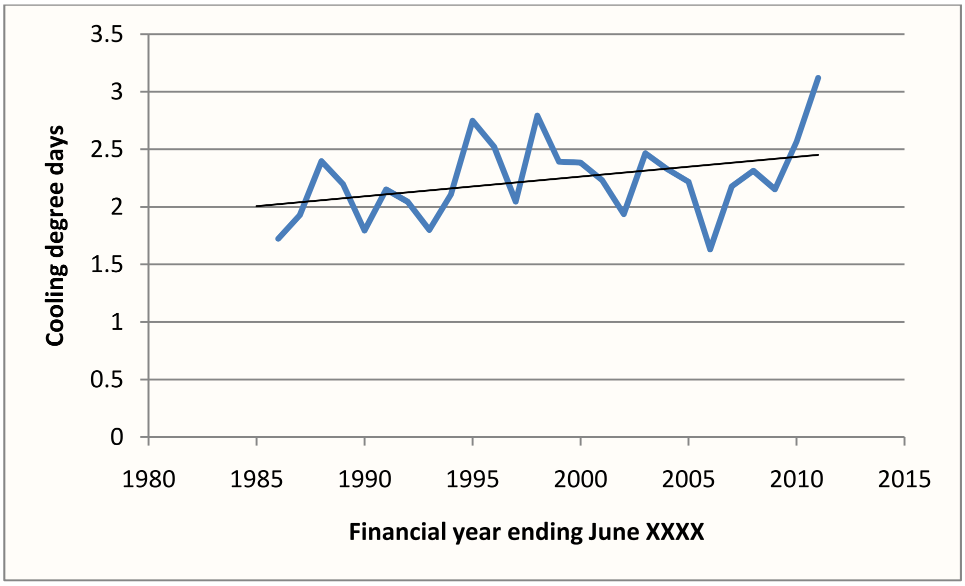
- **Table A-2 Heating and cooling degree days**

Financial year	HDD	CDD	HDD/day	CDD/day
1986	778	629	2.13	1.72
1987	892	704	2.44	1.93
1988	691	877	1.89	2.40
1989	740	802	2.03	2.20
1990	895	655	2.45	1.79
1991	823	783	2.26	2.15
1992	751	748	2.05	2.04
1993	828	653	2.28	1.80
1994	767	769	2.10	2.11
1995	609	942	1.78	2.75
1996	366	436	2.12	2.52
1997	413	401	2.11	2.04
1998	595	849	1.96	2.79
1999	715	873	1.96	2.39
2000	714	872	1.95	2.38
2001	764	814	2.09	2.23
2002	792	703	2.18	1.94
2003	740	900	2.03	2.47
2004	771	852	2.11	2.33
2005	793	810	2.17	2.22
2006	950	595	2.60	1.63
2007	693	795	1.90	2.18
2008	691	847	1.89	2.31
2009	747	785	2.05	2.15
2010	793	937	2.17	2.57
2011	699	1,139	1.92	3.12

▪ **Figure A-5 Trend of heating degree days**



▪ **Figure A-6 Trend of cooling degree days**



A.2 Results

This section provides a summary of the tests that were carried out. The modelling summary for is presented using three tables for each of the tariffs that were tested. The first table summarises the model parameters for all test scenarios conducted for that tariff. Ticks "✓" and crosses "×" in the table indicate where a parameter has been included in the test. If a parameter has different sources, then ticks and crosses have been replaced by notation as summarised in Table A-3.

Table A-3 Definition of terms

Parameter	Term	Description
Method	WP	Western Power's approach
	SKM	SKM MMA's sensitivities
Consumption	Daily	Average daily energy consumption (WP's data – actual)
	Ave Daily	Average daily energy consumption per customer (WP's data – actual)
Temp.	Composite	Temperature data from January 2007 measured at East Perth. Prior data derived by averaging the temperature ratios between East Perth and Perth Airport between January 2007 and March 2011 then, multiplying average ratio to BOM data to derive values prior to January 2007.
	BOM	Bureau of Meteorology data measured at Perth Airport
	CDDpd	Cooling degree-days divide by number of data points per month per year based on BOM data. This is used instead of CDD to overcome missing data points.
	HDDpd	Heating degree-days divide by number of data points per month per year based on BOM data. This is used instead of HDD to overcome missing data points.
Price Index	2.75%	WP's approach to converting nominal prices in to real
	CPI	SKM MMA's approach converting nominal prices to real using CPI index relative to January 2011. Future CPI using 2.75%
	CPI325	SKM MMA's approach converting nominal prices to real using CPI index relative to January 2011. Future CPI using 3.25%
	Ln	Natural log applied to the underlying price.
	L1b1	Alternative business price constructed using **Band 1** of ***Small*** *business tariff (non-contestable)* using CPI indexation
	L1b2	Alternative business price constructed using **Band 2** of ***Small*** *business tariff (non-contestable)* using CPI indexation
	S1	Alternative business price constructed using ***Large*** *business* ***low-*** *voltage tariff (non-contestable)* using CPI indexation
	T1	Alternative business price constructed using ***Large*** *business* ***high-*** *voltage tariff (non-contestable)* using CPI indexation
GSP	Early	Gross State Product as per 2009-10 update
	Late	Gross State Product as per 2010-11 update. Future GSP using 4.5% for
	/ Capita	Per Capita - Gross State Product divide by population
PV		Photovoltaic include in model
Dummy		Set to 1 for winter months – defined as May to October. Used with prices to model price impacts during winter months

The second table presents total energy consumption over the financial years from 2011-12 to 2016-17 and the coefficient of determination (R^2) value for the energy forecast. Where appropriate the R^2 value for customer numbers is also included. WP's model used daily consumption as the dependent variable in their model. In some of the tests SKM MMA used average daily consumption per customer as the dependent variable. In order to derive energy value, the backcasted or forecasted average daily consumption per customer had to be multiplied by backcasted-forecasted customer numbers. Therefore, a regression analysis and for customer numbers was also carried out.

The third table presents the significance of the inputs modelled in the regression. Inputs are considered as significant if the absolute value of its corresponding t-Stat is greater than two. The table uses filled circle "●" to imply the parameter was significant to the model. Unfilled circles "○"denote parameters do not make a significant impact to the model whilst "●○" and "●●○" indicate the t-Stat was around 1.5 and just below 2, respectively.

The following sections present the summary results. Highlight rows are SKM MMA's suggested approach.

A.2.1 RT1

- **Table A-4 Test inclusions**

Test No.	Method	Consumption	Temp.	Price Index	GSP	PV	Dummy
1	WP	Daily	Composite	2.75%	Early	✓	✓
2	WP	Daily	BOM	2.75%	Early	✓	✓
3	WP	Daily	CDDpd, HDDpd	2.75%	Early	✓	✓
4	WP	Daily	CDDpd, HDDpd	CPI	Early	✓	✓
5	SKM	Daily	CDDpd, HDDpd	CPI	Early/Capita	✓	✓
6	SKM	Daily	CDDpd, HDDpd	CPI	Early/Capita	✓	×
7	SKM	Ave Daily	CDDpd, HDDpd	CPI	Early/Capita	✓	✓
8	SKM	Ave Daily	CDDpd, HDDpd	CPI	Early/Capita	✓	×
9	SKM	Ave Daily	CDDpd, HDDpd	CPI	Early/Capita	×	✓
10	SKM	Ave Daily	CDDpd, HDDpd	CPI	Early/Capita	×	×
11	WP	Daily	Composite	2.75%	Late	✓	✓
12	SKM	Ave Daily	CDDpd, HDDpd	CPI	Late	✓	×
13	SKM	Ave Daily	CDDpd, HDDpd	CPI	Late	×	×
14	SKM	Ave Daily	CDDpd, HDDpd	CPI	Late/Capita	✓	×
15	SKM	Ave Daily	CDDpd, HDDpd	CPI	Late/Capita	×	×
16	SKM	Daily	CDDpd, HDDpd	CPI	Late/Capita	✓	×
17	SKM	Daily	CDDpd, HDDpd	CPI	Late/Capita	×	×
18	SKM	Daily	CDDpd, HDDpd	CPI325	Late/Capita	✓	✓
19	SKM	Daily	CDDpd, HDDpd	CPI325	Late/Capita	×	✓
20	SKM	Ave Daily	CDDpd, HDDpd	CPI325	Late/Capita	✓	✓
21	SKM	Ave Daily	CDDpd, HDDpd	CPI325	Late/Capita	×	✓

Table A-5 R-squared and projected energy

Test No.	R^2 – Consumption	R^2 - Customer number	$\sum_{yr=2012}^{2017} ProjectedEnergy(yr)$
1	0.88		32602.52
2	0.91		32204.92
3	0.89		33172.63
4	0.89		33549.27
5	0.88		33132.30
6	0.89		34147.93
7	0.84	0.99	33363.52
8	0.84	0.99	34394.07
9	0.84	0.99	34672.87
10	0.84	0.99	34347.96
11	0.89		33233.56
12	0.84	0.99	34343.54
13	0.84	0.99	34347.96
14	0.84	0.99	34696.36
15	0.84	0.99	34147.11
16	0.88		35563.17
17	0.88		34881.48
18	0.88		35098.86
19	0.88		35183.05
20	0.84	0.99	33845.54
21	0.84	0.99	34647.51

Table A-6 Significance of variable using t-Test

Test No.	Temp.	$Temp.^2$	HDD	CDD	Price Dummy	Dummy	GSP	GSP / Capita	PV
1	●	●			●	●	●		●
2	●	●			●	●	●		○
3			●	●	●	●	●		○
4			●	●	●	●	●		○
5			●	●	●	●		●	○
6			●	●	●			●	○
7			●	●	●	●		●	○
8			●	●	●			●	○
9			●	●	●	●		●	
10			●	●	●	●		●	
11	●	●			●	●	●		○
12			●	●	●			●	○
13			●	●	●			●	
14			●	●	●			●	○
15			●	●	●			●	

Test No.	Temp.	Temp.^{2}	HDD	CDD	Price Dummy	Dummy	GSP	GSP / Capita	PV
16			●	●	●●○			●	○
17			●	●	●			●	
18			●	●	●●○			●	○
19			●	●	●	●		●	
20			●	●	●			●	○
21			●	●	●	●		●	

A.2.2 RT2

- **Table A-7 Test inclusions**

Test No.	Method	Consumption	Temp.	Price Index	GSP
1	WP	Daily	Composite	2.75%	Early
2	SKM	Daily	CDDpd, HDDpd	CPI	Late
3	SKM	Daily	CDDpd, HDDpd	CPI	Ln, Late
4	SKM	Daily	CDDpd, HDDpd	Ln, CPI	Late
5	SKM	Daily	CDDpd, HDDpd	Ln, CPI	Ln, Late
6	SKM	Daily	CDDpd, HDDpd	L1b1, CPI	Late
7	SKM	Daily	CDDpd, HDDpd	L1b1, CPI325	Late

- **Table A-8 R-squared and projected energy**

Test No.	R^2 – Consumption	$\sum_{yr=20122017} \mathit{ProjectedEnergy}(yr$
1	0.83	10081.43
2	0.87	9826.22
3	0.87	9657.04
4	0.87	9942.81
5	0.87	9762.66
6	0.87	9821.56
7	0.87	9858.34

- **Table A-9 Significance of variable using t-Test**

Test No.	Temp.	Temp.^{2}	HDD	CDD	Price	Ln(Price)	GSP	Ln(GSP)
1	●	●			●		●	
2			●	●	●		●	
3			●	●	●			●
4			●	●		●	●	
5			●	●		●		●
6			●	●	●		●	
7			●	●	●		●	

A.2.3 RT3

- **Table A-10 Test inclusions**

Test No.	Method	Consumption	Temp.	Price Index	GSP	Dummy
1	WP	Daily	Composite	2.75%	Early	✓
2	SKM	Ave Daily	CDDpd, HDDpd	CPI	Late/Capita	×

- **Table A-11 R-squared and projected energy**

Test No.	R^2 – Consumption	R^2 - Customer number	$\sum_{yr=2012}^{2017} ProjectedEnergy(yr)$
1	0.78		1220.5450
2	0.71	0.97	1198.92

- **Table A-12 Significance of variable using t-Test**

Test No.	Temp.	$Temp.^2$	HDD	CDD	Price Dummy	Dummy	GSP	GSP / Capita
1	●	●			●	●	●	
2			●	●	○●			○

A.2.4 RT4

- **Table A-13 Test inclusions**

Test No.	Method	Consumption	Temp.	Price Index	GSP
1	WP	Daily	Composite	2.75%	Early
2	SKM	Daily	CDDpd, HDDpd	CPI	Late
3	SKM	Daily	CDDpd, HDDpd	CPI	Ln, Late
4	SKM	Daily	CDDpd, HDDpd	Ln, CPI	Late
5	SKM	Daily	CDDpd, HDDpd	Ln, CPI	Ln, Late
6	SKM	Daily	CDDpd	CPI	Late
7	SKM	Daily	CDDpd	Ln, CPI	Ln, Late
8	SKM	Daily	CDDpd, HDDpd	L1b1, CPI	Late
9	SKM	Daily	CDDpd	L1b1, CPI325	Late

50 2012 projection does not align with report value

- **Table A-14 R-squared and projected energy**

Test No.	R^2 – Consumption	$\sum_{yr=2012}^{2017} ProjectedEnergy(yr)$
1	0.74	11601.46
2	0.79	11045.88
3	0.79	10887.18
4	0.80	11505.13
5	0.80	11337.94
6	0.78	10983.43
7	0.80	11284.20
8	0.79	11027.26
9	0.78	11115.10

- **Table A-15 Significance of variable using t-Test**

Test No.	Temp.	$Temp.^2$	HDD	CDD	Price	Ln (Price)	GSP	Ln(GSP)
1	○	●			●		●	
2			○	●	●		●	
3			○	●	●			●
4			○	●		●	●	
5			○	●		●		●
6				●	●		●	
7				●		●		●
8			○	●	●		●	
9				●	●		●	

A.2.5 RT5

- **Table A-16 Test inclusions**

Test No.	Method	Consumption	Temp.	Price Index	GSP
1	WP	Daily	Composite	×	Early
2	SKM	Daily	CDDpd, HDDpd	CPI	Late
3	SKM	Daily	CDDpd	CPI	Late
4	SKM	Daily	CDDpd, HDDpd	T1 - CPI	Late
5	SKM	Daily	CDDpd	T1 - CPI	Late
6	SKM	Daily	CDDpd	T1, CPI325	Late

Table A-17 R-squared and projected energy

Test No.	R^2 – Consumption	$\sum_{yr=2012}^{2017} ProjectedEnergy(yr)$
1	0.81[51]	2576.93
2	0.84	2625.06
3	0.84	2615.13
4	0.82	2479.14
5	0.81	2479.61
6	0.81	2476.26

Table A-18 Significance of variable using t-Test

Test No.	Temp.	HDD	CDD	Price	GSP
1	●				●
2		○	●	●	●
3			●	●	●
4		○	●	○	●
5			●	○	●
6			●	○	●

A.2.6 RT6

Table A-19 Test inclusions

Test No.	Method	Consumption	Temp.	Price Index	GSP
1	WP	Daily	Composite	2.75%	Early
2	SKM	Daily	CDDpd, HDDpd	CPI	Late
3	SKM	Daily	CDDpd	CPI	Late
4	SKM	Daily	CDDpd, HDDpd	S1, CPI	Late
5	SKM	Daily	CDDpd	S1, CPI	Late
6	SKM	Daily	CDDpd	L1B2, CPI325	Late

51 Could not reproduce results

■ **Table A-20 R-squared and projected energy**

Test No.	R^2 – Consumption	$\sum_{yr=2012}^{2017} ProjectedEnergy(yr)$
1	0.95	8693.70
2	0.97	8539.17
3	0.97	8539.10
4	0.96	8797.59
5	0.96	8797.65
6	0.97	8547.74

■ **Table A-21 Significance of variable using t-Test**

Test No.	Temp.	$Temp.^2$	HDD	CDD	Price	GSP
1	●	●			●	●
2			○	●	●	●
3				●	●	●
4			○	●	○●	●
5				●	○●	●
6				●	●	●

A.2.7 RT7

■ **Table A-22 Test inclusions**

Test No.	Method	Consumption	Temp.	Price Index	GSP
1	WP	Daily	Composite	×	Early
2	SKM	Daily	CDDpd, HDDpd	CPI	Late
3	SKM	Daily	CDDpd, HDDpd	T1 - CPI	Late
4	SKM	Daily	CDDpd, HDDpd	×	Late
5	SKM	Daily	CDDpd, HDDpd	T1, CPI325	Late

■ **Table A-23 R-squared and projected energy**

Test No.	R^2 – Consumption	$\sum_{yr=2012}^{2017} ProjectedEnergy(yr)$
1	0.78	19214.43
2	0.81	19069.06
3	0.80	18725.56
4	0.80	18936.99
5	0.81	19030.70

- **Table A-24 Significance of variable using t-Test**

Test No.	Temp.	HDD	CDD	Price	GSP
1	●				●
2		●	●	●	●
3		●	●	○	○●
4		●	●		●
5		●	●	●	●

A.2.8 RT8

- **Table A-25 Test inclusions**

Test No.	Method	Consumption	Temp.	Price Index	GSP	Index
1	WP	Daily	Composite	×	×	✓
2	SKM	Daily	CDDpd, HDDpd	CPI	Late	×
3	SKM	Daily	CDDpd, HDDpd	S1 - CPI	Late	×
4	SKM	Daily	CDDpd, HDDpd	×	Late	×
5	SKM	Daily	CDDpd	×	Late	×

- **Table A-26 R-squared and projected energy**

Test No.	R^2 – Consumption	$\sum_{yr=2012}^{2017} ProjectedEnergy(yr)$
1	0.62	1413.61
2	0.71	1427.62
3	0.69	1386.73
4	0.68	1373.50
5	0.66	1368.15

- **Table A-27 Significance of variable using t-Test**

Test No.	Temp.	Index	HDD	CDD	Price	GSP
1	●	●			●	●
2			●	●	●	●
3			○●	●	○	○
4			○●●	●		●
5				●		●

A.2.9 RT9, RT10

- **Table A-28 Test inclusions**

Test No.	Method	Consumption	GSP
RT9	WP	Daily	Early
RT10	WP	Daily	Early

- **Table A-29 R-squared and projected energy**

Test No.	R^2 – Consumption	$\sum_{yr=2012}^{2017} ProjectedEnergy(yr)$
RT9	0.00[52]	669.83
RT10	0.25[53]	210.25

[52] Could not reproduce results
[53] Could not reproduce results

A.3 Summary and recommendation

- **Table A-30 Results summary**

Tariff	Forecast Energy[54]	Regressed Forecast[55]	RegressionReplicated [56]	Forecast Replicated[57]	Recommended Parameter changes	Other possible changes	Indicative change (%)[58]
RT1	33124	32603	✓	×	CPI[59], BOM[60], CDD[61], HDD, Remove PV[62] GSP/Capita, GSP[63]	Customers verses population, average daily per customer	6.2%
RT2	10081	10081	✓	✓	CPI, BOM, CDD, HDD, GSP		-2.2%
RT3	1457	1221	✓	×	As per RT1		
RT4	11599	11601	✓	✓	As per RT2, L1b1[64]		-4.2%
RT5	2689	2577	×	×	CPI, BOM, CDD, GSP	Prefer use of T1 prices but it is not significant in the model	-2.7%
RT6	8694	8694	✓	✓	CPI, BOM, CDD, GSP, S1[65], L1b2		-1.7%
RT7	19214	19214	✓	✓	CPI, BOM, CDD, HDD, GSP		-1.0%
RT8	1415	1414	✓	✓	CPI, BOM, CDD, HDD		0.9%
RT9	773	670	×	×			
RT10	208	210	×	×			

54 Total over 2011-12 to 2016/17 as per forecasting document

55 Total over 2011-12 to 2016/17 as per replicated forecast

56 Does the R^2 and coefficients match with those published in Energy and Custmer number forecast document.

57 Does the sum of energy forecasts (replicated using regression), for the period 2011/12 to 2016/17, match with those in the WP's Energy and Customer number forecast document over the same period. Where regression parameters have been replicated, differences may be explained by new block loads that were not added in the replicated model.

58 Percentage change in energy forecast under the recommended option relative to the published forecast

59 Index price by CPI and use budget figure of 3.5% for future periods

60 Use Perth Airport temperature data

61 Use CDD and HDD or alternatively CDD per day and HDD per day if complete temperature data is not available. Per day is a count of the days where data is available. It equals to days in month when no data is missing

62 Remove PV if using CDD and HDD. PV is significant when T and T^2 are used

63 Update to more recent GSP

64 L1b1 = L1 prices constructed using band 1 rates; L1b2 = L1 prices constructed using band 2 rates

65 Try S1 prices

For more information please contact:

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Appendix E. Cost sharing methodology with System Management Markets

This document is not available for public release and has been supplied separately as confidential supplementary information and forms a part of this submission.

Appendix F. Escalation Reports

F.1 CEG - Updated labour and materials escalation factors

F.2 Macromonitor – Updated forecasts of Labour Costs – Electricity, Gas, Water and Waste Services Sector – Western Australia

Updated labour and materials escalation factors

A report for Western Power

May 2012

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Executive Summary

1. CEG has been commissioned by Western Power to provide an expert report updating the material and labour escalators that we previously estimated[1]for Western Power's capital and operational expenditures for the revised access arrangement for the AA3 period.

2. This report re-estimates cost escalators for the same inputs as provided in our previous report – ie, labour costs, aluminium, copper, zinc, steel and crude oil. The Economic Regulation Authority (ERA) has raised objections to our use of average weekly ordinary time earnings (AWOTE) as an input into our labour cost escalators, preferring forecasts based on the wage price index (WPI). We continue to believe that AWOTE is the correct basis upon which to escalate Western Power's forecast expenditures. Otherwise, the ERA has not objected to the methodology that we proposed. Therefore, the methodology that we have utilised to estimate these escalation factors is identical to that used previously, except where we specifically say otherwise.

3. CEG's estimates of Western Power's escalation factors are set out in Table 1 below. For completeness, we show labour escalators calculated both using AWOTE and WPI forecasts. However, we recommend the use of AWOTE.

Table 1: Escalation factors for Western Power, real

Financial year	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Aluminium	-13.0%	2.6%	5.3%	3.9%	2.9%	2.5%
Copper	-10.4%	1.3%	0.4%	-1.5%	-3.4%	-3.9%
Zinc	-14.9%	1.0%	1.9%	2.8%	4.1%	3.6%
Crude oil	2.6%	7.6%	-2.2%	-3.4%	-2.4%	-1.5%
Steel	-6.8%	-4.0%	3.5%	1.8%	0.3%	-0.1%
Labour - AWOTE	2.2%	1.6%	2.9%	3.6%	3.1%	3.1%
Labour - WPI	2.2%	1.6%	1.8%	2.3%	2.0%	2.0%

4. The above estimates do not include the impact of the Commonwealth Government's carbon price on the cost of inputs. While carbon dioxide is used in the production of many of the inputs for which we have forecast prices[2] our forecasts are based on the

[1] See CEG, *Escalation factors: A report for Western Power*, September 2011

[2] With the exception of labour costs, carbon dioxide, in the form of energy used, is an input into all of the inputs we have forecast. For the absence of doubt, it is useful to note that while the nominal forecasts are unaffected by the carbon tax the forecast real input costs are lower due to the carbon tax impact on CPI (noting that we have used a carbon tax inclusive CPI forecast sourced from the RBA). However, the nature of the regulatory framework is that the same carbon tax inclusive CPI will be used to index Western Power's revenues. Therefore, the net effect on the nominal compensation received by Western Power will be zero (ie, higher forecast CPI inclusive of carbon tax reduces forecast real input costs but higher actual CPI inclusive of carbon tax is used to index Western Power's compensation with the net impact 'a wash'). More

expected level of the internationally traded price of those forecasts (expressed in US dollars and converted to Australian dollars using foreign currency futures prices). It is reasonable to assume that the Australian carbon price will not materially influence globally determined commodity prices.

5. Any compensation to Western Power for the effect of the carbon price on its cost inputs would need to be above and beyond the forecasts in this report.

generally, this illustrates why it is the case that indexing Western Power's revenues to the carbon tax inclusive CPI does not provide any compensation to Western Power for the cost of the carbon tax on its inputs. All that indexing by the carbon tax inclusive CPI does is to 'give back' compensation that has already been removed in anticipation of it being given back via indexation.

1. Introduction

6. Western Power has engaged CEG to provide updated annual escalation factors for its operating and capital expenditure programs. The terms of reference for this engagement are set out at Appendix A.

7. The motivation for and the principles behind the estimation of escalation factors have been comprehensively set out in our earlier report for Western Power.[3] The focus of this update report is to:

- respond to ERA commentary in its draft decision on CEG's escalation factors;
- document new data that has been relied upon to update these escalation factors and to explain any changes in methodology since our previous report; and
- show the differences between the escalation factors previously estimated and our new estimates.

8. Guidelines for Expert Witnesses in Proceedings in the Federal Court of Australia" dated 5 May 2008.We have reviewed those guidelines and our report has been prepared consistently with the form of expert evidence required by those guidelines.

9. This report has been prepared by Dr Tom Hird, a Director of CEG and based in its Melbourne office. Dr Hird has been assisted in the preparation of this report by Daniel Young and Johanna Hansson, both economists in CEG's Sydney office. Curricula vitae are set out atAppendix Bto this report.

10. In preparing this report, we have made all the inquiries that we believe are desirable and appropriate and no matters of significance that we regard as relevant have, to ourknowledge, been withheld.

[3] See CEG, *Escalation factors: A report for Western Power*, September 2011, particularly section 2.

2. Forecasts of labour cost inputs

11. In order to update our labour escalation factors, CEG has commissioned forecasts from Macromonitor for the growth of labour costs in the EGW sector in Western Australia.

12. We continue to use actual salary increases paid by Western Power and thereafter salary increases outlined in the Western Power + CEPU Union Collective Agreement 2008, which operates until 1 October 2013.[4] The ERA has similarly adopted this methodology.

13. However, the ERA has rejected our use of labour escalation factors based on Macromonitor's AWOTE labour cost forecasts, instead preferring escalation factors based on Macromonitor's WPI forecasts. In making this argument, the ERA relies upon:

    - recent decisions by the AER, in which it preferred a WPI measure over AWOTE; and
    - the ERA's view that Western Power should not be compensated for compositional changes in its labour force.[5]

14. Our previous report set out in detail reasons as to why the use of AWOTE forecasts to estimate labour cost escalation factors is appropriate and consistent with the underlying objects being escalated.[6] The ERA has not responded directly to any of the issues that were raised in that report.

15. In the following subsections we respond to the reasons raised by the ERA in support of its preference for WPI over AWOTE to estimate labour cost escalation factors.

2.1. AER's preference for WPI/LPI measures

16. The AER has expressed a preference for use of the forecasts based on the labour price index (LPI) to escalate labour costs. The AER reasoning for using LPI rests on the assumption that any increase in total labour costs resulting from promoting existing employees or employing more highly skilled workers is automatically offset by reductions in the number of employees needed. This is a form of 'task based'

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[4] Western Power + The Communications, Electrical, Electronic, Energy, Information, Postal, Pluming and Allied Services Union of Australia, Western Power + CEPU Union Collective Agreement 2008.

[5] ERA, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, 29 March 2012, p. 83

[6] CEG, *Escalation factors: A report for Western Power*, September 2011, section 3

productivity – where a smaller number of more skilled workers are able to perform the same tasks as a larger number of less skilled workers.

17. The AER's reasoning will only be valid if the reason that businesses are promoting/hiring more skilled workers is because they are able to displace workers who are less skilled. In reality, firms may engage in training/hiring a more skilled workforce for reasons other than displacing less skilled workers.

18. For example, technological change in the industry may mean that more skilled workers are required to operate equipment. The benefits of this need not be reflected in fewer less skilled labour resources being needed but might be reflected in lower expenditure on capital equipment or simply in increases in the quality of output (eg, the safety and reliability of the network).

19. A business may also be pushed by market forces to promote existing staff in order to retain them in a tight labour market. That is, higher wages associated with a promotion need not reflect the promoted employees' ability to displace less skilled staff, but will often simply reflect labour market realities about the external employment options those employees have. Similarly, the increased wages paid when hiring employees at a higher job classification need not reflect the fact that the hired workers can displace more workers at lower job classifications – it may simply reflect the fact that market forces are pushing firms to recruit at higher job classifications because the number/quality of applicants at lower job classifications is low.

20. In this regard we note that at the time of writing Western Australia's unemployment rate as estimated by the Australian Bureau of Statistics stands at the historically low level of 3.8%. This is also the lowest rate in Australia and much lower than the national average of 4.9% which itself is historically low. This low unemployment rate is achieved despite Western Australia having the highest workforce participation rate (68.9% versus 65.2%). It is clear that the employment market in Western Australia is very tight. In these circumstances it is, in our opinion, certain that much of the difference between AWOTE and WPI growth will reflect these demand factors rather than higher productivity associated with the industry workforce.

2.2. ERA's preference for WPI/LPI measures

21. The ERA's own reasoning for WPI over AWOTE rests on its assertion that:[7]

> *"if current labour costs are deemed to be efficient then Western Power should only be compensated for forecast changes in the price of that labour and should not be distorted with the addition of compositional changes."*

22. In effect, the ERA is saying that it can accept that the current composition of Western Power's workforce is efficient, but that future changes to this composition that result in

7 ERA, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, 29 March 2012, p. 83

higher wages must reflect inefficiencies. The ERA does not set out any reasons in support of this assertion. At section 2.1 above we suggest at least two reasons why a change in the composition of a workforce that leads to higher wage costs will be efficient.

2.3. Efficiency adjustments

23. The ERA has decided that it would be reasonable to set an efficiency target of 2% per year on Western Power's operating expenditure.

24. The ERA's choice of WPI in preference to AWOTE means that it has already forecast that Western Power will achieve labour cost efficiencies in the order of 1% per year by constraining the compositional change of its workforce to a level below that of the industry in general without affecting output. The ERA should be aware of this when assessing the reasonableness of any additional assumed efficiency growth.

25. That is, the 1% per year higher (than WPI) rate of growth of AWOTE is a real higher rate of growth in per worker costs for the industry. By adopting WPI the ERA is effectively assuming that Western Power can offset this by employing 1% fewer workers per year. By imposing a further efficiency adjustment of 2% per yearon Western Power's operating expenditure, it is in essence assuming that Western Power can achieve at least 3%per year efficiencies on its labour inputs.[8]

2.4. Labour cost escalation factors

26. Transitioning from modelling wage increases based on actual data, as occurring once a year, to an index based on quarterly changes in wages can result in a biased estimate of wages escalation. That is, we are transitioning from an index that measures actual wage-setting processes, where Western Power pays its employees four quarters of wage increases 'up front', to a stylised framework that assumes it can spread these increases out over a year. Under such a transition, even if the actual wage outcomes and the wages forecasts are perfectly consistent, escalation factors may be underestimated. Our previous report contains a full discussion of the nature of this problem and the solutions that CEG has applied to resolve this bias.[9]

27. Table 2 below shows the financial year escalation factors that we calculate using this methodology on Macromonitor's updated forecasts of AWOTE and WPI. For reference, we compare this to our previous forecast, based on AWOTE only.

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8 In CEG's view, the assumption may amount to considerably more than 3% per year since it is likely impractical to consider that significant efficiencies can be made in respect of materials inputs.

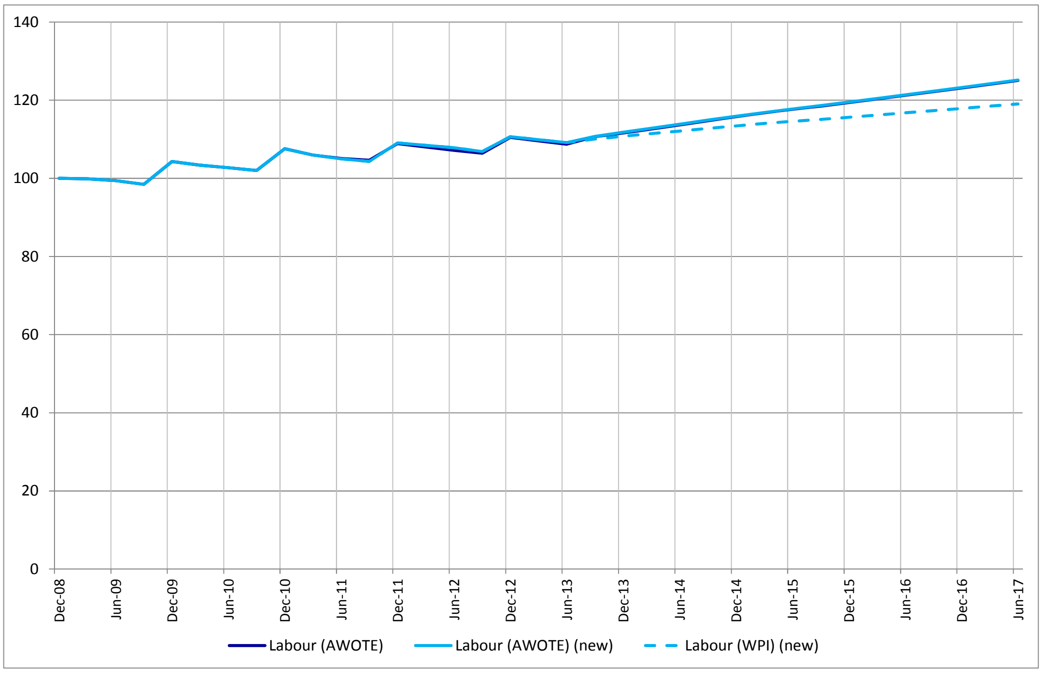
9 CEG, *Escalation factors: A report for Western Power*, September 2011, Appendix A

Table 2: Escalation factors for labour components, real

Financial year	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
AWOTE (updated)	2.2%	1.6%	2.9%	3.6%	3.1%	3.1%
WPI (updated)	2.2%	1.6%	1.8%	2.3%	2.0%	2.0%
AWOTE (previous)	1.9%	1.5%	3.1%	3.7%	3.1%	3.1%

28. Figure 1shows the price trend implied by the updated escalation factors for labour, against the escalation factors predicted in our previous report. Note that Figure 1 illustrates quarterly changes in labour costs, as opposed to the equivalent figure in our previous report which showed annual changes.

Figure 1: Indexed price levels for labour components



December 2008 = 100
Source: Western Power, Macromonitor, CEG analysis

3. Forecasts of material cost inputs

29. In respect of materials, the ERA did not raise any issues with the robustness or accuracy of the escalation factors estimated by CEG. However, in supporting its reasons for preferring zero real escalation on materials, the ERA notes that:[10]

> *…the forecast additional cost due to the materials escalation factors, in real dollar terms, is quite a small amount in the context of the total expenditure for the third access arrangement period.*

30. In our view, the ERA needs to be careful in making its assessment of what is a "small amount". Substituting an estimate of zero real escalation in place of escalation factors that have been robustly and accurately estimated is likely to give rise to bias. As we stated in our previous report:[11]

> *…we note the distinction between precision and accuracy. Although [there] is considerable imprecision in predicting the future, this is not a reason to estimate escalation factors that are artificially biased upward or downward, even if this bias is relatively small.*

31. We note that the AER continues to rely on materials escalators calculated on the same basis as presented in both this report and our previous report for Western Power.

32. The remainder of this section sets out the considerations that are relevant to the update of the material cost escalators for Western Power's expenditure programs.

3.1. Aluminium, copper and zinc

33. In respect of aluminium, copper and zinc, a detailed discussion of the methodology used to derive escalation factors is available in our previous report for Western Power.[12]

34. In order to update these escalation factors, we have sourced updated historical and futures prices from the London Metals Exchange (LME) for the month of March 2012. We have also used updated Consensus forecasts.[13]

[10] ERA, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, 29 March 2012, p. 83

[11] CEG, *Escalation factors: A report for Western Power*, September 2011, p. 17

[12] Ibid, pp. 22-25

[13] Consensus Economics, *Energy & Metals Consensus Forecasts,* April 16, 2012.

35. The latest Consensus forecasts now supply long-term forecasts in nominal (as well as real) terms. We have adopted the nominal forecasts, consistent with our use of nominal futures rates and our view of Consensus forecasts as being specific industry forecasts rather than expert forecasts of US inflation.

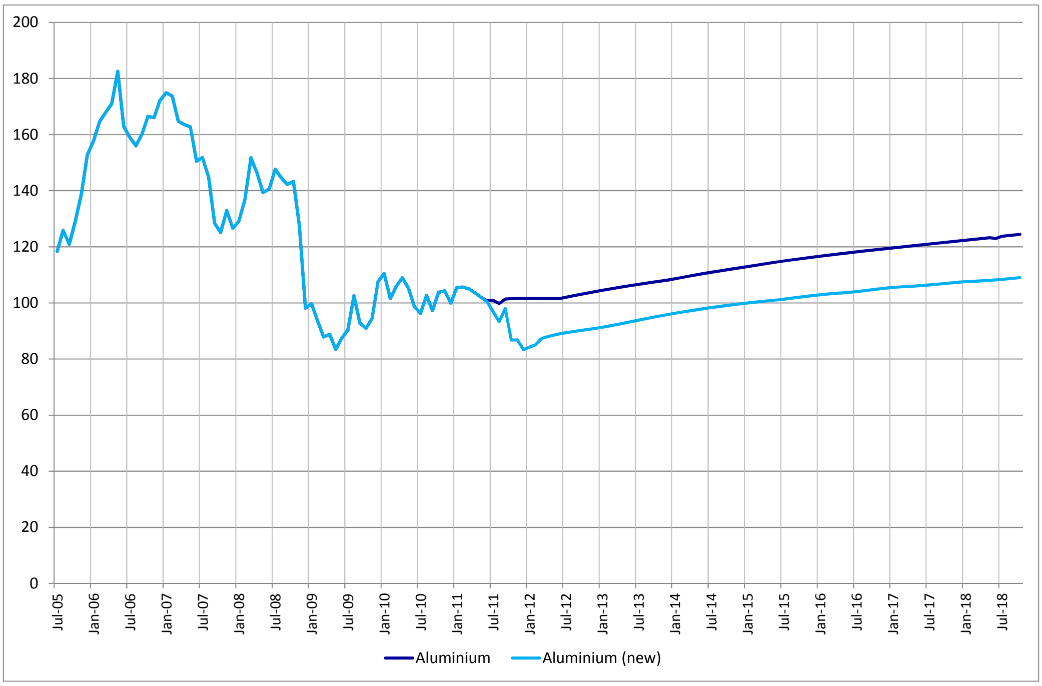
36. The estimated escalation factors have all been affected by a significant downturn in commodity prices over the second half of 2011. The updated escalators are shown in Table 3 below.

Table 3: Escalation factors for aluminium, real

Financial year	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Aluminium (updated)	-13.0%	2.6%	5.3%	3.9%	2.9%	2.5%
Copper (updated)	-10.4%	1.3%	0.4%	-1.5%	-3.4%	-3.9%
Zinc (updated)	-14.9%	1.0%	1.9%	2.8%	4.1%	3.6%
Aluminium (previous)	-0.9%	2.8%	4.1%	3.9%	3.3%	2.6%
Copper (previous)	-5.3%	-0.8%	-0.8%	-1.7%	-2.4%	-3.1%
Zinc (previous)	-8.6%	2.2%	3.5%	4.4%	3.8%	3.1%

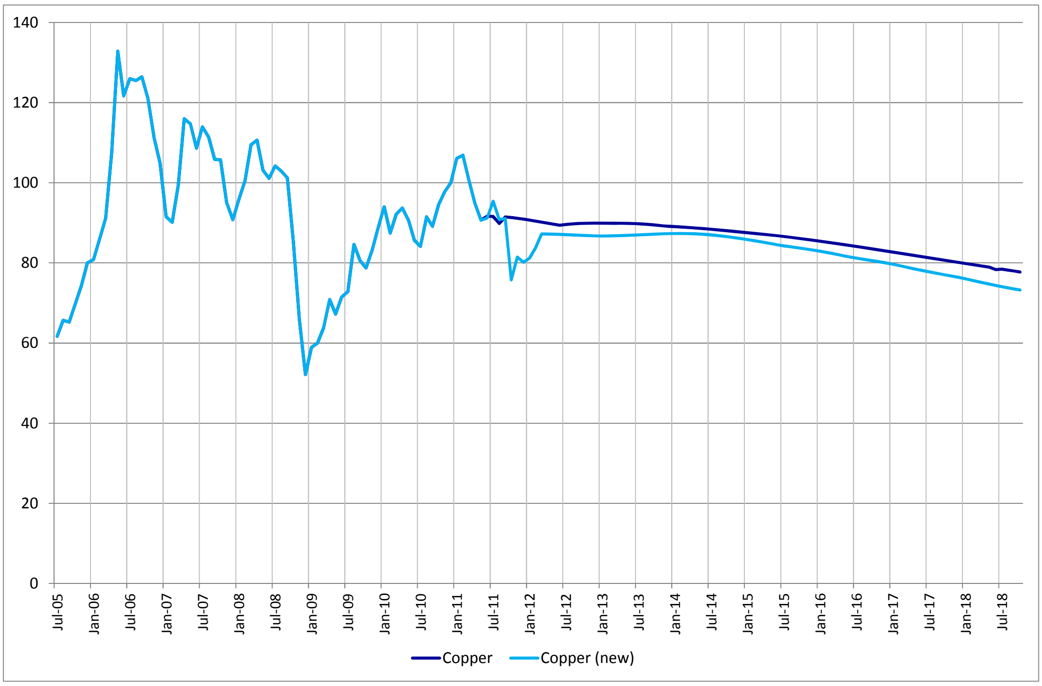
37. Figure 2, Figure 3 and Figure 4 below show theprice trend implied by the updated escalation factors for aluminium, copper and zinc respectively against the path predicted by our previous escalation factors. These charts are shown on a monthly basis, as opposed to the annual basis shown in our previous report.

Figure 2:Indexed price levels for aluminium, real



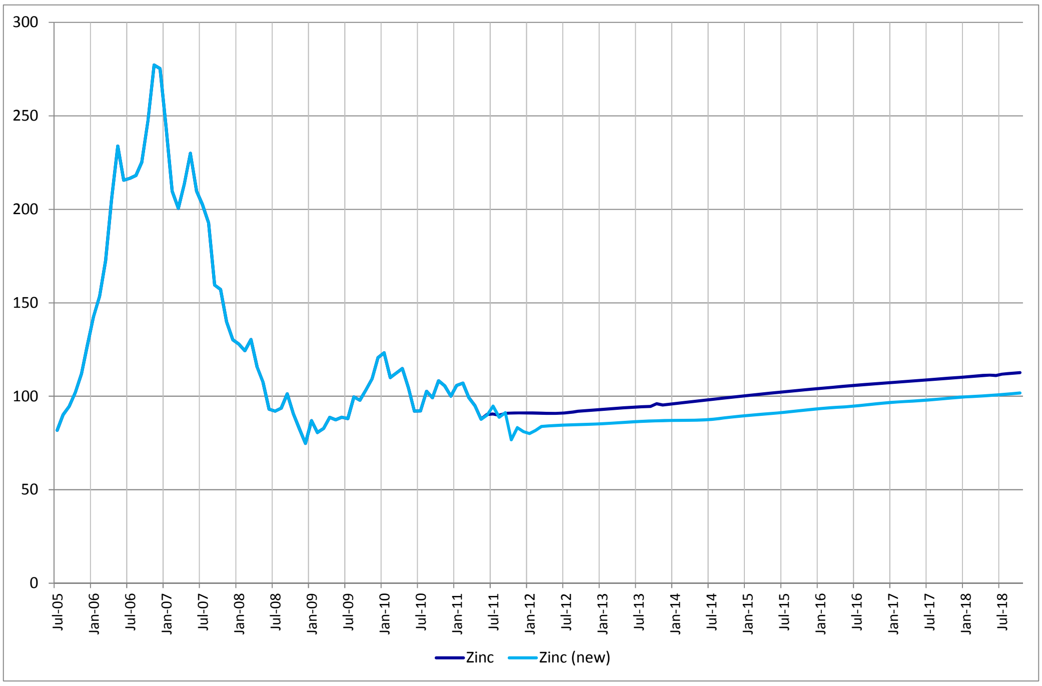
December 2010 = 100
Source: Bloomberg & Consensus Economics

Figure 3: Indexed price levels for copper, real



December 2010 = 100
Source: Bloomberg & Consensus Economics

Figure 4: Indexed price levels for zinc, real



December 2010 = 100
Source: Bloomberg & Consensus Economics

3.2. Crude oil

38. In respect of crude oil, we have relied upon a methodology to estimate escalation factors that is unchanged from that discussed in our previous report for Western Power.[14]

39. We have updated the input data into this methodology to incorporate EIA historical crude oil prices up to and including March 2012. NYMEX future prices predicting prices for the month of May 2012 and beyond were sourced over March and April 2012.

40. The updated and previous escalators for crude oil are shown in Table 4 below.

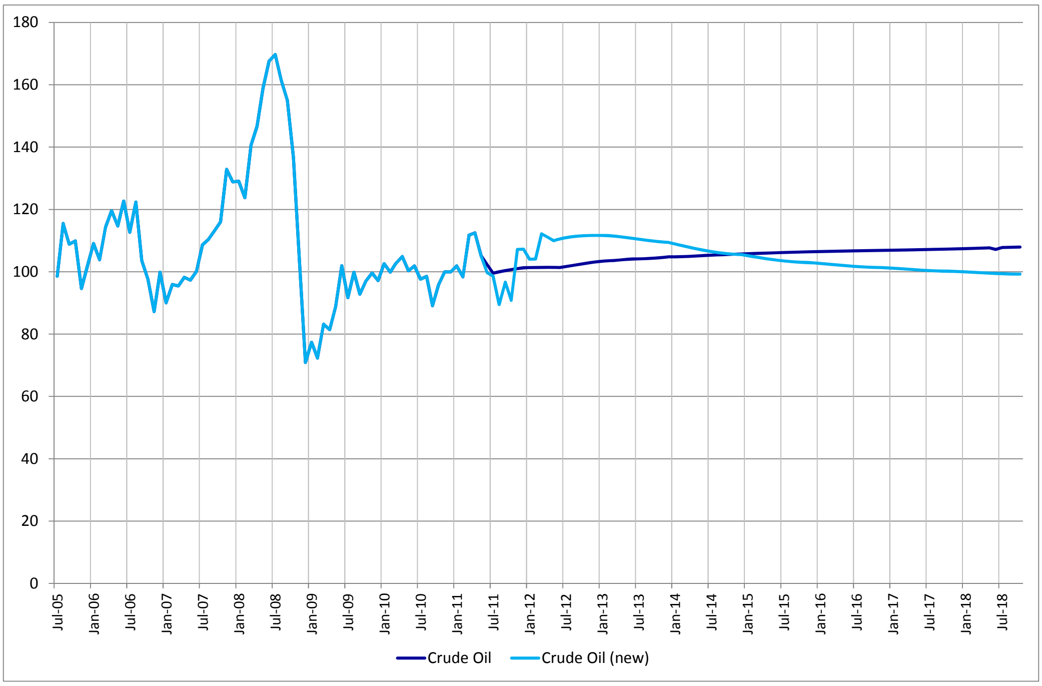
Table 4: Escalation factors for crude oil, real

Financial year	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Crude oil (updated)	2.6%	7.6%	-2.2%	-3.4%	-2.4%	-1.5%
Crude oil (previous)	-0.2%	2.1%	1.6%	1.0%	0.7%	0.4%

41. Figure 5 below shows the price trend implied by the updated and previous escalation factors for crude oil.

[14] CEG, *Escalation factors: A report for Western Power*, September 2011, pp. 25-26

Figure 5: Indexed price levels for crude oil, real



December 2010 = 100
Source: Bloomberg & Consensus Economics

3.3. Steel

42. The methodology use to estimate escalation factors for steel is discussed in detail in our previous report for Western Power.[15]

43. We have made two changes in our use of data to estimate updated steel escalation factors. Both changes reflect new information that enables us to improve the accuracy of our escalation factors.

    i. As with aluminium, copper and zinc, we use nominal long-term Consensus forecasts which were previously unavailable in preference to real long-term forecasts.

    ii. Consensus forecasts have also recently introduced forecasts of Asian HRC prices. We have adopted this as being more likely to give close estimates of the change in Australian steel prices, in preference to our previous methodology of averaging United States and European forecasts.

44. For consistency with the use of Asian steel Consensus forecasts, we have also adjusted our use of historical series to a MEPS Asian series sourced from Bloomberg.MEPS is a leading consultancy company operating in the steel sector

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15 CEG, *Escalation factors: A report for Western Power*, September 2011, pp. 27-28

worldwide. The specific price index used is the MEPS carbon steel products index for Asia based on USD/Tonne values.[16]

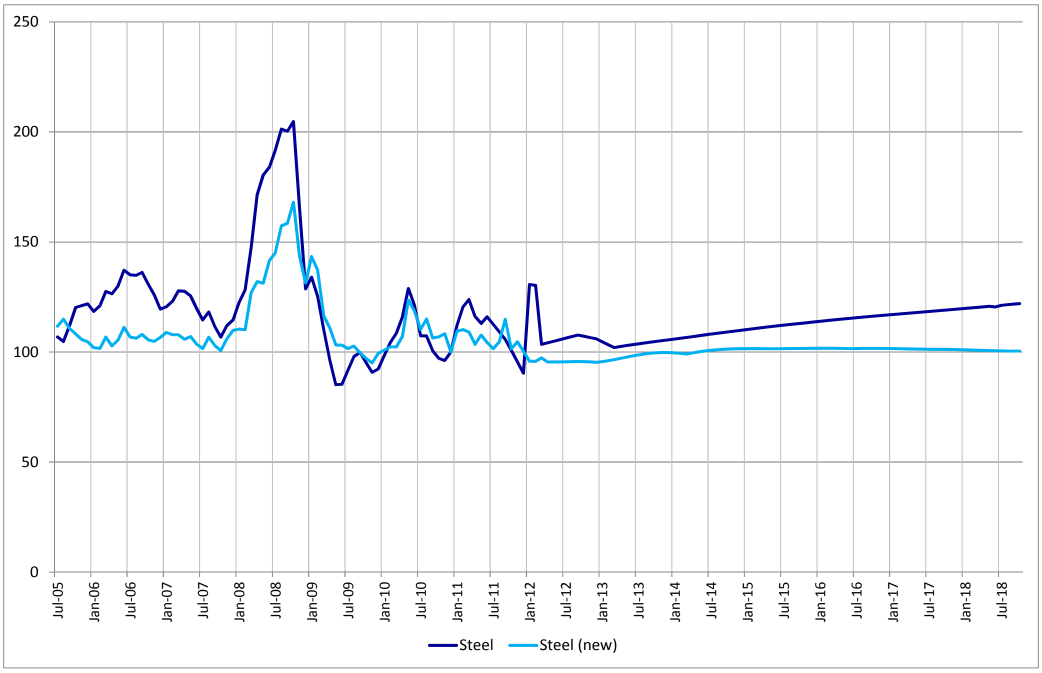
45. The updated and previous escalation factors derived on the basis of short term and long term Consensus Economics forecasts are shown in Table 5 below.

Table 5: Escalation factors for steel, real

Financial year	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Steel (updated)	-6.8%	-4.0%	3.5%	1.8%	0.3%	-0.1%
Steel (previous)	-1.3%	-2.6%	0.7%	4.1%	3.4%	2.7%

46. Figure 6 below shows the updated and previous price trends implied by the escalation factors for steel. The different historical information arises because of the different series used since our previous report, as explained above. As with the other metals prices, the outlook for steel is lower than in our previous update.

Figure 6: Indexed price levels for steel, real



December 2010 = 100
Source: Consensus Economics

3.4. Other data

47. In addition to the data updated discussed in the previous sub-sections, our updated escalation factors also rely upon:

16 Bloomberg code MEPSASPR Index.

- updated actual and forward currency exchange between the Australian and United States dollars. Historical information has been obtained from the Reserve Bank of Australia (RBA) whilst future rates have been obtained from forward rates reported by Bloomberg.
- updated actual and forecast rates of Australian inflation. Historical information has been sourced from the Australian Bureau of Statistics (ABS) and short-term forecasts are based on those provided in the RBA's February 2012 Statement on Monetary Policy. Beyond this horizon we continue to assume expected inflation of 2.5% per annum.

Appendix A. Terms of reference

Western Power is seeking an independent expert review of the ERA's draft decision as regards input cost escalation for materials and labour. This review should:

- critically examine the method, analysis and logic relied upon by the ERA in reaching its draft decision on labour and materials escalation, and explain and provide evidence for instances where CEG considers the ERA or its consultant's method, analysis and logic is deficient
- determine if (and if so how and to what extent) any of the ERA's findings would cause CEG to alter its expert view about the appropriateness of Western Power:
    1. applying forecast real price escalation to input materials in its forecast capital and operating expenditure
    2. employing the AWOTE as the best measure of expected labour cost increases applicable to Western Power during the AA3 period (2012/13 to 2016/17).
- examine the reasonableness or otherwise of the ERA's decision to disallow real input cost escalation for materials by reference to recent decisions made by other Australian economic regulators.

Appendix B. Curricula vitae

Tom Hird

Tom Hird is a founding Director of CEG's Australian operations. In the three years since its inception CEG has been recognised by Global Competition Review (GCR) as one of the top 20 worldwide economics consultancies with focus on competition law. Tom has a Ph.D. in Economics from MonashUniversity. Tom is also an Honorary Fellow of the Faculty of Economics at Monash University and is named by GCR in its list of top individual competition economists.

Tom's clients include private businesses and government agencies. Tom has advised clients on matters pertaining to: cost modeling, valuation and cost of capital.

In terms of geographical coverage, Tom's clients have included businesses and government agencies in Australia, Japan, the UK, France, Belgium, the Netherlands, New Zealand, Macau, Singapore and the Philippines. Selected assignments include:

Recent

Expert evidence to the Australian Competition Tribunal on the cost of debt for several regulated Australian electricity and gas network businesses.

Advising NSW, ACT and Tasmanian electricity transmission and distribution businesses on the cost of capital generally and how to estimate it in the light of the global financial crisis.

Advisingelectricity and gas network operators in SA, NSW and Tasmania on estimating escalation factors used to forecast future capital and operating expenditure for regulatory purposes.

Advice to T-Mobile (Deutsche Telekom) on cost modeling in the mobile telecommunications market.

Expert testimony to the Federal Court of Australia on alleged errors made by the Australian Competition and Consumer Commission (ACCC) in estimating the cost of capital for Telstra (the incumbent telecommunications provider).

Advising the Energy Networks Association on cost of capital issues in the context of the Australian Energy Regulator (AER) five year review of the cost of capital in the NER.

Advising Telecom New Zealand on issues associated with the cost of providing the New Zealand universal service obligation (TSO).

Industry modeling of the seaborne iron ore market for Japanese Steelmakers in the context of BHPB's initial merger proposal for Rio Tinto and subsequently its proposed Joint venture with Rio Tinto.

Advice to Webb Henderson on setting reserve prices for auction of digital radio spectrum.

2007

Advising the Victorian gas distributors in relation to their response the ESCV's draft decision on the cost of providing gas network services (four reports).

Advising the Energy Networks Association on the appropriate estimation technique for the risk free rate used in CAPM modeling.

Advising on the cost of capital for Victorian electricity distributors' metering operations.

Earlier

Advising the ACCC on the market modeling of the electricity generation sector.

Advising Melbourne water utilities on the potential reform to the process for establishing and maintaining Bulk Water Entitlements.

Advising the ENA on the relative merits of CBASpectrum and Bloomberg's methodology for estimating the debt margin for long dated low rated corporate bonds.

Advising the Australian Competition and Consumer Commission, Australia on the correct discount rate to use when valuing future expenditure streams on gas pipelines.

Tom Hird | Director | C E G

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Daniel Young

Daniel Young is an Economist with CEG, based in its Sydney office. Daniel has a Masters degree in Economics and a Bachelors degree in Operations Research from Auckland University. He has worked as a professional economist for 5 years. Prior to joining CEG, Daniel was an Analyst at NERA Economic Consulting.

Daniel has extensive experience across a wide range of matters relating to economic regulation, antitrust issues and commercial damages in Australia and overseas. He has worked for clients in the electricity, gas, rail, mining, telecommunication, and finance sectors.

Daniel has particular expertise in relation to the implementation of economic principles in computer modelling and has created models for telecommunications costs, electricity pricing, demand response and competition in electricity generation that have been applied in Australia and overseas. Selected assignments include:

Recent

Analysis of the debt risk premium for regulated energy network businesses in Australia as part of regulatory processes and in support of appeals on these matters to the Competition Tribunal.

Preparation of a revenue model relied upon by an independent price expert to set prices for AAT's car terminals on the eastern seaboard of Australia.

Preparation of reports for Optus relating to the regulatory valuations of Telstra's fixed line network, outlining improvements to the approach used.

Providing assistance and research in support of the preparation of reports on the implications on competition of the proposed iron ore joint venture between BHP Billiton and Rio Tinto.

Assisting in the preparation of reports for Australian electricity and gas network businesses estimating the rate of inflation for regulatory purposes and calculating and forecasting materials escalators.

Econometric testing using Australian data of the specification of the Sharpe CAPM equation for the ENA in relation to the AER's cost of capital review.

Providing advice to a European firm regarding the implications on competition in the UK electricity generation market of a number of proposed corporate transactions.

Prior to 2008

Estimating the likely response in the demand for electricity to the increased proliferation of time of day and critical peak tariffs as part of the MCE's cost/benefit analysis of the introduction of smart meters.

Analysing the results of the 2006 household survey of electricity, gas and water consumption in the Sydney region and preparing a report summarising these on behalf of IPART.

Undertaking research for the Australian Railways Association into charging regimes for rail and road access across a number of Australian jurisdictions. Critiquing econometric modelling of the effect of road charges on rail

Advising the electricity regulator in Macau about efficient tariff reform using modelling of the short run and long run marginal cost of supply in Macau.

Assisting in determining the market gas price on behalf of Santos in arbitration for two major gas supply contracts.

Developing a modelling framework for the ACCC to understand the increased incentives of merged generators in the NEM to engage in strategic withholding of capacity.

Estimating the long run marginal cost of Integral Energy's distribution network and applying this to improve the efficiency of tariffs.

Daniel Young | Economist | C E G

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Johanna Hansson

Johanna Hansson joined CEG as an Economist in early 2010, and is based in its Melbourne office. Johanna has a Masters degree in Economics and two Bachelor degrees in Economics and Management from Uppsala University. She has conducted extensive academic research on behalf of both the Swedish Competition Authorities and the Swedish Energy Market Inspectorate. Prior to joining CEG, Johanna also interned for several month in the Competition Policy Practice at Frontier Economics in their head office in London.

Johanna has experience across a wide range of matters relating to economic regulation, antitrust issues and commercial damages in Australia and overseas. She has worked for clients in the electricity, gas, water, transport and telecommunications sectors.

Recent selected assignments include:

2011

Preparing a report on behalf of Commercial Radio Australia (CRA) to respond to ACMA's options paper on revisions of Commercial Radio Standards.

Providing expert advice to the Vanuatu government in respect of the correct country risk premium to apply in the context of a dispute and arbitration to determine the cost of capital for UNELCO.

Advising regulated gas businesses ActewAGL and Jemena Gas Networks in the preparation of their appeals to the Australia Competition Tribunal against the AER's decision.

Advising Everything Everywhere on appeal of Ofcom's determination on wholesale mobile voice call termination.

Preparing and presenting a model of the Australian Amalgamated Terminal's (AAT) costs in order to estimate efficient cost-recovery prices as part of a regulatory process overseen by a price expert.

2010

Preparation of expert reports advising Envestra of the risk-free rate, debt risk premium and equity beta to be used in its original and revised access arrangement proposals.

Preparation of an expert report for Vector, New Zealand, responding to the Commerce Commission's proposed input methodologies for estimating the cost of capital.

Developing mobile cost models for Digicel in three Pacific Island jurisdictions for submission in regulatory proceedings. Estimating benchmarks for Digicel for mobile termination prices using econometric analysis for two Pacific Island jurisdictions.

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Updated forecasts of Labour Costs – Electricity, Gas, Water and Waste Services Sector

Western Australia

Report prepared for Western Power

May 2012

macromonitor

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1. Summary

This report provides updated forecasts of labour costs in the electricity, gas, water and waste services (EGWW) sector in Western Australia. Macromonitor's original report was issued in September 2011. This report updates the data and forecasts from the original report, along with some notes outlining the changes. Note that this update report should be read in conjunction with Macromonitor's original report, which contains more complete discussion of the data sources and the forecasting methodology.

Table 1 provides the updated annual forecasts, in year ended June terms, covering average weekly ordinary time earnings (AWOTE), the wage price index (WPI) and unit labour costs.

Table 1

Labour Costs - Electricity, Gas, Water & Waste Services Sector Western Australia - Annual % Change

Year Ended June	Average Weekly Ordinary Time Earnings *(Full Time Workers)* $	Wage Price Index - Ordinary Time Hourly Rate Index: 08/09=100	Unit Labour Costs - $ Wages per $ Real Gross Value Added $
2006	9.2	8.0	17.4
2007	5.1	4.5	6.5
2008	4.9	4.1	13.7
2009	9.7	7.2	19.5
2010	5.9	5.2	6.4
2011	9.0	4.0	20.5
Forecasts			
2012	5.5	4.3	8.7
2013	6.3	5.0	7.9
2014	6.7	5.4	7.2
2015	6.3	5.0	5.8
2016	5.7	4.5	4.3
2017	5.7	4.5	4.1
Average Annual Growth Rates			
2001-2006	5.3	4.5	10.0
2006-2011	6.9	5.0	13.2
Forecasts			
2011-2017	6.0	4.8	6.3

Source: ABS & Macromonitor

Since our initial report there have been three additional quarters of data released by the Australian Bureau of Statistics (ABS); for the June, September and December quarters of 2011.

These data indicate that wage increases in 2011 were a little weaker than we had expected. The causes of this are likely to include a weaker and more uncertain world economic outlook, weaker growth in some parts of the Australian economy and a drop in employment in the Electricity, Gas, Water and Waste Services sector.

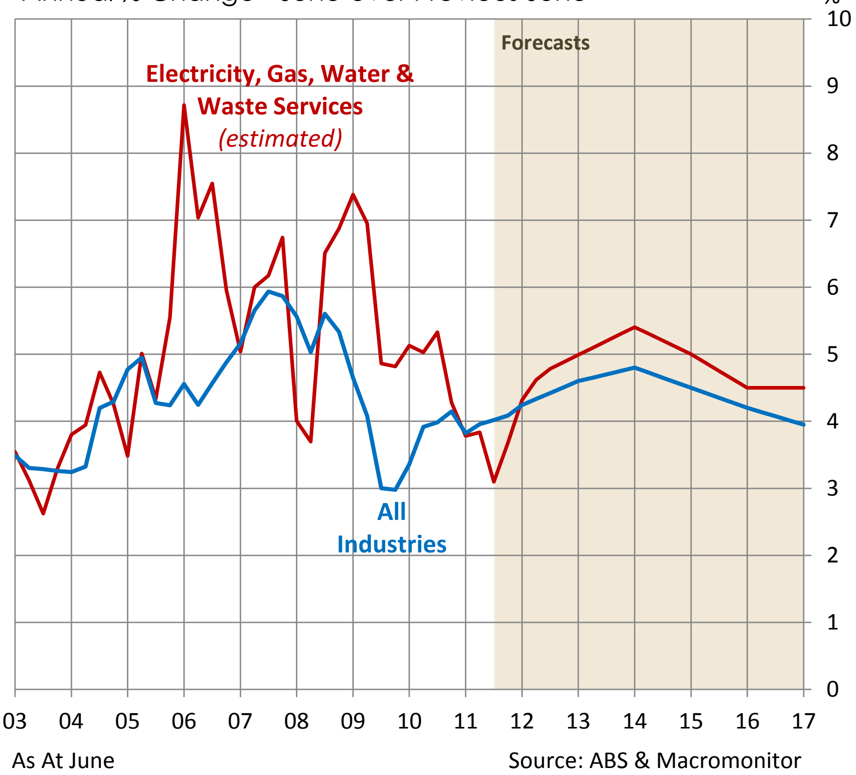
The factors which acted to dampen wages growth 2011, however, are expected to diminish over the next year and beyond, and the forecasts of rising rates of wages growth in our original report are still valid in our view.

2. Updated Forecasts of Labour Costs

In this section we present updated forecasts for both the WPI and AWOTE measures of labour costs. Please note, as discussed in our original report, the data for the EGWW sector WPI in Western Australia is not sourced from the ABS, but rather is estimated by Macromonitor (see Section 2.3 in our original report).

Chart 1 shows the Wage Price Indexes in Western Australia, for the EGWW sector (estimated) and for all industries.

Chart 1
Wage Price Indexes - Western Australia
Annual % Change - June over Previous June



This chart shows that there was a dip in wages growth in the EGWW sector during 2011 calendar year. The total change in the WPI measure, for the EGWW sector in Western Australia, from December 2010 to December 2011 is estimated to have been 3.2%.

This weaker growth during 2011 was particularly apparent in the March and June quarters of 2011. The September and December quarters registered stronger increases, averaging a bit over 1% per quarter, according to our estimates, or around 4.5% annualised.

We expect a similar rate of growth to continue through the first half of 2012, resulting in a total forecast increase over the 12 months to June 2012 of 4.3% (note that this relates to the WPI measure in the EGWW sector of Western Australia).

The easing in the rate of wages growth during 2011 was likely the result of some combination of the following factors:

- Weaker growth in some parts of the Australian and WA economies, such as residential building and government capital spending,
- More uncertain conditions in the world economy (related mainly to Euro Zone sovereign debt and fiscal problems), and
- A modest decline in employment in the EGWW sector in WA.

With regard to the first point above, changes in government programs and policies have had a significant impact on some sectors of the economy. Dwelling commencements dropped 20% in Western Australia in 2011, impacted by the conclusion of the Federal Government's *First Home Owners Grant Boost Scheme.* Also, the conclusion of the *Building the Education Revolution* projects impacted on non-residential building. The decline in non-residential building commencements also relates to the commencement of the Fiona Stanley Hospital project in the previous year (2009/10).

With regard to the last point, employment in the EGWW sector tends to be volatile from year to year, but the underlying trend has been strongly upwards since the early 2000s. We expect a return to positive employment growth in the sector during 2012.

As a result of the weaker than expected data in 2011, the growth rates for the financial years 2010/11 and 2011/12 are lower in this update report than they were in our original report, for both the WPI and AWE measures.

However, the negative factors listed above are expected to turn around over the course of 2012 and 2013, and the stronger rates of wages growth forecast in our initial report are still valid in our view.

The Western Australian economy is expected to strengthen again, as a result of the next round of major resources sector investments (focused on iron ore, LNG and associated infrastructure projects) and the conclusion of the negative effects of the Government fiscal policy changes mentioned above.

We are still forecasting growth in the EGWW sector WPI (in Western Australia) to reach 5% in 2012/13 and 5.4% in 2013/14.

Furthermore, we still expect a downturn in the construction and minerals investment cycles starting around 2015. We therefore expect a moderation of EGWW sector wages growth at this time also, prior to a stabilisation in 2016/17.

With regard to the Average Weekly Earnings measure of wages, growth was also a little slower than expected during 2011. Growth in average weekly earnings (in the EGWW sector in Western Australia) in 2011/12 is now expected to reach 5.5% (down on our previous forecast of 6.3%). As with the WPI measure, we anticipate that the growth in the average weekly earnings measure will increase once again during 2012/13, and we believe that our previous forecasts for 2012/13 and beyond are still valid.

Table 2 on the following page contains our current forecasts of both the WPI and AWOTE measures of wages in Western Australia's EGWW sector.

Table 2
Wage Cost Indicators - Western Australia
Electricity, Gas and Water Sector

Annual Averages

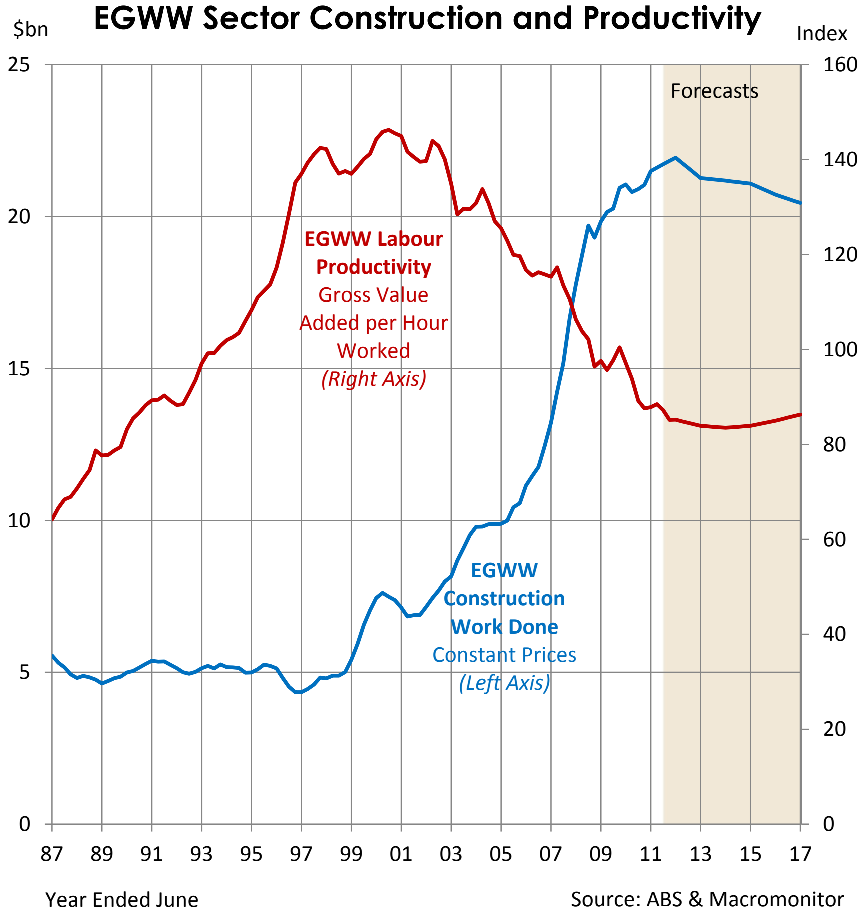
Year Ended June	Wage Price Index (as at June)		Average Weekly Ordinary Time Earnings (annual average)	
	Index: 2008/09=100	Ann. % Ch	$	Ann. % Ch
1998	63.0		791.7	
1999	64.8	2.9	827.2	4.5
2000	67.4	4.1	871.3	5.3
2001	69.6	3.1	922.6	5.9
2002	72.1	3.7	987.5	7.0
2003	74.9	3.9	1037.3	5.0
2004	77.6	3.5	1072.2	3.4
2005	80.3	3.5	1094.9	2.1
2006	86.7	8.0	1196.2	9.2
2007	90.6	4.5	1257.7	5.1
2008	94.4	4.1	1319.1	4.9
2009	101.2	7.2	1447.5	9.7
2010	106.4	5.2	1533.4	5.9
2011	110.7	4.0	1670.8	9.0
Forecasts				
2012	115.5	4.3	1762.2	5.5
2013	121.2	5.0	1872.5	6.3
2014	127.7	5.4	1997.4	6.7
2015	134.1	5.0	2123.3	6.3
2016	140.2	4.5	2244.3	5.7
2017	146.5	4.5	2372.2	5.7
Average Annual Growth Rates				
2001-2006	4.5		5.3	
2006-2011	5.0		6.9	
Forecasts				
2011-2017	4.8		6.0	

Source: ABS & Macromonitor

3. Updated Forecasts of Productivity Adjusted Labour Costs

The final measure of labour costs which we make us of in this report is Unit Labour Costs (ULC), which can alternatively be called productivity adjusted labour costs.

Chart 2
EGWW Sector Construction and Productivity



Source: ABS & Macromonitor

The new productivity data which have become available since our original report are very much on track with our expectations and forecasts. Therefore the updated Unit Labour Costs data and forecasts are also very close to those in our original report.

We previously estimated that productivity in the EGWW sector would decline by 8.9% in 2010/11, while the actual figure turned out to be a decline of 9.6%. Productivity data so far available for 2011/12 are consistent with our previous forecast of a 3% decline for the year.

Our previous forecast for growth in unit labour costs in 2011/12 was 9.5%. This is now replaced with an estimate of 8.7%, with the forecasts from 2012/13 onwards unchanged.

Our updated forecasts of labour productivity and unit labour costs are shown in Table 3 on the following page.

Table 3
Electricity, Gas & Water Labour Costs - Western Australia

Year Ended June	Average Weekly Ordinary Time Earnings		Wage Price Index - Ordinary Time Hourly Rate		Productivity - Real Gross Product per Hour Worked		Unit Labour Costs - $ Wages per $ Real Gross Product	
	$	Ann. % Ch	08/09=100	Ann. % Ch	08/09=100	Ann. % Ch	$	Ann. % Ch
1998	791.7	-	63.0	-	142.2	-	0.14	-
1999	827.2	4.5	64.8	2.9	137.0	-3.7	0.16	8.5
2000	871.3	5.3	67.4	4.1	144.3	5.3	0.16	0.0
2001	922.6	5.9	69.6	3.1	145.0	0.5	0.16	5.4
2002	987.5	7.0	72.1	3.7	139.7	-3.7	0.18	11.1
2003	1037.3	5.0	74.9	3.9	134.9	-3.4	0.20	8.7
2004	1072.2	3.4	77.6	3.5	130.8	-3.0	0.21	6.6
2005	1094.9	2.1	80.3	3.5	125.5	-4.1	0.23	6.4
2006	1196.2	9.2	86.7	8.0	116.8	-7.0	0.26	17.4
2007	1257.7	5.1	90.6	4.5	115.3	-1.2	0.28	6.5
2008	1319.1	4.9	94.4	4.1	106.3	-7.8	0.32	13.7
2009	1447.5	9.7	101.2	7.2	97.6	-8.2	0.38	19.5
2010	1533.4	5.9	106.4	5.2	97.2	-0.5	0.41	6.4
2011	1670.8	9.0	110.7	4.0	87.8	-9.6	0.49	20.5
Forecasts								
2012	1762.2	5.5	115.5	4.3	85.2	-3.0	0.53	8.7
2013	1872.5	6.3	121.2	5.0	83.9	-1.5	0.58	7.9
2014	1997.4	6.7	127.7	5.4	83.5	-0.5	0.62	7.2
2015	2123.3	6.3	134.1	5.0	83.9	0.5	0.65	5.8
2016	2244.3	5.7	140.2	4.5	85.0	1.3	0.68	4.3
2017	2372.2	5.7	146.5	4.5	86.3	1.5	0.71	4.1
Average Annual Growth Rates								
2001-2006	5.3		4.5		-4.2		10.0	
2006-2011	6.9		5.0		-5.5		13.2	
Forecasts								
2011-2017	6.0		4.8		-0.3		6.3	

Source: ABS & Macromonitor

Appendix G. GHD – Report for Review of ERA Technical Consultants Report

CLIENTS | PEOPLE | PERFORMANCE

Western Power

Report for Review of ERA Technical Consultants Report

May 2012

INFRASTRUCTURE | MINING & INDUSTRY | DEFENCE | PROPERTY & BUILDINGS | ENVIRONMENT

This Review of the ERA Technical Consultant's Report *("Report") on Western Power's AA3 Access Arrangement Application:*

1. *has been prepared by GHD Pty Ltd ("GHD") for Western Power;*
2. *may only be used and relied on by Western Power;*
3. *must not be copied to, used by, or relied on by any person other than Western Power without the prior written consent of GHD;*
4. *may only be used for the purpose of seeking an independent opinion on the ERA Technical Consultants Report on the Western Power AA3 Access Arrangement Application (and must not be used for any other purpose).*

GHD and its servants, employees and officers otherwise expressly disclaim responsibility to any person other than Western Power *arising from or in connection with this Report.*

To the maximum extent permitted by law, all implied warranties and conditions in relation to the services provided by GHD and the Report are excluded unless they are expressly stated to apply in this Report.

The services undertaken by GHD in connection with preparing this Report:

- *were limited to those specifically detailed in Section 2. Review Scope of this Report;*
- *did not include verification or validation of Western Power data used and referred to in the ERA Technical Consultant's Report provided to GHD, or the further independent analysis performed by Geoff Brown and Associates as author of the report for ERA on Western Power data; and*
- *did not include verification or validation of Geoff Brown and Associates data used and referred to in the ERA Technical Consultant's Report provided to GHD.*

The opinions, conclusions and any recommendations in this Report are based on assumptions made by GHD when undertaking services and preparing the Report ("Assumptions"), including (but not limited to):

- *the data provided by Western Power and Geoff Brown and Associates is true and accurate for the access arrangement periods referred (AA2, AA3, AA4) in the ERA Technical Consultant's Report and provided to GHD;*
- *the data provided by Western Power and Geoff Brown and Associates is complete for the access arrangement periods referred (AA2, AA3, AA4) in the ERA Technical Consultant's Report and provided to GHD;*

GHD expressly disclaims responsibility for any error in, or omission from, this Report arising from or in connection with any of the Assumptions being incorrect.

Subject to the paragraphs in this section of the Report, the opinions, conclusions and any recommendations in this Report are based on conditions encountered and information reviewed at the time of preparation and may be relied on until 30 June 2012, after which time, GHD expressly disclaims responsibility for any error in, or omission from, this Report arising from or in connection with those opinions, conclusions and any recommendations.

Contents

Executive Summary

GHD has completed a preliminary review of the Western Australian Economic Regulation Authority Technical Consultant's Report prepared by Geoff Brown and Associates (GBA), New Zealand in support of the Regulator's draft determination on Western Power's AA3 Access Arrangement. The GBA report has been provided to our Company by Western Power.

In the time frame available to respond to the Economic Regulation Authority the preliminary review has comprised a study of the GBA document with reference to Western Power's AA3 Access Arrangement Submission and the Access Code primarily in the seven key focus areas as stipulated by Western Power within the report.

In the seven key focus areas, GHD has found the GBA report to be generally a comprehensive assessment of the AA3 with well reasoned conclusions and recommendations. Notwithstanding this view GHD believes that alternative conclusions and recommendations may be drawn from the assessment of AA3 and as such we disagree or offer alternative opinions to GBA as summarised in the conclusions section of this report.

The major areas where GHD consistently takes a differing viewpoint and offers alternative opinions to those expressed in the GBA report relate to the current base condition of Western Power's South West Interconnected Network (SWIN). The GBA AA3 assessment appears to be predicated on the SWIN being in a condition commensurate with benchmark networks in the National Electricity Market. GHD finds that Western Power has based its AA3 submission on the true average condition of the SWIN which is of a uniformly lower standard than those benchmarks.

GHD has found that the GBA AA3 assessment does not appear to fully recognise Western Power's stated intent to address the formal findings and concerns surrounding the base condition of the SWIN expressed by the WA Government Parliamentary Enquiry and the Energy Safety Regulator 2009 Order.

As a result the SWIN issue appears to also flow through to the GBA recommendations on the critical areas of asset maintenance, economies of scale and efficiency adjustment. GHD has offered alternative opinions in these areas taking a greater account we believe of the current SWIN asset condition.

1. Introduction

Western Power is required to periodically make submission to the Western Australian Economic Regulation Authority (ERA) for its Network Access Arrangements. Access arrangements detail the terms and conditions, including prices, which apply to third parties seeking the use of regulated electricity networks within Western Australia.

Western Power's South West Interconnected Network (SWIN) is the only regulated network within the State of Western Australia at present, and is regulated under the Electricity Networks Access Code (Access Code).

Section 4.1 of the Access Code dictates the network service provider (Western Power) must submit periodic access arrangements, together with access arrangement information to the ERA. The first access arrangement submission AA1 was required within six months of the electricity network first being covered and addressed the 2006/7 to 2008/9 periods. The subsequent access arrangement AA2 covers 2009/10 to 2011/12 the periods.

Western Power received the ERA draft determination on its third access arrangement (AA3) submission on 29 March 2012. In support of its determination ERA commissioned Geoff Brown and Associates (GBA), New Zealand to review and report on Western Power's AA3 submission. ERA has issued that report to Western Power as part of its draft determination.

Western Power has engaged GHD Pty Ltd to independently review and report on the assumptions and conclusions provided to ERA by GBA in support of its response to the draft determination.

2. Review Scope

Western Power engaged GHD Pty Ltd to review and report independently on the assumptions made and conclusions drawn by GBA in their review of the proposed access arrangement AA3 Submission. The GBA review of Western Power’s AA3 Access Arrangement Submission is also referred to as the ERA Technical Consultant’s Report.

In support of the independent assessment by GHD, Western Power identified the following key focus areas to be included in the review scope. They are:

- Field Data Capture
- Peak Demand
- Asset Maintenance
- Economies of Scale Factors
- Efficiency Adjustments
- Strategic Program of Works Expenditure
- Review of Efficiency of Network Control Services

The following are not included in scope:

- Verification or validation of Western Power data used and referred to in the ERA Technical Consultant’s Report provided to GHD, or the further independent analysis performed by Geoff Brown and Associates as author of the report for ERA on Western Power data; and
- Verification or validation of Geoff Brown and Associates data used and referred to in the ERA Technical Consultant’s Report provided to GHD.
- Review of Western Power's proposed revised access arrangement (AA3) submission. Documentation available on the ERA website has been referred on an as required basis only for clarification in the review of the GBA report.

GHD understands the purpose of the review that it has been commissioned to undertake is to provide Western Power with an independent and alternative technical opinion on the GBA report findings. It has been GHD’s intention to respond to those findings by identifying critical issues that we believe need to be addressed in Western Power’s response to the ERA draft determination on its third access arrangement (AA3) submission.

3. Key Focus Areas

3.1 Field data capture

GBA concludes that the proposed Field Data Capture Programme proposed by Western Power is the largest of its kind undertaken in Australia and that the benefits are overstated.

GHD has carefully examined the comments and conclusions by GBA on project objectives and benefits of the programme claimed by Western Power. In consideration of costs involved and the relative project alternatives GHD is in general agreement with the GBA observations.

There is no doubt that the proposed programme would improve data quality and provide the Western Power business with better asset information however the critical issue is Western Power's historical performance updating asset data to reflect the current state of the electricity network. It is apparent that this performance may have damaged Western Power's credibility when seeking funding approval for the Field Data Capture Programme.

While Geoff Brown & Associates' (GBA) report quotes the 2011 Asset Management Systems Review (AMSR) report on the difficulties in getting data and information reports from the existing systems and the lack of correlation between the various sources of data (e.g. wood pole inspections). The GBA report also observed that field data integrity was an ongoing problem for Western Power and suggest that Western Power need to pay more attention to getting field data into their asset management systems so that management reporting is factual and useful, the resort concluded in section 10.6.2.1 that the cost benefit of spending $34m on the mobile data collection solution did not appear to be a good solution and was not supported. The basis of this conclusion appeared to be that a comparative cost of field data capture solutions implemented by other equivalent utilities were significantly lower cost than that proposed by Western Power.

For our experience during the 2011 AMSR project, GHD found that Western Power needed better field data capture systems and needed to address poor data from legacy information. Our experience indicated that GBA are correct in that the proposed solution appeared to be excessive and that better value for money could be achieved with a refined scope of work or alternate methods of addressing legacy data. The other issue which is unclear is why the data cannot be captured during the standard inspection and maintenance activities. While we have not reviewed the source data (Business Case) for this project and therefore have not had an opportunity to analysis the proposed costs and work scope, our experience has been that other utilities clients are implementing more economical solutions to the collection of asset management data.

GBA also questions why Western Power needs field data capture to GIS locate poles with an accuracy of better than 5.0m and questions the relevance of "dial before you dig" as a reason for the project. GHD would agree with this observation and concluded that much of the location details can be achieved as a desktop exercise using aerial photos and other survey sources with sufficient accuracy.

During our discussions with Western Power's asset management staff during the AMSR project, the lack of legacy data had been evident in the databases for many years and although the condition assessment process had included capturing missing data (such as the installed dates), the data in Western Powers systems had not been updated. For example, installed dates were missing ion at least 2% of the 400 pole records and default dates were recorded in at least 5% of the sample recorded reviewed. We had discussed using the planning approval records or adjoining pole installed dates as suitable default date with the IT staff, who agreed that this would be a very good idea and that additional filed inspections should not be needed.

GHD concluded that expending $34.0m to address the accuracy of field data does not appear to be an efficient or effective use of technology or resources and agrees with GBA's conclusion. GHD suggests that the proposed scope of works for this project should be further investigated to determine whether a more cost effective solution is available to remedy the field data capture issues.

GHD concludes that the more cost effective scope of works is an imperative for Western Power in its response to the ERA draft determination given the current condition of the South West Interconnected Network (SWIN) would suggest that a GBA recommended reduction of 50% in the OPEX requirement forecast by Western Power is unreasonable if there are tangible benefits to be gained through effective implementation of the Field Data Capture Programme.

3.2 Peak Demand

GBA has made a number of assessments regarding a change in the peak demand forecast that occurred post Western Power's AA3 submission and how this change has then impacted on the forecast growth related investment. GHD was requested to assess the method GBA has used to recommend a reduction in forecast investment. This involved forming an opinion as to whether there is a direct relationship between reduction in system demand and reduction in system investment.

In GHD's opinion GBA have assessed the forecast growth related network investment against both the reduced peak demand forecast in Western Power's 2011 Annual Planning Report (APR) and the actual recorded 4005 MW peak demand in 2011 which was significantly higher than forecasted in the AA2 review.

The two critical issues arising from the GBA report in relation to forecast growth related investment are:

- GBA reasons that there is a direct one to one relationship between peak demand forecast and growth related investment.
- GBA appear to have also concluded that given the network successfully sustained a significantly higher than forecast load of 4005 MW in 2011, it follows in real terms that the network investment requirement can be reduced in AA3.

Firstly the assertion that there is a simple and direct one to one relationship between peak demand forecast and growth related investment appears to ignore the complex interdependence between the growth related investment and the existing network. The electricity network asset age ranges from new to sixty years old suggesting growth related investment will on many occasions abut assets of an age and condition that are incapable of supporting the new asset without significant reinforcement to meet the increased load transfer and operational interconnection required by legislation and the regulatory framework. By definition this reinforcement requirement is essential to the establishment of the growth investment as a fully operational covered service and can therefore be legitimately be classed as capex. In making this assertion GBA appears to be drawing a comparison between Western Power and other Australian / New Zealand network operations where the asset condition is of a uniform higher standard. In framing its response to the ERA draft determination, Western Power is encouraged to stress the fact that its network has been shown convincingly to be well below a uniform high standard against national benchmarks and that notwithstanding a reduction in peak demand forecast, forecast growth related investment is entirely justifiable to systematically reduce and stabilise the backlog of network reinforcement and maintenance.

Secondly the GBA report also appears to imply that since the network can sustain an unusually higher than forecast peak load then it has demonstrated the ability to manage that growth and this in turn obviates significant growth related investment.

This conclusion may appear reasonable from a high level perspective but oversimplifies the issue as to whether the network can sustainably maintain its regulated target performance under those peak load conditions. Operating the network successfully under an unusually high peak load condition does not give valid argument to or obviate prudent reinvestment in the assets at the levels proposed by Western Power in AA3.

In GHD's extensive network design and operational experience, utilities can run assets beyond their design capacity for a period without immediate impacts, however running assets at or above their capacity will reduce their effective life of the assets and significantly increase the risk of catastrophic failure. The lag time frame is dependent on the extent of overloading and condition of the asset. Reliability engineering techniques; such as failure modes and effects, criticality analysis; can be used to predict the impact of peak demand loading on assets, but the predictive analysis modelling is reliant on having historical failure data or good test load performance data. This is not available to Western Power, as their demand management approach has been to intervene by planned upgrades to the network assets before the performance or effective life has been affected. This is a very sound asset management strategy, which advocates balancing cost with levels of service requirements and risk. The difficulty with any analysis is that it is based on the validity of the input data, in this case peak demand forecasts. GHD would suggest that Western Power is in a better position to forecast demand projections that GBA and would be more likely to be correct. In framing its response to the ERA draft determination, Western Power is encouraged to stress this argument and the fact that its network may endure short term high loads but is not in a uniform state to sustain that performance and further deprival growth related investment funding will likely increase the risk growing the current backlog of network reinforcement and maintenance.

The conclusions in Sections 7 and 8 of the GBA report that support a reduction in forecast growth related network investment in both transmission and distribution assets appear to ignore the significant impact of the historical condition of the network on AA3 asset management requirements. GHD made the following observations when examining these sections of the GBA report.

- The forecast capital expenditure Table 7.1: Forecast AA3 Transmission Capex for the regulatory compliance requirements during the first three years of AA3 does not appear to be commensurate the findings and concerns expressed by the State Government Enquiry and the Energy Safety Regulator.
- While the GBA report acknowledges in Section 7.1 that the capacity expansion capex in AA2 was lower both as a result of the global financial crisis and asset programme delivery problems within Western Power and that a catch up investment is required, this does not appear to translate through to the conclusions on forecast growth related network investment. GHD s of the view that this is a significant underling omission in the GBA argument.
- The same section acknowledges the ageing Western Power asset base and the bias towards replacement of wood pole assets. This is not a new issue however the GBA report does not

appear to acknowledge the extent of the backlog of investment required in this asset class that now represents a significant cost "bow wave" that dictates and accelerated forecast growth related network investment if the SWIN is to be restored to the condition of comparable size networks in the National Electricity Market (NEM). The GBA report appears to assume the underlying condition of the SWIN is similar to that of other Australian networks and therefore new forecast growth related network investment can be considered in isolation from historical problems that exist in the surrounding interconnected electricity network.

In our asset management experience, most utilities have a backlog of maintenance or renewals from constrained resources or funding. During the AMSR project, the wood pole investigation identified that there was a significant liability in the wood pole replacement program and although poles are replaced on condition, the average age of the poles across the network was well beyond 20 years and therefore more than half way through their lives. This trend was similar for other assets groups as detailed in the Asset Management Plans (TAMP and DAMP) which indicated that there was a significant renewals liability across most assets. Sound asset management practice recognises that managing backlog is an acceptable strategy as long as the backlog remains stable and is reduced. GHD suspects that Western Power's backlog and average asset condition has been increasing based on discussions with Western Power staff, although we found no evidence during the AMSR project on the backlog trends.

- GHD supports the Western Power bottom up approach to the general preparation of capex forecasts that consider the previous point and factor in the shortfall of prudent network reinvestment during previous years.
- Perth CBD capex investment is reduced under the GBA report recommendation however there is insufficient evidence in the analysis for GHD to determine if the reduction has taken into full account the N+2 contingency requirement for the security of supply mandated for the city centre and whether adequate consideration has been given for future major loads planned for redevelopment areas such as the Perth City Link.

3.3 Asset Maintenance

GBA's assessment of Western Power's scale escalation factors assumes that there is a direct relationship between CAPEX and OPEX in that new assets do not need maintenance or operations. This argument (as presented by Nuttall) assumed that a capital investment in a new asset will reduce the operational expenditure as new assets do not require maintenance. This argument is not supported by the Asset Management Council (need to cite AMC Journal reference) which discusses the "bath tub" curve OPEX profile over the life of infrastructure assets. The accepted view in asset management is that new assets need more OPEX as new components have a higher failure rate through manufacturing, assembly and installation. Once the initial settling in period has passed, the OPEX settles to a lower rate and may slowly increase over time as age, condition and utilisation impact on the equipment's reliability.

The other part of the discussion also ignores that average and the condition of assets across the network and the OPEX needed to maintain the existing assets. In many cases, new assets are required to replace asset at the end of their life or capacity, but the average age of the assets across the network may not have changes. As mentioned previously in the Demand section, the Distribution and Transmission Asset Management Plans and discussions with Western Power's asset management staff indicated that the average condition and age of the assets was increasing and that a significant liability for renewals should have been forecast. However, the investigation into Western Power's information systems did not find evidence to support this observation. Generally then information available to the review team had a short time line of five years, which for long life assets does not provide a holistic picture of the future CAPEX funding needs.

Our belief is that as Western Power's current assets age, the cost of OPEX will increase until that number of assets being renewed balances the age deterioration of existing assets.

Nutall's hypotheses is only valid in the CAPEX improves the average age, condition or performance of the network. Given the current state of Western's Powers assets and the average age of the assets, it will be many years before the Nutall hypothesis will be a valid argument. The Asset Management Council does not support Nutall's hypothesis and in the Asset Management Journal (Issue 1, Volume 3 2009) in an article titles "Common Errors in Maintenance Reliability Theory and Practice" by D Shermin, discusses the "bath tub" curves which show that the probability of failure of asset components is highest during the first third of its life (related to quality issues) and then declines during the second third (random failures) before increasing in the final third (wear our stage). The article explains failure modes and frequency analysis and the impacts of component renewals on the system failure rates. The article is an example of many maintenance engineering texts and articles that recognise the "bath tub" and refutes the Nutall hypothesis.

GHD does not support GBA's direct correlation between CAPEX and OPEX for Western Power, because it ignores the current condition of the assets and the minimal impact CAPEX over the AA3 period will have on OPEX liabilities and uses a false argument that new assets do not need operation or maintenance.

3.4 Economies of Scale Factors

GBA believe Western Power should demonstrate operational efficiencies in its AA3 forecasts. GBA has applied an economy of scale factor to the network growth and customer growth escalators. This has been based on their assumptions regarding Western Power's proportion of fixed to variable cost components associated with operating expenditure. GHD makes the following observations:

- GBA's proposition in their report that Economies of Scale (EOS) arise because opex is an aggregate of a fixed cost component and a variable cost component. As the network increases in size variable costs will increase but fixed costs will remain unchanged. GHD does not agree with GBA's assessment and proposes that opex is directly related to the number and type of assets within a network. Fixed cost, such as condition and performance inspections are a planned activity and the cost is based on the extent of the inspection (time taken for the task) and the frequency that it is required to be performed. Therefore the more assets a utility owns, the more fixed costs are incurred. The only opportunity for cost saving is where there is space maintenance capacity or where additional assets are in the same location and travel time can be shared. Based on the geographic spread of Western Power's network, travel costs optimisation would be very minimal and unlikely to contribute to any economies of scale savings. The underling presumption here, again appears to be that the condition of the SWIN equals the condition of the NEM whereas the GBA report concludes in the case of unassisted asset failures it is deemed to be 4-20 times worse than the NEM.
- GBA claim that Transmission assets require active operation whereas many assets incorporated into the composite networks growth indicator used for escalation purposes, including low voltage

lines, distribution voltage spur lines and distribution transformers have little impact on a distribution network's operating costs.

From the operational perspective this is considered incorrect since these asset classes can be operated on a daily basis to facilitate new connections, switching interconnection and voltage regulation activities.

We consider the application of 30% and 95% EOS factors could potentially grow the opex backlog in the SWIN rather than reduce it as a result of the reduction in funding and reasonably the reduction in delivery of associated programmes.

3.5 Efficiency Adjustments

GBA have assessed from the SPOW programme and its own benchmarking that Western Power is capable of demonstrating greater operational efficiencies in the AA3 forecasts. GBA have applied a 2% compounding efficiency dividend to Western Power's total operating expenditure. GHD makes the following observations:

- The GBA proposition that a 2% efficiency dividend should apply to Western Power's total operating expenditure is again predicated on the overall condition of the electricity network being better than it is currently.
- As much of the operating expenditure is delivered through alliance contracts the efficiency adjustment needs to take into account the gains possible using this approach. There is insufficient information for GHD to form an opinion on this issue.

3.6 Strategic Program of Works Expenditure

The GBA report has reviewed in detail Western Power's Strategic Programme of Work (SPOW) with a focus on the cost overruns relating to the AA2 programme. Some portions of these cost overruns have been deemed to not satisfy the New Facilities Investment Test (NFIT). GHD is in general agreement with the GBA on cost overruns and makes the following observations in support of Western Power's response to the ERA draft determination:

- The original proposed AA2 SPOW forecast capex for MWS and ISAM passed NFIT as prescribed in the Access Code Section 6.52. There was no data provide for assessment of MDM.
- The question of whether the cost overrun portions meet NFIT is answered if the forecast cost to complete inclusive of the total cost to date for each SPOW project would pass a fresh NFIT test.
- This level of project review is common practice within the private sector and GHD would expect it to be so in the public sector. GHD has not examined financial detail relating to the cost overruns and assumes the stated figures to be correct.
- GHD considers, without detailed knowledge of individual delegated financial authority levels within Western Power, the unapproved cost overruns as stated to be excessive and well above those that would be expected in the private sector.
- IT appears that the level of project management being applied to the portfolio of SPOW projects is below expected commercial standards in view of the magnitude of cost overruns estimated to be 22% of approved capex. There appears to be a lack of adequate cost control processes or earned value reporting.

GBA appear to have played to Western Power's project management weaknesses on behalf of ERA and therefore GHD recommends these are addressed assertively in the AA3 draft determination response in a manner that positions Western Power to win the confidence of ERA that the cost overruns can be arrested and that firm estimates of costs to complete for each SPOW project can pass a fresh NFIT test.

3.7 Review of Efficiency of Network Control Services

The GBA report has recommended to ERA that the in the application of Network Control Services (NCS) by Western Power, associated operating expenditure should not be included in the network operator's revenue cap. GHD disagrees with this recommendation and makes the following observations:

- The Electricity Networks Access Code 2004 under Chapter 6 Price Control is very clear under Non Capital Costs Clauses 6.40 and 6.41 that a network operator pursuing the augmentation of a covered network is entitled to include the non-capital cost(s) component of the approved total cost(s) provided it is commensurate with those incurred by a service provider efficiently minimising costs. The Code is equally clear that where a service provider considers alternative options to provide covered services and choses one of those options then they are entitled to include the non-capital cost(s) component of the approved total cost(s) provided it is commensurate with those incurred by a service provider efficiently minimising costs. The recommendation to ERA as contained in the GBA report is in our opinion inconsistent with the Access Code provisions.
- The GBA report suggestion that Western Power recover all Network Control Services (NCS) costs through the Access Code provision contained in Clause 6.76 is not unreasonable. However from the network asset augmentation perspective, the required growth and capacity investment in the network employing traditional capex methods versus NCS, it could be further argued and interpreted under the Access Code that both approaches are inextricably linked therefore the latter should be treated as legitimate opex.

Western Power advises that they not be able to recover NCS opex costs through the Access Code and therefore it is recommended that Western Power make the above point strongly in the response to the ERA draft determination. It is recommended that the principles underpinning the accepted NCS process are stressed and as a legitimate alternative to conventional network capex expansion it only needs to pass the New Facilities Investment Test (NFIT) to be accepted and implemented into the network. This premise is implied under the service provider efficiently minimising costs condition.

4. Conclusions

GHD has completed a preliminary review of the ERA Technical Consultant's Report prepared by Geoff Brown and Associates (GBA), New Zealand and as provided to us by Western Power.

In the time frame available the preliminary review has comprised a study of the GBA document by GHD's Norman McKendry and Mark Bourhill with reference to Western Power's AA3 Access Arrangement Submission and the Access Code primarily in the seven key focus areas (KFA) as stipulated by Western Power.

In the seven key focus areas, GHD has found the GBA report to be generally a comprehensive assessment of the AA3 with well reasoned conclusions and recommendations. Notwithstanding this view GHD believes that alternative conclusions and recommendations may be drawn from the assessment of AA3 and as such we disagree or offer alternative opinions to GBA in the following areas.

In the KFA Field Data Capture, GHD believes that a GBA recommended reduction of 50% in the OPEX requirement forecast by Western Power is unreasonable if there are tangible benefits to be gained through effective implementation of the Field Data Capture Programme. GHD recommends that a revised and more cost effective scope of works is an imperative for Western Power to develop and include in its response to the ERA draft determination given the current condition of the South West Interconnected Network (SWIN).

In the KFA Peak Demand, GHD has formed alternative views on a number of GBA recommendations and conclusions. They are:

1. The GBA apparent conclusion that there is a direct one to one relationship between peak demand forecast and growth related investment ignores in our opinion the complex and necessary interdependence between the growth related investment and the existing network condition.
2. The GBA apparent conclusion that if the SWIN network successfully sustains a significantly higher than forecast peak load, it will follow in real terms that the network investment requirement could be reduced in AA3, oversimplifies in our opinion the issue as to whether the network can maintain its regulated target performance under sustained peak load conditions.
3. The GBA view of the Forecast AA3 Transmission Capex for the regulatory compliance requirements during the first three years of AA3 does not appear to fully recognise and reflect the formal findings and concerns expressed by the WA Government Parliamentary Enquiry and the Energy Safety Regulator 2009 Order.
4. While the GBA report acknowledges the valid reasons for lower than forecast capex in AA2, this does not translate to reasonable acceptance of AA3 forecast growth related network investment. GHD is of the opinion that this is a significant underlying omission in the GBA argument.
5. The GBA report acknowledges the ageing Western Power asset base and the bias towards replacement of wood pole assets. However the GBA report does not appear to acknowledge the extent of the backlog of investment required in this asset class that now represents a significant

cost “bow wave” that dictates an accelerated forecast growth related network investment if the SWIN is to be restored to a stable condition that is comparable to benchmark networks in the National Electricity Market (NEM)

6. Perth CBD capex investment is reduced under the GBA report recommendation however there is insufficient evidence in the analysis for GHD to determine if the reduction has taken into full account the N+2 contingency requirement for the security of supply mandated for the CBD.

In the KFA Asset Maintenance GHD does not support the GBA report direct correlation between CAPEX and OPEX for Western Power because it appears to ignore the current condition of the assets and the minimal impact CAPEX over the AA3 period will have on OPEX liabilities. It also relies in our opinion on a false argument that new assets do not need operation or maintenance.

The KFA Economies of Scale the view put forward by GBA is that the as network increases in size variable costs will increase but fixed costs will remain unchanged. GHD does not agree with GBA’s assessment and proposes that opex is directly related to the number and type of assets within a network. The GBA viewpoint that Transmission assets require active operation whereas many assets incorporated into the composite networks growth indicator used for escalation purposes have little impact on a distribution network’s operating costs is not in our opinion correct. From operational experience these asset classes can be operated on a daily basis to facilitate new connections, switching interconnection and voltage regulation activities.

GHD has been unable to, within the time frame of this assignment; review the KFA Efficiency Adjustments in the depth we would have preferred. The two underlying issues in our opinion that work against the proposed 2% operating expenditure efficiency adjustment are common to the other key focus areas. They are the current condition of the SWIN network as benchmarked against the NEM networks and the field delivery issues that have resulted in under expenditure during AA2. It is recommended Western Power place a greater focus on these areas in its response to the ERA draft determination.

In the KFA Strategic Programme of Works Western Power has in our opinion and as assessed by GBA not adhered to the appropriate level of cost control and project management process. GHD recommends Western Power place a greater focus on these areas in its response to the ERA draft determination.

In the KFA Review of Efficiency of Network Control Services (NCS) it is GHD’s opinion that the Access Code makes clear provision for Western Power to recover associated NCS operating expenditure within its revenue cap. The Code provides that a network operator pursuing the augmentation of a covered network is entitled to include the non-capital cost(s) component of the approved total cost(s) provided it is commensurate with those incurred by a service provider efficiently minimising costs. The Code is equally clear that where a service provider considers alternative options to provide covered services and choses one of those options then they are entitled to include the non-capital cost(s) component of the approved total cost(s) provided it is commensurate with those incurred by a service provider efficiently minimising costs. It is recommended that the principles underpinning the accepted NCS process are stressed by Western Power in its response to the draft determination and as a legitimate alternative to conventional network capex expansion NCS only needs to pass the New Facilities Investment Test (NFIT) to be accepted and implemented into the network

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Draft	N McKendry	M Bourhill		N McKendry		16.5.12

Appendix H. Revised 2011 growth forecasts

Revised 2011 growth forecasts

Key Messages

Western Power's growth forecasts are revised annually as part of the annual planning cycle. Revised forecasts of demand, energy consumption and customer numbers have been prepared by Western Power since the initial submission to the Authority on September 30, 2011.

The growth forecasts have been revised as follows.

- **Peak demand forecast has been revised downwards from an average annual increase of 3.2% to a 2.9% increase**
- **Number of customers forecast has been revised upwards from an average annual increase of 2.4% to a 2.7% increase**
- **Energy consumed by distribution-connected customers forecast has been revised downwards from an average annual increase of 2.8% to a 2.2% increase.**

The revised growth forecasts reflect more recent data, better input assumptions and modelling approaches – particularly those related to the increased penetration of photovoltaic (PV) systems and the impact of increasing retail tariffs. SKM/MMA has independently assessed the methodology and forecast outcomes as being consistent with good electricity industry practice.

2011 growth forecasts

As part of the annual planning cycle, Western Power prepares its demand forecasts and publishes them in the Annual Planning Report (typically around November). The September 2011 submission reflected the 2010 demand forecasts and indicated that the 2011 forecasts would be available around November 2011.

The 2011 demand forecasts were completed and published in the October 2011 Annual Planning Report.[1]

The 2010 energy consumption and customer number forecasts were developed by Deloitte. Western Power has subsequently integrated the energy consumption and customer number forecasts into the annual demand forecasting process and so these forecasts have also been revised.

The 2011 forecasts for demand, energy consumption and customer numbers underpin Western Power's proposed revisions to the capital expenditure forecasts in this draft decision response.

The key changes to the average annual growth rates over the AA3 period are as follows:

- Peak demand forecast has been revised downwards from an average annual increase of 3.2% (2010) to a 2.9% increase (2011)
- Number of customers forecast has been revised upwards from an average annual increase of 2.4% (2010) to a 2.7% increase (2011)
- Energy consumed by distribution-connected customers forecast has been revised downwards from an average annual increase of 2.8% (2010) to a 2.2% increase (2011)

[1] Annual Planning Report 2011 - available on the Western Power website at http://www.westernpower.com.au/aboutus/publications/Annual_planning_report_.html

Western Power engaged SKM/MMA to independently review the forecasting method, input assumptions and results of the 2011 growth forecasts. SKM/MMA concluded that “the methodology and its application to be commensurate with good forecasting practice”[2].

SKM/MMA also recommended some further incremental improvements, which Western Power will implement as it evolves its forecasting practices in AA3 and beyond.

Western Power notes that the Authority’s technical consultant Geoff Brown & Associates stated that it had “reviewed Western Power’s demand forecasting methodology and consider it consistent with good industry practice”.[3]

The remainder of this appendix explains the changes to the peak demand, energy consumption and customer number forecasts between the 2010 and 2011 growth forecasts. Further detail is available in the 2011 Annual Planning Report (available on the Western Power website), 2011 Energy and Customer Number forecast 2011/12 to 2016/17[4] and the SKM/MMA report that are supplementary documents to the submission.

Reduction in the annual average increase in peak demand

In the September 2011 submission, Western Power indicated that it would revise its peak demand forecasts in November 2011 and that they would most likely be lower. Western Power did not expect that the reduction in peak demand would result in a material impact on our investment proposal because:

- Western Power’s capital investment requirements are driven by growth at the zone substation level. If a reduction in peak demand at the system level is not accompanied by a reduction in peak demand at those zone substations that require additional capacity, there will be no change in investment
- investment to increase capacity is necessarily lumpy. This means that often an increase in load will result in a larger increase in capacity as the minimum size of new facilities may be greater than the new load
- Western Power expects some reductions in peak demand at the system level due to the installation of photovoltaic (PV) systems. However, this will only reduce investment requirements if the PV systems are concentrated at locations with existing network constraints
- one result of lower demand forecasts may be to improve our compliance with the Technical Rules in areas where investment is not avoided but the spare capacity available has increased
- Western Power expects less variation in block loads as our forecasts do not include loads that are uncertain

This has proven to be the case and the impact of the revised demand forecasts on the investment proposal is discussed in the main Access Arrangement Information document.

A number of factors have contributed to the lower 2011 peak demand forecasts, which are explained in the 2011 Annual Planning Report.[5] The reduction in peak demand growth is predominantly due to the impact of PVs being taken into account for the first time.

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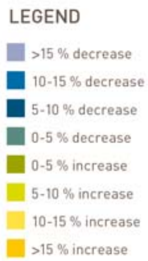
[2] Page 1, Review of Western Power’s Energy and Maximum Demand Forecasting Methodologies and Forecasts, SKM MMA, March 2012.
[3] Page 4, Technical Review Of Western Power’s Proposed Access Arrangement for 2012 to 2017, Geoff Brown and Associates Ltd, March 2012
[4] DM8655584, Energy and Customer Numbers Forecast 2011/12 to 2016/17, October 2011.
[5] Pages 56-57, Annual Planning Report 2011 - available on the Western Power website at http://www.westernpower.com.au/aboutus/publications/Annual_planning_report_.html

Figure 1 shows the variation in growth in capacity required by region by the end of the AA3 period.



REGION	FORECAST 2012 PEAK DEMAND (MW)	FORECAST 2017 PEAK DEMAND (MW)
Metro CBD	383	421
Metro North	1098	1302
Metro South	1361	1568
Metro East	196	237
Country North	240	267
Country South	450	532
Country East	200	203
Country Goldfields	79	90
TOTAL	4007	4619

Figure 1: Forecast increase in peak demand by region by 2017 (2011 Growth Forecasts)

The impact of PVs also affects the energy consumption forecasts which are described below.

<u>Increase in the annual average increase in customer numbers</u>

The 2011 forecast customer numbers for AA3 are slightly higher than the 2010 customer numbers for AA3. The changes result from a combination of more recent data with respect to actual customer numbers, input assumptions and modelling approach.

The 2010 forecast used projected household numbers from the Australian Bureau of Statistics (ABS) to derive residential customer numbers and discounted gross state product (GSP) forecasts for the business customer number growth. The ABS produces population projections every two to three years and these have not been updated by the Bureau since June 2010.

The 2011 forecast uses GSP to forecast changes to customer numbers for both residential and business. Although GSP is not typically used to forecast residential customers, the data available shows a strong correlation between GSP and the number of residential customers (R^2 = 0.99 for the RT1 anytime energy residential tariff).

The GSP forecasts utilised in the 2011 Energy and Customer Numbers forecasts for the AA3 period is 4% per annum which is consistent with WA Department of Treasury financial projections released in the 2011/12 State Budget Forecasts.[6] The more recent GSP forecasts are slightly higher than those underpinning the September 2011 submission.

Reduction in the annual average increase in energy consumption

The 2011 energy consumption forecast is lower than the 2010 energy consumption forecast. The differences reflect the inclusion of new inputs and data that were not included in the September 2011 submission such as the impact of PVs, weather variation and increasing retail electricity prices.

Impact of PVs

PVs reduce the amount of energy distributed across the network. PV penetration on Western Power's network has grown significantly over the last couple of years as a result of government incentives that have reduced the effective cost of PV systems for customers. The increasing demand has encouraged competition between an increased number of suppliers, which has helped to further reduce the costs of PV systems. More recently government incentives have been reduced. However, the costs of PV systems continue to decline and the PV penetration is expected to continue, albeit at lower levels.

The following chart depicts the assumed PV penetration scenarios. The central scenario, which reflects a return to the longer term growth rate of 2,000 PV systems per month, was used in the energy consumption forecasts.

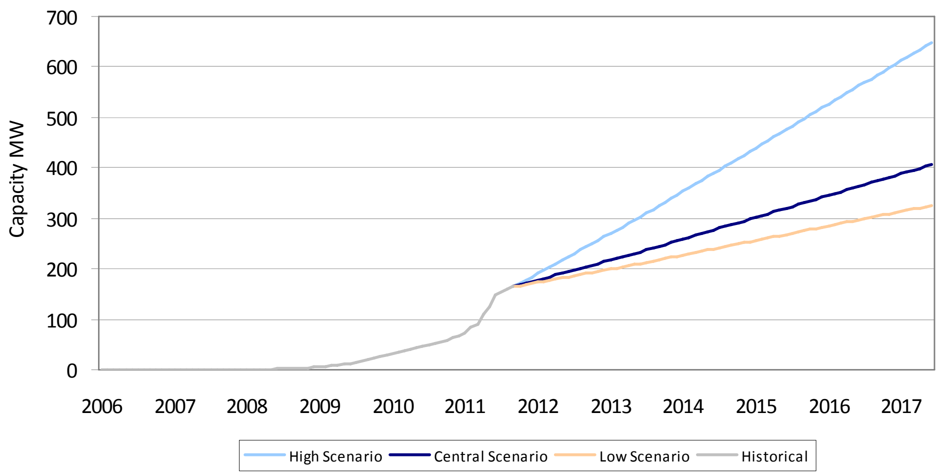


Figure 2: Forecast Photovoltaic Uptake

Impact of weather

The 2010 energy consumption forecasts did not account for weather variation on annual energy consumption. There was however relatively extreme weather in 2009/10 and 2010/11 which caused an upwards bias in the forecast. The revised forecasts prepared by Western

[6] 2011/12 Budget Overview, Government of WA, http://www.treasury.wa.gov.au/cms/uploadedFiles/State_Budget/Budget_2011_12/2011_12_budget_overview.pdf, May 2011.

Power in 2011 include weather, by utilising temperature as an input to the energy forecasting, and are not biased by the recent extreme weather.

The graph below shows the average monthly temperature observed over the period for which consumption data is available. An upward trend (blue trace) is visible in summer temperatures, and a downward trend is visible in winter temperatures. This trend is not expected to continue, and has not continued in 2011/12.

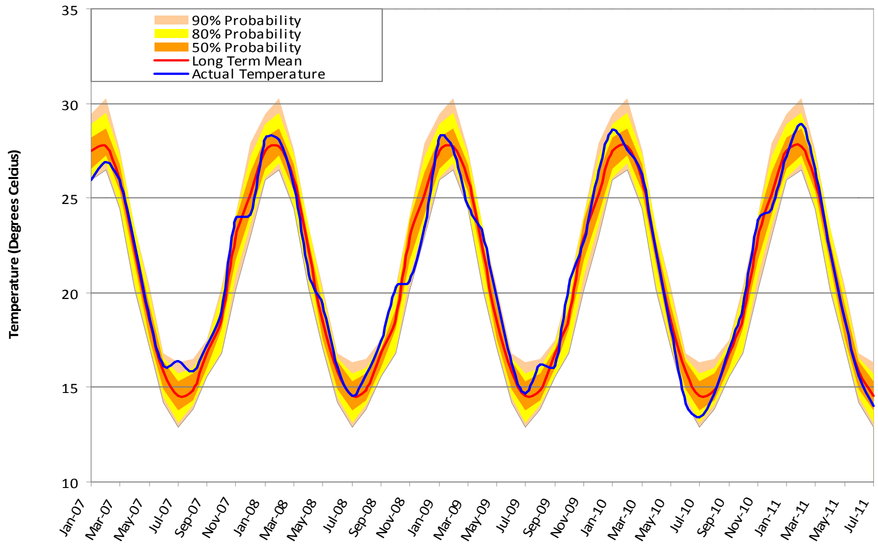


Figure 3: Analysis of Observed Mean Monthly Temperature

<u>Impact of increasing retail electricity prices</u>

Residential and small business retail electricity prices have increased recently after a period of being ‘frozen’. These increases are expected to continue in line with current government policy to transition to cost reflective tariffs.

A central price scenario was developed based on the assumed glide path for retail electricity prices in the State Budget papers. The assumed glide path is presented in Figure 4. The price elasticity of demand, which was developed and applied to each network tariff, ranged between 0 and -0.7.

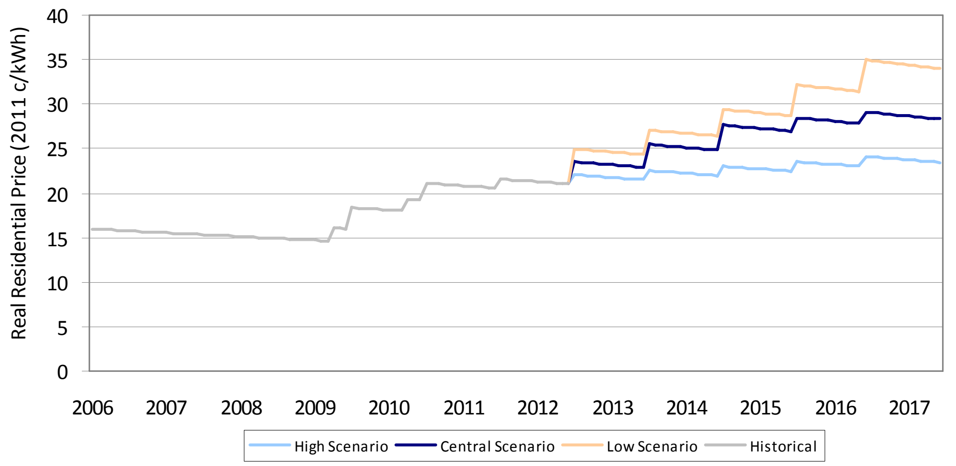


Figure 4: Forecast Residential Retail Unit Price

Charts and Tables depicting 2011 forecast

The following charts and tables show history and the revised 2011 growth forecasts. Where applicable, the 2010 growth forecasts are shown for comparison purposes.

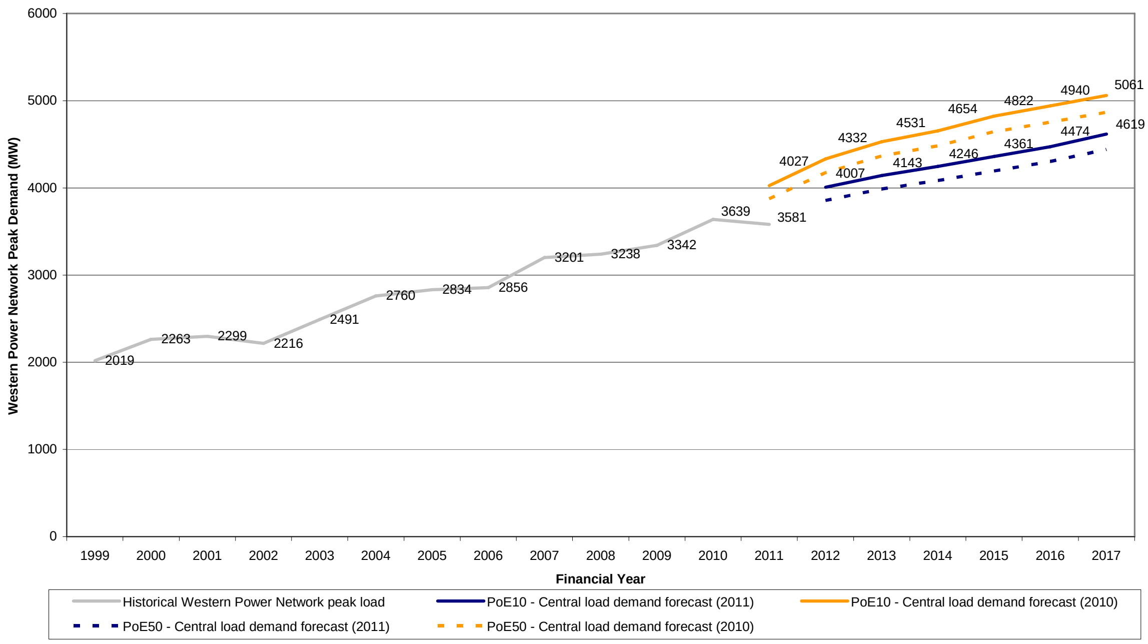


Figure 5: Peak demand forecasts 2011 – central growth scenario

Table 1: Peak demand forecast (MW) 2011 – central growth scenario

Western Power Network Peak Demand	2010/11 (Actual)	2011/12 (Forecast)	2012/13 (Forecast)	2013/14 (Forecast)	2014/15 (Forecast)	2015/16 (Forecast)	2016/17 (Forecast)
Actual Peak Demand (MW)	3581						
Demand Forecast (MW) PoE50		3857	3987	4086	4195	4302	4441
Demand Forecast (MW) PoE10		4007	4143	4246	4361	4474	4619
Annual Change (MW)			135	104	114	113	145
Annual Growth (%)			3.4%	2.5%	2.7%	2.6%	3.2%

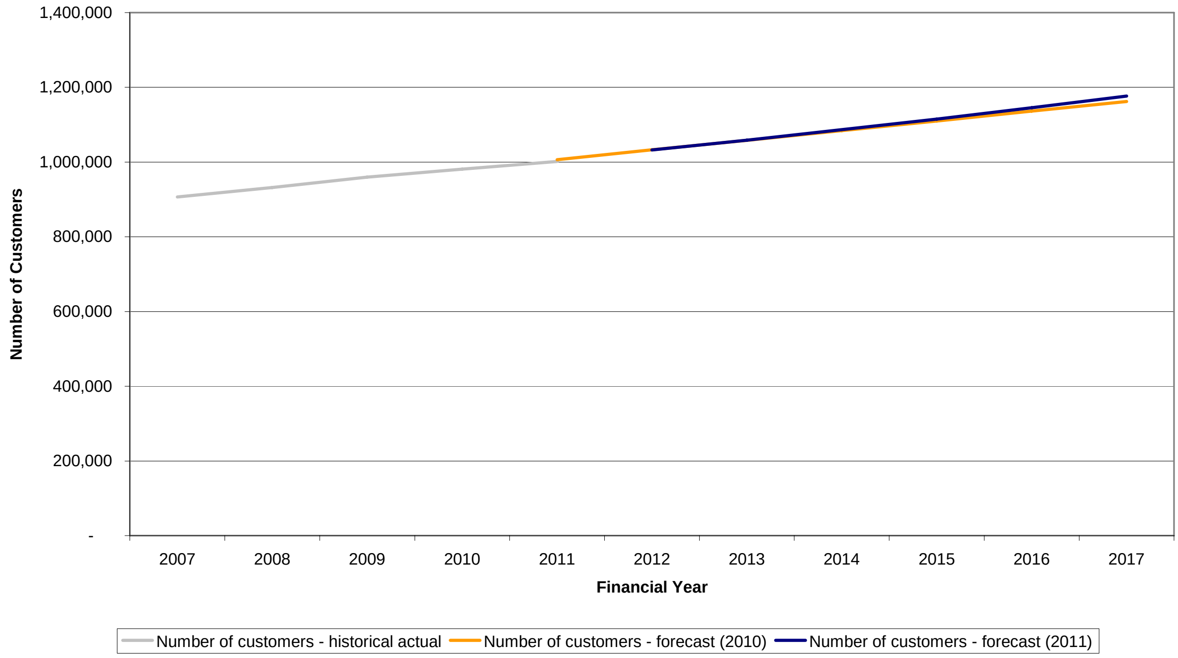


Figure 6: Forecast number of customers

Table 2: 2011 forecast number of customers, by customer group

Number of Customers	2010/11 (Actual)	2011/12 (Forecast)	2012/13 (Forecast)	2013/14 (Forecast)	2014/15 (Forecast)	2015/16 (Forecast)	2016/17 (Forecast)
Residential	898,774	927,623	953,161	979,719	1,007,337	1,036,057	1,065,925
Small Business	74,131	74,702	75,329	75,982	76,660	77,366	78,100
General Business Small	24,180	24,688	25,029	25,385	25,755	26,139	26,539
General Business Medium	2,865	3,025	3,122	3,223	3,329	3,438	3,552
General Business Large	1,100	1,193	1,255	1,320	1,387	1,457	1,530
Low Voltage >1MVA	165	173	179	185	191	198	205
High Voltage <1MVA	119	130	136	142	148	155	162
High Voltage >1MVA	376	381	384	388	392	396	400
Total Distribution Customer Numbers (ex SL & UMS & Tran loads)	1,001,711	1,031,914	1,058,596	1,086,344	1,115,199	1,145,205	1,176,412
Total Customer Numbers (ex SL & UMS)	1,001,743	1,031,948	1,058,632	1,086,379	1,115,234	1,145,241	1,176,448
Total Customer Numbers (growth p.a.)		30,205	26,684	27,747	28,855	30,007	31,207
Total Customer Numbers (% growth p.a.)		3.0%	2.6%	2.6%	2.7%	2.7%	2.7%

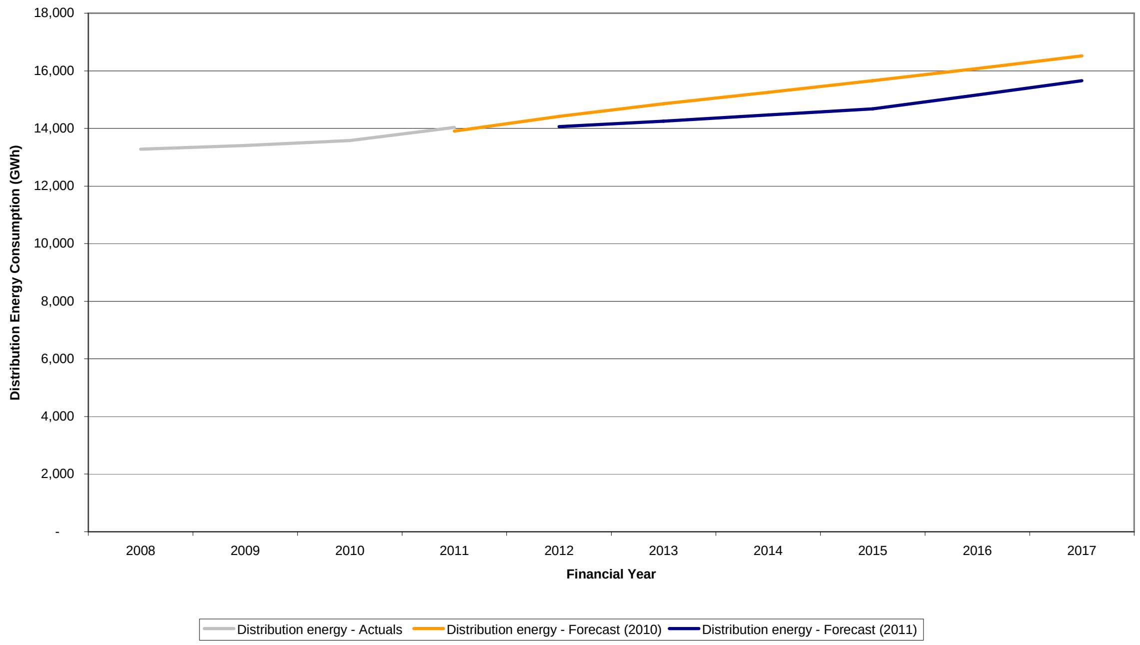


Figure 7: Forecast energy consumed by distribution-connected customers

Table 3: 2011 forecast energy consumed by distribution-connected customers (GWh), by customer group

Distribution Energy Consumption Forecast	2010/11 (Actual)	2011/12 (Forecast)	2012/13 (Forecast)	2013/14 (Forecast)	2014/15 (Forecast)	2015/16 (Forecast)	2016/17 (Forecast)
Residential	5,486	5,423	5,533	5,654	5,775	5,987	6,210
Small Business	547	539	544	551	557	575	594
General Business Small	1,618	1,614	1,601	1,592	1,579	1,618	1,667
General Business Medium	1,139	1,154	1,143	1,134	1,121	1,150	1,187
General Business Large	1,319	1,358	1,372	1,389	1,404	1,458	1,517
Low Voltage >1MVA	571	562	558	557	554	564	574
High Voltage <1MVA	171	185	196	209	221	235	249
High Voltage >1MVA	3,186	3,227	3,298	3,383	3,471	3,572	3,657
Total Distribution Connected Customers (ex S/L UMS and Tran)	14,037	14,062	14,246	14,467	14,681	15,160	15,656
Growth (GWh per annum)		25	183	221	215	478	496
Growth (% per annum)		0.2%	1.3%	1.6%	1.5%	3.3%	3.3%

Table 4: 2011 forecast sent-out energy (GWh)

Forecast Sent-out Energy (GWh)	2010/11 (Actual)	2011/12 (Forecast)	2012/13 (Forecast)	2013/14 (Forecast)	2014/15 (Forecast)	2015/16 (Forecast)	2016/17 (Forecast)
Distribution Consumption (ex S/L & UMS)	14,037	14,062	14,246	14,467	14,681	15,160	15,656
Distribution Consumption (UMS & S/L)	147	152	156	161	165	171	176
Distribution Consumption (Total)	14,185	14,215	14,402	14,627	14,847	15,331	15,831
Distribution Losses	661	662	671	682	692	714	738
Transmission (Dist connected)	14,846	14,877	15,073	15,309	15,539	16,045	16,569
Transmission Loads	2,603	3,134	3,565	3,721	3,950	4,031	4,020
Transmission Energy (T&D)	17,449	18,011	18,638	19,030	19,488	20,076	20,589
Transmission Losses	469	484	501	512	524	540	554
Sent-out Energy	17,918	18,496	19,139	19,542	20,013	20,617	21,144

Appendix I. Operating expenditure

I.1 Opex Scale Escalation Table

I.2 Opex Efficiency Examples

Scale driver	Source of data verification
Customer numbers	• Appendix I: Revised 2011 Growth Forecasts Summary
Distribution line length	• confidential Appendix X: Inclusion of line length and transformers for AA3 forecasting purposes • confidential Appendix X Distribution capacity expansion AA3 project list
Transmission line length	• confidential Appendix Y: Internal memo: Inclusion of line length and zone substation capacity for AA3 forecasting purposes • confidential Appendix Y: Transmission capacity expansion and customer driven increase to line length and zone substation capacity in AA3
Transmission zone substation capacity	• confidential Appendix Y Internal memo: Inclusion of line length and zone substation capacity for AA3 forecasting purposes • confidential Appendix Y: Transmission capacity expansion and customer driven increase to line length and zone substation capacity in AA3 • confidential Appendix Y: Internal memo: Inclusion of customer information for AA3 network growth forecasting purposes • confidential Appendix Y: Queue for Customer Solutions May 17th for AA purposes
Distribution transformers	• confidential Appendix X: Internal memo: Inclusion of line length and transformers for AA3 forecasting purposes • confidential Appendix X Distribution capacity expansion AA3 project list • confidential Appendix X: Customer driven transformer volumes

Efficiency of Western Power's operating expenditure

This appendix provides specific examples of the efficiency of Western Power's largest operating expenditure programs:

- Distribution corrective emergency and corrective deferred expenditure $582 million
- Distribution and transmission vegetation management $218 million
- Distribution and transmission pole inspections $141 million
- Distribution pole maintenance $135 million
- Distribution metering $114 million
- Transmission substation preventative routine $70 million
- Corporate Expenditure $576 million

Together, these programs make up approximately 69% of Western Power's operating expenditure.

Distribution corrective emergency and corrective deferred expenditure

Efficiencies in delivery method

Under the distribution corrective emergency and corrective deferred programs, Western Power responds to network faults, remedying them at the time of the initial emergency response (corrective emergency) or making the area safe and restoring power to customers ahead of full rectification works on a subsequent visit (corrective deferred).

Western Power's primary delivery method for corrective emergency and corrective deferred expenditure work in rural areas is via internal crews. This is because costs are minimised by using crews from country depots that are spread across the south west of Western Australia, reducing travel time and minimising restoration time for customers. The same work crews are used to conduct preventative maintenance activities in these areas to maximise labour utilisation (bundling across work programs where similar skill sets are used). A recently undertaken KPMG study into pole replacement unit costs (see section 9.2.2.2) has demonstrated that Western Power's internal crews were able to deliver at lower costs in country areas (compared to external service providers) driven by lower mobilisation costs.

Western Power's primary delivery method for this work in metropolitan areas is via internal crews. This is because in metropolitan areas, a specialised skill-set and detailed network knowledge is required to address faults on complex equipment (such as CBD switchgear) or that have the potential to impact many customers. In metropolitan areas, fault response personnel operate under a 'single person response' model with additional resources only mobilised as determined by the fault condition.

Western Power currently has 32 primary responders on a 24/7 roster to attend all metropolitan distribution network faults. These resources are supplemented with external contractors only during significant events (major storms). The unit rates for these services are negotiated in advance (annually) to control costs. Utilising internal crews to attend faults is consistent with good electricity industry practice as determined through comparison with Western Power's Australian peers.

Efficiencies in work packaging

Western Power introduced the Trouble Call System in August 2008. This system delivered a step change improvement in integration between the SCADA system and the distribution management system which enabled the business to automate the groupings of individual faults reports into efficient bundles ahead of field response. Figure 7 demonstrates the reduction in the individual trouble calls from the improved integration and call grouping of faults to be addressed. The system resulted in approximately a 40% improvement from 2008 to 2009.

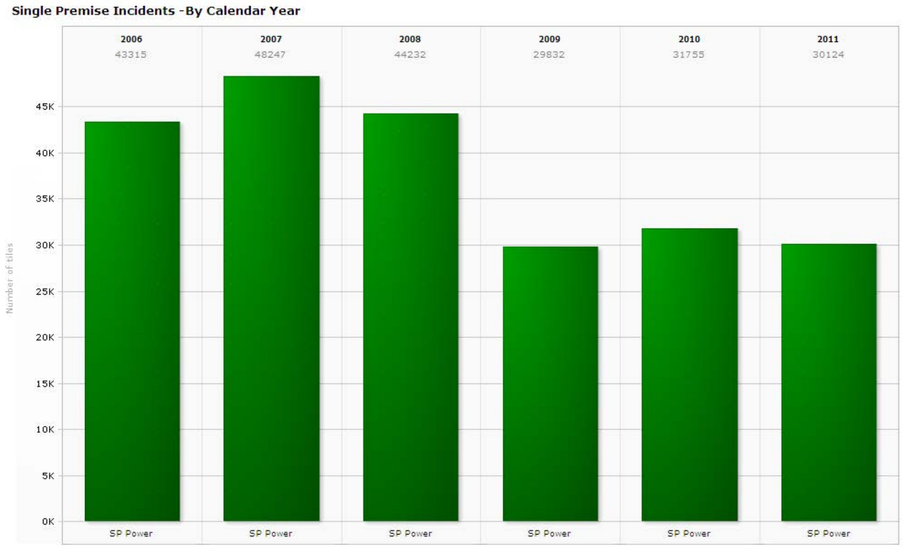


Figure 1: Number of single premise incidents addressed by fault crews

Conclusion

Western Power operates a minimum cost delivery strategy in rural and metropolitan areas through utilisation of internal crews. Rural crews have been benchmarked as delivering at lower cost than external providers. The need for detailed network knowledge and experience in addressing metropolitan faults, as recognised by Western Power's peers, does not align with an outsourcing model. The risk of losing network knowledge for the CBD area in particular would result in increased risk of long duration outages for metropolitan customers.

Western Power has introduced improved system technology to assist in identifying the source of faults to reduce fault response times by crews and improve visibility of where faults are located.

Given the level of faults occurring on the network is not expected to reduce and Western Power's delivery method is structured to minimise costs where possible, Western Power's only opportunity to reduce expenditure on this program would be to amend resource levels. This would mean reducing the number of crews or response staff allocated to addressing faults or restricting responses to non public-safety related faults to normal working hours to avoid overtime payments.

The impact to customers from this would be increased response times on faults reducing the service level experienced by customers and the ability to meet service standard benchmarks. This would also potentially breach Western Power's distribution license conditions to maintain compliance with the Electricity Industry (Network Quality and Reliability of Supply) Code 2005. Western Power is obliged, under sections 9 and 10 of the Electricity Industry (Network Quality and Reliability of Supply) Code 2005 to, as far as is reasonably practicable:

- ensure that the supply of electricity to a customer is maintained and the occurrence and duration of interruptions is kept to a minimum (section 9)
- reduce the effect of any interruption on a customer (section 10 (1)).

Distribution and transmission vegetation management

Efficiencies in delivery method and scope

Western Power's distribution and transmission vegetation management program is a critical component of its bushfire management and safety strategies. This program includes activities associated with vegetation inspection, fuse pole inspections and line easement vegetation maintenance. Under this activity, vegetation is inspected and any vegetation growing inside or likely to grow inside the clearance zone before the next inspection cycle is cut and removed. In particular, this activity ensures all lines in extreme and high fire risk areas are inspected and cleared by 15th November each year.

Western Power outsources delivery of this work to three service providers who specialise in vegetation inspection and cutting. The existing commercial arrangements were competitively procured via a market tender process in 2009. Western Power will undertake a new market tender process in October 2012. The current commercial arrangements include efficiency incentives which place 5% of the contract sum at risk subject to performance driven KPIs.

For distribution, inspection and cutting is packaged into geographic zones to reduce mobilisation costs. Through introduction of competitive tender processes and work packaging by geographic zones, Western Power has been able to reduce the unit rate over time as demonstrated in Figure 2.

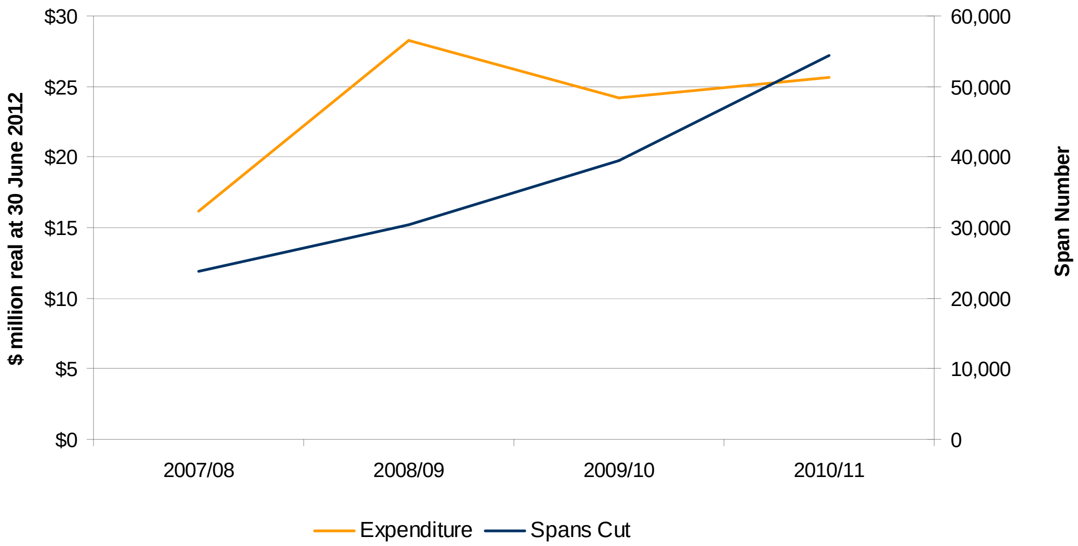


Figure 2: Cost of distribution vegetation cutting 2007/08 to 2010/11

For transmission, the whole network is inspected annually due to the importance of lines to network reliability and the increased risk to public safety, with cutting undertaken on individual lines as determined by the number of conditions present. Quality assurance activities are carried out by a mix of internal and external resources.

To manage network risk in allocating work packages to the multiple delivery partners, Western power ensures that no contractor has more than 40% of the estimated total volume of cutting across all programs and that each delivery partner has a balance of bushfire and non-bushfire cutting volumes.

Conclusion

Western Power operates a minimum cost delivery strategy for vegetation management as the external service providers were procured competitively and work is bundled geographically to efficiently minimise costs. The only opportunity to reduce expenditure on this program would be to amend the scope.

Options to reduce costs would be to reduce the volume of work and consequently increase cycle times. This could potentially lead to increased bushfires, public safety incidents and increased network outages and increased risk of asset initiated fires as a result of vegetation triggered faults. This would be inconsistent with good electricity industry practice and would increase long term costs. Faced with possible expenditure restrictions, Western Power would still undertake vegetation management activities in high and extreme fire risk areas choosing instead to stop activities in other maintenance areas.

Distribution and transmission pole inspections

Efficiencies in delivery method and scope

The power pole bundled inspection activity includes the inspection of wood pole, concrete poles, pole top hardware, conductors, sectionalisers, reactors and pole top switches. Under this category of expenditure, Western Power also undertakes any minor repairs that are able to be completed by the inspector. The outcomes of this activity is the serviceability status of the poles, pole top equipment and conductors in the form of a condition status and a serviceability index (SI) for every distribution pole.

Inspections and quality assurance checks on these assets are conducted by a combination of internal and external (contractor) supervisors.

Western Power outsources delivery of this work to two external service providers supplemented by a further external provider when required. The existing commercial arrangements were competitively procured via market tender processes in May 2010. Western Power will undertake a new market tender process in October 2012.

Western Power packages distribution pole inspections by geographic zone to reduce mobilisation costs. A similar process is followed in transmission for rural areas, with a quarter of metropolitan transmission lines inspected per annum.

Conclusion

Western Power operates a minimum cost delivery strategy for pole inspections as the external service providers were procured competitively and work is bundled geographically to efficiently minimise costs. The only opportunity to reduce expenditure on this program would be to amend the scope.

This could be achieved by increasing inspection cycles, which would be inconsistent with good electricity industry practice, Western Power's wood pole management plan and commitments to Energy*Safety*. In addition, reducing the frequency of inspections could result in conditions not being identified and addressed in a timely manner, increasing the risk of additional corrective emergency expenditure, pole failure incidents and related risks of bushfires and reliability issues.

Distribution pole maintenance

Efficiencies in delivery method and scope

The distribution pole maintenance program addresses conditions identified from bundled pole inspections and includes: maintenance of poles and pole tops, repair of burnt or broken line taps, maintenance and re-tensioning of conductors, replacement of insulators and treatment for white ants. Pole maintenance is a critical component of sustaining the life of the asset; it corrects pole conditions that are not addressed by Western Power's pole replacement and reinforcement programs which are targeted at high safety risks.

The maintenance policy is aligned and benchmarked with good electricity industry practice.

Western Power delivers this program via a mix of internal and external service providers in accordance with the balanced portfolio delivery strategy. The external providers include two distribution delivery partners (DDPs) established through a competitive market tender process in 2009. The existing contractual arrangements have been extended to June 2013 although Western Power will undertake a new market tender process in late 2012.

The existing commercial arrangements employ a 'staircase' pricing model which reduces unit costs for defined incremental increases in the volume of work. This has been included in AA3 forecasts.

Pole maintenance work is bundled with other work programs, for example pole and carrier replacement, which require similar skill sets. In addition, Western Power packages work by geographic zones to reduce mobilisation costs.

Conclusion

Western Power operates a minimum cost delivery strategy for pole maintenance utilising the balanced portfolio approach and ensuring external service providers were procured competitively. The work is bundled with other programs and zoned geographically to efficiently minimise costs. The only opportunity to reduce expenditure on this program would be to amend the scope. This would result in extended time to address defects / conditions, or could involve the implementation of run to failure strategies increasing the life cycle cost of assets. This could potentially lead to an increase in bushfires, electrocution and reliability incidents or increases in corrective emergency work.

Distribution metering

Efficiencies in delivery method and scope

Distribution metering operating expenditure consists of: manual and remote meter reading, data management (labour costs for data input, validation, analysis and management), compliance costs, information technology costs, meter reading systems and office & depot costs. The majority of meter reading is done via manual bi-monthly reads with estimates taken where Western Power is unable to get access for an actual read. Western Power aims to reduce the amount of estimates (currently 5% of meter readings) as much as possible as this causes inaccurate billing and is a major cause of customer complaints and dissatisfaction.

In 2007, Western Power transitioned from delivery arrangements which involved a mix of multiple meter reading agreements with different labour hire agencies as well as internal staff meter readers, to a more outsourced model. An external service provider was competitively procured via a market tender process in October 2007. This delivered savings in excess of $4 million over two years. In July 2009, Western Power outsourced a further 24 meter reader positions realising an additional $1 million per annum in savings. The commercial arrangements include performance based KPI's and incentive / penalty reward structures. Western Power will conduct another market supplier tender process in 2013.

Meter reads are geographically bundled together in routes of approximately 400 meters each. Routes are built on a suburb then street by street level to maximise door to door efficiency. Scheduled meter reading dates (bi-monthly) are common for all meters in a route to also improve efficiency.

Conclusion

Western Power operates a minimum cost delivery strategy for metering operating expenditure as services are primarily outsourced and were procured through a competitive process. The only opportunity to reduce expenditure on this program would be to amend the scope.

Western Power would be at risk of breaching type 2 compliance obligations under a number of clauses of the Metering Code and Code of Conduct for the Supply of Electricity to Small Use Customers for not collecting data, and not publishing data to market within prescribed times. Other potential breaches include failure to collect data on time for published meter reading cycles for retailers (as set out in the Model Service Level Agreement) and the Independent Market Operator.

There would be a risk to the accuracy of meter reads (and invoices) and timeliness of income for Western Power resulting in a rise in customer complaints relating to late and/or estimated bills.

Transmission substation preventative routine

Efficiencies in delivery method and scope

Transmission substation preventative routine includes the maintenance of substation primary plant, secondary equipment, substation batteries, ground and buildings maintenance and substation HV equipment testing.

Western Power bundles maintenance and testing activities within a substation to reduce the labour requirement and the number of outages and volume of switching tasks. This practice minimises costs and the impact of this necessary program on customers.

Western Power implemented this approach during AA2, as part of its transmission ‘smart planning’ initiative which minimises planned outages and mobilisation costs through optimal scheduling of transmission maintenance and capital activities. The initiative has been recognised by the Asset Management Council and earned Western Power a Bronze award in May 2011 in recognition of the successful implementation of this improvement initiative.

The majority of transmission substation preventative routine activities are undertaken by internal staff. This is because of the criticality of transmission assets and the need for specialised skill-sets and permits required to work in a substation environment.

Ground and buildings maintenance activities are bundled separately to the other substation maintenance and testing activities because they require a different skill set, one that is not as dependant on experience with critical transmission assets. These services are delivered via a number of external contractors whose services have been procured competitively via a market tender process.

Ground and buildings maintenance activities include security patrols, monitoring of security systems, fire extinguisher maintenance, air-conditioner maintenance, plumbing checks, cleaning, lift and hoist maintenance and substation vegetation management.

Conclusion

Western Power operates a minimum cost delivery strategy for substation preventive routine maintenance. This consists of a fit for purpose delivery model, utilising internal staff where network expertise is essential and bundling work to minimise costs and outages. Where the network experience is less critical, Western Power utilises external contractors that were procured through a competitive process. The only opportunity to reduce expenditure on this program would be to amend the scope.

Western Power participates in international benchmarking of its transmission operation and maintenance activities. The results from the most recent study indicate that Western Power’s substation maintenance costs are consistent with good electricity industry practice. However, substation service performance is lower than average as shown in Figure 3.

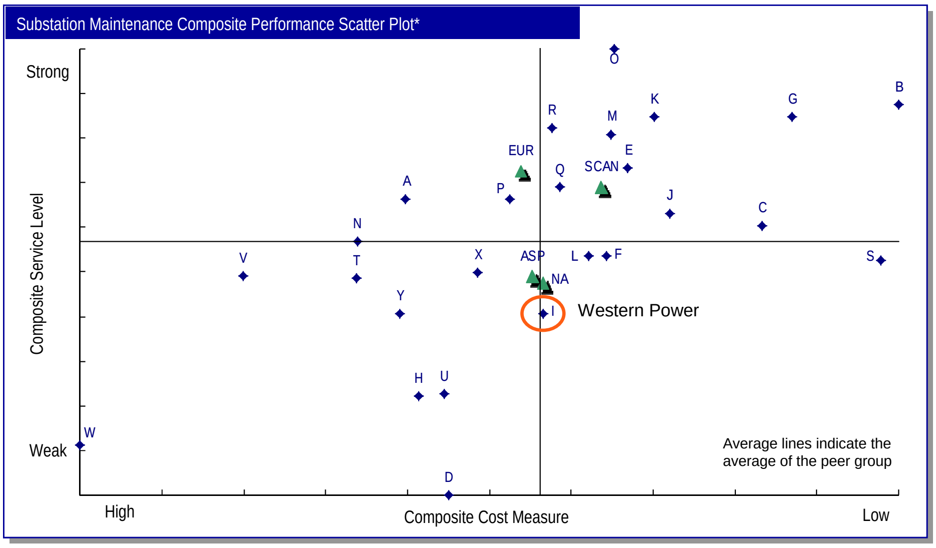


Figure 3: Benchmarking comparison of Western Power to peers for substation maintenance cost and service performance

These results confirm the challenges that Western Power faces due to underinvestment in these assets in the past and the deteriorating condition of assets that is now faced by Western Power. This is likely to have an impact on the number of faults or in-service failures. Any further reduction in costs for this program could only lead to reducing the scope of works, this would potentially lead to a further deterioration in performance.

To implement a reduction in scope, Western Power would need to modify its maintenance strategies to either reduce the frequency or the volumes of assets subject to inspections and testing. In either case, this is likely to result in:

- further deterioration in asset condition – asset condition will not be assessed at the optimal time for intervention
- increase in catastrophic failures – resulting in increased corrective maintenance costs
- potential for increased long duration outages, introducing network constraints and load shedding

In the short-term, Western Power would have to reserve some of the capital investment associated with substation asset replacement for addressing reactive failures of assets in-service. In the medium to long-term, Western Power would experience higher life cycle costs for these assets. Good electricity industry practice dictates the need of preventative maintenance to successfully avoid in-service failures. For example, a recent failure of equipment at the Eneabba substation caused damage to nearby equipment, resulting in repair work that was more than 3 times the cost than if the failed breaker had been maintained and replaced proactively. Failure of a circuit breaker at Muja substation was found to be 2.3 times the cost of proactive replacement. Failure of a current transformer at Kojunup substation was found to be 2.6 times the cost of proactive replacement. Network security was also impacted significantly more than necessary.

Corporate Expenditure

Corporate expenditure includes all of Western Power's operating overhead expenditure. All expenditure in this category is as a result of either Western Power's requirement to meet its statutory obligations or the non-discretionary costs of operating the business. As this expenditure is externally driven, Western Power is unable to recognise efficiencies without risking its ability to comply with its obligations under the code.

Statutory Obligations

Under the access code, Western Power is required to fulfil statutory obligations including but not limited to insurance, rates and taxes, workplace safety, financial reporting and regulation.

- Safety & Health – Western Power has made significant improvement in its lost time injury frequency rate through initiatives establishing safety & health as the businesses' number one priority. A reduction to this spend would compromise these initiatives, increasing the risk to Western Power of lost time injury inefficiency.
- Insurance - Western Power's forecasts are representative of collaborative approach between Western Power and its insurance broker. Using a broker ensures that the most competitive prices are achieved for the insurance required. An independent review has determined the forecasts to be reasonable. Western Power would be forced to reduce other programs to pay for any shortfall in insurance costs caused by the application of efficiencies to this expenditure.
- Rates & Taxes – Western Power's rates and taxes forecasts are derived from advice from the Valuer General's office and Western Power's actual tax liabilities during AA2. Western Power would be forced to reduce other programs to pay for any shortfall in rates or tax caused by the application of efficiencies to this expenditure.

Utilities

Western Power's consumption of utilities is being effectively minimised through the Vista project. Western Power is however, unable to affect the price paid for these utilities.

- Water – installation of water efficient fittings and a grey water system.
- Electricity - installation of energy efficient light fittings and controls estimated to reduce energy consumption by 40%.
- Capacity – Vista has increased the available work space at head Office by 20%.

Redundancy

The remaining expenditure within this category is the labour cost of supporting Western Power's statutory obligations and governance framework. The impact on Western Power of achieving escalating efficiencies on expenditure that it is unable to control will be to incur redundancies in order to continue to fulfil its obligations. The short-term cost of these redundancies will further compromise Western Power's ability to meet its obligations and severely increase the risk of non-compliance with the Access Code.

Appendix J. Wedgewood White – Review of Operating Expenditure Efficiency Adjustment

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Western Power

Review of Operating Expenditure Efficiency Adjustment

23 May 2012

Paul Webber

DM 9392377

1 Introduction

1.1 Terms of Reference

In its draft decision on Western Power's proposed amendments to its access arrangement for the period 1 July 2012 to 30 June 2017 (the AA3 period), the Economic Regulatory Authority (ERA) has imposed a 2% annual compounding reduction in real operating expenditure across both the transmission and distribution businesses. The ERA considers that a 2% annual compounding reduction in expenditure can be achieved through "efficiencies" in Western Power's operations.

I have been engaged by Western Power to:

- critically examine the method, analysis and logic relied upon by the ERA in reaching its draft decision on the ability to achieve real operating expenditure efficiencies of 2% p.a. compounding over the AA3 period and provide an opinion on the ERA or its consultant's method, analysis and logic;

- provide an opinion on the appropriateness and reliability of the ERA's technical consultant's benchmarking to determine an appropriate level of operating expenditure and ability to achieve real operating expenditure efficiencies of 2% p.a. compounding over the AA3 period; and

- provide an opinion on whether a target of 2% p.a. real operating expenditure efficiencies, compounding over the AA3 period, is consistent with the requirements of the Electricity Network Access Code (2004) (the Code).

My terms of reference are included in Appendix 2.

1.2 Relevant Experience

I have 20 years experience in the design and application of economic regulation, and pricing of electricity, gas and water services. For the past 16 years, my experience has been predominantly of Australian regulatory frameworks but I have also undertaken work in New Zealand, Namibia and India. A copy of my curriculum vitae is included in Appendix 1.

I am a director of Wedgewood White Ltd (WWL). WWL and its predecessor firm Wedgewood Consulting Ltd (WCL) have been engaged by Western Power on various occasions since 1999 to provide advice on regulatory and pricing matters. Our most recent engagement was in April 2009, when we were engaged (with NERA Economic Consulting) to report on the basic principles that should underpin an efficient economic test for new facilities investment and to recommend changes to Electricity Code and Western Power practices to reflect these principles. Details of previous engagements are included as Appendix 3.

In preparing this report, I have been assisted by my colleague, Paul White.[1] Notwithstanding his assistance, the opinions expressed in this report are my own.

I have read, understood and complied with the Federal Court Guidelines on Expert Witnesses.

1.3 Structure of the Report

Section 2 discusses Australian regulatory precedents for general efficiency adjustments applied to total operating expenditure.

Section 3 explains that the "X-factors" observed in National Electricity Market regulatory decisions should not be interpreted as efficiency dividends.

Section 4 examines the method, analysis and logic relied upon by the ERA in reaching its draft decision regarding the ability to achieve real operating expenditure efficiencies of 2% p.a. compounding for five years.

Section 5 discusses the reasonableness of relying on the GBA benchmarking to assess the potential for future efficiency gains.

Section 6 on whether a 2% annual compounding efficiency target is consistent with the requirements of the Code.

[1] A copy of Paul White's curriculum vitae is also included in Appendix 1.

2 Regulatory Precedents for General Efficiency Adjustment

Since the year 2000 there have been more than 50 regulatory determinations made by economic regulatory authorities establishing operating and maintenance forecasts for electricity transmission and distribution businesses in Australia.

The typical regulatory approach to setting the operating expense building block is to adjust entity forecasts for particular categories of expenditure where there is some engineering or economic basis for that adjustment.

To my knowledge only six of these determinations imposed a general efficiency adjustment to a transmission or distribution business's total operating costs. In addition, the ERA included a 1% p.a. compounding efficiency target (per connection) for controllable operating expenditure in its 2011 decision for Horizon Power. The ERA decision is distinguished from the other decisions because the efficiency target was applied to only controllable costs, assessed to be 35.5% of Horizon Power's total operating costs.[2] Those decisions are discussed in the remainder of this section.

2.1 Queensland Electricity Distributors 2001

In its 2001 determination for Energex and Ergon Energy, the Queensland Competition Authority's (QCA's) forecast of operating costs included annual efficiency improvements. Energex was assessed to be operating efficiently against Australian and international peers and a 1% p.a. efficiency improvement was set to maintains its ranking relative to other Australian distributors. Ergon Energy was assessed to be inefficient against Australian and international peers and a 2% p.a. efficiency improvement was set to bring Ergon Energy closer to the QCA's assessment of efficient practice over time.[3]

> *This level of improvement should see Ergon Energy make some progress toward closing the efficiency gap to ENERGEX over the four years of this regulatory period, at which time a further assessment can be made of the then relative position of both DNSPs and appropriate decisions made as to the required future efficiency gains.*

Ergon Energy over-spent the QCA's operating expenditure forecast.

Energex under-spent the QCA's operating expenditure forecast. In addition to efficiencies, Energex submitted that a significant driver of the under-spend in operating expenses was the need for additional capital expenditure which diverted resources away from operating programmes. That is, underspend against forecast was not achieved through more efficient expenditure alone: it was achieved by not spending.

---

[2] ERA, *Inquiry into the Funding Arrangements of Horizon Power - Final Report*, March 2011, pp. 51 - 57.

[3] QCA, *Final Determination - Regulation of Electricity Distribution*, May 2001, p.131.

By the time of the 2005 review, the QCA's engineering consultant, BRW, was of the view that the under-spend was unsustainable and inefficient.[4]

> *BRW's assessment was that:*
>
> *" . . . while Energex's documented maintenance practices and policies are generally sound and in accordance with current industry standards, the full potential of these policies has not yet been fully realised due to insufficient commitment of resources. As a consequence of this under-spending in opex, the Energex network is in danger of deteriorating to an unacceptable level."*
>
> *…BRW's assessment that Energex had under-spent on opex was supported by the [Electricity Distribution and Service Delivery Review], which found that:*
>
> *"Energex has not spent sufficient amounts in recent years on maintaining its system and, in particular, has not had an adequate focus on preventative maintenance, such as on vegetation management and cross arm inspections. This has significantly contributed to the number and duration of outages across Energex's system."*
>
> *…BRW's analysis showed that a major part of the forecast increase in opex was required simply to return Energex to more appropriate levels of expenditure. For example, the opex that BRW forecast for Energex in 2005-06, which was 32 per cent higher than Energex's opex in 2003-04, brought it broadly back into line with opex levels for comparable distributors. In addition, BRW allowed for a significant increase in corrective maintenance expenditure to make up for previous under-spending by Energex, particularly in the areas of service cable, sub-transmission line and pole top inspections, as well as thermoscanning and vegetation management.*

Energex's operational expenditure forecast for the 2005 review, whilst much higher than the previous spend, included a 1% annual non-compounding efficiency reduction on the base forecast. This was accepted by the QCA in its final decision. No general efficiency target was included in Ergon's forecast and none was imposed by the QCA.

2.2 Aurora Energy 2003

In its 2003 draft decision for Aurora Energy, the Office of the Tasmanian Energy Regulator (OTTER) proposed a 2% cumulative efficiency adjustment. Aurora argued that:[5]

> *Any efficiency factors should apply to individual building block cost components, and preferably individual cost items, where the*

---

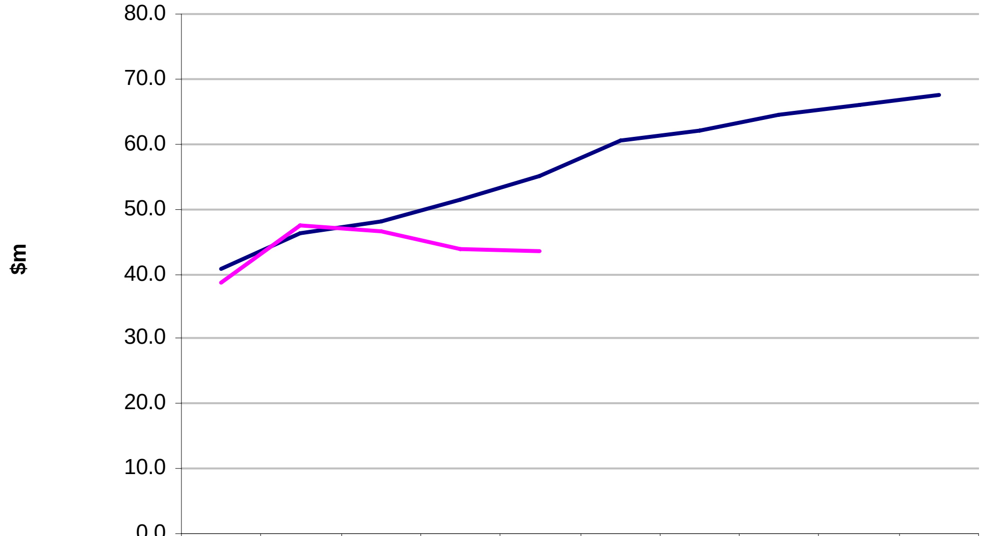
[4] QCA, *Final Determination - Regulation of Electricity Distribution*, April 2005, p.141 - 145.
[5] Aurora Energy, *Submission to the Electricity Pricing Investigation - Response to Draft Report*, July 2003, p.11.

appropriateness or otherwise of proposed targets can be assessed. At the very least the factors should not apply to certain un-reducible costs (vegetation management, LV cable replacement, electrical inspectors, additional personnel recently approved by OTTER, RNPP-approved expenditure, etc.) which already include significant efficiencies, are "locked in" through contract, or are competitively tendered.

In its final decision, OTTER reduced the efficiency adjustment to 1% cumulative and excluded certain expenditure categories. That is, in the final decision, the efficiency factor was not applied to total operating expenses.[6]

Figure 1 suggests that the forecast efficiency improvements were not achieved.

Figure 9: Actual and forecast operating and maintenance expenditure (June 2006$)



	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09	2009-01	2010-11	2011-12
Actual and Forecast	$40.7	$46.3	$48.0	$51.5	$55.1	$60.5	$62.0	$64.5	$66.1	$67.4
2003 Determination	$38.5	$47.4	$46.4	$43.8	$43.5					

Figure 1 – Aurora operating expenditure 2002 to 2006 (source: reproduced from OTTER report[7])

2.3 ActewAGL 2004

In its 2004 final decision for ActewAGL, the Independent Competition and Regulatory Commission (ICRC) set an operating efficiency target of 1% p.a. cumulative over the regulatory control period.[8]

---

[6] OTTER, *Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania - Final Report and Proposed Maximum Prices*, September 2003, p.88.
[7] OTTER, *Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania - Overview to the Draft Report*, July 2007, p.17.

ActewAGL's actual operating expenditure largely matched the ICRC allowance during the regulatory control period. However, in the subsequent period ActewAGL proposed expenditures approximately 23% higher in real terms, so it is not clear that any efficiencies were achieved.[9]

2.4 Transend 2004

The Australian Competition and Consumer Commission's (ACCC's) 2004 decision for Transend included a 2% compounding annual operational expenditure efficiency adjustment. On advice from its engineering consultant, GHD, the ACCC considered the TSNP's forecast of operational expenditure was not reasonable, requiring substitution with the ACCC consultant's own forecast which included a general 2% efficiency adjustment. The ACCC noted that the approach was unusual:[10]

> *The ACCC has not applied an efficiency dividend in its previous decisions. However, each revenue cap decision is unique. The circumstances of Transend are very different to other TNSPs…*
>
> *The efficiency dividend is applied to the base opex amount only and not to additional tasks which have been allowed at full cost. GHD notes in its report that some efficiencies could reduce such costs allowing for other unidentified tasks.*

In particular, the ACCC noted GHD's view that:

> *Given the high level of renewal capex and substantial increases in opex over historical levels, Transend should be able to achieve the 2 per cent efficiency dividend on its base costs without much difficulty.*

The forecast efficiency forecasts appear not to have been achieved. Indeed Figure 2 below shows that by the end of the regulatory control period, Transend's actual operating expenditure was some 45% above the ACCC's forecast.

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[8] ICRC, *Final decision - Investigation into prices for electricity distribution services in the ACT*, March 2004, p83 to p.85.

[9] Wilson Cook, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs Volume 5 – ActewAGL Distribution – Final*, October 2008, p.30.

[10] ACCC, *Final Decision - Tasmanian Transmission Network Revenue Cap 2004–2008/09*, December 2003, p.61.

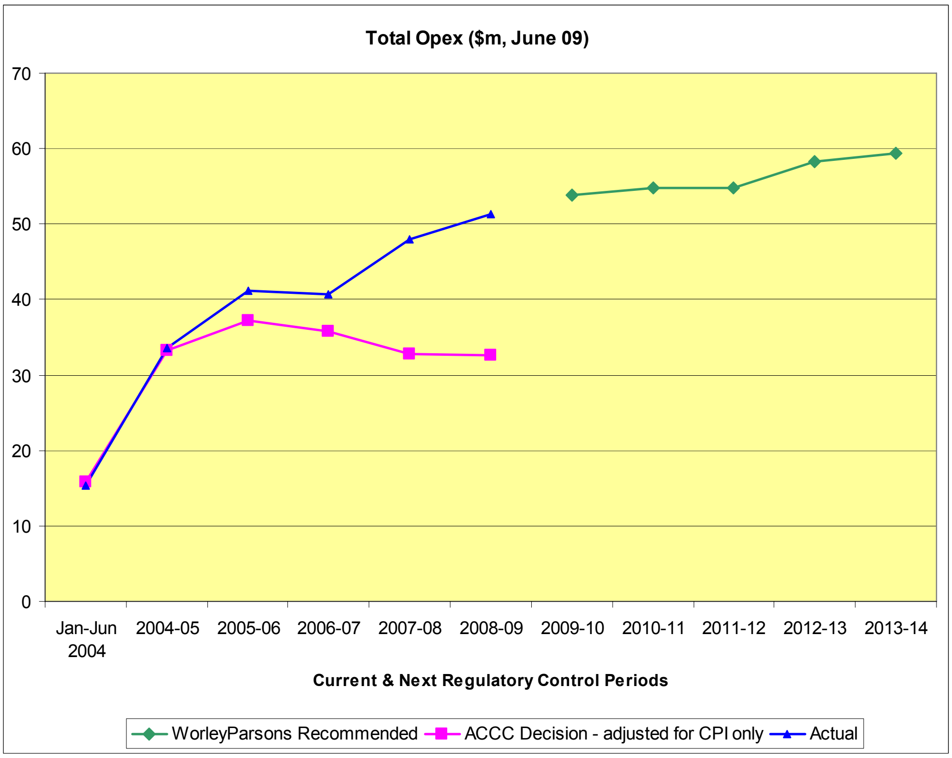

Figure 2 - Transend Opex 2004 to 2009 (source: reproduced from WorleyParsons' report[11])

For its 2009 review, the AER engaged WorleyParsons as its engineering consultant. Worley Parsons considered that Transend's proposed operating expenditure over the regulatory control period was efficient.[12]

> *WorleyParsons has studied the ACCC Decision on the level of Opex expenditure in the Current Regulatory Control Period, and does not understand the basis for that Decision.*
>
> *A detailed dissection of Transend's Opex data (to level 4 dissection) was presented. At this level of detail, WorleyParsons has investigated the cost trends and associated cost drivers in the Current Regulatory Control Period.*
>
> *WorleyParsons concluded that the reasons given by Transend for the cost trends are reasonable and indicative of a well run organization, complying with its statutory obligations in a prudent and efficient manner.*

2.5 TransGrid 2004

Also in 2004, the ACCC's decision for TransGrid included a 2% compounding annual operational expenditure efficiency adjustment to "represent expected productivity

[11] WorleyParsons, Review of the Transend Transmission Network Revenue Proposal, October 2008, p.16.
[12] ibid, p12

improvements" and to "[take] account of general productivity improvements in labour and in the services procured by TransGrid".[13] The adjustment was consistent with a recommendation of the ACCC's engineering consultant, GHD, which deemed TransGrid's methodology for estimating future operational expenditure to be flawed. In particular, GHD considered that TransGrid had identified potential cost reductions but had not included those reductions in its expenditure forecast.[14]

In its subsequent review, the AER formed the view that the forecast efficiencies had been achieved.[15]

2.6 Horizon Power 2011

In its 2011 decision for Horizon Power, the ERA included a 1% p.a. compounding efficiency target (per connection) for controllable operating expenditure in its 2011 decision for Horizon Power.[16]

> *Only a proportion of Horizon Power's operating cost are controllable in the short-term (35.5 per cent) so any efficiency gains should focus on Horizon Power's controllable operating costs. The problem with applying an efficiency target to controllable operating costs is the possibility that the proposed reductions to controllable operating costs from the efficiency target are offset by increases in costs resulting from increased demand for electricity. Increased demand can result from:*
>
> - *the number of customer connections increasing, as more customers connect to a network;*
> - *increases in electricity consumption per connection; or*
> - *both of the above.*
>
> *An alternative to presenting controllable operating cost data in total is to show unit operating costs per kWh or per connection. This removes the effect of growth in energy demanded or numbers of connections on operating costs which aids understanding of the real trends in costs over time.*

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[13]ACCC, *Draft Decision - NSW and ACT Transmission Network Revenue Caps – TransGrid 2004/05-2008/09*, April 2004, p31 and ACCC, *Final Decision - NSW and ACT Transmission Network Revenue Caps – TransGrid 2004/05-2008/09*, April 2005, p.50.
[14]GHD, *TransGrid Regulatory Review - Capital Expenditure and Asset Base, Operational Expenditure and Service Standards*, April 2004, p.67.
[15] AER, *Draft Decision - TransGrid transmission determination 2009–10 to 2013–14, October 2008*, p.109-110.
[16] ERA, *Inquiry into the Funding Arrangements of Horizon Power - Final Report*, March 2011, pp. 51 - 57

The decision for Horizon Power (an integrated electricity, network and retail business) is not directly comparable with the other decisions, which are for only the network part of the supply chain. However, I note that in the Horizon Power decision, the ERA:

- differentiated between costs that were controllable in the short term and those that were not controllable; and
- did not separately adjust for economies of scale and general efficiencies (the efficiency adjustment was applied to the per connection operating costs).

2.7 Summary of Regulatory Precedent

Australian energy regulators have used forward-looking efficiency adjustments for operating expenditure infrequently in the past. I have identified only six instances where a general efficiency adjustment has been made to a regulated electricity network's operating expenditure forecast since the year 2000. Given the large number of regulatory decisions made over that time period, such an adjustment cannot be considered normal or usual practice.

The typical regulatory approach is to adjust entity forecasts for particular categories of expenditure where there is some engineering or economic basis for such an adjustment.

To the best of my knowledge, a cumulative efficiency factor of 2% applied to total operating costs is the highest imposed in Australia since the year 2001.

Excluding the ERA's decision for Horizon Power, all of the precedents identified have occurred in the period to 2004 when Australian regulated network businesses were less mature and therefore efficiency improvements were more likely to be achieved.

Of the six cases that I have identified where a general efficiency adjustment has been imposed, there is only one case where the forecast improvements were clearly achieved (TransGrid). In other cases the operating forecasts were either over-spent (Aurora Energy, Transend, Ergon Energy) or the under-spend was followed by significant expenditure increases (Energex, ActewAGL). In no case was a similar general efficiency improvement imposed by the regulator in the subsequent regulatory control period.

3 Comparing the ERA Efficiency Adjustment with "X-factors"

I note that the ERA included a reference to Alinta Energy (Australia) Pty Ltd's submission regarding an "operating efficiency mechanism".[17]

> *Alinta suggested that Western Power should be subject to some level of base operating efficiency mechanism over the third access arrangement period, similar to the CPI-X framework of the National Electricity Rules.*

To the extent that the ERA has been influenced by this submission or that Western Power's customers are generally of the view the National Electricity Market approach to setting prices includes an additional efficiency mechanism that is not present in the Western Australia framework, this section explains that the "X-factors" observed in National Electricity Market regulatory decisions should not be interpreted as efficiency dividends.

In price control jurisdictions, the X-factor represents an average real price decrease. It is no more than an expected real price path. Because most TNSPs and DNSPs transport more energy per customer in each year, a regulator can set a positive X (i.e. real price decrease) even if costs are escalating at CPI (i.e. there are no efficiencies being achieved).

Moreover, the initial price reset (called P0 or X0 adjustment) and annual real price change (X-factor) can be used to deliver a range of price paths. Regulators use the combination of P0 and X to recover the NPV of target revenues. That is, any efficiencies are built into target revenues rather than arbitrarily being added by way of an additional efficiency factor.

The X-factor is an output that is a function of (amongst other things) expected growth in customers, growth in consumption per customer, changes in sales mix over the period, any one-off price changes, the relationship between DNSP cost escalation and forecast CPI, and productivity improvements.

For example, when in 2000 the Office of the Regulator-General (ORG) set an X-factor (called the X1-factor in Victoria) for Victorian DNSPs of 1%, this did not constitute a uniform 1% cumulative efficiency target for every business. It was merely the ORG's view of an appropriate price path:[18]

> *The Office has... set an X factor which is equal for each distributor for years 2002 to 2005. Setting the X factor the same for each of the last four years of the regulatory period smooths the tariff revenue earned over these years, in contrast to the revenue requirement, which moves more erratically.*

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[17] ERA, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, March 2012, p.79.

[18] ORG, *Electricity Distribution Price Determination 2001-2005, Volume 1 Statement of Purpose and Reasons,* September 2000, p.183.

> *The Office has set the X1 factor equal to 1 per cent. This 1 per cent level has been chosen to provide a relatively stable price path from 2002 to 2005, and to ensure that revenue earned in year 5 is close to the forecast revenue requirement in that year...*
>
> *The X0 factors have been calculated by setting the net present value (NPV) of the allowed tariff revenue over the period 2001-05 equal to the NPV of the forecast revenue requirement, for each distributor.*

To reiterate, any efficiency factors are built into the forecast revenue requirement, not separately added. The ORG's overall price change of 1% X-factor was simply a price path and not comparable with the ERA's proposed 2% efficiency adjustment for operating activities.

Similarly, in revenue cap jurisdictions, the X-factor is generally set to smooth the target revenue path. This was the approach taken by IPART in 1999:[19]

> *The 'CPI-X' component does not represent the impact of inflation and efficiency gains. The CPI-X factor is used to achieve the desired revenue path, resulting in end-year revenues consistent with the building block/pricing and financial/glide path outcomes. The building block components are indexed and the efficiency gains are built into the operating and maintenance expenditure.*

A growing utility that was expected to make no efficiency improvements in addition to the effect of economies of scale would require a negative X-factor under a revenue cap to allow the firm's revenue to increase to recover the additional costs of the additional customers and consumption. That is, a hypothetical productivity-frozen utility under revenue control would require a negative X-factor. As discussed above, the same business under a price control regime would have a positive X-factor.

For the avoidance of doubt:

- the X-factor does not represent the level of expected efficiencies; and
- revenue cap X-factors are not comparable to price cap X-factors.

As discussed in section 2 above, general future efficiency adjustments (such as that proposed by the ERA) are not usually applied by the AER (nor were they usually applied by former state-based regulators) under the National Electricity Rules. The most common approach under National Electricity Rules is to assume that current spending is efficient (because the regime as a whole provides incentives for efficient expenditure) and to make adjustments only to specific components of expenditure when a change in forecast expenditure is justified by the specific circumstances.

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[19] IPART, *Regulation of NSW Electricity Distribution Networks, Determination and Rules Under the National Electricity Code,* December 1999, p.13.

4 Examination of ERA's Method, Analysis and Logic

The first part of my terms of reference asks me to critically examine the method, analysis and logic relied upon by the ERA in reaching its draft decision on the ability to achieve real operating expenditure efficiencies of 2% p.a. compounding for five years and provide an opinion on the ERA's or its consultant's method, analysis and logic.

4.1 GBA's Analysis

Geoff Brown and Associates Ltd (GBA) was engaged by the ERA to undertake a technical review of Western Power's expenditure proposals for the AA3 period. With respect to Western Power's proposed operating expenditure, GBA concluded that Western Power should be able to achieve 2% compounding efficiency improvements in operating and maintenance expenditure. GBA based this conclusion on:

- high-level benchmarking of base year operating costs with aggregate distribution and transmission expenditure in other states;
- GBA's review of Western Power's expenditure governance procedures; and
- the fact that investments in Strategic Program of Works (SPOW) were justified on the basis that they would deliver operating efficiencies and that no such efficiencies were included in the operating expenditure forecast.[20]

GBA's opinion is, "It is difficult to assess the amount of efficiency gains that could potentially be captured during AA3 but, from what we have seen, an annual efficiency target of around 2% should be readily achievable."

4.2 Opinion related to GBA's Analysis

With respect to GBA's analysis (as discussed in section 5 below), it is my opinion that the benchmarking conducted by GBA can not be relied on to conclude that an operating efficiency improvement is possible, nor does it say anything regarding the magnitude of efficiency improvements that could be achieved by Western Power over a five-year period.

Section 3 of GBA's report provides some detail of its review of expenditure governance procedures but does not indicate the magnitude of efficiencies that could be expected from improved expenditure governance.

I agree that the expected operational savings attributable to SPOW (and any other capital projects that have the effect of improving operational expenditure efficiency) should be included in the operating forecast. However, GBA has not provided an analysis of the expected efficiencies attributable to SPOW.

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[20]GBA, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, March 2012, p.139.

Because no analysis was included in the GBA report to justify the magnitude of the recommended efficiency targets, it is not possible to conclude that the method, analysis and logic are reasonable. On the basis of the information included in the GBA report, I do not consider GBA's analysis a robust justification for concluding that Western Power could achieve real operating expenditure efficiencies of 2% p.a. compounding for 5 years.

4.3 ERA's Analysis

In its Draft Determination, the ERA considered that a 2% efficiency adjustment is appropriate:[21]

> *The Authority notes that the Western Australian Government's 2011/12 Budget required all government trading enterprises, including Western Power, to implement an efficiency dividend of 5 per cent each year from 2011/12 to 2014/15. It could be argued that the Authority should make a similar efficiency assumption when determining forecast efficient operating costs. However, the Authority considers that a 2 to 3 per cent annual efficiency target for each year of the third access arrangement period, combined with the adjustments detailed in this section, would result in an appropriate balance between setting the efficient costs while providing Western Power a strong incentive to strive for further efficiencies.*

The reasons stated for anticipating future efficiency savings were that:

- the allowed 2.6% real increase in business support costs should provide scope for efficiencies;
- Western Power's expenditure forecasts did not include any allowance for future efficiency gains;
- GBA's benchmarking of operating expenditure against levels in other states;
- GBA's opinion that the SPOW and IT improvements should yield efficiencies; and
- GBA's opinion that 2% efficiencies should be achievable.

GBA recognised that it will take Western Power some time to achieve efficiencies (for example from productivity improvements derived from better IT systems). GBA recommended that 2% efficiencies be included from the second year of AA3. The effect of GBA's recommendation is that the operating expenses built into the revenue cap in the final year of AA3 are approximately 7.8% lower than GBA's proposed expenditure before the efficiency adjustment.

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[21] ERA, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, March 2012, p.80.

However, ERA's draft decision imposes the efficiency reduction from the first year of AA3. The effect of the ERA's draft determination is that the operating expenses built into the revenue cap in the final year of AA3 are approximately 9.6% lower than ERA's forecast operating expenditure before the efficiency adjustment.

4.4 Opinion related to ERA's Analysis

It is unusual, but not unprecedented, for an economic regulator to propose reductions in expenditure greater that that recommended by its engineering consultant.

The ERA's requirement to add economy-of-scale factors to the scale escalation calculation effectively builds operating expenditure efficiency into Western Power's operating expenditure allowance before the additional 2% p.a. adjustment is applied.[22] That is, the ERA's proposed expenditure proposals include real efficiencies greater than 2% p.a. compounding because the general efficiency adjustment is made to the total operating expenditure, which already includes growth related efficiencies.

The potential to impose efficiencies twice because efficiencies are inherently built into the operating expenditure forecast mechanism was recently recognised by the AER:[23]

> *However, the AER notes Powerlink's opex and capex forecasts include some forecast efficiency improvements. In particular, the AER notes the economies of scale applied in the network growth escalation of Powerlink's opex. The AER agrees with Powerlink that applying labour productivity adjusted labour cost forecasts to these opex and capex forecast would double count these efficiency improvements to some extent since economies of scale will contribute to labour productivity.*

I agree with the ERA that some an efficiency improvement should be expected and, as discussed above, that the expected operational savings attributable to SPOW (and any other capital projects that have the effect of improving operational expenditure efficiency) should be included in the operating forecast.

However, I do not consider ERA's analysis a robust basis for concluding that Western Power could achieve real operating expenditure efficiencies of 2% p.a. compounding for 5 years.

I consider that a robust assessment of the magnitude of possible future efficiencies should include an analysis to identify:

- components of costs that are likely to be efficient and components that are candidates for efficiency improvements; and

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[22] ERA, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, March 2012, pp 66 - 67.
[23] AER, *Final Decision - Powerlink Transmission determination 2012–13 to 2016–17*, April 2012, pp 57 - 58

- the extent to which costs are controllable over the forecast period.

For example, regulated entities often contract operations and maintenance activities to third party service providers. Contract rates for various activities are often set by tender for the period of several years. In this case the expenditure is:

- prima facie efficient (having been subject to competitive tender and therefore include market assessment of both current efficient costs and achievable efficiencies over the contract period); and
- not controllable by the regulated business in the short term.

Western Power's Works Delivery Strategy does not separate works allocation by capital and operating expenditure. Assuming that capital and operating programmes are delivered by the same mix of internal and external resources, then approximately 28% of direct operating costs would be provided by internal labour.[24]

Table 1 shows the ERA's draft determination operating expenditure decomposed into categories, assuming that 28% of direct operating expenses are provided by internal labour.[25] The efficiency target is 9.6% of total costs.

	2016/17
Direct O&M - Internal Labour	95.8
Direct Opex - Other	246.3
Indirect Opex - Business Support	73.6
Indirect Opex - Other	38.6
Total Opex before ERA Efficiency	454.3
ERA Efficiency Target	-43.6
Total Opex after ERA Efficiency	410.7
Reduction in Total Opex (%)	9.6%

Table 1 – ERA's 2016/17 Opex Allowance decomposed into Internal Labour, Business Support and other costs (source ERA, PW analysis)

Table 2 shows that if the ERA's prospective 2% efficiencies must be obtained from only internal labour and business support, then by 2016/17, real expenditure in these categories would need to be some 26% lower than the ERA's amended forecast. This is unrealistic in my opinion.

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[24] Western Power, *Works Delivery Strategy July 2012 – June 2017*, August 2011, p.65.
[25] The "business support costs" category excludes rates, taxes and insurance, which I have categorized as "other" and non-controllable for the purpose of this analysis.

	2016/17
Direct O&M - Internal Labour	95.8
Direct Opex - Other	
Indirect Opex - Business Support	73.6
Indirect Opex - Other	
Total Opex before ERA Efficiency	169.4
ERA Efficiency Target	-43.6
Total Opex after ERA Efficiency	125.8
Reduction in Selected Categories (%)	26%

Table 2 – ERA's 2016/17 Opex Allowance showing Internal Labour, Business Support only (source ERA, PW analysis)

I acknowledge that the above example is simplified. Western Power uses a variety of contracting methods, ranging from alliances (with gain sharing mechanisms) to standard contracts for particular projects, and some of these mechanisms may deliver cost savings within the regulatory control period. However, the general point is that a significant proportion of expenditure is already efficient. Moreover, the mechanisms used to ensure that costs are reasonable (various forms of contracting to achieve price discovery) necessarily limit the subsequent rate of reduction in costs (because rates are to a greater or lesser extent "locked in" by those contracts).

By way of comparison with the ERA approach, in its 2006 determinations for Victorian electricity distribution businesses the Essential Services Commission of Victoria (ESCV) specifically considered expected future labour productivity improvements and the proportion of operating expenditure to which these improvements could be applied. The ESCV considered both Victorian and international estimates of electricity distribution industry labour productivity and decisions from other Australian regulators. The labour productivity estimates were approximately 1% p.a. and this was applied to only a proportion of total operating and maintenance expenditure.[26] The effect, therefore, of the proposed efficiency improvements would be significantly less than 1% p.a. of total operating and maintenance expenditure.

As discussed in Section 2.6 above, the ERA considered short-term controllable and non-controllable costs in its 2011 decision for Horizon Power. The 1% p.a. compounding efficiency target was only applied to 35.5% of Horizon Power's costs.

As discussed in Section 2.7 above, to the best of my knowledge, a cumulative efficiency factor of 2% p.a. applied to total operating costs is the highest imposed in Australia since the year 2001.

I can find no evidence that any analysis was carried out by GBA or the ERA to determine that a 2% compounding efficiency improvement is achievable in the particular circumstances of Western Power.

[26] ESCV, *Electricity Distribution Price Review 2006-10 - Price Determination as amended in accordance with a decision of the Appeal Panel dated 17 February 2006 - Final Decision Volume 1 - Statement of Purpose and Reasons,* October 2006, pp. 205 - 211

5 Analysis of GBA Benchmarking

GBA and the ERA based their conclusions regarding the potential for future efficiencies in part on operating cost benchmark analysis undertaken by GBA.

The second part of my terms of reference asks me to provide an opinion on the appropriateness and reliability of the ERA's technical consultant's benchmarking to determine an appropriate level of operating expenditure and ability to achieve real operating expenditure efficiencies of 2% p.a. compounding for five years.

5.1 GBA's Benchmarking Approach

GBA's benchmarking analysis is set out in 10.3.1.2 of its report.[27]

> *Western Power is the only electricity network business in Australia to operate an integrated transmission and distribution network. This means there are no similar businesses in Australia with which Western Power can be directly benchmarked or compared.*
>
> *To overcome this, we have aggregated the transmission and distribution businesses at a state level and compared Western Power with the aggregated operations in each state. Data for the aggregation was taken from reports published by the AER on its web site. This in itself was difficult since the AER does not publish a consistent data set covering all businesses. Hence the data used for the benchmarking was taken from different reports and did not always relate to the same year. Where possible we used actual rather than forecast data, although in two cases we relied on forecast data from the AER's most recent regulatory decisions.*

GBA presented three benchmarks:

- operating expense per km of line;
- operating expense per customer; and
- operating expense per dollar of asset value.

5.2 Opinion related to GBA Benchmarking

5.2.1 General Assessment of GBA Benchmarking

GBA's benchmarks are for a single year of expenditure. In many cases operating and maintenance expenses change significantly over the period of a few years. For example, during times of high growth, businesses sometimes transfer resources into customer connection activity and network extensions and out of routine maintenance. Similarly,

[27] GBA, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, March 2012, p.115.

significant capital works programmes may divert resources away from routine operational activities. One-off maintenance programmes (for example, safety related equipment replacement) may also distort expenditures in any given year.

I consider that it is necessary to examine several years of expenditure to assess the "normal" level of expenditure before any conclusions can be drawn regarding the efficient level of expenditure. An alternative approach would be to work with comparator businesses to attempt to ensure that each business reported comparable, "normal" levels of expenditure.

The GBA benchmarks are for outcomes rather than practices or processes. Each state has different topographical characteristics, different climatic conditions, different load density distributions, and different asset age distributions and asset condition. Therefore there will be a different level of expenditure in each state even if all businesses were operating efficiently. It is not valid to assume that Western Power's expenditure is inefficient because the expenditure (per customer, circuit km or as a proportion of asset base) is higher than in other states.

If practices and processes are benchmarked, it is necessary to consider both programme level and total cost outcomes together. A business that sets its systems up to be best at one activity might necessarily be sub-optimal at something else. The best overall businesses might be not be the best in their field at any particular activity, but might make the best trade-offs between activities.

The AER has recently applied two dimensions of normalisation (e.g. opex per line length as a function of load density) to attempt to partially capture differences in network characteristics.[28]

The AER recognises the limitations of benchmarking for assessing efficiency:[29]

> *Benchmarking is a useful tool available to the AER to compare DNSPs. However benchmarking techniques require operating conditions to be accounted for so as to make firms more directly comparable. The limitations of benchmarking are frequently discussed in economic texts and were recently discussed in detail in the AER's recent decisions for South Australia and Queensland electricity distribution. In most benchmarking models, where a firm appears less efficient than its peers, it will be unclear whether this difference is due to real inefficiency, data noise or a failure of the model to account for some firm-specific factor. In order to minimise this problem high quality data is needed.*

[28] For a transmission example see AER, *Draft Decision - Powerlink Transmission determination 2012–13 to 2016–17*, November 2011, p.106.
[29] ER, *Draft decision: Victorian electricity distribution network service providers: Distribution determination 2011–15*, Appendix I, pp. 78–79.

Some of the general limitations of benchmarking and associated possible sources of error are:

- *that the results obtained from the benchmarking are sensitive to the adopted method*
- *that individual efficiency estimates remain sensitive to the assumptions regarding the adopted approach and model specification*
- *errors in the assumptions of the technique used to normalise the data*
- *errors in the selection of measured inputs and outputs (in particular, failing to correctly include relevant inputs or outputs)*
- *errors in the measurement or aggregation of the inputs or outputs*
- *errors in the assumptions about the information that can be obtained from relative productivity information and how that information is best extracted.*

The AER notes the following specific limitations may affect comparisons based on the benchmarking undertaken for this reset:

- *the lumpiness of the capex programs*
- *differing licensing requirements which exist between the NEM jurisdictions*
- *differences in whether DNSPs buy or lease assets*
- *differences in balance dates*
- *variations in the characteristics of DNSPs… and the age, size and maturity of their networks and the markets they serve*
- *capitalisation, cost allocation and other accounting policies, as well as regulated service classifications, are assumed to be the same across all DNSPs, and across regulatory control periods in the sample*
- *the sample includes a cross section of rural, urban and CBD DNSPs.*

For this review the AER has found limitations in the available data that may preclude properly accounting for these factors, especially when making comparisons of business performance between DNSPs in different jurisdictions.

5.2.2 Note on "Expenditure per Dollar of Asset Value" Benchmark

I consider that the "expenditure per dollar of asset value" benchmark is potentially misleading. As pointed out by GBA, the amount of efficient operating and maintenance expenditure per dollar of asset value is a function of asset age.

Consider two assets with a current replacement cost of $1000. Asset A has 45% of its economic life remaining and Asset B has 55% of its economic life remaining. The efficient expenditure on Asset A is higher because it is older, say $40 p.a. The efficient expenditure on Asset B is lower, say $35 p.a. Table 3 shows that the efficient "expenditure per dollar of asset value" benchmark can be very different for two assets (or asset bases) of different age.

	Asset A	Asset B
Replacement Costs	1000	1000
Remaining Life	45%	55%
RAB Value	450	550
Efficient O&M Expenditure	40	35
Opex per RAB Value	9%	6%

Table 3 – Efficient opex per RAB benchmark for assets of different age

Moreover the "expenditure per dollar of asset value" benchmark is also influenced by valuation practices and capital contribution policy.

Consider two identical new assets both created for $1000. Asset C is funded by the utility and the entire value is included in the RAB, and Asset D is 25% funded by capital contributions. The efficient expenditure on both assets is identical, say $30 p.a. Table 4 shows that the efficient "expenditure per dollar of asset value" benchmark can be very different for two assets (or asset bases) funded differently.

	Asset C	Asset D
Replacement Costs	1000	1000
Capital Contribution Funding	0%	25%
RAB Value	1000	750
Efficient O&M Expenditure	30	30
Opex per Asset Value	3%	4%

Table 4 – Efficient opex per RAB benchmark for assets of with different funding

5.2.3 Conclusion regarding GBA's Benchmarking

Appropriate benchmarking could be useful in focussing management on areas for improved performance and, potentially, indicating the magnitude of efficiency gains possible. Benchmarking is used by the AER and other regulators to inform decision making.

However, in my opinion, because:

- Western Power's integrated network businesses with different definitions of transmission and distribution activities from other states makes Western Power, difficult to compare to peers;
- GBA uses only one year of data; and
- the GBA analysis does not normalise for load density or other potential differences between networks;

GBA's analysis cannot, by itself, demonstrate that Western Power is inefficient nor provide guidance regarding the magnitude of potential efficiency gains.

6 Consistency with the Requirements of the Code

The third part of my terms of reference asks me to provide an opinion on whether a 2% annual compounding efficiency target is consistent with the requirements of Code.

6.1 Requirements of the Code

Provisions of the Code relevant to establishing the operations building block, include the Code objective, section 6.4, section 6.40 and the definitions of "efficiently minimising costs" and "good electricity industry practice".

The Code objective is set out in section 2:

> *Code objective*
>
> 2.1 *The objective of this Code ("Code objective") is to promote the economically efficient:*
>
> (a) *investment in; and*
>
> (b) *operation of and use of,*
>
> *networks and services of networks in Western Australia in order to promote competition in markets upstream and downstream of the networks.*
>
> 2.2 *The Minister, the Authority and the arbitrator must have regard to the Code objective when performing a function under this Code whether or not the provision refers expressly to the Code objective.*

The access arrangement must provide the service provider with an opportunity to earn revenue equal to the forward-looking efficient costs of providing covered services.

> 6.4 *The price control in an access arrangement must have the objectives of:*
>
> (a) *giving the service provider an opportunity to earn revenue ("target revenue") for the access arrangement period from the provision of covered services as follows:*
>
> (i) *an amount that meets the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved;*
>
> *plus:*
>
> (ii) *for access arrangements other than the first access arrangement, an amount in excess of the revenue referred*

to in section 6.4(a)(i), to the extent necessary to reward the service provider for efficiency gains and innovation beyond the efficiency and innovation benchmarks in a previous access arrangement;

plus:

(iiA) an amount (if any) determined under sections 6.5A to 6.5E;

plus:

(iii) an amount (if any) determined under section 6.6;

plus:

(iv) an amount (if any) determined under section 6.9;

plus:

(v) an amount (if any) determined under an investment adjustment mechanism (see sections 6.13 to 6.18);

plus:

(vi) an amount (if any) determined under a service standards adjustment mechanism (see sections 6.29 to 6.32);

plus —

(vii) an amount (if any) determined under section 6.37A;

and

(b) enabling a user to predict the likely annual changes in target revenue during the access arrangement period; and

(c) avoiding price shocks (that is, sudden material tariff adjustments between succeeding years).

The non-capital component of total costs must include only certain costs:

6.40 Subject to section 6.41, the non-capital costs component of approved total costs for a covered network must include only those non-capital costs which would be incurred by a service provider efficiently minimising costs.

"Efficiently minimising costs" is defined in section 1.3:

"efficiently minimising costs", in relation to a service provider, means the service provider incurring no more costs than would be incurred by a prudent service provider, acting efficiently, in accordance with good

electricity industry practice, seeking to achieve the lowest sustainable cost of delivering covered services and without reducing service standards below the service standard benchmarks set for each covered service in the access arrangement or contract for services.

"Good electricity industry practice" is also defined in section 1.3:

> *"good electricity industry practice" means the exercise of that degree of skill, diligence, prudence and foresight that a skilled and experienced person would reasonably and ordinarily exercise under comparable conditions and circumstances consistent with applicable written laws and statutory instruments and applicable recognised codes, standards and guidelines.*

6.2 Opinion regarding Consistency with the Requirements of the Code

As discussed above, section 6.4 of the Code requires that an access arrangement establishes a target revenue that includes, inter alia, the forward-looking efficient costs of providing covered services.

Section 6.40 of the Code provides specific guidance related to operating expenses (non-capital costs): the non-capital costs component of target revenue must include only those non-capital costs that would be incurred by a service provider efficiently minimising costs.

"Efficiently minimising costs" is satisfied when the service provider incurs no more costs than would be incurred by a prudent service provider, acting efficiently, in accordance with good electricity industry practice, seeking to achieve the lowest sustainable cost of delivering covered services.

"Good electricity industry practice" means the exercise of that degree of skill, diligence, prudence and foresight that a skilled and experienced person would reasonably and ordinarily exercise under comparable conditions and circumstances.

The Code does not require the target revenue to be set at the costs of a service provider at best industry practice or at the efficient frontier.

The question of Code compliance therefore can be restated as follows:

> *"Would a prudent service provider, applying good industry practice in circumstances and conditions comparable to those currently prevailing in Western Australia be expected to achieve real operating efficiencies of 2% p.a. compounding for five years?"*

or

> *"Would a prudent service provider, applying good industry practice in circumstances and conditions comparable to those currently prevailing in*

Western Australia be expected to achieve a real reduction in operating expenses of 9.6% in five years' time?"

This question requires technical analysis of the particular circumstances of Western Power. I am not able to comment on the particular circumstances of the Western Power. However, I note that:

1. To the best of my knowledge, a cumulative efficiency factor of 2% applied to total operating costs is the highest imposed in Australia since the year 2001.

2. In the period from 2000 to 2004, when some regulators did imposed efficiency improvements of up to 2% p.a., those efficiencies were generally not achieved.

3. Western Power's Works Delivery Strategy competitively procures a significant proportion of operating expenses. These costs are likely to be efficient and not able to be reduced in the short term. The corollary of this observation is that Western Power would need to achieve efficiency gains in other components of operating cost that are significantly greater than 2% p.a. to meet the ERA's proposed efficiency targets.

4. The ERA's requirement to add economy-of-scale factors to the scale escalation calculation effectively builds operating expenditure efficiency into Western Power's expenditure forecasts before the additional 2% p.a. adjustment is applied.

Based on the above observations (but without investigation into the particular circumstances of Western Power), I consider that a 9.6% real reduction in total operating costs over a 5-year regulatory control period is unlikely to be achievable.

The ERA has not demonstrated that its recommended efficiency adjustments are achievable by a service provider applying good industry practice in circumstances and conditions comparable to those currently prevailing in Western Australia. That is, the ERA has not demonstrated that its proposed efficiency adjustment is consistent with the Code requirements.

7 Declaration

I have made all inquiries that I believe are desirable and appropriate to answer the questions put to me. No matters of significance that I regard as relevant have to my knowledge been withheld.

Paul Webber

Appendix 1 – Wegdewood White Ltd Profile and CVs for Paul Webber and Paul White

Wedgewood White Ltd

Company Profile

Wedgewood White Ltd (WWL) provides strategic advice and investment decision support to energy and infrastructure businesses, governments, investors and lending agencies. Our advice covers the fields of:

- economic regulation of infrastructure (including developing access arrangements, rate cases, expenditure proposals and other regulatory submissions and design of regulatory mechanisms);
- energy, water and gas pricing design and analysis (network access and retail pricing);
- financial and economic analysis of infrastructure projects and investment decisions, including preparation of business cases;
- decision support analysis recognising uncertainty (including decision tree, real options analysis and Monte Carlo simulations); and
- reform, restructuring, introduction of retail competition and third-party access to significant infrastructure.

Our clients include:

- Aurora Energy (Australia);
- Asian Development Bank (ADB, a Philippines-based multilateral lending agency);
- Counties Power (New Zealand);
- Department for International Development (DFID, United Kingdom);
- Engconsult Ltd (Canada);
- Gladstone Area Water Board (GAWB, Australia);
- Horizon Power (Australia);
- Hunter Water (Australia);
- Integral Energy (Australia);
- Integration Umwelt & Energie GmbH (Germany);
- McConnell International Property (New Zealand);
- Manson Venture Capital (New Zealand);
- Mighty River Power (New Zealand);
- Queensland Water Commission (Australia);
- Technoconsult International Limited (Bangladesh); and

- Western Power (Australia).

As sub-contractors to other leading strategy and engineering consultants, WWL has advised:

- Central Lakes Trust (New Zealand);
- CitiPower and Powercor (Australia);
- Essential Services Commission of Victoria (Australia);
- Independent Pricing and Regulatory Tribunal (IPART) of New South Wales (Australia);
- Melbourne water retailers (Australia);
- NamPower (Namibia);
- Sydney Water (Australia);
- Tasmanian water corporations (Australia);
- Vector (New Zealand); and
- Victorian Government's Department of Treasury and Finance (Australia).

WWL's directors are Paul White and Paul Webber. Together they have more 40 years' experience in the water, electricity, gas, petroleum and airline industries and have worked in 20 countries. Paul White and Paul Webber are both qualified in engineering and commercial disciplines. This makes WWL well placed to assist in financial and economic analysis of complex technical projects.

Paul Webber

Paul has advised governments, businesses and regulators in Victoria, New South Wales, South Australia, Western Australia, Tasmania, Queensland, New Zealand and India. Paul's experience includes:

- financial and economic analysis;
- pricing and economic regulation of network industries;
- utility restructuring, market reform and privatisation;
- operation of wholesale energy markets, pools and access mechanisms; and
- retail deregulation strategy, customer valuation and retail profitability assessment.

Career Summary

Paul Webber is director of WWL. For the past fifteen years, Paul has undertaken a wide variety of infrastructure industry projects for private sector and government clients in Australasia. Prior to establishing WWL, Paul was sub-contracted by Troughton Swier & Associates as project manager assigned to the privatisation of Multinet/Ikon, one of the Victorian bundled gas distribution and retailing businesses.

Between 1995 and 1999, Paul was employed by Ernst & Young New Zealand in its Energy and Strategy Consulting Groups. In 1997, Paul was seconded to Ernst & Young Consulting's Melbourne practice to work on aspects of the Victorian gas industry reform and privatisation.

Between 1992 and 1995, Paul was employed as an analyst in the commercial division of Power New Zealand (then New Zealand's second largest electricity distribution and retail business) where he was responsible for design of distribution tariffs. Other projects included design and management of demand-side management programmes, development of a network investment policy and model, and assisting in the production of a formal Asset Management Plan.

Financial and Economic Analysis

Paul provides ongoing advice to the Gladstone Area Water Board (GAWB) on economic regulation and pricing matters, including impact of network asset purchase and divestment proposals. Paul was also responsible for financial evaluation of options for augmenting GAWB's water supply. Paul then assisted the Queensland Treasury Corporation to develop the business case for GAWB's preferred augmentation.

Paul Webber and Paul White developed a real options analysis of GAWB's demand augmentation and drought response strategy.

WWL recently advised Hunter Water regarding its evaluation of options to respond to drought. Options included restrictions, demand side management, building pipelines to neighbouring utilities, expanded use of bore fields and freighting water in ships. A Monte Carlo simulation was recommended to assess the cost and level of service achieved for each portfolio of drought response activities, considering uncertainty in future hydrological conditions.

For Sydney Water, Paul designed a financial analysis framework for assessing the revenue risk associated with several pricing structures and regulatory mechanisms. Monte Carlo analysis of demand uncertainty demonstrated that each arrangement delivered different incentives for demand management and different gross margin distributions.

Paul advised a New Zealand property development company on electricity and gas infrastructure ownership/divestment strategy. The analysis considered benefits, risks and regulatory implications of ownership and control of utilities. 'Synthetic' ownership and divestment values were quantified. Options for bundling gas and electricity infrastructure with telecommunications, water, wastewater and security infrastructure ownership and operation were developed.

At Ernst & Young, Paul was project manager of a valuation of Taranaki Combined Cycle power station for debt holders. The project included valuation of hedge portfolio, including analysis of counter-party risk associated with separation of electricity retail and distribution companies in New Zealand.

Paul project managed production of an Independent Appraisal Report (under New Zealand Stock Exchange rules) of a major transaction involving securitisation of cash flows from a gas supply agreement between Natural Gas Corporation, Fletcher Energy and the New Zealand Government. The project involved co-ordination of financial, legal and technical investigations into aspects of New Zealand gas supply contracts and United States debt security markets.

Industry Reform

As part of a consortium with Farrier Swier Consulting and Intelligent Energy Systems, Wedgewood White Ltd assisted in preparation of a feasibility study for a large user water market for urban Melbourne. The study was required to identify the incentives for conserving water and reducing waste from a large user water market, scope out a market proposal consistent with the state-wide water resources framework, and quantify the benefits and costs of such a market mechanism based on a triple bottom line assessment. Paul's role included conceptual development of tariff arrangements to mimic wholesale water market outcomes as a possible transition to a full bi-lateral market.

As a subcontractor to Farrier Swier Consulting, Paul worked on the Independent Pricing and Regulatory Tribunal (IPART) of New South Wales' review of Pricing and Industry Structure for Water and Wastewater Services in the greater Sydney Region. Paul's work focused on options for pricing third party access to network services (to facilitate efficient private investment in the water supply for Sydney), including surveying international water access charging experience, modelling access charges under various methodologies, and developing pricing principles.

Paul was involved in the structural reform of the Victorian gas industry. His primary responsibilities concerned network pricing and access arrangements for Victorian gas market including:

- project manager of distribution pricing design for all three gas distribution businesses;
- assisting in development of transmission pricing regime; and

- assisting in development of regulatory instruments including agency agreement (payment arrangements and formulae) and related contracts, Victorian Gas Industry Tariff Order, and access arrangement and supplementary information documents.

Paul was a member of several gas industry working groups set up by Victorian Department of Treasury and Finance to facilitate the gas industry reform:

- Gas Market Rules Review Group;
- Economic and Regulatory Working Group; and
- Capital Structure and Tariffs Working Group.

Paul subsequently acted as project manager for Troughton Swier & Associates, assigned to the $A1.98b privatisation of Multinet/Ikon, one of the Victorian bundled gas distribution and retailing businesses.

Design of Pricing and Access Arrangements for Infrastructure Industries

As discussed above, Paul led the team of analysts responsible for designing tariffs for regulated gas distribution businesses in Victoria. Paul has also designed electricity, gas or water pricing/access arrangements for:

- Aurora Energy;
- GAWB;
- Integral Energy;
- Horizon Power;
- Mighty River Power;
- Sydney Water; and
- Western Power.

Other pricing-related engagements for Western Power include:

- review of the transmission system capital contributions regime and application of Western Australia's regulatory test for roll-in of new investment;
- preparation of discussion papers for Western Power's triennial regulatory review including comparisons of various incentive regulation regimes and asset valuation methodologies;
- strategic review of options for facilitating renewable energy generator access to Western Power's electricity distribution network; and
- distribution and transmission regulation design for Western Power.

Paul was engaged by Marsden Jacobs Associates to undertake a peer review of the approach, analysis and presentation of results used in their *Identifying Wastewater Costs* report for WSAA, on best practice pricing for wastewater services.

Paul has recently undertaken a peer review of Mt Isa Water Board's pricing model.

As a subcontractor to Farrier Swier Consulting, Paul provided advice to the Tasmanian water corporations related to the pricing and regulatory modelling requirements of the businesses.

Before establishing Wedgwood White Ltd, Paul was a senior manager with Ernst & Young. Infrastructure pricing/access engagements were undertaken for the following clients:

- Allgas Energy (Australia);
- Queensland electricity distribution businesses (Australia);
- United Energy (Australia);
- United Networks (New Zealand); and
- Transpower (New Zealand).

Economic Regulation of Infrastructure Industries

Paul was engaged by the Queensland Water Commission to provide economic advice relating to the transition of the South East Queensland water industry to independent economic regulation.

Paul has advised Aurora Energy and Integral Energy during regulatory reviews. Paul's role included strategic advice, analysis and drafting parts of the utilities' submissions.

In 2009 and 2010 Paul reviewed Western Power's access arrangement development process. In conjunction with NERA, Paul reviewed the New Facilities Investment Test arrangements in the Western Australia electricity code. This test governs regulator's ability to add capital to Western Power's regulated asset base.

From late 2003 to early 2004 Paul provided strategic input to Sydney Water's decisions on price structure and wholesale step pricing related to IPART's price structure investigation and planning for the 2005 price review. Paul's role included:

- designing tools to quantify financial risks and incentives associated with various pricing and regulatory structures; and
- reviewing regulatory submissions and providing detailed drafting assistance for pricing and regulatory sections.

In 2004 and 2005, Paul worked with the GAWB's CEO and senior staff to develop policy positions on appropriate design of a water regulatory regime for the Queensland bulk water supply utility. Component projects included:

- analysis of the problems associated with applying generic network regulatory regimes developed for other industries (predominately electricity and gas) to the water industry without appropriate modifications; and

- development of a water contract trading regime appropriate for the specific requirements of the Boyne River catchment.

Paul was the principal author of GAWB's 2005 submissions to the Queensland Competition Authority on form of economic regulation, pricing, contracts trading, treatment of capital contributions, regulatory treatment of extraordinary circumstances (supply emergencies) and efficiency carryover mechanisms. He was also engaged to provide a financial review of options for augmenting water supply in the region and to develop a financial evaluation framework for consistent treatment of supply-side and demand-side projects.

Paul also provided advice to GAWB in relation to its 2010 price review.

Paul was the principal author of Mighty River Power's submission to a Ministerial Inquiry into the Electricity Industry and Commerce Select Committee inquiry. Issues discussed included structural reform, generator market power, retail competition and network regulation.

At Ernst & Young, Paul worked with the New Zealand Ministry of Commerce's team on several engagements analysing effectiveness of the gas and electricity disclosure regulations.

Paul has acted as an advocate for clients' preferred policy positions to the Western Australian Office of Energy, Queensland Competition Authority, the Tasmanian Department of Treasury and Finance and the Tasmanian Energy Regulator.

Development / Review of Market Mechanisms

Paul advised an Australian generator on strategy for entering the National Electricity Market, including establishment of a trading function, risk assessment and trading philosophy, implications for generation scheduling, operations and maintenance.

As project manager for a major gas demand-side management initiative, Paul worked with wholesale gas market participants to determine the best method of offering demand-side 'bids' into the Victorian gas market.

Paul was engaged in a litigation support role for the Victorian government's defence of BHP's challenge to the authorisation of the wholesale gas market. Paul's role included preparing papers comparing the efficiency merits of a wholesale markets and contract carriage markets.

For a major New Zealand gas industry participant, Paul analysed retail competition issues arising from New Zealand's gas transmission pricing regime. In particular transmission company pricing practices that advantaged its associated retailer were identified and quantified.

As a senior manager with Ernst & Young, Paul reviewed pricing policy for the HVDC link connecting the North and South Islands of New Zealand. The analysis included modelling the economic benefits of the link to electricity market participants and recommending a pricing system that was consistent with the operation of the energy market. Consideration was given to rationing of access, allocation of loss and constraint rental, financial hedges and physical capacity rights.

Paul also reviewed the provision of ancillary services (instantaneous reserve, voltage support, black start, etc.) for the New Zealand electricity system in a deregulated environment. The review considered both procurement and charging mechanisms. Proposed charging mechanisms were evaluated against regulatory and economic criteria and reviewed for consistency with the wholesale electricity market operation.

Utility Retailing Strategy and Retail Pricing

In several engagements between 2005 and 2007 Paul advised Integral Energy on:

- changes to the methodology for calculating competitive retail offers to mass-market customers;
- default tariff strategy; and
- assessment of retail profitability in Queensland.

Paul was engaged as adviser to Mighty River Power, a state-owned New Zealand electricity generator/retailer. Projects included:

- retail and brand strategy development;
- retail profitability analysis and customer valuation;
- retail pricing advice, including customer retention strategies, analysis of sustainable retailing margins in a contestable market;
- investigation of metering business strategic options including merger and divestment valuation; and
- analysis of efficient operating costs for retailing, value of retail business mergers, and utility retailing economies of scale.

Paul was engaged by Bay of Plenty Electricity to analyse that company's vulnerability to new entrant retail competition and recommend changes to retail pricing structures. For Fresh Start Energy Paul undertook a review of acquisition strategy, brand strategy and retail pricing.

Paul has also provided retail pricing and contestable market readiness advice to Aurora Energy and Western Power.

Qualifications

Paul Webber holds a first class honours bachelor's degree in Electrical and Electronic Engineering and a Graduate Diploma in Business, both from the University of Auckland. He has also completed postgraduate papers in finance and undergraduate papers in English and philosophy from Massey University.

Paul White

Paul White has undertaken strategic, financial, economic and technical analysis projects and roles throughout Australasia and Asia, primarily in the utilities sector. He has worked with local companies, governments, development agencies, and as a staff consultant to the World Bank and Asian Development Bank. Paul's experience includes:

- financial and economic analysis of government development initiatives and private sector business opportunities;
- international experience in business valuation, regulated asset base valuation, investment prioritisation and project evaluation;
- strategic planning and corporate finance experience in large organisations; and
- development of businesses cases and other decision-support analyses.

Career Summary

Paul White is director of WWL. For the past twelve years, Paul has undertaken a wide variety of infrastructure industry projects for private sector and government clients in Australasia, Asia and Africa.

Country experience includes:

- Afghanistan
- Australia
- Bangladesh
- Cambodia
- Canada
- China
- India
- Micronesia
- Mongolia
- Mozambique
- Myanmar
- Namibia
- Nepal
- New Zealand
- Pakistan
- Spain
- Sri Lanka
- Thailand
- USA
- Viet Nam

Prior to establishing WWL, Paul was a senior financial analyst at Air New Zealand and Challenge Petroleum. Significant projects for Challenge Petroleum included:

- preparation of a medium-term pricing analysis and strategy for the Challenge Petroleum retail and wholesale petroleum network (incorporating macroeconomic analysis, financial modelling and analysis of competitors' likely retaliatory actions); and
- detailed financial analysis and preparation of an expansion plan for the Challenge Petroleum retail and wholesale network.

Between December 1995 and November 1996, Paul White was resident advisor to Cambodian Government on electricity generation, transmission and distribution planning. During this engagement, Paul was the acting Deputy Director of Planning at Electricité du Cambodge.

Between 1991 and 1995, Paul was employed as a power systems engineer/analyst by Worley International, responsible for power systems analysis and planning studies, including detailed modelling, load forecasting and the economic analysis of projects.

Financial, Economic and Strategic Analysis

Recent and ongoing projects include:

- As a subcontractor to Strategic International Advisors Ltd, WWL analysed options to manage a short-term generation supply shortage in Namibia. Options considered included building conventional and renewable generation, leased emergency generation, demand side management and importing energy from neighbouring countries. WWL developed a model to allow NamPower to select the least cost (capital and operating costs) portfolio over 20 years. The model simulated dispatch by season, considering seasonal changes to hydrological conditions and demand characteristics throughout the year.
- Preparation of a power generation expansion plan for the Pohnpei Utilities Corporation (PUC) (Micronesia) and provision of advice on the future revenue requirements of the utility. Also prepared an independent review of electricity tariffs.A review of the technical assistance program of the UK's Department for International Development (DFID) to the power sector in Madhya Pradesh, India. Interviewed all key sector stakeholders and consultants, and undertook an analysis of Technical Assistance (TA) successes and failures. Prepared a set of recommendations for the next phase of DFID support and communicated these recommendations through a state-level workshop, chaired by the Energy Secretary.
- Leading a team of international and domestic consultants undertaking due diligence in relation to a proposed loan from the Asian Development Bank to the Government of Nepal for the Government of Nepal's proposed equity investment in the 750MW West Seti hydropower project. Assessed the economic value of the project to Nepal, and the financial value of the project to the Government of Nepal and the project company. Assisted in the estimation of the macroeconomic impact of the project on Nepal. Confirmed the position of the West Seti project on India's least cost expansion path (90% of the project's output will be exported to India).
- Economic analysis of a series of gas transmission and distribution and gas field development projects proposed for funding under an Asian Development Bank loan to the Government of Bangladesh.
- Preparation of discounted cash flow based valuation of a NZ hydropower generation company on behalf of the company's owner (as subcontractor to Wilson Cook).
- Financial and economic analysis of a series of proposed large hydropower projects in the Indian state of Himachal Pradesh in relation to a proposed loan from the Asian Development Bank to the Government of India for hydropower development.

- Financial and economic analysis of a series of power transmission projects in the Indian's northern and north-eastern regions in relation to a proposed loan from the Asian Development Bank to the Government of India for national grid augmentation.

- Leading a team of international and domestic consultants undertaking project feasibility and due diligence in relation to a proposed sector loan for power sector development in the Indian state of Bihar. Duties include cost estimation, demand forecasting, least cost analysis, technical appraisals, economic analysis, power planning assessments, and financial analysis of projects.

- Preparation of a rural electrification master plan for Mozambique. Duties included cost estimation and financial and economic analyses of a selection of low cost rural electrification schemes and for the overall master plan.

- Leading a team of international and domestic consultants undertaking project feasibility and due diligence in relation to a proposed multi-tranche finance facility to the Government of India for electricity transmission and distribution system development in the state of Madhya Pradesh. Undertook detailed project economic analysis, power planning assessments, and technical analysis of projects. Also provided support for financial analysis work.

- Project financial and economic analysis in relation to the Asian Development Bank's proposed loan to Pakistan for renewable energy development, including developing an economic model that can be used by the loan implementing agencies for follow-on loans and training the implementing agencies on how to use the model, developing a handbook of the procedures and methodologies for subproject economic analysis, reviewing the current regulations on independent power producers (IPPs), and assisting in developing a sample PPA for use by the subprojects.

- Development of financial valuation models for Mighty River Power's investigation of geothermal, gas and coal-fired generation investments.

- Technical adviser to a major New Zealand electricity distribution company in relation to its three-yearly asset valuation for financial reporting purposes (as subcontractor to Wilson Cook).

- Financial and economic analysis of a series of proposed electricity transmission and distribution rehabilitation projects as part of the ADB's country strategy for Afghanistan, preparation of a financing plan for the project, formulation of opening and projected financial statements for the state-owned power utility, and financial management capability assessment of the newly formed Ministry of Energy and Water.

- Financial and economic analysis, from both Tajik and Afghani perspectives, of a proposed transmission line from Tajikistan to Afghanistan to be funded by the ADB as a regional project.

- Financial and economic analysis for the Project Preparation Document for transmission and substation sub-projects on the Indonesian islands of Kalimantan and Java under the Power Transmission Improvement (PTI) project (ADB).

- Advice to a New Zealand electricity lines company concerning financial, technical and regulatory considerations for its proposed venture into electricity generation.

- Investigation of options for investment in European wind energy sector including financial models and managing relationships with financial institutions, equity providers, inter-jurisdictional tax and legal advisers.

- General business case development for Mighty River Power, including analysis of MRP's prepayment metering product and meter reading business strategy.

- Development of strategy for entry into Australian renewable energy sector (through secondment to Vortec Energy).

- Project manager of an infrastructure strategy development engagement for McConnell International Property, including hold or divest decision support.

- Strategic review of options for facilitating renewable energy generator access to Western Power's electricity distribution network.

- Pre- due diligence target and market analysis on behalf of potential offshore investor in New Zealand electricity metering business.

- Valuation of the electricity distribution network of Dhaka Electric Supply Company (Bangladesh) using the ODRC methodology as input into tariff setting process.

Retailing and Pricing Strategy

Paul was the lead consultant in developing GAWB's 2010 pricing model. Paul also was involved in WWL's peer review of Mt Isa Water Board's 2010 pricing model.

Paul worked with Paul Webber on a review of Integral Energy's methodology for calculating prices for competitive retail products in the mass-market (discounted pricing plans). Modelling included estimating customer profitability by tariff and consumption band. Recommendations included adopting a methodology to assess the profitability of each competitive offer and changing the way Integral models both profit margin and retail cost to serve.

Similar projects for Mighty River Power have included:

- retail profitability analysis and customer valuation;

- investigation of metering business strategic options including merger and divestment valuation; and

- analysis and preparation of business case for monthly meter reading.

Technical Analysis

Paul has a strong power systems engineering background, and continues to undertake technical analysis roles including:

- technical consultant to the Victorian Essential Services Commission (as subcontractor to Wilson Cook) for the 2006 Electricity Distribution Price Review;

- technical consultant to the Asian Development Bank for various power sector projects in India and Nepal;

- assessment of market prospects for domestic energy efficiency-related technology, as developed by a New Zealand start-up company, undertaken for a potential investor in the technology, and included preliminary valuation of the technology and the company, and later negotiation for investment on investor's behalf;

- operational review for Electricite du Cambodge (World Bank staff consultancy assignment) including a review of technical aspects of power sector redevelopment in Cambodia and an investigation of power sector commercial operating environment in Phnom Penh;

- technical and financial analysis of options for power system development in the Chinese cities of Hangzhou and Ningbo, the Indian state of Maharashtra and distribution system projects in Myanmar;

- preparation of a 20-year plan for power system development in the city of Colombo (Sri Lanka), including electricity demand forecasting, financial and technical appraisal of expansion options, and packaging of construction work for funding by commercial lenders; and

- preparation of planning criteria and methodology for cable selection for 22 kV, 33 kV and 115 kV underground cable networks, including design of models for cable capacity calculations, hot-spot temperature rise, calculation and the determination of cyclic ratings as part of PEA's establishment of design standards for underground power reticulation.

Qualifications

Paul White holds a bachelor's degree in Business Studies (Finance) from Massey University and a first class honours bachelor's degree in Electrical and Electronic Engineering from the University of Auckland.

Appendix 2 – Terms of Reference

SCOPE OF WORK

NAME OF PROJECT:

Expert advice reviewing the ERA's draft decision regarding operating efficiencies.

LOCATION:

Head Office

BRANCH/DIVISION:

Access Arrangement, Regulation & Sustainability Division

PURPOSE:

Critically review and respond to the Economic Regulation Authority's (ERA) draft decision regarding operating efficiencies for the AA3 period (2012/13 to 2016/17).

BACKGROUND:

Western Power is the electricity distribution and transmission network service provider in Western Australia. Western Power owns and operates the transmission and distribution network which forms the Western Power network (network). The terms and conditions on which users (typically generators and retailers) can obtain access to the network are described in Western Power's access arrangement.

Western Power is subject to economic regulation under the *Electricity Network Access Code 2004* (Code) which is administered by the Economic Regulatory Authority (ERA). Western Power is currently preparing its response to the ERA's draft decision on the AA3 access revisions for submission to the ERA on 29 May 2012.

<u>Relevant provisions of the Code</u>

The relevant provisions relating to the economic regulation of electricity distribution and transmission networks in WA are found in the Code. A copy is attached.

Under Section 2.1:

> *"The objective of this Code is to promote the economically efficient:*
>
> *a) investment in; and*
>
> *b) operation and use of,*
>
> *networks and services of networks in Western Australia in order to promote competition in markets upstream and downstream of the networks."*

Under section 2.2 the ERA is obliged to have regard to this objective.

The key Code provisions relevant to this proposed engagement, and with which the Access Arrangement must comply, are clauses 6.4 and 6.40 which state that:

> **6.4** *"The price control in an access arrangement must have the objectives of:*
>
> *a) give the service provider an opportunity to earn revenue for the access arrangement period from the provision of covered services as follows:*
>
> *i. an amount that meets the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved; plus*
>
> *ii. for access arrangements other than the first access arrangement, an amount in excess of the revenue referred to in section 6.4(a)(i), to the extent necessary to reward the service provider for efficiency gains and innovation beyond the efficiency and innovation benchmarks in a previous access arrangement; plus*
>
> *iii. an amount (if any) determined under section 6.6; plus*
>
> *iv. an amount (if any) determined under section 6.9; plus*

v. *an amount (if any) determined under an investment adjustment mechanism (see sections 6.13 to 6.18); plus*

vi. *an amount (if any) determined under a service standards adjustment mechanism (see sections 6.29 to 6.32); plus*

vii. *an amount (if any) determined under section 6.37A; and*

b) *enabling a user to predict the likely annual changes in target revenue during the access arrangement period; and*

c) *avoiding price shocks (that is, sudden, material tariff adjustments between succeeding years)."*

6.40 *"Subject to section 6.41, the non-capital costs component of approved total costs for a covered network must include only those non-capital costs which would be incurred by a service provider efficiently minimising costs."*

These sections use a number of definitions that are found in section 1.3, including 'efficiently minimising costs'.

ERA's Draft Decision

In its draft decision[1], the ERA assessed the Western Power's operating expenditure forecasts and determined that:

- Western Power's operating expenditure forecasts have made no provision for progressively increasing efficiency.
- The benchmarking exercise undertaken by GBA indicates that there was scope for Western Power to achieve efficiency gains to improve its performance to the level of its peers in Australia.
- a 2 to 3 per cent annual efficiency target for each year of AA3, combined with the adjustments made as part of the Draft Decision, would result in an appropriate balance between setting the efficient operating costs while providing Western Power a strong incentive to strive for further efficiencies;
- A 2 per cent compound annual efficiency target to apply from 2102/13 is reasonable.

The ERA's draft decision was informed by a report from its technical consultant, Geoff Brown and Associates Ltd (GBA). Chapter 10 of the GBA report provides GBA's assessment of Western Power's proposed operating expenditure forecasts. A copy is attached.

PROJECT SCOPE:

Western Power is seeking an independent expert review of the ERA's draft decision as it relates to the efficiency of Western Power's proposed operating expenditure forecasts.

The independent expert will provide an opinion report that is suitable for reliance by the ERA when conducting its functions under the Code that:

- critically examines the method, analysis and logic relied upon by the ERA in reaching its draft decision on the ability to achieve operating expenditure efficiencies of 2 per cent compounding each year over AA3 and provide an opinion on the ERA or its consultant's method, analysis and/or logic
- provides an opinion on the appropriateness and reliability of the ERA's technical consultant's benchmarking to determine an appropriate level of operating expenditure and ability to achieve reductions in operating costs of 2 per cent compounding each year from 2102/13
- provides an opinion on whether a 2 per cent compound annual efficiency target to apply from 2102/13 is consistent with the requirements of the Code.

TARGET COMPLETION DATES:

The independent expert will:

- provide an draft report by 23 May 2012

[1] 29 March 2012, Economic Regulation Authority, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network.*

- provide the final revised report by 27 May 2012
- be available to provide advice in response to the ERA final decision
- be available as an expert witness where necessary

RESOURCES:

The expert will be expected to liaise closely with Western Power and review other sources of information, such as, Western Power data, the work of other experts, regulatory proposals, regulatory decisions and advice.

DELIVERABLE:

At the completion of the task the expert will provide an independent expert report that addresses the project scope set out above.

The report will:

- be a standalone document of a professional standard that can be submitted to and relied upon by the ERA for the purpose of assessing WP's AA3 revision proposal
- be able to be made available to the public and be in an appropriate format to be accessible on the internet
- summarise WP's instructions and attaches these term of reference
- summarise the expert's experience and qualifications and attaches curriculum vitae
- identify 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
- identify any pre-existing relationship with the business
- carefully set out the facts that the expert has assumed in putting together the report and the basis for those assumptions
- set out each of the expert's opinions separately from the factual findings or assumptions
- reference any documents relied on by the person(s)
- address where possible recent deliberations by the AER and ERA
- be prepared in accordance with the Federal Court Guidelines for Expert Witnesses set out in Attachment 1 and acknowledge that the expert has read the guidelines

SELECTION CRITERIA:

The criteria used to select the successful experts are as follows:

- experience of the project team in providing similar advice in the electricity or gas industry
- proposed methodology
- demonstrated ability to deliver within the required timeframes
- demonstrated ability to deliver a report that will withstand scrutiny from the economic regulator

Any queries regarding this Request for Proposal should be directed to:

Sally McMahon
Project Director
Access Arrangement Branch
T: (08) 9326 7139   M: 0421 057 821   E: sally.mcmahon@westernpower.com.au

Appendix 3 – Engagements for Western Power

In April 2009, WWL and NERA Economic Consulting were engaged to (1) prepare a report on the basic principles that should underpin an efficient economic test for new facilities investment (including the allocation of costs through an associated capital contributions policy); (2) review the current Code provisions against the principles developed in the previous stage; and (3) recommended changes to both the Code and Western Power practices.

In January 2009, WWL was engaged to review the preparation and outcomes of Western Power's AA2 Access Arrangement Information for the transmission and distribution networks. The scope of work for the engagement included reviewing the effectiveness of the submission and the efficiency of the process used to develop the submission.

In January 2008, WWL was engaged to analyse the impact of Western Power's current capital contributions policy on investment in major projects, in particular timeliness and efficiency of generation connection. We compared Western Australia practice to that of other Australian jurisdictions and the United Kingdom. We recommended changes to Western Power's approach, including investigation of allowing generators to connect without having to fund removal of constraints on the shared network.

In November 2000, WWL was engaged to develop a retail profitability model to examine profitability of customers from a competitor's perspective under various pricing and tariff assumptions. WWL recommended a strategy for minimising value loss to new entrant retailers.

In June 2000, WWL was engaged to reviewed Australian, New Zealand and United Kingdom approaches for charging generators for network access. We produced a public paper reviewing options for commercial arrangements for energy balancing for renewable energy generators (so-called top-up and spill market) connected to Western Power's electricity network.

In October 1999, WCL was engaged to produce a series of papers comparing Australian, UK and NZ regulatory practices. Issues discussed included: form of regulation; network pricing; valuation methodology; and technical issues around WACC and regulated asset base roll-forward. These papers formed the basis for a public discussion paper released as part of a review of network regulation.

Appendix K. Extract and restate of June 2010 and June 2011 Regulatory Financial Statements

Extract and restate of 'June 2010 Regulatory Financial Statements'

8. Capital expenditure (regulatory financial statement) for the year ended 30 June 2010

Covered transmission

Description	Base Account $'000	Adjustment (Ref 11.2) $'000	Adjustment (Ref 11.5) $'000	Regulatory Account $'000	Support Reference	Regulatory Account Revised* $'000	
Growth							
Capacity expansion	107,904	(4,830)	5,237	108,311		103,074	
Customer access	28,263	(1,259)	2,349	29,353		27,004	
Customer driven	24,223	(1,340)	2,664	25,547		22,883	
Generation driven	30,066	(3,452)	1,294	27,908		26,614	
Gifted assets	1,486	-	-	1,486		1,486	
	191,942	(10,881)	11,544	192,605		181,061	
Asset replacement and renewal							
Asset replacement	5,529	(221)	10,976	16,284		5,308	
Improvement in service							
Reliability driven	1,671	(4)	102	1,769		1,667	
SCADA/communications	9,357	-	(324)	9,033		9,357	
	11,028	(4)	(222)	10,802		11,024	
Compliance							
Regulatory (safety, environmental, statutory)	11,256	(271)	(368)	10,617		10,985	
Corporate							
Information technology and market reform	10,176	-	-	10,176		10,176	
Administration and support	7,297	-	-	7,297		7,297	
	17,473	-	-	17,473		17,473	
Total additions	237,228	(11,377)	21,930	247,781	11.2, 11.5	225,851	11.2

Covered distribution

Description	Base Account $'000	Adjustment (Ref 11.2) $'000	Adjustment (Ref 11.5) $'000	Regulatory Account $'000	Support Reference	Regulatory Account Revised* $'000	
Growth							
Capacity expansion	62,750	-	(141)	62,609		62,750	
Customer access	203,070	-	(452)	202,618		203,070	
Gifted assets	84,262	-	-	84,262		84,262	
	350,082	-	(593)	349,489		350,082	
Asset replacement and renewal							
Asset replacement	80,119	-	(180)	79,939		80,119	
Metering	11,148	-	(25)	11,123		11,148	
State Underground Power Project (SUPP)	21,084	-	(47)	21,037		21,084	
	112,351	-	(252)	112,099		112,351	
Improvement in service							
Reliability driven	9,344	-	(21)	9,323		9,344	
Rural Power Improvement Program (RPIP)	8,173	-	(18)	8,155		8,173	
SCADA/communications	3,262	-	(7)	3,255		3,262	
	20,779	-	(46)	20,733		20,779	
Compliance							
Regulatory (safety, environmental, statutory)	63,674	-	(143)	63,531		63,674	
Corporate							
Information technology and market reform	16,102	-	-	16,102		16,102	
Administration and support	11,546	-	-	11,546		11,546	
	27,648	-	-	27,648		27,648	
Total additions	574,534	-	(1,034)	573,500	11.2, 11.5	574,534	11.2

Regulatory adjustments for the year ended 30 June 2010

	Description	Base Account $'000	Covered Transmission $'000	Covered Distribution $'000	Independent Market Operator $'000
11.2	**Capitalised borrowing costs b/fwd**	33,411	33,411	-	-
	Net movement in the year	11,377	11,377	-	-
	Capitalised borrowing costs c/fwd	**44,788**	**44,788**	**-**	**-**

11.3 Tax is calculated on regulatory adjustments at a rate of 30%.

11.4 To align Western Power's statutory disclosures with the Access Arrangement 2 disclosures, ie the cost of unregulated fleet and regulated information technology depreciation is reported as regulated operating expenditure costs (via the approved works program) and not depreciation and amortisation.

11.5 To gross-up year to date capital additions for statutory reporting inventory accounting entries.

Extract and restate of 'June 2011 Regulatory Financial Statements'

8. Capital expenditure (regulatory financial statement) for the year ended 30 June 2011

Covered transmission

Description	Base Account $'000	Adjustment (Ref 12.2) $'000	Adjustment (Ref 12.5) $'000	Adjustment (Ref 12.6) $'000	Regulatory Account $'000	Support Reference	Regulatory Account Revised* $'000	
Growth								
Capacity expansion	49,003	-	6,997	(5,237)	50,763		56,000	
Customer driven	41,751	-	1,523	(5,013)	38,261		43,274	
Generation driven	7,391	-	5,685	(1,294)	11,782		13,076	
	98,145	-	14,205	(11,544)	100,806		112,350	
Asset replacement and renewal								
Asset replacement	31,569	-	-	(10,976)	20,593		31,569	
Improvement in service								
SCADA/communications	5,655	-	-	324	5,979		5,655	
Reliability driven	1,313	-	-	(102)	1,211		1,313	
	6,968	-	-	222	7,190		6,968	
Compliance								
Regulatory (safety, environmental, statutory)	11,146	-	-	368	11,514		11,146	
Corporate								
Information technology and market reform	14,878	-	-	-	14,878		14,878	
Administration and support	12,388	-	-	-	12,388		12,388	
	27,266	-	-	-	27,266		27,266	
Other								
Capitalised interest	8,757	(8,757)	-	-	-		-	
Total additions	183,851	(8,757)	14,205	(21,930)	167,369	12.2,12.5,12.6	189,299	12.2,12.5

Covered distribution

Description	Base Account $'000	Adjustment (Ref 12.2) $'000	Adjustment (Ref 12.5) $'000	Adjustment (Ref 12.6) $'000	Regulatory Account $'000	Support Reference	Regulatory Account Revised* $'000	
Growth								
Customer driven	233,503	-	-	452	233,955		233,503	
Gifted assets	53,951	-	-	-	53,951		53,951	
Capacity expansion	34,081	-	338	141	34,560		34,419	
	321,535	-	338	593	322,466		321,873	
Asset replacement and renewal								
Asset replacement	98,032	-	-	180	98,212		98,032	
State Underground Power Project (SUPP)	18,744	-	-	47	18,791		18,744	
Metering	15,992	-	-	25	16,017		15,992	
	132,768	-	-	252	133,020		132,768	
Improvement in service								
Reliability driven	8,136	-	-	21	8,157		8,136	
SCADA/communications	3,196	-	-	7	3,203		3,196	
Rural Power Improvement Program (RPIP)	(180)	-	-	18	(162)		(180)	
	11,152	-	-	46	11,198		11,152	
Compliance								
Regulatory (safety, environmental, statutory)	61,078	-	-	143	61,221		61,078	
Corporate								
Information technology and market reform	25,105	-	-	-	25,105		25,105	
Administration and support	20,902	-	-	-	20,902		20,902	
	46,007	-	-	-	46,007		46,007	
Total additions	572,540	-	338	1,034	573,912	12.2,12.5,12.6	572,878	12.2,12.5

Regulatory adjustments for the year ended 30 June 2011

	Description	Base Account $'000	Covered Transmission $'000	Covered Distribution $'000	Unregulated $'000
12.2	**Capitalised borrowing costs b/fwd**	44,788	44,788	-	-
	Net movement in the year	8,757	8,757	-	-
	Capitalised borrowing costs c/fwd	**53,545**	**53,545**	**-**	**-**

To align Western Power's statutory accounting policy with regulatory accounting policy, ie borrowing costs are not capitalised from the profit and loss account (regulatory financial statements) to the balance sheet (regulatory financial statement).

12.3 To transfer contributions received for capital projects subsequently cancelled by the customer.

12.4 To reclassify depreciation as operating expenditure to offset the credit (from business unit charge recovery) in Corporate

12.5 To gross-up capital expenditure in the regulatory financial statement for the 2010/11 statutory write downs previously recognised

12.5 To reverse the 2010/11 statutory write down for cancelled/deferred capital projects, ie this capital expenditure qualifies for

12.6 To reverse the 2009/10 gross-up to capital expenditure in the regulatory financial statement for the year-end statutory inventory

Appendix L. AA2 Capital Expenditure

L.1 NFIT Compliance Summary for Equip & Works Data Warehouse

L.2 NFIT Compliance Summary for Ellipse 6.3

L.3 NFIT Compliance Summary for NetCIS 3

NFIT Compliance Summary for

Equipment and Works Management Data Warehouse (EWD)

Original Issue: May 2012

1 Purpose

This NFIT Compliance Summary has been prepared to support Western Power's response to the Economic Regulation Authority's (ERA's) request for additional information relating to a number of AA2 capex projects and programs. Its primary purpose is to:

i. demonstrate that Western Power applied its normal management procedures (as defined in its Work Program Governance Framework) over the course of the project/program and

ii. demonstrate that the capital expenditure fully complies with the requirements of the New Facilities Investment Test (NFIT).

This purpose is primarily achieved by providing references for the key documents that capture the decisions and justifications made throughout the course of the project/program. These are the key 'phase record' documents that are required (by Work Program Governance Framework) to be approved prior to proceeding through a gate to the next phase.

Where relevant, this NFIT Compliance Summary also supplements these key phase record documents by:

- Collating/summarising information relevant to NFIT compliance in the original project documents;
- Providing references to additional information and documents which assist in demonstrating NFIT compliance, created during AA2 but not referenced or included in the key project documentation;
- Providing supplementary information which supports and/or demonstrates the NFIT compliance of the project where this was not apparent in any existing documentation; and
- Providing evidence of compliance with the Works Program Governance Framework.

2 NFIT Compliance

<table>
<tr><td>Project / Program Numbers:</td><td colspan="3">WR3427</td></tr>
<tr><td>Strategy/Activity Description:</td><td colspan="3">The Strategic Program of Work (SPOW) is a program of work that governs a portfolio of IT works that address a growing range of business operational and efficiency issues arising from the business's large number of disparate legacy applications, databases, and computing hardware. An overview of SPOW is provided in DM# 8821900.

The Equipment and Works Management Data Warehouse (EWD) is the design and implementation of a data warehouse for equipment and works management that will consolidate all data into a single repository that is accessible to all relevant areas of the business.</td></tr>
<tr><td>Business case(s):</td><td colspan="3">Phase 1 = DM# 5459630

Phase 2 = DM# 7148022

Phase 3 = DM# 7835005

Phase 4 = DM# 8882198</td></tr>
<tr><td>Regulatory Category: RD, CE etc</td><td colspan="3">Other – IT – SPOW Capex</td></tr>
<tr><td colspan="4">Investment reconciliation overview ($'000, real 30 June 2012):</td></tr>
<tr><td></td><td colspan="2">AA2 submission</td><td>6,361</td></tr>
<tr><td rowspan="3">Internal approvals</td><td colspan="2">Business case</td><td>7,869</td></tr>
<tr><td colspan="2">Business case + Change control</td><td>8,036</td></tr>
<tr><td colspan="2">Pending change control</td><td>-</td></tr>
<tr><td>AA2 NFIT</td><td colspan="2">AA2 Actual + Forecast</td><td>7,194</td></tr>
<tr><td rowspan="2">Variances</td><td colspan="2">To AA2 submission</td><td>833</td></tr>
<tr><td colspan="2">To internal approvals</td><td>-</td></tr>
<tr><td>New Facilities Investment (real 30 June 2012):</td><td colspan="3">$7.194m</td></tr>
<tr><td>Refinement of Cost Estimate/s over time:</td><td colspan="3">The forecast expenditure that was included in the AA2 submission for SPOW was based on a preliminary analysis only.

Given the expected level of change within Western Power over the life of the SPOW project in general and the EWD project in particular, a phased approach to implementation was adopted. Each phase or sub-phase targets particular information subject areas and treated as a deliverable in its own right. The phased approach is outlined in the Implementation Approach (DM# 5463504).

Each phase of this project went through a detailed cost estimating process using a bottom up build. These cost estimates were then used as the basis for each business case value.</td></tr>
</table>

<table>
<tr><td>Variation Explanation:</td><td>The variation between the AA2 submission and the actual and forecast expenditure has been explained above.

The variation between the AA2 actual and forecast expenditure and the business case value is due to a timing issue – the fourth phase will not be completed by the end of June 2012 and therefore there will be additional expenditure during AA3.</td></tr>
<tr><td colspan="2">S. 6.51A – the new facilities investment may be added to the capital base if it satisfies the new facilities investment test (NFIT).</td></tr>
<tr><td colspan="2">NFIT PART A - S. 6.52(a) – new facilities investment does not exceed the amount that would be invested by a service provider efficiently minimising costs.</td></tr>
<tr><td>Identified Need & Timing</td><td>Western Power's current asset management systems comprise a number of disparate computer applications and databases all integrated via a complex network of point-to-point interfaces to support the management of the transmission and distribution asset base.

With the growing requirements for visibility of asset management information, it is becoming increasingly difficult to produce consistent results from these disparate data sources. In addition, these data sources do not efficiently support data and reporting needs of the other SPOW initiatives. The "SPOW Statement of Program Intent" (DM# 6172280) provides an overarching view of the need for the EWD project.

The project requires immediate execution as current custom asset management systems do not have the flexibility to meet new business requirements. In addition there are inter-dependencies with other current projects as discussed in section 4 of the Implementation Approach (DM# 5463504).

Further detail is provided in the data warehouse phase one business case (DM# 5459630) and Appendix J of the business case for ISAM (DM# 6242018).</td></tr>
<tr><td>Options Analysis:</td><td>The project has been undertaken in four phases.

Phase 1: Sourcing network equipment and condition information from legacy systems

The options that were considered in the Business Case for the first phase (DM# 5459630) were:
1. Do Nothing
2. Full Scope Implementation
3. Business Priority Driven Phased Implementation.

Option 3 was the recommended option as it better manages implementation risks and costs, as well as supporting a flexible response to changing business priorities.

Option 1 was rejected as it does not address the identified need or (importantly) support the data and reporting needs of the SPOW initiatives. Option 2 was rejected as being too costly and risky due to its significant business impact.

Phase 2: Sourcing Network Incident, Network Load and Network Reliability data from legacy systems

The options that were considered in the Business Case for the second phase (DM# 7148022) were:
1. Full scope build of all subject areas in the current phase</td></tr>
</table>

	2. Reduce scope of current phase to fit within the current budget 3. Do nothing. Option 1 was the recommended option. Option 2 was rejected as it would lead to a more costly overall implementation. Option 3 was rejected as the risk and cost to other SPOW Asset and Works sub-program projects would significantly increase as each project would need to satisfy, independently, the gap in reporting that would be created. **Phase 3: Migrate from legacy systems to Ellipse** The options that were considered in the Business Case for the third phase (DM# 7835005) were: 1. Do nothing further 2. Undertake "must do" items only 3. Undertake items to maximise investment made to date. Option 3 was the recommended option. Option 1 was rejected as it would render the data warehouse unusable when the legacy systems are replaced, effectively writing off the investment made to-date and reversing the benefits received. Option 2 was rejected as a number of "non-enterprise solutions", with associated risks, would remain. **Phase 4: Complete migration from legacy systems to new IT systems** The options that were considered in the Business Case for the fourth phase (DM# 8882198) were: 1. Do nothing 2. Undertake only scope items that will support ISAM implementation 3. Undertake all scope items to maximise investment made to date. Option 2 was the recommended option. Option 1 was rejected as it would result in a largely unusable solution following the implementation of the ISAM project as the old data warehouse would no longer be updated. Option 3 was rejected due to the risk of delivering the project within estimated budget and time constraints given the scale of scope items that are not directly linked to ISAM changes and the scale of change being introduced across the business over the implementation timeframe.
Scope of Works:	The scope of work includes the design and implementation of a data warehouse solution for equipment and works management including consolidation of equipment and works data into a single repository to provide enhanced analytical functionality and information access. Further details are provided in section 3.2 of the business case (DM# 5459630), the Information Needs Analysis (DM# 5304513), the Architecture Options document (DM# 5492994), and the Requirements Specification (DM# 4241817).

Implementation Timing:	**Phase 1** Proposed: July 2009 – June 2010 Actual: August 2011 **Phase 2** Proposed: May 2010 – April 2011 Actual: April 2012 **Phase 3** Proposed: May 2011 – October 2011 Revised: January 2012 Actual: April 2012 **Phase 4** Proposed: 1 February 2012 – 30 June 2012 Actual: n/a (work in progress)
Implementation Cost:	☒ Cost variance does not change preferred option Reason for variance: ☐ changed timing ☐ un-costed activities ☐ changed scope ☐ cost control ☐ other The total cost is forecast to be less than the total business case value.
Engineering Design	This project focuses on standard commercial hardware and software solutions and is being implemented through a phased approach that aligns with Western Power's IT capital governance procedures (DM# 5329211) and gating process in order to mitigate risks. Details of the implementation approach for the data warehouse are set out in DM# 5463504. Further information relating to the architecture and the context of this implementation can be found in DM# 5492994 and DM# 6172280.
Procurement	Western Power's standard procurement channels and procedures apply to the data warehouse implementation. Phase 1 of the project utilised the hardware and software that was used for the existing data warehouse solution. The data integration tool required for phase 2 was procured through a competitive tender process. Additional infrastructure to host the data integration tool was purchased through Western Power's existing contracts. The development services required for Phase 1 was procured through a competitive tender process with vendors on the IT Applications panel. The tender was evaluated with the expectation of selecting a service provider to use on all phases, recognising the efficiency gains of remaining with a single provider throughout the life of the project. The phase 1 contract was extended to phases 2, 3 and 4.

Project/Program Governance:	This project is governed by Western Power's IT capital approval and delegated financial authority procedures (DM# 3435391). The business cases were approved by Western Power's Managing Director in accordance with the applicable program governance procedures. The Equipment and Works Data Warehouse Project Management Plan (DM# 5234991) details the project structure and key roles & responsibilities, including that of the Project Sponsor.
Project/Program Management:	This project is being delivered under Western Power's standard project management practices which set out the required approaches to: • Project change/scope management • Project time, cost and risk management • Project performance monitoring • Project closure. These activities are detailed in the Equipment and Works Data Warehouse Project Management Plan (DM# 5234991).
Complies with S6.52(a)?	☒ Yes – necessary efficient minimum cost investment ☐ No
NFIT PART B - S. 6.52(b) – *the incremental revenue has been shown to exceed cost, there is a demonstrated net benefit in the covered network, or the investment is necessary to maintain the safety, reliability or performance of the network in providing the covered services (or is ancillary to maintaining the covered services).*	
Justification Applied & Recoverable Portion (real 30 June 2012):	☐ Incremental revenue $ ☐ Net benefits $ ☒ Safety, reliability, performance $7.194m
Justification Description:	Western Power submits that the expenditure meets the Safety and Reliability test. The project will enable the business to gain better visibility of network equipment including nameplate information, condition, age, fault history, and work history. This allows the business to develop more accurate asset management plans and maintain network reliability.
Complies with S6.52(b)?	☒ Yes fully ☐ In part ☐ No
S. 6.51A(b) – *the new facilities investment may be added to the capital base if the Authority otherwise approves it being added to the capital base provided it is the subject of a contribution, and it meets the requirements of section 6.52(a) of the NFIT, and there is no double recovery of costs as a result.*	
Capital Contribution (if applicable):	☐ Yes $_________ ☐ Appendix 8 work ☒ None applicable
S. 6.51A(b) Amount:	$0
S. 6.58 – *any part of the speculative investment amount that satisfies the new facilities investment test at the later time may be added to the capital base*	

Speculative Investment Amount (if applicable):	$0

3 Compliance with works program governance framework

The following table provides key documentation references as evidence that this program has been managed in compliance with Western Power's IT capital program governance procedures (DM# 5329211). The primary evidence is the existence of mandatory phase record documents prior to the project/program progressing to the next phase.

Phase	Mandatory Phase Record Document/s	DM Reference
1 - Initiation Phase	Strategic Planning documents: SPoW Statement of Program Intent	6172280
2 - Scoping Phase	Implementation Approach	5463504
3 - Planning Phase	Business Cases (one per Phase)	5459630 7148022 7835005 8882198
4 - Execution Phase	Project Management Plan Change Controls	5234991 6875117 6875118
5 - Closeout Phase	Not applicable as project is not complete	-
6 - Benefits Realisation Phase	Not applicable as project is not complete	-

4 Endorsements

All information presented in this document is considered accurate and is intended for use in supporting Western Power's AA3 submission.

Endorsed by:

Name	Position	Signature	Date
Neil Canby	Branch Manager Foundation Transformation Programs		

NFIT Compliance Summary for

Ellipse 6.3

Original Issue: May 2012

1 Purpose

This NFIT Compliance Summary has been prepared to support Western Power's response to the Economic Regulation Authority's (ERA's) request for additional information relating to a number of AA2 capex projects and programs. Its primary purpose is to:

i. demonstrate that Western Power applied its normal management procedures (as defined in its Work Program Governance Framework) over the course of the project/program and

ii. demonstrate that the capital expenditure fully complies with the requirements of the New Facilities Investment Test (NFIT).

This purpose is primarily achieved by providing references for the key documents that capture the decisions and justifications made throughout the course of the project/program. These are the key 'phase record' documents that are required (by Work Program Governance Framework) to be approved prior to proceeding through a gate to the next phase.

Where relevant, this NFIT Compliance Summary also supplements these key phase record documents by:

- Collating/summarising information relevant to NFIT compliance in the original project documents;
- Providing references to additional information and documents which assist in demonstrating NFIT compliance, created during AA2 but not referenced or included in the key project documentation;
- Providing supplementary information which supports and/or demonstrates the NFIT compliance of the project where this was not apparent in any existing documentation; and
- Providing evidence of compliance with the Works Program Governance Framework.

2 NFIT Compliance

Project / Program Numbers:	WR3532
Strategy/Activity Description:	The Strategic Program of Work (SPOW) is a program of work that governs a portfolio of IT works that address a growing range of business operational and efficiency issues arising from the business's large number of disparate legacy applications, databases, and computing hardware. An overview of SPOW is provided in DM# 8821900. This project involves the upgrade of the Ellipse Enterprise Resource Planning software from version 5.2.3.8 to version 6.3.
Business case(s):	DM# 6693029
Regulatory Category: ***RD, CE etc***	Other – IT – SPOW Capex

Investment reconciliation overview ($'000, real 30 June 2012):

	AA2 submission	4,294
Internal approvals	Business case	4,500
	Business case + Change control	6,100
	Pending change control	-
AA2 NFIT	AA2 Actual + Forecast	6,460
Variances	To AA2 submission	2,166
	To internal approvals	360

New Facilities Investment (real 30 June 2012):	$6.460m
Refinement of Cost Estimate/s over time:	The forecast expenditure that was included in the AA2 submission for SPOW was based on a preliminary analysis only. Given the expected level of change within Western Power over the life of SPOW, a flexible approach to implementation was adopted. The upgrade to Ellipse 6.3 is a fairly unique undertaking. Whilst significant effort was made to develop accurate cost estimates prior to the project commencing in full, there remained a number of significant unknown areas. This was explicitly recognised in the business case and a contingency of 25% was approved for the project accordingly. The alternative approach would have been to incur up to 50% of the total cost of the project prior to approving the full business case. This was not considered an efficient approach and did not encourage the project behaviours and environment that supports efficient and effective delivery.

<table>
<tr><td>Variation Explanation:</td><td>The business case was approved for $4.50 million based on initial estimates of costs with a margin of error of 25%. That is, the business case was approved for a value up to $5.63 million.

The total costs exceeded the business case estimate and the upper limit due to:

1. Significantly greater effort than planned in the business case to migrate customisations and reports and to configure and test the new payroll modules

2. Unavailability of key business resources planned in the business case, replaced with higher cost external resources

3. The loss of key resources, most importantly the Project Manager (who resigned from Western Power) and key Business Analysts (who were deployed to higher priority projects).

4. The engagement of an external service provider at a higher unit costs and for a longer duration to allow the resources to acquire the necessary knowledge and understanding of the project, not factored in to the business case.</td></tr>
<tr><td colspan="2">S. 6.51A – the new facilities investment may be added to the capital base if it satisfies the new facilities investment test (NFIT).</td></tr>
<tr><td colspan="2">NFIT PART A - S. 6.52(a) – new facilities investment does not exceed the amount that would be invested by a service provider efficiently minimising costs.</td></tr>
<tr><td>Identified Need & Timing</td><td>Mincom’s Ellipse software has been used by Western Power since 1999. It is used to support the organisation’s core requirements across all streams of the business:
• Asset and Works Management
• Materials / Logistics
• Finance
• HR / Payroll
A number of SPOW initiatives and other IT projects depend on integration with Ellipse functionality and data – it provides a platform to support the implementation of the Integrated Solution for Asset Management (ISAM), the Mobile Workforce Solution, Ariba (purchase to pay modules) and the Enhance Planning and Works Management.
An upgrade to Ellipse 6.3.x was critical to ensure vendor support arrangements were within Mincom’s recommended supported version window (noting that the full standard support was no longer available with version 5.2.3.8), and to provide new functionality to further exploit the use of Ellipse.
The upgraded Ellipse software needed to be in place by October 2010 as it underpinned the delivery of other SPOW projects.
The “SPOW Statement of Program Intent” (DM# 6172280) provides an overarching view of the need for the Ellipse 6.3 upgrade.</td></tr>
</table>

Options Analysis:	The options that were considered in the Business Case (DM# 6693029) were: 1. Do nothing (remain on Ellipse version 5.2.3.8) 2. Upgrade to Ellipse version 6.3.x on a "like for like" basis 3. Upgrade to Ellipse version 6.3.x with new HR modules and clean up 4. Incorporate the upgrade into another SPOW project 5. Implement Ellipse version 6.3.x with new HR modules, clean up and additional focus on Time and Attendance and Training modules Option 5 was the recommended option. Option 1 was not recommended as it did not support SPOW and the IT Application Landscape proposed by the Architecture Review Group. Option 2 was not recommended as it would provide minimal benefits as it failed to realise any business process improvements, rationalisation of customisations and security profiles, exploit new functionality or achieve the efficiencies and cost savings associated with them. Option 4 was not recommended as it would dramatically increase the project delivery risks. Option 3 and Option 5 were similar. Option 5 was $500k more expensive than Option 3, but enabled changes in the Ellipse Time and Attendance and Training Modules to be fully implemented and associated savings of $500k per annum to be achieved. Option 5 was therefore preferred to Option 3.
Scope of Works:	The major items of the Ellipse project were: 1. Expand the use of Ellipse functionality based on Business Requirements Statement (BRS) outputs. 2. Rationalisation of customisations and security profiles in Ellipse. 3. Development of Ellipse 6.3.x including new Ellipse modules. 4. Migration of critical customisations and reports. 5. Supporting business processes to leverage new functionality within Ellipse particularly in the areas of: a. Payroll and timesheets b. Leave management c. Health and safety d. Training management. Full details are provided in Appendix D of the business case (DM# 6693029).
Implementation Timing:	Start date: September 2009 Proposed completion: October 2010 Actual completion: October 2010 for base upgrade, September 2011 for the remaining scope items

Implementation Cost:	☒ Cost variance does not change preferred option Reason for variance: ☒ changed timing ☐ un-costed activities ☐ changed scope ☒ cost control ☐ other Refer to variation explanation above.
Engineering Design	This project focuses on standard commercial hardware and software solutions and is being implemented through a phased approach that aligns with Western Power's IT capital governance procedures (DM# 5329211) and gating process in order to mitigate risks.
Procurement	Western Power's standard procurement channels and procedures apply to this project. Hardware, software and external labour have been purchased through the relevant IT procurement panels established by Western Power.
Project/Program Governance:	This project is governed by Western Power's IT capital approval and delegated financial authority procedures (DM# 3435391). The business cases were approved by Western Power's Managing Director in accordance with the applicable program governance procedures. The Project Management Plan for the Ellipse 6.3 Upgrade Project (DM# 6708354) details the project structure and key roles & responsibilities, including that of the Project Sponsor.
Project/Program Management:	This project is being delivered under Western Power's standard project management practices which set out the required approaches to: • Project change/scope management • Project time, cost and risk management • Project performance monitoring • Project closure. These activities are detailed in the Project Management Plan for the Ellipse 6.3 Upgrade Project (DM# 6708354).
Complies with S6.52(a)?	☒ Yes – necessary efficient minimum cost investment ☐ No
NFIT PART B - S. 6.52(b) – *the incremental revenue has been shown to exceed cost, there is a demonstrated net benefit in the covered network, or the investment is necessary to maintain the safety, reliability or performance of the network in providing the covered services (or is ancillary to maintaining the covered services).*	
Justification Applied & Recoverable Portion (real 30 June 2012):	☐ Incremental revenue $ ☐ Net benefits $ ☒ Safety, reliability, performance $6.460m
Justification Description:	Western Power submits that the expenditure meets the safety, Reliability or Ability to Provide Covered Services test as the project is integral to the ongoing operations of Western Power.

Complies with S6.52(b)?	☒ Yes fully ☐ In part ☐ No
S. 6.51A(b) – *the new facilities investment may be added to the capital base if the Authority otherwise approves it being added to the capital base provided it is the subject of a contribution, and it meets the requirements of section 6.52(a) of the NFIT, and there is no double recovery of costs as a result.*	
Capital Contribution (if applicable):	☐ Yes $________ ☐ Appendix 8 work ☒ None applicable
S. 6.51A(b) Amount:	$0
S. 6.58 – *any part of the speculative investment amount that satisfies the new facilities investment test at the later time may be added to the capital base*	
Speculative Investment Amount (if applicable):	$0

3 Compliance with works program governance framework

The following table provides key documentation references as evidence that this program has been managed in compliance with Western Power's IT capital program governance procedures (DM# 5329211). The primary evidence is the existence of mandatory phase record documents prior to the project/program progressing to the next phase.

Phase	Mandatory Phase Record Document/s	DM Reference
1 - Initiation Phase	Strategic Planning documents: SPoW Statement of Program Intent	6172280
2 - Scoping Phase	Implementation Approach (included in Business case)	6693029
3 - Planning Phase	Business Case	6693029
4 - Execution Phase	Project Management Plan Change Controls	6708354 8052760
5 - Closeout Phase	Close Out Report	-
6 - Benefits Realisation Phase	-	-

4 Endorsements

All information presented in this document is considered accurate and is intended for use in supporting Western Power's AA3 submission.

Endorsed by:

Name	Position	Signature	Date
Neil Canby	Branch Manager Foundation Transformation Programs		

NFIT Compliance Summary for

NetCIS 3 Implementation

Original Issue: May 2012

DM# 8784613

1 Purpose

This NFIT Compliance Summary has been prepared to support Western Power's response to the Economic Regulation Authority's (ERA's) request for additional information relating to a number of AA2 capex projects and programs. Its primary purpose is to:

i. demonstrate that Western Power applied its normal management procedures (as defined in its Work Program Governance Framework) over the course of the project/program and

ii. demonstrate that the capital expenditure fully complies with the requirements of the New Facilities Investment Test (NFIT).

This purpose is primarily achieved by providing references for the key documents that capture the decisions and justifications made throughout the course of the project/program. These are the key 'phase record' documents that are required (by Work Program Governance Framework) to be approved prior to proceeding through a gate to the next phase.

Where relevant, this NFIT Compliance Summary also supplements these key phase record documents by:

- Collating/summarising information relevant to NFIT compliance in the original project documents;
- Providing references to additional information and documents which assist in demonstrating NFIT compliance, created during AA2 but not referenced or included in the key project documentation;
- Providing supplementary information which supports and/or demonstrates the NFIT compliance of the project where this was not apparent in any existing documentation; and
- Providing evidence of compliance with the Works Program Governance Framework.

2 NFIT Compliance

<table>
<tr><td>Project / Program Numbers:</td><td>WR3654</td></tr>
<tr><td>Strategy/Activity Description:</td><td>The Strategic Program of Work (SPOW) is a program of work that governs a portfolio of IT works that address a growing range of business operational and efficiency issues arising from the business's large number of disparate legacy applications, databases, and computing hardware. An overview of SPOW is provided in DM# 8821900.

The Network Customer Information System (NetCIS) is a network billing and customer relationship management solution, eliminating the dependency on Synergy for billing data and enabling improvements in processes supporting customer initiated work and in customer service activities.

NetCIS has been implemented in three phases. The third phase, NetCIS3, is the subject of this NFIT Compliance Summary. NetCIS3 implements the learning from NetCIS2 to expand functionality to stakeholders, further users and customer segments. NetCIS3 will capitalise on the implementation of a new geographical Information System (GIS), and works and asset management systems to bring together customer and network data, effectively integrating the customer into network operations and planning.</td></tr>
<tr><td>Business case(s):</td><td>Analysis and Design Phase
• DM # 7232613
Implementation Phase
• DM # 8099678</td></tr>
<tr><td>Regulatory Category: RD, CE etc</td><td>Other – IT – SPOW capex</td></tr>
<tr><td colspan="2">Investment reconciliation overview ($'000, real 30 June 2012):
<table>
<tr><td></td><td>AA2 submission</td><td>2,653</td></tr>
<tr><td rowspan="3">Internal approvals</td><td>Business case</td><td>3,900</td></tr>
<tr><td>Business case + Change control</td><td>4,500</td></tr>
<tr><td>Pending change control</td><td>-</td></tr>
<tr><td>AA2 NFIT</td><td>AA2 Actual + Forecast</td><td>4,448</td></tr>
<tr><td rowspan="2">Variances</td><td>To AA2 submission</td><td>1,795</td></tr>
<tr><td>To internal approvals</td><td>-</td></tr>
</table></td></tr>
<tr><td>New Facilities Investment (real 30 June 2012):</td><td>$4.448 million</td></tr>
</table>

Refinement of Cost Estimate/s over time:	Preliminary work only had been undertaken in forecasting the costs associated with this project for the AA2 submission. Given the expected level of change within Western Power over the life of SPOW, a flexible approach to implementation, via phases, was adopted. Within the NetCIS projects, each project was itself split into 2 phases; an analysis and design phase followed by an implementation phase. The analysis and design phase incorporated developing the cost estimates for the scope options and solutions being considered. The analysis and design phase also involved obtaining a fixed price quote for a major component of the work from an external service provider to provide greater confidence on the cost estimates.
Variation Explanation:	The variation between the AA2 submission and the actual and forecast expenditure has been explained above. The key factors for the variation in costs between the business case and the actual and forecast expenditure are: 1. Higher complexity of integration design and build leading to an extended project duration and increased cost as a consequence 2. Lack of specialised integration resources leading to a delayed commencement of build activities and a higher than expected unit cost.
S. 6.51A – *the new facilities may be added to the capital base if it satisfies the new facilities investment test (NFIT).*	
NFIT PART A - S. 6.52(a) – *new facilities investment does not exceed the amount that would be invested by a service provider efficiently minimising costs.*	

Identified Need & Timing	As a network operator, Western Power has always "engaged" its stakeholders and customers but these activities tended to be conducted by separate business units. Customer, stakeholder, property, metering and network asset data is held on separate systems. This fragmented approach prevents a holistic view and inhibits efforts to improve decision-making and coordinate engagement of customers, stakeholders and communities. A holistic and shared view of customers and stakeholders would: • inform segmentation of our customer base • strengthen customer-focused decision making • support proactive community engagement • facilitate a coordinated approach to proactive strategic stakeholder engagement This need for a shared view of customers and stakeholders underpins the emerging customer service focussed approach encapsulated in our value proposition and the following customer service principles: • Understand me – knowledge of customers and communities • Keep me informed – relevant, accurate and timely information • Keep your promises – a reliable and responsive service • Make it easy – accessible and clear processes and language The purpose of NetCIS 3 (and future phases) is to support these principles by: 1. Understanding – collecting, retaining and sharing information about customers and stakeholders and their relationship with us and our assets 2. Informing – targeting customers and stakeholders with specific, timely and relevant information about their requests and network activities affecting them 3. Keeping promises – monitoring our activities to ensure we respond reliably and consistently within stated timeframes 4. Making it easy – providing information, history and web self service allowing customers to apply and track requests online Additionally, the planned decommissioning of the Distribution Quotation Management system (DQM) relied on NetCIS to replace the Customer Funded Work related work streams. NetCIS3 expands on NetCIS2, which was included in the "SPOW Program of Intent" (DM# 6172280).

Options Analysis:	NetCIS 3 has been undertaken in two phases. The options that were considered in the Business Case for the high level analysis and design phase (DM# 7232613) were: 1. Do nothing or delay implementation 2. Complete high level analysis and design 3. Proceed directly to implementation Option 2 was the recommended approach. Given the pressure on the business to improve customer service, it was considered that option 1 would likely result in much of the scope being delivered via normal activities in an unstructured way, which is sub-optimal both in terms of solution and costs. Given the uncertainty around implementation costs and the need to operate in a constrained funding environment, option 3 was not recommended. The options that were considered in the Business Case for the implementation phase (DM# 8099678) were: 1. Do nothing or delay implementation 2. Proceed with complete scope implementation 3. Proceed with phased scope implementation Option 3 was the recommended approach with the first phase covering Stakeholder Relationships and Payment Claims Stamping, and the second phase covering Customer Funded Works and Web Portal. Given the pressure on the business to improve customer service, it was considered that option 1 would likely result in much of the scope being delivered via normal activities in an unstructured way, which is sub-optimal both in terms of solution and costs. Option 2 was not recommended as it was considered to be likely that this option would result in rework and additional cost as there were ongoing discussions at that time about Customer Funded works boundaries and Web Portal technology.
Scope of Works:	The scope of works comprises: • Review of IT Architecture to ensure that existing and planned infrastructure can support the development of further customer care functionality • Implement the review recommendations by extending the current NetCIS solution to: o Support customer and stakeholder engagement by building on existing data attributes to enhance the management of customers o Manage customer applications – connection applications, customer funded projects and customer payment claims o Retire existing IT applications – CusREMS, Extended Outage Payment Scheme system, Ministerial Tracking System, Project Tracker, Salesforce.com Full details are provided in section 4.1 of the business case (DM# 8099678).

Implementation Timing:	**Phase 1 – Analysis and Design Phase** • Proposed: September 2010 to December 2010 • Actual: September 2010 to January 2011 **Phase 2 – Implementation Phase** • Proposed: April 2011 to December 2011 • Revised: April 2011 to May 2012 • Actual: April 2011 to May 2012
Implementation Cost:	☒ Cost variance does not change preferred option Reason for variance: ☒ changed timing ☒ un-costed activities ☒ changed scope ☐ cost control ☐ other
Engineering Design	This project focuses on standard commercial software and hardware solutions and is being implemented through a phased approach that aligns with Western Power's IT capital program governance procedures (DM# 5329211) and gating process in order to mitigate risks.
Procurement	The project leverages the hardware and software being used for the existing NetCIS application. Procurement of software and hardware systems was therefore not required under this project. Implementation services were the subject of an RFP to companies on Western Power's IT Application Services panel. IBM was the preferred supplier as a result of the RFP process and was awarded the contract under an existing Master Service Contract (DM# 5382377).
Project/Program Governance:	This project is governed by Western Power's IT capital approval and delegated financial authority procedures (DM# 3435391). The business case documents (see above) were approved by Western Power's Managing Director in accordance with the applicable program governance procedures. The NetCIS 3 Project Management Plan (DM# 8183512) details the project structure and key roles & responsibilities, including that of the Project Sponsor.
Project/Program Management:	This project is being delivered under Western Power's standard project management practices which impose specific controls in relation to: • Project change/scope management; • Project time, cost and risk management; • Project performance monitoring; and • Project closure. These activities are detailed in the NetCIS 3 Project Management Plan (DM # 8183512).
Complies with S6.52(a)?	☒ Yes – necessary efficient minimum cost investment ☐ No
NFIT PART B - S. 6.52(b) – *the incremental revenue has been shown to exceed cost, there is a demonstrated net benefit in the covered network, or the investment is necessary to maintain the safety, reliability or ability of the network to provide covered services.*	

<table>
<tr><td>Justification Applied & Recoverable Portion (real 30 June 2012):</td><td>☐ Incremental revenue $
☒ Net benefits $4.448 million
☐ Providing covered services (safety and reliability)</td></tr>
<tr><td>Justification Description:</td><td>The tangible (financial) benefits associated with NetCIS3 are:
• Termination of Salesforce.com software licence
• Reduction in IT applications – CusREMS, EOPS, MTS and Project Tracker
• Reduction in CSC customer funded project costs
• Reduced damage to distribution infrastructure from inadequately managed customer funded projects.
In addition, there are tangible (non financial) and intangible benefits that are identified in section 3.1 and Appendix A of the business case (DM# 8099678).</td></tr>
<tr><td>Complies with S6.52(b)?</td><td>☒ Yes fully ☐ In part ☐ No</td></tr>
<tr><td colspan="2">S. 6.51A(b) – the new facilities investment may be added to the capital base if the Authority otherwise approves it being added to the capital base provided it is the subject of a contribution, and it meets the requirements of section 6.52(a) of the NFIT, and there is no double recovery of costs as a result.</td></tr>
<tr><td>Capital Contribution (if applicable):</td><td>☐ Yes $________ ☐ Appendix 8 work
☒ None applicable</td></tr>
<tr><td>S. 6.51A(b) Amount:</td><td>$0</td></tr>
<tr><td colspan="2">S. 6.58 – any part of the speculative investment that satisfies the new facilities investment test at the later time may be added to the capital base</td></tr>
<tr><td>Speculative Investment Amount (if applicable):</td><td>$0</td></tr>
</table>

3 Compliance with IT projects governance arrangements

The following table provides key documentation references as evidence that the program has been managed in compliance with Western Power's IT capital program governance procedures (DM# 5329211). The primary evidence is the existence of mandatory phase record documents prior to the project/program progressing to the next phase.

Phase	Mandatory Phase Record Document/s	DM Reference
1 - Initiation Phase	Strategic Planning Document: SPoW Statement of Program Intent	6172280
2 - Scoping Phase	-	
3 - Planning Phase	Business Cases	7232613 8099678
4 - Execution Phase	Project Management Plan Change Requests	8183512 8789181 9119235 9136331 9122881
5 - Closeout Phase	Project Closure Form to be completed on completion of the project	-
6 - Benefits Realisation Phase	A formal benefits realisation will be undertaken post program completion	-

4 Endorsements

All information presented in this document is considered accurate and is intended for use in supporting Western Power's AA3 submission.

Endorsed by:

Name	Position	Signature	Date
Neil Canby	Branch Manager Foundation Transformation Programs		

Appendix M. AA1 NFIT compliance for Target Reliability

NFIT Compliance Summary for AA1 Targeted Reliability Driven Reclosers and Reinforcement/40 Worst Feeders

Original Issue: May 2012

DM# 9387618

1 Purpose

The primary purpose of this NFIT summary is to:

i. demonstrate that Western Power applied its normal management procedures (as defined in its Work Program Governance Framework) over the course of the project/program and

ii. demonstrate that the capital expenditure fully complies with the requirements of the New Facilities Investment Test (NFIT).

This purpose is primarily achieved by providing references for the key documents that capture the decisions and justifications made throughout the course of the project/program. These are the key 'phase record' documents that are required (by Work Program Governance Framework) to be approved prior to proceeding through a gate to the next phase.

Where relevant, this NFIT Compliance Summary also supplements these key phase record documents by:

- Collating/summarising information relevant to NFIT compliance in the original project documents;
- Providing references to additional information and documents which assist in demonstrating NFIT compliance, created during AA1 but not referenced or included in the key project documentation;
- Providing supplementary information which supports and/or demonstrates the NFIT compliance of the project where this was not apparent in any existing documentation; and
- Providing evidence of compliance with the Works Program Governance Framework.

2 NFIT Compliance

Project / Program Numbers:	40 Worst Feeders (20 Metro, 10 North Country 10 South Country) N0198957, N0200930, N0227108
Strategy/Activity Description:	This is a program of capex works that contribute to achievement of several reliability Service Standard Benchmarks for the AA1 period (2006/07-2008/09). The targeted deployment of automated switchgear (Reclosers and Load Break Switches) on the High Voltage network during the 2006/07 to 2008/09 financial years is representative of the projects that make up this program.
Sample Business cases:	DM # 3541469, 3797205, 3807370, 3454550, 3454672
Regulatory Category:	Reliability Driven

Investment reconciliation overview ($m, real 30 June 2012):

	Project Name	**Targeted Reliability Driven Programs - AA1**
		All $'000 in Real June 2012
	AA1 Submission	47,481
Internal Approvals	Business Case	-
	Business Case + Change Control	-
	Pending change control	-
AA1 NFIT	AA1 Actual	56,209
Variances	To AA1 submission	8,728
	To internal approvals	-

Variances between AA1 submission, business case and AA1 actuals are explained in following sections.

New Facilities Investment (real 30 June 2012):	$ 56.2M

<table>
<tr><td>Refinement of Cost Estimates over time (including explanation of variances):</td><td>Western Power’s AA1 submission included $47.8M Targeted Reliability Driven expenditure to achieve the Service Standard Benchmarks prescribed in the Access Arrangement. The expenditure forecast was based on reliability forecasts and models of the expected SAIDI benefits of distribution automation, as outlined in the Reliability Strategies Consolidation Paper (DM# 2281704).

The strategy was for a two phased approach – a pilot phase and a rollout phase.

At the time of the AA1 submission the pilot project had not been undertaken and hence the estimated cost for the targeted reliability program was based on preliminary desktop estimates only.

The pilot revealed that the unit costs were higher than the preliminary estimates, and as a result actual costs were higher than the costs included in the business cases. This was due to additional costs associated with the communications component of automation devices including network communication and interfacing to the SCADA system, and earthing issues encountered during installation.</td></tr>
<tr><td colspan="2">S. 6.51A – the new facilities investment may be added to the capital base if it satisfies the new facilities investment test (NFIT).</td></tr>
<tr><td colspan="2">NFIT PART A - S. 6.52(a) – new facilities investment does not exceed the amount that would be invested by a service provider efficiently minimising costs.</td></tr>
<tr><td>Identified Need & Timing</td><td>Section 11.1 of the Access Code requires that:

“…A service provider must provide reference services at a service standard at least equivalent to the service standard benchmarks set out in the Access Arrangement and must provide non-reference services to a service standard at least equivalent to the service standard in the access contract”

Section 11.1 of the Access Code, has the effect that the service standard benchmarks are minimum service standards. Through our licences, Western Power has a legal obligation to meet these benchmarks.

Section 3.18 of the Access Arrangement defines the Service Standard Benchmarks that Western Power is obligated to achieve over the AA1 period. Table 1 represent the targeted 25% improved service standard levels required for distribution reliability in AA1.

Western Power is required to deliver the required outcomes, as defined by the Service Standard Benchmarks, at the least cost.

The intent of the 2006/07 – 2008/09 Targeted Reliability Driven Automation program was to improve SAIDI and SAIFI for the SWIS, with Major Event Days excluded, as set out in the table 1.

Table 1 Western Power’s Performance targets AA1 and actual figures
<table>
<tr><th></th><th>2008/2009</th><th>2008/2009 actual</th></tr>
<tr><td>SAIDI</td><td>224</td><td>221</td></tr>
<tr><td>SAIFI</td><td>2.78</td><td>2.20</td></tr>
</table>

Table 1 also includes the actual performance in 2008/2009, which is slightly better than the reliability target for the final year of AA1. The targeted reliability program therefore contributed to the improvements and targeted benefits required in the Service Standard Benchmarks.</td></tr>
</table>

Options Analysis:	A wide range of potential options were considered for implementation across 2006/07 – 2008/09, including roll-out of distribution automation and targeting the top 40 worst feeders (by contribution to SAIDI) in the SWIS. The various options were evaluated to provide the greatest benefit in terms of reliability improvement and cost efficiency, as measured by $ per SAIDI minute saved. As a baseline for assessing reliability improvement programs, a do-nothing option was considered. Three broad approaches were developed and assessed to achieve the reliability improvement required, as defined by the June 2009 benchmarks. The options provide for: • Targeted distribution automation and network reinforcement solutions to meet the June 2009 Reliability SAIDI/SAIFI benchmark requirements in each feeder category • Targeted works for the Top 40 worst feeders covering siliconing, surge arrestor installation, spreader/spacer installation and load break switch solutions to meet the June 2009 Reliability SAIDI/SAIFI benchmark requirements across the SWIN as a whole • Increased asset replacement expenditure to reduce the number of outages due to equipment failures The first two of these comprise packages of individual projects that have been specifically developed to provide the greatest benefit in terms of reliability improvement and cost efficiency across the individual feeder categories and the SWIN as a whole. To achieve the Service Standard Benchmarks at the least cost, the option for 'Targeted Distribution Automation and targeted top 40 worst feeder works to meet the June 2009 Reliability SAIDI/SAIFI benchmark requirements in each feeder category' was recommended.
Scope of Works:	Each of the program business cases sets out the high level scope of works. The scope includes targeted works such as rebuilding line sections, undergrounding, reconductoring, pole top switch installations, and automated switches and reclosers. Project cost estimates were based on Western Power's standard estimating practices. At the time of preparing business cases, pilot projects had not been undertaken, so desktop estimates were used.
Implementation Timing:	To meet the agreed Service Standard Benchmarks the required in-service date was 30 June 2009.
Implementation Cost:	☒ Cost variance does not change preferred option Reason for variance: ☐ changed timing ☐ un-costed activities ☒ changed scope ☐ cost control ☐ other (reduced volume) (reduced costs)
Engineering Design	Reliability Automation works designed in accordance with Western Power's standard designs (DM#3808525) to ensure compliance with good electricity industry practice, relevant Australian Standards and safety requirements. During AA1 the governance framework demonstrates that designs were completed efficiently, including the 'Distribution Automation' manual (DM#4806893). This manual ensures understanding of end-to-end process flows, accountabilities, task requirements, links to policies and preliminary engineering assessments.

Procurement	Materials and services for this project have been procured in line with the Western Power's Procurement Policy (DM#4096273) that is designed to achieve best value for money outcomes. The Procurement Policy requires that procurement is conducted in accordance with Western Power's Commercial Principles (DM#4472656) and: • provides value for money on a total cost of ownership basis • reflects procurement best practice • applies a competitive process as a default position • agreements are established via a competitive process to meet business requirements and deliver value for money • all distribution inventory and equipment procurement is facilitated by panel agreements, short form contracts or strategic alliance agreements • offers transparency across all key commercial processes • opportunities for bundling Reliability Driven projects within other work are also explored in the interests of gaining further efficiency improvements. In practice, the most efficient procurement strategy for a project may include a mix of approaches such as long-term contractor agreements, competitive tendering, strategic alliances and internal resourcing. In order to ensure efficient delivery and value for money, a delivery strategy consistent with Western Power's balanced portfolio framework has been adopted for all programs of work, and Project Delivery is responsible for all Project Management activities, including overseeing procurement. In the case of Targeted Reliability Driven Automation Western Power procures reclosers through a preferred vendor arrangement. The preferred vendor (Nu-Lec) was chosen through a competitive tender process.
Project/Program Governance:	The strategy document (DM# 2281704) included the capital project approval sign-off form. Work flow for this program of works as set out in the Planned Automation Process Manual (DM# 4821340) was controlled by Western Power's Distribution Quotation Management (DQM) system from 2008. DQM includes mandatory gates and work flows to ensure processes for estimating costs and seeking approvals are followed. The project sponsor also meets with the Project Manager regularly to update and document progress, and quarterly to update forecasts.
Project/Program Management:	This project was delivered under Western Power's standard project management practices which impose specific controls in relation to: • Project change/scope management • Project time management • Project cost management • Project risk management • Project performance monitoring • Project closure. This is an on-going program of work which does not require a project management plan under the Western Power program governance procedures.

Complies with S6.52(a)?	☒ Yes – necessary efficient minimum cost investment ☐ No ☐ Not applicable
NFIT PART B - S. 6.52(b) – *the incremental revenue has been shown to exceed cost, there is a demonstrated net benefit in the covered network, or the investment is necessary to maintain the safety, reliability or ability of the network to provide covered services.*	
Justification Applied & Recoverable Portion (real 30 June 2012):	☐ Incremental revenue $ ☐ Net benefits $ ☒ Providing covered services (safety and reliability) $56.2M ☐ Not applicable
Justification Description:	Western Power submits that this expenditure meets the requirements of the Safety and Reliability test since without the program, Western Power would be in breach of the Service Standards Benchmarks required under a number of regulatory instruments, including the Access Arrangement.
Complies with S6.52(b)?	☒ Yes fully ☐ In part ☐ No ☐ Not applicable
S. 6.51A(b) – *the new facilities investment may be added to the capital base if the Authority otherwise approves it being added to the capital base provided it is the subject of a contribution, and it meets the requirements of section 6.52(a) of the NFIT, and there is no double recovery of costs as a result.*	
Capital Contribution (if applicable):	☐ Yes $_________ ☐ Appendix 8 work ☒ None applicable
S. 6.51A(b) Amount:	$0
S. 6.58 – *any part of the speculative investment amount that satisfies the new facilities investment test at the later time may be added to the capital base*	
Speculative Investment Amount (if applicable):	$0

3 Compliance with works program governance framework

The following table provides key documentation references as evidence that program has been managed in compliance with Western Power's Work Program Governance Framework that was in place during AA1. The primary evidence is the existence of mandatory phase record documents prior to the program progressing to the next phase. This process was managed via workflow in the DQM system.

Phase	Mandatory Phase Record Document/s	DM Reference
1 - Initiation Phase	Strategic Planning documents: • Reliability Consolidation Paper	• DM#2281704
2 - Scoping Phase	Strategic Planning documents: • Reliability Consolidation Paper	• DM#2281704
3 - Planning Phase	Business Case documents: • Business Case Standard design documents: • Index of manuals • Automation Standrds	• DM#3541469, 3797205, 3807370, 3454672, 3454550 • DM#4806893, 3808525
4 - Execution Phase	• Change control request	• DM#4569453, 4002210
5 - Closeout Phase	Post Implementation report	
6 - Benefits Realisation Phase	Service Standard Measures documents: • Service Standard Measures	• DM#8294036

4 Endorsements

All information presented in this document is considered accurate and is intended for use in supporting Western Power's AA3 submission.

Endorsed by:

Name	Position	Signature	Date
Dave Fyfe	Manager Network Performance		

Appendix N. Calculation to support distribution project costs as a percentage of transmission project costs

Appendix N: Calculation to support distribution project costs as a percentage of transmission project costs

Date: May 2012

westernpower

DM 9385608

1 Transmission driven distribution project costs as a percentage of transmission project costs

To accurately estimate the average cost of distribution works for corresponding transmission projects, the total cost of the projects need to be considered as capacity expansion projects tend to span a number of years. There were a number of transmission projects that were completed in AA1 for which the distribution projects were completed over the AA1 and AA2 period (e.g. Rivervale & Vic Park Conversion).

An analysis of a sample of transmission projects broken into the following categories was carried out:

- Distribution costs associated with voltage conversions
- Distribution costs associated with the implementation of a new zone substation
- Distribution costs associated with the upgrade of an existing zone substation (2nd or 3rd Transformers installations)

The analysis found that, on average, the cost of the distribution works was approximately 25.6% of the transmission costs, as demonstrated in Table 1, Table 2 and Table 3.

Table 1: Voltage conversion projects

Substation	Dist Project Number	Distribution cost	Transmission Cost	Ratio
RVE - conversion	N0276856	$4,649,124		
RVE - conversion	N0207927	$4,619,860		
RVE - conversion	T0027450		$13,570,612	**68%**
CTE 6.6kV to 11kV	N0202986	$4,184,000		
CTE 6.6kV to 11kV	57480		$14,743,000	**28%**
WD 6.6kV to 11kV	N0215530	$4,020,000		
WD 6.6kV to 11kV	T0219394		$6,620,000	**61%**

Table 2: New substation projects

New substation	Trans Cost	Dist cost	Ratio
WAI - new sub	$11,353,936	$3,658,130	**32%**
MDN - new sub	$12,735,906	$3,692,812	**29%**
HZM - new sub	$8,883,494	$2,392,475	**27%**
MSS - new sub	$15,571,000	$3,244,213	**21%**
JDP - new sub	$12,360,593	$2,285,522	**18%**
HBK - new sub	$15,040,694	$2,646,360	**18%**
WLN - new sub	$9,549,456	$1,206,000	**13%**
WGA - - new sub	$12,347,421	$1,521,759	**12%**

Table 3: Upgrade of existing zone substation (second or third transformer) projects

Substation	TX #	Trans Cost	Dist cost	Ratio
PBY - 3rd TX	3	$3,338,305	$1,993,289	**60%**
WAI - 2nd TX	2	$4,009,313	$1,612,509	**40%**
MSS - 2nd TX	2	$4,502,898	$1,120,321	**25%**
MUR - 2nd TX	2	$3,489,834	$800,822	**23%**
BIB - 2nd TX	2	$3,385,604	$610,713	**18%**
MO - 3rd TX	3	$3,992,313	$291,475	**7%**
MLG - 3rd TX	3	$4,602,355	$155,050	**3%**
CKN - 2nd TX	2	$3,503,259	$61,891	**2%**
PBY - 2nd TX	2	$3,157,797	$49,811	**2%**

The estimated costs for distribution projects, identified for transmission projects for the AA3 period and beyond, is consistent with this analysis.

Appendix O. WACC expert reports

O.1 SFG Consulting - Estimating beta: Reply to Draft Decision

O.2 Ernst & Young - Advice on Capital Asset Pricing Model for response to ERA Draft Decision

O.3 CEG - Estimating equity beta for Australian regulated energy network businesses

O.4 CEG - Western Power's proposed debt risk premium

O.5 CEG - Internal consistency of risk free rate and MRP in the CAPM

Estimating beta: Reply to Draft Decision

Report for Western Power

29 May 2012

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Contents

1. Executive summary

Background and context

1. SFG Consulting (**SFG**) has been engaged by Western Power to consider the approach to estimating equity beta that has been adopted by the Economic Regulation Authority of Western Australia (**the Authority**) in its Western Power Draft Decision of 29 March 2012.

2. We have previously provided a report in relation to this matter titled *An appropriate equity beta estimate for Western Power*, and dated 13 July 2011 (previous **SFG Report**).

3. We have been instructed to prepare a report that, having regard to the relevant provisions of the Access Code:

   a) Considers and responds to the ERA's criticisms of the SFG report (which explains why a mechanical approach to estimating the equity beta should not be used); and

   b) Provides a simple reasonableness check of the ERA's approach to estimating the equity beta using the ERA's analysis in the Draft Decision.

4. This report has been authored by Professor Stephen Gray. I am Professor of Finance at the UQ Business School, University of Queensland and Director of SFG Consulting. I have honours degrees in Commerce and Law from the University of Queensland and a PhD in Finance from the Graduate School of Business at Stanford University. I have extensive experience in advising companies, government, and regulatory agencies on issues relating to weighted-average cost of capital.

Summary of conclusions

5. Our primary conclusions are:

   a) The Draft Decision is in error in concluding that there is an a priori expectation that the equity beta of the benchmark firm must be less than one as:

      i) This is based on an out-dated interpretation of an AER position, which the AER itself has since clarified; and

      ii) The ability to pass through financing costs has nothing to do with a priori expectations of equity beta, as set out in the SFG Report of 1 February 2009 and the AER's WACC Review Final Decision, and this important point was not considered in the Western Power Draft Decision;

   b) The empirical estimates presented in the Draft Decision are statistically unreliable for a number of reasons:

      i) They are based entirely on a set of domestic firms that even the AER has described as being unlikely to provide a robust equity beta estimate;

      ii) The individual estimates are implausible, inconsistent and vary so much over time that they cannot reasonably be considered to be reliable;

      iii) The final estimate of beta has been selected without any consideration of the imprecision and reliability of the individual estimates. It is incorrect and contrary to standard practice, to interpret any empirical estimate in the absence of information about the quality of that estimate;

iv) The range of 0.5 to 0.8 and the point estimate of 0.65 have no basis in that the large number of estimates presented by the Authority does not support the selection of such a range and the Draft Decision does not explain how the range was selected from the estimates presented in it. Rather, the final range and point estimate adopted in the Draft Decision appear to have been arbitrarily selected, with the implication being that the empirical estimates presented in the tables are so variable over such a wide range and so statistically imprecise that they cannot be used to reject those values.

c) Our previous conclusion (that the regulatory approach produces asset beta estimates that vary wildly over time and that by any measure, the variation in these beta estimates over time is extreme) also applies to the AER's sample of US energy distribution utilities;

d) The required return on unlevered equity must be higher than the required return on debt in the same firm. This is because a debt investment in the firm is of unambiguously lower risk. This basic requirement is contravened in the Draft Decision; and

e) The allowed return on equity in the Draft Decision cannot be reasonably considered to be commensurate with the prevailing conditions in the market for funds when, based on the Authority's own estimates, investors in comparable firms can reasonably expect to receive a return that is at least 45% higher than what is being allowed to investors in the benchmark firm.

6. The WA Electricity Networks Access Code (2004) sets out the objectives of:

a) Promoting the economically efficient investment in networks;[1] and

b) Giving the service provider the opportunity to earn revenue sufficient to meet the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved.[2]

7. In our view the beta value adopted in the Draft Decision does not meet these objectives because:

a) The regulatory beta estimates are unreliable in a number of respects, as set out above;

b) The Draft Decision provides a return to unlevered equity in the benchmark firm that is lower than the return to first-ranking debt in the same firm; and

c) The Draft Decision provides a return to levered equity in the benchmark firm that is materially lower than equity investors might reasonably expect to be able to earn in comparable firms with a similar degree of commercial risk.

Declaration

8. I have been provided with a copy of the Federal Court Guidelines for Expert Witnesses and have prepared this report in accordance with them. In preparing this report, I have made all the enquiries

[1] WA Access Code, s 2.1.
[2] WA Access Code, s 6.4.

that I believe are desirable and appropriate and no matters of significance that I regard as relevant have, to my knowledge, been withheld from the Court.

2. Consideration of the SFG Report in the Draft Decision

Overview

9. In this section of the report, we review the Authority's responses to the SFG Report of 13 July 2011.

A priori expected value of beta

10. The SFG Report of 13 July 2001 notes that:

> There are two things that determine the relative systematic risk, or equity beta, of a particular firm:
>
> a. The type of business that the firm operates; and
>
> b. The amount of financial leverage employed by the firm.
>
> This was explicitly recognised by the AER in its Review of WACC Parameters where the Explanatory Statement correctly notes that a firm's systematic risk (its equity beta) depends "on its business activities and its level of financial leverage."[3]

11. The SFG Report concluded that:

> It is generally accepted that the business activities of regulated electricity network distribution and transmission businesses have less systematic risk than average. But it is also clear that such businesses have much higher financial leverage than the average firm. It has become standard to assume 60% debt financing for a regulated network distribution or transmission business, whereas the average firm has 30% debt financing. That is, the two effects operate in different directions for regulated network distribution and transmission businesses:
>
> a. Their business activities would suggest lower than average systematic risk; but
>
> b. Their financial leverage would suggest higher than average financial risk.
>
> Consequently, the appropriate a priori expectation is that the equity beta for these business is no different from that of the average firm, which is 1.0.[4]

12. The Draft Decision agrees that the equity beta depends upon the type of business and the degree of leverage and also agrees that these two effects operate in opposite directions for the benchmark firm:

> Overall, the Authority agrees that, with regard to regulated electricity network distribution and transmission businesses, a lower business risk results in a lower equity beta compared with the market. Also, the higher gearing level leads to a higher equity beta in comparison with the market. These two effects may act to offset each other.[5]

[3] SFG Report, Paragraphs 39-40.
[4] SFG Report, Paragraphs 44, 47.
[5] Draft Decision, Paragraph 820.

13. However, the Draft Decision concludes that the first effect (business activities of the benchmark firm implies a lower than average systematic risk) outweighs the second (financial leverage of the benchmark firm implies higher than average systematic risk):

> The Authority is of the view that the exposure of regulated electricity network distribution and transmission businesses to business risk and financial risk overall is less than that of the average business or the market. As such, the Authority considers that the equity beta for regulated electricity network distribution and transmission businesses should be less than one.[6]

14. The only justification for this conclusion in the Draft Decision is that:

> The Authority agrees with the AER's view that, unlike the unregulated businesses, the cost of debt, including the debt risk premium and the risk free rate for regulated businesses, is based on prevailing market conditions at the time of the regulatory decisions. The Authority is of the view that this "pass-through" nature of borrowing costs is likely to reduce exposure to financial risk faced by regulated businesses.[7]

15. The essence of this argument is that the effect of financial leverage (which serves to increase systematic risk) is materially attenuated for the benchmark firm, so the nature of the business (which suggests a lower than average systematic risk) dominates. In support of this view, the Authority cites the Explanatory Statement (Draft Decision) from the AER's last Review of WACC Parameters.

16. However, the AER recanted that view in its Final Decision. In particular, the SFG Report of 1 February 2009 (submitted as part of the AER WACC Review process) explains why the argument about the pass-through nature of borrowing costs is irrelevant to the determination of an appropriate a priori estimate of beta. Indeed that report shows that, under the approach adopted by the AER and the Authority, leverage has the same effect on beta whether or not the firm can pass through its borrowing costs. In its Final Decision, the AER concludes that:

> The AER accepts that as the benchmark regulated electricity network service provider is assumed to be 60 per cent geared, whereas the average business in the Australian market is around 35 per cent geared, it is likely that the benchmark regulated electricity network business has greater exposure to financial risk than the average business.[8]

and that:

> The AER maintains its position that due to the nature of the industry and the regulatory regime the asset beta of a benchmark efficient NSP is likely to be significantly less than the market asset beta.
>
> The AER also considers that due to the higher level of gearing the financial risk of a benchmark regulated electricity NSP is likely to be greater than a business with the market average level of gearing.

[6] Draft Decision, Paragraph 822.
[7] Draft Decision, Paragraph 819.
[8] AER WACC Review Final Decision, p. 252.

> However, these two effects (i.e. business risk and financial risk) may well act to offset each other, and the AER acknowledges that the net effect on the equity beta of a benchmark efficient NSP is unclear.[9]

17. In its Final Decision, the AER further clarified the position set out in the Explanatory Statement. Specifically, the AER notes that its comments about the pass-through nature of borrowing costs have nothing at all to do with the a priori estimate of beta, but in fact relate to the extent to which the set of listed firms that the AER has used to empirically estimate beta can be considered to be truly comparable to the benchmark firm:

> …the AER's position in its explanatory statement was that a benchmark regulated electricity network service provider with gearing of 60 per cent, may face lower financial risk (i.e. interest rate risk or the risk of financial distress) compared to a business operating in a competitive market that was also 60 per cent geared. This was reasoned based on the 'pass through' nature of borrowing costs for regulated utilities and the high price inelasticity of electricity.[10]

18. We agree with the AER on this point. There are a number of reasons why the set of firms that the AER (and the Authority) use to empirically estimate beta are not perfectly comparable with the benchmark firm. Some of these reasons would imply that the benchmark firm is less risky and some would imply that it is more risky than the set of "comparables." The pass-through nature of borrowing costs is one consideration among many, and all should be properly thought through when interpreting empirical beta estimates.

19. We also agree with the AER that none of this has anything to do with the a priori expectation of equity beta for the benchmark firm. The a priori expectation, by definition, is the expected value *before* one turns to any empirical estimates. The pass-through argument relates to empirical estimates from "comparable" firms, and is therefore irrelevant to a priori expectations.

20. In summary, we agree with the AER's position in its Final Decision that there is no a priori reason to expect the equity beta of the benchmark firm to be different from the beta of the average firm, which is 1.0. The two effects set out above "may well act to offset each other" so that "the net effect on equity beta is unclear."

21. In our view, the Western Power Draft Decision is in error in concluding that there *is* an a priori expectation that the equity beta of the benchmark firm must be less than one as:

    a) This is based on an out-dated interpretation of an AER position, which the AER itself has since clarified; and

    b) The ability to pass-through financing costs has nothing to do with a priori expectations of equity beta, as set out in the SFG Report of 1 February 2009 and the AER's Final Decision, and this important point was not considered in the Western Power Draft Decision.

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[9] AER WACC Review Final Decision, p. 254.
[10] AER WACC Review Final Decision, pp. 252-253.

Statistical reliability of regulatory estimates of equity beta

22. The SFG Report of 21 July 2011 sets out a number of reasons why regulatory estimates of beta using data from the small set of Australian comparable firms are statistically unreliable. The Draft Decision does not address any of these issues on the basis that:

> The AER and its consultant on the issue, Professor Henry from the University of Melbourne, responded to SFG's comments at length in the Final Decision on its WACC Review released in May 2009. The Authority agrees with and adopts the AER and Henry's responses. As such, the Authority is of the view that these arguments should not be reconsidered in this decision.[11]

23. In this section of the report, we show that the majority of the statistical reliability points raised in our earlier report have not been addressed by the AER and the others remain live issues for other reasons.

Lack of relevant data

24. The SFG Report notes that the sample of Australian firms that formed the basis of the AER's WACC Review estimate is extremely small by any measure:

> The sample of data that forms the basis of the AER's empirical estimates of beta consists of returns for only six firms, none of which is a pure play distribution or transmission business, and for only two of which is data available for the (short) period specified by the AER.
>
> In our view, the scant and incomplete data set that is relied upon by the AER is not sufficient to produce beta estimates that are robust or reliable.[12]

25. The AER confirmed, in its WACC Review Final Decision, that it considers:

> that a sample of four firms is unlikely to provide a robust equity beta estimate[13]

yet the data set on which the AER's estimates are based consists of four firms or less for the majority of the sample period. The AER has never explained how its statement about four firms being insufficient to produce a robust beta estimate can be reconciled with the way it proceeded to estimate beta.

26. The Western Power Draft Decision is even more problematic in this regard. The Draft Decision uses the same small sample of Australian firms as the AER used in its WACC Review. However, whereas the AER at least had regard to data from international comparables "due to the perceived limitations of the data obtained from the Australian market (such as the number of firms and the reduction in the number of observations due to mergers and acquisition activities),"[14] the Draft Decision is based entirely on the small set of Australian firms.

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[11] Draft Decision, Paragraph 824.
[12] SFG Report, Paragraphs 68-69.
[13] WACC Review Final Decision, p. 255.
[14] WACC Review Final Decision, p. 260.

Individual estimates are implausible and inconsistent at face value

27. The SFG Report notes that the AER is of the view that "the consistency of empirical estimates (over time, across businesses, across empirical methods)"[15] are all "key objective criteria" for estimating WACC parameters. The SFG Report also notes that:

    a) Several of the AER's estimates of beta are clearly implausible and could not possibly be taken seriously as estimates that one would use in the CAPM to estimate the required return on equity;[16]

    b) There is also substantial variation in beta estimates across firms. The re-levered beta estimates for different firms reported by Henry (2008) (which are all supposed to be estimates of the same thing) range from less than 0.3 to more than 1.0;[17]

    c) There is also substantial variation in beta estimates across empirical methods, including different estimation techniques (OLS, LAD, etc.) and different sampling frequencies (weekly, monthly, etc.); and

    d) The estimates that have been produced also vary substantially over time. For example, the recursive estimates computed by Henry (2008) show that it is quite common for equity beta *estimates* for the same firm to double or triple over the course of several months.[18] These figures also illustrate the tremendous width of the confidence intervals, which in almost every case contain the value of 1.0

28. The SFG Report concludes that "it is difficult to imagine any set of estimates faring worse on the AER's key objective criteria." [19]

29. None of these points have been dealt with by the AER or by any report from Associate Professor Henry.

30. The Western Power Draft Decision further confirms the lack of reliability of the regulatory beta estimates. Tables 83, 85, 87 and 89 of the Draft Decision report a total of 72 beta estimates computed by the Authority. The Authority's beta estimates range from to 0.07 to 1.35. The confidence intervals range from -0.94 to 3.14. In half of the cases, the confidence interval contains either zero or one – in a number of cases it contains both.

31. The Draft Decision also reports estimates for the same firms using the AER's sample period and then updating to include some more recent data. This updating results in changes between estimates (for the same firms using the same method but an updated data set) ranging from -91% to 109%.

32. Further, in the Draft Decision, the Authority seeks to replicate the beta estimates that were compiled for the AER's WACC Review in 2008-09. The Authority has used the same set of firms, the same data period, and the same data frequency as was employed in the AER's WACC Review. The Draft Decision sets out the results of this attempt to replicate the AER estimates in Tables 80 and 81. The

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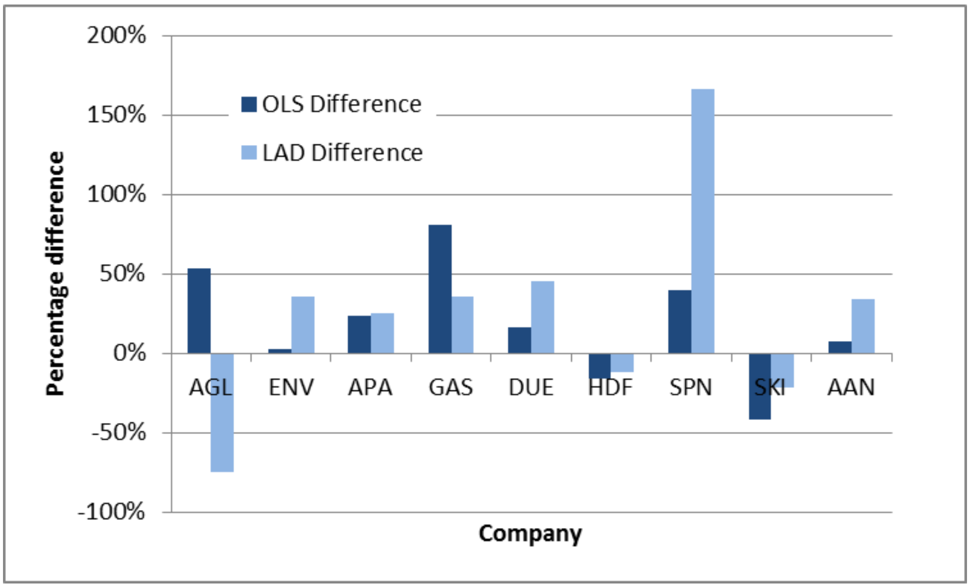
15 *Explanatory Statement*, p. 48.
16 0.0375 × 6% = 0.225%.
17 Henry (2008), p.18.
18 Henry (2008), Appendix 1 and 2.
19 SFG Report, Paragraph 74.

differences between the Authority's estimates and the AER's estimates for the *same firms* over the *same period* are summarised in Figure 1 below.

Figure 1: Difference between AER and ERA estimates of equity betas



Source: Draft Decision Tables 80, 81. SFG calculations.

33. Figure 1 shows that there is an extraordinary degree of variation between the Authority's estimates and the AER's estimates of the same beta for the same firm using the same data period. The majority of estimates differ by more than 20% and in a number of cases the difference is more than 50%. That is, two regulators have sought to estimate the same beta for the same firm using the same data period, and in the majority of the cases their estimates differ by more than 20%. In our view, the only reasonable interpretation of this evidence is that it supports the proposition that the regulatory estimates of beta are unreliable.

34. However, the Draft Decision adopts the opposite interpretation on the basis that:

   a) Although the two sets of regulatory estimates generally differ by a large amount in an absolute sense;

   b) Both sets of estimates are so statistically imprecise and have such large standard errors that they cannot be classified as being significantly different:

> The last two rows of Table 81 show that no estimates based on the same sampling period of monthly observations were statistically different.[20]

35. In our view, the fact that the regulatory estimates are characterised by imprecision and large standard errors is not a reasonable basis for affirming their reliability, but rather, the opposite is true. Not only do the two sets of regulatory estimates of the same thing generally differ by more than 20%, but they are also highly imprecise.

[20] Draft Decision, Paragraph 868.

Regulatory estimates ignore important information about the imprecision of the beta estimates: Standard errors

36. The SFG Report notes that, in its last WACC Review, the AER gave no consideration to the precision of its empirical estimates, to standard errors or to confidence intervals. The AER stated that:

> …it is likely that a forward-looking equity beta will be represented by a the [sic] point estimate of the equity beta rather than the upper and lower bounds.[21]

and that in relation to beta estimates:

> …the AER has had regard to the point estimates rather than the range of possible estimates within confidence intervals.[22]

37. The AER confirmed this view in its WACC Review Final Decision.[23] We note that the AER's decision to ignore information about the imprecision of the point estimates runs against the advice of its consultant, Associate Professor Henry, who went to some lengths to calculate standard errors and confidence intervals for all of the estimates he produced.

38. Similarly, the Western Power Draft Decision makes no use of standard errors or confidence intervals other than to conclude that both sets of regulatory estimates are so imprecise that it is statistically impossible to distinguish between them.

39. In our view, it is incorrect and contrary to standard practice, to interpret any empirical estimate in the absence of information about its standard error. The fact that another regulator has made the same error does not make it less of an error.

Regulatory estimates ignore important information about the reliability of the beta estimates: R-squared statistics

40. The SFG Report notes that the AER agrees that in circumstances where the R^2 statistic is low it is "more difficult to obtain statistically reliable estimates."[24] That is, the R^2 statistic is directly informative about the statistical reliability of empirical beta estimates. This is an important consideration that goes to the weight that should properly be afforded to the empirical estimates. However the AER and the Western Power Draft Decisions do not consider (or even report) any R^2 statistics, which is inconsistent with standard statistical and econometric practice.

41. The Western Power Draft Decision does not address this issue on the basis that it has been considered by the AER as part of the Henry (2009) report that it commissioned. Henry (2009) takes issue with one technical element of the SFG simulation analysis that seeks to quantify the effect of this known bias. Even if that point were correct (which it is not, as demonstrated below), it would only go to the quantification of the bias. The existence of the bias, and the directional effect of the bias, is well-known and accepted by the AER. Consequently, it should be considered when interpreting empirical beta estimates, but it is not considered in the Western Power Draft Decision.

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[21] *Explanatory Statement*, p.219, error in original.
[22] *Explanatory Statement*, p.219.
[23] WACC Review Final Decision, p. 243.
[24] *Explanatory Statement*, p.215.

42. The technical point raised by Henry (2009) is that the SFG simulation analysis uses a uniform (rectangular) distribution for stock return volatility whereas Henry would prefer to use a normal (bell-shaped) distribution. The purpose of the analysis is to document the relationship between the R^2 statistic and the reliability of beta estimates. Using a rectangular uniform distribution produces an even range of R^2 statistics – some low, some medium and some high. Using a normal distribution would produce predominantly medium values, making it difficult to determine the relationship between the R^2 statistic and the reliability of beta estimates.

43. All the SFG simulation exercise shows is that *if* the R^2 statistic is low, the beta estimate is statistically unreliable. It says nothing about the frequency of low R^2 statistics among beta estimates – just that if an estimate has a low R^2 statistic, it is less likely to be statistically reliable.

44. Henry's point is that, among the population of all listed firms, the frequency of very low R^2 statistics is likely to be low. This is true, but inconsequential since it is known that:

    a) The firms in the set of regulatory comparables *do* have low R^2 statistics; and

    b) Estimates that have low R^2 statistics are less likely to be statistically reliable.

45. By analogy, it would be quite reasonable to assume that an Olympian is good at their sport. The fact that relatively few people are Olympians is irrelevant to this logic – given that one *does* encounter an Olympian, it would be reasonable to assume that that person is good at their sport. Similarly, if a regulatory asset beta estimate *does* have a low R^2 statistic, it is less likely to be statistically reliable.

Regulatory estimates make no adjustment to correct for the demonstrated bias in beta estimates

46. The SFG Report explains why all empirical beta estimates that are less (more) than 1.0 are downwardly (upwardly) biased and concludes that:

> The AER's beta estimate of 0.8 is based on a range of estimates that are less than 1.0. All beta estimates that are less than 1.0 are downwardly biased. The simulation analysis in Table 3 shows that the degree of bias can be material. Yet the AER's analysis does not recognise the existence of bias and does nothing to quantify or correct for that bias in the estimates of equity beta – even though the existence of bias is well-recognised in the relevant literature and bias correction methods are commonplace among commercial data service providers.

47. This issue, which is independent of the R-squared issue above, has never been addressed by the AER and remains unaddressed in the Western Power Draft Decision.

No basis for range of 0.5 to 0.8 or estimate of 0.65

48. The Western Power Draft Decision adopts an equity beta estimate of 0.65 as the mid-point of a range of 0.5 to 0.8.[25] The Authority has provided no basis for the selection of this range. Even apart from the statistical reliability issues set out above, the 0.5 to 0.8 range is not supported by the Authority's own estimates (even if they had been properly executed and were statistically reliable):

    a) The vast majority of the point estimates presented in the tables in the Draft Decision fall outside the 0.5 to 0.8 range;

[25] Draft Decision, Paragraphs 883-884.

b) An even bigger proportion of the confidence intervals of the estimates presented in the tables in the Draft Decision fall outside the 0.5 to 0.8 range; and

c) The Authority has not explained how it has reached a final estimate that is vastly different from the AER's estimate when the Authority's "updated estimates are consistent with the estimates from Henry (2009)."[26]

49. Rather, the range of 0.5 to 0.8 and the point estimate of 0.65 appears to have been arbitrarily selected on the basis that the empirical estimates presented in the tables are so variable over such a wide range and so statistically imprecise that they cannot be used to reject those values. In particular, the Draft Decision points to the:

> High level of imprecision of the estimate of the equity beta[27]

as being the reason why:

> The Authority maintains its decision with regard to the estimates of the equity beta adopted in the current access arrangement of 0.5 and 0.8.[28]

50. But of course the Authority's previous beta estimate was based on even less data and is even more unreliable. Consequently, a conclusion that the current range should be maintained because the current estimates are so imprecise and unreliable that they should not form the basis for change is illogical and inconsistent with the objectives of the Code – an estimate of the required return that is without proper basis will not promote efficient investment or provide the service provider with a reasonable opportunity to earn a return on investment commensurate with the commercial risks involved.

51. Moreover, the current Draft Decision adopts a materially different point estimate of beta from within the 0.5 to 0.8 range, relative to the previous decision. The reasons for the adoption of the 0.65 value are set out in Paragraph 884 of the Draft Decision. But all of these reasons applied equally at the time of the last decision. It appears that the 0.65 point estimate has been arbitrarily selected without basis – the Draft Decision provides no basis for the extreme change from its previous decision.

52. If the 0.65 figure was not selected arbitrarily, the Authority will be able to explain the way in which it has mathematically processed the vast range of estimates and confidence intervals presented in the tables in the Draft Report to arrive at that figure, and why it was inappropriate to arrive at that figure in its last decision.

Conclusion

53. In our view the empirical estimates presented in the Draft Decision are statistically unreliable for a number of reasons:

[26] Draft Decision, Paragraph 882.
[27] Draft Decision, Paragraph 883.
[28] Draft Decision, Paragraph 883.

a) They are based entirely on a set of domestic firms that even the AER has described as being unlikely to provide a robust equity beta estimate;

b) The individual estimates are implausible, inconsistent and vary so much over time that they cannot reasonably be considered to be reliable;

c) The final estimate of beta has been selected without any consideration of the imprecision of the individual estimates. It is incorrect and contrary to standard practice, to interpret any empirical estimate in the absence of information about its standard error;

d) The Draft Decision does not take into account other important statistical information about the reliability and bias of the estimates presented in it; and

e) The range of 0.5 to 0.8 and the point estimate of 0.65 have no basis in that the large number of estimates presented by the Authority does not support the selection of such a range and the Draft Decision does not explain how the range was selected from the estimates presented in it. Rather, the final range and point estimate adopted in the Draft Decision appear to have been arbitrarily selected, with the implication being that the empirical estimates presented in the tables are so variable over such a wide range and so statistically imprecise that they cannot be used to reject those values.

Regulatory estimates produce nonsensical results – wild variation in systematic risk

54. The SFG Report of 21 July 2011 demonstrates that the Authority's approach to estimating equity beta produces nonsensical outputs over time when applied to other industries. In particular, that approach produces outputs which suggest that:

a) the asset beta of the Metals and Mining industry has halved and then doubled over the sample period;

b) the Health Services and Equipment industry had zero systematic risk at the start of the sample period, but average risk by the end of it; and

c) the systematic risk of the Commercial Services industry halves and doubles on a regular basis, and was all but eliminated by the end of the sample period.

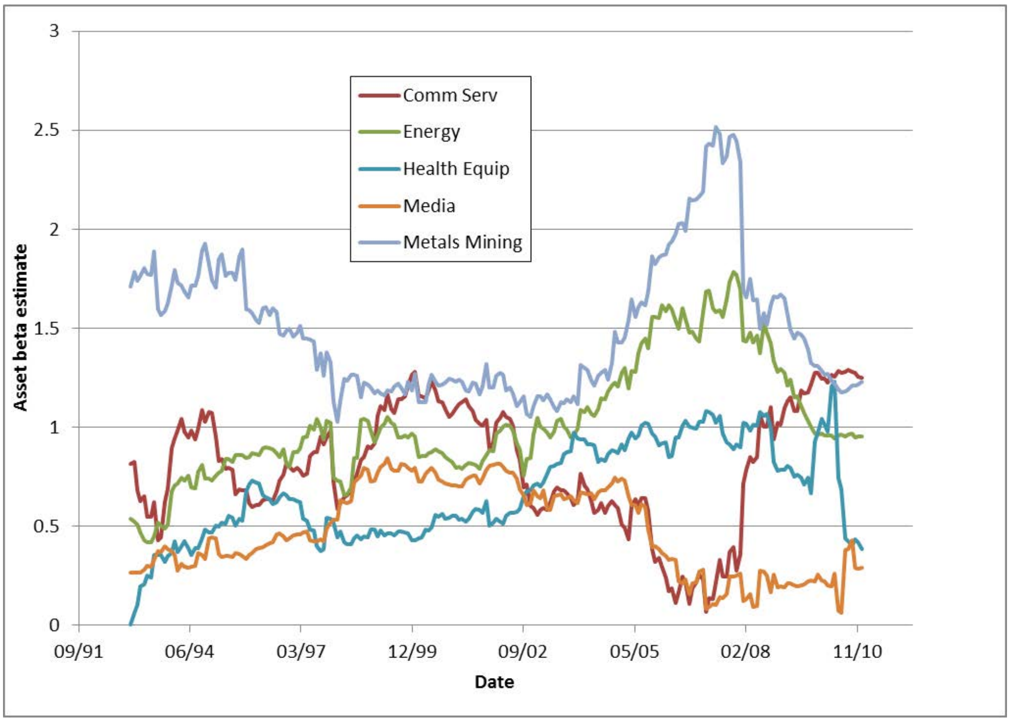
55. The SFG Report concludes that the Authority's estimation technique:

> produces asset beta estimates that vary wildly over time. By any measure, the variation in these beta estimates over time is extreme.[29]

56. We have updated that analysis to the end of 2010 and summarise the results in Figure 1 below.

[29] SFG Report, Paragraph 105.

Figure 2: Time series variation in regulatory methodology beta estimates



Source: Datastream, Aspect. SFG calculations.

57. This updated analysis clearly reinforces the conclusion that "the Authority's estimation technique produces asset beta estimates that vary wildly over time. By any measure, the variation in these beta estimates over time is extreme."[30]

58. The Draft Decision[31] notes that it is impossible to examine the time series variation in the Authority's estimate of beta from the set of Australian comparables – because the majority of those comparable firms have been listed for only a short time. That is, the historical time series of data that would be required to determine whether the Authority's estimation approach produces reasonable estimates over time simply does not exist. This is why the SFG Report examined other industries – for which the required historical time series does exist.

59. The Draft Decision goes on to dismiss the evidence that the Authority's estimation technique produces outputs that vary wildly over time on the basis that the SFG Report examined a range of industries that are not closely comparable to the utilities sector:

> …the Authority considers that only energy industries are sufficiently linked to the utilities sector in Australia.[32]

60. That is, the Draft Decision contends that:

   a) Although the Authority's estimation approach produces output that varies wildly over time when applied to a wide range of other industries;

[30] SFG Report, Paragraph 105.
[31] Draft Decision, Paragraph 826.
[32] Draft Decision, Paragraph 829.

b) It is possible that it would produce stable and plausible estimates over time for the energy and utilities industry only.

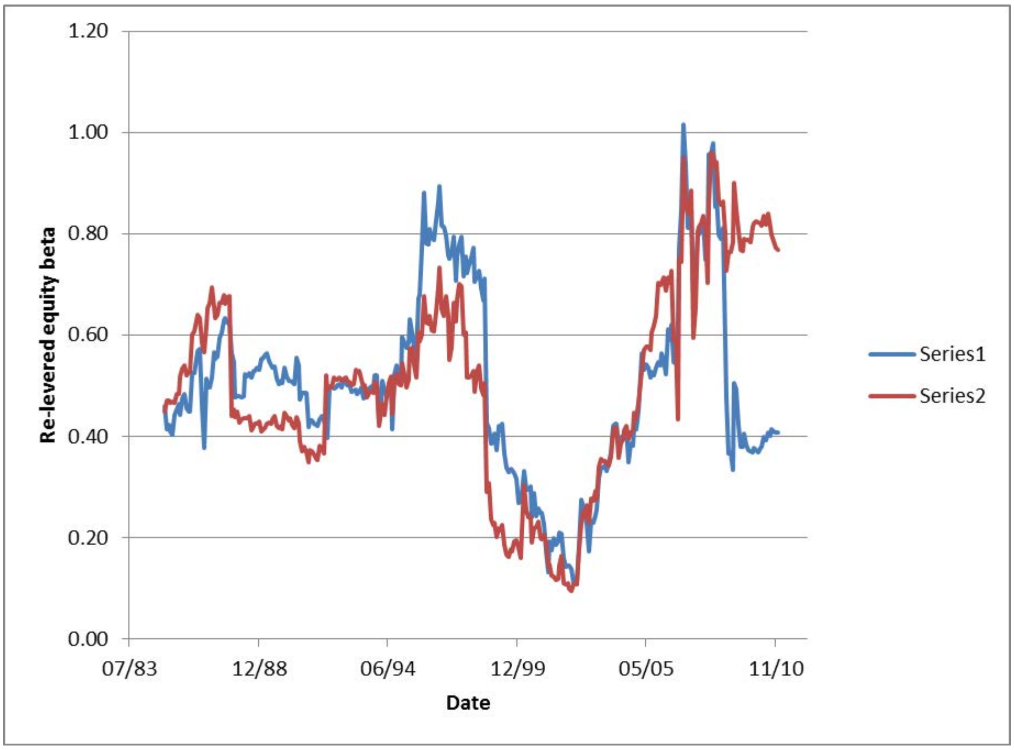
61. To rule out this remote possibility:

a) We note that one of the industries that was examined was the Australian energy industry as defined by the standard GICS code; and

b) We apply the analysis from the previous SFG Report to two samples of US utilities drawn from among the US firms that the AER included in its set of foreign comparables in its last WACC Review.

62. In its last WACC Review, the AER directed Henry (2008, 2009) to investigate a specific set of US comparables that had been selected by the AER. Eight of those firms have a full set of monthly data available from the beginning of 1985 to the end of 2010. We have divided these firms into two portfolios of four firms each and plot the time series of mean re-levered equity betas in Figure 1 below.

Figure 3: Time series variation in regulatory methodology beta estimates as applied to US comparables selected by the AER



Source: Datastream, SFG calculations.
Series 1 contains the firms EHG, CNP, EAS, and NJR
Series 2 contains the firms NI, NU, POM, and UIL

63. Figure 1 shows that:

a) Both series exhibit extreme variation over time – they regularly double then halve then double again;

b) Some of the biggest variations occur dramatically – for example both series fall by more than 40% between July and August 1998; and

c) The two series frequently diverge from each other – even though they are supposed to be estimates of the same thing.

64. In summary, our previous conclusion (that the regulatory approach produces asset beta estimates that vary wildly over time and that by any measure, the variation in these beta estimates over time is extreme[33]) also applies to the AER's sample of US energy distribution utilities.

Regulatory estimates produce nonsensical results – return on debt lower than unlevered equity

65. The Draft Decision sets the equity beta to 0.65 and gearing to 60%. The Draft Decision also adopts the following equation for the relationship between the levered equity beta and the unlevered asset beta:

$$\beta_e = \beta_a\left(1+\frac{D}{E}\right).$$

66. All of the Authority's beta estimates in the Draft Decision are based on this formula. Consequently, it is clear that the Authority's estimate of the unlevered asset beta is 0.26 since:

$$\begin{aligned}\beta_e &= \beta_a\left(1+\frac{D}{E}\right)\\ 0.65 &= 0.26\left(1+\frac{60}{40}\right).\end{aligned}$$

67. That is, according to the Draft Decision, if the benchmark firm that was financed entirely by equity, those equity holders would require a return of:

$$\begin{aligned}r_e &= r_f + \beta_e \times MRP\\ &= 3.67\% + 0.26\times 6\% = 5.23\%.\end{aligned}$$

68. By contrast, the Draft Decision concludes that if the benchmark firm is financed 60% by debt, those debt holders will require a return of 5.82%. (These calculations are the direct result of the parameter estimates and re-levering formula adopted in the Draft Decision.)

69. However, the required return on unlevered equity must be higher than the required return on debt in the same firm. This is because a debt investment in the firm is of unambiguously lower risk. In the case at hand, we have debt holders who have financed 60% of the firm's assets, but have first claim over 100% of the firm's cash flows. The debt holders will receive their promised return in full unless 100% of the firm's cash flows are insufficient to pay the return on the 60% of debt financing.

70. By contrast, if the same firm was entirely financed by equity, the Draft Decision posits that those equity holders would require a return of only 5.23% even though they would face substantially higher risk.

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[33] SFG Report, Paragraph 105.

71. In summary, take a given firm and suppose it is financed by 100% equity, and think about the risk facing those equity holders and the return that they would require. Then take the same firm and now suppose it is financed with 60% first-ranking debt finance and 40% residual equity. Think about the risk facing the first-ranking debt holders (who have provided 60% of the financing and have a first claim over 100% of the cash flows and assets) and the return they would require. It must be the case that those 60% debt holders face less risk and would require a lower return than would equity holders who had collectively financed 100%. In our view, there is no credible argument against such a basic point.

72. The Draft Decision interprets this point as implying that "there is no business debt because businesses are fully funded by equity. There is only debt issued by government…"[34] and then goes on to conclude that the business debt (which is said to be non-existent) should have a debt risk premium of zero.[35] In our view, the Draft Decision is in error when it concludes that "if companies are fully funded by equity, the debt risk premium should be zero." [36] Rather, if companies are fully funded by equity, the debt risk premium does not exist because the debt does not exist. The argument in the Draft Decision speculating about the price of debt that does not exist is not only confused, but is also irrelevant.

73. The point here is a simple one – the Authority concludes that:

a) The benchmark firm is optimally structured with 60% debt financing at a rate of 5.82%, when

b) By the Authority's own figures, 100% equity financing could be employed at a rate of only 5.23%.

74. It is inconsistent with basic corporate finance principles to assume that a 100% equity investment in the benchmark firm could possibly be less risky than a 60% first-ranking debt investment in the same firm. Consequently, an allowed return that is based on that assumption is inconsistent with the Code Objectives.

75. We note that none of these issues would arise if a higher value had been adopted for equity beta.

76. In summary, the Draft Decision is wrong when it concludes that "SFG is not comparing 'apples with apples' in this exercise." To explain why, we reiterate two basic corporate finance principles – for a given firm:

a) Levered equity has more systematic risk than unlevered equity (and consequently beta is higher for levered equity); and

b) Unlevered equity has more systematic risk than first-ranking debt (and consequently beta is higher for unlevered equity).

77. This, of course, implies that levered equity has more systematic risk than first-ranking debt, but that does not invalidate the comparisons in (a) and (b) above. Sydney is bigger than Melbourne, and Melbourne is bigger than Brisbane. The fact that Sydney is bigger than Brisbane does not invalidate the comparison between Melbourne and Brisbane.

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[34] Draft Decision, Paragraph 839.
[35] Draft Decision, Paragraph 839.
[36] Draft Decision, Paragraph 839.

Regulatory estimates produce nonsensical results – allowed return on equity materially lower than returns available from comparable firms

Overview

78. It is well-known that, in a dividend imputation system, there are three components to the return to equity holders:

 a) Dividends;

 b) Capital gains, and

 c) Imputation tax credits.

79. In this section of the report, we calculate a lower bound on each of the three components of return that investors might reasonably expect to receive from the average comparable firm. Taken together, this provides a lower bound on the aggregated return that investors might reasonably expect to receive from an investment in a comparable firm. This lower bound can then be compared with the allowed regulatory return as one test of whether the allowed return can reasonably be considered to be commensurate with the prevailing conditions in the market for funds.

Lower bound on the return from dividends

80. In its Draft Decision, the Authority presents its own estimates of the current observable dividend yields of a sample of six comparable firms. The Authority reports that the mean dividend yield for these firms is 7.34%.[37] That is, if an investor were to buy shares in the average comparable firm today, and if that firm was to simply maintain its current dividend with no increase in dividends at any time, that investor would receive a return of 7.34% p.a. on their investment every year in perpetuity. We note that this calculation is based on current observable dividend yields that are currently available to investors in the set of firms the Authority has identified as being comparable to the benchmark firm.

81. To the extent that the average comparable firm is likely to increase its dividend over time,[38] the 7.34% return from dividends that is currently available should be considered to be a lower bound. If the level of dividends is increased in the future, those higher dividends would represent a return on the initial investment of more than 7.34%. We note that the historical experience has been for firms, on average, to increase dividends over time and that brokers are currently forecasting increases in the dividends of the average comparable firm over the next two years. However, we make no use of these historical or forecasted increases in dividends, other than to note that they imply that the currently available return from dividends of 7.34% should be interpreted as a lower bound of the return that investors might presently expect from dividends from the average comparable firm. We also note that this figure is the Authority's estimate.

[37] Western Power Draft Decision, Table 78, Paragraph 845.

[38] Note that the relevant time horizon here is the indefinite future – there is an expectation that the dividend being paid by the average comparable firm will increase over the long-term indefinite future.

Lower bound on the return from capital gains

82. In its Draft Decision, the Authority adopts an estimate of expected inflation of 2.55%.[39] This implies that if the share price of the average comparable firm just maintains its real value, with no real appreciation at all, investors will receive a nominal return of 2.55% in the form of capital gains.

83. As for dividends, the historical experience has been, and the future expectation is, that share prices provide real returns to investors. For this reason the assumption that share prices will just maintain their value (over the long-term future) and will provide no real return at all to investors should be considered to be a lower bound. An allowed return that incorporates a decline in real asset values on the basis that investors in comparable firms would also suffer real declines, when in fact there is no evidence of any such expectation, would be inconsistent with the Code Objectives of promoting efficient investment and providing the service provider with a reasonable opportunity to earn a return on investment commensurate with the commercial risks involved.

Lower bound on the return from imputation credits

84. Officer (1994), the paper on which the whole CAPM-WACC regulatory framework is based, presents specific formulas to compute, for a given estimate of gamma, the return from imputation credits. In particular, he shows that the return from dividends and capital gains only must be "grossed up" to reflect the value of imputation credits by multiplying by a factor of:

$$\frac{1-T(1-\gamma)}{1-T}$$

where T is the corporate tax rate and γ represents the extent to which imputation is assumed to affect the corporate cost of capital.

85. In the present case we have:

$$(7.34\% + 2.55\%)\frac{1-0.3(1-0.25)}{1-0.3} = 10.95\%.$$

86. This implies a lower bound on the return from imputation credits of 1.06% (10.95 - [7.34+2.55]). This should also be interpreted as a lower bound as the proportional grossing-up factor from Officer (1994) has been applied to lower bound estimates of the returns from dividends and capital gains.

Conclusions

87. We have used the Authority's own estimates from the Draft Decision to compute a lower bound on the return that investors might reasonably expect from an investment in the average comparable firm. The result is a lower bound in the sense that:

    a) The return from dividends is based on the Authority's estimate of the currently available dividend yield from the average firm (7.34%). The lower bound estimate assumes that the firm simply maintains the current dividend and there is no growth in dividends whatsoever;

[39] Western Power Draft decision, Paragraph 798.

b) The return from capital gains is based on the Authority's estimate of expected inflation (2.55%). The lower bound estimate assumes that the firm's share price will just maintain its value and will provide no real return at all to investors; and

c) The return from imputation credits is based on the Authority's estimate of gamma (0.25) and the corporate tax rate (30%). It is a lower bound in the sense that the proportional adjustment is applied to lower bounds for dividends and capital gains.

88. This all implies that, on the Authority's own estimates, investors in the shares of comparable firms would reasonably expect to receive a return of at least 10.95%. This can be compared with the Authority's allowed return on equity of 7.57%.

89. It is not clear how the Authority's allowed return on equity of 7.57% can be reasonably considered to be commensurate with the prevailing conditions in the market for funds when, based on the Authority's own estimates, investors in comparable firms can reasonably expect to receive a return that is at least 45% higher than what is being allowed to investors in the benchmark firm.

Conclusions

90. We have used the Authority's own estimates from the Western Power Draft Decision to compute a lower bound on the return that investors might reasonably expect from an investment in the average comparable firm. The result is a lower bound in the sense that:

a) The return from dividends is based on the Authority's estimate of the currently available dividend yield from the average firm (7.34%). The lower bound estimate assumes that the firm simply maintains the current dividend and there is no growth in dividends whatsoever;

b) The return from capital gains is based on the Authority's estimate of expected inflation (2.55%). The lower bound estimate assumes that the firm's share price will just maintain its value and will provide no real return at all to investors; and

c) The return from imputation credits is based on the Authority's estimate of gamma (0.25) and the corporate tax rate (30%). It is a lower bound in the sense that the proportional adjustment is applied to lower bounds for dividends and capital gains.

91. This all implies that, on the Authority's own estimates, investors in the shares of comparable firms would reasonably expect to receive a return of at least 10.95%. This can be compared with the Authority's allowed return on equity of 7.57%.

92. It is not clear how the Authority's allowed return on equity of 7.57% can be reasonably considered to be commensurate with the prevailing conditions in the market for funds when, based on the Authority's own estimates, investors in comparable firms can reasonably expect to receive a return that is at least 45% higher than what is being allowed to investors in the benchmark firm.

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Advice on Capital Asset Pricing Model for response to ERA Draft Decision

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16 May 2012

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16 May 2012

Private and confidential

Advice on Capital Asset Pricing Model for response to ERA Draft Decision

Dear Noel

Please find attached my report prepared in accordance with the Federal Court of Australia expert witness guidelines.

If you have any queries, please contact me on (02) 9248 5196 or craig.mickle@au.ey.com.

Yours sincerely

Craig Mickle
Partner
Ernst & Young

Advice on Capital Asset Pricing Model for response to ERA Draft Decision

Contents

Introduction

1. Western Power has sought my advice on certain issues arising in the use of the Capital Asset Pricing Model (**CAPM**) for estimation of the expected rate of return on equity or, from the perspective of a network service provider, the cost of equity.

2. I am a Partner of Ernst & Young, working in its Economics, Regulation and Policy practice. My curriculum vitae is at Appendix A.

The assignment

3. Western Power submitted proposed revisions to the Access Arrangement for the Western Power Network (**Access Arrangement**) to the Western Australian Economic Regulation Authority (**ERA**) on 30 September 2011. These revisions were submitted pursuant to the requirements of section 4.48 of the *Electricity Networks Access Code 2004* (**Access Code**).

4. On 29 March 2012, the ERA published its Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network (**Draft Decision**).

5. Required Amendment 20 of the Draft Decision required that Western Power's proposed revisions to the Access Arrangement be amended to adopt a real post-tax rate of return of 3.87%. This rate of return was to be established using a nominal post-tax cost of equity of 7.57%. The nominal post-tax cost of equity was to be estimated using the CAPM.

6. I have been instructed to prepare a report which provides an opinion on whether the cost of equity, estimated as required by the ERA using the CAPM, was a reasonable estimate and whether it meets the requirements of the Access Code.

7. To the extent that the cost of equity determined by the ERA does not meet the requirements of the Access Code, I have been asked what features of the CAPM might account for this result.

8. Western Power has instructed that my report consider the following:

   - Does the CAPM provide good estimates of expected rates of return on financial assets relative to other methods?
   - How well does the CAPM explain expected rates of return in terms of all elements of risk that an investor would consider?
   - How well does the CAPM account for the dynamics of investment behaviour relative to other methods?
   - How well does the CAPM take into account the effects of idiosyncratic risks on asset prices relative to other methods?
   - How well does the CAPM account for diversity in investor expectations about investment opportunities and returns relative to other methods?
   - How well does the CAPM take into account developments in behavioural finance relative to other methods?

Information

9. The documents that I have relied upon for the purposes of preparing this report are listed in Appendix B.

10. I have not conducted an audit or other verification of any information supplied to me. I have assumed that the information supplied to me is accurately stated.

11. Neither I, nor Ernst & Young, warrant the accuracy or reliability of any of the information supplied to me.

12. The opinions set out in this report may alter if there are any changes to the information supplied to me.

13. I have received all relevant information requested during the course of preparing this report.

Qualifications

14. My opinion is based on my experience in the field of regulatory economics, on my interpretation of the relevant provisions of the Access Code, and on the information provided to me by Western Power. Should a court of law find that another interpretation of the Access Code is to be preferred, or should there be changes to any of the information provided to me by Western Power, my conclusions may change.

Reliance on this report

15. My report has been prepared, and may be relied on, solely for the purposes outlined in paragraphs 3 to 8 above. The report has been prepared specifically for Western Power. Neither I, nor Ernst & Young, takes any responsibility to any person, other than Western Power, in respect of this report, including in respect of any errors or omissions howsoever caused.

Assistance by colleagues

16. I have sought the assistance of my colleague, Dr John Williams, in preparing my report, and his curriculum vitae is included at Appendix A.

17. However, the opinions expressed in the report are mine.

Conduct of this assignment

18. I understand that my report is to be prepared in respect of the ERA's Draft Decision. I acknowledge that the report will be provided to the ERA by Western Power in response to the Draft Decision.

19. I have been instructed that the report is to be prepared in a form which satisfies the requirements of the guidelines for expert witnesses in proceedings in the Federal Court of Australia. These guidelines are set out in Federal Court of Australia Practice Note CM7.

20. I have read, understood and complied with the Practice Note.

21. I have made all the inquiries which I believe are desirable and appropriate. No matters of significance that I regard as relevant to my opinion have, to my knowledge, been withheld.

Structure of the report

22. The structure of the remainder of my report is as follows:

- paragraphs 24 to 36 contain a summary of my opinion;
- paragraphs 37 to 96 set out the matters which I have been instructed to consider in providing my opinion; more specifically:
  - paragraphs 37 to 43 set out the provisions of the Access Code which require the use of a cost of equity, and which govern the determination of that cost
  - paragraphs 47 to 54 describe the CAPM and the way in which it is derived
  - paragraphs 55 to 59 consider the question of how well the CAPM accounts for the dynamics of investment behaviour relative to other models;
  - paragraphs 60 to 81 address the question of whether the CAPM explains expected rates of return in terms of all elements of risk that an investor would consider;
  - paragraphs 82 to 84 examine the way in which CAPM takes into account idiosyncratic risks;
  - paragraphs 85 to 87 address the question of how well the CAPM accounts for diversity in investor expectations about investment opportunities and returns;
  - paragraphs 88 to 91 consider the implications of behavioural finance for the CAPM;
  - paragraphs 93 to 96 address the question of whether the CAPM provides good estimates of expected rates of return on financial assets; and
- paragraphs 97 to 109 set out the conclusions which I have drawn from consideration of these matters, and which constitute my opinion.

Summary of opinion

23. A summary of my opinion is set out in paragraphs 24 to 36. This summary should be read in conjunction with my full report, which follows.

24. The Access Code requires that the capital-related costs component of the approved total costs which may be used to derive a price control which sets a service provider's target revenue be calculated by applying a weighted average cost of capital (**WACC**) to the capital base of a covered network.

25. In the current circumstances, where no determination by the ERA of a preferred WACC methodology is in effect, the WACC to be used to calculate the return component of the service provider's capital-related costs must be based on an accepted financial model such as the CAPM.

26. Basing the WACC on an accepted financial model such as the CAPM is necessary but, without careful consideration of the values of the input parameters to that model, the resulting WACC may not necessarily be sufficient for the purposes of the Access Code. Under the Access Code, the WACC must also:

    ► represent an effective means of promoting the economically efficient investment in, and the economically efficient operation and use of, networks; and

    ► give the service provider an opportunity to earn revenue for the access arrangement period of an amount that meets the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved.

27. The possibility then arises that the WACC to be used to calculate the return component of the service provider's capital-related costs is based on the CAPM, but does not represent an effective means of promoting the economically efficient investment, and does not give the service provider an opportunity to earn a return on investment commensurate with the commercial risks involved.

28. The reasons why a WACC based on the CAPM may not meet these requirements of the Access Code lie in the limitations of the CAPM. Even if the parameters of the model are correctly estimated, the CAPM may not provide an estimate of the cost of equity which leads to a WACC which is an effective means of promoting economically efficient investment, and which gives the service provider an opportunity to earn a return on investment commensurate with the commercial risks involved.

29. The CAPM is limited in the following ways:

    ► the CAPM is essentially a static model; when the dynamics of investment behaviour are taken into account at least one other risk factor is required to explain asset prices;

    ► the CAPM explains expected rates of return in terms of only one type of risk; the effects of other types of risks, in particular, technological and regulatory risks, although potentially important for a network service provider, are excluded by the form of the economic model of choice from which the CAPM is derived;

- the CAPM does not take into account the effects of idiosyncratic risks on asset prices; the effects of these risks are assumed to be eliminated by portfolio diversification, but the existence of the required diversification is not supported by the evidence;

- for derivation of the CAPM, investor expectations about investment opportunities and returns are assumed to be homogeneous; however, recent research, which examines the implications of the more reasonable view that investor expectations are heterogeneous, finds that optimal portfolios may not be well diversified, and idiosyncratic factors may be important in explaining expected rates of return; and

- dissatisfaction with the psychological foundations of the rational actor framework of financial economics has led to the emergence of behavioural finance, which further challenges the adequacy of the CAPM as an explanation of the economic processes through which asset prices are generated.

30. These limitations may not matter much if the CAPM provided satisfactory predictions of asset prices. However, empirical research has shown that the CAPM does not necessarily provide good estimates of expected rates of return on financial assets.

31. Other asset pricing models have been developed to address the limitations in the CAPM. Some of these other models address specific assumptions made for the derivation of the CAPM which are seen as being problematic. Some introduce different and more comprehensive characterisations of the risks which are being priced.

32. Only a few of the other asset pricing models which have been developed (in particular Black's Capital Asset Pricing Model and the Fama-French three factor model) have been used by financial market practitioners. They are more complex and more difficult to use than the CAPM.

33. In these circumstances, the CAPM remains widely used, but financial market practitioners who use it apply the model with care. They recognise its limitations and the difficulties of parameter estimation. They use their commercial judgements to ensure that the outcomes of model use accord with market reality.

34. Use of any model involves simplification and approximation. It also involves error in parameter estimation. Simplification, approximation and estimation error allow the possibility that the result obtained is not the "true" result. In the case of use of the CAPM, the estimate of the cost of equity obtained may not be the result which would lead to a WACC which:

- represents an effective means of promoting the economically efficient investment in, and the economically efficient operation and use of, networks; and

- gives the service provider an opportunity to earn revenue for the access arrangement period of an amount that meets the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved.

35. In my opinion, if the CAPM is applied to determine the cost of equity to be used in determining a WACC for use in calculating the return component of capital-related costs (as is required by the Access Code), Western Power must exercise judgement in establishing the individual inputs to the model to ensure that the resulting WACC:

- represents an effective means of promoting the economically efficient investment in, and the economically efficient operation and use of, the Western Power Network; and

- gives Western Power an opportunity to earn revenue for the access arrangement period of an amount that meets its forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved.

36. The results obtained from other asset pricing models, and from market based evidence (such as the evidence prepared for Western Power by Strategic Finance Group) can, in my view, guide Western Power's exercise of judgement in establishing the individual inputs to the CAPM.

Opinion

Requirements of the Access Code

37. The Access Arrangement incorporates a price control in accordance with section 6.1 of the Access Code. The price control sets target revenue by reference to Western Power's approved total costs in accordance with section 6.2 of the Access Code.

38. A service provider's approved total costs, in relation to covered services provided by means of a covered network for a period of time, are defined as:

    - the capital-related costs determined in accordance with section 6.43 of the Access Code; and

    - those non-capital costs which satisfy the test in (as applicable) section 6.40 or section 6.41 of the Access Code.

39. In accordance with section 6.43 of the Access Code, the capital-related costs component of approved total costs is to be calculated by:

    - determining a capital base under sections 6.44 to 6.63;

    - calculating a return on the capital base by applying a WACC calculated under section 6.64 to the capital base; and

    - calculating the depreciation of the capital base under section 6.70.

40. By a notice dated 22 April 2010, the ERA advised that no determination of WACC methodology under section 6.65 of the Access Code had effect. In these circumstances, section 6.64(b) of the Access Code requires that the WACC be calculated in a manner consistent with section 6.66.

41. Section 6.66 of the Access Code requires that a determination of preferred methodology for calculating the WACC in access arrangements under section 6.65:

    - represent an effective means of achieving the Access Code objective and the objectives in section 6.4; and

    - be based on an accepted financial model such as the CAPM.

42. The Access Code objective is set out in section 2.1. It is: the promotion of the economically efficient investment in, and the economically efficient operation and use of, networks and services of networks in Western Australia in order to promote competition in markets upstream and downstream of the networks.

43. Section 6.4(a) of the Access Code requires that the price control have the objective of giving the service provider an opportunity to earn revenue (target revenue) for the access arrangement period from the provision of covered services of an amount that meets the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved.

44. I conclude from the above:

- the capital-related costs component of the approved total costs which may be used to derive a price control which sets a service provider's target revenue is to be calculated by applying a WACC to the capital base of the covered network;
- in current circumstances, where no determination by the ERA of a preferred WACC methodology is in effect, the WACC to be used to calculate the return component of the service provider's capital-related costs must be based on an accepted financial model such as the CAPM;
- in circumstances where no determination by the ERA of a preferred WACC methodology is in effect, basing the WACC to be used to calculate the return component of the service provider's capital-related costs on an accepted financial model such as the CAPM is necessary but may not necessarily be sufficient for the purposes of the Access Code; under the Access Code the WACC must also:
  - represent an effective means of promoting the economically efficient investment in, and the economically efficient operation and use of, networks; and
  - give the service provider an opportunity to earn revenue for the access arrangement period of an amount that meets the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved; and
- the possibility then arises that the WACC to be used to calculate the return component of the service provider's capital-related costs is based on the CAPM, but does not represent an effective means of promoting the economically efficient investment, and does not give the service provider an opportunity to earn a return on investment commensurate with the commercial risks involved.

45. The reasons why a WACC that is based on the CAPM might not meet the requirements of the Access Code are to be found in the assumptions made to derive the model, and in its empirical validation.

Capital Asset Pricing Model

46. This section of my report describes the derivation of the CAPM. Particular attention is paid to the assumptions made for the purposes of that derivation.

47. The CAPM is derived from an economic model of choice in which an investor chooses, at a point in time, a portfolio of financial assets which yield returns one period later. A financial asset is an instrument for the transfer wealth between the current period (today) and a specified future period (tomorrow). By purchasing a financial asset today, and selling that asset tomorrow, an investor can defer expenditure in the expectation of increased wealth tomorrow from the return on the investment in the financial asset.

48. The economic model of choice from which the CAPM is derived is a simple model. The only economic activities that are modelled are the buying and selling of financial assets. This model does not incorporate the buying and selling of goods and services including labour services, the production of those goods and services, the investment in the physical assets need to produce those goods and services, technological change, financial institutions, government and the regulation of economic activity, or economic growth.

49. The following assumptions are made for the derivation of the CAPM:

- a fixed supply of financial assets is available, and those assets are perfectly divisible and perfectly liquid (marketable);
- the market in which the financial assets are traded is perfectly competitive; investors take the market prices of the assets as given;
- there are no restrictions on the short selling of financial assets, no transaction costs are incurred when assets are traded, and there are no taxes;
- one of the financial assets available in the market is a risk free asset; investors can borrow and lend, in unlimited amounts, at the rate of return on this risk free asset (the risk free rate of rate of return) which is fixed and determined outside the model;
- the return on a portfolio of assets is not known with certainty at the time the portfolio is chosen, but all investors know the true joint probability distribution of asset returns at the end of the period; and
- investors maximise the expected utility of end-of-period wealth by choosing among alternative portfolios which can be ranked in terms of expected portfolio return and risk, with risk measured as the variance, or standard deviation, of portfolio return (mean-variance framework).

50. The model which is derived from these assumptions – the CAPM – explains the expected rate of return on a financial asset as the sum of a risk free rate of return and a premium for risk:

$E(r_e) = r_f + [E(r_m) - r_f] \times \beta$,

where:

- $E(r_e)$ is the nominal post-tax expected rate of return on the financial asset;
- r_f is the nominal risk free rate of return; and
- $E(r_m) - r_f$ is the market risk premium.

51. Beta (β) is the covariance of the rate return on the asset in question and the rate of return on the market portfolio divided by the variance of the rate of return on the market portfolio:

$\beta = cov(r_e, r_m)/var(r_m)$.

52. The covariance is a measure of the linear association between the rate return on the asset in question and the rate of return on the market portfolio. Beta is, then, a measure of the contribution which the asset makes to the risk of the market portfolio.

53. The risk which the CAPM takes into account in explaining the price of a financial asset – the product of beta and the market risk premium – is the contribution made by the asset in question to the riskiness of the market portfolio.

54. When the CAPM was first derived in the 1960s, this was an important theoretical insight into the relationship between expected rate of return and risk. When the assumptions listed in paragraph 49 are made, the variance or "riskiness" of the return on the asset – its "own risk" – is not a factor which explains the expected rate of return.

How well does the CAPM account for the dynamics of investment behaviour relative to other methods?

55. The CAPM appears to incorporate time through the way in which it is derived: an investor is assumed to purchase a portfolio of assets which provides returns one period later, and those returns are not known with certainty at the time the portfolio is chosen. There is, however, no process of economic change in this assumption. The CAPM is a static model.

56. In 1973, economist Robert Merton made the following assessment of the state of asset pricing theory:

Although the model has been the basis for more than one hundred academic papers and has had a significant impact on the non-academic financial community, it is still subject to theoretical and empirical criticism. Because the model assumes that investors choose their portfolios according to the Markowitz mean-variance criterion, it is subject to all the theoretical objections to this criterion, of which there are many.[1]

57. The model to which Merton was referring was the CAPM. Merton sought to avoid the theoretical objections to the mean-variance framework which had earlier been adopted for CAPM derivation by deriving a general form of the asset pricing relationship using the standard model of intertemporal choice from microeconomic theory.

58. Merton's use of intertemporal choice theory also allowed the assumption of a single time period to be dropped, and opened the way to explicit consideration of the role of time in investment decisions and asset pricing.

59. Merton showed that expected rates of return must compensate investors for bearing market risk (the key insight of the CAPM), and must also compensate for the bearing of the risk of unfavourable shifts in the set of investment opportunities over time. If economic conditions change, the explanation of the CAPM is inadequate, and a second risk factor is required to explain asset prices.

[1] Merton (1973), page 867.

Does the CAPM explain expected rates of return in terms of all elements of risk that an investor would consider relative to other methods?

60. The simple model of choice from which the CAPM is derived precludes an explanation of expected rate of return in terms of all elements of risk that an investor would consider.

61. As I have noted in paragraph 59, Merton has shown that when economic conditions change over time, the single risk factor explanation of the CAPM is inadequate, and a second risk factor is required to explain asset prices.

62. The use of intertemporal choice, which was pioneered by Merton, and is now the dominant approach to the theory of asset pricing, leads to a simple but abstract asset pricing model:

$p_t = E_t[m_{t+1}x_{t+1})]$,

where p_t is the equilibrium asset price at time t, x_{t+1} is the uncertain payoff on the asset at time t + 1, and m_{t+1} is a stochastic discount factor.[2]

63. This model expresses the idea that, in a competitive capital market, the price of an asset is simply its expected discounted payoff, the expectation being formed at time t, the time at which a decision to purchase the asset is made.

64. Since the rate of return on the asset is $r_{t+1} = x_{t+1}/p_t - 1$, the stochastic discount factor model can be written in terms of the rate of return rather than the asset's price so that:

$E_t[m_{t+1}(1 + r_{t+1})] = 1$.

65. The stochastic discount factor, m_{t+1}, is determined by the ratio of the marginal utility from the consumption of goods and services tomorrow (period t + 1) to the marginal utility of consumption today (period t). It reveals a fundamental determinant of asset prices and, hence, of rates of return: the rate at which investors are willing to substitute consumption tomorrow for consumption today. This rate is, in turn, determined by the rate of growth in consumption between today and tomorrow. Asset prices, and rates of return, are, therefore, determined by expectations about consumption growth. This important result explicitly links asset prices to the state of the economy.

66. For a number of reasons, relating the stochastic discount factor directly to consumption growth does not facilitate the development of asset pricing models beyond the rather abstract form in paragraph 62 (or paragraph 64). In these circumstances, more specific representations of the discount factor have been sought. In one important line of research, the discount factor is "linearized", so that the expected rate of return on an asset is modelled as a linear function of the economic factors, fi, which determine consumption growth. The asset pricing model is:

$E_t(r) = a + b_1 \times \beta_{f1,\, r} + b_2 \times \beta_{f2,\, r} + \ldots + b_n \times \beta_{fn,\, r}$,

where $E_t(r)$ is the expected rate of return on an asset; a is a constant; $b_i = \alpha \times var(fi)$, α a constant; and $\beta_{fi,\, r} = cov(fi, r)/var(fi)$.

2 See, for example, the derivation in Cochrane (2005), Chapter 1.

67. These linear factor models have been an area of theoretical and empirical research in financial economics for at least two decades. A key issue for this research has been the question of what are the appropriate factors. Theoretical considerations, as outlined above, require that they be variables which can be explicitly related to investor marginal utility or consumption growth.

68. One such factor is the return on a portfolio of total wealth. Consumption is high when investor returns on a portfolio of all assets is high. This portfolio of all assets would comprise financial assets, real – tangible – assets, and intangible – but valuable – assets such as investments in human capital. If the number of factors is restricted to one, and that one factor is the return on a portfolio of total wealth (r_w), the asset pricing equation of paragraph 66 reduces to:

$E_t(r_{t+1}) = r_f + [E(r_w) - r_f] \times \beta_{w, r}$.

69. This is the conditional capital asset pricing model, in which the expected rate of return is conditional on the information available today. If further assumptions are made (for example, returns distributions are identically and independently multivariate normal), the conditioning can be removed, and the model reduces to the CAPM.

70. Restriction of the number of parameters to one – return on a portfolio of total wealth – is, however, arbitrary. Multiple linear factor models now dominate empirical asset pricing research, and one of the most widely recognised – and tested – of these is the Fama-French three-factor model.[3]

71. Although early empirical work provided some support for the CAPM, further work during the 1980s began to reveal "anomalies" – asset pricing behaviour which appeared to deviate from the predictions of the CAPM.[4] These anomalies included:

- a size effect: low market value shares have higher returns than can be explained by the CAPM;
- a value effect: returns are predicted by ratios of market value to accounting measures such as earnings and book value of equity; and
- a momentum effect: shares with high returns during the past three to 12 months tend to have higher returns in the immediate future.

72. Fama and French proposed that these anomalies were interrelated and captured by a three-factor model of asset prices. The three factors are:

- the excess return to the market portfolio, $E(r_m) - r_f$;
- the difference between the return to a portfolio of high book-to-market shares and the return to a portfolio of low book-to-market shares (HML); and
- the difference between the return to a portfolio of small capitalization shares and a portfolio of large capitalization shares (SML).

73. The Fama-French three-factor model is:

$E(r) = r_f + \beta_{rm} \times [E(r_m) - r_f] + h \times HML + s \times SMB$.

[3] Cochrane (2005), page 438.

[4] Campbell (2000), pages 1526-1529.

74. Tests using US stock market data have shown that the three factor model appears to have significantly greater explanatory power than the CAPM.[5] Similar results have also been obtained using Australian share prices.[6]

75. Intertemporal choice theory, and linearization of the stochastic discount factor, has opened up new insights into asset pricing, "connecting" asset prices with macroeconomic risks through multiple risk premiums established in asset markets.

76. Although intertemporal choice theory indicates the appropriateness of a multiple factor model such as that proposed by Fama and French, it does not provide specific guidance on the choice of factors. This has led some financial economists to argue that the fact that the three factor model provides a better "fit" than the CAPM is not indicative of superior explanatory power, but a fortuitous outcome from judicious choice of the relevant "explanatory" variables.[7]

77. Others concur with Fama and French that the three factors are proxies for specific macro-economic risks. Liew and Vassalou (2000), for example, find a positive relationship between the factor HML and future growth in the economy, and between SMB and future growth. They conclude that their work supports the contention of Fama and French that these variables act as state variables in the context of intertemporal capital asset pricing. Further support for this view is provided by Vassalou (2003).

78. The multiple linear factor models derived from intertemporal choice theory indicate that estimation of a rate of return using the CAPM does not take into account all elements of risk that an investor would consider relevant. However, these models themselves, embody a limited characterisation of risk. Through the way in which they are derived, the only risk which they identify for asset pricing is investor consumption risk as measured by the covariance of asset return with investor expectations about consumption growth. (In the case of the CAPM, investor expectations about consumption growth are seen as being correlated with variation in the return on a portfolio of total wealth, and risk is then the contribution of a specific asset to the riskiness of the market portfolio.) Irrespective of whether the approach to risk is through the mean-variance framework within which the CAPM is derived, or whether it is the framework of intertemporal asset pricing which leads to, among others, the Fama-French model, the underlying theoretical scheme is limited to investors buying and selling financial assets. This scheme is that of a simple exchange economy. It does not incorporate production, the regulation of productive activity, or technological change and economic growth. Pricing models derived by assuming a simple exchange economy cannot provide a complete explanation of the determinants of asset prices. They do not take into account the technological, and regulatory and other risks to which the owners of physical assets are exposed.

5 See, for example, Fama and French (1996).

6 See, for example, Gaunt (2004).

7 See, for example, MacKinlay (1995).

79. In consequence, some have argued that these technological, regulatory and other risks to which the owners of physical assets are exposed are not relevant to the rates of return on the financial assets which finance those physical assets. This is not the case. Those risks are seen as not being relevant because they are excluded by the choice of the premises from which the CAPM and the models developed within the intertemporal choice framework are derived. These models are derived from premises which reduce the economy to exchanges of financial assets intended to maximise investor utility from consumption subject to an initial distribution of investor wealth. Technological, regulatory and other risks are, then, irrelevant not because they are unimportant but because the premises chosen for model derivation exclude such factors as technological change, investments in physical assets, and competition and regulation in the markets in which those assets are operated.

80. As Cochrane (2007) has argued, the macroeconomic shocks – the sources of risk which asset pricing models seek to price – are seen not only in aggregate consumption data, but also in production, investment and employment data. The focus on the consumption decision which is at the core of intertemporal choice theory is a "weak link".

81. Asset pricing should also be linked to production through explicit modelling of the behaviour of firms within a general equilibrium framework broader than that in which intertemporal capital asset pricing has been developed. This is not new.[8] The derivation and testing of asset pricing models which incorporate production, investment and economic growth is an active area of research. However, it has not yet led to widely accepted models of asset pricing.

How well does the CAPM take into account the effects of idiosyncratic risks on asset prices relative to other methods?

82. The risk captured by the CAPM is commonly referred to as systematic risk. Systematic risk is described, somewhat loosely, as the risk which is measured by the covariation of asset return with another variable representing the state of the economy (in the case of the CAPM, the expected rate of return on the market portfolio). Equally loosely, risks which are independent of the state of the economy, but which affect the returns on particular assets, are called unsystematic or idiosyncratic risks.

83. Systematic risk is, from the perspective of the CAPM, the only type of risk for which investors are compensated by market rates of return. Underlying the CAPM is a view that investors do not need to be exposed to idiosyncratic risks. By holding well diversified portfolios, they can limit the risk to which they are exposed to systematic risk (which, because it is economy-wide, cannot be eliminated by diversification). Market rates of return do not, therefore, need to compensate investors for bearing idiosyncratic risks.

8 An early study of this type which examines the impact of one aspect of government – taxation – on asset pricing within a production context is Brock (1982). More recent work which shows that technological and other risks may be important in the explanation of asset prices is indicated by the growing number of pricing models developed within a dynamic general equilibrium framework incorporating production as well as exchange and consumption. These models are relatively new and untested. See, for example, Cochrane (1996); Jermann (1998); Gomes, Kogan and Zhang (2003); Kogan (2004); and Gomes, Kogan and Yogo (2009).

84. The view that portfolio diversification limits the risks to which an investor is exposed to systematic risk is a theoretical view. It is a conclusion reached in a process of reasoning from certain premises. It is not a statement of fact. Investors typically do not hold well diversified portfolios of assets.[9] A large percentage of household wealth is held in the form of human capital, sole proprietorships, partnerships, pension plans, superannuation funds, and residential real estate. Among institutional investors, an increasing amount of wealth is allocated to a limited number of asset types including private equity, venture capital, commercial real estate, and hedge fund investments.

How well does the CAPM account for the diversity in investor expectations about investment opportunities and returns relative to other methods?

85. The CAPM is based on an assumption of homogeneous expectations: the returns on financial assets are not known with certainty at the time portfolios are chosen, but all investors know the true joint probability distribution of asset returns at the end of the period.

86. The assumption of homogeneous expectations, and the related use of representative agent models (the behaviour of all investors is modelled as the behaviour of a single representative investor), have been the subject of much questioning given the inability of economic models which incorporate these assumptions to predict the Global Financial Crisis.

87. The failure of investors to hold well diversified asset portfolios may not be, as some have suggested, the result of investor irrationality, and something which should therefore be ignored. Recent research has shown that when investors hold expectations about investment opportunities and expected returns which are different from the expectations held by other investors (that is, when expectations are not, as assumed for CAPM derivation, homogeneous), optimal portfolios will not be well diversified, and idiosyncratic factors are important in explaining asset prices.[10]

How well does the CAPM take into account developments in behavioural finance relative to other methods?

88. The CAPM, like many of the more recent models for explaining asset prices, is derived within a conceptual framework in which investors are assumed to maximise the expected utility of end-of-period wealth by choosing among alternative portfolios subject to constraints on investment and consumption opportunities, including constraints on wealth and on the availability of information. Although a part of standard microeconomic theory, the assumption that choice can be described in terms of a rational individual maximising expected utility has been seen as problematic since axiomatic expected utility theory was first advanced during the 1950s.[11]

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9 See, for example, Campbell, Lettau, Malkiel and Xu (2001).

10 The models are relatively new and untested, but are indicative of a growing area of research in asset pricing. See, for example, Constantinides and Duffie (1996); Campbell, Lettau, Malkiel and Xu (2001); Brav, Constantinides and Geczy (2002); Fu (2009); and Longstaff (2009).

11 Machina (1987) provides a review of the issues.

89. Concern has been expressed over the psychological foundations of the rational actor framework and, more specifically, over the presumption of expected utility maximization. During the 1980s, these concerns, and the fact that rational actor models did not seem to provide adequate explanations of financial markets, drove the emergence of a new conceptual framework – behavioural finance – based on more realistic psychological foundations, and supported by experimental and empirical analysis.[12]

90. After reviewing the then recent research on asset pricing models which relates a stochastic discount factor to macroeconomic risks, and nearly two decades of work in behavioural finance, Campbell concluded his 2000 survey of asset pricing:

Despite the promise of such [stochastic discount factor] *research, in my opinion it is unrealistic to hope for a fully rational, risk based explanation of all the empirical patterns that have been discovered in stock returns. A more reasonable view is that rational models of risk and return describe a long-run equilibrium toward which financial markets gradually evolve. Some deviations from such models can be quickly arbitraged away by rational investors; others are much harder to arbitrage and may disappear only after a slow process of learning and institutional innovation.*[13]

91. The research which has been (and is being) undertaken within the behavioural finance paradigm provides further reasons to expect that the CAPM does not provide a complete view of the economic processes through which asset prices are determined.

Does the CAPM provide good estimates of expected rates of return on financial assets relative to other methods?

92. In the preceding paragraphs I have examined the ways in which the CAPM is deficient as a model explaining the economic processes through which asset prices are determined. There has, however, been much debate within the discipline of economics about the question of whether theories or models are to be judged in terms of the validity of their assumptions, or whether theories or models, by their very nature use unrealistic assumptions and must be judged in terms of the accuracy of the predictions which can be made using them.

93. I shall not discuss this essentially philosophical debate. Having examined the limitations of the model, I turn to the issue of predictions made using the CAPM.

94. That the CAPM does not provide good estimates or forecasts of expected rates of return became apparent when the first econometric tests of the model were carried out in the late 1960s and early 1970s.[14] Early empirical work on the CAPM indicated that it broadly explained the behaviour of asset prices: high beta shares tended to have higher returns than low beta shares, and the relationship between rate of return and share price was "roughly linear". However, the slope of the relationship between rate of return and beta appeared to be less than the slope implied by the CAPM, and the model appeared to "explain" only a small percentage of the variation in rates of return.[15]

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12 Shiller (2003) provides a brief history of behavioural finance and a review of the earlier literature.

13 Campbell (2000), pages 1557-1558.

14 See, for example, Friend and Blume (1970); Black, Jensen and Scholes (1972); Bloom and Husic (1973); and Fama and MacBeth (1973).

15 Empirical studies of the CAPM are reviewed in Campbell, Lo and MacKinlay (1997); Campbell (2000); and Cochrane (2005).

95. Subsequent studies, using more refined statistical methods, continued to show that the CAPM was not a particularly good model of asset pricing.[16]

96. A number of the assumptions listed in paragraph 49 above are questionable, and have been identified as possible causes of the empirical failure of the CAPM. Brennan (1970) and Black (1972), for example, identified the assumption of unrestricted borrowing and lending at the risk free rate of return as being problematic, and derived asset pricing models within the mean-variance framework within which the CAPM was derived, without assuming the existence of a risk free asset, and without assuming unrestricted borrowing and lending.

Conclusions drawn

97. The CAPM provides an important, but incomplete, insight into the relationship between expected rates of return on financial assets and risk.

98. There are at least six reasons why a cost of equity, estimated using the CAPM, may not be a reasonable estimate, and may not meet the requirements of the Access Code. These are:

- the CAPM is essentially a static model; when the dynamics of investment behaviour are taken into account at least one other risk factor is required to explain asset prices;
- the CAPM explains expected rates of return in terms of only one type of risk; the effects of other types of risk, in particular, technological and regulatory risk, although potentially important, are excluded by the form of the model of choice from which the CAPM is derived;
- the CAPM does not take into account the effects of idiosyncratic risks on asset prices; the effects of these risks are assumed to be eliminated by portfolio diversification, but the existence of the required diversification is not supported by the evidence;
- for derivation of the CAPM, investor expectations about investment opportunities and returns are assumed to be homogeneous; recent research, which examines the implications of the more reasonable view that investor expectations are heterogeneous, finds that optimal portfolios will not be well diversified, and idiosyncratic factors are important in explaining expected rates of return;
- dissatisfaction with the psychological foundations of the rational actor framework of financial economics has led to the emergence of behavioural finance, which further challenges the adequacy of the CAPM as an explanation of the economic processes through which asset prices are generated; and
- empirical research has shown that the CAPM does not provide good estimates of expected rates of return on financial assets.

16 See, for example, Banz (1981), Reinganum (1982), Gibbons (1982), Stambaugh (1982), Shanken (1987), and Fama and French (1992).

99. The CAPM, Black's Capital Asset Pricing Model and the Fama-French three factor model can be regarded as three specific forms of the multiple linear factor model derived from intertemporal capital asset pricing. Each of these three forms provides an important insight into the way in which asset prices are determined, and each has been used to some extent by financial market practitioners. However, each also has recognized weaknesses, and each is no more than a partial representation focusing on particular determinants of asset prices.

100. I have not estimated the parameters of these other asset pricing models, but such estimates have been made by others.[17] The results indicate the possible magnitude of the error associated with using the CAPM to estimate the cost of equity. This is shown in the following table. (I have been instructed to assume, for the purpose of preparing the table, a market risk premium of 6.5%).

Risk premiums from alternative asset pricing models

Service Provider	Model	Premium above risk free rate
	CAPM $E(r_e) - r_f = [E(r_m) - r_f] \times \beta$ $= 6.5\% \times 0.65$	4.2%
Jemena Gas Networks[1]	Fama-French three factor model $E(r_e) - r_f = [E(r_m) - r_f] \times \beta + HML \times h + SMB \times s$ $= 6.5\% \times 0.59 + 6.24\% \times 0.48 - 1.23\% \times 0.30$	6.5%
WA Gas Networks[2]	Black's Capital Asset Pricing Model $E(r_e) - r_f = z + [E(r_m) - r_f - z] \times \beta$ $= 6.5\% + [6.5\%. - 6.5\%] \times 0.65$	6.5%
	Fama-French three factor model $E(r_e) - r_f = [E(r_m) - r_f] \times \beta + HML \times h + SMB \times s$ $= 6.5\% \times 0.65 + 3.61\% \times 0.38 + 2.58\% \times 0.44$	6.7%
	Zero-beta Fama-French three factor model $E(r_e) - r_f = z + [E(r_m) - r_f - z] \times \beta + HML \times h + SMB \times s$ $= 6.5\% + [6.5\% - 6.5\%] \times 0.65 + 3.61\% \times 0.38 + 2.58\% \times 0.44$	9.0%
DBP[3]	Black's Capital Asset Pricing Model $E(r_e) - r_f = [E(r_m) - r_f] \times \beta$ $= 6.5\% + [6.5\%. - 6.5\%] \times 0.53$	6.5%
	Fama-French three factor model $E(r_e) - r_f = [E(r_m) - r_f] \times \beta + HML \times h + SMB \times s$ $= 6.5\% \times 0.56 + 5.90\% \times 0.40 - 0.08\% \times 0.30$	6.0%
	Zero-beta Fama-French three factor model $E(r_e) - r_f = z + [E(r_m) - r_f - z] \times \beta + HML \times h + SMB \times s$ $= 6.5\% + [6.5\% - 6.5\%] \times 0.56 + 5.90\% \times 0.40 - 0.08\% \times 0.30$	8.8%

1 Jemena Gas Networks (NSW) Access Arrangement Information – Appendix 9.1, 26 August 2009, page iii.
2 WA Gas Networks, Response to Draft Decision (Public Version), 8 October 2010, pages 34-35.
3 DBP, Submission 55: Rate of Return, 20 May 2011, page 33.

[17] Network service providers regulated under the National Gas Rules are not restricted to use of the CAPM, and at least three of them have proposed the use of other asset pricing models. WA Gas Networks (now ATCO Gas Australia) and DBP (operator of the Dampier to Bunbury Natural Gas Pipeline) have had expert financial economists estimate the cost of equity using Black's Capital Asset Pricing Model and the Fama-French three factor model. They have also examined the cost of equity using a zero-beta version of the Fama-French model (the derivation of which, like the derivation of Black's Capital Asset Pricing Model, does not require the assumption of unrestricted borrowing and lending at the risk free rate). Jemena Gas Networks has also proposed use of the Fama-French model. The table below sets out results obtained using these other models, and the cost of equity estimated using the CAPM.

101. A clear pattern emerges, as might be expected from my earlier discussion of the limitations of the CAPM. The cost of equity estimated from Black's Capital Asset Pricing Model and the Fama-French three factor models is some 200 basis points or more above the cost of equity estimated using the CAPM. Removing the assumption of unlimited borrowing and lending at the risk free rate (Black's Capital Asset Pricing Model and the zero-beta version of the Fama-French three factor model), and adopting a broader characterization of risk, leads to models which yield higher estimates of the cost of equity.

102. These higher estimates of the cost of equity from Black's Capital Asset Pricing Model and the Fama-French three factor model are consistent with the estimate of that cost which Strategic Finance Group (SFG) made for Western Power's proposed revisions to the Access Arrangement using dividend yield data. SFG found the cost of equity was between 11.5% and 12.5%. At the time of SFG's report for Western Power (July 2011), the nominal risk free rate was around 5.5% (based on yields on Commonwealth Government bonds with terms to maturity of 10 years), indicating a premium above the risk free rate of 6.0% to 7.0%. Again, the estimate of the cost of equity was some 200 basis points or more above the cost of equity estimated using the CAPM at the time it was made.

103. If the SFG estimates were further adjusted to include a component of equity return from franking credits (which they do not appear to include), the premiums above the risk free rate which they imply are around 7% to 8% (assuming a tax rate of 30% and a value of gamma of 0.25). They are closer to the premiums obtained from the zero-beta versions of the Fama-French three factor model which do not require the assumption of unlimited borrowing and lending at the risk free rate, and which adopt a broader characterization of risk.

104. At the present time, there is no single specific relationship which may be used to reliably estimate expected rates of return on financial assets: there is, at present, no single model which explains the economic processes which generate asset prices.

105. In these circumstances, the CAPM remains widely used. However, it must be used with care.

106. Use of any model, including the CAPM, involves simplification and approximation. It also involves error in parameter estimation. Simplification, approximation and estimation error allow the possibility that the result obtained is not the "true" result. In the case of use of the CAPM in the context of the Access Code, the estimate of the cost of equity obtained may not be the result which would lead to a WACC which:

- represents an effective means of promoting the economically efficient investment in, and the economically efficient operation and use of, networks; and
- gives the service provider an opportunity to earn revenue for the access arrangement period of an amount that meets the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved.

107. The financial market practitioners who use the CAPM recognise its limitations and the difficulties of parameter estimation. They use their commercial judgements to ensure that the outcomes of model use accord with market reality.

108. In my opinion, if the CAPM is applied to determine the cost of equity to be used in determining a WACC for use in calculating the return component of capital-related

costs (as is required by the Access Code), Western Power must exercise judgement in establishing the individual inputs to the model to ensure that the resulting WACC:

- represents an effective means of promoting the economically efficient investment in, and the economically efficient operation and use of, the Western Power Network; and

- gives Western Power an opportunity to earn revenue for the access arrangement period of an amount that meets its forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved.

109. The asset pricing models derived by relaxing the assumptions made for CAPM derivation (in particular, Black's Capital Asset Pricing Model), and derived from intertemporal choice theory (in particular, the Fama-French model), are alternatives to the CAPM but also have limitations. Nevertheless, the results obtained from use of these models can, in my view, guide Western Power's exercise of judgement in establishing the individual inputs to the CAPM. In these circumstances, market based evidence on rates of return (such as the evidence prepared for Western Power by Strategic Finance Group) can also guide the exercise of judgement.

Appendix A Curricula vitae

Craig Mickle
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Background

Craig has over 15 years experience in providing strategic advice and economic analysis across a range of infrastructure industries that are subject, or potentially subject, to economic regulation of the services they offer and the charges they impose.

He has particular experience working with infrastructure businesses across the energy, water and industrial transport sectors on:

- Infrastructure asset transactions; and
- Regulatory issues, such as the risk of regulation and its potential impacts on value, the cost of capital, the treatment of risk, 'related party' transactions, cost benchmarking, pricing, the form of price control, incentive mechanisms and the economic aspects of legal challenges to regulation. He has also addressed competition policy (e.g. merger) issues.

Prior to professional advisory services, Craig was previously Chief Economist at TXU Australia (now SP AusNet and TRUenergy).

Selected experience

Experience	Value to client
Infrastructure asset transactions	Provided regulatory due diligence (VDD and buy side) and advised on how to optimise the value of those potential acquisitions for numerous (well over a dozen) infrastructure asset transactions. This includes: ► The Expression of Interest for the Abbott Point Coal Terminal T4-T7 (2011) ► The sale of the Abbot Point Coal Terminal X50 (2011) ► APA Group – proposed sale of assets to the Energy Investment Trust (2010) ► Spark Infrastructure – strategic review (2010) ► Sydney Water – issues pertaining to the potential sale of the desalination plant (2010) ► Queensland Government – Provided regulatory advice on the sale of Queensland Rail (2010) ► North Queensland Gas Pipeline (2008) ► Spark Infrastructure – UK water asset due diligence (2009) ► Origin Energy Networks (2007) ► Allgas (2006) ► Murraylink (2006) ► Duke Energy's Australasian energy assets (2003) ► Advised the DUET Group on several acquisitions opportunities (2003-2005) ► Advised SP AusNet on its IPO (2006)

	► Advised AMP Henderson/Alinta on the acquisition/ownership reorganisation of United Energy, MultiNet and AlintaGas (2003) ► CitiPower (2001) ► Advised on the sale of several energy retailers.
Regulatory issues	► Advised on regulatory issues to clients including: Alinta, AGL Energy, APA Group, Aurora Energy, the Australian Gas Association, Brookfield, CKI, CitiPower, Country Energy, DUET, ElectraNet, Energex, EnergyAustralia, Envestra, Ergon, ETSA Utilities, Goldfields Gas Pipeline, Hastings Funds Management, HKE, Horizon Power, Integral Energy, Multinet, Origin Energy, PAWA, Powercor, Spark Infrastructure, SP AusNet, TransGrid, United Energy and Western Power.
Financial Investor Group	► Advised the eight major energy asset owners in Australia (APA Group, Brookfield, CKI, DUET, Hastings Funds Management, Hong Kong Electric, Singapore Power, Spark Infrastructure) on the AER's first review of the cost of capital to apply to regulated energy network businesses, particularly in light of the Global Financial Crisis. ► Undertaken several engagements on the cost of capital for this group.
Financial Investor Group	► Advised on the performance of the AER in respect of merits appeals.
Five Victorian electricity network businesses	► Advised on the long term performance of these businesses in respect of network charges in light of the recent debate on increasing electricity prices.
Energy industry reforms in Australia, Oman, Israel and Korea	Australian examples include: ► Better Place: advised the business on the policy and regulatory reform needed to facilitate the penetration of electric vehicles in the NEM. ► Victorian Department of Primary Industries (DPI): Policy advice into Large-Scale Solar Electricity Feed-In tariff design. ► Ministerial Council on Energy: Advised on the retail market impacts associated with rolling-out 'smart' electricity meters for small customers. ► Energy Reform Implementation Group: Advised on the potential impediments in the capital markets to greater investment in the market.

Professional qualifications

- Bachelor of Business, Curtin University, Western Australia
- Diploma in Applied Finance and Investment, FINSIA
- MBA (Hons) Middlesex University Business School, London UK

John Williams
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Background

Dr John Williams is an economist with over 15 years experience in industry restructuring, economic regulation and pricing, particularly in electricity and gas, but also in ports, railways and water.

Areas of expertise

- Strategic advice to government agencies and regulated private businesses
- Design of economic regulation for imperfectly competitive markets
- Analysis of competition policy issues
- Development of third party access arrangements for businesses subject to access regulation
- Pricing, and financial modelling for price determination
- Investment evaluation and cost benefit analysis
- Cost of capital determination
- Cost analysis and benchmarking

Selected experience

Client	Value to client
Dampier Bunbury Pipeline	Assisted Dampier Bunbury Pipeline and legal counsel prepare grounds for merits review, by the Australian Competition Tribunal, of those parts of the Western Australian Economic Regulation Authority's decision on proposed revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline on rate of return.
Dampier Bunbury Pipeline	Advised Dampier Bunbury Pipeline on second revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline, including the design and determination of revised reference tariffs, required under the *National Gas Access (WA) Act 2009*, which implements the *National Gas Law* and the *National Gas Rules* in Western Australia.
WA Gas Networks (now ATCO Gas Australia)	Assisted ATCO Gas Australia and legal counsel prepare grounds for merits review, by the Australian Competition Tribunal, of those parts of the Western Australian Economic Regulation Authority's decision on proposed revisions to the Access Arrangement for the Mid West and South West Gas Distribution Systems on rate of return.
WA Gas Networks (now ATCO Gas Australia)	Advised WA Gas Networks (now ATCO Gas Australia) on second revisions to the Access Arrangement for the Mid West and South West Gas Distribution Systems, including the design and determination of revised reference tariffs, required under the *National Gas Access (WA) Act 2009*, which implements the *National Gas Law* and the *National Gas Rules* in Western Australia.

Dampier Bunbury Pipeline **WA Gas Networks** **Goldfields Gas Transmission** **Tokyo Electric Power** **Epic Energy (South Australia)**	Determination of cost of capital for access pricing.

Qualifications and professional affiliations

- Doctor of Philosophy, Murdoch University
- Master of Business Administration, University of Western Australia
- Bachelor of Economics, University of Western Australia
- Bachelor of Science, University of Western Australia
- Member – American Economic Association
- Member – International Association of Energy Economists
- Member – Expert Panel for Western Australian Electricity Review Board

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Estimating equity beta for Australian regulated energy network businesses

A report for Western Power

Tom Hird (Ph.D)

May 2012

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1. Executive summary

1. The ERA has estimated betas for a sample of Australian regulated infrastructure owners. While I estimate similar weekly betas, my estimate of monthly betas is materially higher. I also estimate higher still daily betas (which the ERA did not report). My results and those for the ERA are provided in the table below. I have also calculated the 95% confidence intervals for both individually sampled observations and the population mean.

Table 1: CEG estimates of confidence intervals (re-levered equity betas)

	Mean	Sample standard deviation	95% confidence interval for individual firm	95% confidence interval for population mean
ERA weekly	0.60	0.36	(-0.00, 1.20)	(0.32, 0.88)
CEG weekly	0.61	0.39	(-0.03, 1.24)	(0.31, 0.91)
ERA monthly	0.45	0.24	(-0.05, 0.85)	(0.27, 0.63)
CEG monthly	0.59	0.38	(-0.03, 1.22)	(0.30, 0.88)
CEG daily	0.66	0.32	(0.14, 1.18)	(0.42, 0.90)

Source: Bloomberg, CEG analysis

2. It appears to me that the ERA monthly figures involve an error, especially in the relation to the HDF beta estimate. This would explain why the ERA monthly beta estimate is lower than all of the other beta estimates reported above (including the ERA's weekly beta estimate).

3. Based purely on the Australian weekly betas a point estimate may be in the vicinity of the ERA's chosen 0.65. However, taking all of the relevant data into account, the reasonable range for equity beta extends well up beyond the value of 0.8 determined by regulatory precedent and would encompass an estimate of 1.0. While the data in the ERA's beta sample provides some evidence in support of a reduction in beta from 0.8 to 0.65, in my view this evidence, even taken in isolation, is not persuasive.

4. Moreover, there is evidence not considered by the ERA which, in my view, should not only make the ERA cautious in lowering the equity beta but which actually suggests raising the equity beta above 0.8 may be appropriate.

5. Most importantly, there is a great deal of information available on the equity betas for regulated US utilities. The ERA sample has only 9 businesses and 3 of these ceased trading several years ago. Moreover, of the remaining 6 businesses only 2 were listed on the stock market over the entirety of the ERA's estimation period. By contrast, I have estimated beta for at 74 regulated energy infrastructure owners in the US. Eight of the regulated utilities in the sample of 74 regulated utilities do not have data for the entire ERA estimation period; however betas have been estimated for these regulated

utilities over the period for which data is available. This is consistent with ERA's methodology in its draft determination.

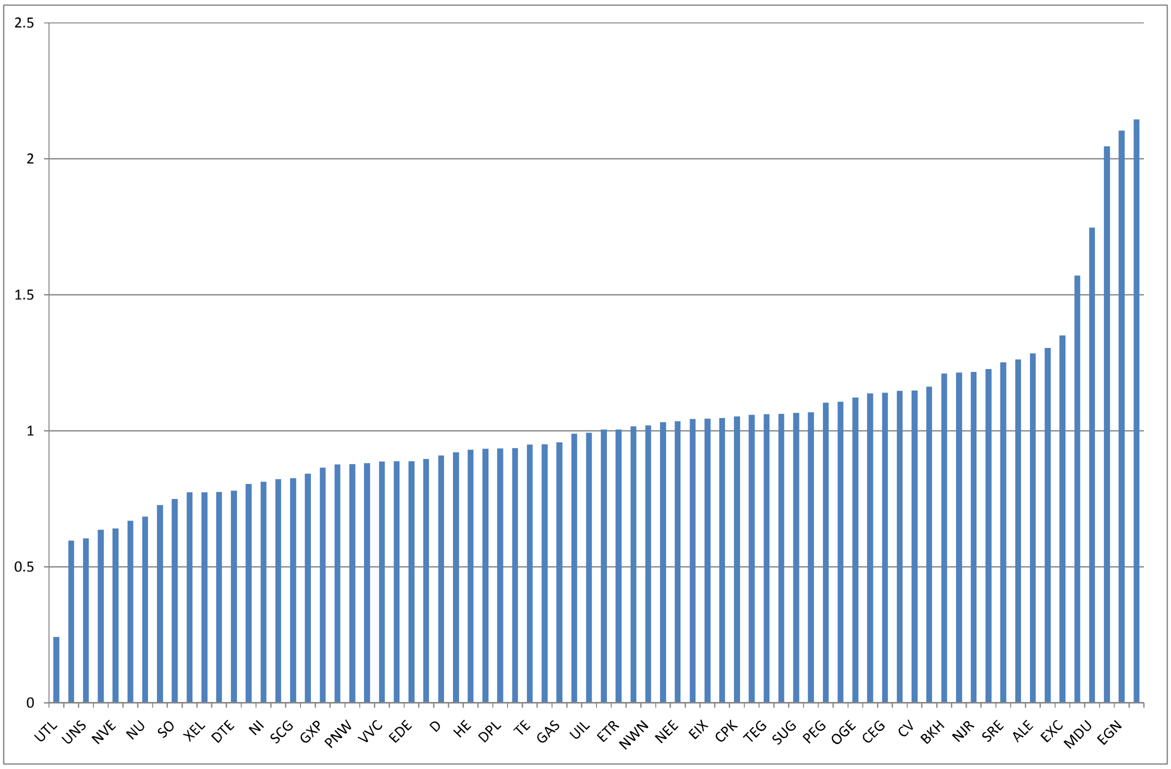
6. There is strong regulatory precedent for having regard to US betas for regulated energy utilities when estimating the cost of equity for Australian and New Zealand regulated utilities. This precedent includes:

   - The New Zealand Commerce Commission who sets the equity beta for New Zealand energy businesses based almost exclusively on a sample of 69 US equity beta estimates for regulated energy businesses;
   - The AER (and Olan Henry) who used a sample of 11 US regulated energy businesses as a cross-check on Australian betas[1];
   - The Essential Services Commission of Victoria (ESCV) who used a sample of 12 US regulated energy businesses as a cross-check on Australian betas.

7. The evidence from my sample strongly supports an equity beta estimate of around 1.0. The figure below shows the daily betas (de-levered and re-levered to 60% gearing) for 74 regulated utilities identified by using the Regulatory Research Associates (RRA) database that tracks regulatory decisions for US energy businesses. The mean/median equity beta for this sample is 1.03/1.00 (the maximum is 2.14 and the minimum is 0.24).

[1] The 11 regulated utilities in the AER/Olan Henry sample are CHG, CNP, EAS, NI, NJR, NST, NU, SRP (now NVE), UIL, POM and POR. Note that data is only available for the entire ERA estimation period for 8 of the 11 regulated utilities CHG, CNP, NI, NJR, NST, NU, NVE and UIL. EAS stopped trading on 16 September 2008. POM started trading on 31 July 2002 and POR started trading on 31 March 2006.

Figure 1: Daily equity betas over 9.75 years ending 31 October 2011 for 74 US regulated utilities identified by RRA



Source: Bloomberg, RRA, CEG analysis

8. All but one of these betas is above 0.5 and most are clustered around the mean/median.

9. However, it is useful to sanity check the results from using this RRA sample with the results of using samples selected by other regulators. The table below provides the results from applying other regulators' sample over the ERA's estimation period.

Table 2: Different samples of US daily equity betas 9.75 years ending 31 October 2011

Sample source	Sample size	Mean	95% confidence interval for the daily mean
RRA	74	1.03	(0.95, 1.10)
NZCC	69	1.00	(0.94, 1.06)
ESCV	12	0.97	(0.83, 1.11)
AER/Henry	11	0.84	(0.69, 0.99)

Source: Bloomberg, CEG analysis.

10. The RRA and the NZCC samples are the largest and have the most reliable mean estimates (statistically speaking). The ESCV sample is smaller but has a similar mean to the NZCC and RRA samples. The AER/Henry sample is the smallest and has the lowest mean estimate.

11. All confidence intervals for the population mean equity beta capture 1.0. For the two most reliable samples in terms of sample size, the confidence interval for the mean estimate is above 0.8 (as is the confidence interval for the smaller ESCV sample). All 95% confidence intervals are above the 0.65 equity beta estimate proposed by the ERA.

12. In terms of combining the US beta estimates with the Australian beta estimates, I note that the average of my Australian monthly, weekly, daily beta estimates is 0.62. The largest US sample is the RRA sample with a mean is 1.03. If I give 50% weight to the RRA sample mean and 50% weight to the Australian sample mean then I estimate a beta of 0.83.

13. It should be noted that such an approach gives more than 8 times the weight to each Australian observation as it does to each US observation. One would have to give the US observations almost zero weight in order to justify a beta of 0.65.

14. I have also examined whether there is any basis for concluding that US betas overestimate the risk of domestic Australian utilities (discussed in section 5.3). In my view this is not the case and, if anything, the opposite is likely to be true. I note that this is similar to the conclusion that the New Zealand Commerce Commission arrived at and the same conclusion upon which Professor Lally advised the QCA.

15. However, even if US betas are an imperfect proxy, the larger number of these estimates means that the mean can be more accurately estimated. In my view, it is imprudent to give little weight to these estimates. This is similar to the logic expounded by the Australian Competition Tribunal in ActewAGL where it was found that the AER was in error to give little or no weight to particular classes of bonds just because they were not perfect proxies for BBB+ rated bonds.

> *In the Tribunal's view, if it were reasonable not to include A- and BBB bonds in the population (because they are not representative of BBB+ bonds), it was unreasonable for the AER not to consider whether useful information could be obtained from taking these bonds into account without including them in the population.*[2]

[2] ACT, ActewAGL, para 63., available at http://www.austlii.edu.au/au/cases/cth/ACompT/2010/4.html

16. In addition to the evidence that robustly estimated samples of US betas are higher than 0.8, I consider that there are important additional reasons not to rely on the ERA sample results to lower the regulatory beta below 0.8.

17. One important reason why Australian utility betas may be low (other than pure statistical fluke as a result of a small sample) is that the Australian market index has, over the ERA estimation period, been influenced by extreme movements in mining stocks due to extreme movements in commodity prices. I quantify this in section 6.2 and describe why it would be inappropriate to allow these factors to feed into a lower equity beta.

18. I also note in section 6.5 that the empirical finance literature finds strong support for adjusting estimates of beta towards 1.0. This literature supports the ERA choosing a value from the top of its range of equity beta estimates.

19. Finally, a further important reason for caution is that, in my view, the ERA's draft decision tends to set all CAPM parameters at the bottom end of any reasonable range. The cumulative impact of this is that the overall cost of equity that results leaves no margin for error. Given the uncertainty that underpins the estimation of equity beta it is my opinion that the ERA should be cautious in simultaneously lowering beta while setting other parameters at low levels (see discussion in sections 6.1, 6.3, and 6.4).

20. I am instructed that Western Power is proposing a value for the equity beta of 0.80. In my view, based on the analysis and evidence examined in this report, an equity beta of 0.80 is consistent with the requirements of the Access Code.

2. Introduction

21. Western Power has commissioned me to review the extent to which the Economic Regulation Authority's (ERA's) decision to lower its beta estimate from 0.80 to 0.65 in its revised access arrangement proposal satisfies the requirements of the Access Code. Western Power has also asked me to review the ERA's draft decision of its access arrangement proposal. The terms of reference for my review are set out at Appendix B to this document.

22. The remainder of this report is set out as follows:

- section 3 attempts to reproduce the ERA's reported beta estimates;
- section 4 describes the degree of statistical confidence that can be had in the Australian beta estimates. The key finding of this section is that the small sample of Australian comparable along with material variability inherent in this sample gives rise to significant uncertainty in the sample mean;
- section 5 examines evidence from US regulated energy business betas and describes how this can be used to inform an estimate of beta in Australia. Having regard to US beta estimates suggests that, if anything, the ERA's beta estimate should be raised above 0.8 rather than reduced;
- section 6 describes a range of other factors that, even absent the evidence from US betas, provide strong reasons for not lowering the ERA's beta estimate below 0.8; and
- section 7 concludes.

23. I have read, understood and complied with the Federal Court Guidelines on Expert Witnesses. I have made all inquiries that I believe are desirable and appropriate to answer the questions put to me. No matters of significance that I regard as relevant have to my knowledge been withheld.

24. I have been assisted in the preparation of this report by Daniel Young and Johanna Hansson from CEG's Sydney office. However, the opinions set out in this report are my own.

Thomas Nicholas Hird

18 May 2012

3. Reconciliation of ERA estimates

25. The ERA has produced estimates of equity beta sampled monthly and weekly which are intended to be "like for like" comparisons with those produced by Professor Olan Henry for the AER,[3] using the same dataset.

26. The ERA's analysis finds that, when relying on an extended dataset from January 2002 to October 2011, the monthly estimates range from 0.0675 to 0.9688 (mean of 0.4569 and median of 0.4253), and then weekly estimates range from 0.2168 to 1.3378 (mean of 0.5204 and median of 0.4261).

27. Based on this, the ERA maintains that the point estimate of the equity beta of 0.65 (the average of the upper and lower bounds of the adopted range), is reasonable.

28. The Authority's monthly estimates of equity betas are presented in Table 85 of its draft decision, and the weekly estimates in Table 87.[4] It notes that the monthly and weekly estimates are based on the time period January 2002 to October 2011.

29. I note that only two companies have data for the entirety of this period (Envestra and APA), and that for the remaining seven companies the betas estimates relate to a (sometimes much) shorter time period. In three cases (AGL, GasNet and Alinta), the last available price is from several years prior to the 31 October 2011.[5]

3.1. Replicating the Authority's beta estimates

30. I have been able to estimate weekly betas that are consistent with, but not exactly the same as, those reported by the ERA. However, my estimates of monthly betas appear to be materially different to the ERA's estimates.

31. In attempting to replicate the ERA's estimates I have assumed that the estimates have the number of periods (N) specified in Table 85 and 87 respectively. Further to this, I have taken into account dividends as at the ex-dividend date. I have focused on OLS "$\hat{\beta}$" for the purposes of this comparison.

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3 Henry, O., *Estimating beta*, 23 April 2009.

4 ERA, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, March 2012, pp. 202-204

5 The last price for Jemena (AGL) is available on 11 October 2006, the last price for GasNet (GAS) is available on 14 November 2006 and the last price for WestNet (AAN) is available on 17 August 2007. We have estimated the beta for these three companies on the last day price was available.

32. I have calculated gearing using data from the end of each month using net debt and market value of equity, noting that most companies only report net debt semi-annually.[6]

33. A comparison of the monthly estimates for $\hat{\beta}$ by the Authority and CEG is provided at Table 3 and Table 4 below. Table 6 and Table 7 compare the Authority and CEG estimates for $\hat{\beta}$ sampled weekly. Table 5 and Table 8 summarise the minimum, maximum, mean and median for each sample. Like the Authority, I have sourced the data underlying the estimates from Bloomberg.

34. I have estimated all possible definitions of weekly and monthly betas. In particular, I have estimated 5 different weekly betas (one for each different day of the (trading) week). I have also estimated 31 different monthly betas one for every possible day of the month on which it is possible to measure returns.[7] I have averaged the weekly/monthly betas across all the different definitions of weekly/monthly betas.

35. An inspection of Table 3 and Table 4 shows that overall the estimates are relatively closely aligned for weekly betas, and that most differences could be attributed to the Authority having made slightly different assumptions in regards to the date on which the betas were estimated or how dividends were accounted for.

36. The two firms for which there are material differences are Alinta and HDF. The Alinta difference is primarily attributable to different estimates of gearing with the CEG estimate of gearing for Alinta (31.6%) higher than that estimated by the Authority (39.1%) resulting in a higher beta estimate.

37. The HDF estimate is explained by differences in raw beta estimates. The CEG average monthly beta estimate for HDF is 1.36, which is significantly higher than the ERA's estimate of 0.0675 (despite estimates for gearing being relatively similar). Moreover, the CEG estimate of the minimum beta (i.e. the lowest monthly beta estimated) is 0.39 – which is still materially above the ERA's reported beta. I note that the ERA's monthly beta estimate for HDF makes up the lower bounds of its monthly beta estimates (see paragraph 26).

6 I have relied on the Bloomberg fields NET_DEBT and CUR_MKT_CAP to estimate gearing.

7 For example, one beta measuring returns from the 1st of one month to the 1st of the next month, another measuring beta from the 2nd of one month to the 2nd of the next etc. Where a particular date does not exist for one month (eg, no 31st of June) the last day of that month is used in the calculation.

Table 3: Authority estimates of $\hat{\beta}$, sampled monthly

	AGL	ENV	APA	GAS	DUE	HDF	SPN	SKI	AAN
$\bar{G}$	0.2753	0.7181	0.5864	0.6367	0.7620	0.3964	0.6080	0.5019	0.3911
w	1.8117	0.7049	1.0340	0.9083	0.5950	1.5089	0.9800	1.2452	1.5224
$\hat{\beta}$	**0.6993**	**0.4585**	**0.6665**	**0.2588**	**0.3836**	**0.0675**	**0.2591**	**0.4154**	**0.8090**
N	57	116	116	58	85	81	69	69	67

Source: Economic Regulation Authority draft decision

Table 4: CEG estimates of $\hat{\beta}$, sampled monthly

	AGL	ENV	APA	GAS	DUE	HDF	SPN	SKI	AAN
$\bar{G}$	0.2820	0.7198	0.5556	0.6340	0.7567	0.3870	0.6111	0.4881	0.3159
w	1.7949	0.7004	1.1110	0.9149	0.6083	1.5325	0.9722	1.2797	1.7103
$\hat{\beta}$	**0.5847**	**0.4686**	**0.6421**	**0.1950**	**0.3723**	**1.3639**	**0.1856**	**0.5224**	**0.9988**
N	57	116	116	58	85	81	69	69	67

Source: Bloomberg, CEG analysis

38. Table 5 shows the minimum, maximum, mean and median of the monthly $\hat{\beta}$ estimates from the Authority and CEG respectively.[8]

Table 5: Comparison of results for $\hat{\beta}$, sample monthly

	Minimum	Maximum	Mean	Median
Authority	0.0675	0.8090	0.4464	0.4154
CEG	0.1856	1.3639	0.5926	0.5224

39. Table 6 and Table 7 present weekly equity betas estimated by the ERA and CEG respectively. An inspection of these tables shows that the overall the estimates are relatively closely aligned. Some differences in respect of gearing remain, and the remaining discrepancies can quite reasonably be accounted for by way of differing assumptions. Notably, the Authority's estimate for HDF is closely aligned with the CEG estimate, unlike for the monthly estimates. The similarities are reflected in Table 8, which summarises the minimum, maximum, mean and median for both sets of estimates.

[8] Note that the range provided by the Authority also includes estimates for $\tilde{\beta}$

Table 6: Authority estimates of $\widehat{\beta}$, sampled weekly

	AGL	ENV	APA	GAS	DUE	HDF	SPN	SKI	AAN
$\bar{G}$	0.277	0.718	0.587	0.637	0.761	0.396	0.607	0.501	0.398
w	1.806	0.703	1.031	0.905	0.595	1.508	0.980	1.246	1.504
$\widehat{\beta}$	**0.753**	**0.359**	**0.611**	**0.329**	**0.317**	**1.337**	**0.219**	**0.492**	**0.960**
N	249	509	509	254	373	356	303	303	293

Source: ERA draft decision

Table 7: CEG estimates of $\widehat{\beta}$, sampled weekly

	AGL	ENV	APA	GAS	DUE	HDF	SPN	SKI	AAN
$\bar{G}$	0.282	0.720	0.556	0.634	0.757	0.387	0.611	0.488	0.316
w	1.795	0.700	1.111	0.915	0.608	1.532	0.972	1.280	1.710
$\widehat{\beta}$	**0.5541**	**0.4172**	**0.5774**	**0.2851**	**0.3240**	**1.4188**	**0.2598**	**0.5876**	**1.0487**

Source: Bloomberg, CEG analysis

Table 8: Comparison of results for $\widehat{\beta}$, sample weekly

	Minimum	Maximum	Mean	Median
Authority	0.219	1.337	0.597	0.492
CEG	0.2598	1.4188	0.6081	0.5541

3.2. Conclusion

40. I estimate the mean $\widehat{\beta}$ sampled monthly as 0.59, and the mean $\widehat{\beta}$ sampled weekly as 0.61. These estimates are slightly higher than the estimates determined by the ERA for weekly betas but materially higher for monthly betas (largely a result of the very low monthly estimate for HDF provided by the ERA). These mean beta estimates are slightly below the ERA's proposed 0.65 value for beta and are materially below the value of 0.80 which reflects past regulatory precedent.

4. Statistical confidence in Australian betas

41. I now turn to the question of what degree of certainty one can place on the average betas for the firms in the ERA's sample. In doing so, I focus on the daily betas but also report and analyse weekly and monthly betas as have been reported by the ERA.

42. While the mean in the ERA sample is below 0.65 for weekly and monthly betas there is substantial statistical uncertainty associated with the sample. In particular:

- each beta estimate for each company is estimated with imprecision (especially the monthly betas); and
- there is wide dispersion between beta estimates within the sample.

43. In addition, I have estimated daily betas for the ERA's sample and I find that the mean of daily betas is 0.66 (slightly above 0.65).

44. The ERA acknowledges a high level of uncertainty at paragraph 883 of the draft decision when determining a range of 0.5 to 0.8 for the equity beta. However, I consider that this range does not capture the full level of uncertainty associated with the Australian beta estimates.

4.1. One period estimate

45. The beta estimates that make up the ERA sample are the estimates of the beta for a specific period in the past. The beta that the ERA is ultimately attempting to estimate is not the beta that existed in the past but the beta that investors expect to exist in the future.

46. Given that the ERA estimation period includes an extraordinary minerals boom and a global financial crisis unprecedented since the 1930s there is good reason to question whether this estimation period is reflective of the market conditions that investors believe the future is most likely to hold. If not, then the best estimate of the beta in the estimation period will not be the best estimate of the forward looking beta for the sample.

4.2. Statistical imprecision of point estimates

47. All beta estimates are estimated with imprecision. The level of imprecision is a function of the number of observations used and the underlying 'noise' in the data. This creates uncertainty that attaches to the individual beta estimates and is captured in the estimates of bounds for each beta reported by the ERA.

48. In fact, three out of nine of the ERA's monthly observations have an upper bound that is in excess of 1.0 and four out of nine have a lower bound that is less than zero. The degree of precision is higher for weekly betas but is still non-trivial. Three out of nine estimates are still above 1.0 but none of the lower bound estimates are below zero (the lowest is 0.13).

49. The higher uncertainty around monthly beta estimates are consistent with Olan Henry's advice to the AER that statistical inference on monthly is less reliable than for weekly betas. This is because, for any given estimation period, monthly betas have fewer observations than weekly betas (there are less than one quarter as many monthly observations as there are weekly observations) that can be used in any regression. Consequently, less confidence can be had in the results of that regression.[9]

> *The bulk of the work in this report uses data sampled at a weekly frequency. Given the sparse nature of the data there are too few monthly observations available for many of the stocks to produce statistically reliable estimates of β. For some of the stocks and portfolios considered in this report there are less than 30 monthly observations meaning that statistical inference using monthly data is unlikely to be reliable.*

50. While the ERA estimation period uses more data than Henry, which reduces this problem with monthly betas, it does not eliminate it.

51. By way of example, the ERA's mean weekly/monthly beta estimates for AAN are 1.0/0.8. However, the monthly beta estimate has a confidence interval that extends from below 0.0 to 1.6. By contrast, the ERA's weekly beta estimate has a confidence interval of between 0.6 to 1.3. Notably, despite the weekly beta point estimate being close to 0.2 higher than the monthly beta point estimate, the weekly beta estimate has an upper bound estimate that is materially lower than the monthly beta estimate.

52. Moreover, there is an additional problem with monthly betas in that they depend heavily on what day of the month is used to measure the returns. In the previous section I reported monthly betas based on the average of all 31 possible monthly betas. If instead I had simply and randomly chosen one day of the month to measure monthly returns to then very different betas can result. By way of example, the table below compares monthly betas measured to the 7th day of the month with monthly betas measured to the 31st (last day) of the month.

9 Henry, O., *Econometric advice and beta estimation*, November 2008, p. 13

Table 9: CEG estimates of $\widehat{\beta}$, sampled monthly – using returns to different days of the month

Return period	AGL	ENV	APA	GAS	DUE	HDF	SPN	SKI	AAN	Average
7th	0.50	0.58	0.73	0.22	0.55	1.93	0.27	0.69	1.20	0.74
27^{th} day	0.83	0.36	0.64	0.19	0.24	0.47	0.10	0.25	0.75	0.42
Difference	-0.33	0.22	0.09	0.04	0.31	1.46	0.17	0.44	0.46	0.32

Source: Bloomberg, CEG analysis

53. For this reason I consider that, unless one is prepared to exhaustively check monthly beta estimates for these sorts of bias by estimating all possible monthly betas, shorter sampling periods, such as weekly or daily betas, are to be preferred because there is less scope for arbitrary decisions to materially affect the estimated beta.

4.3. Daily

54. In contrast to weekly and monthly betas, there is only one meaningful definition of a daily beta. The ERA does not report daily betas for its sample but I do so here. I find that daily betas are higher than both the average of weekly and the average of monthly betas.

Table 10: CEG estimates of $\widehat{\beta}$, sampled daily

	AGL	ENV	APA	GAS	DUE	HDF	SPN	SKI	AAN
$\bar{G}$	0.282	0.720	0.556	0.634	0.757	0.387	0.611	0.488	0.316
w	1.795	0.700	1.111	0.915	0.608	1.532	0.972	1.280	1.710
$\widehat{\beta}$	0.76	0.44	0.76	0.27	0.35	1.22	0.40	0.77	0.96
s.e.*	0.075	0.024	0.033	0.049	0.022	0.075	0.033	0.040	0.089
$\hat{\beta}_u$*	0.908	0.492	0.831	0.367	0.397	1.365	0.464	0.856	1.141
$\hat{\beta}_l$*	0.608	0.398	0.699	0.170	0.307	1.066	0.333	0.694	0.785
N	1208	2489	2489	1234	1814	1737	1486	1484	1411
Raw beta	0.42	0.64	0.69	0.29	0.58	0.79	0.41	0.61	0.56
s.e.	0.04	0.03	0.03	0.05	0.04	0.05	0.03	0.03	0.05

*Source: Bloomberg, CEG analysis. * I report regression statistics for daily betas because there is only one regression performed. The weekly/monthly betas I report are the average across 5/31 regressions and, therefore, it is not meaningful to talk of the standard error for a single regression.*

55. The average beta (levered to 60% gearing) is 0.66.

56. It should be noted that daily betas have the potential to underestimate the beta for thinly traded stock. If the stock in question is "thinly traded", then daily betas will tend

to underestimate the true beta.[10] Of course, this is a reason for believing that daily betas might, for some firms, be underestimates of beta – it is not a reason for disregarding daily betas especially if these are higher than weekly/monthly betas which is the case on average.

4.4. Differences in point estimates across firms

57. The statistical imprecision in the estimation of each beta is only one, and not necessarily the most important, source of uncertainty in the beta estimates. This measure of uncertainty does not capture the uncertainty that is associated with variation between the point estimates within the sample.

58. In order to talk about this form of uncertainty it is necessary, for a moment, ignore the statistical uncertainty in the estimation of the beta and instead assume that the regression estimates are perfect (have zero confidence intervals). Even if this were true and each individual beta was known with certainty, the variability between the nine sample point estimates gives rise to statistical uncertainty about the beta for another firm not in the sample (such as Western Power) or for the beta of mean of the sample.

59. In order to quantify this uncertainty a further strong assumption must be made about the distribution of the population of betas from which my sample was drawn. I assume that this population is normally distributed (of course, having made this assumption the true level of uncertainty is obscured by the following analysis as the population may not be normally distributed).

60. Having made this assumption, I then estimate confidence intervals for the equity beta population mean and an individual company's equity beta.[11]

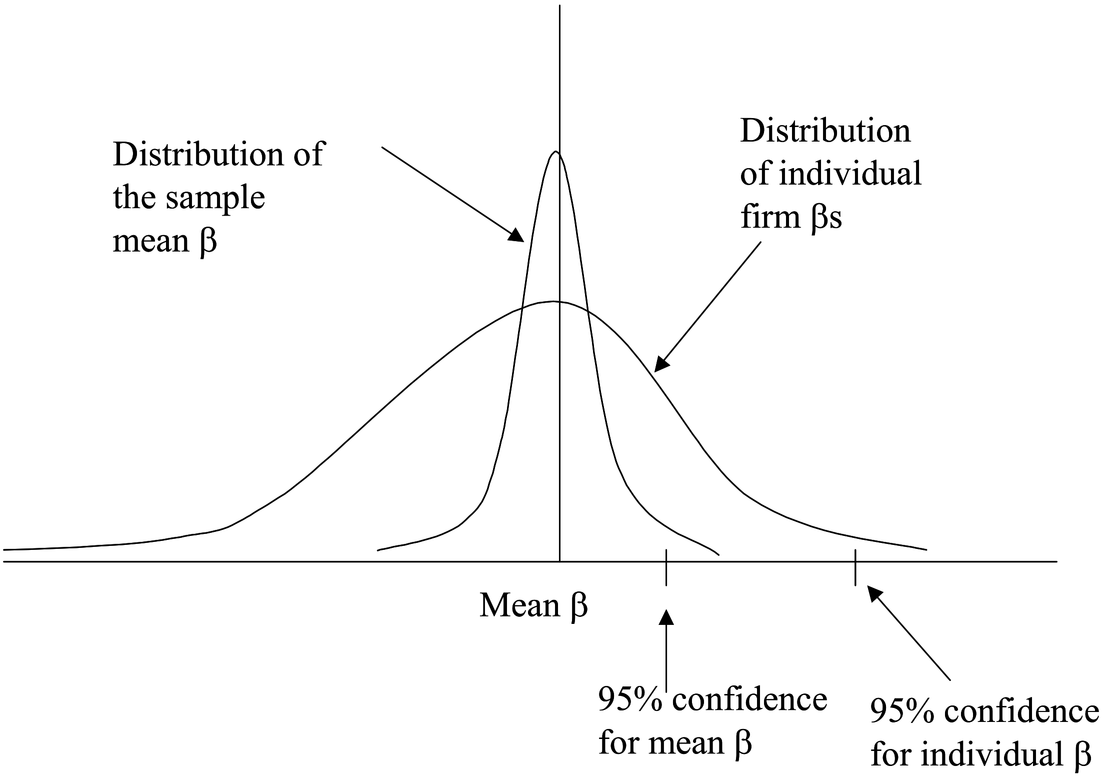
61. The difference between the confidence interval for the population mean an individual company is illustrated graphically below. Assume that a sample of comparable firms' equity beta are estimated and that a sample mean is likewise calculated. The 'wide' distribution in the below graphic is a depiction of the probabilistic distribution of equity betas for comparable firms not in the sample. The most likely value for any such firm's equity beta is the sample mean.

62. The 'thinner' distribution is the expected distribution of the *population mean* (ie, the mean of all of all comparable (in and out of the sample) firms' equity betas) around the

[10] By "thinly traded" I mean that the impact of news which affects the market return on that day does not impact the return on the stock in question until the following day(s) because of a lack of trading in the stock. If thin trading exists then regressions using daily return periods will tend to underestimate the sensitivity of a stock to market returns because it will assume that the impact of the news on the stock was lower than it really was because it does not capture the lagged impact on the stock return.

[11] Following my assumption of normality, I apply the t-distribution and the normal distribution respectively to form these confidence intervals.

sample mean that has been estimated. This distribution is 'thinner' because there is greater certainty that the sample mean is a good approximation for the population mean than there is that the sample mean is a good approximation of any individual firm's equity beta.



63. Algebraically, the difference between the 95% confidence upper bound for the population mean and for the β of an individual firm can be seen by examining the formula for the standard deviation for the sample mean versus the sample standard deviation for the individual firm's β.

Sample standard deviation for individual firm's β	s
Standard deviation of the sample mean β	$\frac{s}{\sqrt{n}}$

*Where s is the cross sectional standard deviation with the sample and n is the sample size.

64. Therefore, the confidence intervals arising from these estimates are:

95% confidence interval for individual firm	Sample mean $\beta \pm z_{\alpha} \times s$
95% confidence interval for population mean	Sample mean $\beta \pm t_{\alpha,n-1} \times \frac{s}{\sqrt{n}}$

65. In my opinion there is a basis for giving weight to each of the above confidence intervals. The confidence interval for the population mean is relevant to an assessment of what the average beta is across all comparable companies. By contrast, the 95% confidence interval for the individual firm is relevant to an assessment of the beta for a specific regulated business not in the sample (such as Western Power).

66. Table 11 below provides my estimates of the 95% confidence interval based on a t-value of 2.31 (based on a 95% confidence interval and sample size of 9) and a z value of 1.96 (95% confidence interval).

Table 11: CEG estimates of confidence intervals for 60% levered equity beta

	Mean	Sample standard deviation	95% confidence interval for individual firm	95% confidence interval for population mean
ERA weekly	0.60	0.36	(-0.12, 1.31)	(0.32, 0.88)
CEG weekly	0.61	0.39	(-0.15, 1.37)	(0.31, 0.91)
ERA monthly	0.45	0.24	(-0.02, 0.92)	(0.26, 0.63)
CEG monthly	0.59	0.38	(-0.15, 1.34)	(0.30, 0.88)
CEG daily	0.66	0.32	(0.04, 1.28)	(0.42, 0.90)

Source: Bloomberg, CEG analysis

67. It can be seen that the 95% confidence interval for the 60% levered beta of any individual firm extends well above 1.0 for all samples except the ERA monthly sample. The confidence interval for the population mean extends well above 0.8 for all samples except the ERA monthly sample. It must be recalled that, consistent with the analysis in section 2, the ERA monthly sample appears to contain an error that leads to underestimation of both the mean of the sample and the standard error of observations within the sample.

68. When interpreting these figures it must be recalled that they do not capture any of the estimation uncertainty detailed in the previous section. This means that, especially for the monthly beta estimates, the confidence intervals described above are artificially narrow. This is because they assume that the point estimates have been estimated without error when this is known not the case. (Ideally both sources of uncertainty would be combined but there is no simple statistical process for doing so without further information on the independence or otherwise of each beta estimate.)

69. I consider that the confidence interval for an individual firm's beta is relevant because the ERA is setting the beta for an individual firm (Western Power). Consequently, the confidence that it is setting this value correctly is given by the confidence interval for an individual firm.

70. Based on the confidence intervals for weekly and monthly betas the ERA cannot, based on the sample of Australian beta estimates, rule out that Western Power's beta is as high as 1.2 (based on the 95% confidence interval around the CEG estimates). Similarly, the ERA cannot rule out with 95% confidence that the mean of all comparable businesses is 0.9.

4.5. Conclusion

71. There is material uncertainty surrounding the beta for Western Power. Based purely on the daily, weekly and monthly Australian beta estimates for the ERA sample the most likely estimate may be in the vicinity of the ERA's chosen 0.65. However, when all the relevant data is taken into account, including the confidence intervals of the sample little confidence can be had that this is the correct estimate. That is, a reasonable range extends well upwards beyond the value of 0.8 determined by regulatory precedent. While the data in this sample provides some evidence in support of a reduction in beta from 0.8 to 0.65, in my view this evidence, even taken in isolation, is not persuasive.

72. The following two sections provide further context and information that is not taken account of when coming to this conclusion. When this further evidence is considered the above conclusion is not only strengthened but it is apparent that if any change to regulatory precedent is justified it is an increase in beta rather than a reduction.

5. Information from US equity betas

73. The high degree of uncertainty associated with attempting to estimate an equity beta from nine domestic Australian observations suggests that considerable effort should be undertaken in attempting to gather additional information from alternative sources. This includes equity beta estimates for regulated businesses in other countries such as the United States (US).

5.1. Regulatory precedent

74. There is regulatory precedent for having regard to betas estimated for regulated US energy businesses.

- the New Zealand Commerce Commission set the equity beta for New Zealand energy businesses based almost exclusively on a sample of 69 US equity beta estimates for regulated energy businesses;
- The AER (and Olan Henry) used a sample of 11 US regulated energy businesses as a cross-check on Australian betas[12]; and
- The Essential Services Commission of Victoria (ESCV) used a sample of 12 US regulated energy businesses as a cross-check on Australian betas.[13]

75. It can be argued that US regulated utility equity beta estimates are an imperfect proxy for Australian equity beta estimates. This may be true, although arguably US regulated utility betas would need to be positively adjusted before being used as a proxy for Australian regulated utility betas. For example:

- the New Zealand Expert Panel (Myers Franks and Lally) report refers approvingly of work by Alexander et al., in a World Bank paper, who estimated that incentive based regulation (such as exists in Australia) raises equity betas relative to more rate of return regulation such as exists in the US[14];
- Professor Lally has advised the NZ Commerce Commission that US asset betas should be raised by 0.1 to make them comparable with NZ asset betas;

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12 The 11 regulated utilities in the AER/Olan Henry sample are CHG, CNP, EAS, NI, NJR, NST, NU, SRP (now NVE), UIL, POM and POR. Note that data is only available for the entire ERA estimation period for 8 of the 11 regulated utilities CHG, CNP, NI, NJR, NST, NU, NVE and UIL. EAS stopped trading on 16 September 2008. POM started trading on 31 July 2002 and POR started trading on 31 March 2006.

13 ESCV, Gas Access Arrangement Review 2008-2012, Draft Decision, 28 August 2007, p. 309.

14 Alexander, I., Mayer, C. and Weeds, H., Regulatory structure and risk: an international comparison, Policy research working paper 1698, The World Bank, December 1996. Franks states “Alexander et al. (1996) provide a classification of jurisdictions by regulatory risk. They find that the US, where rate revisions occur frequently, has low regulatory risk, whereas utilities in the UK, with its five year regime, are exposed to higher risk.”

- the NZ Commerce Commission followed Lally's advice until recently when it determined that no adjustment was necessary; and
- Academic precedent exists along the same lines. For example, He and Kryzanowski[15] argue that US beta estimates should be used to determine the cost of capital for Canadian utilities.

76. I discuss the issue of the need for an adjustment to the US beta estimates further below.

77. Even if one believes that US betas are imperfect proxies for Australian betas, this is not a reason for disregarding this evidence or even for giving it less weight than the Australian data. There is a paucity of Australian beta data and a wealth of US beta data for regulated utilities. Even if US betas are an imperfect proxy, the larger number of these estimates may well justify giving more weight to the mean of US beta estimates than to the mean of a much smaller sample of Australian betas.

78. This is similar to the logic expounded by the Australian Competition Tribunal in ActewAGL, where it was found that the AER was in error to give little or no weight to particular classes of bonds just because they were not perfect proxies for BBB+ rated bonds.

> *In the Tribunal's view, if it were reasonable not to include A- and BBB bonds in the population (because they are not representative of BBB+ bonds), it was unreasonable for the AER not to consider whether useful information could be obtained from taking these bonds into account without including them in the population.*[16]

5.2. US equity betas

79. The figure below shows daily betas (de-levered and re-levered to 60% gearing) for the ERA's estimation period for 74 regulated utilities that had trading data for the entirety of this period. These 74 regulated utilities were identified by using the Regulatory Research Associates (RRA) database that tracks regulatory decisions for US energy businesses. The mean/median equity beta for this sample is 1.03/1.00 (the maximum is 2.14 and the minimum is 0.24).

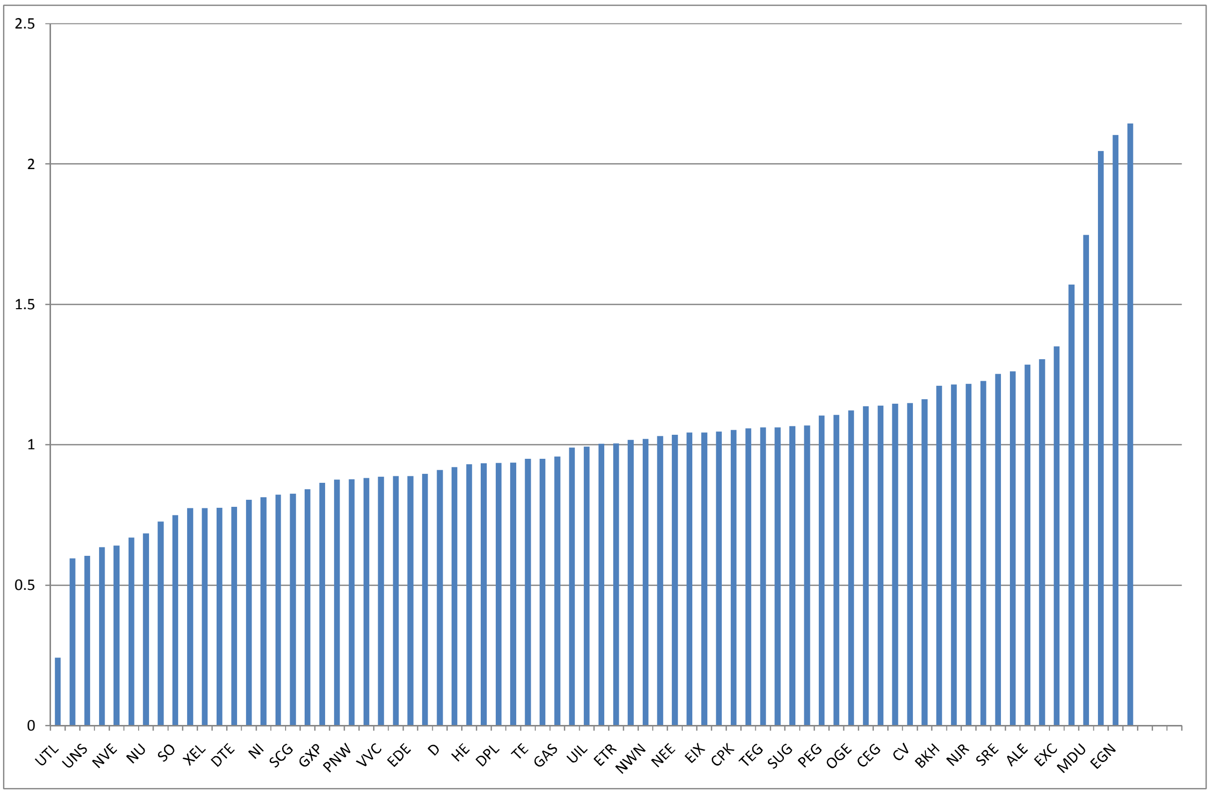
80. I focus on daily betas because these are free of the sort of arbitrary selection bias associated with weekly and monthly betas as discussed earlier. On such large sample of businesses I would have to estimate for each firm 36 different betas for each firm (ie, 36*74) in order to ensure that I had estimated all possible monthly/weekly betas.

[15] Cost of equity for Canadian and U.S. sectors The North American Journal of Economics and Finance Zhongzhi He and Lawrence Kryzanowski (August 2007)

[16] ACT, ActewAGL, para 63., available at http://www.austlii.edu.au/au/cases/cth/ACompT/2010/4.html

However, I did estimate weekly betas for the week ended Friday and found that these were very similar to my estimates of daily beta). Specifically, the mean beta was 1.00, median beta 0.94, maximum beta of 2.16 and minimum of 0.39.

Figure 2: Daily equity betas over 9.75 years ending 31 October 2011 for 74 US regulated utilities identified by RRA



Source: Bloomberg, RRA, CEG analysis

81. All but one of these betas is above 0.5 and most are clustered around the mean/median.

82. It is useful to sanity check the beta estimates resulting from the RRA sample with the results of using samples selected by other regulators. The table below provides the results from applying other regulators' samples over the ERA's estimation period.

Table 12: Different samples of US daily equity betas 9.75 years ending 31 October 2011

Sample source	Sample size	Mean	95% confidence interval for the daily mean
RRA	74	1.03	(0.95, 1.10)
NZCC	69	1.00	(0.94, 1.06)
ESCV	12	0.97	(0.83, 1.11)
AER/Henry	11	0.84	(0.69, 0.99)

Source: Bloomberg, CEG analysis.

83. The RRA and the NZCC samples are the largest and have the most reliable mean estimates (statistically speaking). The ESCV sample is smaller but has a similar mean and median to the NZCC sample. The AER/Henry sample is the smallest and has the lowest mean/median estimate.

84. All confidence intervals for the population mean equity beta capture 1.0. For the two most reliable samples in terms of sample size, the confidence interval for the mean estimate is above 0.8. All 95% confidence intervals are above the 0.65 equity beta estimate proposed by the ERA.

85. In terms of combining the US beta estimates with the Australian beta estimates, I note that the average of my Australian monthly, weekly, daily beta estimates is 0.62. The RRA sample mean is 1.03. If I give 50% weight to the RRA sample mean and 50% weight to the Australian mean then I estimate a beta of 0.83.

86. It should be noted that such an approach gives more than 8 times the weight to each Australian observation as it does to each US observation. One would have to give the US observations almost zero weight in order to justify a beta of 0.65.

5.3. US beta estimates are directly comparable to Australian betas

87. To the extent that there are differences in the operating environment of US and Australian regulated energy utilities any adjustment for comparability is likely to raise US equity betas rather than lower them. In this regard, I note that, in the Expert Panel advising the New Zealand Commerce Commission comment that:[17]

> *Alexander et al. (1996)[18] provide a classification of jurisdictions by regulatory risk. They find that the US, where rate revisions occur frequently, has low regulatory risk, whereas utilities in the UK, with its five year regime, are exposed to higher*

[17] Para 140 page 33 of “Recommendations to the New Zealand Commerce Commission on an Appropriate Cost of Capital Methodology” (18 December, 2008).

[18] Alexander, I., Mayer, C., Weeds, H. (1996), “Regulatory Structure and Risk and Infrastructure Firms: An International Comparison”, Policy Research Working Paper Series 1698, World Bank.

risk. These cross-country differences would drive intrinsic variation in asset beta estimates.

88. The New Zealand Commerce Commission has, in 2011, relied almost solely on betas from US regulated companies to set its beta.[19] In those regulatory proceedings the issue about comparability of US beta estimates was focused around whether these estimates should be increased and, if so, by how much in order to make them comparable to New Zealand – noting that the New Zealand regulatory regime being adopted involves 5 year (or shorter) reviews similar to Australia. The New Zealand Commerce Commission stated:

> *6.9.68 While the Commission considers that regulatory differences can affect the systematic risks faced by the regulated suppliers,* ***and has previously adjusted US estimates upward*** *to account for regulatory differences, it finds that in contrast to previous evidence (e.g. Alexander et al.), the current asset beta estimates in Table 6.14 for US electricity utilities now appear to be higher than the estimates from the UK, Australia and New Zealand.*[20] [Emphasis added.]

89. The New Zealand Commerce Commission ceased to make this upward adjustment in this decision on the basis that it could not find reliable empirical evidence that differences in regulatory regimes affected the beta of the regulated businesses. Certainly, there was no suggestion by the New Zealand Commerce Commission that US betas should be adjusted downwards to make them comparable to New Zealand five year price cap regulation.

90. I also note that Professor Martin Lally has, in January 2011, advised the Queensland Competition Authority that betas for rate of return regulated US energy and water companies are likely to underestimate the betas for comparable firms subject to price cap regulation in Australia. Lally starts by describing revenue cap regulation as having the least systemic risk and proceeds to state:

> *A second form of regulation, faced by Australian gas network businesses and some electricity distribution businesses, is "price capping". This regime matches revenue capping except that prices rather than revenues are fixed (typically for five years). Accordingly, firms subject to this regime would face exposure to demand shocks. Since these are partly systematic in nature, the betas of price capped firms should be larger than those of revenue capped firms. A third form of regulation, faced by most US electric utilities, is "rate of return regulation".*

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[19] Appendix H8, New Zealand Commerce Commission Input Methodologies (Electricity Distribution and Gas Pipeline Services) Reasons Paper December 2010

[20] New Zealand Commerce Commission, Input Methodologies Electricity Distribution Service Draft Reasons Paper June 2010. Page 293.

Under this regime, prices are set consistent with the firm's actual costs (subject to the possibility of some costs being disallowed) and a prescribed rate of return. In addition, prices are reset if the actual rate of return deviates materially from the prescribed rate, with resetting initiated by either the firm or its customers. The US water companies are subject to the same regime.

In comparing systematic risks under these three regimes, the exposure to demand and cost shocks is fundamental. In respect of demand shocks, revenue-capped firms are not exposed to these shocks, rate-of-return regulated firms face these for shocks for less than five years (because the output price would be reset more quickly than this in response to a demand shock), and price capped firms with a five year regulatory cycle would be exposed to these shocks for up to five years. In respect of cost shocks, the exposure of firms to these shocks seems similar under the three regulatory regimes. ***Thus, revenue-capped firms are likely to have the lowest asset betas followed by rate-of-return regulated firms, and then price-capped firms.*** *In all cases, asset betas should be low because exposure to systematic risk is low.*[21]

91. If one accepts that US regulated businesses are less, or at least no more, intrinsically risky than Australian regulated businesses the only possible reason for believing that US betas overestimate Australian betas is if the US market is somehow materially lower risk than the Australian market.

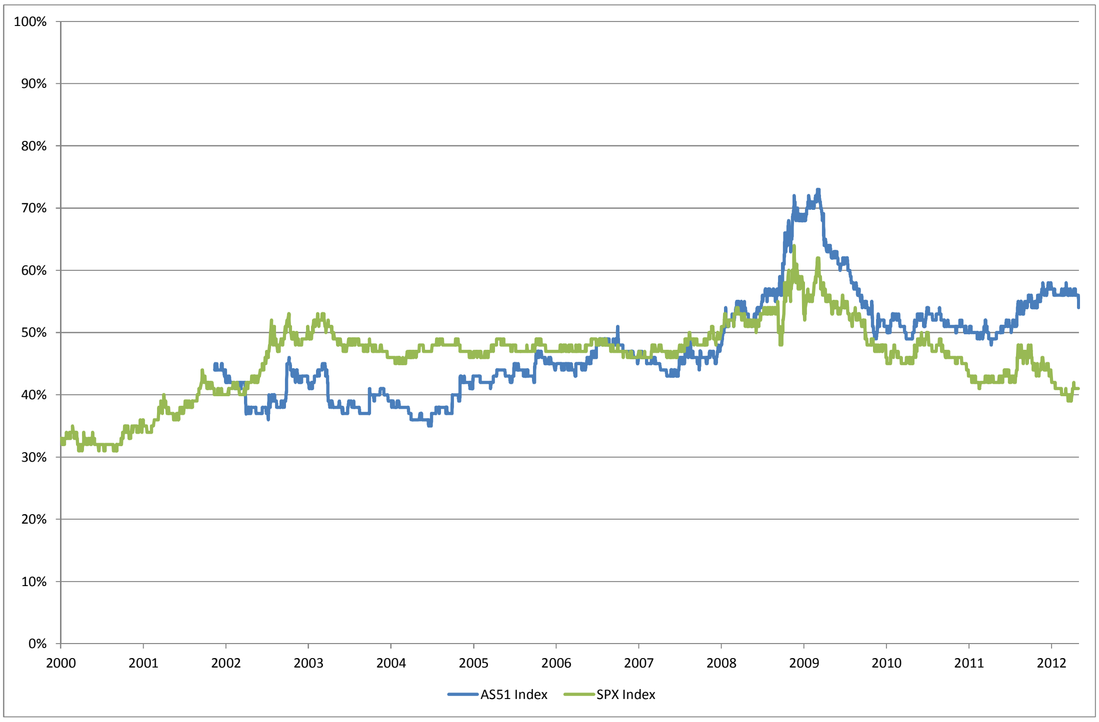
92. Recalling that beta is a measure of a firm's risk relative to the risk of the market index. If the US market is materially lower risk than the Australian market then a high equity beta measured relative to the US market might imply a lower equity beta measured relative to the Australian market.

93. However, there is no evidence to support a conclusion that over the estimation period the US market was lower risk than the Australian market and there is evidence to support the opposite conclusion. I note that the level of market gearing in the US appears to have been very similar in the US and Australia – so this is not a relevant source of difference.[22]

[21] Lally, The estimated WACC For The SEQ Interim Price Monitoring5 January 2011 Pages 22 to 23

[22] However, the elevated levels of market gearing in the late 2000s and early 2010s is a reason for believing that both Australian and US equity markets had higher risk in the than normal. The effect of higher market gearing will be, other things equal, to increase the risk of the market relative to that of a firm (ie, reduce the equity beta) with a constant level of gearing. That is, the higher observed gearing can be expected to be lowering equity beta at a benchmark 60% gearing level. Of course, if the MRP is not being increased to reflect this higher market gearing and higher market risk then it is inappropriate and internally inconsistent to adopt the lower value of beta estimated as a result of this higher market gearing.

Figure 3: Gearing of the ASX and NYSE, Jan 2000 to May 2012



Source: Bloomberg, CEG analysis

94. US stock market volatility is also higher over the ERA beta estimation period than Australian stock market volatility. From 1 January 2002 to 31 October 2011, the standard deviation of weekly returns (measured for the week ending Friday) on the ASX200 are 2.78%, compared to 3.03% for the S&P500. For daily returns the figures are 1.10% for the ASX200 versus 1.38% for the S&P500.

95. Higher market volatility implies a riskier market investment. Beta is a measure of risk *relative* to the market. This means that any US beta measured in the US over the period post 2002 will be a measure of risk *relative* to a riskier and more volatile market. Consequently, that implies a still higher beta relative to a less risky market. Naturally, the relative volatility in the indexes observed was not necessarily expected nor is it necessarily expected to continue in the future. Nonetheless, this is further evidence to the effect that any adjustment to US betas estimated post 2002, in order to make them comparable to betas that regulated Australian firms would experience over the same period, should be upwards not downwards.

96. Of course, it would be ideal if there were large numbers of regulated Australian utilities which had a long history of beta estimates – in which case one would not have to theorise about comparability. However, compared with the limited Australian data in practice, and as observed by the Victorian Essential Services Commission when estimating betas in its 2006-20011 Electricity Distribution Price Review (EDPR):

Analysis of equity betas of firms in the US has the advantage of being able to make use of a much larger set of listed entities, as well as information over a longer period (Page 351, Final Decision)

5.4. Conclusion

97. In my view it is appropriate to give each US equity beta estimates equal weight with each Australian equity beta estimate. This gives rise to an equity beta estimate around 1.0 and certainly in excess of 0.8. Even if one determined not to give US equity beta's the same weight as Australian equity betas, the US betas provides compelling evidence that the ERA should not depart from regulatory precedent and lower beta below 0.8.

6. Other reasons for caution in lowering the equity beta

98. For the reasons set out in the previous sections there is at best a great deal of uncertainty whether the equity beta should be reduced from 0.8 and, in my view, a strong case for it being raised. However, there are a range of additional facts and reasons, not canvassed in the above sections, for further caution in lowering the equity beta.

6.1. Investment incentives and lack of 'headroom' in the cost of equity

99. The Access Code requires the ERA to provide a forward-looking return on investment commensurate with the commercial risks involved with providing covered services. If Western Power is not provided with this return then it will have an incentive to delay or avoid necessary (socially efficient) capital expenditure. Such an outcome is not in the long term interests of end customers. To the extent that there is uncertainty in the best estimate of the equity beta there is a case for the ERA choosing a value that is towards the top of any reasonable range in order to ensure that investment incentives are not inappropriately impeded.

100. In my companion report on the internal consistency between the MRP and the risk free rate I set out serious concerns for believing that, in current market circumstances, the ERA's combination of a prevailing government bond rate with a historical average MRP will materially underestimate the cost of equity. In this context it is my view that the ERA should be especially cautious about simultaneously lowering the allowed equity beta.

6.2. Mining boom and financial instability depressing utility betas

101. The ERA follows the standard practice in Australian energy regulation which is to use the capital asset pricing model (CAPM) to estimate the cost of equity. Implementing the CAPM requires estimates of the market risk premium, the equity beta and the risk free rate. The ERA's approach involves estimation of each of these parameters over what are effectively different time periods (multi decade long periods for the MRP, approximately a decade for the beta and a matter of weeks for the risk free rate).

102. This approach cannot be presumed to give rise to accurate estimates of the CAPM cost of equity in all circumstances – unless the three different estimation periods for the three different CAPM parameters all happen to result in values that are consistent with the forward looking expectations of investors. I have addressed issues in relation to inconsistency between MRP and risk free rate in my companion report for Western Power on the internal consistency of the risk free rate and the MRP.

103. In this section I address the reasons why I believe the measured equity beta for Australian regulated businesses are likely to be pushed down by factors during the estimation period that are associated with a higher than average MRP.

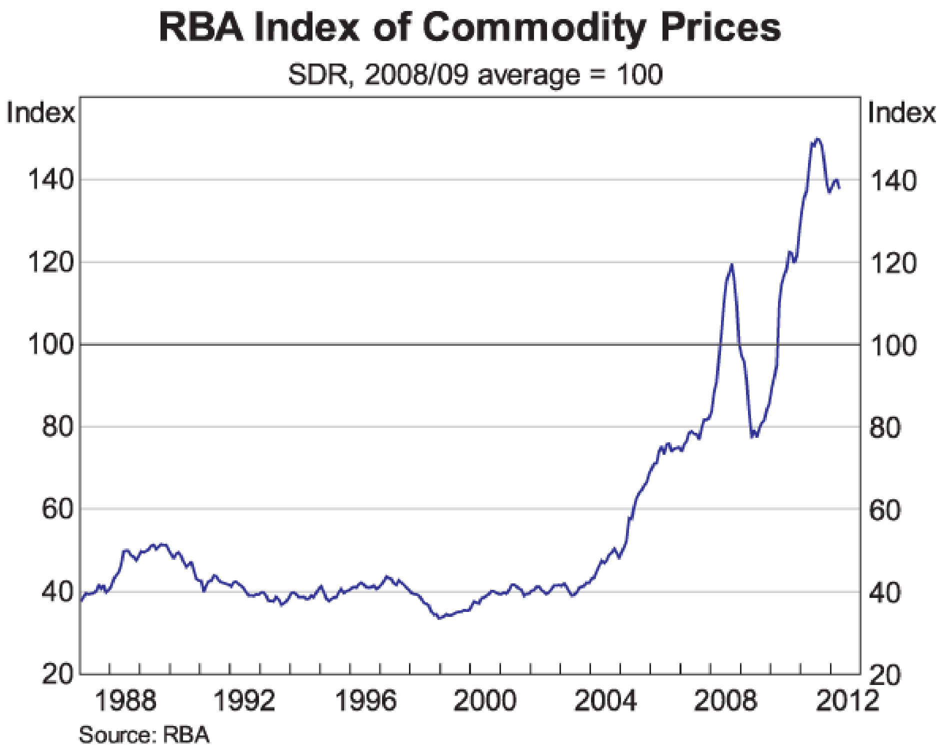
104. Consistency of beta with the MRP will be an important issue. As a general rule, if a firm/industry has a low beta in periods of high market risk then it would be inappropriate (internally inconsistent) to estimate a low beta from a period of high market risk and apply that beta to a MRP estimate that is based on long run normal market conditions.

105. Similar internal consistency issues exist in relation to betas estimated over atypical market conditions as discussed below.

6.2.1. Implications of commodity super cycle and volatility

106. The following chart shows the movements in the RBA's commodity price index over the last quarter century.

Figure 4: RBA commodity price index



107. It is clear that since 2005 there has been a dramatic, but volatile, increase in commodity prices. The result of this has been that mining stocks have increased in value dramatically and have been particularly volatile. This can be summarised as a

‘boom-bust-boom’ cycle with the relatively short lived ‘bust’ coinciding with the GFC. The inevitable result of this is that the betas for mining stocks (weighted by mining stocks’ value in the index) have risen very dramatically.

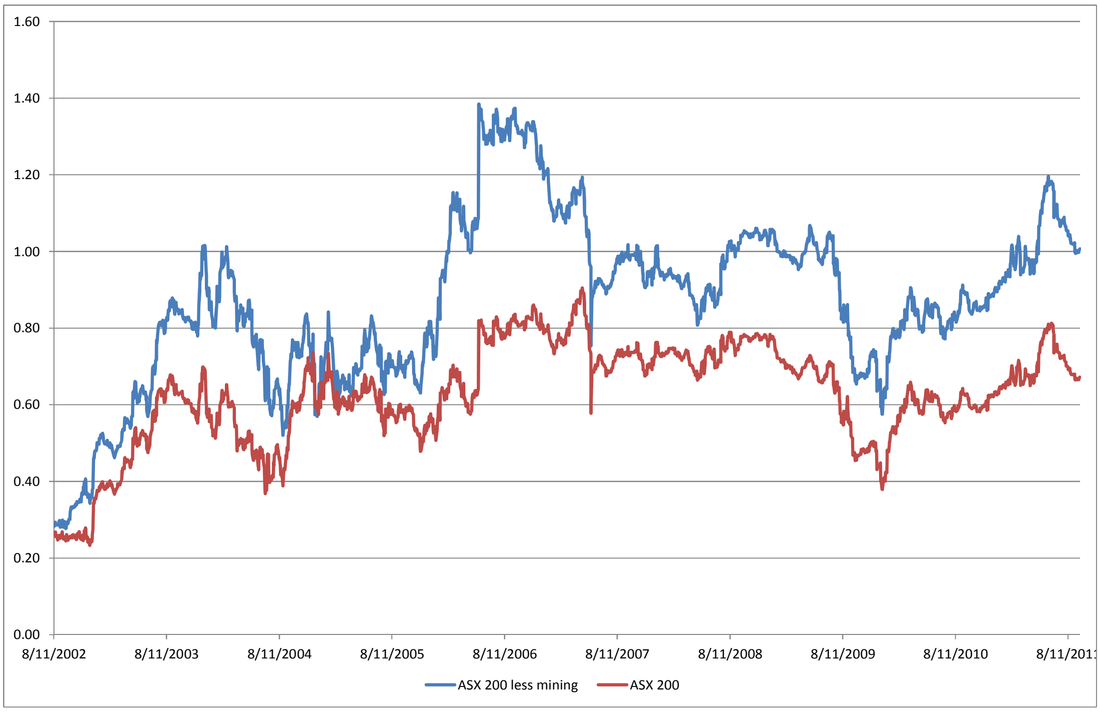
108. A corollary of this is that measured betas for other industries will, on average, have been depressed by this process. This is because the weighted average beta for the market must sum to 1.0. A mining boom of the type that has been experienced since 2005 means that one would expect that utility betas will be depressed by this phenomenon. This is especially true in the case of Australian utilities given the very high weight of mining stocks in the ASX200 (currently around 25% versus around 18% for the FTSE and around 1% for the S&P500).

109. However, it would be wrong to presume that lower measured betas due to the mining boom imply that the absolute return required by investors in utilities is lower. Below is a figure that illustrates my estimate of the impact of the commodities boom on Envestra and APA’s beta (Envestra and APA are the only utilities with constant listing on the ASX from the early 2000s).

Figure 5: Envestra 1 year beta measured against ASX200 with and without mining stocks

Source: Bloomberg, CEG analysis

Figure 6: APA 1 year beta measured against ASX200 with and without mining stocks



Source: Bloomberg, CEG analysis

110. These figures illustrate the depressing effect of the commodities boom on measured beta for non-commodity stocks post 2005.

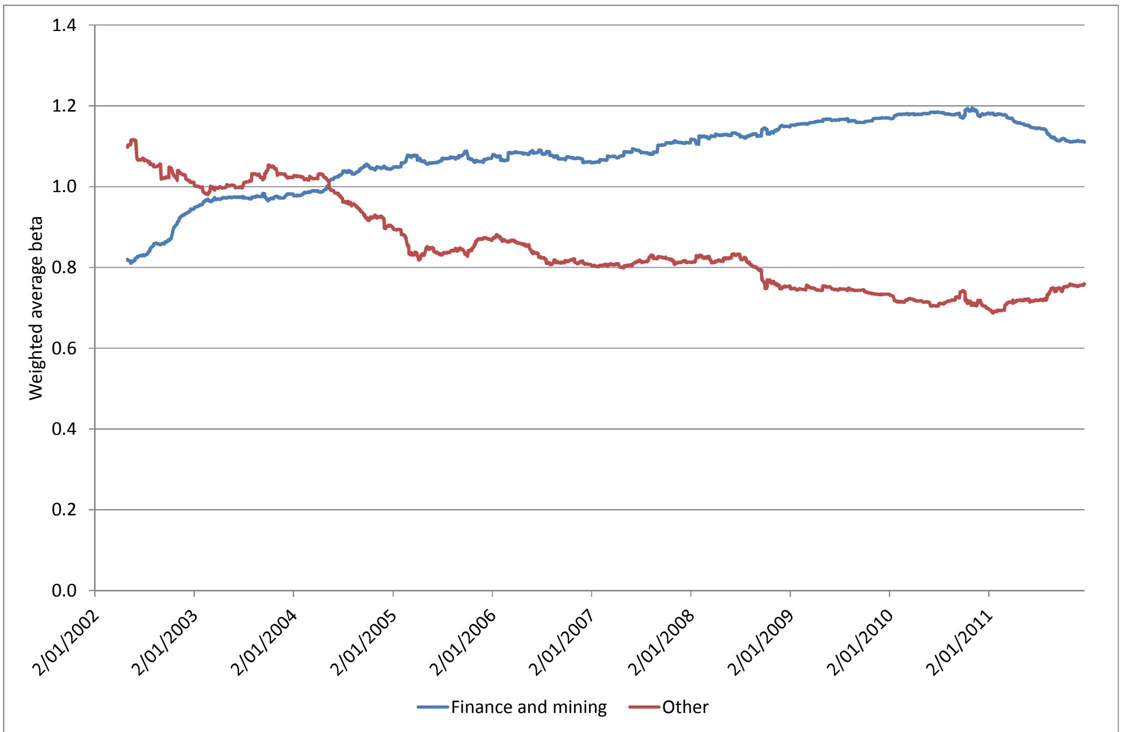
6.2.2. Implications of GFC and SDC

111. Similar issues exist in relation to the interpretation of beta estimates for utilities over the last four years of financial uncertainty. Market volatility and increasing risk premiums amongst investors resulting from the financial crisis may well have the effect of depressing the beta for industries less affected by the crisis. In particular, the 2008/09 global financial crisis (GFC) and subsequent sovereign debt crisis (SDC) can reasonably be expected to have increased volatility in financial stocks and depressed utility betas.

112. However, it would be a mistake to estimate the cost of equity by taking a beta that is depressed by a period of high market risk and applying that beta to a market risk premium that is not similarly based on the same market conditions. As already described, there is a need for internal consistency in the estimate of beta and MRP used.

113. The following chart shows the movements in weighted average beta for mining/financial stocks in the ASX200 compared to other industries. This is intended to illustrate the combined impact of both the GFC and SDC and the commodity super cycle on industry betas.

Figure 7: Australian mining/finance average beta vs the rest (2 year daily betas)



Source: Bloomberg, CEG analysis

114. This figure shows a steady decline in betas for all industries that were not mining/finance related since 2004.

115. Analysis of this type is of critical importance in interpreting the trend for an individual industry's beta. Observing continued low betas for utilities one might be tempted to assume that this reflects industry specific factors (eg, investors increasing appreciation of the 'safety' of utility investments). However, an alternative, and in my opinion more compelling, explanation is that utilities' betas, like all non-mining/finance industries betas, have been depressed by the mining boom and the financial crisis post 2004.

116. Of course, it is only reasonable to use betas that are depressed in this fashion if one simultaneously reflects the reason for this depression in a higher MRP estimate.

117. In this regard I note that the ERA draft decision acknowledges recent seemingly heightened risk in financial markets but states that it has set the MRP based on long

run historical averages and that it believes that this reflects forward looking expected market conditions.

> *691 The Authority is aware of current developments in the financial markets both in Australia and overseas. However, the Authority is of the view that the investors' expectations of the long-run forward-looking MRP is unlikely to change frequently in response to any developments in the financial markets in the short term.*
>
> *692. It is noted that, one of the approaches the Authority has adopted to estimate the MRP is to use a historical return on equity premia. In that analysis, the Authority has considered a much longer period in which the MRP is derived, ranging from 20 years to 40 years. In addition, also in the same analysis, the term to maturity of a risk-free rate of 5-year is adopted.*

118. Consistency would suggest that, if the ERA does not raise its MRP estimate on the basis of the GFC/SDC phenomenon, it should not use a beta estimate that is depressed by the same GFC/SDC phenomenon.

119. That is, even if the ERA is right that the forward looking MRP does reflect the long run historical average, the market conditions during the ERA's beta estimation period do not reflect the long run historical average (encapsulating in it a financial crisis to rival the great depression and an unprecedented mining boom). I believe I have demonstrated that these unusual market conditions depressed measured utility betas (and all non-mining/banking betas) during the ERA estimation period and that the ERA should take this into account when selecting a beta.

6.3. Consistency with DRP

120. The ERA's estimated cost of equity is extremely low compared with the prevailing cost of debt observed in finance markets.

121. Using the ERA's point estimate for the equity beta of 0.65 and the ERA's MRP of 6.0% the ERA's equity risk premium (ERP)[23] is 3.9%. That is, the ERA assumes that regulated businesses can attract equity investors by offering 3.9% return above the risk free rate. By contrast the ERA has set the debt risk premium at 2.0%.

122. For the ERA's position to be internally consistent a 60% geared regulated utility must be able to attract investors to risky equity by offering only 1.9% more than is promised to debt investors. In my view these are internally inconsistent estimates. A debt

[23] Note that the ERP is for a specific firm and is not the same as the MRP which is the risk premium for the average of the market as a whole.

investor has the first right to cash-flows and will only fail to receive his or her promised return if equity holders have already had the entire value of their investment destroyed.

123. That is, a debt investor promised a 2.0% premium above the Government bond rate only receives less than this if equity investors have not only made a zero return but have lost the entire value of their investment (i.e., made a negative 100% return). In my view it is intuitively unlikely that an equity investor would willingly expose themselves to be the first in line to absorb all company losses simply in the expectation of receiving 1.9% more than promised to debt providers.

124. In any event, standard finance theory can be brought to bear on whether such a ratio of the equity risk and debt risk premiums is likely. In order to answer this question I follow the financial logic set out in Professor Grundy's report to the New Zealand Commerce Commission.[24] Finance theory suggests that the ERP for a 60% geared business will be *at least* 2.67 times the debt risk premium. The general formula for the relationship between the equity and debt risk premia is given by:

$$\frac{ERP}{DRP} \geq \frac{1/_{L} - L}{E}, \text{ where:}$$

L = the proportion of debt in the finance structure, i.e., gearing; and

E = the proportion of equity = 1-L

125. This follows mathematically from two well accepted propositions. The first is the application of the Modigliani-Miller result that the WACC (total firm level risk adjusted return) is unaffected by financial structure (i.e., WACC is invariant to L). The second is that the debt risk premium is convex in the level of gearing. That is, the debt risk premium increases slowly initially but then increases more rapidly as more and more debt is issued (increasing the probability of default on debt).[25] Note that these propositions allow us to define the *minimum* ratio for the ERP to the DRP. The actual ratio of ERP to DRP will likely be higher than this lower bound.

126. With debt risk premiums in the order of 2.0% being estimated by the ERA for the notionally 60% geared benchmark regulated firm the corresponding lower bound ERP is 2.67 times this level - or 5.4%. This compares with the ERP based on an equity beta of 0.65 of just 3.9% (ie, 1.5% lower than the lower bound value that is internally consistent with the DRP).

---

24 Grundy, *The Calculation of the Cost of Capital*, 13 August 2010.

25 It is standard practice to assume that the cost of debt is convex (rises at an increasing rate) with the level of gearing. This relationship is commonly taught to undergraduate finance students. For example, see Figure 18.5 in Damodaran, Aswath, 2001, Corporate Finance: Theory and Practice, 2nd edition, (John Wiley and Sons, Inc., NJ).

127. In my view this is sufficient reason for the ERA to choose a value for the equity beta that is from the top of the range and provides persuasive evidence for not lowering the equity beta.

6.4. Consistency with term of debt issue

128. As described in my companion report on the debt risk premium, by adopting a 5 year term of the risk free rate the ERA is imposing a benchmark gearing assumption that will materially raise the risk attached to equity (equity beta). Moreover, it will raise the equity beta for a benchmark firm above the equity beta for the businesses in the ERA's equity beta sample because these firms tend to issue longer term debt (which lowers the risk that equity investors are exposed to).

129. In this context it is my view that the ERA should be especially cautious about simultaneously lowering the benchmark term of the cost of debt and the equity beta.

6.5. Empirical evidence in favour of Blume style adjustment

130. It is a well-accepted empirical fact that the approach to implementing the CAPM using historically estimated equity betas underestimates the cost of equity for firms with an estimated beta of less than 1.0. That is, low beta firms will have actual returns that are closer to the average of all firms (beta = 1.0) than predicted by the ERA's implementation of the CAPM. There is also a great deal of uncertainty in the theoretical and empirical literature about why this is the case.

131. This suggests that one should tend to favour a cost of equity estimate that is closer to the 'normal' or 'average' market return (associated with a beta = 1.0) rather than one that follows by a mechanical 'plugging in' of the estimated beta into the CAPM formula.

132. The commonly used 'Blume' adjustment does precisely this. The Blume adjustment increases (reduces) low (high) beta estimates toward 1.0 using the following formula:

$$\beta_{Adjusted} = 0.67 \times \beta_{Raw} + 0.33 \times 1.0$$

133. Of course, a similar effect can be achieved by choosing from the top of the range of statistical uncertainty when the estimated range is below 1.0 and vice versa when the estimated range is above 1.0.

134. Professors Franks and Myers recommended that adjustments of this type be made by the New Zealand Commerce Commission.[26]

[26] Franks, J., Lally, M. and Myers, S., *Recommendations to the New Zealand Commerce Commission on an Appropriate Cost of Capital Methodology*, December 2008, p. 27.

> ***Recommendation 33*** *Professors Franks and Myers agree that some form of Bayesian adjustment to beta estimates may be sensible, but do not strongly recommend a specific adjustment method.*

135. Professor Myers explicitly advises the New Zealand Commerce Commission that:[27]

> *Empirical evidence shows that average returns for low-beta firms are higher than predicted by the classical CAPM.*

136. This source of this bias is best illustrated by examining the figure from Fama and French (2004) referenced by Professor Handley. Professor Handley, consultant for the AER states, in relation to this empirical finding, that:[28]

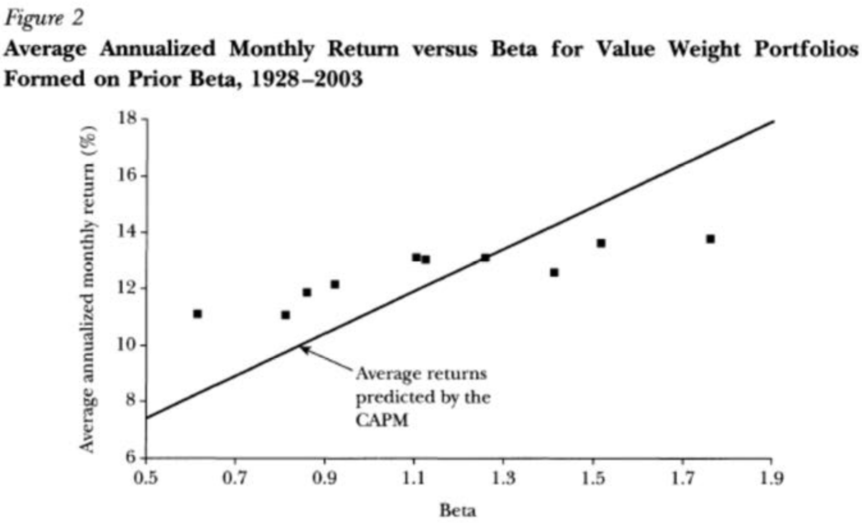
> *This empirical finding is well illustrated by Figure 2 in Fama and French (2004) who updated the evidence to the end of 2003.*

137. Professor Handley goes onto state that there is disagreement about *why* this empirical relationship exists. However, the uncertainty about *why* the empirical relationship exists does nothing to alter the existence of the relationship. The existence of this relationship is all that is required to conclude that the implementation of the CAPM without a Blume style adjustment will underestimate required returns on low beta stocks. Figure 2 in Fama and French referred to by Handley above is reproduced here.

[27] Ibid, p. 9.

[28] Handley, *Peer Review of Draft Report by Davis on the Cost of Equity*, January 2011, p. 2.

Figure 8: Figure 2 from Fama and French (2004)



138. In the above figure, the solid line shows the predicted returns of the CAPM as implemented by the AER – showing a strong positive relationship between measured beta (horizontal axis) and the return on the stock (vertical axis). The dotted observations represent the average actual relationship observed over the 75 years between 1928 and 2003. The actual relationship, while positive, is much weaker (flatter) than the predictions that arise from the AER's implementation of the CAPM. The weaker relationship between measured beta and actual returns has been found repeatedly over different time periods and in different countries (including in Australia)[29]. In the words of Handley:[30]

> *"… there is no dispute concerning the results reported by Black, Jensen and Scholes (1972), Fama and MacBeth (1973) and Fama and French (2004)…"*

139. While both Handley and Davis propose implementations of the CAPM that might be free from this downward bias, the ERA does not implement these. Of course, the fact that the bias could potentially be overcome without a Blume style adjustment by making some other adjustment to the implementation of the CAPM does not provide a justification for making no adjustment at all.

140. The important conclusion is that the literature on low beta bias is a further reason for the ERA choosing its beta from the top of the range.

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[29] CEG (September 2008); *Estimation of, and correction for, biases inherent in the Sharpe CAPM formula*

[30] Handley, *Peer Review of Draft Report by Davis on the Cost of Equity*, January 2011, p. 3.

7. Conclusion

141. I have introduced new information and analysis of a number of factors that, each on their own, mean that the ERA's point estimate for equity beta of 0.65 is too low and should be reconsidered. These are:

- a great deal of uncertainty around the Australian beta estimates;
- much more reliable US beta estimates point to dramatically higher beta estimates (higher than both 0.65 and 0.80);
- evidence that the Australian betas have been depressed by the influence of the mining boom and the GFC/SDC on the market index;
- evidence that a 0.65 beta estimate is inconsistent with the risk premium allowed on the cost of debt;
- the empirical evidence that suggests that estimates of betas well below 1.0 should be adjusted upwards towards 1.0;
- the aggressiveness of other aspects of the ERA decision mean that there is negative or zero 'margin for error' left in the WACC when one comes last to beta.

142. Based on my analysis of all of the available empirical evidence, including US beta estimates, and taking into account all the relevant factors to cross-check the beta estimates, I consider that 0.8 would be at the bottom of any reasonable range for equity beta. Taking into account some of the issues outlined above, a reasonable range would encompass an equity beta of 1.0.

143. Western Power proposes an equity beta of 0.8, which is at the bottom of this range. I therefore consider that Western Power's proposed equity beta is consistent with the requirements of the Access Code by providing a forward-looking return on equity commensurate with the commercial risks involved in providing covered services.

144. I note that Western Power's proposed equity beta of 0.8 also falls within the range proposed by the ERA of 0.5 to 0.8. For the reasons set out in this report, even if the ERA does not amend this range, an estimate at the top end of its range should be preferred over the midpoint.

Appendix A. Sample and beta estimates

145. Supplied separately on in excel format to the ERA on a confidential basis.

Appendix B. Terms of Reference

146. Please provide your estimate of the beta that should be applied to a benchmark 60% geared electricity network business subject to the same fundamental risks as Western Power. In doing so, please advise whether the equity beta would differ depending on whether the benchmark firm's debt portfolio was based on the issue of 5 vs 10 year debt. Please also advise the extent to which your analysis and conclusions are consistent with the facts presented in the ERA's draft decision.

147. The report should have particular regard to the following requirements within the Access Code for the estimation of the WACC:

    (a) The Code Objective

    (b) Objectives within Section 6.4

    (c) Section 6.64 (b)

    (d) Section 6.66

Western Power’s proposed debt risk premium

A report for Western Power

Dr. Tom Hird

May 2012

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1. Executive summary

1. Western Power has commissioned me to review the extent to which aspects of the WACC in its revised access arrangement proposal satisfies the requirements of Western Australia's Electricity Networks Access Code 2004 ("the Access Code"), and to review the Economic Regulation Authority's (ERA) draft decision of its access arrangement proposal.

2. In this report, I address the extent to which Western Power's revised estimate of 3.67% for the debt risk premium (DRP), estimated using the Bloomberg BBB fair value curve assessed at 7 years and observed over the 20 business days to 30 March 2012), satisfies the requirements of the Access Code.

3. I assess the reasoning in the ERA's draft decision that concludes that the benchmark credit rating should be A- and the benchmark term for the cost of debt should be 5 years. In my opinion, the evidence put forward by the ERA, properly interpreted, supports a benchmark credit rating of BBB+ or lower and provides strong evidence that benchmark term for the cost of debt should be 10 years.

4. I consider that relying on an independent expert opinion, such as that of Bloomberg and specifically its BBB corporate fair value curve, is, subject to appropriate reasonableness testing, likely to give rise to a more accurate estimate of the DRP than reliance on specific bond yields as proposed by the ERA. In essence, the ERA's approach to determining the DRP attempts to replicate the type of analysis conducted by Bloomberg without utilising or understanding the data and tools used by Bloomberg to estimate its fair value curves. I believe that a presumption should exist in favour of adopting Bloomberg's estimate, unless there is compelling evidence suggesting that the measurement of the DRP based on the Bloomberg curve would be unreasonable. In my view, the ERA has not provided such evidence.

5. Bloomberg only estimates its corporate fair value curves to 7 years. There is some debate about the best methodology to extrapolate the BBB fair value curve forward to 10 years. In this report I survey the empirical evidence informing a range of possible extrapolations for the Bloomberg fair value curve. I identify a range of extrapolation possibilities giving rise to DRP estimates between 3.67% and 4.03% over the 20 days to 30 March 2012.

6. In this report, I conduct an assessment of the reasonableness of Bloomberg's (extrapolated) fair value curve during the relevant averaging period by reference to observed bond yields (both Australian dollar and foreign currency), curve fitting based on bond yield information and foreign fair value curves.

7. In my view, the results of the analysis in this report demonstrate that the extrapolated Bloomberg BBB fair value curve is reliable from an empirical perspective as well as a principled one. Given that the Bloomberg fair value curve provides a good fit to the data, I consider that it would be unreasonable to attempt to artificially amend the

Bloomberg estimate – especially if such amendments were undertaken in an unsophisticated manner without an in-depth understanding of the available data.

8. Based on the analysis in this report, there is no reason to depart from the use of the Bloomberg BBB fair value curve. Extrapolating the Bloomberg BBB fair value curve forward from 7 to 10 years produces a range of reasonable extrapolations. I consider that Western Power's proposed DRP sits at the lower bound of this range and consequently is consistent with the requirements of the Access Code.

2. Introduction

9. Western Power has commissioned me to review the extent to which aspects of the WACC in its revised access arrangement proposal satisfies the requirements of the Access Code, and to review the ERA's draft decision of its access arrangement proposal. The terms of reference for my review are set out at Appendix E to this document.

10. In this report, I address the extent to which Western Power's proposed estimate of 3.67% for the DRP, estimated using the Bloomberg BBB fair value curve assessed at 7 years and observed over the 20 business days to 30 March 2012), satisfies the requirements of the Access Code.

11. The remainder of this report is set out as follows:

- section 3 reviews the considerations of the ERA in forming the benchmark for the cost of debt;
- section 4 introduces and analyses data relevant to addressing whether Western Power's proposed DRP is consistent with comparable observed yields on bonds issued by Australian companies both in Australian dollars and in foreign currency terms. The key finding of this section is that the Bloomberg BBB fair value curve is a good fit to the available bond data;
- section 5 examines a number of further cross-checks on the reasonableness of the Bloomberg BBB fair value curve, including curve-fitting directly on the bond yield data and comparison to foreign fair value curves;
- section 6 considers a possible range of information by which to extrapolate the Bloomberg BBB fair value curve from 7 years to 10 years; and
- section 7 assesses the methodology employed by the ERA to estimate the DRP against the considerations of sections 4 and 5; and
- section 8 concludes.

12. I have read, understood and complied with the Federal Court Guidelines on Expert Witnesses. I have made all inquiries that I believe are desirable and appropriate to answer the questions put to me. No matters of significance that I regard as relevant have to my knowledge been withheld.

13. I have been assisted in the preparation of this report by Daniel Young and Johanna Hansson from CEG's Sydney office and Dr Yuliya Moore from CEG's Melbourne office. However, the opinions set out in this report are my own.

Thomas Nicholas Hird

18 May 2012

3. Requirements of the Access Code for the benchmark credit rating and maturity

14. In its draft decision for Western Power, the ERA concludes that a benchmark credit rating of A- and a benchmark maturity of 5 years for the cost of debt are appropriate. It bases this conclusion on surveys of the credit rating and debt maturity profiles of a number of Australian regulated energy network businesses.

15. In general terms, I agree with the methodology set forward by the ERA for determining these benchmarks. I consider that surveying the actual behaviour of regulated energy network businesses is a reasonable and appropriate method for arriving at the benchmark assumptions. Such an approach will tend to reflect the efficient behaviour of these businesses in estimating their costs and will therefore be consistent with section 6.4 of the Access Code.

16. However, in this report I identify a number of errors committed by the ERA in its collection and interpretation of its survey data. Correcting these errors and properly interpreting the adjusted data confirms that a benchmark credit rating of BBB+ and a benchmark term to maturity of 10 years remain appropriate estimates and consistent with the requirements of the Access Code.

3.1. Wording of the Access Code

17. I have been instructed by Western Power to have particular regard to the following requirements within the Access Code in assessing its DRP:

- The Code Objective;
- Objectives within Section 6.4;
- Section 6.64 (b); and
- Section 6.66.

18. I have reviewed the Access Code and particularly the clauses highlighted in Western Power's instructions. The Code Objective, as set out at Section 2.1 of the Access Code, is to:

> *…promote the economically efficient:*
>
> *(a) investment in; and*
>
> *(b) operation of, and use of,*
>
> *networks and services of networks in Western Australia in order to promote competition in markets upstream and downstream of the networks.*

19. Section 6.4 of the Access Code sets out the additional price control objectives. 6.4(a)(i) appears most relevant to my considerations in this report:

The price control in an access arrangement must have the objectives of:

(a) giving the service provider an opportunity to earn revenue ("target revenue") for the access arrangement period from the provision of covered services as follows:

(i) an amount that meets the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved;

20. Section 6.64(b) directs that consideration be had to Section 6.66 if a determination of the regulator's preferred approach to calculating the weighted cost of capital in access determinations, as set out at Section 6.65. Section 6.66 states:

A determination under section 6.65:

(a) must represent an effective means of achieving the Code objective and the objectives in section 6.4; and

(b) must be based on an accepted financial model such as the Capital Asset Pricing Model.

3.2. ERA's consideration of the benchmark credit rating

21. The ERA surveys 13 Australian regulated energy network businesses to arrive at a benchmark credit rating of A- based on the median of this sample. I reproduce the ERA's table below in full at Table 1 below.

Table 1: ERA Table 71 – Standard & Poor's credit rating for Australian energy companies, December 2011

Company	Current rating by S&P	Comments
AGL	A-	
Alinta	BBB	[Discontinued, last on 15/9/04]
Alinta Network	BBB	[Discontinued, last on 15/9/04]
Country Energy	AA-	
DUET	BBB-	
ElectraNet Pty Ltd	BBB	
Energy Australia	N/A	
Envestra Ltd	BBB-	
Ergon Energy Corporation	AA	
ETSA Utilities	A-	
Integral Energy	AA-	Aa3 by Moody
GasNet	BBB	
SPI PowerNet	A-	
SP AusNet Group	A-	

Source: ERA

22. There are a number of data errors in the collection and use of the credit rating information at Table 1 above, which I set out below. In addition to these observations, I note that GasNet, included in Table 1, is not rated with Standard & Poor's, but that its 2006 acquirer the APA Group is currently rated BBB with that agency.

3.2.1. Incorrect rating assigned to AGL

23. The ERA has incorrectly assigned AGL a credit rating of A-, when in fact it is rated BBB with Standard and Poor's and has been since 20 October 2006.[1] When this adjustment is made, the median credit rating observation in the ERA's sample is BBB.

3.2.2. Inclusion of Australian state-supported credit ratings

24. The ERA has included the credit ratings of three regulated businesses which reflect support by Australian state governments. Standard and Poor's states that its ratings from Ergon Energy (AA) is not a standalone rating and:[2]

> *…reflects our opinion that there is an 'extremely high' likelihood that the Queensland government would provide timely and sufficient extraordinary*

[1] Available from Standard & Poor's website.

[2] Based on Standard and Poor's summary dated 12 March 2012. This except can be seen at http://www.researchandmarkets.com/reports/2087677/summary_ergon_energy_corp_ltd_and_ergon_energy.

support to EEC in the event of financial distress to ensure the timely repayment of the group's financial obligations

25. Endeavour Energy (previously Integral Energy) and Essential Energy (previously Country Energy) no longer have ratings with Standard & Poor's. However, they have equivalent ratings of Aa3 with Moody's. Moody's states that these credit ratings has been estimated based on these firms being government-related issuers that that there is a:[3]

…high likelihood of support from, and high dependence on, the state.

26. The ERA does not appear to have explored the consequences of the inclusion of Ergon Energy, Endeavour Energy and Essential Energy in its benchmark sample.

27. Section 6.4(a)(i) of the Access Code requires that the cost of debt set by the ERA for Western Power reflects the commercial risks involved with providing covered services. In using credit rating benchmarks that reflect government support, the ERA is overestimating the credit rating of the benchmark firm and underestimating the cost of debt associated with providing covered services on a commercial basis.

28. Removing these firms, in addition to my previous corrections, leaves the median credit rating observation from the ERA's sample unchanged at BBB.

3.2.3. Inclusion of foreign state-supported credit ratings

29. The ERA has included the credit rating of SPI PowerNet and SP AusNet separately. However, SPI PowerNet is a subsidiary of SP AusNet and so, at best, there is only one relevant observation provided by these two firms. Moreover, SP AusNet is ultimately owned by the Singapore government and rated A-. The AER's consultant, Oakvale Capital, stated in regard to bonds issued by SPI E&G:[4]

During the averaging period the bond was attracting one of the lowest yields, in contrast to other A- bonds observed (as per the CEG report). The key feature supporting the bond was the parental support of the issuer's owners and the link to the Government of Singapore.

30. Consistent with my observations at section 3.2.2 above, I consider that it is inappropriate to use these firms to determine the benchmark credit rating. Removing these firms, in addition to my previous changes, leaves the median credit rating observation from the ERA's sample unchanged at BBB.

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3 Based on Moody's credit opinion, 25 September 2011. This part of Moody's assessment is freely available from its website.

4 Oakvale Capital, *The impact of callable bonds*, February 2011, p. 24

3.2.4. Regard to Synergy's credit rating

31. The ERA appears to validate its selection of an A- credit rating by reference to the A+ credit rating of Synergy, an electricity retailer in Western Australia.

32. Synergy is not a business that is engaged in the provision of the type of energy network services that are covered by the Access Code. There are significant differences between the risk profiles of operating a retail business and operating a network infrastructure business. The ERA does not explain why it would consider these businesses to be comparable.

33. In my opinion, Synergy's credit rating has no bearing on determining the credit rating of the benchmark regulated energy network infrastructure business and the ERA should not have regard to irrelevant information in formulating this benchmark.

3.2.5. Conclusion

34. I consider that the ERA has had regard to a great deal of credit rating information that is either incorrect or not relevant to its assessment of the benchmark credit rating used to set the DRP and determining Western Power's cost of capital under the Access Code.

35. In my view, based on a proper interpretation of the sample identified by the ERA Western Power's proposed credit rating of BBB+ is reasonable if not conservative.

3.3. Benchmark term for the cost of debt

36. In its draft decision, the ERA determined a benchmark term for the cost of debt of 5 years. It reached this conclusion through a survey of the debt maturity profiles of five privately owned and eight publicly owned regulated energy network businesses. It also examined data collected by Standard & Poor's on the debt maturity profile of Australian utilities generally.

37. As discussed previously, I agree with the methodology proposed by the ERA to determine the benchmark term for the cost of debt. Specifically, I consider that the best estimate of the term for the cost of debt can be obtained by examining the debt-raising practices of similar regulated businesses.

38. However, the ERA has misinterpreted the evidence to which it has had regard. In my opinion, proper consideration of this evidence suggests that a benchmark term of 10 years is appropriate.

3.3.1. Evidence on term of debt raised by regulated energy network businesses

39. The evidence put forward by the ERA suggests that approximately 50% of debt carried by regulated firms has more than 5 years to maturity, while 50% has less than this.

This is consistent with debt maturity profile information that I have previously observed for regulated energy network businesses both in Australia and overseas. I set out this information at Appendix A to this report.

40. For example, by examining annual reports the ERA concludes that:[5]

> *in the sample of privately owned Australian energy networks, 52.5 per cent of total debt instruments have an average term of 5 years or less.*

41. My understanding of the data put forward by the ERA is that it measures the term of debt measured not from time of issue, but from the time of reporting. That is, I consider that the ERA has established that the average term to maturity *remaining* on debt for regulated energy network businesses may be approximately five years. This is entirely consistent with the average term to maturity of debt *at issue* by regulated network businesses being 10 years.

42. To see this, suppose a firm issued 10-year bonds each year of uniform amounts and had done so for some time. At any point in time, looking now, the average term to maturity remaining on its debt would be 5 years. This is because the maturity profile of the firm will consist of debt maturing in equal amounts over the next 10 years. On average, one would expect the average remaining time to maturity on a debt portfolio to be about half the average time to maturity at issue.

43. However, it is the term to maturity at issue that is relevant in assessing the cost of debt for a borrower. The price and coupon yield for a bond are determined at issue and these are the parameters that determine the cost of debt for a borrower. Conversely, measuring the yield to maturity on debt halfway to its 10-year maturity, as the ERA in essence proposes to do, may capture the market price for that debt but does not capture the cost of borrowing, which is determined at issue.

44. This has been accepted by the AER in its final statement of regulatory intent on the revised WACC parameters.[6] The AER also accepted that the average maturity of debt portfolios at the time of issuance was approximately 10 years:[7]

> *Taking into account this new information, the AER has verified that the weighted average maturity of debt portfolios at the time of issuance for these businesses is 10.14 years as presented above in table 6.1. That is, the further information confirms that these businesses refinance on average every 10 years.*

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[5] ERA, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, March 2012, p. 178

[6] AER, *Final decision: Review of the weighted average cost of capital (WACC) parameters*, May 2009, p. 157

[7] Ibid, p. 159

45. I further note that the AER subsequently estimated an "effective term" of 7.11 years by applying an artificially lower maturity to floating rate debt, motivated by the assumption that:[8]

> *… given that (at least a portion of) the yield on floating rate debt resets on a quarterly (i.e. 3 monthly) basis, this yield is likely to be lower than the equivalent fixed rate yield assuming an upward sloping yield curve. On this basis the prevalence of floating rate debt in the debt portfolios of these businesses is expected to alter the extent of the term premium faced at the time of physical debt issuance. In turn, this has an impact on the AER's consideration of the benchmark term assumption for the cost of debt (and the risk-free rate).*
>
> *Given these conceptual considerations, the AER considered that even if the weighted average maturity of debt at issuance is around 10 years as reported by the businesses (see table 6.1), the weighted average duration (and therefore cost) of debt at issuance may be somewhat less than 10 years once the impact of floating rate debt is taken into account.*

46. However, the AER's reasons for asserting that the yield on floating rate debt is likely to be lower than fixed rate debt are conceptually flawed. The Australian Competition Tribunal has accepted that principles of arbitrage mean that the expected yield to maturity on fixed and floating rate debt will be approximately the same and should be treated equivalently.[9]

3.3.2. Alignment of the term of debt to the regulatory period

47. Some regulators have recently justified the adoption of a 5-year term for the cost of debt on the basis that this matches the term of the regulatory period. For example, IPART has accepted this in its recent review of the DRP.[10]

48. The proposed logic for basing the benchmark term of debt issued on the term of regulatory period ignore the efficient term of debt financing in its derivation. The logic for doing so is the assumption that *if* a business refinanced all debt at the beginning of each regulatory period then the present value of compensation would only equal the present value of costs if the present value of compensation was based on issuing 5 year debt.

49. This is correct; however, it is only true if this is what businesses actually do. Whether or not businesses do this will depend on whether it is efficient to do so. There is nothing in the above logic that establishes that it is efficient to issue 5 year debt.

8 Ibid, pp. 158-159

9 Application by ActewAGL Distribution [2010] ACompT 4 (17 September 2010), paras. 49-58.

10 IPART, *Developing the approach to estimating the debt margin, Other Industries – Final Decision,* May 2011, pp. 19-21, 28

50. The fact that regulated energy infrastructure businesses issue debt at approximately 10-year terms is a good indication that this is efficient financing practice, noting that the regulatory framework to date gives no incentive for firms to engage in inefficient financing practices. Section 6.4(a)(i) of the Access Code requires the ERA to allow Western Power to earn revenue sufficient to cover its forward-looking and efficient costs.

51. Issuing 5-year debt may lead to a lower interest rate cost for a business than issuing 10-year debt (although even this is unclear). Looked at in isolation it may appear that assuming firms issue 10-year debt results in them being allocated a higher interest cost than is efficient (i.e. not the lowest interest rate cost available to the firm).

52. However, this logic is naïve and fails to properly take account of the interrelationship between the maturity structure of the debt issued by a company and the cost of equity as described by the Modigliani-Miller theorem. If we observe that, in the real world, there is a dominant debt raising strategy, such as issuing long-term debt; then Modigliani and Miller demonstrated that this must be because transaction costs are positive (financial markets are less than perfect). If we observe a dominant strategy of issuing long-term debt then this must be because there are advantages to issuing long-term debt, such as lessening exposure to refinance risk and potential insolvency and bankruptcy transaction costs. I set out more fully the types of considerations that are required in assuming a shorter term for the cost of debt in Appendix B to this report

53. This suggests that it is important to look at what businesses actually do – which is what the ERA did do. However, the ERA made an error in its interpretation of this data. The ERA's review of the debt raising practices of regulated energy network businesses reveals that these businesses raise debt with terms to maturity of approximately 10 years. On this basis, I consider that a benchmark term for the cost of debt of 10 years will be consistent with the requirements of the Access Code. The ERA's proposed term of debt of 5 years is not consistent with these requirements.

3.3.3. ERA reasoning in the DBP decision

54. In its Dampier to Bunbury Pipeline final decision the ERA sets out its views on the appropriate term of the risk free rate.[11] The risk free rate only need be used in the application of the CAPM when estimating the cost of equity. There is no requirement that the cost of debt be estimated on the assumption that a business issues all of its debt with a term equal to the term of the risk free rate used. Nonetheless, the ERA's discussion proceeds as if this was the case – with the focus of the evidence discussed relating to the term of debt issues for regulated businesses.

55. The ERA appears to conclude that an assumption that businesses issue 5-year debt is appropriate because:

[11] ERA, *Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline*, 31 October 2011, paras. 467-475

i. The ERA found that privately owned energy networks in Australia have 52.5% of total debt instruments with an average term of less than 5 years.

ii. 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 5 years

iii. 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 5 years, using interest rate swaps.

iv. The 3-year government bond future contracts are highly traded compared with the 10-year government bonds. The ERA considers that the shorter trading term is preferred by market participants over the longer trading term of 10 years.

56. The ERA appears to have misunderstood the data and theory underlying these issues. First, as discussed above the ERA appears to be making an error in its interpretation of the debt maturity profile of businesses. Specifically, 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 the time of issue.

57. 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 5-year debt. This is incorrect. Even if a business issued 10-year debt but used interest rate swaps in the way the ERA suggests, it still must pay a DRP equal to the DRP 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 DRP associated with 10-year debt.

58. If one 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 (QCA) where:

- the DRP is based on 10 year debt issues; while
- the risk free rate is based on the term of the regulatory period; and
- in addition to debt raising costs, the business was also compensated for the cost of swap contracts.

59. This would give a materially higher cost of debt than the ERA arrived at in the DBP decision. Even so, there are material shortcomings and internal inconsistencies even in the QCA's methodology.[12]

[12] See CEG, *WACC estimation: A report for South East Queensland water businesses*, February 2011, available at http://www.qca.org.au/files/W-CEG-SubWACCInterimPriceMonitoring-0311.pdf .

60. The final point raised by the ERA appears to be a response raised by AMP. I consider both the initial point raised by AMP and the ERA’s response misguided. CGS futures contracts are very liquid – whether they be at 3, 5 or 10 years. The 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.

4. Analysis of the debt risk premium

61. I have been instructed by Western Power to examine the extent to which its proposed DRP estimate of 3.67%, estimated using the Bloomberg BBB fair value curve assessed at 7 years and observed over the 20 business days to 30 March 2012, satisfies the requirements of the Access Code.

62. As described above, I proceed in this section using a benchmark of 10-year BBB+ corporate bonds as being consistent with the requirements of the Access Code. In this section and throughout the report, unless otherwise stated, all charts depicting the Bloomberg BBB fair value curve show a range of extrapolations between 7 and 10 years of between 0 and 12 basis points per annum. I note that Western Power's DRP proposal is effectively the lower bound of these possibilities.

4.1. Reliance on independent fair value estimates

63. Prior to August 2010, there were two main commercial providers of fair value estimates for corporate bonds yields in Australia; Bloomberg and CBASpectrum. Regulatory practice at that time was in general limited to determining which of Bloomberg, CBASpectrum or an average of the two was preferable as a basis for calculating the DRP.

64. With the cessation of the CBASpectrum fair value estimates, Bloomberg is now the only major provider of independent fair value estimates. I consider that relying on an independent expert opinion, such as that of Bloomberg and specifically its BBB corporate fair value curve, is likely to give rise to a more accurate estimate of the DRP than reliance on specific bond yields to adjust Bloomberg's view.

65. It must also be kept in mind that the observations of bond yields that can be obtained from providers such as Bloomberg and UBS are not often actual bond yields but are estimates of bond yields if the bonds were to trade. Some estimates will be better than others depending on factors such as when the most recent trade took place in that bond (or other of the issuers' bonds) and the extent to which comparable bonds have recently traded. Moreover, some bond yield estimates may be more reliable than others. For example, a UBS yield estimate might be more reliable for a particular bond than an ABNAmro yield estimate because UBS trades in those bonds more frequently (or vice versa). Properly synthesising debt market information is a difficult and complex task. Ideally, this is a task for industry experts/participants.

66. Second guessing the expertise of Bloomberg in gathering and interpreting information relevant to determine a fair value curve is a fraught exercise. In my view, a presumption should exist in favour of adopting Bloomberg's estimate, unless there is compelling evidence suggesting that the measurement of the DRP based on the Bloomberg curve would be unreasonable. In sections 4 and 5 below, I conduct an assessment of the reasonableness of Bloomberg's (extrapolated) fair value curve by reference to observed bond yields.

67. In my opinion, these considerations of a vast array of quantitative evidence strongly support the use of the extrapolated Bloomberg BBB fair value curve in estimating the DRP. The reasons set out by the ERA for rejecting the use of the Bloomberg fair value curve are not robust. The "bond-yield" analysis that it prefers to estimate the DRP is not sufficiently developed or sophisticated that it could be capable of replacing the type of expertise provided in Bloomberg's fair value estimates.

68. I note that the Tribunal has, in its decisions over the last two years (including most recently for Envestra and APT Allgas), accepted the use of the extrapolated Bloomberg BBB fair value curve to estimate the benchmark DRP.[13] These decisions were made in the context of various arguments by the AER that observed bond yield data supported a benchmark DRP lower than estimated by the extrapolated Bloomberg BBB fair value curve. For example, in its most recent decision for Envestra, the Tribunal states:[14]

> *Envestra provided to the AER strong evidence in support of the EBV, in particular by its response to the May 23 letter. The view of Dr Hird of CEG was that that material did not demonstrate any basis for the substitution of an alternative estimate for the EBV. As noted, the AER itself accepted the relevance of the EBV. Whilst the Tribunal accepts that the AER properly considered the reliability of the EBV, it has reached the view on the available material that there is no reason shown from the available material why the use of the EBV should not be adopted in this particular matter. There is no viable alternative methodology at present, other than making a decision on all the material. The observations of the Tribunal in ActewAGL at [74]-[78] suggest also that, on the existing material, it is appropriate to vary the decision in the manner indicated.*

69. Most recently, the AER has proposed a sampling method similar to that proposed by the ERA,[15] but has since withdrawn this, citing as its reasons the Tribunal's most recent decisions.

4.2. Assessment of Bloomberg fair value curve by reference to Australian dollar yield data

70. In assessing the reasonableness of Bloomberg's extrapolated BBB fair value curve, I have regard to observed yields on Australian dollar corporate bonds issued in Australia as reported by UBS and Bloomberg. Since Bloomberg has a number of bond yield sources available, I have used in declining order of preference BGN, BVAL and BCMP

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13 See: Application by ActewAGL Distribution [2010] ACompT 4 (17 September 2010) ; Application by Jemena Gas Networks (NSW) Ltd (No 5) [2011] ACompT 10 (9 June 2011) ; Application by United Energy Distribution Pty Limited [2012] ACompT 1 (6 January 2012) ; Application by Envestra Limited (No 2) [2012] ACompT 3 (11 January 2012); and Application by APT Allgas Energy Limited (No 2) [2012] ACompT 5 (11 January 2012)

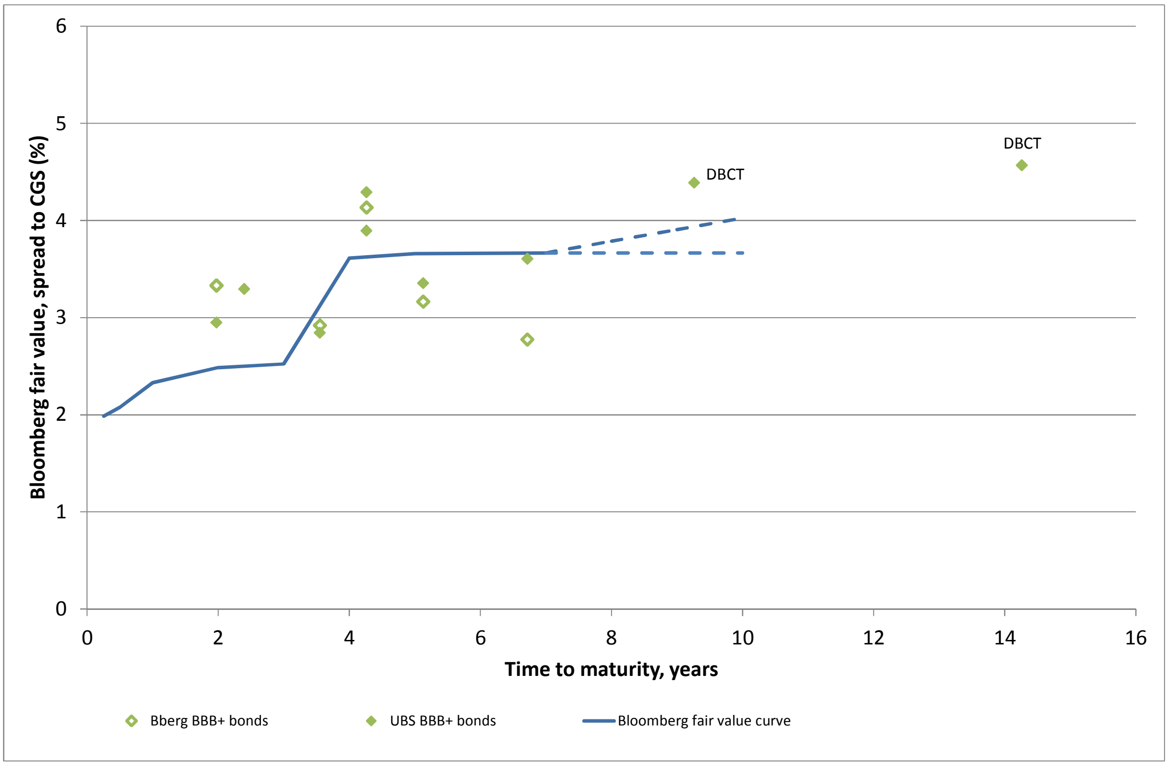
14 Application by Envestra Limited (No 2) [2012] ACompT 3 (11 January 2012), para. 123

15 AER, *Draft distribution determination: Aurora Energy Pty Ltd*, November 2011; and AER, *Final decision: Powerlink transmission determination*, April 2012, p. 34

4.2.1. Yields on BBB+ rated bonds

71. Figure 1 below updates the equivalent chart in my previous DRP report for Western Power.[16] It sets out the average yields on all fixed and floating Australian dollar corporate bonds rated BBB+ with maturity greater than one year over the 20 days to 30 March 2012. Bonds rated BBB+ are the logical starting point because, as described above, the requirements of the Access Code are consistent with BBB+ rated debt.

Figure 1: Bonds with maturity greater than one year rated BBB+



Source: Bloomberg, UBS, RBA and CEG analysis

72. Only two bonds in Figure 1 have a maturity date which is more than 8 years in the future, both of which are issued by DBCT. The spread of these bonds are either above or within the extrapolation range of the Bloomberg BBB fair value curve. Table 2 summarises the spreads for the DBCT bonds, which are only available from UBS.

[16] Ibid, Figure 1

Table 2: Bonds with maturity greater than 8 years rated BBB+

Issuer	S&P rating	Maturity (yrs)	UBS spread	BB spread
DBCT	BBB+	9.26	4.39	-
DBCT	BBB+	14.26	4.57	-

Source: Bloomberg, UBS, RBA and CEG analysis

73. The quantitative evidence presented in Figure 1 and Table 2 above strongly suggest that the extrapolated Bloomberg BBB fair value provides a reasonable estimate for bonds rated BBB+ and is a good fit to the available bond yield data.

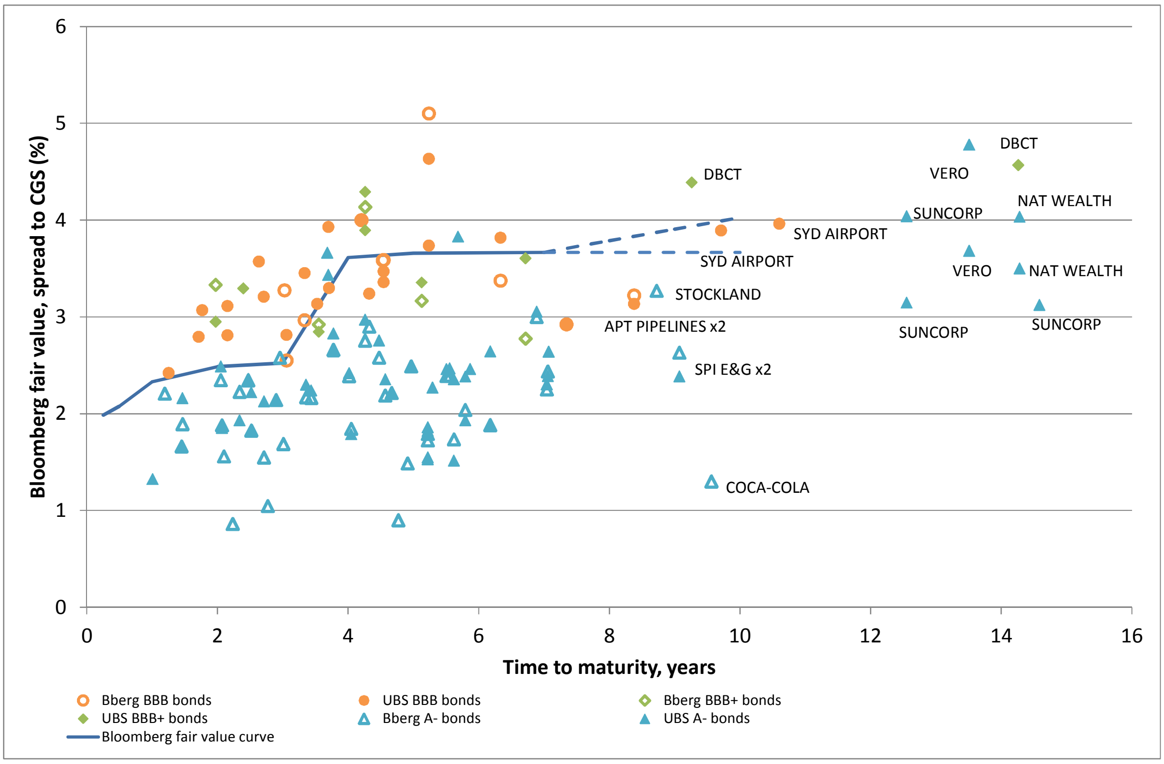
74. It is relevant to note that DBCT is an Australian infrastructure issuer rated BBB+. To the extent that one takes the view that infrastructure issuer's bonds are more relevant to an assessment of the BBB+ benchmark then these long dated bonds may be given more weight than other bonds.

75. Figure 1 above indicates that the extrapolated Bloomberg BBB fair value curve is a very good fit to the available data for BBB+ bonds. However, the only two bonds with a maturity of above eight years in Figure 1 were issued by the same issuer. Whilst I have no reservations about the usefulness of the DBCT bonds as concerns their comparability to the benchmark bond, I do not consider the evidence based on a single issuer can be fully determinative.

4.2.2. Yields on bonds rated BBB to A-

76. Figure 2 below expands the selection of bonds to include fixed and floating corporate bonds issued in Australia in Australian dollars rated BBB to A-, with maturity greater than one year. This larger dataset provides a further cross-check on the reasonableness of the extrapolated Bloomberg BBB fair value curve, as well as providing a cross-check upon the BBB+ data used in Figure 1 above for that purpose.

Figure 2: Bonds with maturity greater than one year rated BBB to A-



Source: Bloomberg, UBS, RBA and CEG analysis

77. Including bonds rated BBB and A- expands the number of bonds available with a maturity greater than 8 years from 2 to 15 bonds, as well as providing 7 distinct further issuers (not counting Suncorp and Vero separately as these are part of the same company group). The spreads of these bonds are both above and below the Bloomberg BBB fair value curve, and are detailed in Table 3 below.

Table 3: Bonds with maturity greater than 8 years rated BBB to A-

Issuer	S&P rating	Maturity (yrs)	UBS spread	BB spread
APT Pipelines	BBB	8.38	3.13	3.22
Sydney Airport	BBB	9.71	3.89	-
Sydney Airport	BBB	10.60	3.96	-
DBCT	BBB+	9.26	4.39	-
DBCT	BBB+	14.26	4.57	-
Stockland	A-	8.73	-	3.27
SPI Electricity & Gas	A-	9.07	2.38	2.63
Coca Cola Amatil	A-	9.56	-	1.30
Suncorp Metway	A-	12.55	4.04	-
Vero Insurance	A-	13.51	4.78	-
Vero Insurance	A-	13.51	3.68	-
National Wealth Management	A-	14.28	3.50	-
National Wealth Management	A-	14.28	4.03	-
Suncorp Metway	A-	14.59	3.12	-

Source: Bloomberg, UBS, RBA and CEG analysis

78. Including bonds rated BBB and A- expands the number of bonds materially. However, it does not provide a basis for altering the conclusion that the Bloomberg fair value curve is a good fit to the available data.

79. The great majority of the A- bonds added have DRPs less than the Bloomberg BBB fair value curve (consistent with what one would expect). However, there are some A- bonds that are above the BBB fair value. Three long-dated A- bonds are the furthest below the curve: Coca Cola, SPI E&G and Stockland.

80. Similarly, the majority of BBB bonds lie above the curve and most that are below the curve are only fractionally so.

4.2.3. Exclusion of Coca Cola Amatil and SPI E&G

81. In this regard I note that two long-dated bonds in Table 3 above are clearly not representative and should be given little or no weight. These are the Coca Cola Amatil bond and the SPI E&G bond.

82. The SPI E&G issuer is part owned by the Singapore Government. The AER's experts, Oakvale Capital, stated in relation to a shorter dated SPI E&G bond in an earlier period that:

> *During the averaging period the bond was attracting one of the lowest yields, in contrast to other A- bonds observed (as per the CEG report). The key feature*

supporting the bond was the parental support of the issuer's owners and the link to the Government. [17]

83. The Coca Cola Amatil bond yield is clearly anomalous given the broader population of DRP estimates as depicted in Figure 2 above. In my view, it would be inappropriate to continue to rely upon the DRP estimated for the Coca Cola Amatil bond to determine the benchmark DRP on 10-year BBB+ corporate bonds.

84. Having regard to the above, I consider that the evidence presented in Table 3 and Figure 2 above indicates that the extrapolated Bloomberg BBB fair value curve is a good fit to the observed bond yield data.

4.3. Analysis of callable bonds

85. Call options allow the issuer of a bond the right to repay the principal of the bond earlier than the final maturity date. There are different types of call options, including those that allow discrete dates at which these options may be exercised and others that permit a call to be made at any point beyond a certain date.

86. The potential exercise of these options may mean that a lender may demand a higher interest rate on these bonds to compensate for the fact that they may be made worse off if the bond is called. For example, the issuer may be likely to call the bond if interest rates have fallen and, as a result, the interest rate on the bond is higher than prevailing rates in the market. However, calling the bond in those circumstances makes the lender worse off – because the lender ceases to earn above market interest rates on the bond.

87. However, if a bond is 'make whole callable' this means that the issuer must pay the borrower a penalty if the bond is called. The penalty is calculated such that the borrower is compensated (or 'made whole') for lost interest as a result of the bond being called. For this type of bond a lender would not expect a higher interest rate due to the callable nature of the bond because the intention is that they would be compensated for losses as a result on the bond being called.

88. The AER appears to accept this contention in its Aurora and Powerlink draft decisions.[18] This reflects the advice of Oakvale Capital, which stated that call options on make whole callable bonds should not raise yields relative to the same bond with no call options (and may even depress yields as investors see some value from the potential that the bond may be called).[19]

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17 Oakvale Capital, *The impact of callable bonds*, February 2011, p. 24

18 See for example: AER, *Draft decision: Powerlink transmission determination*, November 2011, footnote 573. This issue was not addressed in the AER's much shorter DRP commentary in the Powerlink final decision.

19 Oakvale Capital, *Report on the cost of debt during the averaging period: The impact of callable bonds*, February 2011., p. 7.

89. It is also relevant to note that for many bonds issued before the global financial crisis with relatively low coupons/spreads, the ability of the issuer to now or in the future lower financing costs by exercising a call option is negligible.

4.3.1. Should callable bonds be excluded

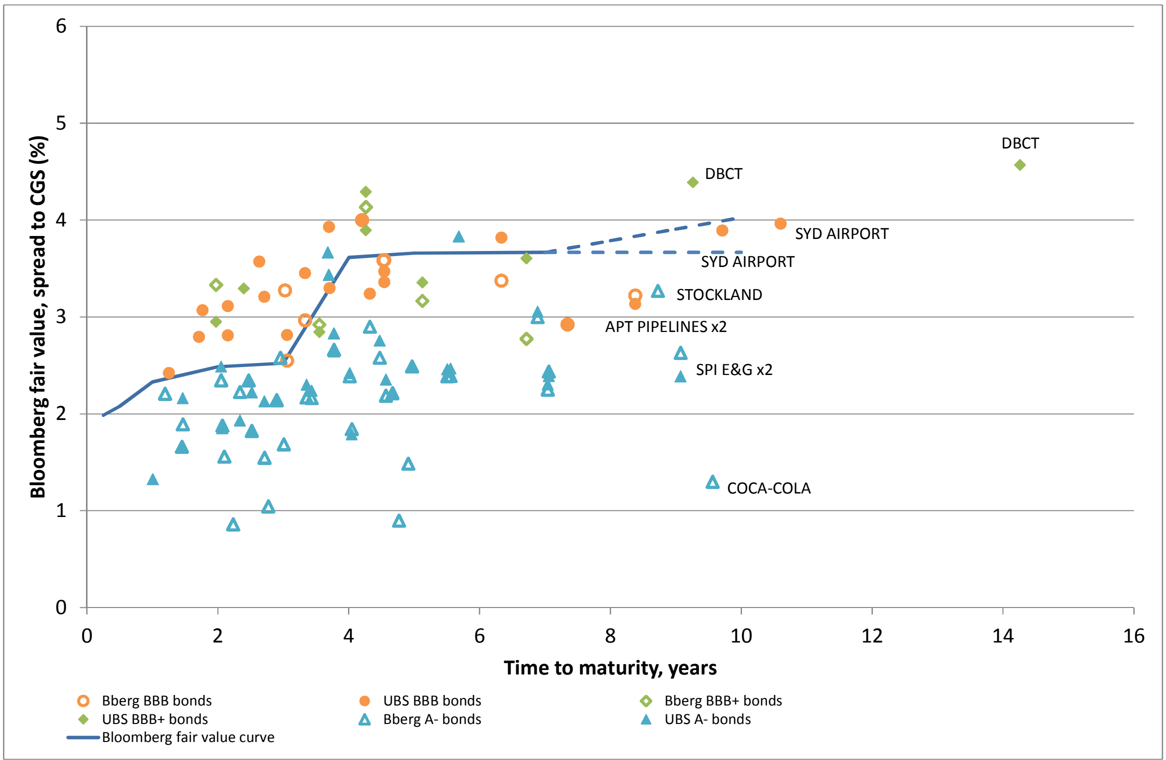
90. I consider that the DRP should be assessed relative to the population of callable and non-callable bonds for the simple reason that businesses, including regulated businesses, prudently issue both callable and non-callable bonds. Moreover, the cost of equity has been estimated by the ERA based on the observed equity betas for regulated businesses. To the extent issuing callable bonds lowers the cost of equity then removing the impact of the call option from the cost of debt involves an element of double counting (as it has already been captured in a lower cost of equity).

91. I note that the ERA has not specifically excluded callable bonds from its "bond-yield" methodology.

4.3.2. Impact of excluding callable bonds

92. Out of the total population of bonds in Figure 2 above, 24 bonds are callable but not make whole callable (for ease of exposition below, I call the class of bonds remaining after excluding callable bonds "non-callable" notwithstanding that they include make whole callable bonds). Figure 3 below is the same as Figure 2, but excluding all such bonds.

Figure 3: Bonds with maturity greater than one year rated BBB to A- (excluding callable but not make whole callable bonds)



Source: Bloomberg, UBS, RBA and CEG analysis
Note: Data sourced as an average over 5 March 2012 to 30 March 2012

93. This chart shows that the majority of non-callable bonds with more than 6 years to maturity have yields that are below the Bloomberg fair value curve.

94. Examined in isolation and assuming that one accepted that the excluded callable bonds had no relevant information, the fact that the majority of non-callable bonds with above 7 years maturity lie below the extrapolated Bloomberg BBB fair value curve might cause one to question the accuracy of that curve in this region.

95. However, there are two reasons why, even if I restricted myself to this very narrow range of information, I reject this conclusion. First, for reasons set out above and in more detail below, I consider that the Coca Cola and SPI E&G bonds are either aberrant observations (Coca Cola) or depressed by the implicit backing of the AAA rated Singapore Government. These bonds have the lowest yields and, removing them leaves only three bonds below the extrapolation range of the fair value curve (with four bonds above or inside the range).

96. Second, looking at the whole population of non-callable bonds it is clear that the sample around 10 years is small and inconsistent with the wider population. For example, the BBB bonds in this sample have a lower average DRP than the BBB bonds with between 4 and 7 years to maturity. In fact, these shorter dated BBB bonds

average 4.75 years to maturity and an average DRP of 3.55%. This compares to 9.01 years maturity and 3.49% DRP for BBB bonds in the sample of the BBB bonds with more than 7 years to maturity. Notably, the DRP calculated for the Brisbane Airport bond is less than that for all the other BBB bonds with 4 or more years to maturity despite the Brisbane Airport bond having more than 7 years to maturity.

97. In order to reconcile these facts one would have to assume that DRP fell as maturity rose. This is not consistent with what one would normally expect for investment grade bonds, what has Australian regulators have historically assumed in past regulatory decisions, nor is it consistent with the findings of my analysis of extrapolation at section 6 of this report.

98. This inconsistency between the long dated sample and the short dated sample illustrates why it is an error to simply reject the accuracy of a curve that is *drawn through all of the data* on the basis of a comparison of that curve with a *subset of the data* as the AER effectively does.

99. In this case the data for bonds maturing at less than 7 years provides information on where the benchmark yield is at those maturities. If one draws a curve through this data *and* long dated bonds then it may be the case that such a curve is higher than a curve drawn through only long dated bonds. However, this does not mean the curve is wrong. It simply means that the sample of long-dated bonds is, once adjusted for maturity, not representative of the population as a whole. (I discuss in section 5 below how one can use mathematical modelling of bond yields to attempt to give proper weight to both short and long dated bonds.)

100. In any event, I do not believe that it is appropriate to restrict myself to this sample of bonds. One reason is that callable bond yields can be adjusted to remove any premium due to their callable nature (rather than simply excluding them outright). I perform this adjustment in the sub-section immediately below.

4.3.3. Adjusting rather than excluding callable bonds

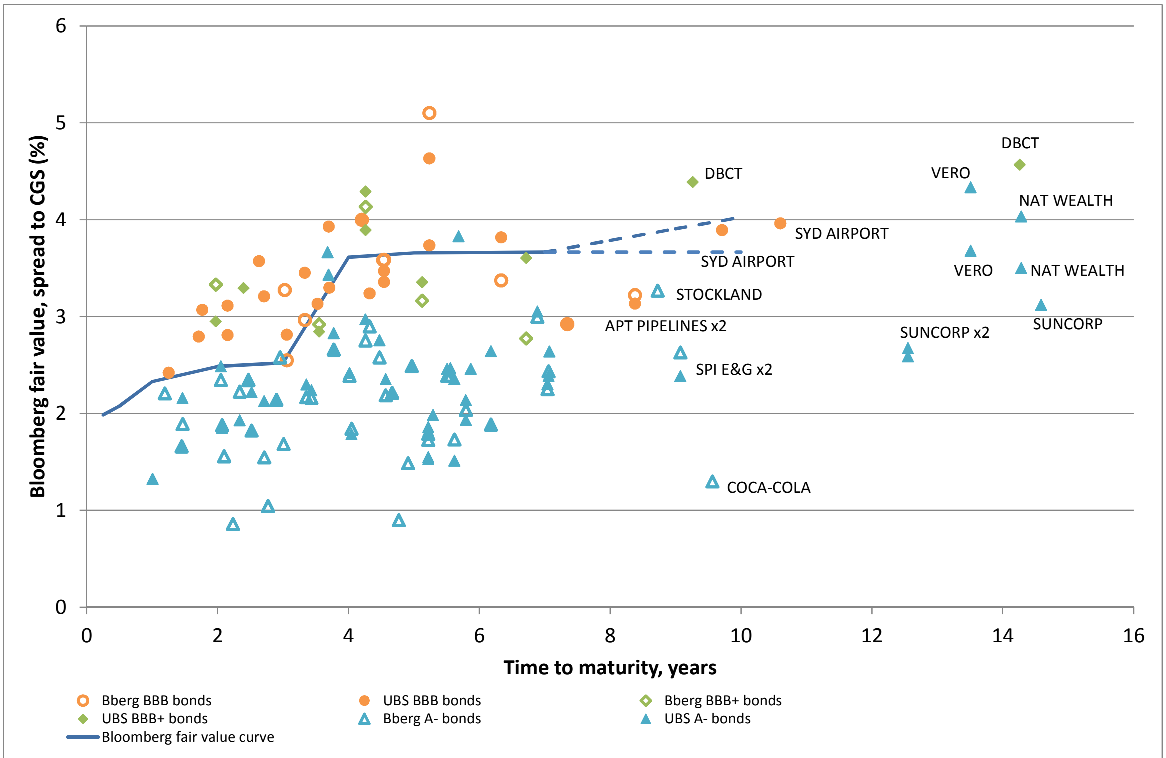
101. Callable bond yields can be adjusted to remove the impact of callability using the adjustment proposed by the AER's consultants, Oakvale Capital. Out of the 9 bonds which Bloomberg describes as callable (and for which there is a yield estimate and which have a time to maturity of more than 8 years) Bloomberg identifies just three as having an embedded option premium. The relevant bonds are summarised in Table 4 below. Figure 4 shows the effect of removing the embedded option premium from all callable bonds in my sample.

Table 4: Callable bonds in sample

ISIN	Issuer	Rating	Maturity	Callable	Make whole	Embedded premium
AU300BBIF034	DBCT FINANCE PTY	BBB+	9/06/2021	Y	Y	N
AU300BBIF042	DBCT FINANCE PTY	BBB+	9/06/2026	Y	Y	N
AU300SUNQ027	SUNCORP METWAY	A-	23/09/2024	Y	N	**Y**
AU300SUNQ019	SUNCORP METWAY	A-	23/09/2024	Y	N	**Y**
AU300VERO013	VERO INSURANCE	A-	7/09/2025	Y	N	N
AU300VERO021	VERO INSURANCE	A-	7/09/2025	Y	N	**Y**
AU300NWML019	NATIONAL WEALTH	A-	16/06/2026	Y	N	N
AU300NWML027	NATIONAL WEALTH	A-	16/06/2026	Y	N	N
AU3CB0003309	SUNCORP METWAY	A-	6/10/2026	Y	N	N

Source: Bloomberg

Figure 4: Bonds with maturity greater than one year rated BBB to A- (Oakvale adjustment applied to callable bonds)



Source: Bloomberg, UBS, RBA and CEG analysis. Maturity dates for callable bonds are final maturity date for the bond (i.e., not call date).
Note: Data sourced as an average over 5 March 2012 to 30 March 2012

102. Making the Oakvale adjustments does not materially change the pattern of bonds from that described in Figure 2.

103. I note that the AER has recently argued that UBS reports yield to call data rather than yield to maturity data for some callable bonds.[20] If correct, then this would mean that some of the callable bond yields would require a further adjustment in order to convert them from yield to call to yield to maturity.

104. I have tested whether the AER is correct by making the adjustment that the AER suggests is required to the DBCT bond that matures on 12 December 2022 but which had a call date listed in UBS as 12 December 2011. I have taken the trading margin from UBS's rate sheets for that bond on 2 December 2011 (300bp to swap) and treated it 'as if' UBS intended it to be a trading margin to call date (rather than to maturity date). Assuming this to be the case, I calculate the fixed equivalent yield to maturity on the bond would be 5.26%. This is equivalent to a DRP of 1.17% (details of this calculation are set out in Appendix A).

105. In my opinion, this is not a credible estimate of the yield to maturity/DRP on this bond. My reason for this conclusion is that there were at the time two other DBCT bonds with similar maturities that, according to the AER logic, required no adjustment (because UBS correctly identified the maturity date of these bonds as their final maturity date).

106. The two bonds not requiring adjustment had similar yields/DRPs to the pre-adjustment yield/DRP of the 12 December 2022 bond. However, they had dramatically higher yield/DRPs than the post adjusted yield on the 12 December 2022 bond. In fact, the adjusted DBCT bond had a yield/DRP that was more consistent with the yield on AA+ rated State Government debt than on a BBB+ bond. It is the incongruous nature of the adjusted DBCT bond yield/DRP relative to the other DBCT bond yields/DRPs that lead me to the conclusion that the AER is incorrect to claim that all UBS trading margin information relates to the call date rather than the maturity date.

20 AER, *Draft decision: Powerlink transmission determination*, November 2011, p. 217

5. Cross-checks on the Bloomberg fair value curve

107. In this section I introduce three methods by which the reasonableness of the extrapolated Bloomberg BBB fair value curve can be tested by reference to data and methods other than those discussed at section 4 above. The cross-checks involve consideration of:

- the yields on bonds issued by Australian firms in foreign currencies, swapped back into Australian dollar terms;
- curve-fitting techniques applied to the yields on bonds issued by Australian firms in Australian dollars; and
- foreign fair value curves, swapped back into Australian dollar terms.

108. I consider that these cross-checks establish conclusively the reasonableness of the extrapolated Bloomberg BBB fair value curve over the 5 March 2012 to 30 March 2012 period that I analyse, and that it is a good fit to the available data.

5.1. Foreign currency bonds issued by Australian firms

109. As I set out at section 4 above, I consider that the information from Australian domestic bonds is sufficient to conclude that the extrapolated Bloomberg BBB fair value curve provides a reasonable estimate for at 10-year BBB+ benchmark. However, additional cross-checks of this conclusion can be made by comparing the extrapolated Bloomberg BBB fair value curve to yield information from bonds issued by Australian companies in foreign currencies. Given the sparseness of Australian dollar denominated long dated bonds in the A- to BBB credit rating it is important to consider the information that is available from other sources.

110. It has been observed by the Tribunal that there appear to be few bonds close to the benchmark maturity of 10 years:[21]

> *There is another point worth noting about the AER's methodology. It arises out of the difficulty in identifying a sufficient number of long term bonds to determine yield. The reason a 10 year bond was originally chosen was because, in the past, many firms favoured long term debt, albeit that it came at a higher cost, because it reduced refinancing or roll-over risks. The high rate was then hedged via interest rate swaps. That may no longer be the position. If not, the AER may need to be reconsider its approach in light of more current strategies of firms in the relevant regulated industry. Further, there seems to be little point in attempting to estimate the yield on a bond which is not commonly issued.*

111. These comments were made in the context of the analysis of Australian dollar bonds issued in Australia. The implicit conclusion drawn in these comments appears to be

[21] Australian Competition Tribunal, Application by ActewAGL Distribution [2010] ACompT 4 (17 September 2010), para 72.

that a maturity of 10 years might not be appropriate because it does not reflect the borrowing behaviour of regulated infrastructure businesses.

112. However, a significant body of evidence exists that indicates that regulated electricity and gas network businesses actually do issue long dated debt, with average time to maturity of greater than 10 years.[22] The seeming inconsistency of this with the above quote from the Tribunal can be reconciled by observing that a significant proportion of long-dated debt issued by these firms is not issued in Australian dollars but rather in foreign currencies.[23] That is, the assumption that regulated firms issue 10 year debt is not wrong. Rather, it is just that much of these firms' long term debt is issued in foreign currencies.

113. I also note that the Tribunal's reference to hedging interest rate risk on domestic debt issues has a parallel in the hedging of currency risk on foreign denominated debt issues by businesses – a process that I discuss below.

114. It is notable that analysis to date on observed bond yields has not generally encompassed Australian bonds issued in foreign currencies. A possible explanation for this is that until quite recently, debate in this area mainly focused on which of Bloomberg or CBASpectrum (or most recently just Bloomberg) fair yields were the best fit to the observed data. Because these sources did not rely upon foreign currency bonds it seemed natural not to do so in analysing them.

5.1.1. Can yields on foreign currency bonds be expressed on an Australian dollar basis?

115. One barrier to the inclusion of foreign currency bonds in the determination of an Australian benchmark bond rate is that yields expressed in foreign currencies cannot be readily compared to Australian dollar yields. Future coupon payments and the return of principal must be assessed at their expected value in Australian dollar terms in order to determine the converted yield.

116. In practice, businesses that issue bonds in foreign currencies often immediately convert these bonds to Australian dollar equivalents using an instrument known as a "cross currency swap". For a bond issued in United States dollars, a business would enter into a swap agreement (or series of swap agreements) where it would receive an amount in US dollars that would cover its coupon and principle liabilities on the US dollar bond. In return, it would promise to pay its counterparty an amount denominated in Australian dollars.

117. By entering into a cross currency swap, the foreign currency bond is converted to an Australian dollar bond without currency risk to the issuer (beyond that inherent in the default of the counterparty to the swap). The converted yield reflects the market cost

[22] See section 2.1 of, CEG, Critique of AER Rule Change Proposal, A report for ETSA, Powercor and Citipower, December 2011.

[23] See for instance, EUAARCC Rule Change Proposal, 17 October 2011, p. 14

in Australian dollars of issuing the bond in US dollars. This is a common practice for Australian companies, including Australian regulated businesses. For example, CEG has been informed by ETSA that it raises US dollar debt which it then swaps back into Australian dollars in this manner.[24]

5.1.2. How does CEG convert foreign currency bond yields to Australian dollar terms?

118. The principles governing the pricing of cross-currency swaps are clear. The conversion is based on observable market instruments indicating investors' expectations about future currency movements.

119. Bloomberg's "XCCY" function estimates cross-currency swap rates between any pair of currencies for given characteristics, such as maturity, coupon payments and payment frequency.

120. Given the number of foreign currency bonds issued in Australia (over 1000, with 20 days of data for each over the averaging period) it is not practicable to use this function to convert each bond on each day of the averaging period. Instead, tables of cross currency swap rates associated with a range of maturity-yield pairs were produced for each currency and interpolation over these points used to convert foreign currency yields into Australian dollar terms. The technique is explained in greater detail at Appendix D below.

5.1.3. Is inclusion of Australian bonds issued in foreign currencies consistent with the Access Code?

121. Section 6.4(a)(i) of the Access Code requires that the revenues on covered services is to be *"the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved"*. There is no wording to suggest that forward-looking and efficient finance costs would involve funds raised only in Australian dollars.

122. Australian businesses do engage in foreign currency bond issues which are swapped back into Australian dollars. The evidence provided by ETSA and referred to above is an example. More generally, the fact that we identify many bonds issued by Australian companies in foreign currencies supports the conclusion that this is an important source of funding for Australian companies.

123. However, even if very few Australian companies issued foreign currency bonds, the potential for an Australian company to do so would place a cap on the interest rate that it was prepared to pay on a bond issued in Australia. Similarly, the potential for a lender to buy a bond denominated in a foreign currency and swap it back into Australian dollars places a floor under the yield that they will accept for lending to a similarly risky entity in Australia.

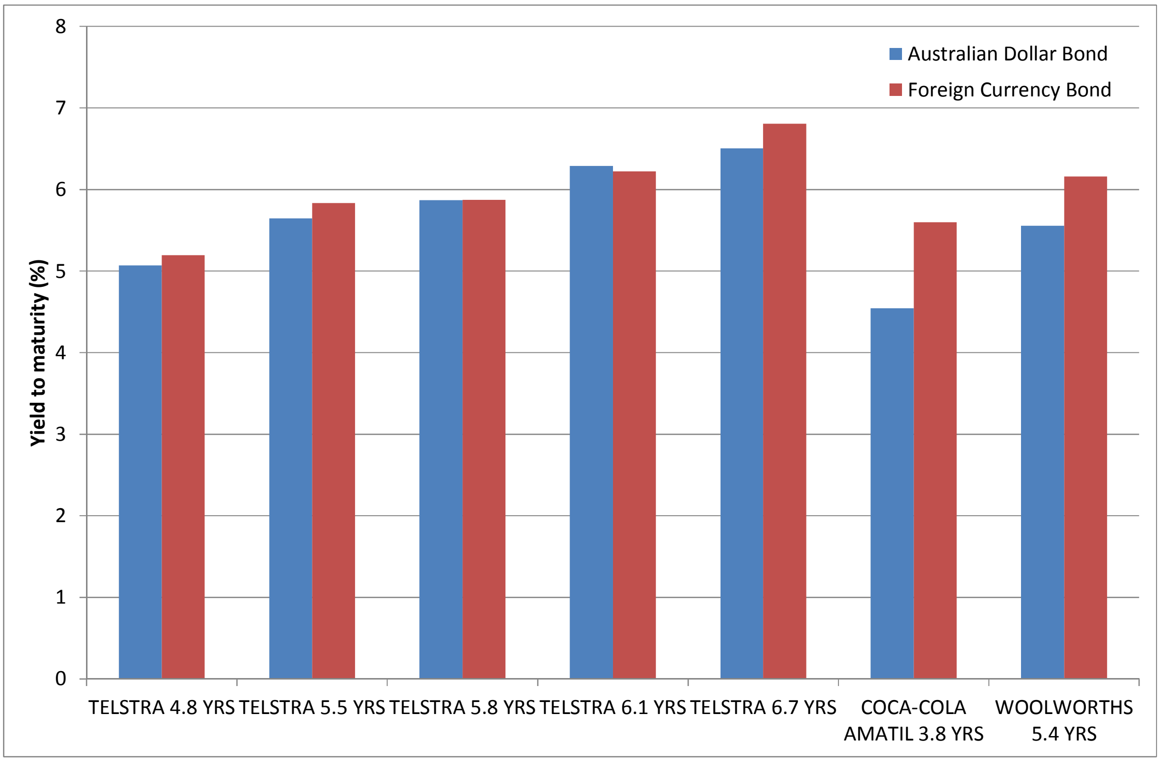
[24] See, CEG, *Critique of AER Rule change proposal, a report for ETSA Utilities, Powercor and Citipower*, December 2011.

124. For these reasons, it is my view that the yields on foreign currency bonds issued by Australian companies are at least relevant to an assessment of the conditions in the market for funds from which Australian companies raise debt. As such, the cost of funding using such a strategy can, at the minimum, be used as a cross-check on the analysis of section 4 where we restrict ourselves to bonds issued in Australian dollars.

5.1.4. Are swapped foreign currency yields consistent with domestic yields?

125. I have compared the swapped yield on the foreign currency bonds relied upon in this report (ie, those issued by Australian firms rated BBB- to A) with the yields on Australian dollar bonds issued by the same firm, with the same rating and with a term to maturity that is within half a year of the foreign currency bond. This comparison captures six bonds which are shown in Figure 5 below.

Figure 5: Comparison of yields on swapped foreign currency bonds and AUD bonds by the same issuer and with similar maturity



Source: Bloomberg, CEG analysis

126. This chart demonstrates that the yields are broadly comparable on bonds by the same issuer. Sometimes the swapped yield is higher than the Australian dollar yield and sometimes it is lower but the differences are not significant. The only exception relates to the Coca-Cola Amatil bond where the Australian dollar yield looks low compared to the swapped foreign currency yield. This large difference validates the concerns I express at section 4.2.3 about the very low Australian dollar yield for this bond.

127. I consider that Figure 5 provides strong evidence to suggest that the yields on swapped foreign currency bonds issued by Australian firms are likely to be a reasonable estimate for how similar bonds would trade (or be assessed) if issued in Australian dollars. I also note that this is consistent with the view of Professor Kevin Davis, who in his report for IPART states:[25]

> *the domestic currency costs of issuing debt in foreign currencies and swapping into domestic currency should generally be the same as issuing debt in domestic currency (although minor differences emerge from time to time due to incomplete market integration) and that using these costs is compatible with use of a domestic CAPM. In essence, because the required return on debt is, unlike that on equity, directly observable for comparable companies, its calculation is "model free".*

5.1.5. Data analysis and conclusions

128. The following charts show the yields on bonds issued by Australian companies in a foreign currency once these are swapped into Australian dollars. These yield observations are compared with the extrapolated Australian BBB Bloomberg fair value curve. All of the data on foreign currency yields is sourced from Bloomberg as are the cross currency swap rates used to convert these into Australian dollars.[26]

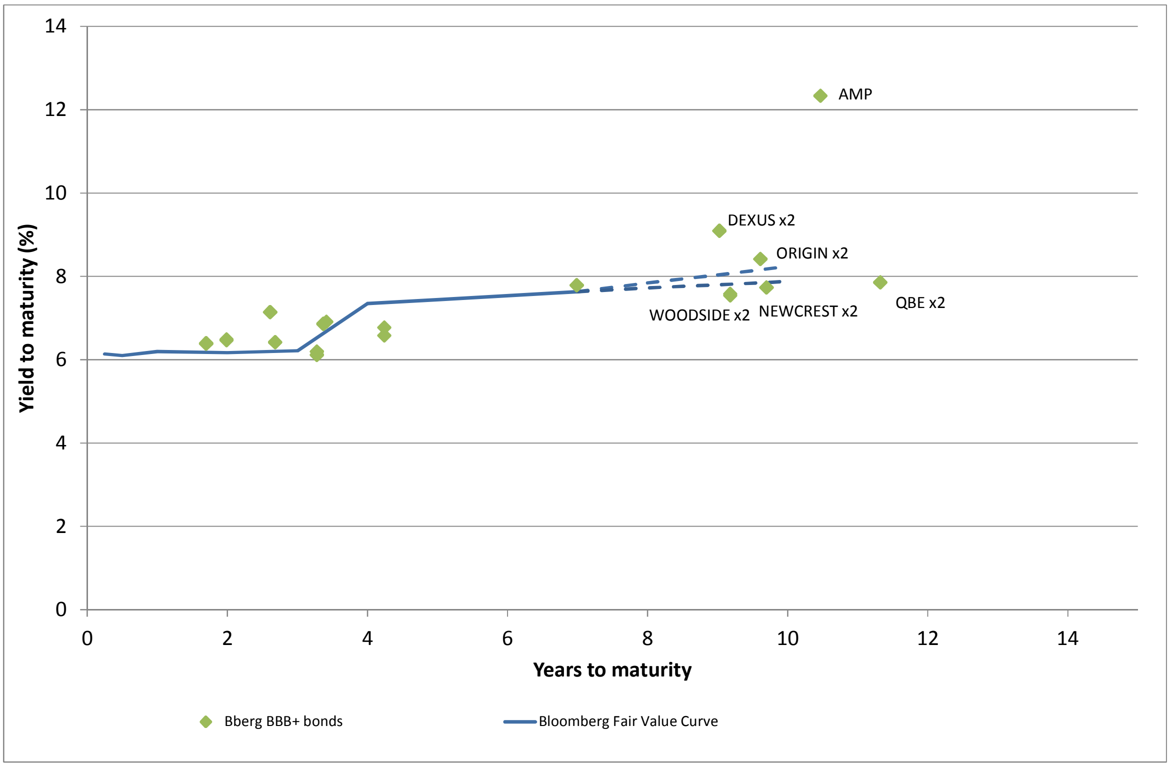
129. I have chosen to exclude all callable bonds that are not make-whole callable from this analysis. This is not because I believe that callable bonds should be excluded from the analysis. Rather, I do so because I wish to make distinct the impact of including foreign currency bonds from the impact of including callable bonds. Moreover, as will become clear in the following analysis, there are sufficient non-callable foreign currency bonds such that one can draw clear conclusions from the additional information. It is, therefore, not necessary to rely on callable bonds, and any contested adjustments thereto, in order to reach a conclusion on the reasonableness of the extrapolated Bloomberg BBB fair value curve.

130. In particular, there are a sufficient number of long dated BBB+ and similarly rated foreign currency bonds issued by Australian companies to allow a robust check on whether the extrapolated Australian Bloomberg BBB fair value curve is consistent with this data.

[25] Davis, K., *Determining debt costs in access pricing*, December 2010, p. 1

[26] Foreign currency yields have been sourced from Bloomberg's BVAL pricing source.

Figure 6: Yields on BBB+ bonds issued by Australian companies in a foreign currency swapped into Australian dollars



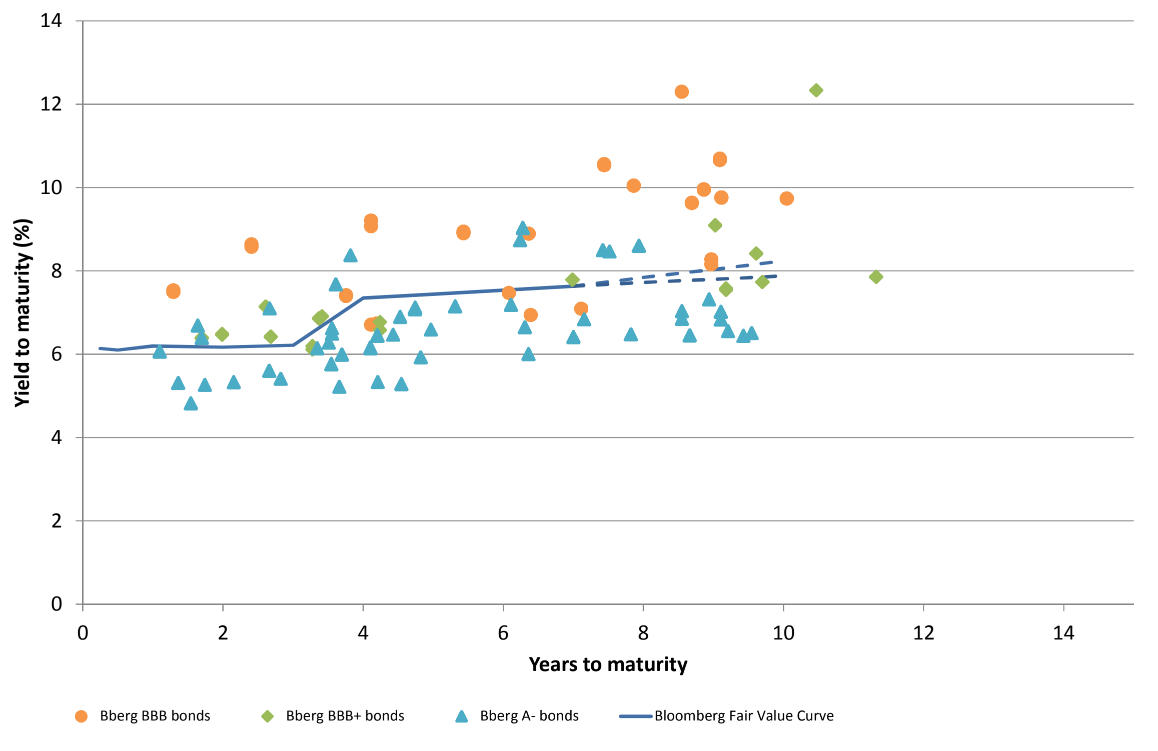
Source: Bloomberg and CEG analysis

Note: Data sourced as an average over 5 March 2012 to 30 March 2012 using cross-currency swap information as at 16 March 2012.

131. As can be seen in Figure 6 above, the yields on BBB+ foreign currency bonds issued by Australian companies and swapped back into Australian dollars provides a very good fit to the extrapolated Bloomberg fair value curve, with the possible exception of the AMP bond which is located considerably above the curve.

132. Following the same logic as was applied in the context of the analysis of Australian currency bonds issued by Australian companies, I now extend the relevant sample to include A- to BBB rated bonds.

Figure 7: Yields on A- to BBB bonds issued by Australian companies in a foreign currency swapped into Australian dollars



Source: Bloomberg and CEG analysis
Note: Data sourced as an average over 5 March 2012 to 30 March 2012 using cross-currency swap information as at 16 March 2012.

133. In this case the foreign currency bonds show a clearer pattern than the Australian currency bonds, with:

- BBB+ bond yields (swapped into Australian dollar terms) sitting mostly on or very close to the extrapolated Australian Bloomberg BBB fair value curve (the curve);
- BBB bonds sitting mostly above, but sometimes below, the curve; and
- A- bonds sitting mostly below, but sometimes above, the curve.

134. This foreign currency bond data provides support for my earlier conclusion, based on Australian currency bonds, that there is no basis for concluding that the extrapolated Australian Bloomberg BBB fair value curve does not provide a good fit for the available data.

5.2. Curve fitting on Australian dollar bonds

135. Since the Tribunal's decision in ActewAGL[27] it has been common practice to assess a benchmark estimate for a 10-year BBB+ DRP by reference to reported yields across credit ratings between BBB and A-. The AER now also has reference to this range of credit ratings in assessing the DRP.[28]

136. Although the AER explains the inclusion of BBB and A- rated bonds in its sample with reference to their 'similarity' to the benchmark bond, this is not identical to the reasoning by the Tribunal when it considered the evidence from these bonds:[29]

> *In the Tribunal's view, if it were reasonable not to include A- and BBB bonds in the population (because they are not representative of BBB+ bonds), it was unreasonable for the AER not to consider whether useful information could be obtained from taking these bonds into account without including them in the population. That A- yields sat above BBB+ yields should have indicated to the AER that by use of its methodology it may not have selected the fair value curve most likely to provide the best estimate of the benchmark bond yield.*

137. In the quote above, the Tribunal is specific that the AER should have had regard to the yields on A- and BBB bonds, not because they were 'representative of' (or similar to) BBB+ bonds, but because they provided information that was potentially relevant to the assessment of the best estimate of the benchmark yield.

138. Similarly, the AER in its Aurora and Powerlink draft decisions included in its bond sample only bonds with maturities of between 7 and 13 years. By doing so, the AER made no use of the information that is embodied in bonds with shorter maturities, or the Bloomberg fair value curves.[30] In fact, the AER draft decisions for Powerlink and Aurora did not show charts of the type that I have shown previously – where all bond yield data, including at short maturities, is included in the chart. I note that the AER's methodology in its draft decision for Powerlink has now been superseded by a final decision in which it has accepted the extrapolated Bloomberg BBB fair value curve pending an industry-wide consultation process.[31]

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27 *Application by ActewAGL Distribution* [2010] ACompT 4 (17 September 2010)

28 See for example, AER, *Draft distribution determination: Aurora Energy Pty Ltd*, November 2011, p. 249

29 *Application by ActewAGL Distribution* [2010] ACompT 4 (17 September 2010), para. 63

30 It is the case that the AER includes a 'sensitivity' where it includes all maturities between 5 and 15 years. However, it makes no use of yields on bonds with fewer than 5 years maturity (which, for the reasons described in the following section leads it into error) and even the 5 to 15 year 'sensitivity' is very crude. The AER simply takes an average of all bond yields in this range and makes no adjustment for the fact that, with the exception of one 15 year DBCT bond, the weight of the sample is very much biased to bonds with lower maturities than 10 years – as can be seen from Figure 2 noting that the AER exclusion of callable bonds and subordinated bonds would exclude all the A- bonds with maturities greater than 10 years in that figure.

31 AER, *Final decision: Powerlink transmission determination*, April 2012, p. 34

139. This failure to properly use information on shorter dated bonds to assess the reasonableness a long dated bond sample can lead to error. I have taken this information into account in the previous sections in a qualitative manner. Specifically, by placing all the yield data points, including at short maturity, on a graph and visually assessing whether the Bloomberg fair value curve is a good fit to that data. This approach ensures I do not incorrectly conclude that the 'true' fair value curve passes through a small sample of long dated bond yields when this conclusion would mean that such a curve must pass well below a larger sample of short dated bond yields.

140. I consider that this visual assessment is an appropriate basis on which to proceed for the purpose of testing whether there is a reason to depart from the Bloomberg fair value curve (which I consider is the appropriate default option for the reasons set out in section 4.1 above).

141. An alternative approach is the approach I adopt in this section, which is to use modelling techniques to estimate an alternative fair value curve based on data sourced from a greater range of credit ratings. This approach is reasonable as an additional cross-check on the reasonableness of the Bloomberg fair value. It is also an appropriate approach if one decided that an alternative to the Bloomberg fair value curve was required.

142. Both of the approaches adopted by me are consistent with the Tribunal's reasoning. The Tribunal's reasoning would justify reliance upon bonds of any credit rating or maturity, where these provide information that is relevant to assessing the benchmark yield. However, trying to use information from, say, two year A bonds to inform the yield on a 10-year BBB+ benchmark bond entails a greater degree of complexity than simply comparing yields to the benchmark.

143. In essence the AER's current practice in forming a sample of only BBB, BBB+ and A-rated bonds with maturities of 7 to 13 years to estimate the benchmark amounts to an implicit assessment that any adjustments required to compare yields across these credit ratings and maturities will be small. The exclusion of other credit ratings/maturities from the AER analysis implicitly reflects an assumption that required adjustments for these differences are both large and uncertain (possibly why the AER has not also considered BBB- and A bonds, for example).

144. However, it is not necessary to assume negligible adjustments between adjacent credit ratings or maturities and set aside the large amount of information available at other credit ratings and maturities when these factors are capable of being assessed qualitatively (as I have done in previous sections) or estimated empirically. In this section, I use the functional form for bond yields introduced by Nelson and Siegel[32] as a framework for processing the bond yield evidence from a much wider sample of bonds than relied upon by the AER.

[32] Nelson, C.R., and Siegel, A.F." Parsimonious Modeling of Yield Curves", *The Journal of Business*, Vol. 60, No. 4. (Oct., 1987), pp. 473-489.

145. I estimate Nelson-Siegel yield curves on three alternative datasets of bonds, relying upon progressively larger datasets. I consider that the application of this methodology provides compelling evidence that the preponderance of bond yield data is supportive of a 10 year BBB+ Australian corporate bond DRP consistent with the range of extrapolated Bloomberg BBB fair value estimates of 3.67% to 4.03%.

5.2.1. Yield curve functional form

146. I have applied a yield curve functional form based on the method introduced by Nelson and Siegel. Nelson and Siegel first used their technique to approximate yield curves for US Treasury bills. This functional form is widely used in the empirical finance literature on yield curves. For example, Christensen et al. state:

> *Our new AF model structure is based on the workhorse yield-curve representation introduced by Nelson and Siegel (1987). The Nelson-Siegel model is a flexible curve that provides a remarkably good fit to the cross section of yields in many countries, and it is very popular among financial market practitioners and central banks (e.g., Svensson, 1995, Bank for International Settlements, 2005, and Gurkaynak, Sack, and Wright, 2006).*[33] [34]

147. The Nelson-Siegel model provides a flexible functional form that allows for a variety of shapes one would expect a yield curve might take but which also limits the amount of computing power required to estimate the relevant parameters.

5.2.1.1. Nelson-Siegel method

148. The functional form used is as set out below:

$$Yield(t, rank) = \beta_{1,rank} + (\beta_2 + \beta_3)\frac{1 - e^{-t/\beta_0}}{t/\beta_0} - \beta_3 e^{-t/\beta_0}$$

149. Conceptually, parameter $\beta_{1,rank}$ can be interpreted as a long-term component (which never decays), β_2 as a short-term component (its loading starts nearly at 1, and then decays over term to maturity), β_3 as a medium-term component (its loading starts at zero, then peaks at some point, and then decays to zero again), and β_0 as a parameter characterising the speed of decay of the short-term and medium-term effects. Therefore, as the term to maturity increases, the estimated yield goes to $\beta_{1,rank}$ rather than to infinity as it would if I had adopted a linear or quadratic

[33] Christensen, Diebold and Rudebusch ,"The affine arbitrage-free class of Nelson–Siegel term structure models", Journal of Econometrics, Volume 164, Issue 1, 1 September 2011, Pages 4–20

[34] See, also Robert R. Bliss. "Testing Term Structure Estimation Methods". *Federal Reserve Bank of Atlanta*, Working Paper 96-12a, November 1996; Elton, Edwin J. Martin J. Gruber, Deepak Agrawal,and Christopher Mann. "Explaining the Rate Spread on Corporate Bonds". *The Journal Of Finance*, Vol. LVI, No. 1 (February 2001).

specification. The above parameters *rank* and t refer to the bond's credit rating and its term to maturity, respectively.

150. This functional form gives the curve the flexibility to take on many different shapes (from monotonically increasing to hump shaped) which allows the curve to be fitted to the data rather than enforcing a shape that may not be consistent with the underlying data.

151. I use this specification in order to estimate a family of yield curves – each corresponding to bonds with the same credit rating. However, by allowing β_1 to vary across credit ratings, I am effectively assuming that the shape of the curve is the same for all credit ratings but the level of the curve is different.

152. I consider that this is a reasonable assumption – especially for credit ratings that are close to each other. That is, I consider that it is reasonable to assume that the underlying shape of the A- and BBB fair value curves is very similar to that of the BBB+ curve. By fitting a different value for β_1 for each credit rating, I am able to use data from A- to BBB in order to inform the shape of the yield curve.

153. I assume that $\beta_{1,A} \leq \beta_{1,A-} \leq \cdots \leq \beta_{1,BBB-}$. With this adaptation, I estimate β_0, β_{1rank}, β_2, β_3 to minimise the sum of squared errors between the fair yield curves and the reported yield data.

154. It is worth noting that the regression above is non-linear due to the inclusion of the speed-of-decay parameter β_0, and many statistics used to evaluate goodness of fit of a linear regression are not suitable for this model.

5.2.1.2. Yield to maturity versus zero-coupon yield curve

155. I first perform my analysis using yield to maturity (YTM) and term to maturity of each bond as the input data. This results in fitted YTM curves consistent with the Bloomberg fair value curve and consistent with the standard way in which bond data has been analysed in regulatory proceedings to date.

156. I then perform analysis using bond prices, terms to maturity, and coupons as the input data. This allows me to estimate a zero-coupon yield curve (a.k.a. the "spot rates curve" or "spot curve"). A point on a zero-coupon yield curve, say at 10 years, represents the discount rate that should be applied to a payment that will be made in 10 years – with no payments between now and then. By contrast, the 10 year point on an YTM curve is the discount rate that, if applied to the final return of principle and all coupons paid before then, will give the present value of the bond's future payments equal to its assessed price.

157. The zero coupon yield at 10 years maturity is not directly comparable to the 10 year yield to maturity from the extrapolated fair value curve – with the latter being an average discount rate applied to coupons and principle while the former is the discount rate applied to 10 year principle only. However, a comparable yield to maturity value

can be calculated from the zero coupon curve by solving for the fixed coupon rate that would be necessary for a ten year bond to trade at par. I perform and report the results of these calculations below.

158. The YTM curve is technically simpler to estimate since all it requires is yield and maturity date information on the bond population to which the model is applied. By contrast, the spot curve is more computationally intensive but has the potential advantage that the estimated discount rates do not depend on the distribution of bonds' coupon rates in the sample.

159. There are seldom any direct observations of zero-coupon yields (they would only be observed for zero-coupon bonds). Hence, it is necessary to start with an assumed spot curve and then use it to compute the present value of all the future payments on each bond in my sample. This gives an estimated or "fitted price" for each bond in the sample. This "fitted price" of the bond then can be compared to its actual price to evaluate the quality of fit. A computer program is then used to repeat this process for different values of spot curve's parameters until the best fit to the data is made.

160. This more complex version of the Nelson-Siegel model gives rise to the following set of equations. Let:

$$r(t, rank) = \beta_{1,rank} + (\beta_2 + \beta_3)\frac{1-e^{-t/\beta_0}}{t/\beta_0} - \beta_3 e^{-t/\beta_0},\ rank = A, A-, \dots, BBB-$$

be the discount rate curve, where *t* refers to the time to the bond's next payment, which is to be discounted at rate $r(t, rank)$ and *rank* stands for bond's credit rating (as before, I allow the long-run values of the discount rates to vary, depending on the perceived bond's riskiness, as characterised by its credit rating).[35] Then, parameters $\beta_0, \beta_{1,rank}, \beta_2, \beta_3$ are chosen to minimise the weighted sum of squared pricing errors

$$\min \sum_{i=1}^{N} \left[w_i\left(P^A{}_i - \hat{P}_i\right)\right]^2$$

where $w_i = \frac{\frac{1}{d_i}}{\sum_{k=1}^{N}\frac{1}{d_k}}$, d_i is Macaulay duration of bond i, N is the total number of bonds in the sample, $P^A{}_i$ is the actual 'dirty' price of bond i, and $\hat{P}_i$ is the fitted price of bond i, defined below:

$$\hat{P}_i = \sum_t C_{it} e^{-r(t,rank)*t},$$

[35] Again, I assume that the long-term value of the discount rate for low-risk bonds is not higher than for high-risk bonds, that is, $\beta_{1,A} \leq \beta_{1,A-} \leq \cdots \leq \beta_{1,BBB-}$.

where C_{it} is a cash flow on bond i promised to be paid t years from now.

161. The method described above provides the estimates of discount rates for bonds of different maturity and credit ratings. However, the BBB+ 10-year discount rate will not fully reflect the cost of debt associated with issuing a 10-year coupon paying bond. To the extent that what we are interested in the coupon rate on a bond issued at par then one needs to calculate this coupon rate from the estimated zero-coupon rates. I do this to arrive at "par-yield" curves – ie, coupon rates that would price a bond at par, given discounting based on the zero-coupon yield curve.

5.2.1.3. Bond yield data

162. In setting up the dataset for this analysis I have been careful to exclude all bonds issued by:

- sovereign governments and their agencies;
- state or provincial governments;
- local or municipal authorities;
- supranational bodies that are supported by governments; and
- bonds explicitly guaranteed by sovereign governments.

163. I have also excluded all bonds that are callable, but not make whole callable, from the analysis. This is not because these bonds do not contain information relevant to the benchmark yield but is a simplification I have made:

- to avoid a point of contention on this issue; and
- due to the extra manual calculations that would be needed to estimate the yield adjustments required to each of these bonds to remove the value of the call options.

164. All yields have been sourced from UBS or Bloomberg, or an average of the two if both are available. I have not attempted to identify and exclude potential outliers from this sample. This means that I have not excluded from this analysis the low-yielding Coca Cola Amatil or SPI E&G bonds whose inclusion in the AER's much smaller sample of bonds I object to.

5.2.2. Estimation of a YTM fair value curve

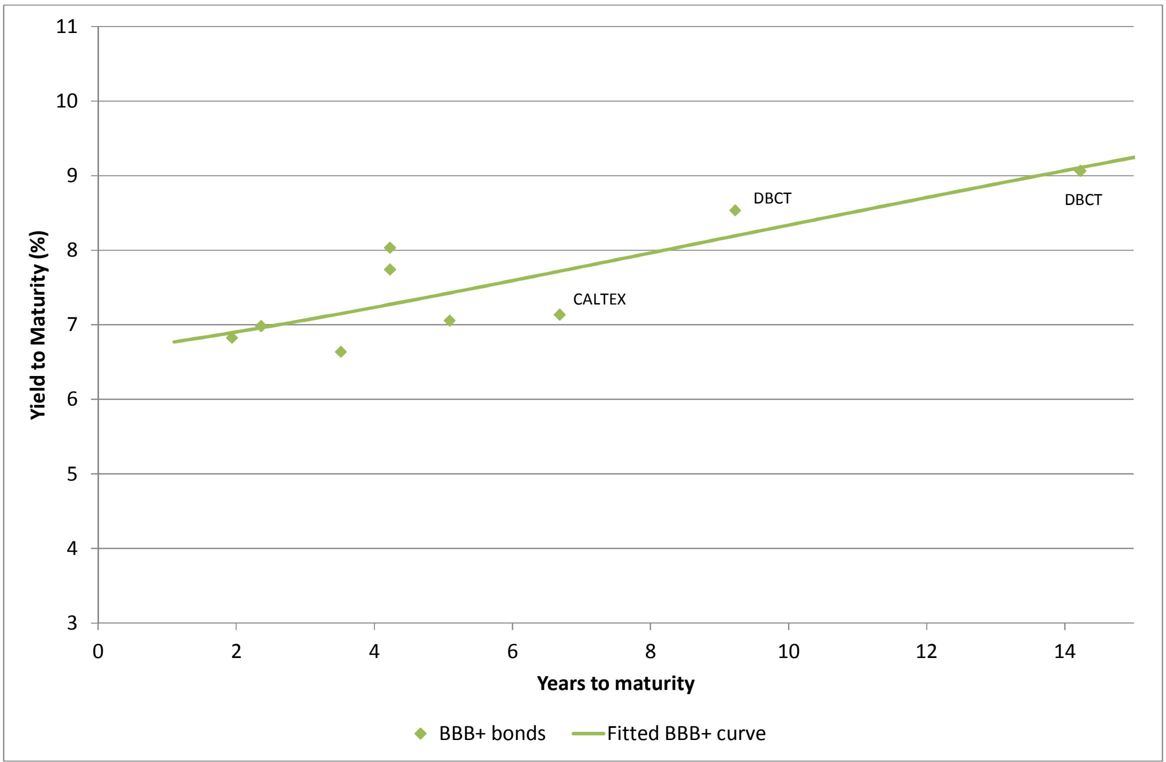
165. I have estimated the Nelson-Siegel equations across three bond populations of bonds issued by Australian companies. Initially I apply the technique to BBB to A- Australian dollar bonds, effectively the same population of bonds identified at section 4.2 above. I then expand this sample further by having regard to BBB to A- bonds issued by Australian issuers in foreign currencies. Finally, I apply the technique across bonds

issued by Australian corporate issuers with credit ratings with Standard and Poor's between BBB- and A.

5.2.2.1. Australian issued Australian dollar bonds rated BBB+ only

166. I estimate the YTM yield curves across 9 bonds issued by Australian firms in Australian dollars, rated BBB+ only by Standard and Poor's. The curve estimates across this dataset is shown in Figure 8 below.

Figure 8: Australian issued Australian dollar bonds rated BBB+ only



Source: Bloomberg, UBS, RBA and CEG analysis
Note: Observations sourced as an average over 5 March 2012 to 30 March 2012. Fitted curve calculated as an average over the same period.

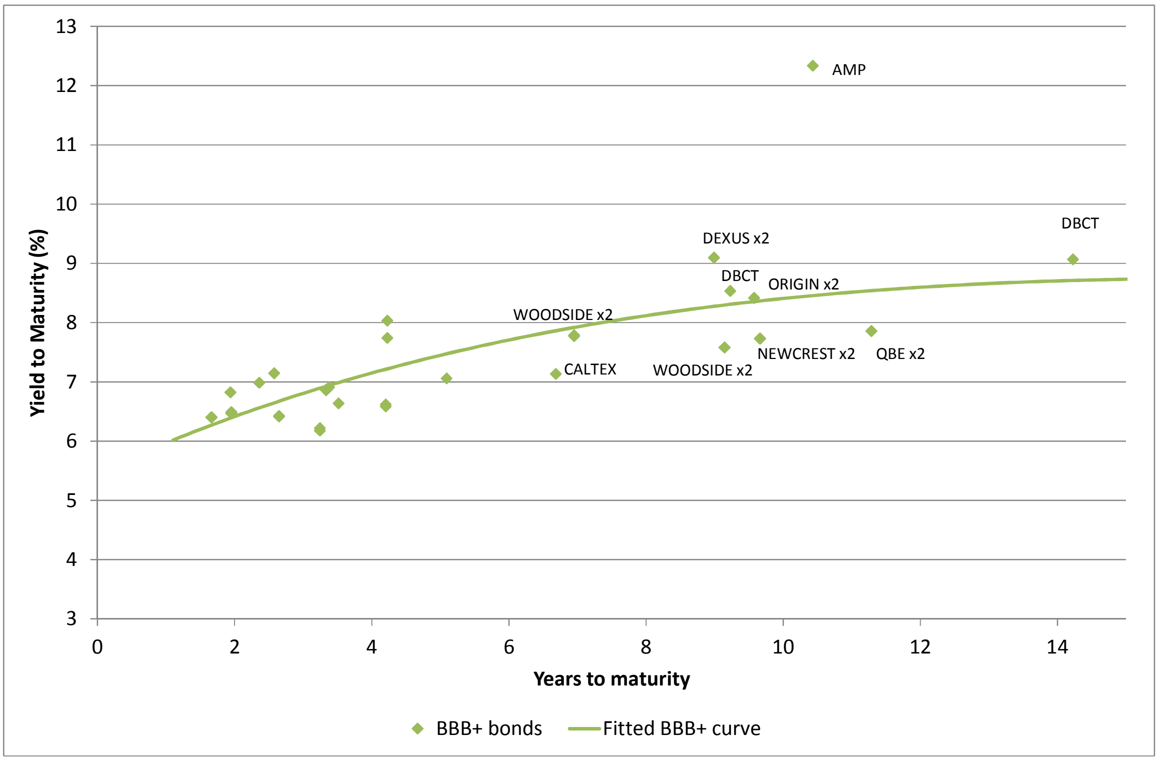
167. At 10 years, the BBB+ yield is estimated to be 8.34%, equivalent to a DRP of 4.13%. This compares with the range of 3.67% to 4.03% estimated using the extrapolated Australian Bloomberg BBB fair value curve.

168. To be consistent in my analysis, I have removed all the bonds with term to maturity of less than a year. Under the current scenario, it meant removing 3 BBB+ bonds that mature on 25 February 2013. It is worth noting, that leaving these three bonds in the sample barely alters the results: the BBB+ yields estimate is 8.35% and that of the DRP is 4.13%.

5.2.2.2. *Australian issued bonds rated BBB+ only*

169. Further including foreign currency bonds issued by Australian companies (swapped back to Australian dollars) increases the dataset of bonds to 41. The curve estimated across this larger dataset is shown in Figure 9 below.

Figure 9: Australian issued bonds rated BBB+ only



Source: Bloomberg, UBS, RBA and CEG analysis
Note: Observations sourced as an average over 5 March 2012 to 30 March 2012. Fitted curve calculated as an average over the same period.

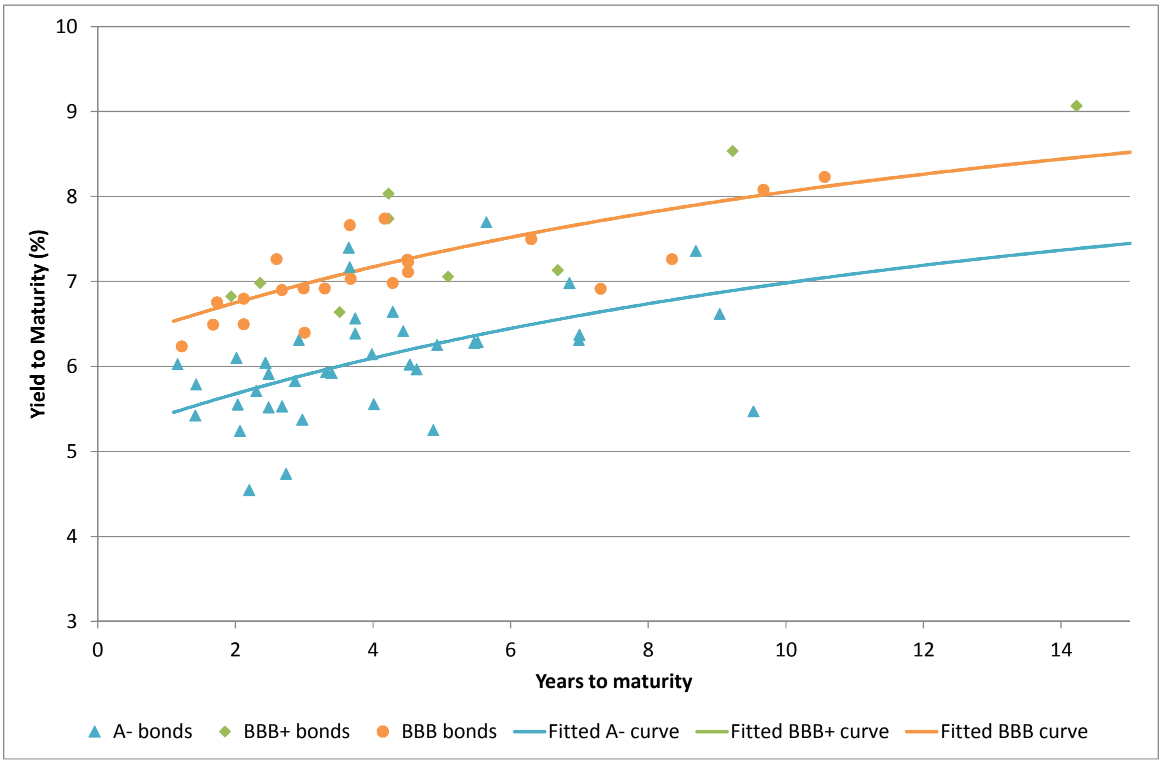
170. At 10 years, the BBB+ yield is estimated to be 8.41%, equivalent to a DRP of 4.20%. This compares with the range of 3.67% to 4.03% estimated using the extrapolated Australian Bloomberg BBB fair value curve.

5.2.2.3. *Australian issued Australian dollar bonds rated BBB to A-*

171. I estimate the YTM yield curves across 70 bonds issued by Australian firms in Australian dollars, rated BBB to A- by Standard and Poor's. I generate fair value curves for each of the BBB, BBB+, and A- credit ratings from this dataset.

172. The BBB+ curve estimated on this dataset is coincident with the BBB curve. This is a reflection of the dataset used which, as demonstrated in Figure 10 below, does not show a material difference in average yields for BBB and BBB+ bonds. By contrast, the A- fair value curve does have a materially lower yield.

Figure 10: Australian issued Australian dollar bonds rated BBB to A-



Source: Bloomberg, UBS, RBA and CEG analysis
Note: Observations sourced as an average over 5 March to 30 March 2012. Fitted curve calculated as an average over the same period.

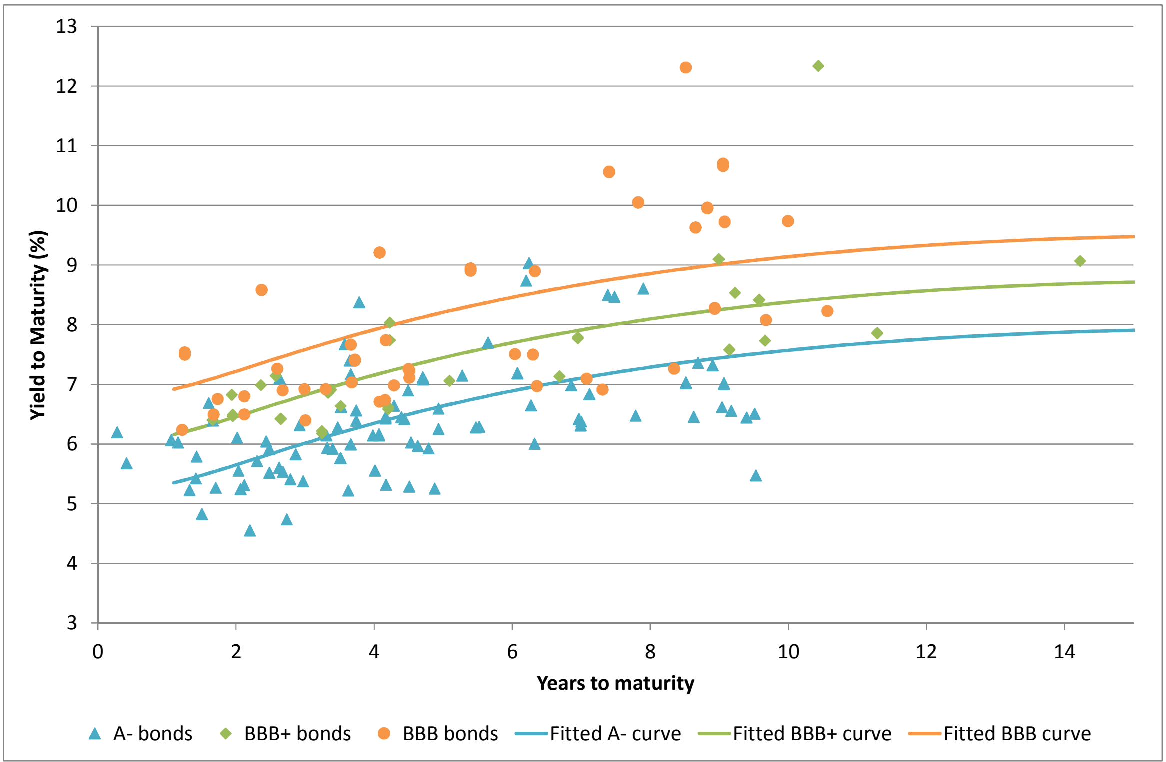
173. At 10 years, the BBB+ yield is estimated to be 8.05%, equivalent to a DRP of 3.84%. This compares with the range of 3.67% to 4.03% estimated using the extrapolated Australian Bloomberg BBB fair value curve.

5.2.2.4. Australian issued bonds rated BBB to A-

174. Further including foreign currency bonds issued by Australian companies (swapped back to Australian dollars) increases the dataset of bonds by 133 bonds (giving 203 observations in total) is available if yields on foreign currency bonds rated BBB to A- issued by Australian firms are also used.[36] Curves estimated on the augmented dataset are shown in Figure 11 below.

[36] Where these yields are swapped into Australian dollar terms using the process described at section 5.1.2 and Appendix D.

Figure 11: Australian issued bonds rated BBB to A-



Source: Bloomberg, UBS, RBA and CEG analysis
Note: Observations sourced as an average over 5 March to 30 March 2012. Fitted curve calculated as an average over the same period.

175. I note that once these foreign currency bonds (swapped back into Australian dollar terms) are included in the sample the estimated BBB fair value curve is clearly above the estimated BBB+ fair value curve.

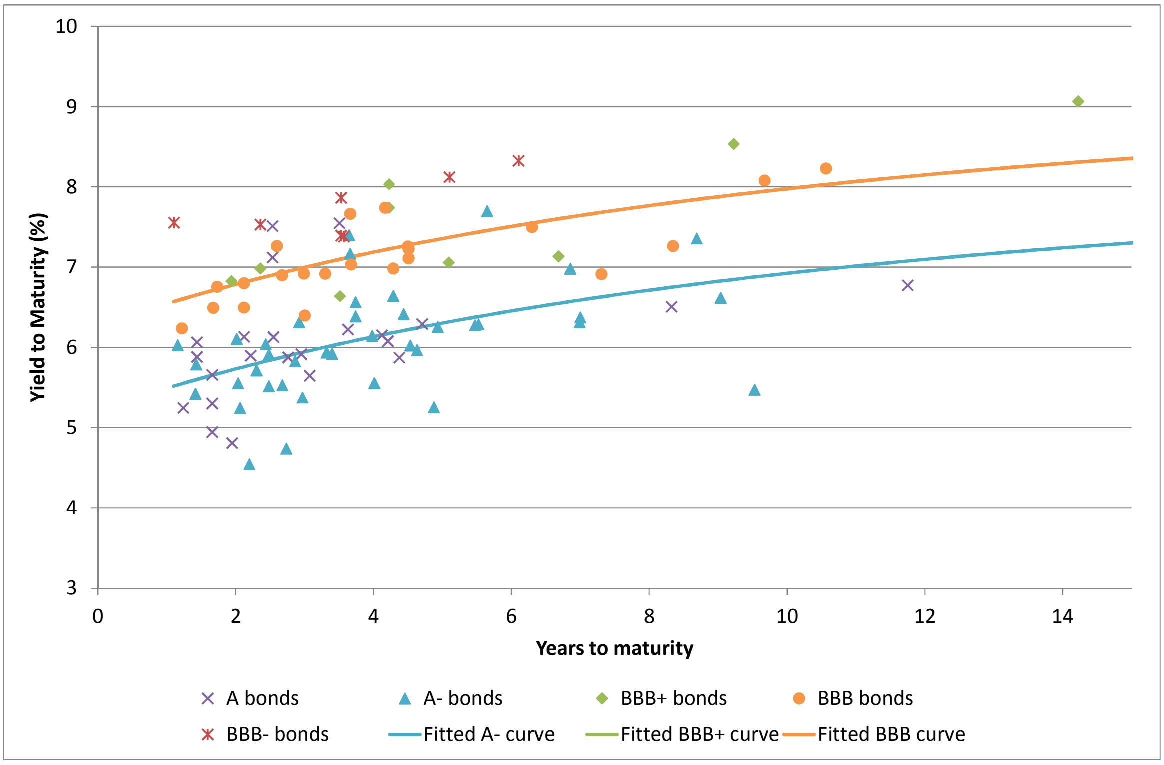
176. At 10 years, the BBB+ yield is estimated to be 8.38%, equivalent to a DRP of 4.17%. This compares with the range of 3.67% to 4.03% estimated using the extrapolated Australian Bloomberg BBB fair value curve.

5.2.2.5. Australian issued Australian dollar bonds rated BBB- to A

177. The generality of the technique described in this section is such that it can be applied to utilise yield information obtained from a wider range of credit ratings. It is important to note that the information obtained from other credit ratings would not be expected to have an effect on the level of the BBB+ curve *per se*, but could provide information that would affect its shape and therefore the yield estimate at 10 years.

178. Consideration of a wider dataset of Australian dollar bonds rated between BBB- and A gives a population of 100 bonds. Curves estimated on this dataset are shown in below. As before, the estimated fair value curves for BBB and BBB+ bonds coincide.

Figure 12: Australian issued Australian dollar bonds rated BBB- to A



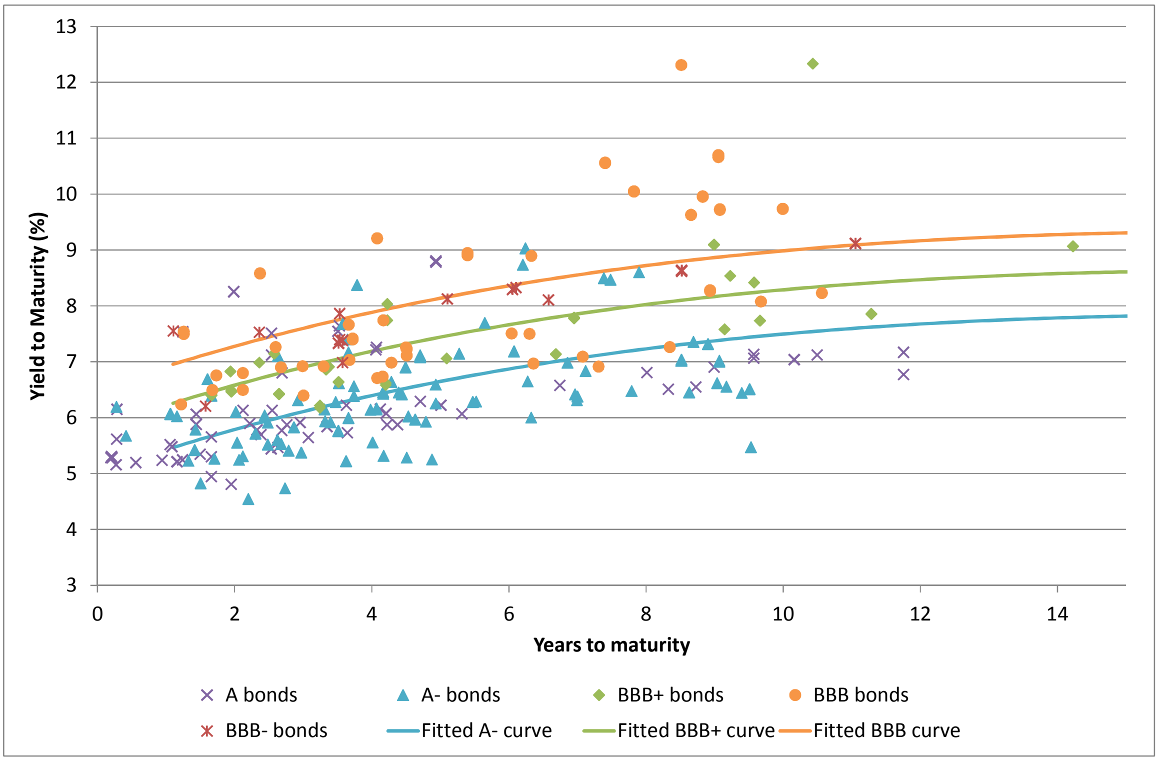
Source: Bloomberg, UBS, RBA and CEG analysis
Note: Observations sourced as an average over 5 March to 30 March 2012. Fitted curve calculated as an average over the same period.

179. At 10 years, the BBB+ yield is estimated to be 7.98%, equivalent to a DRP of 3.76%. This compares with the range of 3.67% to 4.03% estimated using the extrapolated Australian Bloomberg BBB fair value curve.

5.2.2.6. Australian issued bonds rated BBB- to A

180. Extending the dataset further to include all Australian issued bonds (including foreign currency bonds swapped back to Australian dollars) rated between BBB- and A gives a population of 276 bonds. Curves estimated on the augmented dataset are shown in Figure 13 below.

Figure 13: Australian issued bonds rated BBB- to A



Source: Bloomberg, UBS, RBA and CEG analysis
Note: Observations sourced as an average over 5 March 2012 to 30 March 2012. Fitted curve calculated as an average over the same period.

181. At 10 years, the BBB+ yield is estimated to be 8.29%, equivalent to a DRP of 4.08%. This compares with the range of 3.67% to 4.03% estimated using the extrapolated Australian Bloomberg BBB fair value curve.

5.2.3. Application of zero coupon Nelson-Siegel yield curves to estimate par yield curves

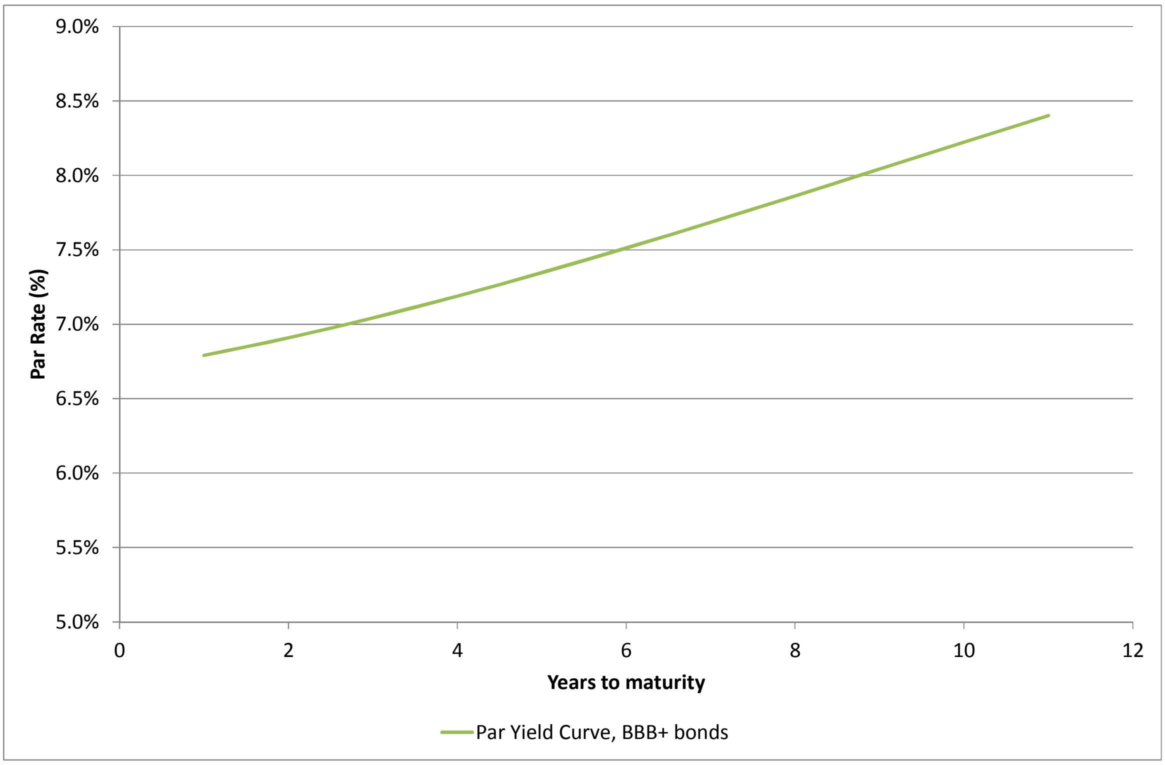
182. I describe in section 5.2.1.2 the process of how I estimate zero-coupon yield curves using the Nelson-Siegel approach and estimate from these par yield curves. I have conducted this analysis for the samples of Australian issued Australian dollar bonds considered in section 5.2.2 above. It would be computationally complex to use bonds issued in foreign currency in the construction of this curve as each coupon would need to be swapped back into Australian dollars individually (rather than each bond). The par yield curves are derived so as to have a single (ie, annualised) coupon for easier interpretation.

183. In each of the diagrams below the par yield curves are shown in isolation without the backdrop of observations. This is not because the curves do not use information from the bond yield observations (in fact, they use more information than the yield to maturity curves derived above) but rather because it is incorrect to directly compare par yield curves with yields to maturity at various different coupon rates.

5.2.3.1. Australian issued Australian dollar bonds rated BBB+ only

184. The BBB+ par yield curve estimated across the dataset of Australian issued Australian dollar bonds rated BBB+ only is shown at Figure 14 below.

Figure 14: Par yield curve for Australian issued Australian dollar bonds rated BBB+ only



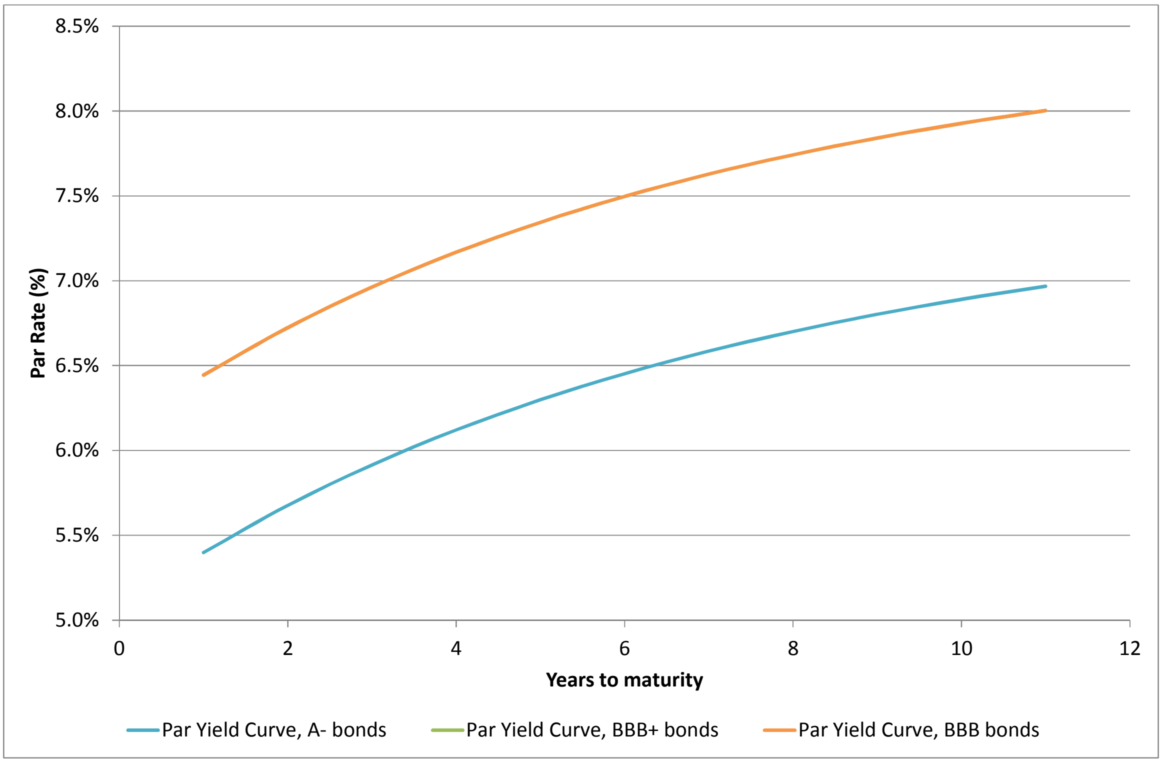
Source: Bloomberg, UBS, RBA and CEG analysis
Note: Observations sourced as an average over 5 March 2012 to 30 March 2012. Fitted curve calculated as an average over the same period.

185. The annual coupon estimated on a 10-year BBB+ bond trading at par is estimated to be 8.22%, equivalent to a DRP of 4.01%. This compares with the range of 3.67% to 4.03% estimated using the extrapolated Australian Bloomberg BBB fair value curve.

5.2.3.2. Australian issued Australian dollar bonds rated BBB to A- only

186. The par yield curves estimated across the dataset of Australian issued Australian dollar bonds rated BBB to A- only is shown at Figure 15 below.

Figure 15: Par yield curve for Australian issued Australian dollar bonds rated BBB to A-



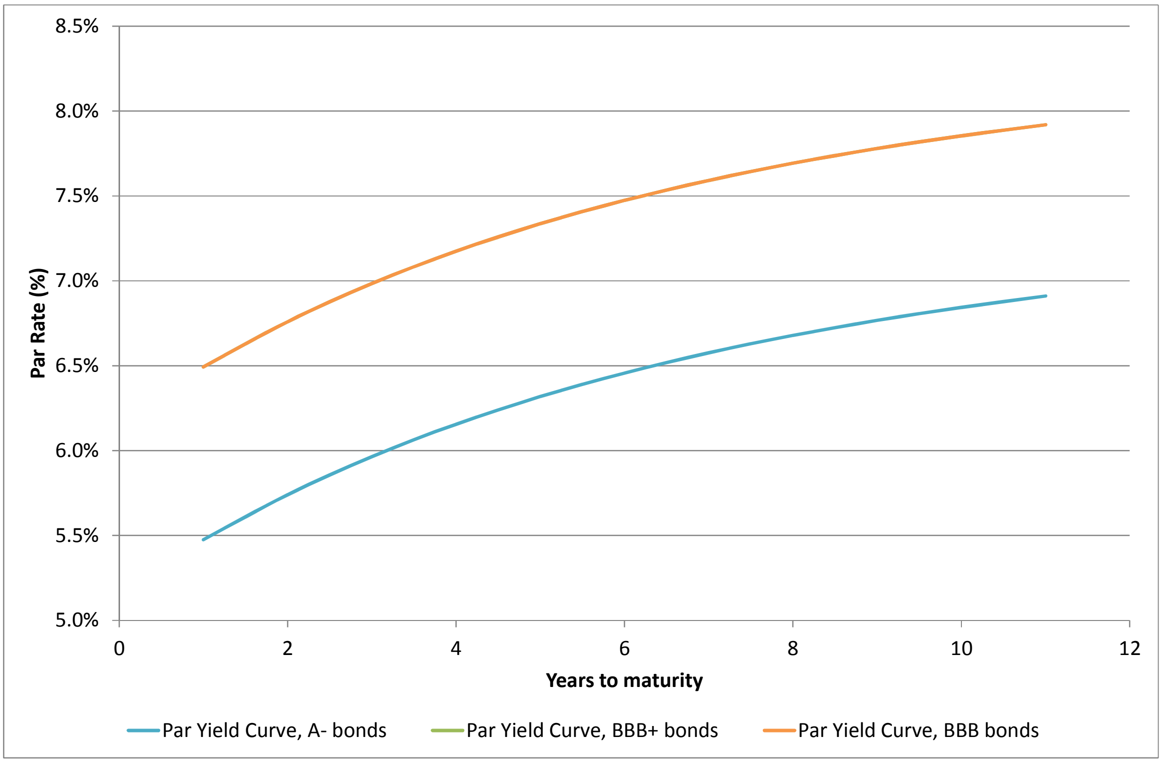
Source: Bloomberg, UBS, RBA and CEG analysis
Note: Observations sourced as an average over 5 March 2012 to 30 March 2012. Fitted curve calculated as an average over the same period.

187. In this chart, as with the equivalent yield to maturity chart at Figure 10, the curves estimated for BBB+ and BBB are coincident. The annual coupon estimated on a 10-year BBB+ bond trading at par is estimated to be 7.93%, equivalent to a DRP of 3.72%. This compares with the range of 3.67% to 4.03% estimated using the extrapolated Australian Bloomberg BBB fair value curve.

5.2.3.3. Australian issued Australian dollar bonds rated BBB- to A only

188. The par yield curves estimated across the dataset of Australian issued Australian dollar bonds rated BBB- to A only is shown at Figure 16 below.

Figure 16: Par yield curve for Australian issued Australian dollar bonds rated BBB- to A



Source: Bloomberg, UBS, RBA and CEG analysis
Note: Observations sourced as an average over 5 March 2012 to 30 March 2012. Fitted curve calculated as an average over the same period.

189. The annual coupon estimated on a 10-year BBB+ bond trading at par is estimated to be 7.85%, equivalent to a DRP of 3.64%. This compares with the range of 3.67% to 4.03% estimated using the extrapolated Australian Bloomberg BBB fair value curve.

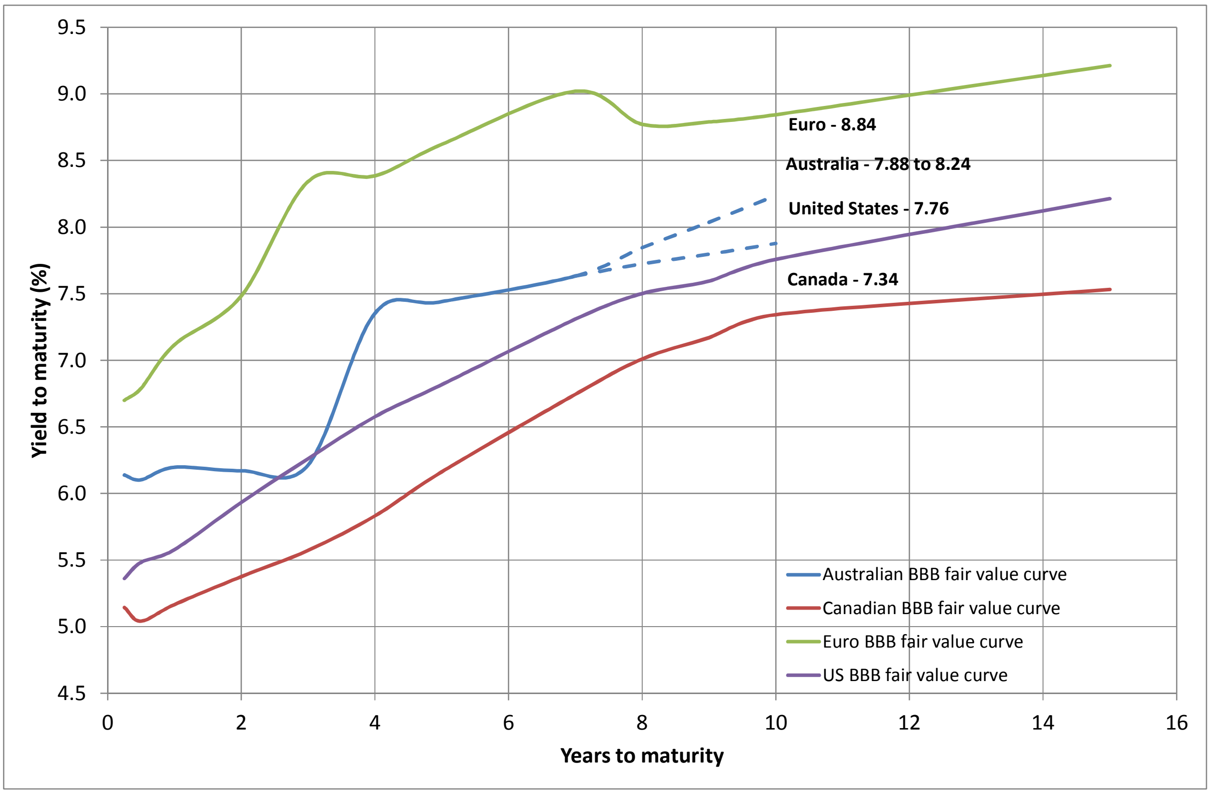
5.3. Foreign fair value curves

190. At section 5.1 above I discuss the availability of evidence from Australian bonds issued in foreign currencies. I consider that this provides an additional source of evidence against which to test potential candidates for extrapolation.

191. In addition to individual bond yields, I have also sourced Bloomberg fair value curves from foreign jurisdictions. These curves can potentially be used as a cross-check on the reasonableness of the Bloomberg fair value curve in Australia. However, these curves represent an estimate for the cost of debt of foreign firms which may be affected by factors not relevant to Australian firms. Consequently, these comparisons are best considered providing only a high level source of information – one that might provide a basis for further investigation of other facts rather than a basis for any strong conclusion on its own.

192. Figure 17 below shows Bloomberg BBB composite fair value curves in Australia, the Eurozone, the US and Canada. The non-Australian fair value curves have been converted into Australian dollar yields using cross currency swap rates available from Bloomberg (see Appendix D for more detail on this conversion process). The Australian curve is extrapolated beyond 7 years using the range discussed in greater detail at section 6 below.

Figure 17: BBB fair value curves – Australia and other jurisdictions



Source: Bloomberg and CEG analysis
Note: Fair value curve yields calculated as an average over 5 March 2012 to 30 March 2012

193. I note that the Australian fair value curve sits close to the US fair value curve and below the Euro fair value curve. This comparison provides no reason to believe that the Australian Bloomberg BBB fair value curve is 'out of kilter' with foreign fair value curves.

6. Extrapolation of the Bloomberg fair value curve

194. Bloomberg's BBB fair value curve extends to 7 years maturity, and Bloomberg has not reported a 10-year BBB fair yield since November 2007. In order to use the information provided by Bloomberg it is necessary to extrapolate its BBB fair value curve to 10 years.

195. In my opinion, it is preferable that this extrapolation is based upon information that is reflective of current market conditions. This is because it is not necessarily the case that one would expect this extrapolation to remain unchanged over a long period of time.

196. In recent reports I have recommended to extrapolate the Bloomberg BBB fair value curve from 7 to 10 years using information from the Bloomberg AAA fair value curve between 7 and 10 years for the 20 days in which it was most recently reported (ie, 20 days to 22 June 2010).[37]

197. In its Aurora and Powerlink draft decisions, although the AER did not use the Bloomberg BBB fair value curve to estimate the DRP, it criticised the ongoing application of this extrapolation methodology. It considered that using this methodology did not reflect "current circumstances in the Australian bond market".[38] However, the AER did not propose an alternative methodology by which the Bloomberg BBB fair value curve could be extrapolated which would reflect these circumstances. Ultimately, in its final decision for Powerlink, it accepted the use of this extrapolation methodology pending an industry-wide consultation process.[39]

198. I agree with the AER's views in its draft decisions that the use of the historical AAA fair value information to extrapolate the BBB fair value curve no longer appears consistent with market conditions, at least for the 5 March 2012 to 30 March 2012 period examined in this report. In this report I have been able to source a greater variety of alternative extrapolations for the Bloomberg BBB fair value curve.

6.1. Testing process previously conducted

199. Although I originally proposed using historical estimates from the Bloomberg AAA fair value curve as a method for extrapolation in 2010,[40] I did not envisage that it would remain appropriate to apply without review for an extended period into the future.

[37] As applied in its final decision for the Amadeus Gas Pipeline, see AER, *Final decision: Access arrangement proposal for the Amadeus Gas Pipeline*, July 2011, p.165

[38] See AER, *Draft Distribution Determination: Aurora Energy Pty Ltd*, November 2011, p. 248

[39] AER, *Final decision: Powerlink transmission determination*, April 2012, p. 34

[40] CEG, *Use of the APT bond yield in establishing the NER cost of debt*, October 2010, pp. 49-56

200. I have conducted such a review for data sourced from May 2011 for APT Petroleum Pipelines, where I concluded that this extrapolation method was still superior to a number of alternatives and generally consistent with contemporaneous market evidence.[41] Alternatives explored in that report included:

- extrapolation based on the shape of the CGS curve (ie, constant DRP between 7 and 10 years);
- linear extrapolation between 7 and 10 years; or
- extrapolation based on trends identified between pairs of bonds with the same issuer dated at approximately 7 and 10 years.

201. I found that none of these alternatives were ideal. Extrapolation based on CGS implied that there would be no increase in DRP between 7 and 10 years. Linear extrapolation produced too high a DRP to appear reasonable in the period under consideration. Extrapolation based on information obtained from bond yields appears sound in principle, however in practice there were too few pairs of bonds to provide a robust sample for extrapolation. Furthermore, extrapolation based on the AAA fair value curve appeared consistent with the bond yield information in that period.

202. On this basis, I recommended the continuing use of the Bloomberg AAA fair value curve information from 2010 to extrapolate the DRP calculated on the Bloomberg BBB fair value curve from 7 to 10 years during May 2011.

6.2. Evidence from paired Australian bonds

203. In theory, it should be possible to discern from reported bond yield data what an average or 'normal' increase in DRP between 7 and 10 years might be. This can be done by comparing the calculated DRPs on bonds, issued by the same issuer, with maturities close to 7 years and 10 years respectively. Ideally these issuers would be rated BBB+, or close to BBB+, since it would not necessarily be the case that the increase in DRP between 7 and 10 years would be the same at very different credit ratings.

204. However, it is unsurprising to note that there are very few issuers that have issued two long-dated bonds that just happen to have maturities close to 7 and 10 years. Based on my search for issuers rated between BBB- and A, only Sydney Airport has bonds that come within a year of these criteria. Relaxing the tolerance still further, bonds issued by SPI E&G come close to meeting these criteria. I have also seen analysis conducted by PwC which used pairs of bonds issued by Stockland and Telstra for the same purpose in a report for Powerlink.[42] I show the evidence obtained from each of these pairs in Table 5 below.

[41] CEG, *Estimating the debt risk premium for the Roma to Brisbane pipeline*, October 2011, pp. 24-29

[42] PwC, *Debt Risk Premium and Equity Raising Costs*, January 2012, pp. 15-16

Table 5: Extrapolation evidence from paired Australian bonds

Issuer	ISIN short maturity	ISIN long maturity	Short maturity (years)	Long maturity (years)	UBS DRP increase per year (basis points)	Bloomberg DRP increase per year (basis points)
Sydney Airport	AU3CB0176485	AU3FN0001244	6.34	9.71	2.2	-
Sydney Airport	AU3CB0176485	AU3FN0001251	6.34	10.60	3.4	-
SPI E&G	AU3CB0145696	AU3CB0173482	5.56	9.07	-2.4	6.7
Stockland (PwC)	AU3CB0138030	AU3CB0164820	2.96	8.73	-	12.0
Stockland	AU3CB0166122	AU3CB0164820	4.32	8.73	-	8.4
Telstra (PwC)	AU300TY30597	AU3CB0152940	4.41	8.36	7.4	7.7
Telstra	AU3FN0000931	AU3CB0152940	4.74	8.36	-3	-

Source: UBS, Bloomberg, RBA and CEG analysis
Note: DRPs assessed on average over 5 March 2012 to 30 March 2012

205. Table 5 includes two pairs of Sydney Airport bonds because two long dated bonds around 10 years maturity exist. For Stockland and Telstra, I have included PwC's bond pairing but have also found alternative pairs from the same issuer where the shorter dated bond is slightly closer to 7 years and have included these for comparison.

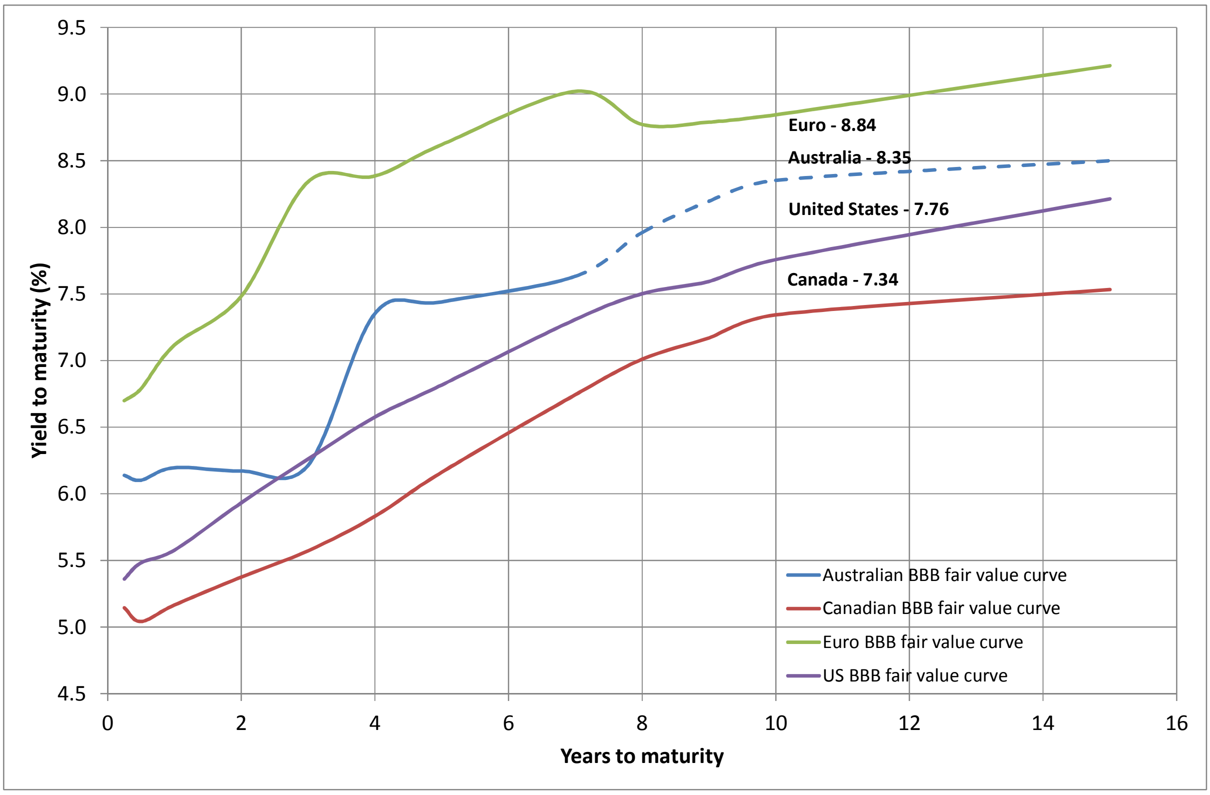
206. I consider that the evidence based on actual bond yields for the increase in DRP between 7 and 10 years is mixed. The most relevant evidence is available from Sydney Airport. Bloomberg-based evidence for Stockland and the first Telstra suggest much higher DRP increase, while UBS data for SPI E&G and the second Telstra pair imply decreasing DRP.

6.3. Availability of new information from foreign currency sources

207. In addition to individual bond yields, in section 5.3 I source Bloomberg BBB composite fair value curves from foreign jurisdictions.

208. Figure 17 below shows these foreign fair value curves against Bloomberg's Australia BBB fair value curve. The extrapolation shown for the Australian curve beyond 7 years uses AAA fair values sourced from June 2010.

Figure 18: BBB fair value curves – Australia and other jurisdictions



Source: Bloomberg and CEG analysis
Note: Fair value curve yields calculated as an average over 5 March 2012 to 30 March 2012

209. I note that the Australian fair value curve sits close to the US fair value curve and materially below the Euro fair value curve at 7 years and similarly at maturities lower than this. However, beyond seven years the extrapolation based on historical Bloomberg AAA fair values flattens and grows slower than both the US and Euro fair value curves.

6.4. Extrapolation implied by fitted curves

210. In section 5.2 above, I estimate a number of curves fitted to a number of alternative samples of bonds. Each of these gives rise to its own estimate of the increase in DRP between 7 and 10 years. These results are summarised in Table 6 below. The average increase in DRP per year is calculated based upon an average increase in CGS yields between 7 and 10 years of 24.5 basis points over the period between 5 March 2012 and 30 March 2012.

Table 6: Extrapolation based on CEG curve fitting

Bond sample	Yield at 7 years (%)	Yield at 10 years (%)	Average increase in DRP per year (bp)
Yield to maturity analysis			
BBB+ Australian only	7.78%	8.34%	10.5
BBB+ Australian and foreign	7.93%	8.41%	7.8
BBB to A- Australian only	7.67%	8.05%	4.6
BBB to A- Australian and foreign	7.91%	8.38%	7.4
BBB- to A Australian only	7.64%	7.98%	2.9
BBB- to A Australian and foreign	7.86%	8.29%	6.2
Par yield analysis			
BBB+ Australian only	7.69%	8.22%	9.7
BBB to A- Australian only	7.63%	7.93%	1.8
BBB- to A Australian only	7.59%	7.85%	0.6

Source: CEG analysis based on Bloomberg, UBS and RBA data

211. The extrapolation results between 7 and 10 years from Table 6 above are quite varied, and range from 0.6bp to 10.5bp depending on the data coverage and the methodology employed.

6.5. Consideration of extrapolation options

212. I consider that this information is best used to assess extrapolation methodologies using this information in the context of the other information that I have considered above.

213. This context is provided Table 7 below, where I review all relevant extrapolation results. In addition to the information that I survey at sections 6.2, 6.3 and 6.4 above, I also include in this table information on the long term average extrapolation obtained along the Australian Bloomberg BBB and AAA fair value curves.[43]

[43] I include this information as it was also considered by the AER in its recent Aurora and Powerlink draft decisions.

Table 7: Range of information relevant to extrapolation

Extrapolation methodology	Average increase in DRP per year (bp)
Bond pair analysis	
Sydney Airport bond pair	2.2 to 3.4
Stockland bond pair	8.4 to 12.0
Telstra bond pair	-3.0 to 7.7
SPI E&G bond pair	-2.4 to 6.7
Foreign fair value curve analysis	
United States Bloomberg composite BBB fair value curve	6.8
Euro Bloomberg composite BBB fair value curve	-14.0
Canada Bloomberg composite BBB fair value curve	11.8
CEG curve fitting analysis	
Yield to maturity domestic	2.9 to 10.5
Yield to maturity domestic and foreign	6.2 to 7.8
Par yield domestic	0.6 to 9.7
Historical Bloomberg fair values	
Australian Bloomberg AAA fair value curve (June 2010)	15.9
Australian Bloomberg AAA fair value curve (2000 - 2010)	3.6
Australian Bloomberg BBB fair value curve (2001 – 2007)	2.5

214. Table 7 shows a very wide range of potential extrapolations. Setting aside the extrapolations based on the Euro Bloomberg BBB composite fair value curve, and Stockland and Telstra bond pairs, which appear to be outliers, I consider that a lower bound for any reasonable extrapolation would be to assume a flat DRP curve. Similarly, setting aside the very highest potential extrapolation based on Australian Bloomberg AAA fair value curve, an upper bound for extrapolation based on this period would appear to be approximately 12 basis points per annum.

215. On the basis of the considerations above, I consider that a reasonable extrapolation methodology for extending the Bloomberg BBB fair value curve from 7 to 10 years over 5 March 2012 to 30 March 2012 would result in an increase in DRP of between 0 and 12 basis points per year, for a total of between 0 and 36 basis points.

216. This range corresponds to a range for the 10-year DRP based on extrapolation of the Bloomberg BBB fair value curve of 3.67% to 4.03%, being:

- the average annualised Australian Bloomberg BBB 7-year fair value over 5 March 2012 to 30 March 2012 of 7.63%; less
- the average annualised 7-year CGS yield over 5 March 2012 to 30 March 2012 of 3.97%; plus
- a range of 0.00% to 0.36%, being between 0 and 12 basis points per annum for three years.

217. I consider that this range represents reasonable estimates for the DRP, having regard to the uncertainty associated with extrapolation of the Bloomberg BBB fair value curve from 7 to 10 years. I note that this range lies beneath the 4.14% estimate that is generated by using the historical Bloomberg AAA fair value curve between 7 and 10 years to achieve this extrapolation.

218. Western Power's proposed DRP of 3.67%, based upon the use of Bloomberg's 7-year BBB fair value estimate, lies at the bottom end of this range. I therefore consider that Western Power's estimate is consistent with the requirements of the Access Code in providing a forward-looking and efficient estimate of financing costs commensurate with the commercial risks involved in providing covered services.

219. The ERA's estimate of DRP in its draft decision of 2.03% is 1.64% lower than the bottom end of this range. I do not consider that the ERA's estimate of DRP is consistent with the requirements of the Access Code.

7. ERA's proposed methodology

220. The ERA utilises a benchmark bond of A- and maturity of 5 years in its draft decision for Western Power. It estimates the DRP on this benchmark as the "term to maturity weighted average" of the DRP calculated for a sample of observations formed as bonds:[44]

- having a rating of A- with Standard and Poor's;
- with time to maturity of 2 years or longer;
- issued in Australia by Australian entities and denominated in Australian dollars;
- that are both fixed and floating;
- that include both bullet bonds and bonds with call/put options; and
- have yield data available from Bloomberg

221. Application of the ERA's filters in Western Power's draft decision resulted in the formation of a sample consisting of 27 bonds and a smaller sub-sample of 8 bonds with less than 5 years to maturity. The benchmark DRP set by Western Power was assessed to be the simple average of the "term to maturity weighted average" DRPs from these two samples, which resulted in a value of 2.027%.

222. I set out in section 3 above why I believe that the ERA's choice of benchmark is inconsistent with the requirements of the Access Code. In my view, the appropriate choice of benchmark is BBB+ debt with 10 years to maturity. I note that the ERA's method would use materially different data if it were addressed at 10-year BBB+ debt as I recommend in this report. Accordingly, in this section I assess the ERA's methodology at a general level.

223. In summary, I consider that the reasons set out by the ERA for rejecting the use of the Bloomberg fair value curve are not robust. The "bond-yield" analysis that the ERA prefers to estimate the DRP is not sufficiently developed or sophisticated that it could be capable of replacing the type of expertise provided in Bloomberg's fair value estimates. The ERA's reliance upon the AER's position in its draft Powerlink and Aurora decisions has now been superseded by the final Powerlink decision in which the AER reverts to the use of extrapolated Bloomberg BBB fair values.

7.1. Reasons for setting aside Bloomberg

224. In my opinion the ERA has given too little weight to the views of Bloomberg as expressed in its fair value curves in assessing the DRP.

[44] See: ERA, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, March 2012, p. 181; and ERA, *Draft Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline*, March 2011, p. 154

225. The ERA expresses concern that:[45]

> *Bloomberg's estimates of fair value curves for BBB+ Australian corporate bonds with longer term to maturity of 7 years and 10 years are problematic; and*
>
> *extrapolation from a 7-year term to a 10-year term is also problematic.*

226. It is difficult to see why the ERA would view this as a concern given that it considers that the benchmark term of debt is 5 years. The ERA's claim that "*extrapolation from a 7-year term into a 10-year term is no longer used by any Australian regulator*" is also no longer true with the AER's recent final decision for Powerlink returning to the use of the extrapolated Bloomberg BBB fair value curve.[46]

227. In any case, I do not consider that the ERA has made a sufficient case to indicate that Bloomberg's 7-year fair value estimate is problematic or that there is not a reasonable basis for extrapolating this to 10 years.

228. In making this claim, the ERA references a discussion paper that it issued in 2010.[47] In this paper, it produces a chart comparing the Bloomberg 7-year BBB fair value yield estimate to yields reported for 13 bonds. I note that in the final year of this chart, only two of the bonds used by the ERA for comparison have a similar or greater maturity than Bloomberg's 7-year benchmark. It is not therefore particularly surprising to me, nor indicative of any problem with the Bloomberg methodology, that Bloomberg's estimate would be amongst the highest in this sample.

229. I note further in this respect that the Tribunal has recently addressed similar arguments regarding the reliability of the Bloomberg fair value curve made by the AER based on its historical performance. The Tribunal comments on this extensively,[48] and concludes:

> *At this point, it is sufficient for the Tribunal to express the view that the performance of the Bloomberg curve during and after the GFC alone would not necessarily have warranted its rejection. The unusual circumstances and market conditions, in particular the restriction of the debt market, that prevailed during the GFC are unlikely to persist for extended periods and might not therefore be viewed as indicative of the likely market conditions that would prevail during the majority of the ten year reference period. At most, the so called "counterintuitive" performance would warrant further investigation of the reliability of the Bloomberg curve.*

45 ERA, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, March 2012, p. 180

46 AER, *Final decision: Powerlink transmission determination*, April 2012, p. 34

47 ERA, *Measuring the Debt Risk Premium: A Bond-Yield Approach*, 1 December 2010.

48 Application by APT Allgas Energy Limited (No 2) [2012] ACompT 5 (11 January 2012), paras. 75-81

230. The evidence in this report indicates that the overwhelming weight of evidence suggests that Bloomberg's current long term BBB fair value estimates are reasonable. While I accept that the requirement to extrapolate these from 7 to 10 years creates some uncertainty, as indicated in the range I produce at section 6 above, this uncertainty is insignificant when considered against the extent to which the ERA has underestimated the DRP with its preferred benchmark and methodology.

231. I consider that having no regard to Bloomberg's fair value estimates in setting a benchmark DRP is an important limitation of the ERA's approach. In assessing information that is indicative of a benchmark bond yield, there is a limited amount of sometimes conflicting information available. In this context, setting aside any relevant information, such as Bloomberg's fair value estimates, is likely to lead to error.

232. In my opinion, it is unreasonable for the ERA to completely set aside the Bloomberg fair value estimate without strong reasons as to why this estimate was not representative of the information obtained from the broader population of bond yields over the relevant period. I do not consider that it has provided such reasons.

233. Following the Tribunal's recent precedent in respect of Envestra's and APT Allgas' DRPs, in its final Powerlink decision the AER has ceased using the bond sample approach (similar to the ERA's bond yield approach) which it had proposed to apply in the Aurora and Powerlink draft decisions. The AER indicated that it considers there may be other methods for estimating DRP that are preferable and foreshadowed a consultation process on the issue. I expect that amongst the methods that would be considered in such a process would be the curve-fitting that I discuss at section 5.2 of this report.

7.2. De minimis adjustment to ERA approach

234. In this section I provide details on how, if one rejected my view that the Bloomberg fair value curve should be used, the ERA's approach to forming a sample could be improved.

235. This review is necessarily limited because the ERA has collected a sample of bonds on the basis of a benchmark credit rating of A- and a benchmark term to maturity of 5 years. As I set out at section 3 of this report, I consider that there are very strong reasons why a benchmark credit rating of BBB+ or lower and a benchmark term to maturity of 10 years are consistent with the requirement of the Access Code.

236. I also make clear at section 7.2.1 below that I consider there are significant drawbacks to the ERA's "bond-yield" methodology. In my view, this type of framework for analysis considerably restricts the amount of information that can be had regard to, and the way in which that information is considered. This view is reflected in my advice below.

237. Specifically, I have been asked to advise:

- what data sources for bond yields should be used;

- what criteria for including/excluding specific bonds from the sample should be used;
- what methodology should be used for arriving at an average across the observations in the sample;
- what estimate for DRP I would arrive at using this approach for both 5 and 10 year maturities; and
- if my estimate at 5 years to maturity differs from the ERA's, why this is the case.

7.2.1. ERA's methodology

238. The ERA's "bond-yield" approach to estimating DRP, at its most general level, involves:

- forming a sample of bonds that have characteristics similar (in some sense) to the benchmark bond;
- obtaining yields and calculating DRPs on these bonds; and
- computing an average (of any sort) across these DRP observations.

239. I have strong concerns about the ability of this approach to adequately consider all the information that is relevant to coming to a reliable estimate of the DRP.

240. Any approach based on a sample, across which an average is taken, starts with an assumption that a set of observations can be taken which are all of equal value in explaining DRP, or at least for which the value can be quantitatively assessed and captured in a weighted average across the sample. Necessarily, application of this approach also implies that any observations not included within the sample are irrelevant to assessing the DRP.

241. In my view, it is not a supportable assumption that in the yields on 27 bonds the ERA has captured all information that is relevant or material to assessing the DRP on 5-year A- rated debt. However, for the purposes of this section I proceed upon the basis that a single sample approach is to be used to determine the benchmark DRP.

7.2.2. Replication of ERA sample and yields

242. My ability to suggest adjustments to the ERA approach is limited by the fact that I am unable to replicate either:

- the precise selection of bonds, fitting the ERA's criteria, as set out by the ERA in its Table 74; or
- the yields reported by the ERA in its Table 75.

243. However, this is not a significant limitation. I have achieved a reasonable degree of approximation to the ERA's results, and my suggested amendments involve the inclusion of a large number of additional bond yields in the ERA's sample.

7.2.2.1. Identification of bonds matching ERA's criteria

244. The ERA estimates the DRP on its benchmark bond as the "term to maturity weighted average" of the DRP calculated for a sample of observations formed as bonds:[49]

- having a rating of A- with Standard and Poor's;
- with time to maturity of 2 years or longer;
- issued in Australia by Australian entities and denominated in Australian dollars;
- that are both fixed and floating;
- that include both bullet bonds and bonds with call/put options; and
- have yield data available from Bloomberg

245. Application of these filters in Western Power's draft decision resulted in the formation of a sample consisting of 27 bonds and a smaller sub-sample of 9 bonds with more than 5 years to maturity. The benchmark DRP set by Western Power was assessed to be the simple average of the "term to maturity weighted average" DRPs from these two samples, which resulted in a value of 2.027%.

246. Using Bloomberg's bond search function, I find 37 bonds that fit the ERA's criteria and have reported yields from one of Bloomberg's sources over the 20 days to 29 February 2012. This list does not three of the 27 bonds found by the ERA, for which I am unable to locate yield data in Bloomberg. The bonds that I was unable to locate such data for were:

- AUST & NZ BANK, ISIN AU0000ANZHA6, maturing 20 June 2022;
- POWERCOR AUSTRALIA, ISIN AU3FN0003521, maturing 15 January 2022; and
- TRANSURBAN FINANCE, ISIN AU300TFC0082, maturing 10 November 2015.

247. Despite looking across several Bloomberg data sources including BGN, BVAL and BCMP, I was unable to find any yields over the relevant period for these bonds. It is unhelpful that the ERA has not specified the source of its data beyond noting that they are from "Bloomberg".

248. Further, I have found 13 other bonds that appear to meet the criteria set by the ERA and had Bloomberg yield information during the relevant period. These bonds are:

[49] See: ERA, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, March 2012, p. 181; and ERA, *Draft Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline*, March 2011, p. 154

- COMMONWEALTH PROPERTY, ISIN AU3CB0171924, maturing 11 March 2016;
- GPT RE LTD, ISIN AU3CB0189009, maturing 24 January 2019;
- QIC SHOPPING, ISIN AU3CB0174464, maturing 7 July 2014;
- SPI ELECTRICITY & GAS, ISIN AU3CB0173482, maturing 1 April 2021;
- TRANSURBAN FINANCE, ISIN AU3CB0176667, maturing 8 June 2016;
- VOLKSWAGEN AUSTRALIA, ISIN AU3CB0179109, maturing 14 July 2015;
- WESFARMERS LTD, ISIN AU3CB0126860, maturing 11 September 2014;
- WESFARMERS LTD, ISIN AU3CB0185478, maturing 4 November 2016;
- WOOLWORTHS LTD, ISIN AU3CB0172039, maturing 22 March 2016;
- WESTPAC BANK, ISIN AU0000WBCHQ0, maturing 25 May 2017;
- ST GEORGE BANK, ISIN AU3CB0067718, maturing 9 May 2018;
- NATIONAL WEALTH, ISIN AU300NWML019, maturing 16 June 2026; and
- SUNCORP METWAY, ISIN AU300SUNQ019, maturing 23 September 2024.

249. It is not clear to me why these bonds have not been included in the ERA's sample.

7.2.2.2. Bond yields reported by the ERA

250. For the 24 bonds that both the ERA and I are both able to find Bloomberg yield data for, I am unable to exactly match the Bloomberg yield data reported by the ERA in its Table 75. This is despite seeking several alternative sources from within Bloomberg and comparing these over a number of time periods.

251. I note that the differences in yield are not large. When I adopt my preferred order for Bloomberg source data (BGN in preference to BVAL in preference to BCMP), I find that the term to maturity weighted average of the annualised yield on these 24 bonds is 5.88% and a DRP of 2.15%, compared to the average on the same 24 bonds in the ERA's Table 75, which is 5.83% with an average DRP of 2.11%. On a bond by bond basis, I consider that I have achieved a reasonable degree of similarity with the ERA's results.[50]

252. When I take a similar average across the 37 bond yields that I have been able to collect data for, the maturity weighted average yield is 6.42% associated with a DRP of 2.58%

50 I note that the ERA itself similarly achieves an approximate level of replication of the beta estimation work of Professor Olan Henry – see ERA, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, March 2012, pp. 198-204

7.2.3. Source for bond yield data

253. The ERA relies solely upon Bloomberg yield data in arriving at its estimate of the DRP in its draft decision.[51] It does not explain why it has only relied upon Bloomberg data, or even what source of data within Bloomberg it has preferred (ie, BGN, BVAL or BCMP).

254. It is not clear to me why the ERA considers that bond yield information sourced from UBS would not be similarly informative. In previous considerations of the DRP, the Tribunal has even stated that it preferred UBS data:[52]

> *On the other hand, we do agree with Professor Handley's criticism of the use of the median reported observed yields from three data sources – UBS, Bloomberg and CBASpectrum. As explained in the Oakvale Report, "the use of a market maker's price sheet such as that provided by UBS is the most commonly used guide for pricing of bond instruments, whether fixed, floating or hybrid structures." The Tribunal prefers the use of the UBS data alone.*

255. UBS reports 60 bonds fitting the ERA's criteria that report yield information, considerably more than the 27 and 37 bonds for which ERA and I respectively have find data for from Bloomberg. 35 of these bonds are bonds that I am unable to find Bloomberg data for, most likely because they are floating rate bonds, which Bloomberg does not generally provide yield estimates for.[53] The inclusion of these bonds increases the bond sample to 72 bonds.

256. I consider it reasonable to take a simple average of the Bloomberg and UBS yield/DRP observations, where both exist for the same bond, to summarise these. The term weighted average yield over these 72 bonds is 6.64%, with the term weighted average DRP being 2.88%.

7.2.4. Selection of sample observations

257. Notwithstanding my criticisms at section 3.2 of the ERA's selection of the benchmark, there are a number of positive attributes to the sample of bonds that is collected by the ERA. Its sample includes both fixed and floating rate bonds. It also does not exclude bonds with embedded options such as call and put options.

258. However, its selection criteria, in general, appear more restrictive than necessary in respect of:

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51 ERA, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, March 2012, p. 181

52 Application by Jemena Gas Networks (NSW) Ltd (No 5) [2011] ACompT 10 (9 June 2011), para. 58

53 It is important to note that in most cases these are not bonds that are unknown to Bloomberg – simply bonds that UBS reports data for where Bloomberg does not. Similarly, I am unable to find UBS yield data for 12 of the 37 bonds I find data for in Bloomberg.

- the use of only A- bonds when similarly rated bonds could also potentially reveal useful information about the DRP on the benchmark bond; and
- the use of Australian dollar bonds only when there is no reason to expect that bonds issued overseas by Australian companies could not also provide information about the benchmark DRP.

7.2.4.1. Yields from bonds with different credit ratings

259. In my view, taking into consideration yield information from bonds with similar credit ratings to the benchmark is likely to improve the reliability of the DRP estimate provided this is done in a way that properly accounts for any difference in credit rating.

260. The ERA's approach to forming a sample is to accept only bonds that have the same credit rating as the benchmark bond. I consider that this excludes a wide range of information that may potentially be relevant to the assessment of the benchmark DRP.

261. While it is true that bonds with other credit ratings may not be expected to have a DRP consistent with the benchmark credit rating, this does not mean that they may not be useful in informing an assessment of that DRP. For example, in the ActewAGL appeal, the Tribunal considered that in assessing the DRP on BBB+ bonds, it was reasonable to consider the yields on A- and BBB bonds:[54]

> *In the Tribunal's view, if it were reasonable not to include A- and BBB bonds in the population (because they are not representative of BBB+ bonds), it was unreasonable for the AER not to consider whether useful information could be obtained from taking these bonds into account without including them in the population. That A- yields sat above BBB+ yields should have indicated to the AER that by use of its methodology it may not have selected the fair value curve most likely to provide the best estimate of the benchmark bond yield.*

262. In having regard only to its sample of 27 A- rated bonds, the ERA does not have adequate regard to the information available on bonds with other credit ratings. In my view, having proper regard to these other yields is most effectively done in a quantitative sense with the type of curve-fitting analysis that I demonstrate at section 5.2 above. Taking into consideration yield information from bonds with similar credit ratings to the benchmark is likely to improve the reliability of the DRP estimate provided this is done in a way that properly accounts for any difference in credit rating.

263. However, in my opinion it is not possible to have adequate regard to these yields within the sample-based "bond-yield" analysis approach preferred by the ERA. Therefore, whilst I remain concerned that the ERA's approach does not take into account as wide an amount of information as would be desirable, an adjustment that would be capable of appropriately using this information would be considerably more than *de minimis*, and therefore outside the scope of this section.

[54] Application by ActewAGL Distribution [2010] ACompT 4 (17 September 2010), para. 63

7.2.4.2. *Yields from foreign currency bonds*

264. In addition to the 72 Australian bonds that I identify above for which yield information is available from either Bloomberg or UBS, there are a further 60 bonds, issued by Australian firms in foreign currencies, for which Bloomberg yield data is available and otherwise satisfy the ERA's criteria.[55]

265. As described in more detail at section 5.1.2 and Appendix D to this report, these foreign currency yields can be re-expressed on an Australian dollar yield equivalent basis. These converted bonds yields can be seen graphically at Figure 11 above.

266. The average maturity of the 60 bonds that I have sourced is 7.11 years, with an average yield of 6.80% and an average DRP of 2.95%. The maturity weighted DRP on this dataset is 2.84%.

7.2.5. Methodology for estimating the benchmark DRP

267. I have been asked to review the method used by the ERA to summarise its samples of 27 and 9 bonds. The ERA uses a "term to maturity weighted average", which I have assumed means that it places weighted across different observations in proportion to the number of years to maturity on each bond.

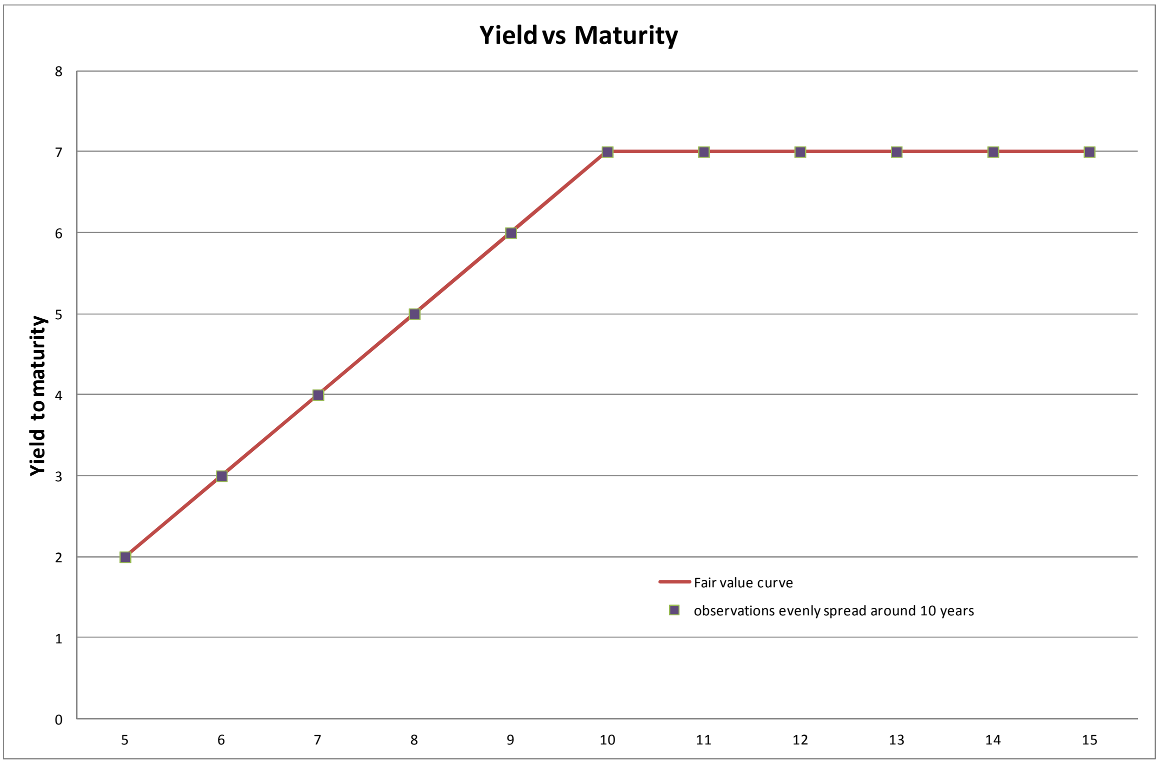
268. In my view no one method of averaging across a sample such as the ERA's is capable of taking into account the shape of the yield curve (and DRP curve) that one would expect, unless one actually seeks to estimate this curve and use this information as I do at section 5.2 of this report.

269. Imagine that the yield curve starts steep at 5 years and flattens out as maturity increases (ie, is concave) – which is what the Bloomberg fair value curve does. In this case, even if the within sample maturity is evenly distributed above and below 10 years (such that the mean maturity in the sample is 10 years) then the mean yield in the sample will be lower than the true 10 year yield.

270. The figure below demonstrates this with an example. There are 11 observations with five having maturity above 10 years and five having maturity below tend years and one with maturity of exactly 10 years. All of these are on the fair value curve so they are all representative of the benchmark cost of debt at their maturity.

55 UBS Australia does not report yields on foreign currency bonds.

Figure 19: Hypothetical scenario with a concave fair value curve



271. The simple average maturity of the sample is 10 years. Yet the average yield of the sample is not the 10 year benchmark of 7.00%. Rather it is 5.64%. This bias in the sample mean as the predictor of the true 10 year rate exists due to the concavity in the fair value curve. It exists despite:

- the mean maturity in the sample being 10 years;
- there being no bias in the sample (in the sense that all bonds are reflective of the benchmark at that maturity); and
- there being an equal distribution above and below 10 years.

272. The bias would be worse if:

- the mean maturity in the sample was less than 10 years;
- there were more bonds below 10 years than above (eg, the mean maturity in the sample was dragged up by a single 15 year bond);
- the sample included some bonds that are clearly biased estimators of the benchmark yield.

273. The ERA has not implemented a method of averaging that takes into account the shape of the yield curve. However, by weighting towards the highest maturity bonds, it

effectively increases the average maturity in its sample in a way that may to some extent counteract the effect of taking just a simple average.

274. For example, over the 27 bond yields that the ERA finds from Bloomberg, the simple average time to maturity is 4.71 years. Although this may appear relatively close to 5 years, the logic above shows that the average yield/DRP calculated over this sample is likely to be lower than what would be commensurate with a 5-year bond.

275. By using the term-weighted average, the effective average time to maturity in the sample is increased to 5.89 years. This effect must offset, to some extent, the downward bias generated by average across a yield curve. Whether this is the case or not is difficult to discern.

276. For completeness, I consider that more reliable methods for using the information from bonds with maturities significantly different from 5 years could possibly include:

- using the Bloomberg fair value curve to adjust all DRPs to the desired benchmark maturity for better comparison; and/or
- estimating an econometric model of the yield (and hence DRP) curve based on the available yield data, similar to my approach at section 5.2 above.

7.2.5.1. Using the Bloomberg A fair value curve to adjust bond DRP for maturity

277. I have sourced the average Bloomberg A fair value curve over the 20 days to 29 February. The yield on each bond is adjusted downward or upward to the preferred benchmark maturity by adding the difference between the Bloomberg fair value at that benchmark and the Bloomberg fair value at the maturity of the bond. The effect of this is simply to increase or decrease the yield of the bond along a line parallel to the Bloomberg fair value curve. The extent to which the bond is below or above this curve will not change with the adjustment – however, it ensures that all bonds are compared on the same maturity basis.

278. Using the Bloomberg A fair value curve, and assuming conservatively no increase in DRP above 7 years, making this adjustment allows me to estimate both 5 and 10 year DRPs on a range of samples. I use a simple average to summarise the yield/DRP of these samples – a maturity weighted average would produce the same result since all bonds become effectively the same maturity. The results of this on a number of samples is shown at Table 8 below.

Table 8: 5-year and 10-year DRP estimates on maturity adjusted samples using Bloomberg A fair value curve, 20 days to 29 February 2012

Sample	5-year DRP estimate	10-year DRP estimate
ERA's sample of 27 domestic bonds, using ERA Bloomberg yields	2.26%	2.54%
ERA's sample of 24 domestic bonds*, using my Bloomberg yields	2.37%	2.66%
ERA's sample of 24 domestic bonds*, using average of my Bloomberg and UBS yields^	2.42%	2.70%
My sample of 37 domestic bonds, using my Bloomberg yields	2.52%	2.80%
My sample of 37 domestic bonds, using average of my Bloomberg and UBS yields^	2.44%	2.72%
My sample of 72 domestic bonds, using average of my Bloomberg and UBS yields^	3.11%	3.40%
My sample of 37 domestic bonds and 60 foreign bonds, using my Bloomberg yields	2.79%	3.08%
My sample of 72 domestic bonds and 60 foreign bonds, average of my Bloomberg and UBS yields^	3.07%	3.35%

** I have only been able to source Bloomberg yield data for 24 of the 27 bonds in the ERA's sample*
^ Average of Bloomberg and UBS yields where these are both available for the same bond

279. In my opinion, this method of summarising yield/DRP data is a considerable improvement on the maturity weighted average yield/DRP used by the ERA. It is noticeable the DRP in Table 8 tends to increase as more information as taken into account. In my view, it is reasonable to suggest that the best estimates from Table 8 above are those which incorporate the greatest amount of information.

7.2.5.2. Curve fitting the benchmark yield

280. For completeness, I note that my results at section 5.2 above also contain estimates of the benchmark yield for bonds rated A- at 5 years to maturity. These benchmarks have been derived by reference to populations of bonds varying in rating between BBB- and A, but it is important to note that the wider dataset affects only the shape of the curves derived. The level of the curve for A- bonds is derived solely by reference to the yields on A- bonds.

281. Table 9 below sets out the results derived in each of the relevant figures above. Note that these yields and DRPs have been calculated over the 20 days to 30 March 2012, and this should be considered in comparing them to DRPs calculated during the 20 days to 29 February 2012, which I use to replicate the ERA's analysis.

Table 9: 5-year and 10-year DRP estimates on maturity adjusted samples using curve fitting, 20 days to 30 March 2012

Figure and sample analysed	5-year DRP	10-year DRP
Figure 10: Australian issued Australian dollar bonds rated BBB to A-	2.50%	2.77%
Figure 11: Australian issued bonds rated BBB to A-	2.86%	3.36%
Figure 12: Australian issued Australian dollar bonds rated BBB- to A	2.52%	2.71%
Figure 13: Australian issued bonds rated BBB- to A	2.87%	3.29%
Figure 15: Par yield curve for Australian issued Australian dollar bonds rated BBB to A-	2.52%	2.68%
Figure 16: Par yield curve for Australian issued Australian dollar bonds rated BBB- to A	2.54%	2.63%

282. These results are broadly consistent with and support the DRPs estimated in Table 8 over the largest samples for the ERA's period.

7.2.6. Conclusion

283. Based on the widest amount of information available and using the results from a range of methods, I estimate that the benchmark A- DRP at 5 years maturity over the 20 days to 29 February 2012 is approximately 3.00%, having greatest regard to those samples with the most bond yields in Table 8 above. At 10 years to maturity, the benchmark DRP is approximately 3.30%.

284. I note that the 5-year estimate is almost 100 basis points higher than the ERA's own term-weighted average based on two samples of 27 bonds and 9 bonds respectively. The primary sources of difference between my estimate and the ERA's are that:

- I have taken into account yield information sourced from both Bloomberg and UBS;
- I have taken into account the yields on 72 bonds as compared to the ERA which considered 27 bonds; and
- I have appropriate accounted for the maturity of bonds in my sample in estimating the benchmark, by either:
  - adjusting their DRP using the shape of the Bloomberg A fair value curve; or
  - estimating my own fair value curve using the same data.

285. My estimate of 3.00% is also modestly above the average 5-year Bloomberg A fair value DRP of 2.88%, which is to be expected given that Bloomberg's fair value curve is constructed using A and A+ rated bonds as well as bonds that are rated A-, and

hence would be expected to have a lower yield than the average of my sample of A-bonds.

8. Western Power's proposed DRP

286. Based on analysis in this report, I consider that Western Power's proposed use of the 7 year Bloomberg BBB fair value estimate for the cost of debt falls at the bottom of a reasonable range. The associated range for the 10-year DRP based on possible extrapolations of the Bloomberg BBB fair value curve of between 3.67% to 4.03%, being:

- the average annualised Australian Bloomberg BBB 7-year fair value over 5 March 2012 to 30 March 2012 of 7.63%; less
- the average annualised 7-year CGS yield over 5 March 2012 to 30 March 2012 of 3.97%; plus
- a range of 0.00% to 0.36%, being between 0 and 12 basis points per annum for three years.

287. Western Power's proposed DRP of 3.67%, based upon the use of Bloomberg's 7-year BBB fair value estimate, forms the bottom end of this range. I therefore consider that Western Power's estimate is consistent with the requirements of the Access Code in providing a forward-looking and efficient estimate of financing costs commensurate with the commercial risks involved in providing covered services.

288. The ERA"s estimate of DRP in its draft decision of 2.03% is 1.64% lower than the bottom end of this range. I do not consider that the ERA's estimate of DRP is consistent with the requirements of the Access Code.

Appendix A. Empirical evidence on the term of debt of regulated energy network businesses

289. In this appendix, I set out empirical evidence that I have previously had regard to in assessing the term of debt for regulated energy network businesses. Overall, these data are consistent with those collected by the ERA and supports my view that the average debt issuance by regulated energy network businesses is approximately 10 years.

A.1. Evidence from Australia

290. Based on a Deloitte report to the AER, CEG has previously estimated that the average term to maturity of *outstanding* debt (as opposed to maturity at issuance) issued by private regulated energy businesses was around 6 years.[56] Deloitte derived the underlying data from financial statements of the businesses. Table 2 from that report is reproduced below:

Table 10: Estimate of the weighted average remaining time to maturity

Time to maturity	Total debt* ($m)	Percentage of total debt	CEG point estimate (years)	Weighted average
Less than 1 year	2,651	13%	0.5	
1 to 5 years	8,868	44%	3	
More than 5 years	8,812	43%	11	
Sum	**20,331**	**100%**		**6 years**

Source: Deloitte and CEG analysis

291. However, this needs to be approximately doubled to provide an estimate of the average time to maturity of debt at the time of issuance – noting that, on average, outstanding debt will tend to be half way through its life. That is, although the debt in Table 10 above has, on average, 6 years to maturity from the current time, the same debt would be expected to have around double this maturity from the time that it was issued.

292. CEG were also provided with the following data from the Joint Industry Associations (JIA) that corroborates this conclusion. CEG was informed that these figures have been reconciled to the 2007 statutory accounts.

56 CEG, *Term of the risk free rate under the NER*, January 2009.

Table 11: JIA estimate of the average time to maturity

Distribution Business	Ownership	Amount	Average Term to maturity	Average term at issuance
CitiPower & Powercor	Private	2,532.0	5.65	10.40
ETSA utilities	Private	2,353.5	7.11	10.81
SPAusnet	Private	3,662.8	4.47	7.27
Envestra	Private	1,960.9	10.91	14.39
Average		**20,331**	**6.55**	**10.14**

Source: JIA

293. The AER inspected these audited accounts and concluded in its Final Statement of Regulatory Intent:[57]

> *Taking into account this new information, the AER has verified that the weighted average maturity of debt portfolios at the time of issuance for these businesses is 10.14 years as presented above in table 6.1. That is, the further information confirms that these businesses refinance on average every 10 years.*

A.2. Regulated utilities internationally

294. I have also examined a large database of all outstanding bonds listed on Bloomberg and classified as being issued by a "utility" (being gas, electricity, water or transport company). Many if not most of these firms will be regulated in a similar fashion to Australian regulated business – including with regular price resets every five or so years. The results of this analysis are reported in Table 12 below.

[57] AER, May 2009, Final Decision, *Electricity transmission and distribution network service providers. Review of the weighted average cost of capital (WACC) parameters*, p. 159

Table 12: Debt issues by utilities internationally

	Amount (bn)	Unweighted average term to maturity at issuance	Weighted average term to maturity at issuance
Utility by sector			
Water	Na	18	na
Gas transmission	Na	10	na
Gas Distribution	Na	12	na
Electricity integrated	na	12	na
Electricity transmission only	na	12	na
Electricity distribution only	na	13	na
All	na	12	na
Utility by currency of issue			
US dollar	476.7	15	14
Euro	161.4	10	9
Canadian dollar	36.4	19	22
Australian dollar	6.4	10	11
British pound	51.5	29	24
Japanese yen	11,467.9	10	11

Source: Bloomberg and CEG analysis

295. Based on the figures in this table, all utility sectors tended to issue debt with a maturity of 10 years or higher. The lowest was gas transmission which had an unweighted average maturity of 10 years. The highest was for the water utilities which had an unweighted average maturity of 18 years.

296. It was not possible to easily calculate a weighted average for sector specific categories because the bonds are issued in a range of currencies (48 currencies in total).[58]

297. However, Bloomberg also allows one to classify bonds issued by utilities by the currency in which they have been issued. In that case it is possible to calculate a meaningful weighted average and these are reported in the table. The weighted average maturity of bonds issued in US dollars is 14 years. The lowest weighted average maturity is 9 years for bonds issued in Euros. The highest weighted average maturity is 24 years for bonds issued in British pounds.

298. It should be noted that this does not mean that European companies tend to issue 9 year bonds and British companies tend to issue 24 year bonds. Rather, it is more likely that European companies tend to issue their long term debt in British pounds (e.g. because the demand for long term corporate debt is highest in Britain).

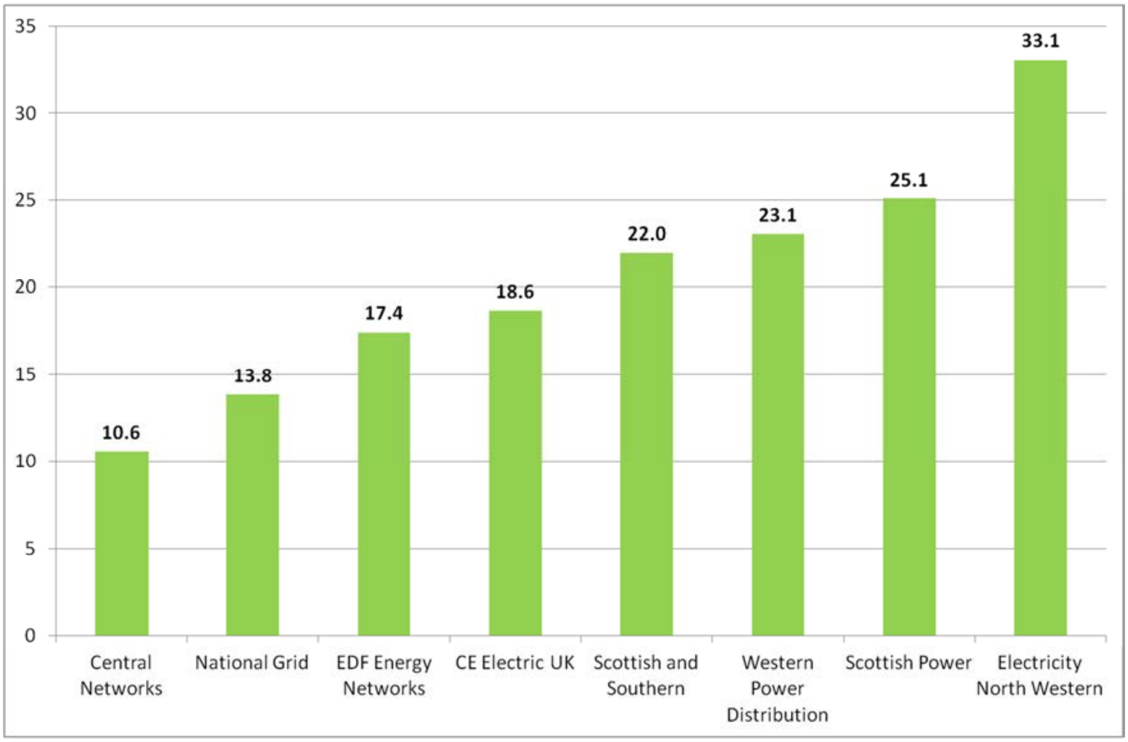
58 In order to calculate a meaningful weighted average maturity it would be necessary to convert each of the outstanding amounts for each bond into a common currency. It is not obvious what exchange rate (eg, nominal or purchasing power parity) should be used in this context and what date should be used (eg, current or time of issue).

299. This data strongly confirms the Australian data that regulated utilities, with long lived assets, have a strong preference for issuing long term debt.

A.2.1. Average debt tenor for electricity businesses in the United Kingdom

300. CEG also assessed independently of Bloomberg the average tenor for electricity companies in the United Kingdom, including National Grid, CE Electric UK, Central Networks, EDF Energy Networks, Scottish Power, Scottish and Southern Energy plc, Electricity North West and Western Power Distribution. The results of this assessment are presented in Figure 20 below.

Figure 20: Average debt tenor for United Kingdom utilities companies



Source: Annual reports, CEG analysis

301. The approach for arriving at the estimate for each company is outlined in Table 13 below.

Table 13: Average debt tenor for Australian utilities companies

Company	Tenor (years)	Maturity (years)	Justification
National Grid	14	7	The National Grid 2009/10 Annual Report and Accounts divides borrowings into six categories (maturing in less than one year, 1 – 2 years, 2 – 3 years, 4 – 5 years and 5+ years). Based on this, we calculate an average weighted maturity of at a minimum 4.2 years and as a best estimate 7 years (if the average maturity of debt for 5+ years is 10 years).[59]
CE Electric UK	18.6	9.3	The CE Electric UK Reports & Accounts divides borrowings into two categories, maturing in one year or less, and maturing in 5+ years. Based on this, we calculate an average weighted maturity of at a minimum 4.7 years and as a best estimate 9.3 years (if the average maturity of debt for 5+ years is 10 years)[60].
Central Networks	10.6	5.3	The E.ON UK Plc Annual Report and Accounts for the year ended 31 December 2009 divides the non-current borrowings into maturing in 1-2 years, 2-5 years and 5+ years. Based on this, we calculate an average weighted maturity of at a minimum 3.3 years and as a best estimate 5.3 years (if the average maturity for debt for 5+ tears is 10 years).[61]
EDF Energy Networks	17.4	8.7	EDF Energy Annual Report and Financial Statements for 31 December 2009 states the maturity date for all non-current borrowings. Based on this, we have calculated a weighted average maturity of 8.7 years.[62]
Scottish Power	25.2	12.6	The SP Distribution Limited Corporate Report & Regulatory Accounts for the year ended 31 March 2010 divides the non-current loans and other borrowings by instrument with maturity date. Based on this, we calculate the average maturity as 12.6 years[63]
Scottish and Southern Energy plc	22	11	The Scottish and Southern Energy plc Financial Report for the year ending 31 March 2010 states that the average debt maturity is 11 years.[64]

[59] National Grid Annual Report and Accounts 2009/10, p. 145

[60] CE Electric Funding Company Report & Accounts to 31 December 2009, p. 76

[61] E.ON UK Annual Report and Accounts 2009, p. 89

[62] EDF Energy Annual Report and Financial Statements 31 December 2009, p. 52.

[63] SP Distribution Limited Corporate Report & Regulatory Accounts, p. 23.

[64] Scottish and Southern Energy Financial Report for the year to 31 March 2010, p. 12.

Company	Tenor (years)	Maturity (years)	Justification
Electricity North West	33	16.5	The Electricity North West Limited Annual Report and Consolidated Financial Statements for the year ended 31 March 2010 divided the non-current borrowings by instrument. Based on this we calculate the average maturity as 16.5 years.[65]
Western Power Distribution	23	11.5	The Western Power Distribution Holdings Limited and Subsidiary Undertakings annual report and financial statements for the year ended 31 March 2010 divides borrowings maturity into four categories (less than one year, one to 5 years, 5 – 15 years and greater than 15 years). Based on this, we calculate weighted average debt maturity as 11.5 years.[66]

302. This data strongly confirms the Australian data that regulated utilities, with long lived assets, have a strong preference for issuing long term debt.

A.2.2. Average debt tenor in the United States

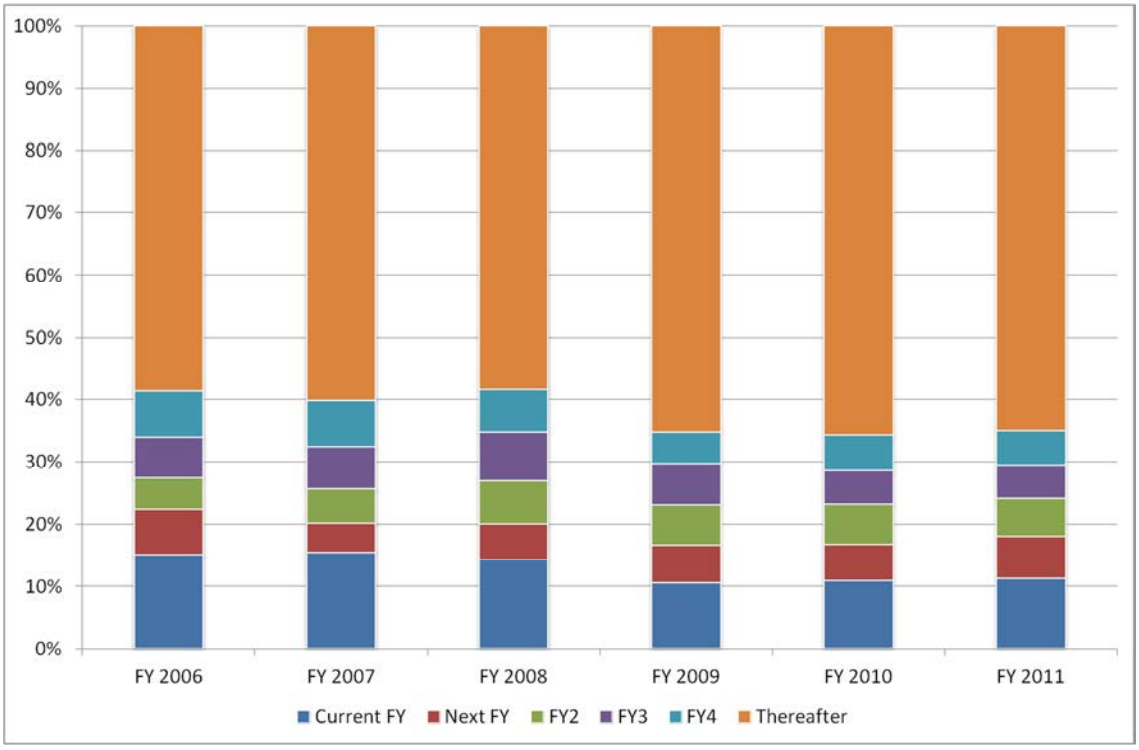
303. CEG has also previously reviewed the weighted average tenor for listed electric and gas utilities in the United States, complied from the database SNL Financial. SNL Financial directly reports the tenor of all outstanding debt issued by the respective companies. The average (median) weighted average debt tenor for these firms (in 2010) was 17.0 (17.4) years. The minimum weighted average debt tenor was 6.0 years and the maximum 27.1 years.

304. I have confirmed that the debt maturity profile has remained stable over time by compiling a time series from 2006 to 2011 of debt maturing in the current financial year, next financial year, each of the next three financial years and thereafter. This time series is based on a sample of 71 power and gas utilities in the United States for which a debt maturity profile is available from SNL financial. The weighted average debt maturity profile for this sample of firms is illustrated in Figure 21 below.

65 Electricity North West Limited Statutory Account 2010 March, p. 52.

66 Western Power Distribution Holdings Limited and Subsidiary Undertakings Annual Report and Financial Statements, p. 51.

Figure 21: Weighted average debt maturity profile for electric and gas utilities in the United States



Source: SNL Financial, CEG analysis

305. This data strongly confirms the Australian data that regulated utilities, with long lived assets, have a strong preference for issuing long term debt.

A.3. Debt issues by Australian companies since the GFC

306. It may be the case that there were no long-term debt issues in the immediate aftermath of the GFC. However, both theory and evidence suggests this does not signify a long term trend. Rather, the empirical evidence shows that Australian firms are returning to issuing long-term debt.

307. Table 14 below summarises bonds issued since the beginning of 2010 in Australia in Australian dollars, with a term of more than 7 years and rated between BBB and A- by Standard and Poor's. The information presented in this table clearly indicates that the 10-year bond market is 'open for business' - and that several firms, including infrastructure firms, are choosing to issue long-term debt.

308. A similar trend is also evidenced in the overseas bond markets, where Australian companies are issuing long-term debt in foreign currencies. This is illustrated in Table 15 which summarises bonds issued since the beginning of 2010 in Australia in *currencies other than the Australian dollar*, with a term of more than 7 years and rated between BBB and A- by Standard and Poor's.

Table 14: Long-term debt issued by Australian firms in Australian dollars (rated A- to BBB)

Issuer	ISIN Number	Crncy	S&P Rating	Issue Date	Maturity	Term
ANZ	AU0000ANZHA6	AUD	A-	3/04/2012	20/06/2022	10.2
Colonial	AU0000CNGHA2	AUD	BBB+	29/03/2012	31/03/2037	25.0
Wesfarmers	AU3CB0192128	AUD	A-	28/03/2012	28/03/2019	7.0
Woolworths	AU3CB0191815	AUD	A-	21/03/2012	21/03/2019	7.0
GPT	AU3CB0189009	AUD	A-	24/01/2012	24/01/2019	7.0
Caltex	AU3CB0186385	AUD	BBB+	23/11/2011	23/11/2018	7.0
Coca Cola	XS0680309191	AUD	A-	27/09/2011	27/09/2021	10.0
Sydney Airport	AU3CB0176485	AUD	BBB	25/05/2011	6/07/2018	7.1
Brisbane Airport	AU3CB0173201	AUD	BBB	4/04/2011	9/07/2019	8.3
SPI E&G	AU3CB0173482	AUD	A-	1/04/2011	1/04/2021	10.0
AMP	XS0608173679	AUD	A-	28/03/2011	26/03/2021	10.0
BaA Bank	AU3FN0012340	AUD	BBB+	15/12/2010	15/12/2020	10.0
Stockland	AU3CB0164820	AUD	A-	25/11/2010	25/11/2020	10.0
APT Pipelines	AU3CB0155133	AUD	BBB	22/07/2010	22/07/2020	10.0
Dexus Finance	AU3CB0147833	AUD	BBB+	21/04/2010	21/04/2017	7.0
SPI E&G	AU3CB0145696	AUD	A-	25/03/2010	25/09/2017	7.5
BaA Bank	AU3FN0009973	AUD	BBB+	13/01/2010	13/01/2020	10.0

Source: Bloomberg, CEG analysis

Table 15: Long term debt issued by Australian firms in currencies other than AUD

Issuer	ISIN Number	Crncy	S&P Rating	Issue Date	Maturity	Term
Goodman	US38239FAE97	USD	BBB	22/03/2012	22/03/2022	10.0
Goodman	USQ4229FAC97	USD	BBB	22/03/2012	22/03/2022	10.0
Transurban	CA89400PAD56	CAD	A-	6/03/2012	6/03/2019	7.0
Insurance AU	NZIAGDT002C5	NZD	A-	15/12/2011	15/12/2036	25.0
SPI E&G	XS0715702824	HKD	A-	13/12/2011	13/12/2021	10.0
Newcrest	US65120FAB04	USD	BBB+	15/11/2011	15/11/2041	30.0
Newcrest	USQ66511AB43	USD	BBB+	15/11/2011	15/11/2041	30.0
Newcrest	US65120FAA21	USD	BBB+	15/11/2011	15/11/2021	10.0
Newcrest	USQ66511AA69	USD	BBB+	15/11/2011	15/11/2021	10.0
Origin Energy	USQ7162LAA28	USD	BBB+	14/10/2011	14/10/2021	10.0
Origin Energy	US68620YAA01	USD	BBB+	14/10/2011	14/10/2021	10.0
Rio Tinto	US767201AQ92	USD	A-	19/09/2011	20/09/2021	10.0
Sydney Airport	CA87124VAC33	CAD	BBB	21/06/2011	27/07/2018	7.1
Rio Tinto	US767201AN61	USD	A-	20/05/2011	20/05/2021	10.0
Woodside	US980236AL79	USD	BBB+	10/05/2011	10/05/2021	10.0
Woodside	USQ98229AG44	USD	BBB+	10/05/2011	10/05/2021	10.0
Woolworths	US980888AF86	USD	A-	12/04/2011	12/04/2021	10.0
Woolworths	USQ98418AK49	USD	A-	12/04/2011	12/04/2021	10.0
Macquarie Bk	US55608XAA54	USD	BBB	7/04/2011	7/04/2021	10.0
Macquarie Bk	US55608YAA38	USD	BBB	7/04/2011	7/04/2021	10.0
Goodman	US38239FAC32	USD	BBB	31/03/2011	15/04/2021	10.0
Goodman	USQ4229FAB15	USD	BBB	31/03/2011	15/04/2021	10.0
Dexus	USQ3200PAB42	USD	BBB+	17/03/2011	15/03/2021	10.0
Dexus	US252391AB35	USD	BBB+	17/03/2011	15/03/2021	10.0
Amcor	XS0604462704	EUR	BBB	16/03/2011	16/04/2019	8.1
SPI Australia	XS0589885960	GBP	A-	11/02/2011	11/02/2021	10.0
Macquarie Gr.	US55608JAE82	USD	BBB	14/01/2011	14/01/2021	10.0
Macquarie Gr.	US55608KAD72	USD	BBB	14/01/2011	14/01/2021	10.0
Goodman	USQ4229FAA32	USD	BBB	12/11/2010	12/11/2020	10.0
Goodman	US38239FAA75	USD	BBB	12/11/2010	12/11/2020	10.0
Rio Tinto	US767201AL06	USD	A-	2/11/2010	2/11/2040	30.0
Rio Tinto	US767201AK23	USD	A-	2/11/2010	2/11/2020	10.0
Sydney Airport	US87124VAA70	USD	BBB	7/10/2010	22/02/2021	10.4
Sydney Airport	USQ8809VAA72	USD	BBB	7/10/2010	22/02/2021	10.4
Woolworths	US980888AD39	USD	A-	22/09/2010	22/09/2020	10.0
Woolworths	USQ98418AH10	USD	A-	22/09/2010	22/09/2020	10.0
Macquarie Bk	XS0543111768	EUR	BBB	21/09/2010	21/09/2020	10.0
Macquarie Gr.	US55608JAD00	USD	BBB	10/08/2010	10/08/2017	7.0
Macquarie Gr.	US55608KAC99	USD	BBB	10/08/2010	10/08/2017	7.0

Issuer	ISIN Number	Crncy	S&P Rating	Issue Date	Maturity	Term
SPI E&G	XS0494132540	HKD	A-	16/03/2010	16/03/2020	10.0
NAB	XS0485326085	EUR	A-	10/02/2010	10/02/2020	10.0
Macquarie Gr.	US55608KAB17	USD	BBB	14/01/2010	14/01/2020	10.0
Macquarie Gr.	US55608JAC27	USD	BBB	14/01/2010	14/01/2020	10.0

Source: Bloomberg, CEG analysis

A.4. Summary

309. While there was a period in the immediate aftermath of the GFC where the Australian long term debt market effectively 'closed' this is no longer the case. Moreover, despite this temporary closure the average tenor of debt issued by Australian and foreign regulated businesses remains at 10 or more years to maturity. This is strong evidence that the most efficient debt issuance policy for regulated utilities is to issue debt of, on average, at least 10 years maturity.

Appendix B. Implications of issuing 5 year debt

310. Issuing 5 year debt will, in most circumstances, lead to a lower interest rate cost for a business than issuing 10 year debt. Therefore, looked at in isolation it may appear that assuming firms issue 10 year debt results in them being allocated a higher interest cost than is efficient (i.e. not the lowest interest rate cost available to the firm).

311. However, this logic is naïve and fails to properly take account of the interrelationship between the maturity structure of the debt issued by a company and the cost of equity. As first described by the Nobel Prize winning finance academics, Modigliani and Miller (1958), changes in the financing structure, including the debt maturity profile, will alter the cost of equity in an offsetting fashion.

B.1. Modigliani-Miller in frictionless financial markets

312. It may well be the case that by assuming that regulated businesses issue five year instead of ten year bonds, the estimated cost of debt for the regulated businesses will be reduced because interest costs on five year bonds are lower than interest costs of 10 year bonds. This, in itself, is not necessarily an error. The error exists if one the fails to analyse what this implies about the cost of equity.

313. Modigliani and Miller (1958) demonstrated that the level of risk in a firm is like the amount of air in a balloon. If one squeezes risk out of one area (e.g. debt) then the risk simply moves to another (i.e. equity). Issuing short-term debt may lower the cost of debt but it does so precisely because it lowers the amount of risk that debt providers have to bear. The corollary of this, however, is that the equity providers have to bear higher risk (i.e. the risk that was previously passed onto debt providers is now retained in the business for equity holders).

314. Miller, 33 years after his seminal paper with Modigliani has used a similar analogy. Miller (1991) states:[67]

> *Think of the firm as a gigantic tub of whole milk. The farmer can sell the whole milk as it is. Or he can separate out the cream, and sell it at a considerably higher price than the whole milk would bring. (Selling cream is the analog of a firm selling debt securities, which pay a contractual return.) But, of course, what the farmer would have left would be skim milk, with low butter-fat content, and that would sell for much less than whole milk. (Skim milk corresponds to the levered equity.) The Modigliani-Miller proposition says that if there were no cost of separation (and, of course, no government dairy support program), the cream plus the skim milk would bring the same price as the whole milk.*

315. In this quote Miller notes that issuing low risk debt securities is analogous to a farmer separating out cream from whole milk. The firm gets a good price (low interest rate)

[67] Miller (1991) *Financial Innovations and Market Volatility*, p. 269

for its debt but the corollary is that the equity it is left with is less desirable (requires a higher return to attract investors).

316. Assuming efficient financial markets and zero transaction costs (as are assumed in the derivation of the CAPM model) Modigliani and Miller demonstrated that the net effect on the weighted average cost of capital will be zero – with the higher cost of equity offsetting the lower cost of debt. Modigliani and Miller effectively described the "law of the conservation of risk" that has its corollary the physical sciences in the "law of conservation of energy".

317. A further conclusion that flowed from Modigliani and Miller was that, if financial markets are perfectly efficient with zero transaction costs, then no debt raising strategy will dominate any other debt raising strategy. All strategies, from issuing very short-term debt to issuing very long term debt, will result in the same weighted average cost of capital (WACC). This means, other things equal, if one were to assume a benchmark regulated utility issued 5 year debt then such a utility would need to have a higher cost of equity than is assumed for a benchmark regulated utility issuing 10 year debt.

318. When similar analysis was put before the AER the AER accepted that it would be incorrect to simply assume that firms could issue 5 year debt at a lower interest rate cost without simultaneously increasing the cost of equity. The below quote from the AER's Final Statement of Regulatory Intent provides a summary of its considerations on the Modigliani and Miller conclusions.[68]

> *The JIA's consultant CEG argues that a focus on the cost of debt in setting the term of the risk-free rate is inappropriate as it violates a fundamental principle of asset pricing theory – that the value of an asset is determined independently of the way in which it is funded. CEG states that:*
>
>> *…one gains the impression that the AER believes that it is efficient to issue short term debt (which has lower interest rates) provided that the transaction costs of issuing short term debt are not higher by an offsetting amount.*
>>
>> *We do not agree with this. The principle of conservation of risk suggests that any lower interest rates available from issuing short term debt will be fully offset by a higher cost of equity – this is known as the Modigliani-Miller theorem.*
>
> *In the AER's view, CEG correctly observes that the impact of current debt financing practices on interest rate risk should already be reflected in empirical equity beta estimates.*

[68] AER, May 2009, Final Decision, *Electricity transmission and distribution network service providers. Review of the weighted average cost of capital (WACC) parameters*, p. 149

319. The AER goes onto state that their intention was only to estimate the cost of debt based on what businesses actually do. Having been convinced that businesses actually do issue 10 year debt (as discussed at section Appendix A above) the AER concluded that it would set the cost of debt based on what businesses actually do.

B.2. Modigliani-Miller financial markets with frictions

320. On the basis of the Modigliani-Miller theorem then, in frictionless financial markets, capital structure simply does not matter. As a result, we would expect to see very similar firms having a great variety of capital structures (some with short term debt and some with long term debt, some with high gearing and others with low gearing etc).

321. By contrast, if we observe that, in the real world, there is a dominant debt raising strategy, such as issuing long term debt; then Modigliani and Miller demonstrated that this must be because transaction costs are positive (financial markets are less than perfect). If we observe a dominant strategy of issuing long-term debt then this must be because there are advantages to issuing long term debt, such as lessening exposure to refinance risk and potential insolvency and bankruptcy transaction costs.

322. These advantages must *more than fully* offset the advantages of gaining a lower interest rate by issuing short-term debt. That is, if issuing long-term debt is a dominant strategy for particular kinds of businesses then it must be the case that issuing short-term debt not only does not reduce the WACC but actually raises the WACC (ie, is less efficient than issuing long-term debt). That is, it must be that the cost of equity increases by more than the cost of debt reduces when short-term debt is issued – otherwise long term debt issuance would not be the dominant observed debt issuance strategy.

323. This suggests that it is important to look at what businesses actually do. When we do this we conclude that businesses with long lived sunk assets of the nature of regulated businesses have, historically, a very strong tendency to issue ten year (or longer) debt.

B.3. Implications of a post GFC trend issue short term debt

324. In the immediate wake of the GFC the Australian corporate bond markets essentially closed for business – with no new corporate bond issues between September 2008 and late March 2009.[69] Most debt issued since then has been for less than 10 years maturity - including debt issued by regulated businesses. The only 10 year debt issued in Australia by an owner of regulated infrastructure has been by APA.

325. The AER has recently compiled the following list of debt issues by businesses with regulated assets and has compared the debt risk premium on the issued bonds with

[69] This is discussed in section 5 of a September 2009 CEG report, *Estimating the cost of 10 year BBB+ debt during the period 17 November to 5 December 2008, available at:* http://www.aer.gov.au/content/item.phtml?itemId=730748&nodeId=79a6910913b3d4264288ba48fb3df96e&fn=CEG%20AMI%20report%20-%20estimating%20cost%20of%2010%20year%20BBB+%20debt%20-%2017/11-5/12/08.pdf

the debt risk premium of between 3 and 4 percent that it has allowed in contemporaneous regulatory decisions (based on a 10 year debt issuance assumption).

Table 16: Table 7.5 from AER Rule Change Proposal (September 2011)

Table 7.5 Observed debt issuances by owners of regulated electricity networks and gas pipelines

Issuer	Type	Issuance	Maturity	Amount ($'m)	Term	DRP (per cent)	Source
SPI	MTN	Feb 2010	Aug 2015	520	5.50	2.06	1
SPI	MTN	Mar 2010	Mar 2020	100	10.00	2.18	1
SPI	MTN	Mar 2010	Sep 2017	300	7.50	2.09	1
APA Group	MTN	Jul 2010	Jul 2020	300	10.00	2.90	1
SPIAA (Jemena)	MTN	Aug 2010	Aug 2015	500	5.00	2.35	2
DUET Group (DBP)	MTN	Sep 2010	Sep 2015	550	5.00	3.56	1/3
SKI	Bank debt	Sep 2010	Sep 2013	165	3.00	2.28	1
SKI	Bank debt	Sep 2010	Sep 2014	85	4.00	2.58	1
ETSA	MTN	Mar 2011	Sep 2016	250	5.50	1.81	1
SPI	MTN	Mar 2011	Apr 2021	250	10.01	2.18	1
DUET Group (UED)	Bank	Apr 2011	Apr 2014	380	3.00	2.14	1/3
DUET Group (UED)	Bank	Apr 2011	Apr 2018	120	7.00	3.06	1/3
Average spread						2.43	

Sources: 1 – ASX, 2 – Newspaper Release, 3 – Merrill Lynch. AER analysis.

326. The first point to note about this table is that it includes five debt issues by entities that are in part owned by the Government of Singapore (SPI and SPIAA). The AER's own consultants, Oakvale Capital, have advised the AER that the debt premiums on such debt are depressed by the implicit government guarantee associated with this ownership structure.

> *During the averaging period the bond was attracting one of the lowest yields, in contrast to other A- bonds observed (as per the CEG report). The key feature*

supporting the bond was the parental support of the issuer's owners and the link to the Government of Singapore.[70][71]

327. For this reason it is inappropriate to draw any conclusions based on the SPI issues. Of the other issuers only one 10 year bond has been issued and the average maturity of the remaining debt is less than 5 years.

328. In relation to these short term issues, the AER's implied (but unstated) conclusion is that lower DRPs for these issues is evidence that the cost of debt that it has set under the existing National Electricity Rules has been "too high" and that the rules need to be changed to allow the AER to set a lower cost of debt that better reflects the actual cost of debt.

329. This conclusion may be intuitively appealing to a lay audience of non-finance experts who do not think in terms of the link between the cost of equity and the cost of debt. However, as explained by Modigliani and Miller (1958), this logic is naïve and fails to properly take account of the interrelationship between the maturity structure of the debt issued by a company and the cost of equity.

330. When considered in the context of Modigliani-Miller, it must be recognised that:

- at least part of the lower cost of debt associated with actual issuance is a reflection of the fact that the maturity of the debt is, on average, much shorter than 10 years; and
- the savings on debt interest costs due to the issuance of short term debt will be offset by higher risks retained by equity providers.

331. The fact that debt market conditions are preventing businesses from issuing long term debt (which the Australian and international evidence clearly shows is the preferred strategy) should properly be associated with a conclusion that the cost of equity has been raised by an amount that is at least equal to the interest savings from issuing short term debt.

332. This means that if the AER's seemingly implicit objective were achieved, and the allowed DRP reflected the actual DRP for issuing short term debt, then there would need to be an offsetting increase in the cost of equity that would leave the WACC unchanged. Put simply, the AER's implicit reasoning implies a free lunch in capital structuring when the finance community has understood, formally since Modigliani and Miller (1958), that no such free lunch exist.

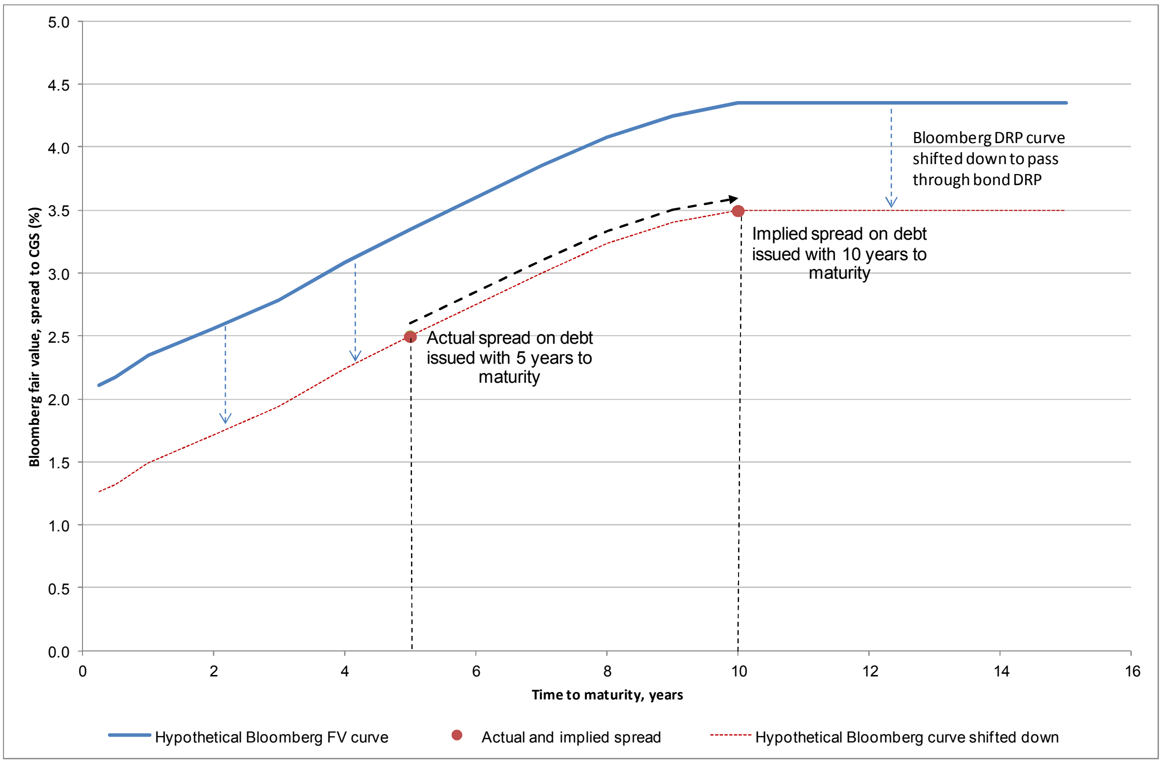
[70] Oakvale Capital, Report on the cost of debt during the averaging period: The impact of callable bonds Prepared for the Australian Energy Regulator, page 24.

[71] Moreover, at least one of these bonds (the 7.5 year maturity bond) had the special characteristic that its coupon would rise if the bond was ever downgraded – providing some protection to investors above and beyond that implied in its A- credit rating. Ibid, para 67.

333. In this regard it is informative to estimate what the implied cost of debt is for the non-SPI issues in the above table assuming that they were issued at 10 years. I have done this by adding to the DRP on the bond at the time of issue an increment that reflects the increase in DRP that bond would have needed to offer if it had a 10 year maturity rather than its actual maturity. For each bond I have estimated this increment as the increase in DRP between the actual maturity date and a 10 year maturity date implied by the Bloomberg BBB fair value curve[72] (over the twenty days immediately following the date of issue).

334. This approach is described graphically in Figure 22 below.

Figure 22: Description of methodology for arriving at the implied 10 year DRP for an issuer from shorter dated debt issued by that issuer

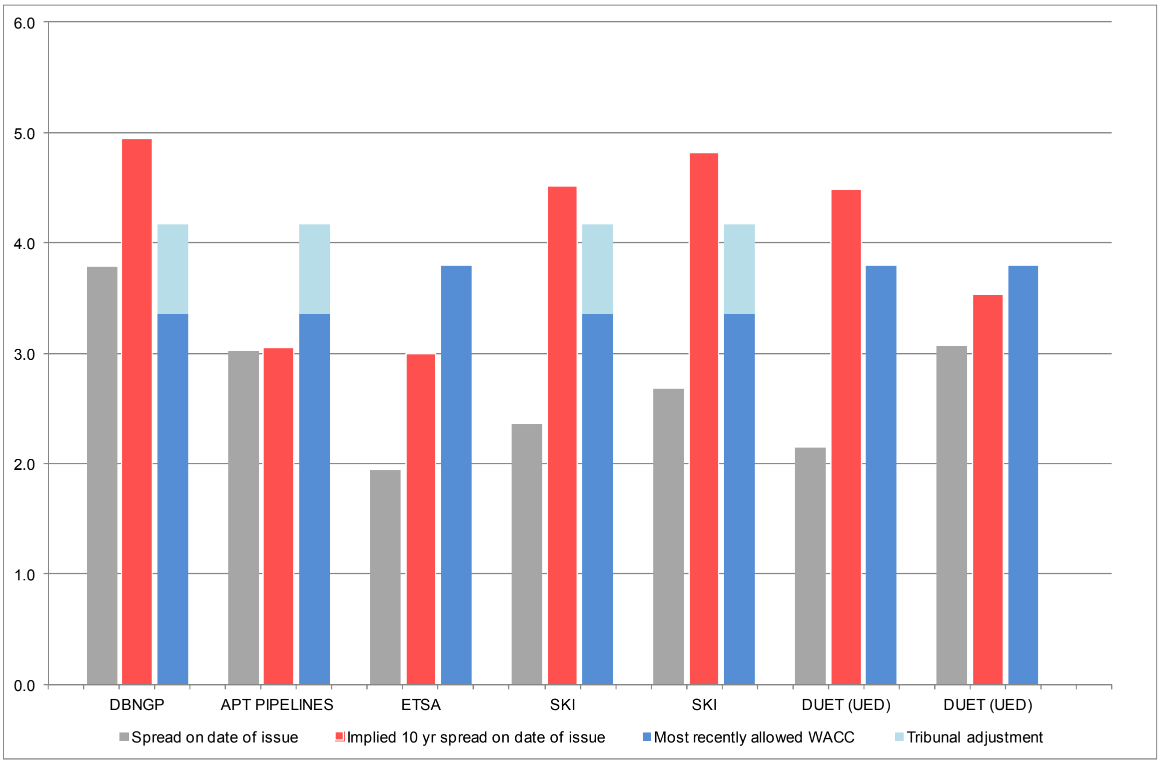


335. As illustrated in this figure, the absolute level of the Bloomberg fair value curve is not being used to determine an implied spread at 10 years maturity. All that is being used is the increase in DRP with maturity implied by the Bloomberg curve.

[72] Extrapolated from7 to 10 years when necessary using the AER's preferred extrapolation methodology – see section C.3.6 on page 255 of the AER's draft decision for Envestra's Queensland gas distribution assets for a description of this method. The decision states that: *the AER considers its extrapolation approach provides the best estimate possible in the circumstances of Envestra.*

336. When the non-SPI DRPs reported by the AER are adjusted to 10 years and then compared with the 10 year DRP allowed by the AER in the decision that is closest to that bond issue a much more useful comparison is made. The results of this comparison are provided in Figure 23 below.

Figure 23: Actual DRP, Implied DRP at 10 years, AER DRP and any adjustment ordered by the ACT



337. This figure shows that in four out of seven cases, when adjusted to 10 years maturity, the DRP on the non-SPI bonds was higher than the DRP allowed by the AER (in the regulatory decision most proximate to that issue). In four cases, the most proximate regulatory decision was that for Jemena Gas Networks (JGN) which was successfully appealed to the ACT. Even when compared to the final DRP allowed (post any appeal) it still remains the case that four out of the seven bond issues had higher implied DRPs at 10 years than allowed.

338. Importantly, had the AER's JGN decision been allowed to stand by the ACT it would have been below the implied DRP at 10 years for five out of the seven non-SPI bonds in the AER's list. Moreover, even the post appeal JGN DRP, when compared to the bond issues for which this is the most proximate regulatory decision, is lower than three out of four of the implied 10 year DRPs on these bonds.

339. Finally, it is worth noting that the one out of the four that had a lower yield was the APA Group (APT) bond. However, this bond has an abnormally low DRP for its maturity

when compared to other bond yields (both included in the AER sample and more generally).[73] Such a conclusion is supported by commentary from market participants such is embodied in the following quote from Australian Ratings.[74]

> *Indeed, the APT 2020 bond is an example of a rare bond that broke new ground with investors, when issued in July 2010. The issue was reported at the time in the market newsletter, The DCM Review, as follows[13]:*
>
> > ***APA Group opens eyes***
> >
> > *As for events that may be more significant for the longer term development of the market, the bond issue by APA Group via its financing subsidiary APT Pipelines Ltd., opened the eyes of many potential corporate issuers. Until now these potential issuers had little confidence in the market as viable source of medium to long term debt and would have gone straight to the US markets.*
> >
> > *Perhaps they will now reconsider.*
> >
> > *The deal sets a new record as being the first ten year bond issued by a „BBB" rated issuer. Snowy Hydro (then BBB+) issued ten year bonds in 2003 and Southcorp (then BBB+) was the first to do so in 2000.*
> >
> > *The deal is one of only six bond issues with a term to maturity of ten years or more, made this year, and Telstra is the only other non-financial institution issuer to do so. It is also one of only seven „BBB" category issuers this year.*
> >
> > *An examination of this group of issuers reveals an interesting pricing comparison. Dexus Property Group issued A$180 million of bonds for seven years in April (before the recent troubles in financial markets broke out), priced at 270bps over swap. Against this, the pricing of APA Group"s issue at 240bps over, looks sensational, being rated one notch lower and with a term to maturity three years longer.*
>
> *The unusual and rare nature of the bond was recognised in subsequent industry awards from KangaNews and FinanceAsia at the end of 2010.[14]*
>
> *Footnote 13: The DCM Review 19 July 201*
>
> *Footnote 14: KangaNews Volume 5, Issue 46, FinanceAsia.com Achievement Awards 2010*

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[73] For example, see CEG report for APT in relation to the Roma to Brisbane pipeline cost of debt, available at http://www.aer.gov.au/content/item.phtml?itemId=750414&nodeId=402c105751874ba522a25e733f8e2c2f&fn=Attachment%206.1%20CEG%20Debt%20premium.pdf

[74] Australian Ratings, Expert Opinion Prepared for N.T. Gas Pty Limited, Estimating the Debt Risk Premium, 26 May 2011.

Appendix C. Conversion calculations from YTC to YTM

C.1. Background

340. UBS quotes floating rate bonds by reference to "trading margins". A trading margin is the same as a DRP but instead of being measured relative to the CGS rate the trading margin is measured relative to the swap rate. Quoting risk premiums for floating rate bonds relative to the swap rate is standard market practice. UBS quotes trading margins for floating rate bonds rather than DRPs. All of the bonds discussed below are floating rate bonds and so the discussion is primarily in terms of trading margins. The equivalent fixed rate yield on a bond is calculated as the trading margin plus the swap rate to the relevant maturity. However, in a given maturity range, the DRP is a roughly constant level above the trading margin reflecting a roughly constant difference between the swap rate and the CGS rate.

C.2. AER views

341. The AER appears to believe that where a UBS rate sheet lists a bond's next call date under the 'maturity' column then the yield/trading margin for that bond should be interpreted as a yield/trading margin to call rather than a yield/trading margin to maturity.[75]

342. If that is correct, the yield to maturity will be lower than the yield to call for any bond that is trading at less than its face value (ie, where the trading margin on the bond is more than the coupon margin the bond is paying).

343. This is because the capital gain payable on the bond if held to maturity (the difference between the trading value and the face value), while the same as the capital gain received if the bond is called, is received later (ie, at maturity rather than at the first call date). Put simply, if the capital gain occurs at maturity rather than call date then the bond is less attractive (has a lower yield to maturity) than if the capital gain is realised at the (earlier) call date.

344. If this is correct then I would be wrong to include the yields on these bonds at their actual maturity.

C.3. AER views can be tested by examining DBCT bonds relative to each other

345. It is possible to test this speculation by comparing the yields on different DBCT bonds. If the AER is correct, two of the three labelled DBCT bonds in the charts in this report do not require adjustment because they are quoted 'to maturity'. One does require adjustment because it is quoted 'to call' and therefore, under the AER's contention, should be adjusted. However, as outlined below, if the adjustment is made, the DBCT

[75] AER, *Draft decision: Powerlink transmission determination*, November 2011, p. 217

bond is given a DRP that is not credible relative to the DRPs for the other two DBCT bonds - where it is agreed by the AER that no adjustment is necessary. Specifically, the adjustment would result in a DRP of around 1.2% (calculation described below) which is inconsistent with the DRPs of the other two DBCT bonds which are in excess of 4.0%.

346. This demonstrates that UBS's trading margin is, at least for this bond, best interpreted as applying 'to maturity' rather than 'to call'.

347. However, this technique of pair-wise comparison cannot be applied to other bonds in question (eg, Suncorp and Vero) because, unlike the DBCT bonds, there is no single bond from these companies where UBS lists the true final maturity date. All of these bonds would, if the AER was correct, require adjustment and, therefore, there is no 'control' against which the adjusted yields can be compared for reasonableness.

348. Moreover, these bonds all have call dates that are much later than the DBCT bond – which means that the required adjustment would be much smaller. For these reasons, one cannot so readily demonstrate that the AER's hypothesis is not credible with respect to these bonds. However, it remains the case that the AER's hypothesis is speculation rather than fact and that this speculation is clearly wrong in relation to at least one of the callable bonds, namely the DBCT bond maturing on 12 December 2022.

C.4. Details of DBCT adjustment calculations

349. The DBCT bonds provide the best basis on which to test the AER's hypothesis because:

- There are two DBCT bonds where UBS lists the final maturity of the bond in its rate sheets. Therefore, it is uncontested that the trading margin information for these bonds is associated with the final maturity of the bond.
- There is one DBCT bond where UBS lists the first call date in its rate sheets:
  a. The first call date for this bond was on 12 December 2011 but the final maturity is 11 years later;
  b. The trading margin on this bond is well above the coupon margin on the bond (300bp vs 29bp on the 2nd December 2011).

350. The coupon rate on the DBCT bond to be adjusted is only 29bp above the swap rate (that is the bond will pay coupons equal to the swap rate plus 0.29% of the face value of the bond).

351. Consequently, in order to earn a return of 300bp above the swap rate, the remaining return of approximately 271bp (300bp-29bp) must come in the form of a capital gain at the time the bond is redeemed (its maturity date or its call date). This capital gain reflects the difference between the bond's trading price and its face value.

352. If the AER is correct that UBS's yields are expressed to the first call date then UBS must be estimating that an approximate 271bp annual capital gain is to be delivered on the bond's first call date, only 10 days after 2 December 2011 (being the date from which the UBS trading margin of 300bp was taken). However, because the call date is only 10 days away, it is equivalent to an absolute capital gain of around 7.4bp (271*(10/365)).

353. If this were indeed the case then this same 7.4bp capital gain, realised at maturity (11 years time) gives just 0.7bp capital gain per annum (7.4bp/11 years)

354. When this annual capital gain is added to the 29bp coupon return the total margin above the swap rate to maturity is only around 30bp. A 30bp trading margin is associated with a DRP of around 1.0% (given a margin between swap and CGS rates of around 73bp on 2 December 2012).

355. The nature of the calculations set out above are approximate because they are limited to simple addition and division of the relevant UBS rate sheet values. This makes the calculations, and the underlying financial logic, simple to understand. However, a precise estimate, discounting all relevant cashflows to determine the internal rate of return, would not differ materially from these values. We have performed these calculations and estimate an adjusted DRP for the DBCT bond of 1.17% on 2 December 2012.

C.5. Use of Bloomberg YASN function to make the adjustment

356. In the Powerlink draft decision the AER gas stated that:

> *The AER is aware of a method that applies the Bloomberg YASN function to make the adjustments discussed above. However, the AER has had technical issues with the application of the function, and is undertaking further analysis to address these issues. Accordingly, the AER considers the method for adjusting callable bonds is not, in the current circumstances, sufficiently reliable to include these bonds in the sample. (Page 217).*

357. However, we are able to use this function to make the necessary adjustments. We have used this function in Bloomberg to estimate the yield to maturity of the DBCT bond maturing on 12 December 2022 if one interprets the UBS trading margin as being a yield to call.[76] The result is a yield to maturity of 5.10% (which is very close to our own estimate of 5.17%).

[76] This is achieved by substituting a price for the bond into the YASN function that is equal to the price in the UBS rate sheets on the 2nd of December 2012. I note that the price in the UBS rate sheets appears to be a mechanical calculation that solves for the price that is consistent with the trading margin and the maturity date that is listed in the spreadsheet. In the case of this bond, the maturity date is the call date and, therefore, the price is the price that would exist if the trading margin were expressed on a trading margin to call basis. (I note that, for the reasons described above, the only reasonable interpretation of this data is that the UBS trading margin is expressed on a yield to maturity basis but that the rate sheet

Figure 24: Screenshot of Bloomberg YASN function

Source: Bloomberg

mechanically derives an (incorrect) price for the bond by treating that trading margin as being expressed on a 'to call' basis.)

Appendix D. Method to calculate Australian dollar equivalent yields on foreign currency bonds

358. Bloomberg's XCCY function estimates cross-currency swap rates between any pair of currencies for given characteristics, such as maturity, coupon payments and payment frequency.

359. Given the number of foreign currency bonds issued in Australia (over 1000, with 20 days of data for each) it is not practicable to use this function to convert each bond on each day, given that each historical conversion is a manual process. To resolve this practical difficulty, I establish a mapping between foreign currency bond yields and Australian dollar bond yields for each currency using a cross-section of conversions obtained from Bloomberg at different maturity-yield pairs averaged over three days in the averaging period. Given the maturity and yield of the foreign currency bond to be swapped, I use interpolation across these points to identify the equivalent Australian dollar yield at that maturity.

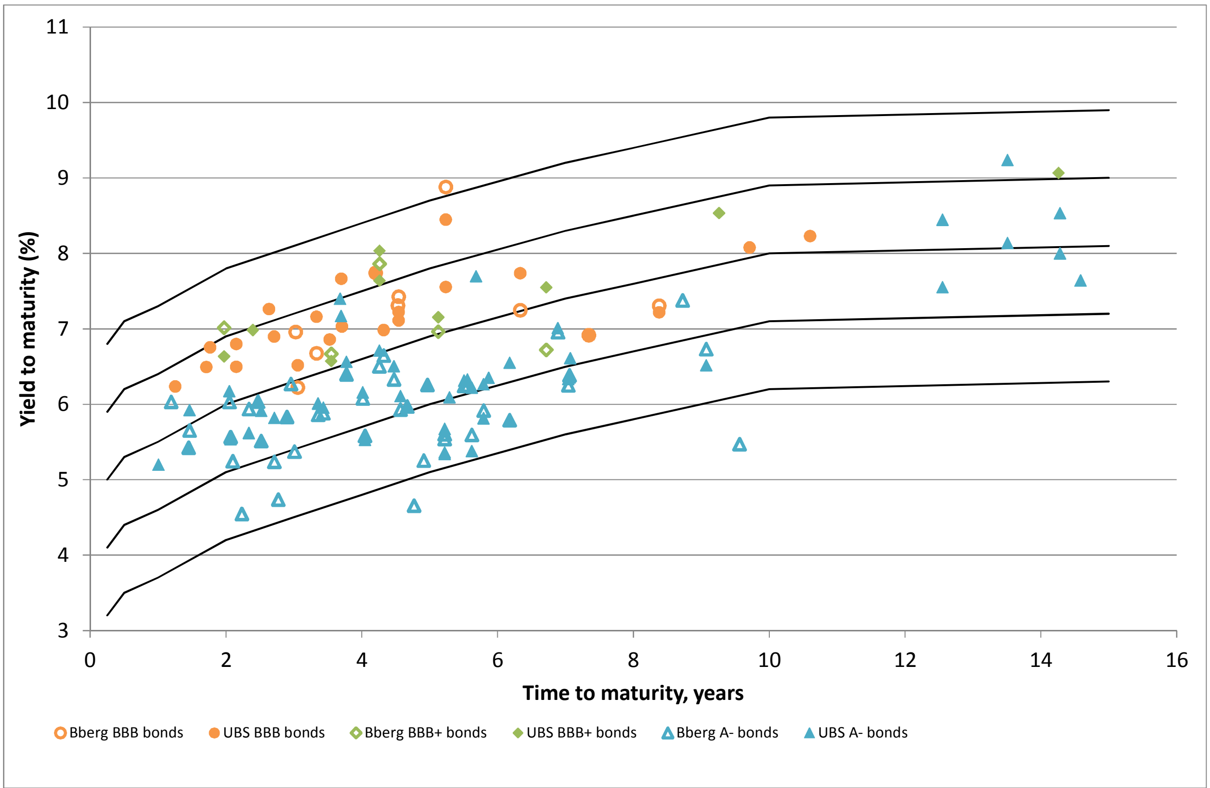
360. It is convenient to establish this mapping on a common set of Australian dollar maturity-yield pairs. The following table of Australian dollar yields was swapped into equivalent foreign currency terms for the nine most common currencies for 16 March 2012, a date in the middle of Western Power's averaging period. These currencies were CAD, CHF, EUR, GBP, HKD, JPY, NZD, SGD and USD. It is important to note that the yields in Table 17 below have been chosen based on typical yields observed at each maturity in Australian dollar terms in order to establish a range that will encompass the majority of bond yields. However, the selection of these yields only forms a 'mesh' of points at which cross-currency conversions are made and then used to inform conversions at other points. The results of the methodology do not turn on the selection of these particular points.

Table 17: Australian dollar yield-maturity pairs used for cross-currency swap calculations

Maturity					
0.25	3.20	4.10	5.00	5.90	6.80
0.5	3.50	4.40	5.30	6.20	7.10
1	3.70	4.60	5.50	6.40	7.30
2	4.20	5.10	6.00	6.90	7.80
3	4.50	5.40	6.30	7.20	8.10
4	4.80	5.70	6.60	7.50	8.40
5	5.10	6.00	6.90	7.80	8.70
7	5.60	6.50	7.40	8.30	9.20
8	5.80	6.70	7.60	8.50	9.40
10	6.20	7.10	8.00	8.90	9.80
15	6.30	7.20	8.10	9.00	9.90

361. To understand why I consider that the yield-maturity pairs used in Table 17 above are likely to produce reasonable estimates of Australian dollar yields, Figure 25 below shows these charted against the yields on the population of domestic bonds rated BBB to A- (as shown earlier at Figure 2 above).

Figure 25: Cross-currency yield-maturity pair matrix against BBB to A- domestic bond yields



Source: Bloomberg, UBS, RBA and CEG analysis
Note: Data sourced as an average over 5 March 2012 to 30 March 2012

362. I note that the precision of the approximation obtained could always be improved by collection of more maturity-yield pairs. However, I judge in the circumstances that the pairs in Table 17 above are sufficient to provide a reasonable approximation.

363. The swapped United States table was derived from Bloomberg for 16 March 2012 as illustrated in Table 18 below. Each element in Table 18 is mapped from the equivalent element in Table 17. Table 18 is provided for illustrative purposes but it should be noted that similar tables are produced for each of the nine currencies that I obtain bond yield information from.

Table 18: United States dollar calculated yield-maturity pairs used for cross-currency swap calculations

Maturity					
0.25	-1.088	-0.191	0.707	1.605	2.502
0.5	-0.789	0.109	1.006	1.904	2.802
1	-0.400	0.464	1.329	2.193	3.058
2	0.180	1.028	1.876	2.725	3.573
3	0.585	1.418	2.251	3.084	3.917
4	1.019	1.839	2.658	3.477	4.296
5	1.456	2.263	3.069	3.876	4.683
7	2.193	2.978	3.763	4.548	5.333
8	2.493	3.268	4.044	4.819	5.595
10	3.060	3.819	4.578	5.337	6.096
15	3.468	4.193	4.919	5.644	6.370

Source: Bloomberg

364. In order to swap bonds from foreign currency yields into Australian dollar yields, the tables are used to interpolate five foreign currency yields and five equivalent Australian dollar yields at the maturity of the bond. Then the foreign currency yield is used to interpolate across the five Australian dollar yields to give the resulting estimate in Australian dollar yield terms.

365. For example, the following table of foreign currency and Australian dollar yields can be constructed for a United States dollar bond with maturity of 9 years:

Table 19: Example of swap calculation

Maturity	Yield 1	Yield 2	Yield 3	Yield 4	Yield 5
AUD	6.000	6.900	7.800	8.700	9.600
USD	2.776	3.544	4.311	5.078	5.845

366. If the bond in question has a yield in United States dollars of 5.00%, then by interpolating between the third and fourth columns in the table above it is possible to show that the approximately equivalent Australian dollar yield is 8.61%. Yields for other foreign currency bonds are converted into Australian dollar yields in the same way.

Appendix E. Term of reference

Assuming that you were required to estimate the DRP based on the average DRP for a sample of bonds, as adopted by the ERA in their Draft Decision for Western Power, please advise on the following

1. in your opinion what data sources for bond yields should be used?
2. in your opinion what criteria for including/excluding specific bonds from the sample should be used?
3. in your opinion what methodology should be used for arriving at an average?
4. in your opinion what estimate for DRP you would arrive at assuming a 10 vs. 5 year issuance?
5. to the extent that your 5 year issuance estimate differs from the ERA's please provide reasons
6. how does the ERA's approach reconcile with recent Tribunal decisions in respect of estimating the DRP.
7. in your opinion does the ERA's bond yield approach meet the requirements of the Access Code.

Internal consistency of risk free rate and MRP in the CAPM

Prepared for Western Power

May 2012

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Executive summary

Idiosyncratic application of the CAPM

1. The ERA and other Australian regulators set the cost of equity for regulated businesses using the Sharpe Lintner CAPM formula. The Sharpe Lintner CAPM formula states:

$$Cost\ of\ equity = Prevailing\ RFR + (Prevailaing\ beta\ x\ Prevailing\ MRP)$$

2. The ERA's methodology adopts the prevailing yield on 5-year CGS as a proxy for the risk free rate. However, this methodology involves an idiosyncratic application of the CAPM whereby:

   - the risk free rate proxy is estimated over a 20-day interval prior to the start of the regulatory period; but
   - the market risk premium (MRP) is estimated by reference to the long run historical average excess return on equities relative to CGS; and
   - equity beta is estimated by measure to the long run correlation between returns for benchmark companies and returns on relevant share markets.

3. This construction means that the risk free rate as used by the ERA in the CAPM is highly volatile. Twice in this period, first in early 2009 and then in late 2011, yields have fallen to levels not previously seen in the last fifty years. However, the ERA's estimates of MRP and equity beta will be relatively stable over time. The effect of this is that movements in CGS yields are passed through 'one-for-one' into movements in the ERA's estimate of the cost of equity, but that changes in current values of MRP and equity beta will not immediately be reflected in the cost of equity.

Current MRP is higher than historic average

4. This will be problematic if, during the relevant regulatory period, the MRP significantly departs from the long term average. Where the MRP is significantly higher during a regulatory period than its long-term average, the ERA's methodology will underestimate the overall cost of equity. The empirical evidence suggests that the current MRP is elevated above the long term average preferred by the ERA and therefore the ERA's methodology will underestimate the overall cost of equity.

5. I undertake three empirical methods for estimating the current MRP and equity risk premiums for utilities:

   - Bloomberg's internal estimates of the current MRP for Australian equities, based on dividend growth model (DGM) analysis, indicate that it is 8.61%;

- current MRP can be approximated using dividend yields in a method used by AMP Capital Investors and previously relied upon by the AER. The AMP method suggests MRP of 7.75% in March 2012; and
- a DGM for the six listed Australian regulated utilities suggests an average equity risk premium for utilities of at least 6.73% over the month to 9 March 2012. Given a range of equity beta of 0.8 to 1.0, this suggests an MRP of between 6.73% and 8.41%.

6. All these risk premiums have been estimated relative to risk free rates proxied by 10-year CGS yields. By their construction, they would be higher measured relative to 5-year CGS yields.

Negative relationship between CGS yields and risk premiums

7. The problems with the idiosyncratic application of the CAPM are further exacerbated where there is a negative relationship between risk premiums and risk free rates. In these circumstances the ERA's methodology will result in an unstable estimate of the cost of equity that at the present time is likely to be considerably biased downward.

8. The evidence is clear that risk premiums are not constant through time. Rather, risk premiums tend to move in the opposite direction to the yield on CGS (noting that the ERA uses CGS yields as the proxy for the risk free rate in the CAPM). This evidence was sufficiently clear for Smithers and Co, a firm of asset allocation specialists from whom the UK economic regulators sought advice, which recommended that the best estimate was that any rise/fall in the risk free rate would be fully offset by a countervailing rise/fall in investor's required return for risk.

   > *Given our preferred strategy of fixing on an estimate of the equity return, **any higher (or lower) desired figure for the safe rate would be precisely offset by a lower (or higher) equity premium, thus leaving the central estimate of the cost of equity capital unaffected.***[1] (Emphasis added)

9. The negative relationship between the risk free rate and the market risk premium is factored into regulatory regimes in the UK and the US.

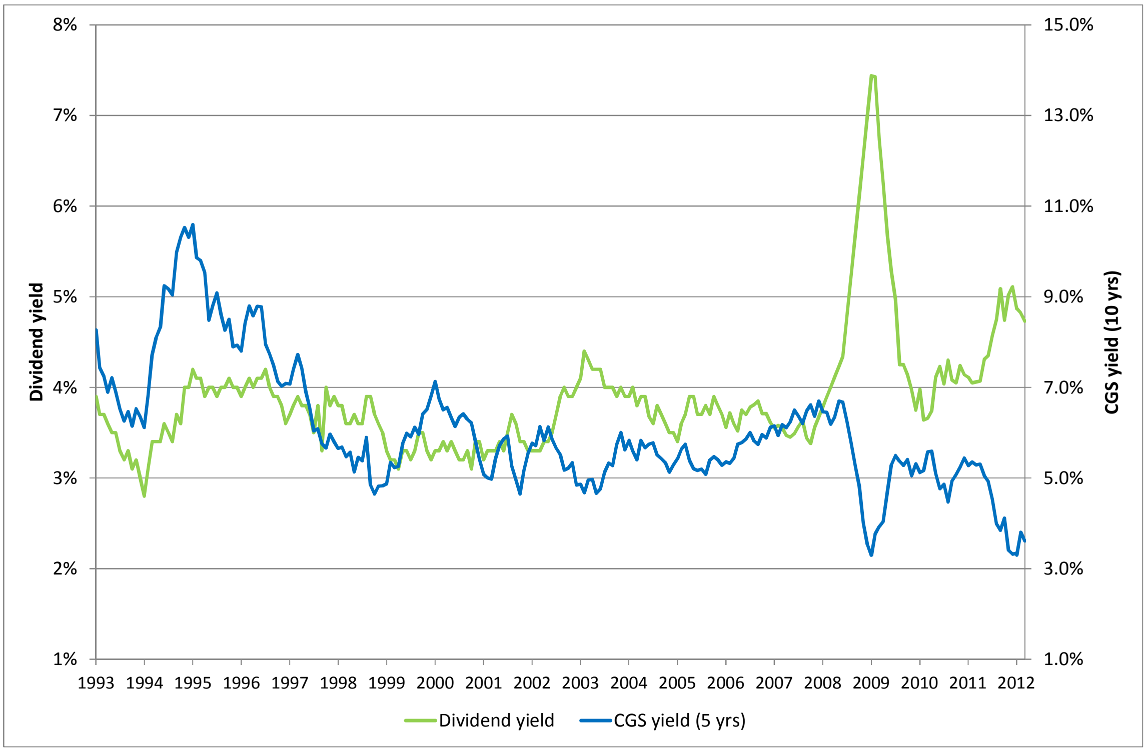
10. In Australia this negative relationship is well illustrated by Figure 13 of this report, which is reproduced below. The figure shows a time series for the equity risk premium for Australian publicly listed equities estimated using the AMP method as described in the body of this report (and as previously relied upon by the Australian Energy Regulator to support its estimate of the MRP) against the 10 year yield on Commonwealth Government Securities (CGS) (noting that I consider that the 10 year CGS rate is the best proxy for the risk free rate to be used in the Sharpe-Lintner CAPM formula set out above).

[1] Smithers and Co, A Study into Certain Aspects of the Cost of Capital for Regulated Utilities in the U.K., A report commissioned by the U.K. economic regulators and the Office of Fair Trading. (2003), p. 49

11. The figure shows that there is a clear negative relationship between the equity risk premium and the yield on 10 year CGS. The equity risk premium is lowest when CGS yields are highest and highest when CGS yields are lowest (in early 2009 and once more at the time of writing in early 2012).

12. Moreover, this negative relationship can be clearly discerned even when CGS yields are at less extreme levels. For example, between 1998 and 2005, peaks in the MRP are generally coincident with troughs in CGS yields (in late 1998, 2003 and 2005), whilst peaks in CGS yields occur with troughs in the MRP series (in 2000, in 2002 and again in 2004).

Risk premiums on listed equities (AMP method) vs. 10 year yield on CGS

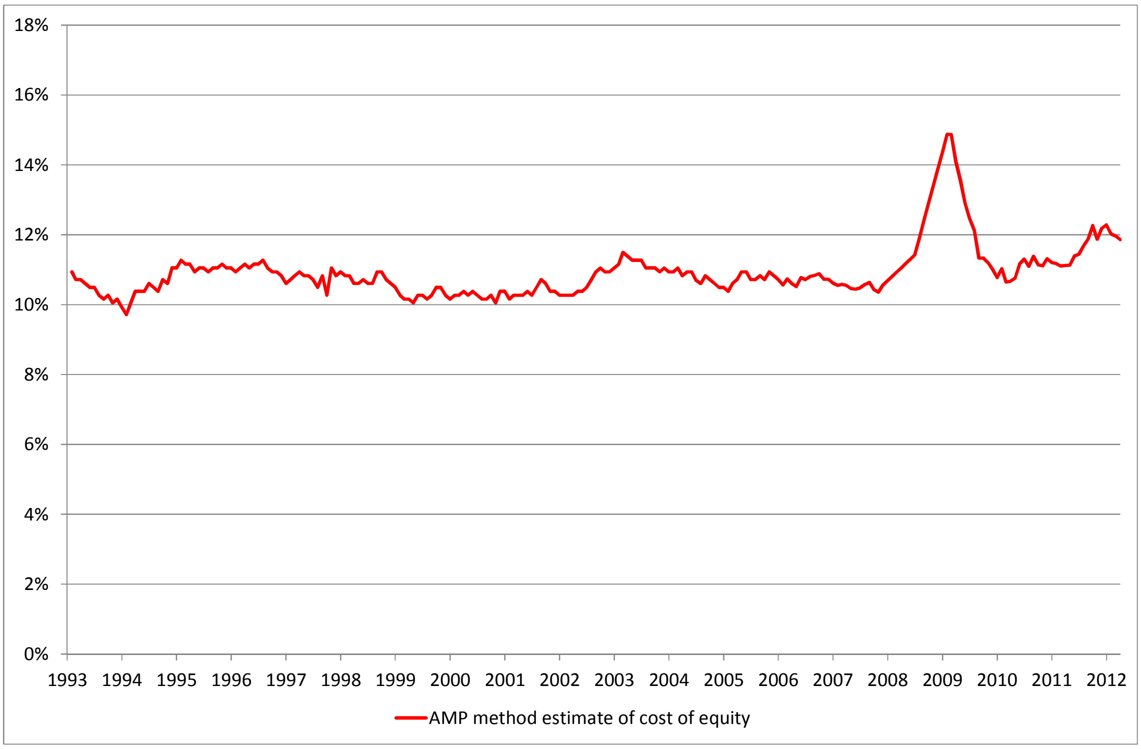


Source: RBA, CEG analysis

13. The negative relationship between risk premiums and yields on CGS illustrated in the figure above is intuitively easy to understand. In periods of high investor risk aversion there is a flight from risky assets to safe assets. This tends to push up the price and push down the yields on safe assets. For this reason, falling risk free rates tend to be associated with rising investor risk premiums (and vice versa).

14. Given this negative relationship between the risk free rate and the risk premiums on listed equities, it is unsurprising that the sum of them, being the required return on the listed equity market, is, consistent with the advice of Smithers and Co, much more stable than its constituent parts. This relative stability of the required return on equity is illustrated in Figure 14 in the body of the report, and reproduced below.

Total cost of equity (AMP method)



Source: RBA, CEG analysis

15. I note that this relative stability is in contrast to the volatility in estimates of the cost of equity using the ERA method – exemplified by its recent draft decision for Western Power where the ERA sets a dramatically low cost of equity (relative to past regulatory decisions) despite the AMP method determining an increase in the market cost of equity.

16. The AER applies a similar methodology to the ERA (the only material difference being the use of a 10 year CGS rate at the risk free rate proxy). The last time it implemented this application of the CAPM during a period of historically low yields on CGS was in early 2009 – when MRP estimates using the AMP method were at historically high levels, as is illustrated in the two figures above. The issue of the measurement of the risk free rate (including the time period over which it should be measured) was the subject of a merits review brought by the NSW electricity distributors, and the NSW and Tasmanian electricity transmission operators.

17. In those proceedings I advised the electricity distributors and transmission operators, drawing upon analysis which is similar to that presented in this report (while the time periods are different the key facts are remarkably similar). The Tribunal agreed that using historically low interest rates to set the cost of equity without increasing the

market risk premium was likely to underestimate the cost of equity. The Tribunal stated:[2]

> *The Applicants submitted that these facts demonstrated that basing a risk free rate on the AER's specified averaging periods would not achieve the objective of an unbiased rate of return consistent with market conditions at the date of the final decision. They appealed to expert opinion that the market risk premium was far higher than its deemed value while the risk free rate was abnormally low, so that the return required by investors was much higher than the AER's specified averaging period would generate.*
>
> …
>
> *The Tribunal considers that an averaging period during which interest rates were at historically low levels is unlikely to produce a rate of return appropriate for the regulatory period.*

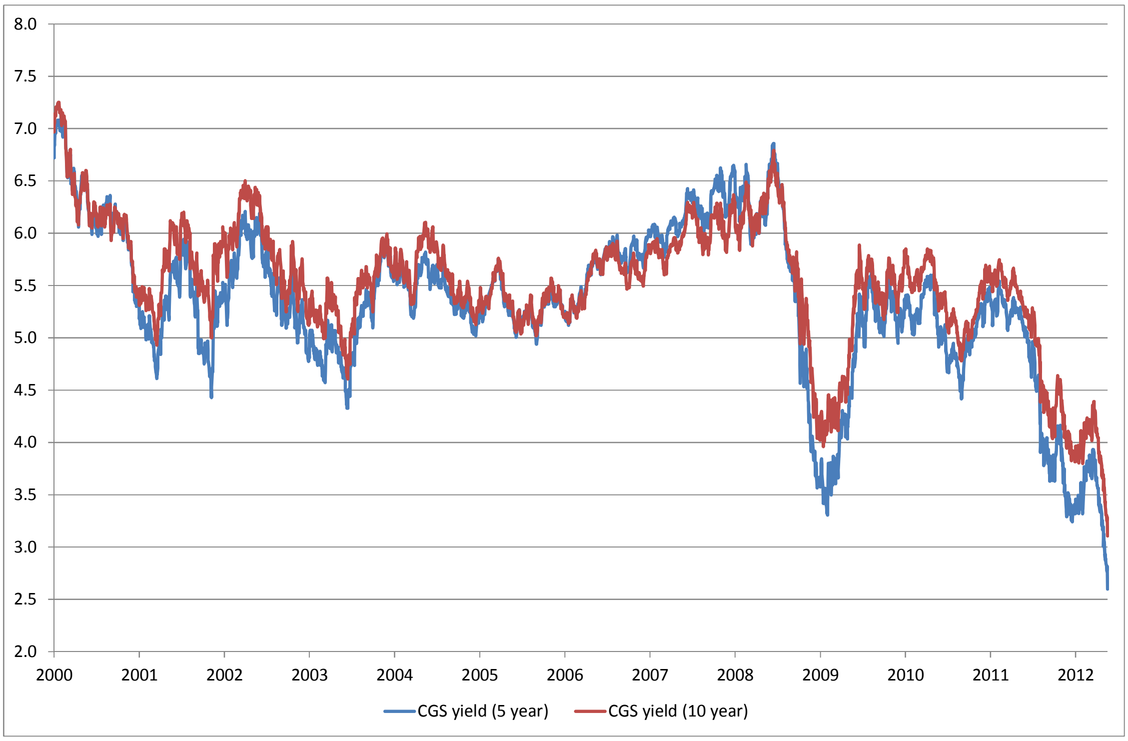
Adoption of 5 year CGS as risk free rate proxy magnifies the problems

18. It is relevant to note that the real risk free rate set in the ERA's Western Power draft decision is even lower than the real risk free rate that was overturned in the decision discussed above (1.1% versus 1.8%). In part this reflects the fact that all CGS rates are at historically low levels. However, the extremely low risk free rate estimate adopted by the ERA is exacerbated by the decision to adopt a 5 instead of a 10 year term.

19. Yields on 10-year CGS are materially more stable than for CGS with shorter maturities. The below figure illustrates the yields of five and ten year CGS since 2000.

[2] *Application by EnergyAustralia and Others (includes corrigendum dated 1 December 2009)* [2009] ACompT 8 (12 November 2009), paras. 112-114

Commonwealth Government Security yields



Source: Reserve Bank of Australia, CEG analysis

20. A visual inspection of this curve demonstrates that there is higher volatility of bond rates at the short maturity end. The average ten year bond rate is generally slightly higher than the average five year rate (18bp over the period shown). However, it is materially less volatile. When the economy or financial sector is in crisis the short term bond rates drop significantly more than the long term bond rates. Similarly, when market conditions are relatively strong the short term bond rates rise materially more than the long term bond rates.

21. Using 5 year bond rates now in a CAPM model where the MRP is fixed at some historical average (say 6%) would lead to the, in my opinion wrong, conclusion that the cost of equity in Australia was 3.8% lower than it was immediately prior to the GFC (ie, the 5 year risk free rate was 3.2% on 26 April 2012 but was 7.0% on 16 June 2008). By comparison the 10 year risk free rate peaked at a slightly lower level (6.9% instead of 7.0% on the same day) and has fallen to a lower level (3.7% vs 3.3% at the time of writing).

22. This effect is captured in statistical measures of volatility. The variance of the five year bond rates in the figure above is 0.56. The variance of the ten year bond rate is 0.36 (more than a third lower). This greater volatility of short term debt is exemplified during the recent global financial crisis, where short term bond rates fell much faster and further than long term bond rates.

23. As a result of this property of Government bond rates, adopting a term shorter than 10 years for the bond rate will increase the volatility of the estimated cost of equity. This reflects the ERA's methodology which involves adding a fixed premium (beta multiplied by MRP) to the Government bond rate.

24. Other things equal, volatility in allowed equity returns is undesirable and, on this basis alone, it would be reasonable to believe that long term estimates of the risk free rate are preferred to short term estimates. This is the approach of many regulators who do not reflect short term movements in bond rates in the allowance for the cost of equity (as discussed in section 6). However, other things are not equal. The inverse relationship between the risk free rate and prevailing MRP described above means that the cost of equity tends to move less than one for one with CGS rates (and can often move in the opposite direction). Consequently, if one does not adjust the MRP to reflect prevailing as opposed to historical market conditions, adopting the more volatile 5 year CGS rate will make the overall cost of equity estimate less accurate (too low when risk free rates are low and too high when risk free rates are high).

RBA views on heightened risk premiums and scarcity premiums for CGS

25. Reserve Bank of Australia commentary from a range of publications supports the contention that risk premiums are currently elevated, and that the fall in CGS rates is a symptom of higher risk premiums (rather than a symptom of falling required returns on risk assets).

26. Moreover, the RBA has argued that in recent history the yields on CGS have been depressed due to a shortage of supply:

> *One complication in doing this calculation in Australia is that because government paper has been in short supply for many years, it has tended to trade with a scarcity premium. This widens the observable spread between the yield on government paper and the yield on other assets in a way that is not present in most other jurisdictions.*[3] *(Emphasis added)*

27. This scarcity premium increases the price of CGS and, as a result, depresses their yields. That is, investors accept a lower yield in order to have access to the scarce pool of CGS.

28. Material increases in demand for CGS from foreigners and the banking system can also be expected to raise this baseline 'scarcity premium' for the foreseeable future. As noted by the RBA, foreign holdings of CGS have risen to 75% of the market in recent months reflecting, in part, the shrinking pool of AAA rated sovereign debt due to downgrades of US debt in August 2011 and, most recently, French debt in January 2012. Similarly, the RBA has pointed to Basel III liquidity requirements as raising the

3 Guy Debelle, RBA Assistant Governor (Financial Markets), Speech to the APRA Basel III Implementation Workshop 2011 Sydney - 23 November 2011.

demand for CGS (indeed, the pre-existing scarcity of CGS in Australia is an issue explicitly acknowledged in the development of Basel III).

ERA methodology not consistent with 6.4(a)(i) of the Access Code

29. Based on the evidence summarised above, I conclude that the ERA's methodology underestimates the cost of equity in current market conditions. Specifically, the assumption, implicit in the ERA methodology, that the cost of equity has moved one-for-one with CGS yields and is currently at historically low levels is unreasonable. Moreover, it is likely to remain unreasonable in the medium term due to supply and demand dynamics in the market for CGS.

30. I consider that the ERA's overall cost of equity is inconsistent with the requirements of the Access Code, which at section 6.4(a)(i) require revenue on covered services to be determined consistent with "the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved." In my view, the ERA has underestimated the cost of equity and therefore the return on investment required by the Access Code.

Alternatives to the ERA methodology

31. I propose three alternatives to the ERA's methodology that implement the CAPM. I consider that each of these methodologies would comply with 6.4(a)(i) of the Access Code if applied in the current market circumstances. I do not consider that the same is true for the ERA's methodology. My three alternatives are:

    i. Directly estimating the prevailing cost of equity for regulated utilities using the dividend growth model (involving a simultaneous estimate of all parameters of the CAPM).

    ii. Directly estimating the prevailing MRP relative to the prevailing CGS yield being used as the risk free rate. This eliminates potential for error from the ERA's methodology - in which there is no attempt to estimate the MRP relative to the prevailing risk free rate. In this methodology Western Power's proposed value of 0.8 for beta is adopted.

    iii. Estimating a 'normal' cost of equity for regulated businesses by estimating each of the CAPM parameters using suitable historical time periods. This provides a proxy for the prevailing cost of equity if the prevailing cost of equity is relatively stable over time (an assumption supported by the evidence in this report). It also provides a minimum estimate of the cost of equity if one believes that current market conditions are such that the cost of equity is more likely above its long term average than below (a view that is supported by the evidence in this report). A departure from this historical norm could be justified if there was some threshold level of evidence to the effect that currently prevailing market conditions were sufficiently different from the normal market conditions. Whether this threshold was satisfied could be assessed by, for example, application of methodologies i) and ii) above.

32. In the table below (from section 6 of my report) I summarise the results of application of these methodologies. These methods suggest a nominal post-tax cost of equity of at least 10.41%, compared to the ERA's methodology which gives rise to an estimate of 7.57%.

Summary of results from each methodology

	Basis of estimate	Time period	Div. yield	DPS growth	RFR	MRP	Beta	Nominal cost of equity
(i)	**<u>DGM for regulated businesses</u>** DGM model applied to utility stocks in Australia. Range based on long run real dividend growth of between zero and in line with GDP.	Dividend forecasts average 24 Feb and 9 March. Price and CGS averaged over period 24 Feb to 9 March 2012	multiple	2.50 – 6.60%	4.13%	6.73% to 8.41%	0.8-1.0	**10.86%-14.59%**
(ii)	**<u>DGM for the market</u>** Application of the AMP methodology to estimate prevailing MRP and then application of beta of 0.80 along with prevailing rfr	March 2012	5.68%*	6.60%	4.21%	7.75%	0.8	**10.41%**
(iii)	**<u>Historical average RFR plus historical average MRP * beta</u>** Historical CGS with MRP of 6% and beta of 0.8.** Assumes an indexed historical CGS of 3.40%, resulting in a real cost of equity of 8.2%, or 10.8% assuming inflation of 2.5%	Historical CGS based on time series since July 1993	n/a	n/a	3.40% real 5.99% nominal	6.00%	0.8	**10.78%**
(iv)	**<u>ERA methodology</u>** Prevailing CGS with a risk free rate February 2012 of 3.67%, MRP of 6.00% and a beta of 0.65	February 2012	n/a	n/a	3.67%	6.00%	0.65	**7.57%**

Source: Various, CEG analysis
** Dividend yield scaled up using a factor of 1.1125.*

Conclusion

33. I consider that the overwhelming empirical and contextual evidence suggests that the observed low yields on Commonwealth Government Securities (CGS) are as a result of a general flight to safety by investors exacerbating a pre-existing scarcity premium. The current low yields do not signal that investors perceive the economic environment as being less risky. Indeed, the opposite is the case and the fall in CGS yields is symptomatic of greater perceived risks by investors in many classes of assets. The current historically low CGS yields are not a sound basis for concluding that required returns on risky assets are also at historically low levels.

34. However, application of the ERA's methodology leads to changes in CGS yields being passed, one-for-one, into a lower cost of equity, whilst the MRP and equity beta are estimated on a historical basis. In February 2011, the ERA's methodology gives an estimate of the cost of equity of 8.6%, whereas forward-looking measures of the cost of equity that I survey in this report are in excess of 10%.

1. Introduction

35. My name is Tom Hird. I have a Ph.D. in Economics and 20 years experience as a professional economist. My curriculum vitae is provided separately.

36. Western Power has asked me to provide an opinion on:

- whether the approach to the use of the CAPM formula adopted by the ERA results in a cost of equity that meets the requirements of the Access Code;
- how the current cost of equity should be estimated to ensure the requirements of the Access Code are met;
- what the current cost of equity and market risk premium (MRP) is in accordance with these methods; and
- whether the methodology, data and estimates of the MRP considered by the ERA produce a cost of equity that meets the requirements of the Access Code.

37. The terms of reference specific to this report are set out at Appendix C.

38. Section 6.4(a)(i) of the Access Code states:

> *The price control in an access arrangement must have the objectives of:*
>
> *(a) giving the service provider an opportunity to earn revenue ("target revenue") for the access arrangement period from the provision of covered services as follows:*
>
> *(i) an amount that meets the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved;*

39. Section 6.64(b) directs that consideration be had to Section 6.66 in a determination of the regulator's preferred approach to calculating the weighted cost of capital in access determinations under Section 6.65. Section 6.66 states:

> *A determination under section 6.65:*
>
> *(a) must represent an effective means of achieving the Code objective and the objectives in section 6.4; and*
>
> *(b) must be based on an accepted financial model such as the Capital Asset Pricing Model.*

40. The remainder of this report is set out as follows:

- section 2 provides a factual summary of volatility in CGS yields over time, and the impact of this volatility on the cost of equity as estimated by the ERA;
- section 3 sets out the empirical evidence on the current level of the MRP and the equity risk premium for Australian regulated utilities;
- section 4 provides a general discussion of whether there is any reason to assume that the cost of equity will move in line with movements in the risk free rate;
- section 5 provides an analysis of why risk premiums have increased as CGS yields have fallen, resulting in the overall required return has not fallen one-for-one with changes in CGS;
- section 6 examines regulatory practice from the US, UK and Australia that is relevant to the issues involved;
- section 7 provides my views on whether a 5-year or a 10-year CGS rate should be used to proxy the risk free rate in the CAPM
- section 8 provides my views on how the cost of equity can be estimated in the current circumstances in a manner that is consistent with section 6.4(a)(i) of the Access Code; and
- section 9 provides a summary of my conclusions.

41. I have read, understood and complied with the Federal Court Guidelines on Expert Witnesses. I have made all inquiries that I believe are desirable and appropriate to answer the questions put to me. No matters of significance that I regard as relevant have to my knowledge been withheld.

42. I have been assisted in the preparation of this report by Daniel Young and Johanna Hansson from CEG's Sydney office and Dr Yuliya Moore who works with me in Melbourne. However, the opinions set out in this report are my own.

Thomas Nicholas Hird

21 May 2012

2. Movements in the risk free rate and ERA methodology

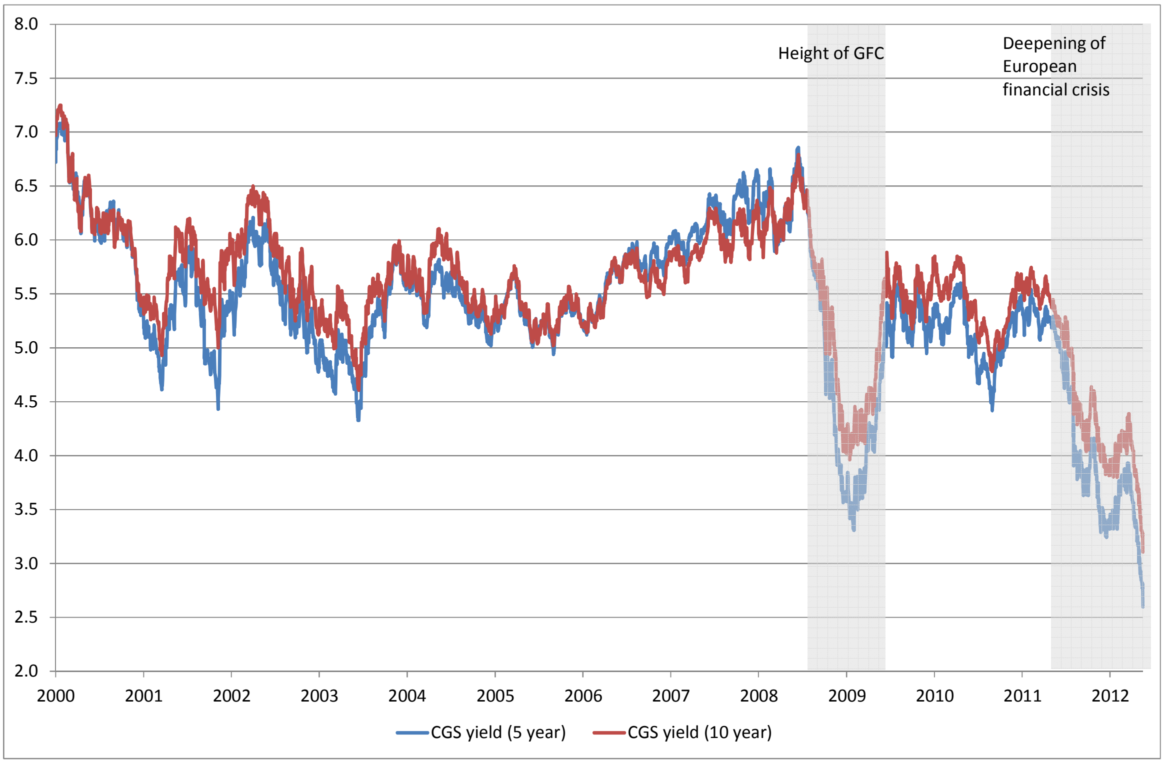
43. This section provides a factual summary of volatility in CGS yields over time, and the impact of this volatility on the cost of equity as estimated by the ERA.

2.1. CGS yields are at historical low levels

44. Figure 1 below illustrates that the yields on 10 and 5 year CGS have been very volatile over the last decade. The figure shows that the largest swings in the risk-free rate were associated with the onset of financial market crises. The first large swing occurred in the aftermath of the collapse of Lehman Brothers and the near collapse of other financial institutions in late 2008. The second large swing occurred in the subsequent recessions in the US and Europe, which then gave rise to a deepening sovereign debt, banking and currency crisis in the Eurozone.

45. During both of these financial crises there has been a dramatic fall in CGS yields in Australia. The decline has left these yields at their lowest levels in the last decade and, indeed, over the past 50 years.

Figure 1: Time series for yields on CGS

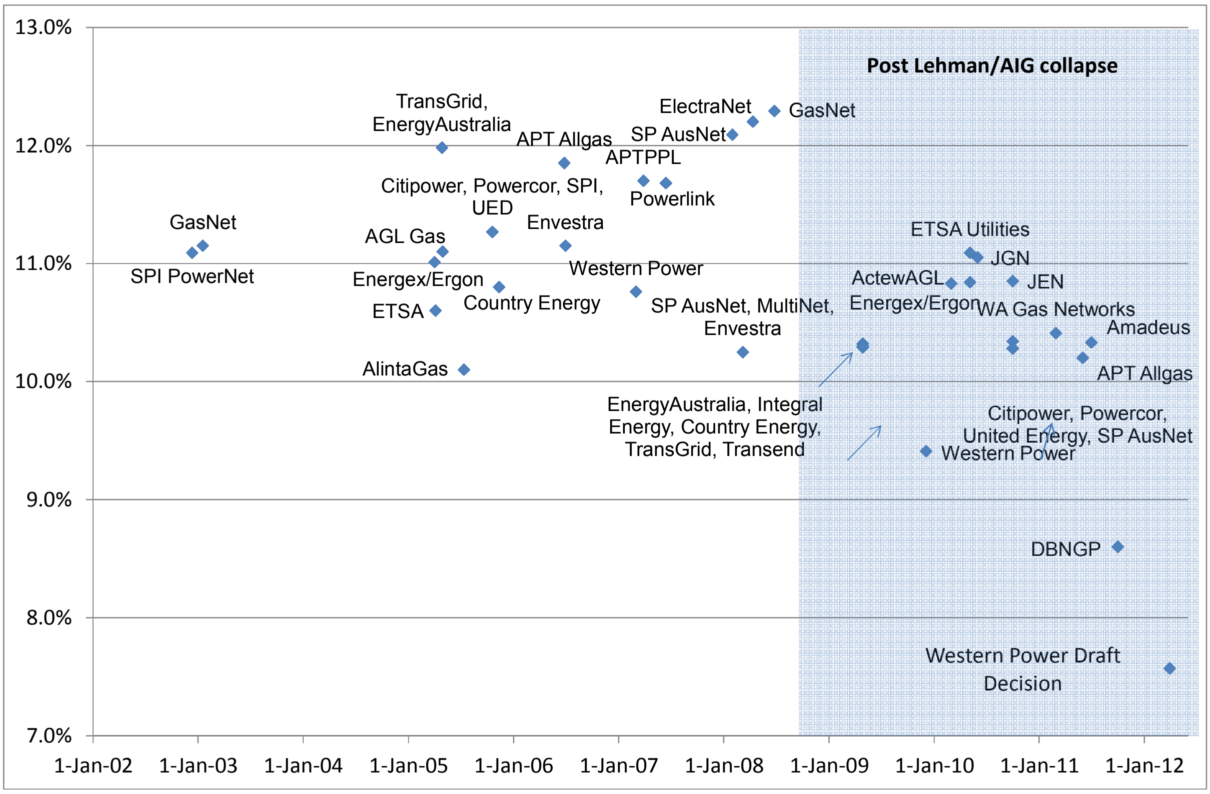


Source: RBA, CEG analysis

2.2. ERA methodology will cause the cost of equity to be at a historically low level

46. The ERA's draft decision assumes that equity investors investing in a 60% geared electricity distribution business require a 7.57% nominal (4.9% real) return on equity. This is by far the lowest cost of equity allowance set by an Australian energy network regulator. By comparison, the allowed cost of equity decisions prior to the global financial crisis of late 2008 were universally above 10%, and averaged 11.28%.

Figure 2: Cost of equity decisions for Australian regulated energy businesses



Source: Regulator's decisions, CEG analysis. Note that 2009 decision for EnergyAustralia et. al. is before amendment by the ACT.

47. Figure 2 above demonstrates an important point: the allowed cost of equity set by the ERA and AER has been lower after the global financial crisis than before it – with the Western Power draft decision being the most recent and extreme observation in this trend.

48. The mechanical explanation for this result is relatively simple to understand. It reflects a methodology which applies the capital asset pricing model in a manner that:

- sets the risk free rate equal to the prevailing risk free rate (which is very volatile); and

- sets the MRP primarily based on the regulator's estimate of the historical average risk premium earned by Australian equity investors (which is, by its construction, very stable).

49. These two variables fit together in the CAPM as per the following equation:

$$Cost\ of\ Equity = Risk\ Free\ Rate + (\beta * Market\ Risk\ Premium)$$

50. This equation makes clear that if the risk free rate fluctuates significantly, and if the MRP estimate is stable then, for any given beta estimate, the cost of equity estimate will move in synchronicity with the risk free rate.

51. However, where the MRP is not stable, an application of the CAPM that estimates the cost of equity by allowing the risk-free rate to vary but maintaining a long-run average for the MRP is likely to produce estimates that do not reflect either the short-run or long-run cost of equity. In particular, where the current levels of MRP are higher than the historical average used by the regulator, this application of the CAPM will underestimate the required cost of equity.

52. I show in the following section that the current MRP, as reflected in equity prices and dividend expectations, is considerably above the historic average of 6.0% as estimated by the ERA.

3. Empirical estimates of the current market risk premium

53. If low CGS yields are simply a reflection of investors accepting a lower return on all assets (risky and riskless) then the ERA's methodology is reasonable. That is, it is reasonable to assume that the cost of equity falls one-for-one with the CGS yields with the equity risk premium remaining constant.

54. However, if CGS yields are falling primarily as a consequence of factors that do not push down the overall cost of equity, then the ERA approach is not valid. An approach that does not lower the cost of equity by the same amount as it lowers CGS yields is appropriate.

55. This issue is one that can be resolved by examination of empirical data. If the ERA is correct then the yields on all assets should fall in line with CGS yields. If the ERA is not correct, then the spread (risk premium) between CGS and other assets should have risen. The evidence summarised in this section clearly demonstrates that the spread (risk premium) between CGS and other assets has risen, that is, the ERA's approach is not valid.

56. In this section I collate and consider a number of estimates and indicators of the current MRP and equity risk premiums required by investors in Australian equities. These estimates are obtained by looking at the future expected dividend payments across the Australian market (and additionally looking at just utilities stocks) to assess the implied cost of equity. The MRP is then calculated as the cost of equity less the risk-free rate, proxied using the annualised yield on 10-year CGS.[4]

57. It is necessarily the case that observations of current or forward-looking MRP must involve making assumptions and the exercise of judgement, such as forecasting the future level and growth of dividend payments. There is not and cannot be perfect knowledge about the MRP that might prevail over a particular period of time in the future. For each set of estimates that I present, I describe which of the inputs to them are:

   - the expert or consensus views of specialist industry forecasters; or
   - additional inputs that I have provided.

58. It would be incorrect to conclude that this requirement for assumptions and judgement invalidates the relevance of these estimates. Where the issue is the accuracy of the inputs, this can be addressed by reviewing these values. Necessarily there will be some imprecision about what values are appropriate for these inputs. These issues go hand-in-hand with an approach that is predictive of future outcomes.

---

4 I note that the ERA prefers the use of 5-year CGS as a proxy for the risk-free rate. All the equity risk premiums I estimate in this section would be approximately 0.43% higher were I to estimate them on this basis, reflecting the difference between 5-year and 10-year CGS yields in March 2012. The effect on MRP estimates would be higher to the extent that equity beta was assumed to be less than 1.0.

59. On the other hand, an approach based only on historical averages could be argued to face comparatively fewer issues of precision, but as described in section 2 above, in some cases will not provide an accurate indicator of the forward-looking cost of equity. The evidence that I survey below suggests that the present time is such a case.

3.1. Dividend growth models

60. A dividend growth model (DGM) is also known as a discounted cash flow (DCF) model uses forecasts and projections about future dividend streams to estimate either equity valuations/prices (for any given investor discount rate) or the implied average investor discount rate (for any given equity valuations/prices). This analysis is founded on the basic financial valuation identity (definition), that the current value of an asset (in this case a share of equity) is equal to the present value of future income streams from that asset (future dividends).

61. DGM can be used to estimate the market risk premium used in the CAPM. It is an alternative to assuming the current forward looking MRP is equal to the historical average MRP. The advantage of DGM analysis is that it is completely forward looking in that it relies only upon contemporaneous data and forecasts. If there are good reasons to believe that current market circumstances differ from the historical average market circumstances (as there are today) then the historical average MRP will be a poor estimate of the prevailing MRP. A DGM analysis provides a basis for determining the forward looking MRP in those circumstances. If one's sole interest is to determine the prevailing cost of equity then, as Damodaran notes:[5]

> *The problem with any historical premium approach, even with substantial modifications, is that it is backward looking. Given that our objective is to estimate an updated, forward-looking premium, it seems foolhardy to put your faith in mean reversion and past data.*

62. The DGM is routinely used by academics, practitioners and economic regulators. For example, in the United States the DGM method is the dominant method used by regulators to establish the equity premium required by investors in regulated businesses. The US Federal Energy Regulatory Commission notes:[6]

> *The Supreme Court has stated that "the return to the equity owner should be commensurate with the return on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital." Since the 1980s, the Commission has used the DCF model to develop a range of returns earned on investments in companies with*

[5] Damodaran, ibid, page 49. Note that in this context when Damodaran's refers to 'faith in mean reversion' he is referring to the fact that adoption of historical average MRP implies an assumption that either the MRP is constant or if it changes this is only ever for such short periods that at any given time the best assumption is that the MRP has already reverted to the historical average.

[6] http://0-edocket.access.gpo.gov.library.colby.edu/2008/pdf/E8-9301.pdf.

corresponding risks for purposes of determining the ROE to be awarded natural gas and oil pipelines.

63. The use of DGM provides the necessary confidence that assumptions into, and outputs from, theoretical models, such as the CAPM, are representative of investor requirements. If one's sole objective is to accurately estimate the forward looking cost of equity then, where there is a substantial disagreement between the DGM results and results based on historical estimates of equity premiums the DGM results should be given greater weight. It is my view that a DGM analysis provides the most appropriate basis for estimating the forward looking MRP relative to the prevailing risk free rate.

64. In this report, I present two alternative DGM approaches. The first is Bloomberg's own DGM modelling conducted over all members of the ASX 200 index. The second utilises dividend forecasts published by Bloomberg, combined with current equity prices, to calculate the implied rate of return and risk premium over the risk free rate required by investors for Australian utilities stocks in particular.

65. These allow one to make inferences about the long term risk premium that equity investors currently require to commit equity funding today.

3.2. Estimates of the market risk premium

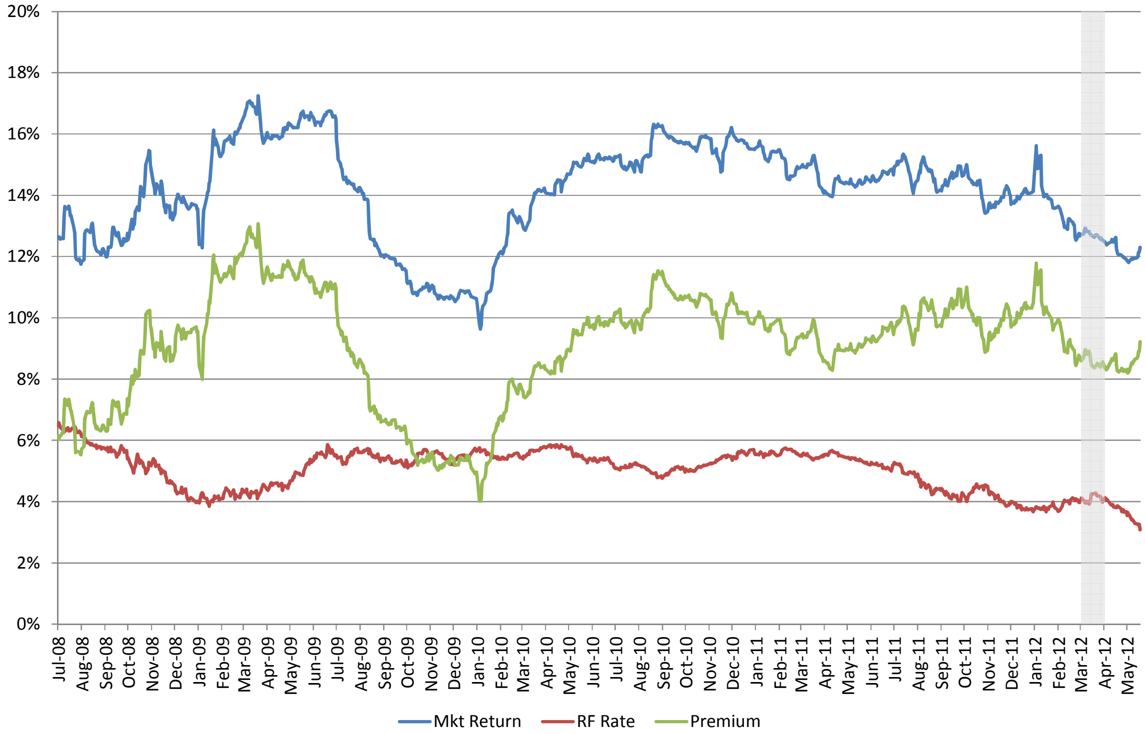
3.2.1. Bloomberg estimate of the market risk premium

66. Bloomberg calculates a measure for market return based on the *capital weighted average of the internal rate of return for all major index members.* The internal rate of return for each index member is calculated using a dividend discount model (DDM) developed by Bloomberg. The dividend discount model is described in more detail at Appendix B to this report.

67. In summary, Bloomberg forecasts a path of future dividend payments for each firm in the ASX 200. Different assumptions are made for each firm depending upon information about its growth profile and analyst forecasts of its dividend payout. The required market return is calculated by aggregating these assumptions across all firms in the market index.

68. Bloomberg calculates an MRP by subtracting from the market return the prevailing risk free rate. The market return, risk free rate and market return premium for Australia (based on the ASX 200 index) is available from Bloomberg for Australia since July 2008 until the present. Figure 3 below depicts the market return, the risk free rate and the market return premium for Australia for the time period in which it is available.

Figure 3: Market return – Australia



Source: Bloomberg

69. The figure shows that the MRP dipped during the second half of 2009 and the early part of 2010 to levels that were briefly below 6% (and below the risk free rate), but has since mid-2010 remained relatively steady at between 8% and 11%, similar to levels experienced during the height of the GFC as experienced in Australia in March 2009.

70. One can also observe a clear inverse relationship between the MRP and the risk free rate in the above figure. In the height of the GFC (late 2008 and early 2009) the risk free rate was at its lowest point of around 4% while the MRP rose to its highest point of over 12%. Similarly, since April 2011 the risk free rate has been falling (on the back of concerns about renewed financial crisis emanating from Europe) while the MRP has been rising. These two effects largely cancel each other out – with the market cost of equity remaining relatively stable since April 2011.

71. The Western Power averaging period is the 20 days between 5 March and 30 Match 2012, indicated with shading in Figure 3 above. Bloomberg estimates that the MRP is on average 8.61% during the averaging period. The average market return on equity during the period was 12.71% and the average risk free rate was 4.10%.[7]

[7] Bloomberg's estimate of the risk-free rate appears to be consistent with yields on 10-year CGS.

72. Bloomberg's measure of 8.6% is above the upper end of the 6.5% to 8.5% range for MRP proposed by Western Power.

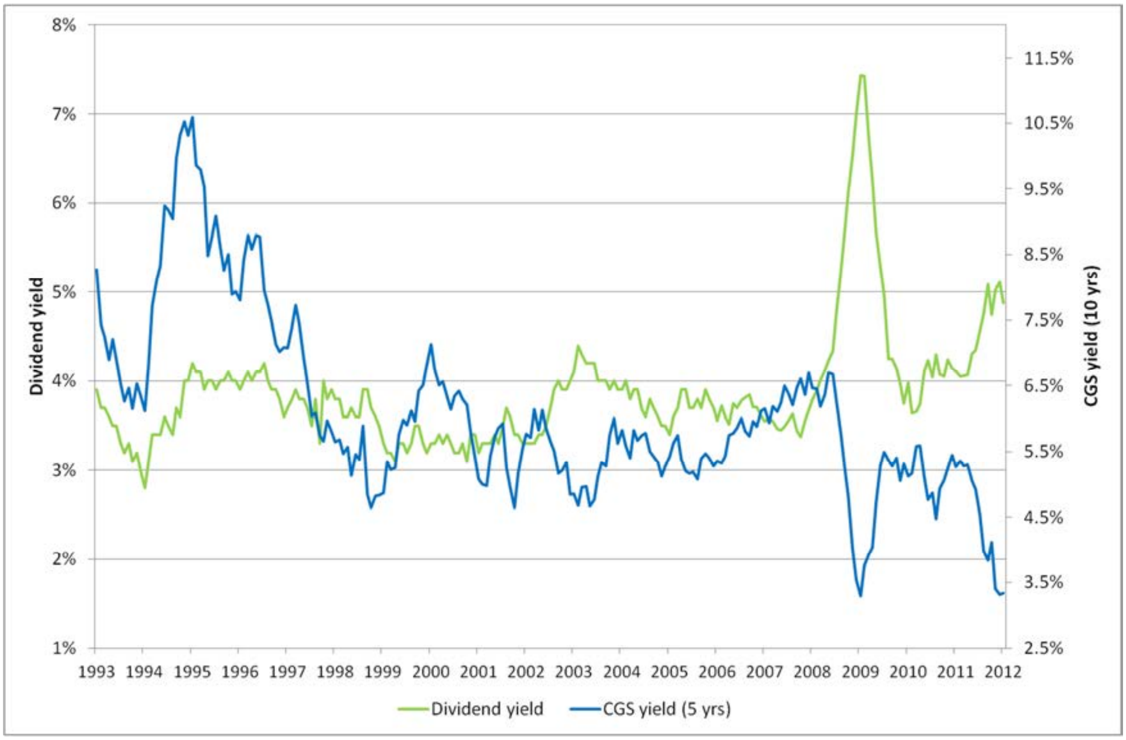
3.2.2. Dividend yields as a proxy for risk premiums and the AMP method

73. It is also common practice to use equity dividend yields as a proxy for prevailing levels of risk aversion (as noted in Fama and French (1989) quoted previously). below shows the dividend yield on the ASX and the contemporaneous yield on 5 year CGS.

74. shows the average dividend yield on Australian listed equities since 1993 and the corresponding yield on 5 year CGS as reported by the RBA. 1993 is chosen as the first year of this series because this coincides with the formal adoption of inflation targeting by the RBA (where the RBA dates the beginning of inflation targeting as 'mid 1993) and the beginning of a period where inflation and inflation expectations have been anchored around the RBA target range of 2-3%.[8]

75. Figure 4 clearly shows that since the late 1990's there has been a clear negative relationship between dividend yields and CGS yields – most noticeable in the 2008/09 financial crisis and most recently since mid-2011.

Figure 4: Dividend yield on the ASX vs. 5 year CGS yields



Source: RBA, CEG analysis. Figures used in this chart are month end figures published by the RBA in the RBA Monthly Bulletins (1993-2012) and correspond to the dividend yield information

[8] See http://www.rba.gov.au/publications/bulletin/1999/may/pdf/bu-0599-2.pdf

76. The dividend yield on listed equities can also be used to arrive at a direct estimate of the prevailing cost of equity using the dividend growth model. In what follows I use the method used by AMP Capital Investors.[9] This methodology has previously been relied on by the AER in support of a position that the then MRP of 6.0% was generous.[10]

> *A more recent estimate is from AMP Capital Investors (2006), who base the growth rate on the expected long-run GDP growth rate, similar to Davis (1998). AMP Capital Investors (2006) estimate the forward looking Australian MRP for the next 5-10 years to be 'around 3.5 per cent' (specifically 3.8 per cent), 1.9 per cent for the US and 2.4 per cent for the 'world'. AMP Capital Investors (2006) considers an extra 1 to 1.5 per cent could be added for imputation credits resulting in a 'grossed-up' Australian MRP of around 4.5 to 5.0 per cent.*

77. The AMP methodology involves approximating a cost of equity by adding the long term average nominal growth in GDP (as a proxy for long term average nominal growth in dividends) to the prevailing dividend yield for the market as a whole. This gives a 'cash' cost of equity. To convert this into a cost of equity including the value of imputation credits the cost of equity needs to scaled up by the relevant factor. In the figure below I have used 6.6% per annum as the long run growth path for nominal GDP (based on average real growth in GDP from 1959 until 2011 plus inflation of 2.5%) and a scaling factor of 1.1125 to capture the value of imputation credits.[11]

78. When I use this method consistently through time (using the time series for dividend yields shown in), I derive the following time series for the prevailing cost of equity, 5 year CGS yields and MRP (measured relative to 5 year CGS yields).

79. Notably, the most recent fall in CGS yields has been associated with a more than offsetting rise in MRP – such that the cost of equity has risen materially since mid-2011. I note that the path of these parameters over time is similar to those recently estimated and presented by Capital Research.[12]

80. This shows a clear negative relationship between the prevailing market risk premium and the prevailing risk free rate. Notably, market cost of equity, being the sum of the CGS and MRP time series is much more stable than either of these two time series. I discuss this fact in more detail in section 5.1.2 below.

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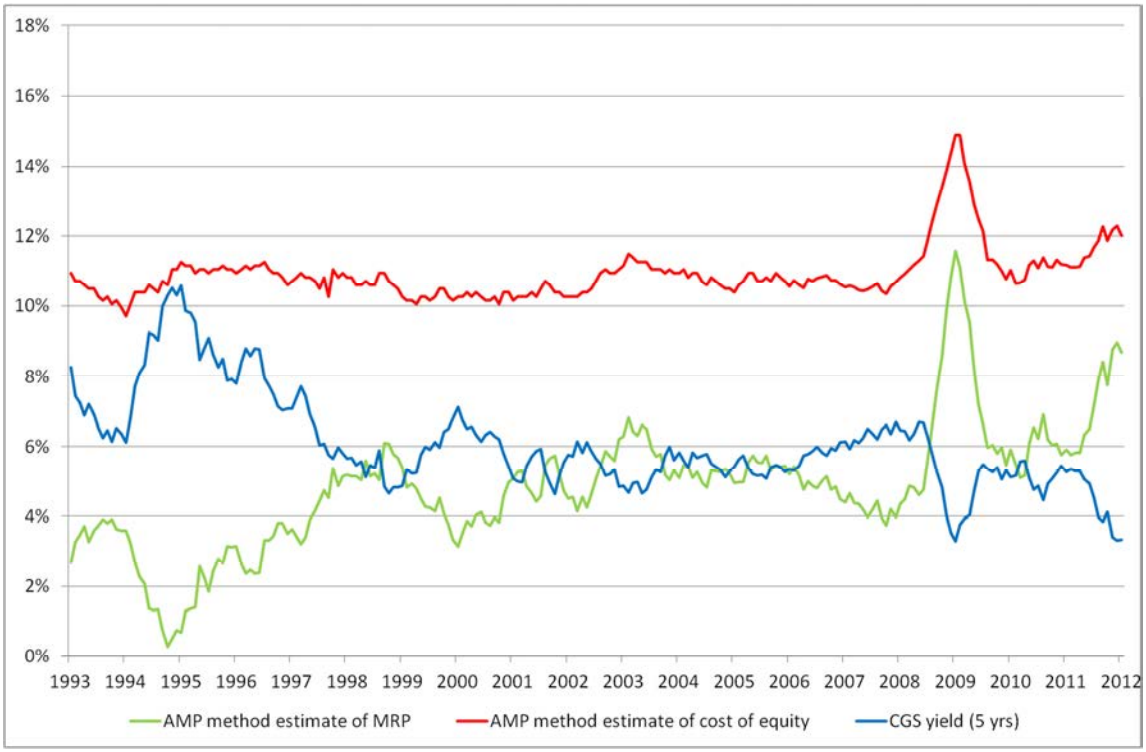
9 AMP Capital Investors (2006), *The equity risk premium – is it enough?* Oliver's insights, Ed.13, 4.

10 AER, *Electricity transmission and distribution network service providers Review of the weighted average cost of capital (WACC) parameters,* December 2008, p. 173

11 This is based on the assumption of a corporate tax rate of 30%, that the value of imputation credits distributed (theta) is 35% of their face value, consistent with Australian Competition Tribunal precedent, and the proportion of dividends that are franked is 75% (consistent with Brailsford, T., J. Handley and K. Maheswaran, Re-examination of the historical equity risk premium in Australia, Accounting and Finance 48, 2008, page 85). The value of 1.1125 is calculated as 1+.30*.35*.75/(1-.3)

12 Capital Research, *Forward Estimate of the Market Risk Premium: Update*, February 2012, Figure 8.

Figure 5: AMP method estimate of RoE and MRP relative to 5 year CGS yields



Source: RBA and CEG analysis

3.3. Risk premiums on utility equities

81. The ERA assumes an average equity risk premium for utilities of 3.9% (derived from a historical average MRP of 6% and a beta of 0.65). The ERA does not adjust this risk premium for consistency with the prevailing risk free rate, rather, it implicitly assumes that the risk premium and the risk free rate are independent. Consequently, the ERA's estimate of the cost of equity has declined with risk free rates since mid-2011.

82. The reasonableness of these assumptions can be assessed by examining market evidence on the prevailing required equity risk premium by Australian regulated utilities. I have undertaken such an analysis based on a DGM using dividend and share price data from six Australian utilities businesses, being APA Group, DUET Group, Envestra, Hastings Diversified Utilities Fund, SPAusNet and Spark Infrastructure, obtained from Bloomberg. The DGM analysis is based on analyst dividend forecasts sourced from Bloomberg on 24 February 2012 and 9 March 2012 and the average price of equities for these firms over the period 9 February 2012 to 9 March 2012. Over the same period the average 10 year CGS yield was 4.13%

83. The basis of DGM analysis is to examine the forecast future distributions of businesses and to derive the discount rate (or cost of equity) that makes these consistent with the market valuation of the equity of those businesses as manifested in the current share price. In order to be conservative I have assumed that investors

place a zero value on any franking credits distributed (this assumption reduces the value of future dividends to investors and reduces the discount rate required to equate the flow of dividends with prevailing share prices).

84. A DGM based on the utilities sector only is not capable of making direct inferences about MRP. However, subtracting the yield on 10-year CGS from the calculated return on equity gives rise to an estimate of the equity risk premium (ERP), where:

$$ERP = \beta \times MRP$$

85. Therefore the ERP provides information about both beta and MRP jointly. Imposing an estimate of beta, it is possible to back-solve for the MRP estimates implied by DGM analysis on utilities firms only.

86. I have sourced analysts' forecasts of dividends for the first two years from Bloomberg, with these averaging to an annual growth rate of 4.6%. However, beyond this date analyst dividend forecasts are not available and it is necessary to make an assumption about the future path of dividend growth/decline beyond this horizon. Because this assumption is necessarily subjective, I have shown a range of assumptions, including those that would be necessary to support the ERA's estimated 3.9% percent equity risk premium. The range that I have used is zero real growth in dividends (2.5% nominal growth) up to growth in line with long run nominal GDP (6.6%).[13] A full description of the DGM assumptions used here is provided at Appendix B to this report.

87. I have included as a sensitivity analysis the long term growth assumption that delivers an average cost of equity equal to 7.6%. This is the cost of equity in the ERA draft decision. The results show that, in order to arrive at this average cost of equity, the assumed growth rate for dividends in the future has to be around -1.1%. Implicit in this result is a long term inflation forecast of 2.5% (in the middle of the RBA's target range). Consequently, the assumed long run growth in dividends for these businesses must be even more negative in real terms (around negative 3.6%).

88. The results of the DGM analysis at varying growth rates are summarised in below.

[13] A detailed basis for the assumptions underlying this DGM analysis is set out at Appendix A to this report.

Table 1: DGM cost of equity analysis for Australian regulated utilities - with dividend growth rates assumptions

Dividend growth rate	-1.10%	2.50%	4.50%	6.60%
APA AU Equity	7.08%	10.3%	12.2%	14.1%
DUE AU Equity	9.48%	12.7%	14.4%	16.3%
ENV AU Equity	7.86%	11.1%	12.9%	14.8%
HDF AU Equity	5.22%	8.6%	10.4%	12.4%
SPN AU Equity	7.85%	11.1%	12.9%	14.8%
SKI AU Equity	7.43%	10.7%	12.5%	14.4%
Weighted average by market capitalisation	7.61%	10.86%	12.67%	14.59%
ERP (beta*MRP) if risk free rate = 4.13%	N/A	6.73%	8.54%	10.46%

Source: Bloomberg, RBA, CEG analysis

3.4. Historical average MRP

89. Historical average MRP estimates are usually based upon the average return on the Australian share market over as long a period as is practical. However, these estimates are subject to considerable imprecision. One could not reasonably reject 8% (the top of Western Power's MRP range) based on historical average estimates of the MRP.

90. In its draft decision the ERA has estimated an excess return relative to the 5 year CGS rate of 5.2% from 1968 to 2011 (and 5.6%/5.0% from 1980/1988 to 2011). The ERA states in relation to these findings that:

> *The analysis presented in Table 69 supports the Authority's view that the estimate of the MRP using the historical equity risk premia is within the range of 5 to 6 percent.*

91. I disagree with this conclusion. The analysis presented by the ERA, assuming it has been correctly carried out, supports only the conclusion that there are three different time periods where the average excess return was between 5 and 6 percent. The ERA does not provide any statistical details of the confidence interval around these estimates nor whether there were other sub periods with materially higher average excess returns.

92. I note that if 1967 rather than 1968 had been chosen as the as the start date for the time series then the historical average excess return would have been around 1% higher. This is because there was a 42% return on the market (before dividends) in 1967 that the ERA's choice of time period omits. On the assumption that dividend yields in 1967 were at least equal to the 5 year government bond return in that year, adding a 42% excess return to the ERA time series will increase the historical MRP by over 0.8% - giving rise to a MRP including imputation credits of over 6.0% (based on

the ERA's own calculations of a 5.2% historical average excess return between 1968 and 2011).

93. Similarly, if 1979 instead of 1980 were chosen as the beginning date for one of the sub-periods the estimated average MRP would be around 6.6%, which is higher than the lower bound of Western Power's proposed range for MRP. This is because there is a 32% excess return in 1979 that the ERA period, which starts in 1980, does not capture.

94. The AER's adviser, Handley, provides point estimates and confidence intervals for his estimates of MRP from historical data.[14] Handley estimates the average MRP (using historical data from 1958 to 2010 is 6.5%.[15] However, Handley reports a 95% confidence interval which extends up to 12.9%. Using the longest stretch of data (1883 to 2010) increases the number of estimates but does so at the cost of introducing less reliable estimates. Even in that case the average is 6.2% and the upper bound of the 95% confidence interval is 9.1%.

95. Handley's results are summarised in the chart below.

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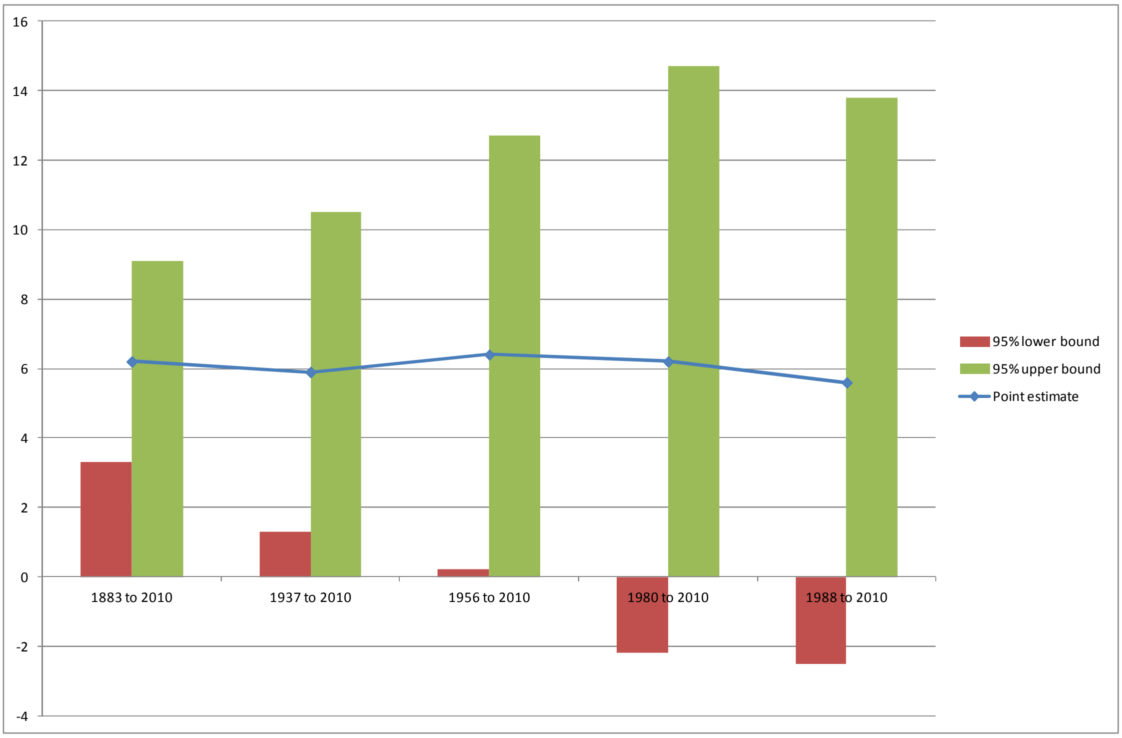
14 Handley, Memorandum to Iftekhar Omar at the AER, Additional Estimates of the Historical Equity Risk Premium for the Period 1883 to 2010, dated 25 May 2011

15 Using an assumed utilisation rate for imputation credits of 0.35.

Figure 6: Handley historical average MRP (utilisation rate = 0.35)



Source: Handley

96. It is clear that the ERA's estimates are lower than those provided by Handley for similar time periods. In particular, Handley estimates that from 1956 to 2011 the average excess return is well in excess of 6% - which compares to the ERA's estimate of 5.2%. Moreover, Handley's estimate is relative to the 10 year government bond rate which should make it lower than the ERA's estimate (given an upward sloping term structure of risk free rates). It is not possible for us to definitively identify the source of this difference because the data sources described by the ERA do not appear to be the actual data sources used.[16]

97. Handley's estimates capture the long run average MRP over a variety of economic conditions (recessions and periods of high growth) and are consistent with an estimate of 6.5%.

[16] At footnote 201 on page 163 of the draft decision the ERA states that it used the ASA30 Index with the field PX_LAST. However, this relates to the All Ordinaries Accumulation index which was only published from 1980. Consequently, it is not clear what series the ERA has used prior to 1980. Non accumulation indices are available on Bloomberg prior to 1980 but one would have to add an estimate of dividend returns from elsewhere to estimate the full returns. Similarly, we are only able to access 5 year CGS returns back to 1970 from the RBA website which is where the ERA states that it accessed this data (see paragraph 676 of the draft decision). It is not obvious to us what bond return series from prior to 1970 was used by the ERA.

98. Stephen Gray has made similar observations in relation to the Handley data in a recent paper for Envestra.[17] I concur with his conclusion that:

> *To adopt a 6% MRP estimate in the current conditions, one would need to be satisfied:*
>
> *a. That 6% is an appropriate long-run average estimate; and*
>
> *b. That risk premiums in financial markets are currently no different from their long-run average levels.*
>
> *However, both of these conditions are difficult to establish given that:*
>
> *a. The estimates of the long-run average MRP from the most reliable data period are 6.4% or 6.6% depending on the estimate of theta; and*
>
> *b. The AER itself has set a debt risk premium at a level that is substantially above the long-run average and pre-GFC levels. It is implausible that risk premiums in debt markets could be substantially above their long-run mean, while equity risk premiums were no higher at all than their long-run means.*

3.5. Consistency with DRP

99. Western Power's proposed estimate for the debt risk premium (DRP) is 3.67% for a BBB+ rated issuer of 10 year debt. I consider that this range is supported by market evidence. This estimate is heightened compared to historical DRPs as estimated prior to the GFC.

100. Standard finance theory predicts that a heightened DRP will also be associated with a heightened MRP. In fact, one can use standard finance theory to estimate the minimum MRP consistent with the estimated DRP. It is therefore relevant to ask whether this level of difference between a debt and equity premium is consistent with the higher level of risk that equity providers face.

101. In order to answer this question I follow the financial logic set out in Professor Grundy's report for Envestra.[18] Standard finance theory suggests that the equity risk premium (ERP)[19] for a 60% geared business will be *at least* 2.67 times the debt risk

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17 Gray, *Issues affecting the estimation of MRP* Report for Envestra 21 March 2011

18 Grundy, The *Calculation of the Cost of Capital* A Report for Envestra Bruce D. 30 September, 2010

19 Note that the ERP is for a specific firm and is not the same as the MRP which is the risk premium for the average of the market as a whole.

premium.[20] The general formula for the relationship between the equity and debt risk premia is given by:

$$\frac{ERP}{DRP} \geq \frac{1/_L - L}{E}, \text{ where:}$$

L = the proportion of debt in the finance structure, i.e., gearing; and

E = the proportion of equity = 1-L

102. This follows mathematically from two well accepted propositions. The first is the application of the Modigliani-Miller result that the WACC (total firm level risk adjusted return) is unaffected by financial structure (i.e., WACC is invariant to L). The second is that the debt risk premium is convex in the level of gearing. That is, the debt risk premium increases slowly initially but then increases more rapidly as more and more debt is issued (increasing the probability of default on debt).[21] Note that these propositions allow us to define the *minimum* ratio for the ERP to the DRP. The actual ratio of ERP to DRP will likely be higher than this lower bound.

103. Consistent with Western Power's proposed DRP of 3.67% for the notionally 60% geared benchmark BBB+ regulated firm, the corresponding lower bound ERP is 2.67 times this level – equivalent to 10.8%. This is consistent with the Bloomberg and other forward looking equity premium estimates presented above. This is consistent with Western Power's proposed range for MRP of 6.5% to 8.5%.

3.6. Other debt based proxies for equity MRP

3.6.1. Risk premiums on high risk bonds

104. It is common practice to use spreads between low risk assets and BBB rated bonds as a proxy for the level of investor risk aversion. Jagannathan and Wang (1996)[22] use the difference between the yield to maturity on short term BBB rated bonds and short term

[20] Note that this is 2.67 times the true debt risk premium (i.e. measured relative to the true risk free rate). If the Government bond rate is an underestimate of the true risk free rate then the DRP will be overestimated by the extent of this bias. It follows that multiplying the DRP so estimated by 2.67 will tend to overstate the ERP by 2.67 times the bias in the risk free rate. This will lead to an overestimate of the cost of equity – with the ERP overestimation being greater than the risk free rate underestimation. For example, if the government bond rate is 1% below the true risk free rate, then the minimum ERP will be 2.67% overestimated using this method. The net effect will

[21] It is standard practice to assume that the cost of debt is convex (rises at an increasing rate) with the level of gearing. This relationship is commonly taught to undergraduate finance students. For example, see Figure 18.5 in Damodaran, Aswath, 2001, Corporate Finance: Theory and Practice, 2nd edition, (John Wiley and Sons, Inc., NJ).

[22] Ravi Jagannathan and Zhenyu Wang, *The Conditional CAPM and the Cross-Section of Expected Returns* The Journal of Finance, Vol. 51, No. 1. (Mar., 1996), pp. 3-53.

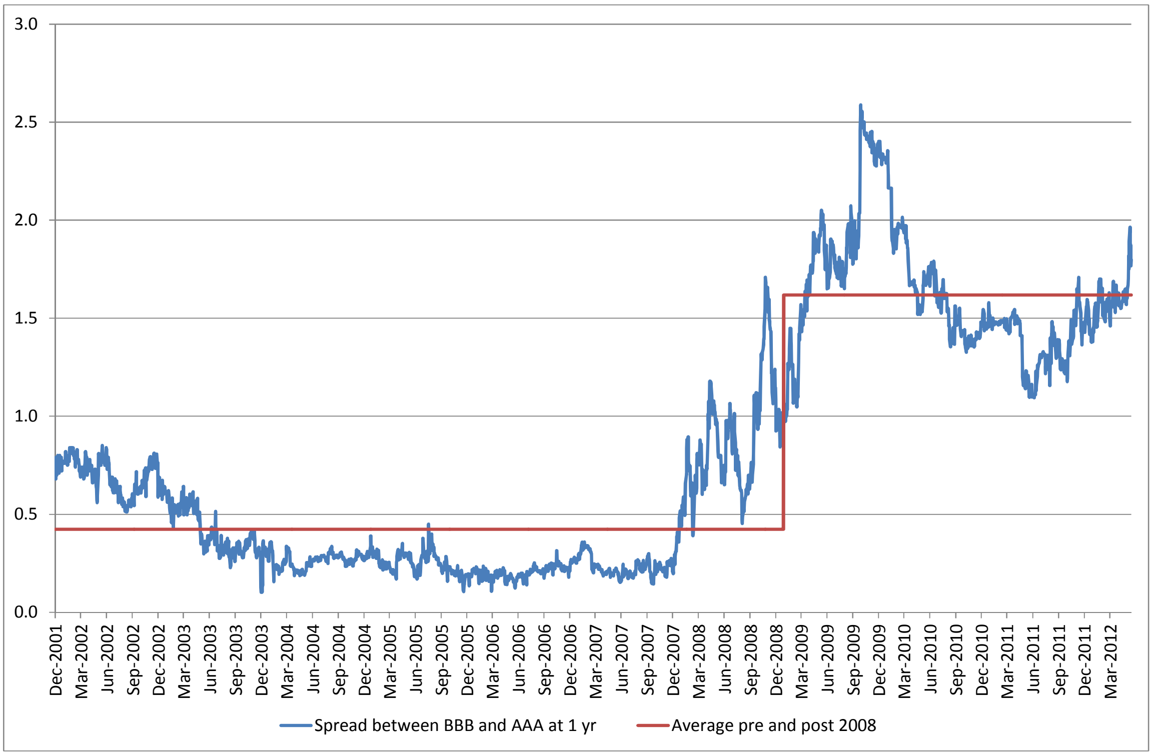
AAA rated bonds as a proxy for the level of risk aversion. They describe this approach as being used extensively in finance:

> *Based on these findings, I choose the yield spread between BAA and AAA rated bonds, denoted by R_{t-1}^{Prem} as a proxy for the market risk premium. The variable R_{t-1}^{Prem} … has been used extensively in finance.*

105. The quote above refers to Moody's credit ratings. The equivalent Standard and Poor's credit ratings are AAA and BBB. When I examine the same measure in Australia using the longest history of fair value estimates available from Bloomberg we observe the following history for the spread between Standard and Poor's AAA and BBB rated bonds with one year to maturity. In Figure 7 below, the spreads between AAA and BBB rated bonds are shown up to May 2012.

106. It can be seen in Figure 7 below that the level of the spread between BBB and AAA rated bonds with one year maturity prior to 2008 was almost always less than 0.5% and averaged 0.42%. Since 2008, the average spread has been over three times higher at 1.6%. While it is true that these spreads peaked in April 2009 at 2.6%, they have not fallen back to pre-crisis levels and are currently very close to their average levels since 2008. Moreover, the level of this spread increased in the second half of 2011 as CGS yields fell.

Figure 7: Spreads between AAA and BBB benchmark bond yields at 1 year maturity



Source: Bloomberg, CEG analysis

107. Bloomberg estimates that in November 2011 AAA to BBB spreads were still more than three times the pre-2008 average yields.[23] This is consistent with ERPs being similarly elevated above their pre GFC levels. This is summarised in Table 2 below.

Table 2: AAA to BBB spreads at 1 year maturity

Sampling period	Spread
Average pre 1 Jan 2009	0.42%
Average post 1 Jan 2009	1.62%
Ratio pre and post 2008	**3.8**
Current	1.8%
Ratio Current to pre 2008 Average	**4.3**

Source: Bloomberg, CEG analysis

3.6.2. RBA estimates of risk premiums relative to CGS

108. The RBA has produced a chart showing movements in risk premiums measured relative to CGS yields[24] on corporate bond of various credit ratings and on near riskless swap transactions (Figure 8 below).[25]

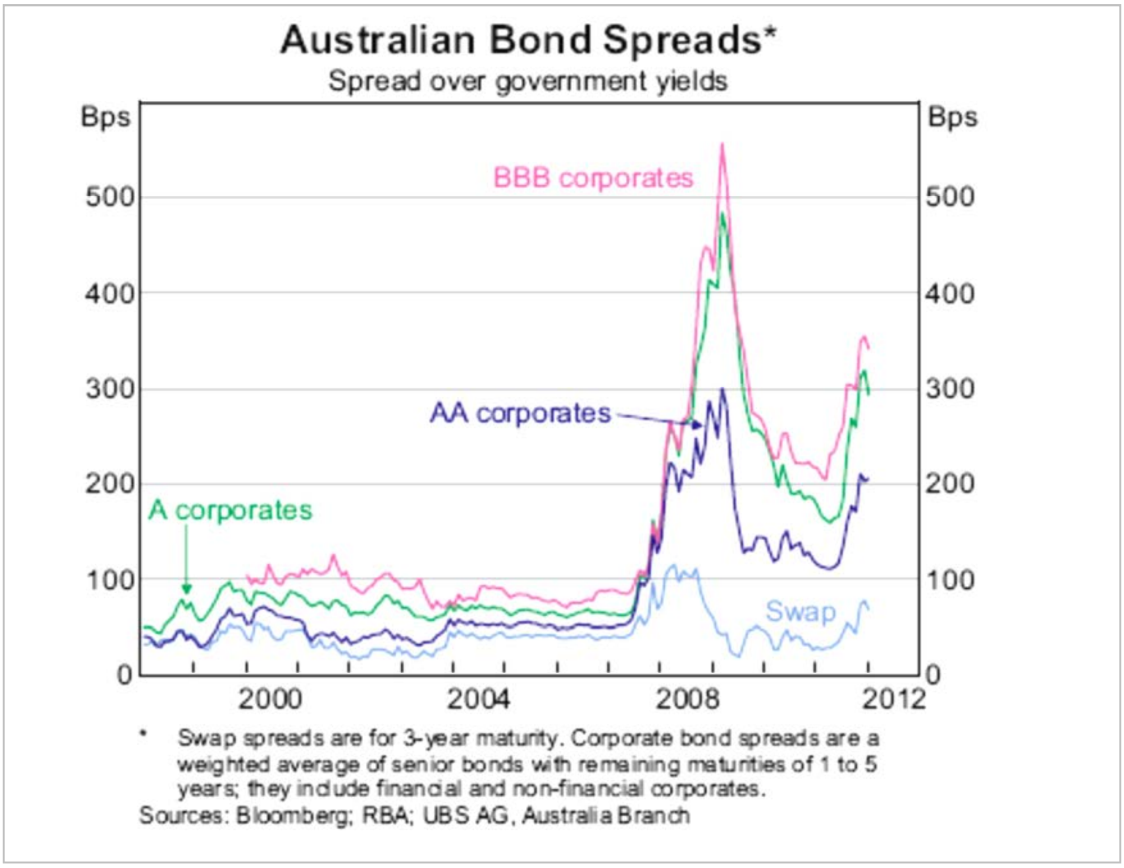
109. The chart shows that all spreads on lower rated bonds increased in the second half of 2011 as CGS yields fell. This is what one would expect in a period of rising risk aversion, namely, widening spreads and spreads widening most on higher risk assets. Similarly, the increase in spreads on A and BBB rated bonds was higher than the increase in spreads on AA rated bonds.

[23] AAA/BBB spreads for December 2011 are estimated at 1.6%.

[24] That is, the difference in yields on corporate bonds and CGS.

[25] Swap transactions do not involve any exchange of principle. If a counterparty defaults the only values potentially at 'risk' are then prevailing differences between short term interest rates and the agreed fixed rate in the contract.

Figure 8: Estimates of spreads on AA, A and BBB corporate bonds



Source: RBA February 2011 Statement on Monetary Policy. The RBA has separately identified the same increases in spreads to CGS for the subset of bonds issued by banks only – see Graph 2.19 in the RBA September 2011 Financial Stability Review

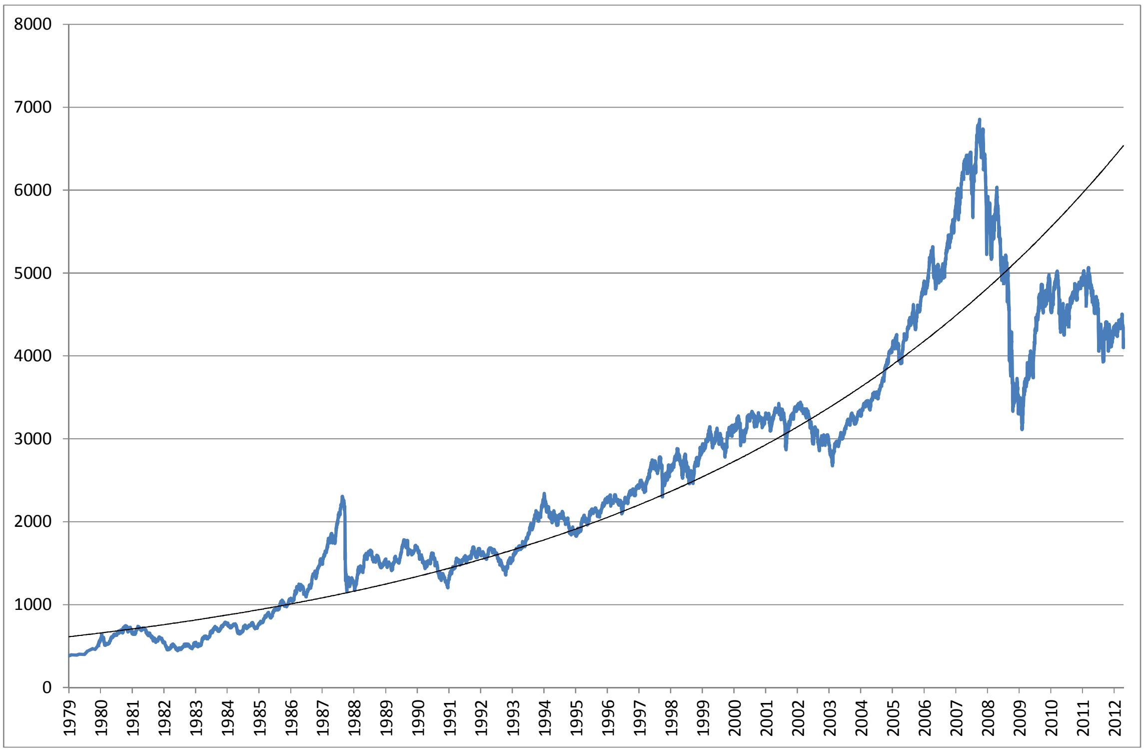
3.7. Do share market gains in 2009/10 suggest risk premiums are back to normal

110. The evidence presented above suggests to me that MRP has, on average, been at elevated levels since the onset of the GFC, and particularly since 2008. There is no indication based on this evidence that forward-looking conditions in equities markets have returned to normal levels.

111. I note that regulators such as the ERA and AER have recently reverted to MRP estimates of 6.0% based upon reasoning that the GFC has either ended or significantly eased. As evidence for this, both regulators have cited the recovery in the Australian share market in late 2009 and 2010.

112. In Figure 9 below I show this recovery in the context of the overall share market trend rate of increase since 1979 (the date to which Bloomberg records these data).

Figure 9: Trend of the All-Ordinaries index, 1979-2012



Source: Bloomberg

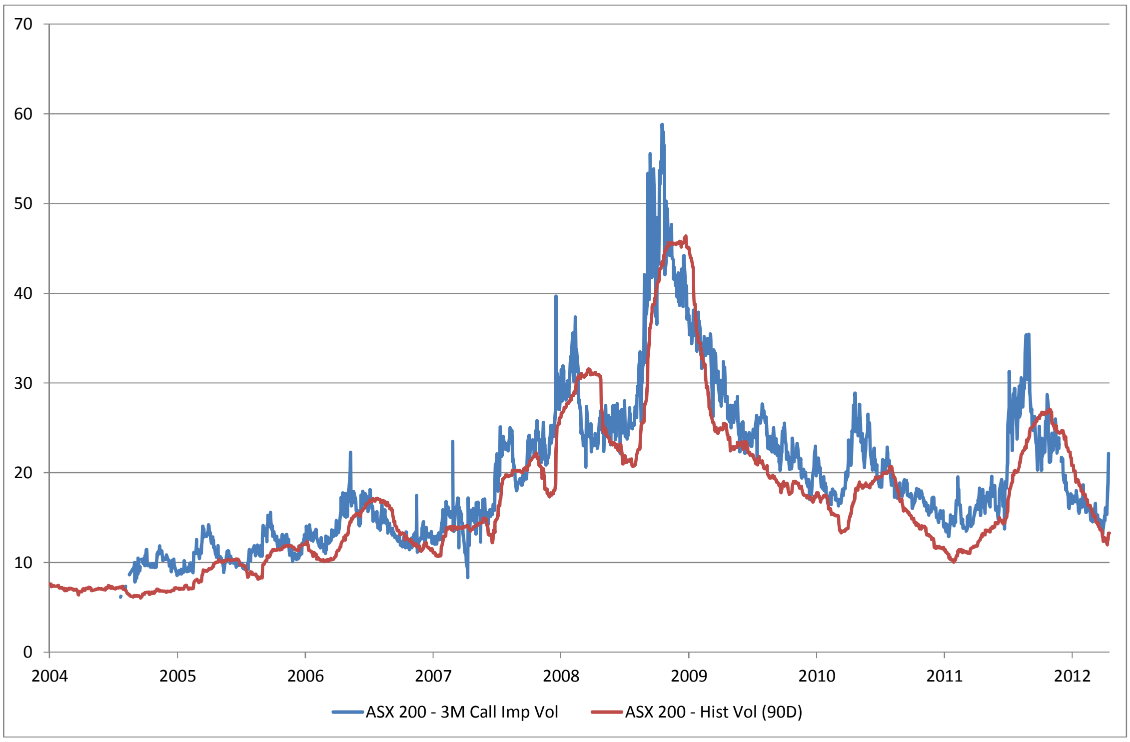
113. In my view, the figure above shows that Australian regulators have been too quick to call an end to the economic uncertainty initially triggered by the events in late 2008 and early 2009. Even after the recovery in late 2009 and 2010, the share market has simply regained half the losses suffered in 2007 and 2008. It has not returned to the trend line I have fitted through 30 years of data. This is true despite high current earnings levels of Australian mining companies associated with high commodity prices. Furthermore, sovereign debt problems in Europe are threatening the stability of the European and world financial system, representing a continuation of heightened economic uncertainty rather than a return to normal, has substantially depressed share markets since the most recent regulatory decisions.

114. In any event, the level of the stock market and/or the expected level of economic growth in a country are not well accepted methodologies for determining investor risk perceptions. I am not aware of any academic theory or analyst practice that uses the rate of change in economic growth or the level of the stock market (divorced from dividend forecasts) as a reliable proxy for the level of investors' risk perceptions.

115. It is the case that the actual and implied volatility of the stock market is sometimes used as an indication of the level of investor risk perceptions. Implied volatility differs from actual (historical) volatility in that it is a measure of the expected level of volatility.

Implied volatility is estimated from index option prices.[26] The figure below shows a history of actual and implied volatility for the ASX200 produced by Bloomberg. It can be seen that actual and implied volatility remain at elevated levels (albeit lower than the absolute peak in late 2008/early 2009).

Figure 10: Actual vs. implied volatility for the ASX200



Source: Bloomberg

3.8. Summary

116. In my opinion, the empirical estimates presented above and the general uncertainty and future economic conditions suggests that reliance on forward-looking MRP estimates is required to provide Western Power an opportunity to recover its efficient forward-looking costs, as required by the Access Code. These results indicate that despite the risk-free rate as proxied by CGS yields being at very low levels, the MRP and the equity risk premium for regulated utilities, calculated relative to this measure, are elevated at levels above 'normal' levels.

117. In these circumstances, it would be unreasonable to apply an historic average estimate of MRP to estimate Western Power's required cost of equity commensurate with the risks of providing covered services as provided for under section 6.4(a)(i) of

[26] Where the value of an option to buy/sell the index will increase with the expected volatility of the index.

the Access Code. I consider that Western Power's proposed of 6.5% to 8.5% is consistent with the available information for the prevailing MRP.

4. Movements in the risk free rate and the cost of equity

118. This section provides a general discussion of whether there is any reason to assume that the cost of equity will move in line with movements in the risk free rate.

4.1. Risk premiums are not constant

119. The CAPM formula describes an investor's required return on any asset – be that asset debt, equity or any other asset. The asset's beta (β) is a measure of the risk of that asset relative to the riskiness of the market portfolio. The MRP describes investors' required compensation for the risk associated with holding the market portfolio. The CAPM formula is set out below:

$$Cost\ of\ Equity = Risk\ Free\ Rate + (\beta * Market\ Risk\ Premium)$$

120. There is nothing in the theoretical derivation of the CAPM formula that implies that either the beta or the MRP are constant over time. The AER's consultant, Professor Davis, made precisely this point in a recent report for the AER:[27]

> *More generally, empirical testing of the model requires application over many time periods, and* ***there is nothing in the model which implies that the parameters of the model will be the same in different time periods.*** *This has led to the distinction between the conditional and unconditional CAPM, in which it is recognized that the CAPM equation could vary period by period, perhaps in some systematic relationship to other observable factors. … The conditional CAPM leads to an unconditional CAPM relationship in which expected asset returns depend on both a market risk factor and an additional factor reflecting the effect of the temporal variation in the conditional CAPM relationship. (See, for example, Jagannathan and Wang, 1996) (Emphasis added)*

And

> *it is my opinion that … there is general agreement that the CAPM needs to be viewed in a conditional form – but that the precise determinants and size of that conditionality (and hence variations over time in beta, MRP etc) are not well agreed.*

121. The Jaganathan and Wang paper referred to by Professor Davis shares his view that the MRP varies over time:[28]

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[27] Davis, Cost of Equity Issues: A Report for the AER, January 2011, p. 4, 21

[28] Ravi Jagannathan and Zhenyu Wang, *The Conditional CAPM and the Cross-Section of Expected Returns* The Journal of Finance, Vol. 51, No. 1. (Mar., 1996), pp. 3-53.

In fact, we know from earlier studies that the expected risk premium on the market as well as conditional betas are not constant (Keim and Stambaugh (1986), Breen, Glosten, and Jagannathan (1989)), and vary over the business cycle (Fama and French (1989), Chen (1991), and Ferson and Harvey (1991)).

122. Fama and French (1989)[29] cited by Jaganathan and Wang conclude:

Our tests indicate that expected excess returns (returns net of the one-month Treasury bill rate) on corporate bonds and stocks move together. Dividend yields, commonly used to forecast stock returns, also forecast bond returns. Predictable variation in stock returns is, in turn, tracked by variables commonly used to measure default and term (or maturity) premiums in bond returns. The default-premium variable (the default spread) is the difference between the yield on a market portfolio of corporate bonds and the yield on Aaa bonds. The term- or maturity-premium variable (the term spread) is the difference between the Aaa yield and the one-month bill rate.

4.2. MRP will often move in the opposite direction the risk free rate

123. Moreover, there is a general consensus that the MRP tends to move in the opposite direction to the risk free rate – especially for material changes in the level of the risk free rate. For example, Lettau and Ludvigson[30] find that the risk premiums tend to move in the opposite direction to the de-trended government bond rate.

124. Amongst other findings, they found a strongly statistically significant negative relationship between the de-trended US bill rates and the change in the log excess return (the variable they introduce akin to the MRP). Such a negative relationship held true without controlling for other potential variables that might affect risk premiums (i.e. a simple correlation suggested that the risk premiums rose 2.1% for every 1% reduction in the de-trended risk free rate). When Lettau and Ludvigson included controls for other variables they still found that when the de-trended risk free rate fell the risk premiums tended to rise by the same amount as the fall in the de-trended risk free rate.

125. Reflecting this negative relationship, Smithers and Co, advisers to the UK economic regulators, have recommended that the cost of equity not be varied based on variations in the risk free rate:

Given our preferred strategy of fixing on an estimate of the equity return, ***any higher (or lower) desired figure for the safe rate would be precisely offset by a lower***

[29] Fama and French, 1989, Business Conditions And Expected Returns On Stocks And Bonds, Journal of Financial Economics

[30] Lettau, Martin and Sydney Ludvigson, 2001, “Consumption, Aggregate Wealth and Expected Stock Returns,” Journal of Finance 56 (3), pp. 815—849.

(or higher) equity premium, thus leaving the central estimate of the cost of equity capital unaffected."[31] (Emphasis added)

126. In the following sections I discuss in more detail the evidence and expert opinion that clearly demonstrates that the current market circumstances are such that there is a negative relationship between risk free rates and the market risk premium. That is, current historically low risk free rates are associated with historically high risk premiums measured relative to those risk free rates.

31 Smithers and Co (2003), *A Study into Certain Aspects of the Cost of Capital for Regulated Utilities in the U.K.*, A report commissioned by the U.K. economic regulators and the Office of Fair Trading, p. 49

5. Why required returns on riskier assets are not falling in line with CGS yields

127. The previous section provided an empirical description of the fact that required returns on other assets have not been falling with the most recent fall in CGS yields – such that risk premiums (spreads) have been rising, even on instruments with very low perceived risk such as state government bonds. Section 5.1 below section explains why this has been happening including by reference to the views of other experts such as the RBA. Section 5.2 of this report also canvasses the RBA's views on the extent to which a 'scarcity premium' or 'liquidity premium' is currently depressing the yield for CGS and the likely implications for future levels of CGS yields.

5.1. Flight from risky to safe assets

128. The CAPM, or, more precisely, the Sharpe-Lintner version of the CAPM, predicts that the expected yield on any asset will be determined by the following formula:

$$Required\ Return\ on\ an\ Asset = Risk\ Free\ Rate + (beta\ for\ that\ asset * MRP)$$

$$Risk\ premium\ on\ asset_i = \beta_i * MRP$$

129. This formula describes an investor's required return on any asset – be that asset debt, equity or any other asset. The asset's beta (β_i) is a measure of the risk of that asset relative to the riskiness of the market portfolio. The MRP describes investors' required compensation for the risk associated with holding the market portfolio.

130. Investors' required compensation for the risk associated with any individual asset can increase for one or both of two reasons:

- the asset's beta can increase (i.e. the asset's risk relative to all other risky assets can increase); or
- the market risk premium can increase.

131. It is ERA's practice to implement the CAPM formula above assuming that the risk free rate is best proxied by the prevailing yield on 5 year CGS. Given this practice, internal consistency requires that the MRP be measured relative to the prevailing yield on 5 year CGS.

132. However, the factual analysis of the previous section demonstrates that the dramatic fall in CGS yields in late 2011 was not associated with similarly dramatic reductions in required yields on other assets – be those assets relatively low risk debt or the relatively high risk listed equity market.

133. The only internally consistent explanation for this evidence is that there has been an across the board increase in the risk premiums (measured relative to CGS yields) that

investors require. This need not be because investors are demanding a higher return on risky assets than they were prior to the fall in CGS rates. It simply means that investors have not demanded a commensurately lower return on risky assets as the yields on CGS fell.

134. A common interpretation for the increase in spreads between CGS and other higher risk/less liquid assets (including by the RBA) is that there has been a flight to the safety and liquidity of AAA rated government debt – which has pushed down the yield on this asset but not all other assets.

5.1.1. Risk premiums on state government debt

135. The most recent fall in the yields on Australian Government CGS has been explained in the following terms by the RBA February 2012 Statement on Monetary Policy:[32]

> Strong demand, particularly from offshore investors, for relatively safe assets in the uncertain global climate has been apparent in the demand for Australian Government bonds over the past couple of months. (As at the end of September, non-residents were estimated to be holding around 75 per cent of Commonwealth Government securities (CGS) on issue.) The yield on 10-year CGS fell to 3.67 per cent in mid January, its lowest level in 50 years….
>
> The strong investor preference for CGS and a deterioration in liquidity in the state government securities market, primarily as a result of heightened risk aversion related to events in Europe, led to a widening of the spread between yields on these securities (Graph 4.4). At their peak, 5-year spreads had widened by around 70 basis points from where they were at the end of October for South Australia and Queensland, and by around 50 basis points for New South Wales and Victoria. In recent weeks, spreads have narrowed and issuance has picked up considerably. Yields on longer-term state government debt have increased since the previous Statement as the increase in spreads has more than offset the fall in yields on CGS, but they remain low by historical standards.

136. In the context of this report, the most relevant elements of the RBA's conclusions are that:

i. Demand for CGS has increased *as a result of an uncertain global climate*, particularly from offshore investors, and pushed down the yields on CGS to its *lowest level in 50 years*;

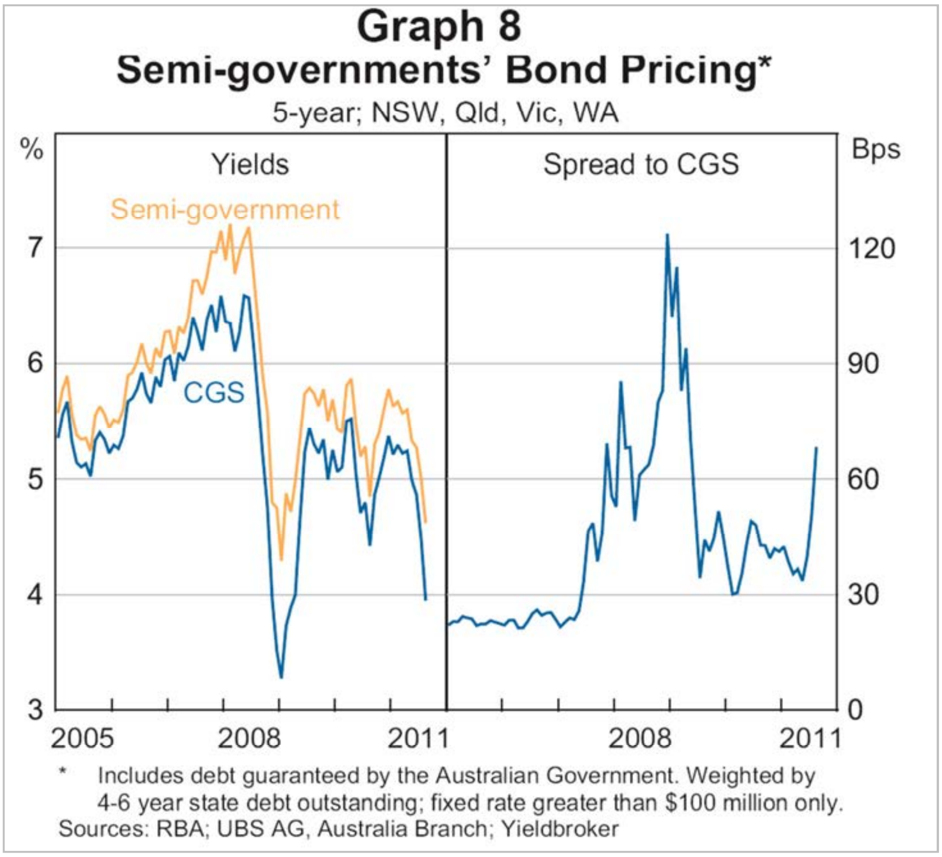
ii. This lower CGS yield *has not* been associated with a commensurately lower required yield on the riskier state government debt. This reflects *heightened risk aversion related to events in Europe* with the effect that risk premiums required on state government debt *rose:* and

[32] Reserve Bank of Australia, *Statement on Monetary Policy*, February 2012, p. 49

iii. Indeed, the increase in risk premiums for state government debt since the previous RBA December Statement on Monetary Policy has more than offset the fall on CGS yields such that yields on state government has *risen* despite the *fall* in CGS yields.

137. Lancaster and Dowling (2011)[33] have made similar observations to those expressed in the RBA Statement on Monetary Policy and quoted above. Published in late 2011, but before CGS yields had reached their recent lows, Lancaster and Dowling compare the yields on semi-government debt to those on CGS. Their graph 8 is reproduced in Figure 11 below.

Figure 11: Semi-governments bond pricing



Source: Lancaster and Dowling

138. Lancaster and Dowling go on to state:[34]

> *Explicit backing by their respective state governments has meant investors generally perceive credit risk for state treasury corporations to be low. This has*

[33] Lancaster and Dowling, *The Australian Semi-government Bond Market*, RBA bulletin, September Quarter 2011

[34] Ibid,

typically resulted in semi-government bonds trading at tight spreads to CGS (Graph 8). Nevertheless, during periods of market distress, semi-government bond spreads generally widen, as investors seek to hold more of the safest and most liquid securities – namely CGS. During the period of market dislocation following mid 2007, the spread between the yields of semi-government securities and CGS widened to over 120 basis points, up from around 25 basis points before the crisis. Although currently well below their peaks in late 2008, recent market uncertainty has caused spreads to rise in recent months. The increase in spreads during periods of heightened risk aversion may in part reflect the fact that some investors, particularly offshore investors, are not always familiar with the extent of vertical fiscal integration in Australia, whereby state governments receive a large share of their revenue via redistributions of Australian Government tax receipts.

139. In the context of this report, the most relevant elements of the above quote from Lancaster and Dowling (2011) are that:

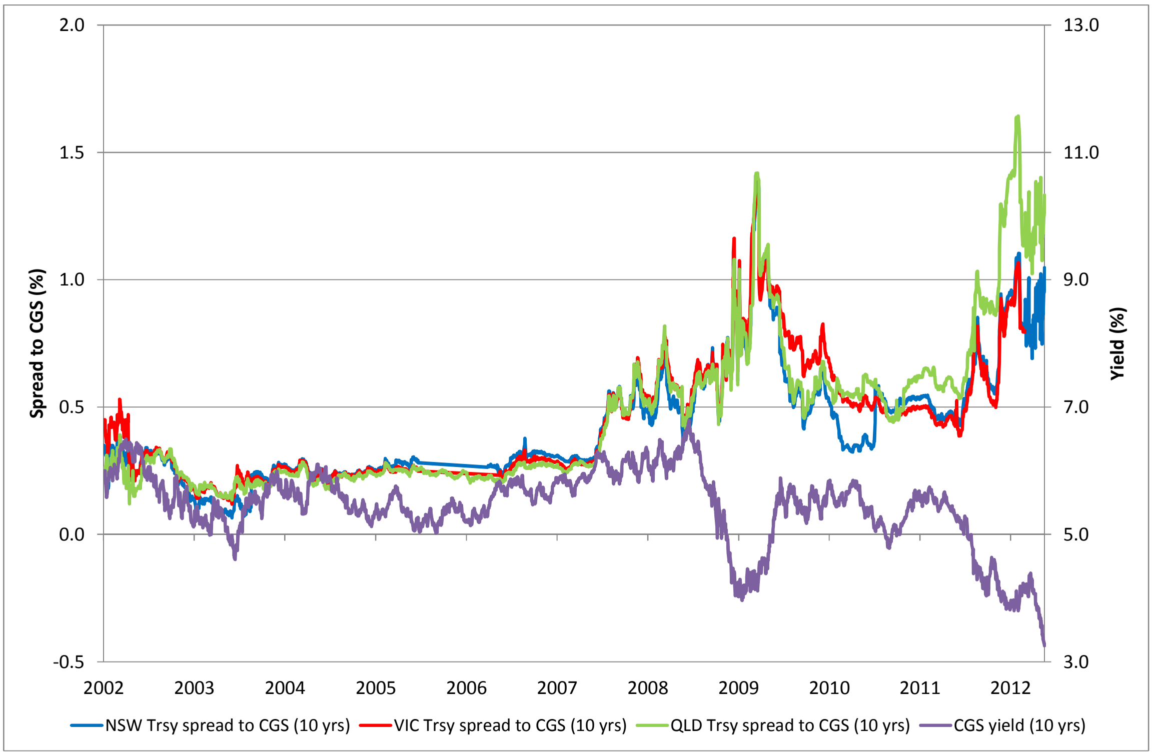
i. During periods of *heightened risk aversion,* CGS yields tend to be pushed down due to a flight to *the safest and most liquid securities.* However, the required returns on other assets, even similarly safe state government debt, do not fall by as much; and

ii. Lancaster and Dowling view the current period as an example of this phenomenon (i.e. heightened risk aversion pushing down CGS yields).

140. This is strong evidence that what was causing the fall in CGS yields was not a general reduction in the return investors required on all assets. Rather, it was a fall in CGS yields driven by a general flight from risk.

141. A powerful demonstration of this evidence is provided by examining the movements in risk premiums on state government debt and the movements in CGS yields on the same graph. Figure 12 below shows the yield difference between state government debt and 5 year CGS on the left hand axis. Because this is measured as a *difference in yields* the scale used for this time series is different to the scale used for the CGS yields – which is shown on the right hand axis.

Figure 12: 5 year risk premiums on state government debt against 5 year yields on CGS



Source: Bloomberg, CEG analysis

142. The scales on the two axes are deliberately chosen to place the CGS time series approximately coincident with the state government debt time series in 2002.[35] This is done in order to allow the reader to see more easily the negative relationship between CGS yields and risk premiums in the financial crisis of 2008/09 and then again in the second half of 2011.

143. This figure shows that the very dramatic fall in CGS yields in late 2008 and early 2009 was associated with an equally dramatic increase in risk premiums (which more than doubled relative to their 2007 levels and quadrupled relative to their pre 2008 levels). Then, as CGS yields recovered in 2009, risk premiums fell. The same pattern is observed in the second half of 2011 with CGS yields falling precipitously and risk premiums simultaneously doubling for NSW and Victorian government debt both rated AAA (and more than doubling for Queensland government debt rated AA+).

144. The risk premiums on state government debt relative to CGS are, at the time of writing, in the vicinity of 30bp higher than when CGS yields began falling in mid-2011. This is a very substantial increase for a relatively low risk asset. Using the CAPM formula

[35] The reader should note that this does not mean that the CGS yields were the same as the risk premium at that time – as CGS yields are shown on the right hand axis which starts at a higher level than the left had axis.

above, it is simple to demonstrate that this implies a much greater increase in the average risk premium for risky assets (i.e. the MRP).

145. To see this, consider New South Wales government debt. This had a risk premium of 102bp at 17 May 2012 which is 55bp higher than the average risk premium of 47bp over calendar year 2010. If one believes that the MRP in 2010 was around 6.0% then this implies a debt beta for Victorian government debt of around 0.08 (=0.47/6). If one assumes that the same beta applies today when risk premiums are around 102bp then this implies an MRP in the vicinity of 13.0% (1.02/0.08).[36]

5.1.2. Risk premiums on listed equities

146. Figure 13 below shows the equity risk premium for Australian publicly listed equities as estimated using the AMP method as described. This figure is simply the CGS and MRP time series from Figure 5 above.

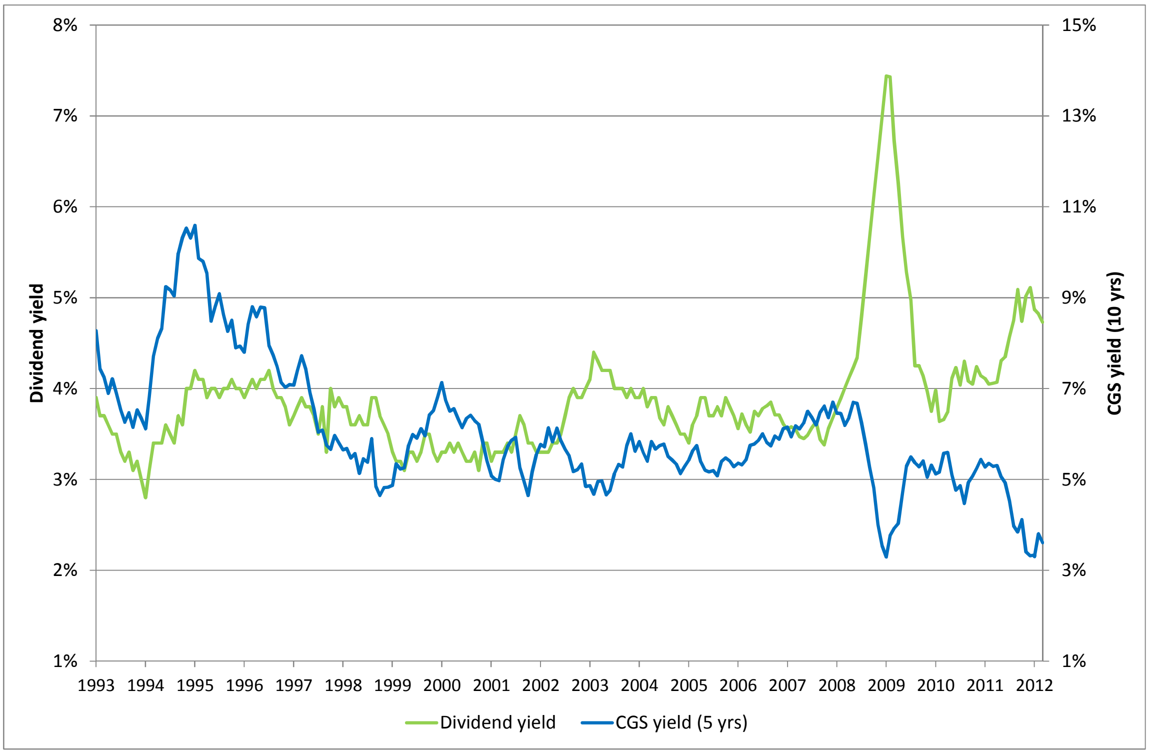
[36] Of course, this does not imply that the absolute required return on risky assets is 300 basis points (3.0%) higher now than it was in 2010. Rather, it simply implies that the required return on risky assets has simply increased *relative to* a falling CGS yield (noting that CGS yields on 28 February were 140 basis points (1.4%) lower than their average over 2010). Thus, based on the logic and assumptions set out above, the CAPM return on the market portfolio would only be 160 basis points higher on 28 February (calculated as 300 bp less 140 bp) compared to the average over calendar year 2010. Of course, if one incorrectly assumed that risk premiums were constant through time then one would conclude that absolute required returns had fallen for all assets when, in reality, required returns on the average asset had risen.

As an aside, I note that any reader accustomed to thinking of the MRP as a stable value derived from long run average historical returns may find it jarring to read about an estimate of the MRP on a given day. However, if the MRP is to be applied in the CAPM formula alongside a CGS yield taken from a given day (or small number of consecutive days) then this is unavoidable – the CAPM requires that the MRP be measured relative to the CGS yield on the same day or set of days that the CGS yield has been estimated on. Formally, the market risk premium is equal to the required return on the market less the risk free rate:

$$MRP = RoE_{Market} - RFR$$

In order for the estimate of the MRP to have any meaning (or, at least, the meaning it has in the CAPM), RoE_{Market} and RFR must be estimated consistently (ie, in the same market conditions).

Figure 13: Risk premiums on listed equities (AMP method) vs 5 year yields on CGS



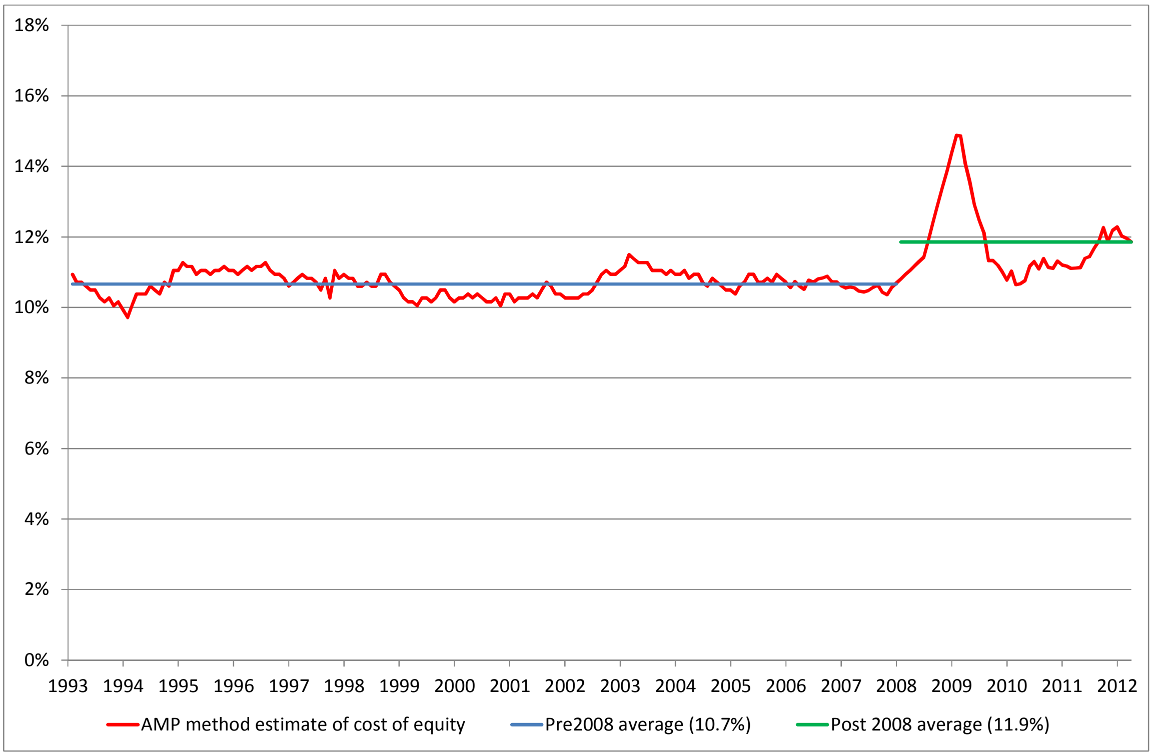
Source: RBA, CEG analysis

147. Figure 13 illustrates, just as Figure 12 did, a clear negative relationship between the yield on CGS and the level of the risk premium. The risk premium is lowest when CGS yields are highest and highest when CGS yields are lowest (in early 2009 and once more at the time of writing in early 2012).

148. Moreover, this negative relationship can be clearly discerned even when CGS yields are at less extreme levels. For example, between 1998 and 2005, peaks in the MRP are generally coincident with troughs in CGS yields (in late 1998, 2003 and 2005), whilst peaks in CGS yields occur with troughs in the MRP series (in 2000, in 2002 and again in 2004).

149. Given this negative relationship between the risk free rate and the risk premium on listed equities, it is unsurprising that the sum of them, being the required return on the listed equity market, is much more stable than its constituent parts.

Figure 14: Total cost of equity (AMP method)



Source: RBA, CEG analysis

150. Examination of Figure 14 suggests that the total cost of equity has been remarkably stable between 10% and 11% since 1993. The clear exceptions to this are the period in early 2009 and, to a lesser extent, in early 2012 when CGS yields were driven to unprecedentedly low levels by historical standards.

151. This chart also shows that, using the AMP method, the average cost of equity for the market post 2008 is somewhat higher than the average pre 2008. This is despite the average CGS yields being materially lower post 2008 (see Figure 1 above).

152. This negative relationship between government bond yields and risk aversion/premiums is not unique to Australia. The RBA has noted precisely the same dynamic at play in other bond markets. When describing investment market turbulence in August 2011, a period in the midst of the CGS yield decline, the RBA noted:[37]

> *S&P subsequently downgraded the credit ratings of a number of US agencies, banks and clearinghouses whose status is dependent on that of the sovereign. This contributed to the increased market turbulence in August. Japan's sovereign credit rating was also downgraded in August; Moody's reduced the*

[37] RBA, *Financial Stability Review*, September 2011, p. 8

> *rating one notch to the equivalent of AA-, bringing it into line with S&P's rating, which had been downgraded earlier in the year.* ***Despite rating changes, long-term government bond yields in the United States and Japan have fallen since the start of August as risk aversion has grown.*** *(Emphasis added)*

153. In the same document the RBA reiterates the fact that the falling CGS yields in the second half of 2011 were contemporaneous with heightened risk aversion:[38]

> ***Risk aversion and volatility in global financial markets have increased sharply since the start of August (****Graph 1.1) …. Across many countries, prices of shares and other risk assets have declined sharply since early August. Bank and insurer share prices have been particularly affected, falling by more than 15 per cent in most countries, to be around their lowest levels since early 2009 (Graph 1.2)…*
>
> *This current episode of risk aversion and volatility follows a number of periods of heightened market turbulence over the past couple of years. These periodic events indicate that financial market participants remain sensitive to bad news following the experience of 2008–09. While the latest bout of market uncertainty is not on the scale of 2008–09, it is unclear at this stage whether it will be another temporary episode or whether it is foreshadowing a more serious market dislocation. (Emphasis added)*

154. It is important to understand that it would be an error to argue, based on the last sentence of this quote, that the regulatory MRP should not be increased to reflect heightened uncertainty/risk aversion because this may only be temporary. Even if we know that the heightened risk aversion is temporary (which we do not), if we are using prevailing CGS as our estimate of the risk free rate, we must still reflect even temporarily higher MRP levels in our cost of equity estimate. To do otherwise would be to pass through a temporarily lower CGS yield that is the 'other side of the coin' of temporarily higher risk aversion.

5.2. Specific supply and demand conditions in the CGS market

155. Figure 12 and Figure 13 above clearly illustrate the negative relationship between risk premiums and the risk free rate that is driven by the flight to safety of CGS in periods of heightened risk aversion. However, there is good reason to believe that there are current aspects of the supply and demand dynamics for Australian CGS that will tend to depress CGS yields, and raise risk premiums, even in periods of 'normal' market conditions. Specifically, the experience of recent years is likely the supply of CGS is small relative to the size of the Australian economy and:

- international events have seen a significant increase in demand for CGS by foreign investors; and

38 Ibid, pp. 5-6

- regulatory changes associated with Basel III banking regulation will require banks to significantly increase their holdings of low risk liquid assets (primarily CGS).

156. The shortage of CGS is well understood to have resulted in a scarcity premium for CGS in recent years - and hence a depressed yield. RBA Assistant Governor Guy Debelle has observed when considering how to interpret differences between the yield on CGS and required returns on other assets:[39]

> *One complication in doing this calculation in Australia is that because government paper has been in short supply for many years, it has tended to trade with a scarcity premium. This widens the observable spread between the yield on government paper and the yield on other assets in a way that is not present in most other jurisdictions. (Emphasis added.)*

157. This scarcity premium has undoubtedly turned upwards for the foreseeable future as a result of the two dot points described above. In relation to the first point, Australian CGS are now amongst very few developed country government bonds that have a AAA credit rating from S&P. The downgrade of US and French Government debt in 2011 (preceded by downgrades to most other Eurozone Government debt) left Australia one of only a very small club of AAA rated sovereigns.[40] This has been associated with a significant increase in demand for CGS by foreign institutions looking for AAA rated sovereign debt.

158. The head of the Australian Office of Financial Management (AOFMO) has been quoted in the press explaining the fall in CGS yields as not just a flight from equities but also as a spill-over from the reduction in the availability of AAA rated government debt in the rest of the developed world. RBA Assistant Governor, Guy Debelle, was quoted in the same article commenting on increased demand for CGS from foreigners:[41]

> *“It's the product of a whole lot of influences,” he said. "Australia is a AAA-rated sovereign, and that's a shrinking club. Investors might be taking money out of equity markets and putting it into the safety of bonds paying fixed interest.*
>
> *”There have been changes in currency level and hedging costs. It's not surprising that demand for Australian government securities should have risen in the current circumstances.”*

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[39] Guy Debelle, RBA Assistant Governor (Financial Markets), Speech to the APRA Basel III Implementation Workshop 2011 Sydney - 23 November 2011.

[40] The others being Canada, Denmark, Finland, Germany, Luxemburg, Netherlands, Norway, Singapore, Sweden, Switzerland and the UK.

[41] The Age, *Australia reaps bond windfall*, Tim Colebatch, *February 16, 2012* available at: http://www.theage.com.au/opinion/political-news/australia-reaps-bond-windfall-20120215-1t6q2.html#ixzz1oQQsnHCl

Reserve Bank assistant governor Guy Debelle said this week the demand for Australian bonds was coming largely from the sovereign wealth funds of foreign governments.

Mr Debelle said the Reserve estimated that 75 per cent of Australian bonds were owned offshore. He said foreign demand for Australian bonds could be partly responsible for the recent strength of the Australian dollar.

159. The heightened demand for CGS from foreign investors appears to have pushed domestic investors into state government debt. While Australian investors only hold around 25% of CGS, they hold around 60% of the market value of state government debt (up from 53% in June 2007). [42]

160. This heightened demand from foreigners comes at the same time that changes to banking regulations are raising the demand for CGS and state government debt from Australian banks. Specifically, under Basel III regulations banks will be required to hold an increased proportion of their balance sheet in high quality liquid assets. The purpose of this regulation is to ensure that banks individually, and the banking system as a whole, can avoid the need to engage in 'fire sales' of illiquid assets in the event of a runs on the banking system (and thereby avoiding a systemic reduction in the value of all such assets held in the banking system).

161. In describing the implementation of Basel III, APRA's Charles Littrel has stated:[43]

First, we intend to ensure that each bank reasonably optimises its use of Commonwealth Government Securities and semi-government securities, which are the most liquid assets in our market. But at the same time, holdings of this stock cannot allow the liquidity in these markets to be soaked up.

162. The problem for Australia is that there simply are too few CGS and state government debt instruments on issue that will allow the Basel III induced demand for these assets to be satisfied (at least without destroying the liquidity of these assets). RBA Assistant Governor Guy Debelle has explained the magnitude of this effect in the following way.[44]

The Basel liquidity standard requires that banks have access to enough high-quality liquid assets to withstand a 30-day stress scenario, and specifies the characteristics required to be considered an eligible liquid asset.

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[42] Lancaster and Dowling, The Australian Semi-government Bond Market, RBA bulletin, September Quarter 2011, page 53.

[43] APRA's Basel III Implementation rationale and impacts, Charles Littrell, Exec. GM, Policy, Research and Statistics, APRA, APRA Finisia Workshop, Sydney, 23 November 2011.

[44] Guy Debelle, RBA Assistant Governor (Financial Markets), Speech to the APRA Basel III Implementation Workshop 2011 Sydney - 23 November 2011.

The issue in Australia is that there is a marked shortage of high quality liquid assets that are outside the banking sector (that is, not liabilities of the banks). As a result of prudent fiscal policy over a large run of years at both the Commonwealth and state level, the stock of Commonwealth and state government debt is low. ***At the moment, the gross stock of Commonwealth debt on issue amounts to around 15 per cent of GDP, state government debt (semis) is around 12 per cent of GDP.[1] These amounts fall well short of the liquidity needs of the banking system.*** *To give you some sense of the magnitudes, the banking system in Australia is around 185 per cent of nominal GDP. If we assume that banks' liquidity needs under the liquidity coverage ratio (LCR) may be in the order of 20 per cent of their balance sheet, then they need to hold liquid assets of nearly 40 per cent of GDP.*

[1]The net stock of Commonwealth government debt on issue is considerably lower at 6 per cent *of GDP, reflecting the assets held by the Commonwealth government, including through the Future Fund.*

163. Lancaster and Dowling in the RBA Bulletin make the same observations about the impact of Basel III on demand for CGS and state government debt:[45]

The demand for semi-government securities is likely to increase over coming years as the introduction of Basel III reforms requires banks to hold higher levels of liquid assets, ***which include semi-government securities, as well as Commonwealth Government securities (CGS),*** *balances held at the Reserve Bank of Australia and cash. (Emphasis added.)*

164. Of course, a well anticipated future increase in demand for CGS will already be factored into a higher current market price (and lower yield) of long term CGS.

165. As a consequence of this recognised shortage of supply, the Basel Committee has explicitly stated that the RBA can attempt to fill the gap by providing a “Committed Liquidity Facility” as a substitute for banks holding CGS and state government debt. In order to access this facility banks would need to agree to pay a 15bp access fee even if they never used the facility (and a further 25bp of penalty interest rates in addition to the access fee if they did use the facility). This gives the bank the right to borrow (access liquidity) from the RBA using less liquid assets as collateral (under a margin scheme that prevents the RBA taking on any credit risk).

166. The only reason a bank would pay these fees for the right to borrow at a penalty interest rate would be if the scarcity/liquidity premium on CGS was high enough to justify this.

[45] Lancaster and Dowling, *The Australian Semi-government Bond Market*, RBA bulletin, September Quarter 2011.

167. In justifying these fees Assistant Governor Debelle, in late November 2011 when CGS yields were at similar levels to those at the time of writing this report, made reference to the heightened liquidity premium that existed at that time.[46]

> ***While at times like the present, liquidity can have considerable value****, the Reserve Bank will not be varying the size of the fee through the cycle. Consequently, the facility is to be priced at a level that takes into account the value of liquidity in more normal conditions, as well as in stressed circumstances.*
>
> *…*
>
> *However, part of the point of the new liquidity regulations is to recognise that the market has underpriced liquidity in the past. Consequently, it is appropriate to levy a fee which is greater than implied by a long run of historical data.* ***The net outcome is thus a weighted average of a relatively low liquidity premium in normal times and a much higher liquidity premium in stressed times.***

168. Importantly, Assistant Governor Debelle was clearly expressing the view that the liquidity premium in the CGS market was, in November 2011, at historically very high levels (and seemingly well in excess of 15bp). The implementation of Basel III can be expected to ensure that this remains so in the foreseeable future.

169. Finally, it is worth noting that the other likely source of increased demand for CGS that can be expected to prevail into the future is a heightened awareness from investors generally about the risks of investing in equities and real estate. The RBA September 2011 Financial Stability Report makes the following observations:[47]

> *Continued net inflows, particularly into superannuation and deposits, offset negative valuation effects associated with falls in share prices. Given the volatility in equity markets in recent years and higher returns being offered on deposits, households have become more conservative in their investment preferences, directing a larger share of their discretionary savings to deposits while* ***reducing direct equity investments****.* ***This is also consistent with surveys showing an increase over the past few years in the proportion of households nominating bank deposits as the wisest place for their savings and fewer nominating equities and real estate.***

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[46] Guy Debelle, RBA Assistant Governor (Financial Markets), Speech to the APRA Basel III Implementation Workshop 2011 Sydney - 23 November 2011.

[47] RBA, *Financial Stability Review*, September 2011, p. 48

6. Regulatory precedent for dealing with volatility in risk free rates

170. The weight of regulatory precedent outside Australia is for the cost of equity to be set in a manner that ensures that unusually low risk free rates are not fully passed on in low allowed cost of equity. There is also material precedent for this in Australia from bodies other than the ERA and AER.

6.1. Australian Competition Tribunal

171. In 2009, the Australian Competition Tribunal found that the AER's approach to estimating the cost of equity for EnergyAustralia was in error because use of the prevailing risk free rate in the AER's CAPM formula resulted in too low a cost of equity. As already noted above, in late 2008 and early 2009, CGS yields plunged during the global financial crisis of that period. This reflected a flight to safety and liquidity by investors as they shunned alternative riskier assets.

172. The NSW electricity distribution businesses and the NSW and Tasmanian electricity transmission operators were advised by both myself and Professor Bruce Grundy that, if the MRP was held constant at historical levels, then measuring the risk free rate at historical lows in the CAPM would result in an erroneous estimate of the cost of equity. The AER contested this view and proceeded to estimate the cost of equity using an MRP of 6% and a nominal (real) risk free rate of 4.3% (1.8%) (the lowest yield on nominal 10 year CGS since the 1950s).

173. This decision was appealed to the Tribunal. The issue of contention was whether the historically low risk free rates during the crisis should be passed through in equally low cost of equity allowances.

174. In the context of those proceedings, I provided expert evidence very much along the lines described above.[48] The Tribunal agreed that using such rates to set the cost of equity without increasing the market risk premium was likely to underestimate the cost of equity. The Tribunal stated:[49]

> *The Applicants submitted that these facts demonstrated that basing a risk free rate on the AER's specified averaging periods would not achieve the objective of an unbiased rate of return consistent with market conditions at the date of the final decision. They appealed to expert opinion that the market risk premium was far higher than its deemed value while the risk free rate was abnormally low, so that the return required by investors was much higher than the AER's specified averaging period would generate.*

48 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009.

49 *Application by EnergyAustralia and Others (includes corrigendum dated 1 December 2009)* [2009] ACompT 8 (12 November 2009), paras. 112-114.

…

The Tribunal considers that an averaging period during which interest rates were at historically low levels is unlikely to produce a rate of return appropriate for the regulatory period.

175. It is relevant to note that the real risk free rate set in the ERA's Western Power draft decision is even lower than the real risk free rate that was that was the subject of variation as a consequence of the merits review brought by the NSW distribution businesses and the NSW and Tasmanian transmission operators (1.1% versus 1.8%). I focus on the real risk free rate because it is the real risk free rate that determines the real level of compensation Western Power can expect to receive.

176. In these circumstances, the ERA's draft decision not only fails to raise the MRP to at least partially offset the impact on the cost of equity of lower risk free rates resulting from a flight from risky assets. In addition, the ERA decided to use its discretion to *reduce* the equity beta to 0.65 - thereby compounding the impact of the falling CGS rates on the allowed cost of equity.

177. The table below compares the CAPM parameters used in the Western Power draft decision to the parameters rejected by the Tribunal as being in error in EnergyAustralia. It also shows the results of applying the same methodology at the time of writing (using average CGS yields in February 2012)

Table 3: Cost of equity estimates

Parameter	Tribunal correction to AER error	AER decision (pre Tribunal correction)	ERA draft decision
Real risk free rate	3.3%	1.8%	1.1%
Beta	1.0	1.0	0.65
MRP	6.0%	6.0%	6.0%
Real cost of equity	9.3%	7.8%	4.9%

178. This table demonstrates that the ERA has set the same MRP but a materially lower risk free rate than the AER set in the EnergyAustralia decision (which the Tribunal overturned). The effect of this is that the ERA draft decision sets a real risk free rate at 0.7% less than the level that the Tribunal found in EnergyAustralia was:[50]

[…] unlikely to produce a rate of return appropriate for the regulatory period.

179. The context of that proceeding was such that the Australian Competition Tribunal had open to it to direct the AER to use an earlier averaging period, as proposed by

[50] *Application by EnergyAustralia and Others (includes corrigendum dated 1 December 2009)* [2009] ACompT 8 (12 November 2009), para. 114.

EnergyAustralia, that did not reflect the prevailing conditions in the CGS market during the AER averaging period. This is what the Tribunal directed should occur.

180. It is relevant to note that, as I understand the legal constraints, the Australian Competition Tribunal did not have open to it the option of varying the market risk premium parameter that was to apply. This is because as a consequence of transitional provisions in the Rules for the regulatory determination processes to apply to the NSW electricity distributors, the market risk premium was fixed at 6 per cent with no ability to depart from that fixed value. For the transmission network operators, the value was similarly fixed at 6 per cent with no ability to depart from that fixed value.

6.2. UK regulators

181. UK regulators have considered the problems associated with using a volatile estimate of the prevailing risk free rate alongside a stable estimate of the market risk premium. As a group, they commissioned Smithers and Co to address this and other issues. The advice from Smithers and Co was that movements in the MRP would tend to move to offset any change in the risk free rate: [51]

> *Given our preferred strategy of fixing on an estimate of the equity return, any higher (or lower) desired figure for the safe rate would be precisely offset by a lower (or higher) equity premium, thus leaving the central estimate of the cost of equity capital unaffected.*

182. UK regulators have largely accepted this advice and they do not, as a rule, use a prevailing estimate of the risk free rate when applying the CAPM. For example, in an annexure report entitled "Decision on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Financial issues" Ofgem adopted the following approach, in March 2011:[52]

> *3.69. Market measures of the real risk-free rate, such as the yield on ILGs, have risen slightly since the data cut-off point for EE's December report. However, they remain near historical lows, partly due to the Bank of England's official interest rate being held at 0.5 per cent and the impact of Quantitative Easing. We, therefore, do not consider it appropriate to rely on spot rates or short-term averages to set the risk-free rate.*
>
> *3.70. Our revised range for the risk-free rate is, therefore, 1.7-2.0 per cent. The lower bound matches the 10-year average yield on 10-year ILGs, while the upper bound corresponds to regulatory precedent in the UK.*

[51] Smithers and Co, *A Study into Certain Aspects of the Cost of Capital for Regulated Utilities in the U.K., A report commissioned by the U.K. economic regulators and the Office of Fair Trading,* 2003, p. 49.

[52] Available at: http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decisionfinance.pdf

183. The market level of the ILG's (Index Linked Gilts) reported in the EE report (and referred to above) were around 0.4%. Consequently, Ofgem's decision involved an increase of between 1.3% and 1.6% relative to these values.

184. In 2006 Ofgem similarly set the risk free rate above market rates. On the basis of Smithers and Co's advice referred to above, Ofgem, in its 26 June 2006 Initial Proposals, stated:

> *In DPCR4, as described above, we observed that the CAPM model gave a wide range of estimates for the cost of equity, reflecting a significant variation between long term average values for the cost of equity and observed market data at a given point in time. We concluded that we could not rely on observed market data due to exceptional factors pushing down interest rates and the instability of the equity beta. (p. 30)*

185. Ofcom stated:[53]

> *Taking account of both current and recent historical evidence, Ofcom's view is that it is appropriate to use a value of 4.6% for the nominal risk free rate. This is somewhat higher than the current rate of about 4.2% to 4.3% (which are lower than historic averages), but consistent with a longer term averages and a real risk free rate of 2.0% and a rate of inflation of 2.5%.*

186. Similarly, Ofwat, the UK water regulator, concluded:[54]

> *The proposed range is consistent with regulatory precedent. Recent regulatory determinations have placed little weight on low gilt rates [Government bond rates]. The Competition Commission, eg BAA plc (2002), has also noted that current yields should be used with caution when estimating the risk free rate because of market volatility. The Smithers & Co study (February 2003) undertaken on behalf of the regulators concludes that a reasonable assumption for the [real] risk-free rate is 2.5%.*

6.3. US regulators

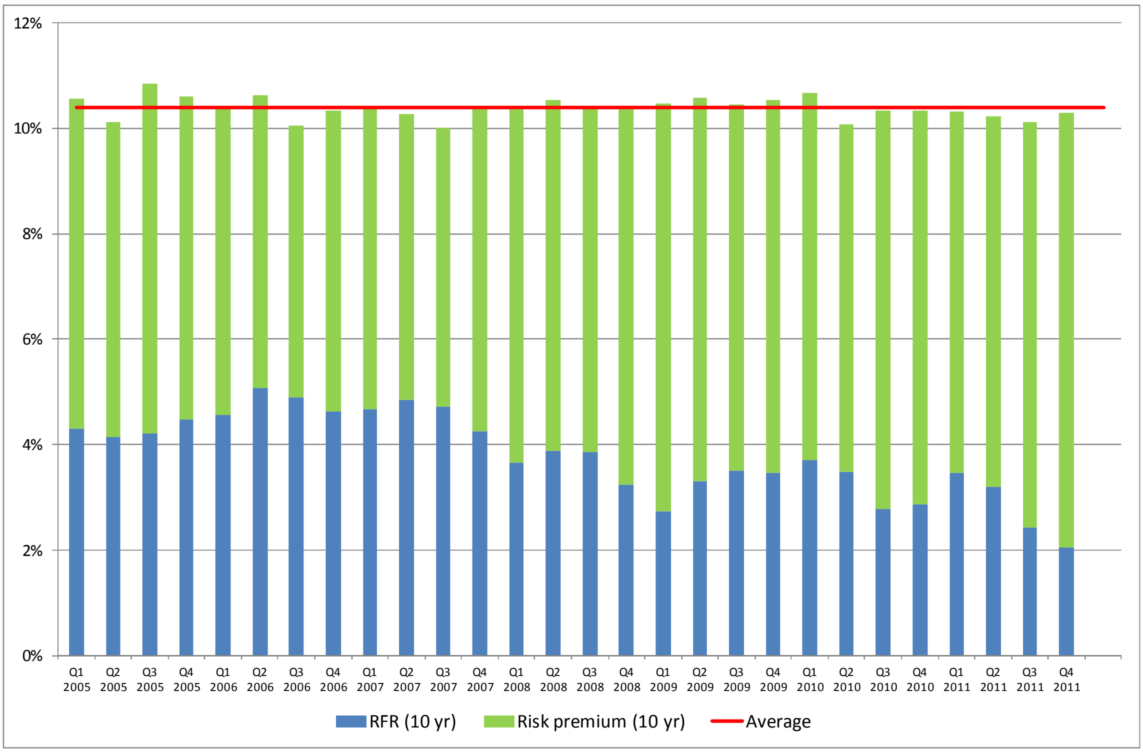
187. Energy regulators, along with most other monopoly regulators in the US, do not tend to reflect variations in the risk free rates, proxied by 10 year Treasury bond rates, in the allowed cost of equity for a regulated business. This reflects the fact that the US regulators attempt to estimate the cost of equity using a wholly forward looking methodology. As a result, any fall in Government bond yields due to a rise in risk aversion will tend to be automatically offset by higher allowed risk premiums.

[53] Office of Communications, Ofcom's approach to risk in the assessment of the cost of capital, 23 June 2005, p. 15

[54] Ofwat, Future water and sewerage charges 2005-10: Final determinations, Appendix 5, Cost of Capital

188. The following figure illustrates this by examining US decisions for regulated gas and electricity transport businesses over the last 6 years –covering the periods pre and post global financial crisis. Over this period US government 10 year bond rates were volatile and are currently around 300bp lower than (less than half) their pre-crisis peak (2.05% versus 5.07%). However, the allowed return did not move in synchronicity with movements in risk free rates – with the average return on equity allowed by US regulators relatively stable at 10.38% in the face of movements in risk free rates.

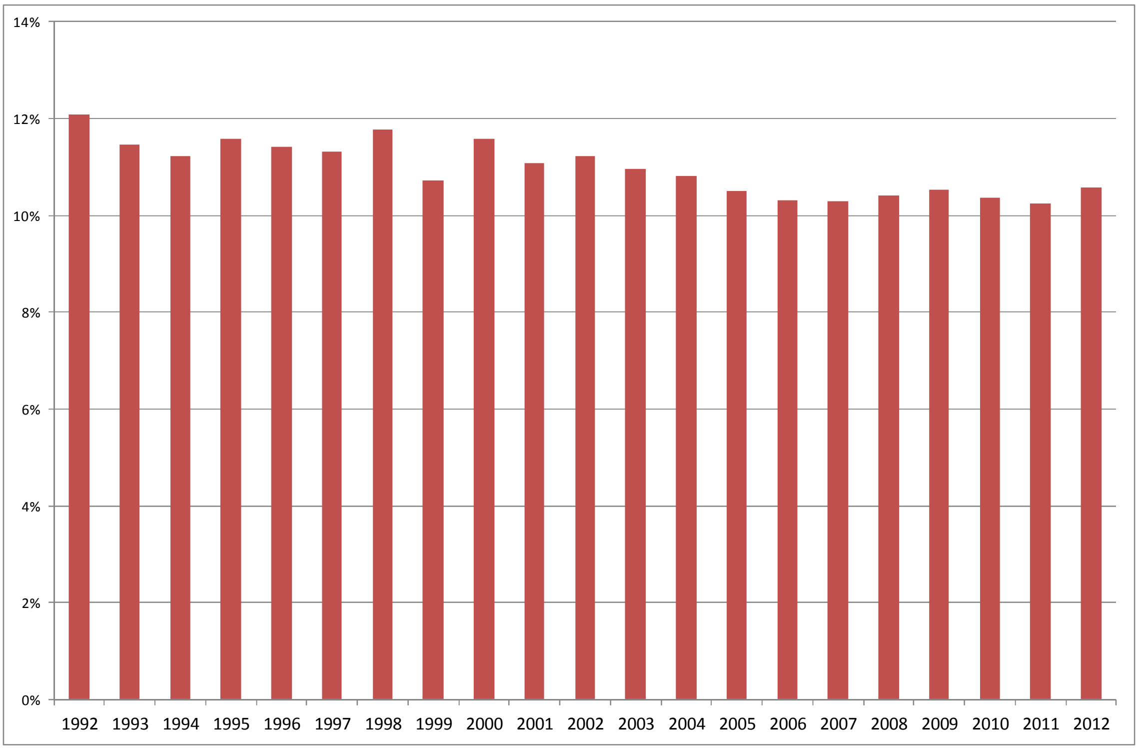
Figure 15: US regulatory decisions over time – broken into risk free rate and risk premium



Source: SNL Financial Business Intelligence Services, Bloomberg, CEG analysis
** Note that the average gearing of the firms in this sample is below 50%. Consequently, the allowed return on equity for these businesses cannot be directly compared with the ERA allowed return on equity for a 60% geared company without making the necessary upward adjustment.*

189. The same pattern of stability in the return on equity is true over an even longer time horizon as shown in the Figure below which shows, for the last twenty years, return on equity allowances for regulated US energy firms averaged across all regulatory decisions (average 11.01%).

Figure 16: US regulatory return on equity decisions over 20 years – average per year



Source: SNL Financial Business Intelligence Services, CEG analysis

190. An additional potential source of information on normal required returns for regulated businesses comes from US regulatory precedent involving the application of the DGM model. For the US regulatory decisions from 2005 to 2011 described previously, I have estimated the average ROE is 10.38% (11.01% over the last 20 years). The average equity premium is 6.57% and average 10 year US Treasury rate is 3.80%. Note that this is based on DGM analysis performed by regulators. However, this is for an average gearing of 47.98%. Adjusting this to 60% gearing gives an **average cost of equity of 12.36%.**[55]

6.4. Australian regulatory practice

191. There is also recent and older Australian regulatory precedent for not setting the risk free rate based on observations that are affected by abnormal conditions in the Government bond market.

192. In a recent decision in relation to the Sydney Desalination Plant, IPART has stated:

[55] 12.36% = 3.805% + (1-0.4798)/(1-0.600)*6.575%

For this review, we consider that the value of the risk free rate is currently well below long term averages and that there is a high level of market uncertainty. We consider the risks in setting a 5-year determination in the current conditions are more significant than under normal market conditions.

We acknowledge the argument that there may be greater stability in the sum of the market risk premium and the risk free rate (i.e., the expected market return) than in the individual components. In the current market circumstances, there is some evidence, as SDP noted, to support the view that expectations for the market risk premium have risen as bond yields have fallen.

193. Consistent with this analysis, IPART set a WACC towards the top of its range. Its stated reason for doing so was as set out below[56]:

We determined the values for the parameters of the WACC based on market conditions over the 20 days to 28 October 2011. The risk free rate and debt margin have been affected by market volatility and the prolonged weak market following the credit crisis of 2008. The change in these factors has potentially created a disparity between these parameters (for which we use short term average data) and the market risk premium (for which we use long term average data).

However, the effects of this disparity are mitigated by our decision to use a point estimate of 6.7%, which is 80 basis points higher than the midpoint of our estimated WACC range. In doing so, we had strong regard to the calculated WACC using longer term averages for market parameters.

194. In addition, the Essential Services Commission of Victoria (ESCV) determined that government bond markets were abnormally affected by the maturity of a large proportion of the relevant CGS market which it believed led to shortage of supply of these bonds and a downward bias in yields (noting that yields are inversely related to the price of a bond).[57] Consequently, the ESCV chose to adopt an averaging period from before this event. The ESCV stated:

[…] the Commission's preferred response is to identify a measurement period that is not influenced by the downward bias, and to sample interest rates from that period. Data after August cannot be relied upon at this time as it is unclear for how long the downward bias may persist. On this basis, the Commission considers that it is appropriate to use the latest market evidence available prior to the biasing event. The Commission has therefore applied a measurement period for the calculation of the risk-free rate as the last 20 trading days of July

56 Ibid., section 9.1, page 80.

57 The yield is the percentage return on a bond. Given that the stream of future payments is predetermined, the higher the price paid for the bond the lower the percentage return on the bond, i.e. the lower the yield.

2005. This amended measurement period excludes any potential downward bias in the month of August, as identified by Westpac and CBA.[58]

195. In the 2002 Powerlink decision[59], the ACCC made an adjustment to its averaging period in order to exclude the impact of the events of September 11. Similar to the current financial crisis, the events of September 11 caused a 'flight to safety' – with the effect that government bond prices were pushed up (pushing yields down) and equity prices fell dramatically. That is, the risk free rate fell at the same time that the perceived riskiness of equities (cost of equity) increased.

196. Importantly, the ACCC (then the regulator) determined that it would be inappropriate to capture a lower risk free rate due to a crisis when that same crisis was likely causing the prevailing MRP to rise (and to increase by more than the decline in the risk free rate). The ACCC stated: [60]

The Commission recognises that the events of 11 September have impacted on the risk free rate, however it believes that it is still too early to fully quantify this impact. Given this uncertainty, the Commission will adopt a forty-day moving average ending on 11 September rather than a forty-day moving average ending on the date of this decision.

The Commission acknowledges that as a result of 11 September there may be an increase to the level of risk experienced by the market. If such an increase in risk exists, it is unclear to what extent CAPM parameters will be effected. However, any movement in the MRP can only be accurately determined by accessing changes in the market over an extended period of time.

Therefore, the Commission will continue to examine the impact of the 11 September events over time and it will take into account any evidence identified for future regulatory decision."

197. In this decision the ACCC explicitly recognised the same problem that we are faced with today in dealing with an averaging period and an economic crisis (although the events of September 11 had a much shorter and shallower impact on financial markets than the current events). The ACCC responded by excising risk free rate data that was affected by the crisis rather than by increasing the MRP.

58 ESCV, October 2006, Final Decision Electricity Distribution Price Review 2006-10 as amended in accordance with a decision of the Appeal Panel dated 17 February 2006, Volume 1 Statement of Purpose and Reasons, p. 343

59 ACCC, *Powerlink Revenue Cap Decision*, November 2002.

60 Ibid, p. 13

7. Term of the risk free rate

198. It is not possible to derive a 'correct' term for the risk free rate to be used in the Sharpe Lintner CAPM from theoretical considerations. This is because the Sharpe Lintner CAPM is a "one period model". That is, the theoretical basis for the CAPM equation is derived in a hypothetical world where all investors:

i) come into existence, imbued with wealth for investing, at a point in time;

ii) invest that wealth in assets with that investment 'locked in' for a single period (i.e. no adjustment of their portfolio is possible); and

iii) withdraw that wealth and consume it in its entirety (i.e. no re-investment or re-allocation of the portfolio occurs at the end of the period).

199. This is one of the many highly restrictive assumptions on which the CAPM formula is based. The assumption was relaxed by the Nobel Prize winner Robert Merton (1973) who demonstrated that, when one allowed for the possibility of reinvestment by investors, the CAPM formula was no longer valid because investors will care about factors other than beta.[61]

200. Two points follow from this:

i. It is impossible to theorise about what the correct term of the risk free rate is in the Sharpe CAPM formula because the Sharpe CAPM formula is derived from a theoretical model that simply does not allow for the possibility of there being more than one discrete and undefined period. This model provides no guidance for how that period should be defined in the real world where it is possible to measure time and investment periods in hours, days weeks, years and decades.

ii. There are very good reasons to believe that this simplifying, but highly restrictive, assumption underlying the CAPM formula explains why the CAPM performs so poorly in empirical tests (including why it tends to underestimate returns for low beta stock).

201. Given that one cannot reason as to the correct term of the risk free rate within the logic of the CAPM, one must decide between a short term and a longer term on other grounds. In my view, all of the below stated reasons tend to point towards choosing a longer term estimate:

i. consistency with how the MRP has been estimated;

ii. an objective of limiting volatility in the cost of capital allowance;

iii. matching the term of the risk free rate to utility investors long term perspective (consistent with the life of the assets they own); and

[61] Merton, R.C., "An Intertemporal Capital Asset Pricing Model", *Econometrica*, Vol. 41, No. 5. (Sep. 1973), pp. 867-887.

iv. consistency with the term of the cost of debt.

7.1. Consistency with the MRP estimate

202. The historical evidence relied upon by regulators to justify a 6% estimate for the MRP uses a 10-year risk-free rate. It would be internally inconsistent to use a MRP estimated in conjunction with anything other than a ten year risk free rate.

203. The cost of equity is determined by the ERA using the capital asset pricing model (CAPM) formula developed in Sharpe (1964), which sets the required return on equity using the following formula:

$$RoE = r_f + \beta \times (market\ return - r_f)\ ; \text{ where } \quad (1)$$

$$RoE = required\ return\ on\ return\ on\ equity$$

$$\left(market\ return - r_f\right) = market\ risk\ premium\ (MRP)$$

$$r_f = risk\ free\ rate$$

$$\beta = asset\ specific\ equity\ beta$$

204. The first point to note is that the choice of the risk free rate will have little effect on the cost of equity estimate if the MRP was relative to the risk free rate based on prevailing market conditions. For any given prevailing RoE, choosing a shorter term lower yielding CGS as the proxy for the risk free rate will simply increase the MRP by the same amount as it reduces the risk free rate.

205. Only if the MRP is arbitrarily fixed at a given level and then the definition of the risk free rate it altered will the choice of a shorter/longer term for the risk free rate affect the estimated cost of equity. However, this involves a fundamental error because the correct MRP must always be measured relative to the risk free rate (as set out above). Therefore, any change in the definition and level of the risk free rate should also result in a change in the definition and (offsetting) level of the MRP.

206. Secondly, Sharpe (1964) himself states in relation to the assumptions underpinning the derivation of the above formula:

> *Needless to say, these are highly restrictive and undoubtedly unrealistic assumptions.*

207. The assumption of a ‘single period’ in the CAPM simplifies the mathematics and allows one to arrive at the above simple formula. However, it also means that there is no financial theory that can be used to conclude that the CAPM, when applied to regulated businesses with five yearly resets, must be implemented with any particular risk free rate. The correct term of the risk free rate to be used in the CAPM is an

imponderable question because the model is incapable of even considering more than one possible risk free rate.

208. In this context an important consideration for choosing the term of the risk free rate is to choose one that is internally consistent with the definition of the MRP $(market\ return - r_f)$. If the MRP has been estimated using a ten year risk free rate then the risk free rate used in the CAPM equation (equation 1) must also be set using the same assumption.

209. This was the basis of the Australian Competition Tribunal's finding in GasNet that the ACCC made an error in the use of a five year risk free rate in the CAPM formula when the MRP had been estimated using a ten year risk free rate.[62]

> *In truth and reality, the use of different values for a risk free rate in the working out of a Rate of Return by the CAPM formula is neither true to the formula nor a conventional use of the CAPM. […] The CAPM is not a model, which is intended to operate in this way. The timescales are dictated by the relevant underlying facts in each case and for present purposes those include the life of the assets and the term of the investment.*

210. The context of this decision was that the ACCC's MRP estimate of 6.0% was based on a historical average excess return relative to the 10-year CGS rate. In my view, Handley's evidence for the AER, summarised at section 3.4 above, makes clear that:

  a. the historical average excess return relative to the 10-year CGS rate is 6% or above over longer time horizons; and

  b. the confidence interval is very wide when one uses short time horizons (as used by the ERA).

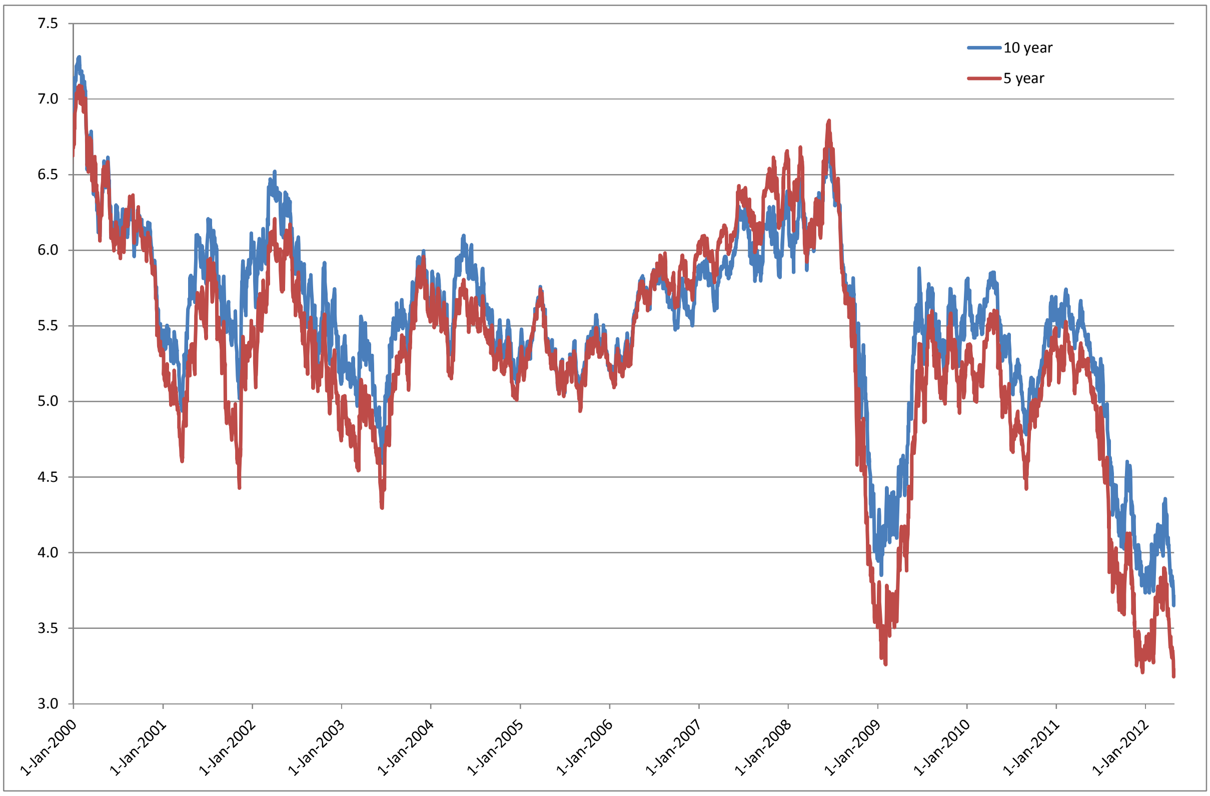
211. To the extent one adopts an MRP of 6% based on historical evidence one should, for internal consistency, adopt a 10-year CGS rate.

7.2. Reducing the volatility of the cost of equity allowance

212. Perhaps even more importantly, yields on 10-year CGS are materially more stable than for CGS with shorter maturities. The below figure illustrates the yields of 5-year and 10-year CGS since 2005.

[62] Australian Competition Tribunal, *Application by GasNet Australia (Operations) Pty Ltd* [2003] ACompT 6, para. 47.

Figure 17: Commonwealth Government Security yields



Source: Reserve Bank of Australia

213. A visual inspection of this curve demonstrates that there is higher volatility of bond rates at the short maturity end. The average 10-year bond rate is generally slightly higher than the average five year rate (18bp over the period shown). However, it is materially less volatile. When the economy or financial sector is in crisis the short term bond rates drop significantly more than the long term bond rates. Similarly, when market conditions are relatively strong the short term bond rates rise materially more than the long term bond rates.

214. Using 5-year bond rates now in a CAPM model where the MRP is fixed at some historical average (eg, 6%) would lead to the, in my opinion wrong, conclusion that the cost of equity in Australia was now 3.8% lower than it was immediately prior to the GFC (ie, the 5 year risk free rate was 3.2% on 26 April 2012 but was 7.0% on 16 June 2008). By comparison the 10-year risk free rate peaked at a slightly lower level (6.9% instead of 7.0% on the same day) and has fallen to a lower level (3.7% vs 3.3% at the time of writing).

215. The higher volatility of 5 year CGS is captured in statistical measures of volatility. The variance of the five year bond rates in above is 0.56. The variance of the ten year bond rate is 0.36 (more than a third lower). This greater volatility of short term debt is exemplified during the recent global financial crisis, where short term bond rates fell much faster and further than long term bond rates.

216. Sections 4 to 5 below set out why I believe that such volatility in the risk free rate should not be automatically reflected in similar movements in the regulatory cost of equity. Put simply, low/high risk free rates tend to be associated with high/low prevailing risk premiums. Passing on volatility in the risk free rate while keeping the assumed MRP constant will tend to cause the cost of equity to be underestimated/overestimated when risk free rates are low/high. In fact, it will commonly tend to cause the regulatory cost of equity to move in the opposite direction to the true cost of equity.

217. While it is an error to use any prevailing CGS yield as the proxy for the risk free rate alongside an historical average MRP of 6%, the magnitude of this error is materially lower if the CGS rate is for a 10-year bond than for a 5-year bond.

218. As a result of this property of Government bond rates, adopting a term shorter than 10 years for the bond rate will increase the volatility of the estimated cost of equity. (Assuming that the ERA maintains its methodology to add a fixed premium of beta multiplied by historical average MRP to the Government bond rate). Moreover, if one does not adjust the MRP to reflect prevailing as opposed to historical market conditions, adopting the more volatile 5 year CGS rate will make the overall cost of equity estimate less accurate (too low when risk free rates are low and too high when risk free rates are high).

7.3. Consistency with long term investment perspective

219. Long term bonds tend to require a higher interest rate in order to attract investors. Whatever the factors are that make investors demand a premium for long term government bonds they are equally likely to be present in relation to equity investors in long lived assets.

220. The value of equity in a regulated business will, like the value of a long term bond, be determined by expectations of economic conditions in the long term. While an investor can sell equity in the short term the same is true of investors in long term government bonds (in fact, the higher liquidity of Government bonds makes it relatively easier for investors to dispose of long term government bonds).

221. This argument is consistent with the natural and intuitive assumption that, because the payback period for the assets in question is long, the term of the risk free rate should also be long. This is consistent with the Australian Competition Tribunal description of standard practice by economists and regulators described previously.

7.4. Consistency with the term of the risk free rate used in the cost of debt calculation

222. In my companion report I have argued that the cost of debt, and therefore the risk free rate used to estimate the cost of debt, must be at least ten years. If one accepts that the risk free rate used to estimate the cost of debt must have a term of at least ten

years, it is natural to adopt the same term for the risk free rate used to estimate the cost of equity and to use this assumption in calculating the MRP.

7.5. Conclusion

223. The choice of the risk free rate would have little effect on the cost of equity estimate if the MRP was relative to the risk free rate based on prevailing market conditions. Only if the MRP is based on some sort of stable historical average estimate will the choice of a shorter/longer term for the risk free rate affect the estimated cost of equity.

224. Although one cannot reason as to the correct risk free rate within the logic of the CAPM, it is my view in the light of the reasons presented in this section and summarized below, that a term of 10-years is preferable over a shorter term due to:

   i. consistency with how the MRP has been estimated;
   ii. consistency with the objective of limiting volatility in the cost of capital allowance;
   iii. consistency with the intuitive assumption that utility investors take a long term perspective (consistent with the life of the assets they own); and
   iv. consistency with the term of the cost of debt.

225. Therefore, it is my opinion that Western Power's proposed 10-year term for estimating the cost of equity is reasonable and satisfies the requirements of the Access Code.

8. How should the cost of equity be estimated

226. This section considers four broad brush approaches/methodologies for arriving at an estimate of the cost of equity and assesses the consistency of these with 6.4(a)(i) if the Access Code which states:

The price control in an access arrangement must have the objectives of:

(b) giving the service provider an opportunity to earn revenue ("target revenue") for the access arrangement period from the provision of covered services as follows:

(ii) an amount that meets the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved;

227. The four approaches considered are:

i. Direct estimate of the cost of equity for firms of comparable risk to the services being regulated (RoE of the reference services or $RoE_{reference\ services}$) using, for example, DGM analysis.

   - This methodology attempts to estimate the future path of dividends that investors' expect for a particular firm (or set of firms that have the same risks as are involved in providing reference services). Having done this, one then calculates the discount rate that equates this dividend path with current market prices. This effectively involves estimating the risk free rate, beta and MRP jointly (i.e. the process delivers an estimate of the cost of equity for the reference services directly).

ii. Direct estimate of the cost of equity for the market portfolio (RoE_{Market}) with a separate process for estimating the adjustment for differences in risk between the market and the reference services.

   - For example, one might attempt to estimate the prevailing market risk premium using DGM analysis applied at the level of the market. Then one might separately estimate the beta of the reference services using historical data for comparable businesses. Having done this, the estimate of the cost of capital can be found using the CAPM formula.

$$RoE_{reference\ services} = Prevailing\ R_f + \beta \times (Prevailing\ RoE_{Market} - Prevailing\ R_f)$$

iii. Proxy the prevailing conditions in the market for funds by establishing the best estimate of the 'normal' cost of equity associated with the reference services. Based on the evidence in this report the cost of equity is more stable than its constituent CAPM parameters. Consequently, the normal cost of equity can be expected to be a good proxy for the prevailing cost of equity in most market conditions. One can test this presumption against other evidence and, if necessary, make an adjustment if that evidence is sufficiently compelling that the prevailing cost of equity is heightened/depressed relative to its 'normal' level. The evidence in this report suggests that if any such adjustment were to be made it would be positive.

iv. Attempt to estimate a 'normal' level of the equity risk premium associated with the reference services (i.e. a 'normal' level for $(RoE_{reference\ services} - R_f)$) and add this to a prevailing estimate of the risk free rate (R_f).

- This is essentially the ERA methodology. The ERA estimates $(RoE_{reference\ services} - R_f)$ as the product of an equity beta estimate (derived from historical market data) and a market risk premium figure (also derived from historical market data). The ERA then adds this to the prevailing estimate of the risk free rate.

228. In my view, each of the first three methodologies is capable of arriving at an estimate of the cost of equity for reference services that is consistent with the Rules across a wide range of market circumstances. In fact, the differences between these approaches are really ones of degree and/or emphasis. All of the first three methodologies share the objective of deriving a forward looking (prevailing) estimate of the cost of equity. Methodologies i) and ii) rely solely on prevailing market data to arrive at an estimate of the cost of equity. Methodology iii) relies on historical average data and the presumption, supported by the evidence presented in this report, that the cost of equity is relatively stable overtime (more stable than the constituent CAPM parameters that tend to move in offsetting directions).

229. In my view, the fourth methodology cannot be relied on to provide a robust estimate of the prevailing cost of equity. This is because it fixes the risk premium on equity based on historical evidence but does not similarly fix a consistent estimate of the risk free rate. Given that risk premiums and risk free rates commonly tend to move in the opposite direction this methodology will tend to underestimate the cost of equity when risk free rates are low and overestimate the cost of equity when risk free rates are high.

8.1. Methodology i)

230. The first methodology is entirely forward looking. Assuming that the CAPM describes how investors determine prevailing conditions in the market for funds, this methodology estimates all components of the CAPM formula jointly. Such an estimate reflects the forward looking assessment of both market risk (MRP) and relative risk of the reference services (beta). This approach also implicitly captures the actual risk free rate that investors use when applying the CAPM (rather than needing to adopt a potentially biased proxy such as CGS).

231. Of course, the first methodology does not provide estimates of the individual CAPM parameters. However, this is a 'feature' and not a 'bug' of this approach because these individual parameters are of little interest if we have already directly estimated

the cost of equity directly (ie, the cost of equity that would result from application of the CAPM if we could accurately estimate each parameter separately).[63]

232. The downside of the first methodology is that it is only possible if there is listed equity with comparable risk to the reference services and there is some methodology for arriving at an estimate of the future dividends that investors expect that equity to pay. In the US, regulators rely in part on a relatively deep pool of analyst forecasts for this purpose. Arguably, the level of analyst coverage for individual regulated businesses, and certainly the pool of regulated businesses, is not as deep in Australia as in the US.

233. Of course, having regard to comparables in other countries, such as the US regulated businesses and US regulatory determinations, is one way to address any perceived lack of depth in Australian data.

234. A further potential objection to this approach is that the estimates of the cost of equity are sensitive to the level of stock prices at the time that the estimate is made. The volatility in equity prices (relative to long run dividend forecasts) means that the DGM estimate of the cost of equity will also be volatile.

235. Once more, this can reasonably be argued to be a 'feature' rather than a 'bug' to the extent that the volatility in equity prices is driven by volatility in prevailing conditions in equity markets (ie, volatility in equity investor's required return on equity). However, at least part of the volatility in equity prices is likely to be driven by illiquidity in the market for a particular equity. Consequently, part of the volatility in DGM estimates may simply reflect movements driven by lopsided buy or sell side activity. Tthis can potentially be addressed by using a longer average of equity prices (e.g. measured over a month or several months).

8.1.1. Application

236. I have used the dividend growth model to forecast a cost of equity for Australian regulated utilities of **between 10.86% and 14.59%.**

237. This is based on analyst dividend forecasts sourced from Bloomberg on 24 February 2012 and 9 March 2012 and the average price of equities for these firms over the period 24 February 2012 to 9 March 2012. The range for the cost of equity is based on a range for long term dividend growth from zero growth in real terms (2.5% nominal) to growth in line with long term average GDP growth (6.6% nominal). More details of the assumptions and results of this analysis are summarised at section 3.3 above.

238. I note that even at the lowest reasonable assumption on dividend growth (zero real growth), the implied equity risk premium over 10-year CGS is 6.73%. Based on a

63 Note that if the CAPM actually describes how investors arrive at required returns then a well implemented DGM analysis will estimate the CAPM cost of capital in the market place. If the CAPM does not describe how investors assess risk then this will not be the case. Of course, that is a another 'feature' of the DGM rather than a 'bug'.

range of equity beta of between 0.8 and 1.0 (consistent with the views set out in my accompanying report on equity beta), this implies an MRP in the range of 6.7% to 8.4%.

8.2. Methodology ii)

239. As with the first methodology, the second methodology relies on a DGM estimate of prevailing returns but instead of being only for comparable firms the DGM is applied to the market as a whole. However, one still needs to separately analyse comparable firms in order to arrive at an estimate of the risk of the reference service relative to the market (beta).

240. The second methodology may not be entirely forward looking if it takes an estimate of relative risk (beta) from historical data. Doing so assumes that investors believe that the equity in question will behave in the same way, and in the same relationship to the market, as it did in the historical beta estimation period. This is only reasonable if investors believe that future shocks to the economy/equity markets will largely be the same (in type, frequency and magnitude) as the shocks experienced over the historical beta estimation period. This may or may not be a reasonable assumption.

241. However, under this methodology, the estimate of relative risk is applied to a forward looking MRP estimate. By doing so the estimate will capture prevailing conditions in the market for funds in general. Provided the *prevailing* relative risk of the reference services (e.g. beta) is consistent with the *historically* estimated value then this will result in an estimate that is commensurate with prevailing conditions in the market for funds for providers of the reference services.

242. Similar issues are associated with the application of the DGM whether it be applied to the market or a subset of comparable firms. However, to the extent the market as a whole is less likely to have prices affected by liquidity issues this may render the results from the market estimate less volatile due to this factor.

8.2.1. Application

243. I estimate a prevailing market cost of equity at 11.96% and MRP at 7.75%. This is based on the AMP method using March 2012 dividend yields from the RBA, long run dividend growth of 6.6% nominal and an assumption that each dollar of dividend delivered to investors comes with 11.125 cents value of franking credits.[64] Assuming a beta of 0.8 and risk free rate of 4.21% over March 2012 this gives a **cost of equity for the reference services of 10.41%.**

244. By way of contrast, Bloomberg, using analysts forecasts of near term dividend growth and its own model of transition and steady state growth, estimates the prevailing

64 Based on theta of 0.35 and 75% of dividends being franked.

market cost of equity at 12.7% and MRP of 8.6% as over Western Power's proposed averaging period of the 20 days to 30 March 2012.

8.3. Methodology iii)

245. Compared to the first and second methodologies the third methodology relies on historical average data. An historical average estimate of the cost of equity can be a reliable proxy for the prevailing cost of equity if the cost of equity is stable through time. The evidence examined in this report demonstrates that movements in risk premiums and CGS yields tend to 'cancel' each other out with the cost of equity relatively stable and much more stable than the constituent CAPM parameters (e.g., see sections 4 and 5 above)

246. Indeed, to the extent that estimation of purely forward looking estimates suffer 'noise' (eg, due to the illiquidity issues discussed above) then the best estimate of the prevailing cost of equity may be the best estimate of the historical average cost of equity. This was precisely the advice of Smithers and Co to UK regulators as set out at paragraphs 125 and 181 above.

247. As with any methodology, it would be appropriate to cross-check the results from its application to the results from other methodologies. However, methodology iii) could reasonably provide an "anchor" estimate of the prevailing cost of equity that could be departed from if some evidentiary threshold for departure was satisfied. This evidentiary threshold may be met with information from the application of either the first or the second methodologies.

248. An estimate of the historical average cost of equity under methodology iii) could reasonably be arrived at by having regard to a historical average of CAPM real parameters (e.g. a historical average real risk free rate, market risk premium and beta estimate.

8.3.1. Application

*8.3.1.1. Historical average risk free rate plus historical average MRP*beta*

249. In my view there are two possible sources of an estimate of the historical average risk free rate that can be used in conjunction with a historical average MRP estimate (such as the ERA's 6% estimate). My preference is to adopt the historical average yield on inflation indexed CGS.[65] This yield is, by definition, the required return on these CGS

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[65] The alternative is to attempt to estimate the expected return on nominal CGS by deducting expected inflation from nominal CGS yields. This is clearly more difficult because it is not possible to directly observe what investors expected inflation to be over the 10 year life of a 10 year CGS. Nonetheless, one possible assumption is that investors have perfect foresight, i.e., that investors expected what actually occurred. With this assumption it is possible to derive an expected real return on historical average nominal CGS.

From mid 1993 onwards the RBA began inflation targeting. Over this period inflation has averaged 2.73% and 10 year nominal CGS have averaged 6.32%. Deducting 2.73% from the nominal CGS yield of 6.32% using the Fisher equation gives a real yield of 3.49% - which is only slightly above the average indexed CGS yield of 3.40% reported above.

bonds after inflation (which is separately compensated based on actual inflation over the life of the bond). Based on a time series from July 1993 the average yield on indexed CGS was 3.40%.[66] I note that this is a conservative estimate because, from late 2008, regulators ceased using indexed CGS as the risk free rate proxy because of evidence that scarcity premium was depressing the required yield on these CGS bonds.

250. Combining my best estimate of the historical average real required return on 10-year CGS with a beta of 0.8 and an MRP of 6.0% gives a real cost of equity of 8.20%. If expected inflation going forward is 2.50% then a 5.99% nominal CGS yield is required to deliver the same 3.40% real yield. Using this nominal CGS yield with a beta of 0.8 and an MRP of 6.0% gives a **nominal cost of equity of 10.78%.**

251. The 6.0% MRP estimate used above is the estimate most commonly used by Australian regulators over the period in relation to which the yields on CGS have been averaged. If the use of a 6.0% MRP over this period was, on average, correct then it is consistent and appropriate that an average CGS yields over this period be added to it.

252. While the genesis of the 6.0% MRP estimate may be based on the average of a longer time series of historical *ex post* returns on equity relative to CGS, I do not consider that this makes it problematic to use a shorter time series for historical average *ex ante* real return on CGS.

253. There are two reasons why I hold this view:

- Firstly, we are interested in estimating the *ex-ante* real risk free rate (i.e. the expected return for investors after accounting for inflation). This can be estimated with much greater accuracy from the early 1990s onwards due to the introduction of inflation indexed bonds which allow us to directly estimate the real CGS yield actually required by investors over that period; and
- Secondly, and by contrast, historical average estimates of MRP must be based on very long time periods because the volatility in the observed *ex post* excess return on equities is so large that a long period is required in order to have any confidence in the average reflecting *ex ante* investor expectations (ie, the excess return investors needed to expect in order to invest). This is not the case with indexed CGS where the promised real yield is the real yield actually delivered. Nor is it the case with nominal CGS in a low and stable inflation environment such as has existed in the post 1993 period of inflation targeting by the RBA.

[66] There is additional data going back to July 1992 for indexed CGS. If this data is included then the average real CGS rate rises slightly to 3.45%. I use the post June 1993 data in order to have a consistent time period for comparison with the nominal CGS yields experienced under the RBA's inflation targeting regime which, as explained earlier in this report, began in mid 1993.

8.3.1.2. Cross checks on the historical average cost of equity estimate

254. An additional potential source of information on normal required returns for regulated businesses comes from US regulatory precedent involving the application of the DGM model. For the US regulatory decisions from 2005 to 2011 described previously, I have estimated the average ROE is 10.38% (11.01% over the last 20 years). The average equity premium is 6.57% and average 10 year US Treasury rate is 3.80%. Note that this is based on DGM analysis performed by regulators. However, this is for an average gearing of 47.98%. Adjusting this to 60% gearing gives an **average cost of equity of 12.36%.**[67]

255. This 12.36% estimate is higher than the 10.78% estimate derived immediately above. If one accepts that US regulators application of the DGM is unbiased and that US regulated businesses have similar underlying risk to Australian regulated businesses then this provides a basis for concluding that the 10.78% is more likely to be too low than too high.

256. The estimates of the cost of equity derived under methodologies i) and ii) are 10.41% and 10.86% to 14.59% respectively, results that are broadly consistent with the 10.78%. Depending on the threshold applied, one might, or might not, determine that the results of these cross checks justified a departure from the estimate derived under methodology iii).

8.4. Methodology iv)

257. The fourth methodology is the ERA's methodology. This methodology fully reflects the prevailing risk free rate in the cost of equity but not the prevailing risk premiums relative to that risk free rate. In the currently prevailing market conditions this gives a materially downwardly biased estimate of the cost of equity because, for the reasons discussed in previous sections, it is clear that historically low CGS yields are currently associated with historically high risk premiums.

8.4.1. Application

258. This methodology arrives at a **nominal cost of equity estimate of 8.57%** using end December 2011 CGS yields of 3.77%. This is materially lower than the estimate arrived at using all of the other methodologies.

8.5. Summary of results from different methodologies

259. Table 4 below summarises the results of the different methodologies.

67 12.36% = 3.805% + (1-0.4798)/(1-0.600)*6.575%

Table 4: Summary of results from each methodology

	Basis of estimate	Time period	Div. yield	DPS growth	RFR	MRP	Beta	Nominal cost of equity
(i)	**DGM for regulated businesses** DGM model applied to utility stocks in Australia. Range based on long run real dividend growth of between zero and in line with GDP.	Dividend forecasts average 24 Feb and 9 March. Price and CGS averaged over period 24 Feb to 9 March 2012	multiple	2.50 – 6.60%	4.13%	6.73% to 8.41%	0.8-1.0	**10.86%-14.59%**
(ii)	**DGM for the market** Application of the AMP methodology to estimate prevailing MRP and then application of beta of 0.80 along with prevailing rfr	March 2012	5.68%*	6.60%	4.21%	7.75%	0.8	**10.41%**
(iii)	**Historical average RFR plus historical average MRP * beta** Historical CGS with MRP of 6% and beta of 0.8.** Assumes an indexed historical CGS of 3.40%, resulting in a real cost of equity of 8.2%, or 10.8% assuming inflation of 2.5%	Historical CGS based on time series since July 1993	n/a	n/a	3.40% real 5.99% nominal	6.00%	0.8	**10.78%**
(iv)	**ERA methodology** Prevailing CGS with a risk free rate February 2012 of 3.67%, MRP of 6.00% and a beta of 0.65	February 2012	n/a	n/a	3.67%	6.00%	0.65	**7.57%**

Source: Various, CEG analysis
** Dividend yield scaled up using a factor of 1.1125.*

9. Conclusion

260. In my view, the appropriate proxy for the risk free rate in the CAPM is the 10 year CGS yield. However, adopting the 5 year CGS yield should not materially alter the cost of equity derived under the CAPM. Any change in the risk free rate due to the adoption of a particular proxy will be offset by an equal and opposite change in the MRP. This is because the definition of the MRP is the market return on equity less the risk free rate proxy. Changing the risk free rate proxy adopted does not change the market return on equity. Rather, the MRP, by definition, alters by an equal and opposite amount when the risk free rate proxy is altered.

261. There is unambiguous evidence that risk premiums in the market for funds have risen to offset the recent fall in CGS yields. The effect of this is that the prevailing cost of equity is at least as high as under normal market conditions – notwithstanding that the CGS yields are at 50 year lows. In these circumstances, it would be an error to estimate the cost of equity using prevailing CGS yields in combination with a historical average estimate of the market risk premium.

262. Alternative methodologies consistent with 6.4(a)(i) of the Access Code involve estimating the cost of equity using:

   i. A DGM estimate of the cost of equity for firms which experience risks that are comparable to those confronted by firms which provide the reference services.

   ii. DGM estimates of the cost of equity for the market portfolio (RoE_{Market}) and a separate process for estimating an adjustment for differences in risk between the market and the reference services (a beta different to 1.0).

   iii. Estimate a 'normal' level for the cost of equity for the reference services and make an adjustment to that based on evidence/proxies that suggest heightened/depressed prevailing conditions in the market for funds relative to 'normal' conditions.

263. Any of these approaches will, in my view, result in an estimate of a cost of equity that of consistent with the requirements of the Access Code of at least 10.41%. This is almost 3% more than is estimated in the ERA's draft decision. In my view, it is not possible to reconcile the ERA's approach in its draft decision with the requirements of the Access Code.

Appendix A. Assumptions used in DGM modelling

264. In order to estimate the average risk premium required by investors across Australian utilities equities I have sourced from Bloomberg median analyst forecasts for six regulated utilities businesses.

265. The forecast cash amount and value of the dividends of the six regulated utilities firms are available only for three financial year periods, including the current, next and subsequent financial year. There are no direct forecasts of dividends per share that we are aware of which extend beyond that period. To enable an estimate of the required rate of return, we have extended the path of dividends into perpetuity based on an assumed long run rate of growth from the final Bloomberg forecast.

266. The Bloomberg forecasts cannot usually be directly compared to capitalisation of firms in order to estimate an implied rate of return because these are forecasts of cash dividends, and as such do not include the value of imputation credits to investors. Usually, I would include the value of imputation credits consistent with a value for theta of 0.35 and a proportion for franked dividends of 75%.[68] This means that on average each dollar of dividends had attached to it imputation credits valued by investors at 11.125 cents $(0.35 * 0.75 * 0.3/(1 - 0.3)$.

267. Accordingly, I would apply an uplift factor to the Bloomberg cash dividend forecasts to reflect the value of imputation credits to investors. However, I have applied no such uplift factor to the six regulated utility firms because the majority of these firms do not currently pay any imputation credits with their distributions. This means that the resulting cost of equity for the utilities firms is a conservative estimate.

268. There is general consensus that long run real dividend growth is best proxied by long run real economic growth. This is the assumption that is made by AMP,[69] Davis,[70] Lally[71] and Damodaran[72]. I consider this approach is appropriate and have developed an estimate for real long run growth of 3.9%.

269. The average annual rate of real growth in gross domestic income between the December quarter 1959[73] and September quarter 2010 was 3.99%. Combined with an

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68 Sourced from Brailsford, T., J. Handley and K. Maheswaran, Re-examination of the historical equity risk premium in Australia, Accounting and Finance 48, 2008, page 85.

69 AMP Capital Investors (2006), *The equity risk premium – is it enough?* Oliver's insights, Ed.13, 4. This methodology uses the long term average nominal growth in GDP as a proxy for long term average nominal growth in dividends).

70 Davis, The weighted average cost of capital for the gas industry, Report prepared for the ACCC and ORG, 18 March 1998, p.15-16.

71 Lally, The cost of capital under dividend imputation, Prepared for the ACCC, 2002, pp.29-34.

72 Damodaran, op cit, p. 53.

73 The Australian Bureau of Statistics (ABS) publishes economic growth figures on its website starting in 1959. Here I use growth in real domestic income of 3.9% (A2304314X of ABS Catalogue 5206.0) rather than nominal growth, since future expectations of inflation are not consistent with the high levels of inflation that were experienced at various times over this period.

average long run inflation forecast of 2.5%, based on the middle of the RBA's target band for inflation, this is equivalent to nominal economic growth of 6.59%. This is also consistent with the 6.9% average expected rate of growth in dividend per share in the US from 1946 to 2008.[74] By way of comparison, equivalent real growth in the US since 1929,[75] starting immediately prior to the great depression, was 3.3%. If the data series begins instead at 1933 the real average growth rate is 4.0%.

270. The use of long run historical economic growth should be distinguished from using the long run historical MRP to predict the currently prevailing MRP. In the latter approach one is using *long run historical* MRP and assuming it is the best estimate of the *prevailing* MRP. This is not akin to how I am using long run historical economic growth. In this approach I am using a *long run historical* economic growth to inform my view about the best estimate of a *long run future* economic growth beyond immediate term forecasts - which I then use, along with current data on equity prices, short-term dividend forecasts and CGS yields as the input into our estimate of the prevailing MRP. Importantly, I am using long run historical estimates as a proxy for long run future estimates – I am not using them to proxy short run (prevailing) conditions.

74 The appropriate data for Australia is not easily accessible – noting that it is desirable to track dividend *per share* growth not dividend growth *per se*. This means we require an estimate of the dividends an investor would receive if they never reinvested dividends nor participated in share buy backs. Also, it is desirable to be able to calculate dividend per share growth on a portfolio that is constantly being reweighted to match the market portfolio over time. Data is available to perform these calculations from the US. The average mean continuously compounding growth rate for dividends, measured on this basis, on the New York Stock Exchange was 6.10% over this period. The standard deviation of the annual continuously compounded growth rate was 11%. Assuming the dividend growth rates are lognormally distributed the expected annual dividend growth rate is $e^{\mu+0.5\sigma^2}$ where μ is the expected annual continuously compounded growth rate and σ^2 is the variance of the annual continuously compounded growth rate.

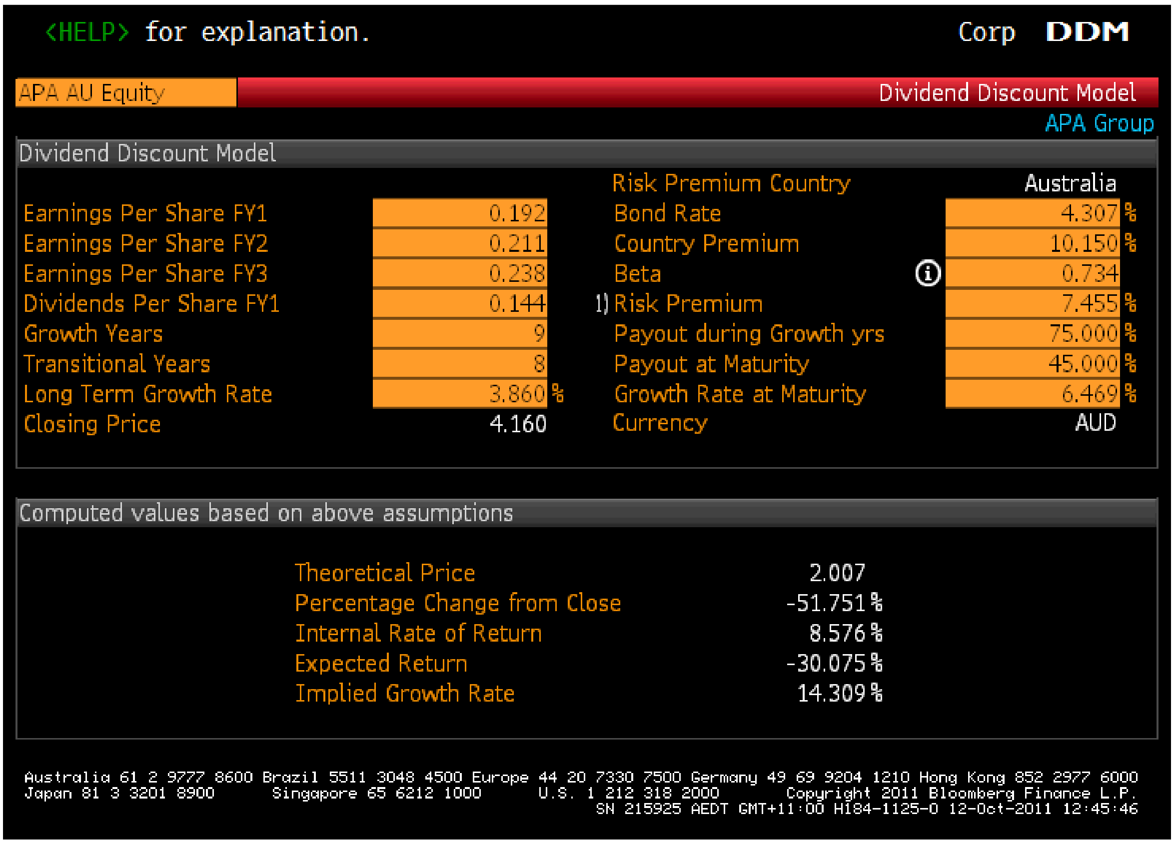
75 The longest published series by the Bureau of Economic Analysis at the US Department of Commerce http://www.bea.gov/national/index.htm#gdp.

Appendix B. Bloomberg measure of market return

271. The Bloomberg market return is calculated as the capital weighted average of the internal rate of return for all major index members.

272. The internal rate of return for each of the major index members is determined by Bloomberg through a Dividend Discount Model (DDM). The DDM is used to calculate the intrinsic value of a selected equity using the present value of future cash flows discounted at an appropriate rate. The DDM for APA AU Equity, resulting in an internal rate of return of 8.576%, is depicted below.

Figure 18: Dividend Discount Model example screen – APA AU Equity



Source: Bloomberg

273. The first step in the process of the DDM is projecting a potential earnings stream using explicit earnings estimate for the current (FY1), following (FY2) and subsequent year (FY3), if available, plus an estimate of the long-term growth rate for those earnings. Based on the projected earnings stream, a dividend payment schedule is derived and discounted to present values.

274. The DDM is split into three stages; growth, transition and maturity. Before the growth stages there are years FY1 and FY2, which enter into the present value calculation.

275. The length of the growth period depends on how the equity is classified (i.e. explosive, high, average or slow growth with a 3, 5, 7 and 9 growth period respectively). In the example of APA shown at Figure 18, Bloomberg has predicted slow growth, which is associated with 9 growth years. During the growth years, EPS grows at the long-term growth rate[76].

276. Following the growth stage is a transition stage, during which the model assumes that the earnings growth rate for the firm approaches the rate that applies to the general market for all mature issuers, i.e. the growth rate at maturity (which can be a decrease or increase depending on the long term growth rate). The model applies the same linear increase or decrease to the payout ratio to arrive at the mature stage payout ratio, which defaults to 45 percent. The default length of the transition period is 14 years for explosive growth issues, 12 years for high growth issues, 10 years for average growth issues and 8 years for slow growth issues. At Figure 18, Bloomberg has predicted slow growth and thereby 8 transitional years.

277. The final stage of the model is the mature stage, at which the model assumes that all issues have the same earnings growth rate and payout rate. The payout defaults to 45 percent at the mature stage (as can be seen in the below table).

278. The growth rate at maturity is linked to the market's required rate of return, i.e. (risk premium + risk free rate) * (1 – payout ratio), where the risk premium is calculated as the country risk premium * applied beta. The applied beta is calculated as the percentage change in the price of an equity for a one percent change in the benchmark index (ASX200 index). The growth rate at maturity in the example is 6.469%.

[76] The long term growth rate is the Bloomberg consensus estimated annual growth rate projected over the next five years. If an estimate is not provided, the model creates a long term growth rate based on the EPS growth from FY2 to FY3. If EPS for FY3 is not available, the model creates an EPS estimate for FY3 and a long term growth rate by the EPS growth from FY2 to FY1.

Table 5: DDM for APA AU Equity broken down into stages

	Year	EPS	Payout	DPS
	1	0.192	75%	0.14
	2	0.211	75%	0.16
Growth stage	3	0.238	75%	0.18
	4	0.25	75%	0.19
	5	0.26	75%	0.19
	6	0.27	75%	0.20
	7	0.27	75%	0.21
	8	0.39	75%	0.22
	9	0.30	75%	0.22
	10	0.31	75%	0.23
	11	0.32	75%	0.24
Transitional stage	12	0.34	71.7%	0.24
	13	0.35	68.3%	0.24
	14	0.37	65.0%	0.24
	15	0.39	61.7%	0.24
	16	0.41	58.3%	0.24
	17	0.43	55.5%	0.24
	18	0.45	51.7%	0.23
	19	0.48	48.3%	0.23
Mat. stage	20	0.51	45.0%	0.23

Source: Bloomberg

279. The internal rate of return is the discount rate that equates the current price of the stock with the dividend stream. In this case, the current stock price is $4.160. Therefore, for the dividend stream to equal the current price, the sum of the present value (PV) and the terminal value (TV) has to equal $4.160. The PV is the net present value of the first 19 years in the table above. The TV is calculated using the Gordon constant growth model, which is the final dividend divided by the internal rate of return discount rate minus the mature stage growth rate.

280. In the case of APA, the discount rate which equates the current price of the stock with the dividend stream is 8.576%.

Appendix C. Terms of reference

We are seeking your opinion on an approach to measuring the cost of equity that is consistent with the Access Code. Specifically we require you to respond to the following

- In your opinion does the approach to CAPM, as adopted by the ERA in their Draft Decision for Western Power, produce an estimate of the cost of equity that meets the requirements of the Access Code? Please provide evidence to support your opinion.

- How should the cost of equity be estimated in today's market conditions to ensure the requirements of the Access Code are met?

- Provide your estimates of the cost of equity and of the market risk premium in accordance with your suggested methods.

We are seeking your opinion on the methodology and data employed by the ERA in their 5 year historical estimate of the MRP and whether the ERA's methodology and estimate produces a cost of equity which meets the requirements of the Access Code.

Appendix P. Ernst & Young – Tax liabilities for regulated revenue purposes

Tax liabilities for regulated revenue purposes

Electricity Networks Corporation
Trading as Western Power

Report of Vaughan Lindfield

18 May 2012

Ernst & Young

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Mr Noel Ryan
Principal Economic Regulatory Advisor
Western Power
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Perth WA 6000
noel.ryan@westernpower.com.au

18 May 2012

Reliance restricted

Tax liabilities for regulated revenue purposes

Dear Noel

Enclosed is the report of Vaughan Lindfield.

Our engagement was performed in accordance with our engagement letter dated 16 April 2012, and our procedures were limited to those described in that letter and provided in your letter of instruction. The two phases of my engagement are as follows:

- *Phase 1*: Determine the most appropriate and reliable information to use as a starting depreciable tax base, including using the 'prime cost' method suggested by the ERA to depreciate the depreciable tax base to 1 July 2012.
- *Phase 2*: Review the tax assumptions applied by Western Power in their calculation of a post-tax WACC and comment on the appropriateness of the outcomes in the context of adopting a post-tax approach.

This report addresses Phase 1 of our engagement.

As outlined in our engagement letter, our report is based on information and instructions provided by you. We have not conducted an audit or other verification of any information supplied to us. We have assumed that the information supplied to us is accurately stated, except where indicated.

Neither Vaughan Lindfield's report nor any part of it may be published or distributed other than for the specified purpose without obtaining the written consent of Ernst & Young, unless disclosed in accordance with any law or by order of a Court of competent jurisdiction or as reasonably required for the purpose of the proceedings.

We appreciate the cooperation and assistance provided to us during the course of our work. If you have any questions, please call me on (08) 9429 2261.

Yours sincerely

VLindfield

Vaughan Lindfield
Partner - Tax Advisory
Ernst & Young

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Contents

A. Abbreviations

In this report, I use the following abbreviations:

Abbreviation	Description
AA2	Western Power's second access arrangement (i.e. for the period 2009/10 to 2011/12)
AA3	Western Power's third access arrangement (i.e. for the period 2012/13 to 2016/17)
Access Code	*Electricity Networks Access Code 2004 (WA)*
Commissioner	Commissioner of Taxation
CRAM	*Cost & Revenue Allocation Method 2010/11*
ERA Draft Decision	*Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, issued by the ERA on 29 March 2012.
ERA	Economic Regulation Authority
ITAA36	*Income Tax Assessment Act 1936*
ITAA97	*Income Tax Assessment Act 1997*
NTER	National Tax Equivalent Regime
RAB	Regulatory Asset Base
the Guidelines	*Guidelines for access arrangement information 2010*
WACC	Weighted Average Cost of Capital
Western Power	Electricity Networks Corporation trading as Western Power

B. Appendices to this report

The following appendices form part of this report and should be read in conjunction with the contents of this report.

Appendix A	My curriculum vitae
Appendix B	Documents I have relied on
Appendix C	Fixed asset register analysis

C. Introduction

1. I am a Partner of Ernst & Young working in its Corporate Tax practice. My curriculum vitae is at Appendix A.

Background

2. I understand that this report has been prepared in respect of the ERA Draft Decision for AA3. This report has been prepared to assist Western Power to estimate its tax attributes for post-tax revenue modelling as part of the revisions to its access arrangement for the Western Power Network. The proposed access arrangement relates to AA3, which is for the five year period from 1 July 2012 to 30 June 2017.

3. I am instructed that the following is the relevant background to this matter:

    - Western Power owns and operates the transmission and distribution networks in South-West Western Australia, which form the Western Power Network.

    - Western Power submitted proposed revisions to its access arrangement for the Western Power Network on 30 September 2011. The revised access arrangement was submitted in accordance with the requirements of section 4.48 of the Access Code and the revisions submitted date specified in the current access arrangement.

    - As part of its Proposed Revised Access Arrangement, Western Power used a real, pre-tax rate of return approach in determining its target revenues in providing covered services (transmission and distribution separately). This approach provides an implicit allowance for tax costs in the return on asset building blocks of the target revenues.

    - The role of the ERA is to determine whether Western Power's proposed revised access arrangement meets the Code objective of promoting economically efficient investment in, and operation and use of, electricity networks and services, and complies with the requirements of the Access Code.

    - Western Power's current access arrangement applies until a new proposed access arrangement is approved by the ERA.

    - The ERA invited submissions from interested parties on the Western Power proposed revised access arrangement on 7 October 2011.

    - On 25 October 2011, Western Power submitted an errata sheet to the ERA.

    - Submissions were received by the ERA from 36 parties. The ERA published the ERA Draft Decision on 29 March 2012 which required Western Power to calculate its WACC on a post-tax real basis. As part of this Decision, the ERA included the following as Required Amendment 23:

      "The Authority requires that Western Power model its tax liabilities explicitly, as a separate nominal 'building block', applying the method set out in this Draft Decision.

      To this end, the Authority requires that Western Power amend the tax liabilities for the purpose of determining its maximum annual revenue requirements to those estimated by the Authority as set out in Table 4 and Table 5."

- The ERA considers that a post-tax approach should be adopted as the ERA considers there is a growing precedent for this approach[1]. The ERA also considers that a pre-tax approach over-compensates service providers for their tax liabilities and that a post-tax approach allows tax liabilities to be estimated more precisely[2].

- The basis behind the ERA shifting to the post-tax approach therefore appears to be consistent with the objectives of the Access Code, economically efficient pricing, and regulatory precedent.

- As part of the ERA Draft Decision, the ERA performed a tax calculation based on the RAB values provided by Western Power and adjusted by the ERA.

- Western Power is part of the NTER. The NTER rules are based on the Federal income tax laws (i.e. the ITAA97 and the ITAA36) with some modifications which are set out in the NTER manual. One of the modifications under the NTER regime is that there are no income tax implications of government initiated restructures.

- NTER entities are assessed on their income tax equivalent liability and pay quarterly instalments of the expected liability to WA Treasury.

- In AA2, the ERA previously excluded $261m of capital expenditure from Western Power's RAB asset balance. This expenditure was incurred in the first access arrangement period and it was excluded by the ERA on the basis that this amount represented inefficiencies in the cost estimation process[3]. The assets associated with the $261m of excluded expenditure are included in the tax fixed asset registers.

- Western Power receives developer and customer contributions towards the extension of electricity infrastructure. Customer contributions can be cash contributions or gifted assets. The Western Power Financial Statements for the year ended 30 June 2011 provides that cash contributions are only recognised as revenue when the developer or customer is connected to the network. The Financial Statements further provide that gifted assets are recognised as revenue when the assets are 'energised' (i.e. installed and ready for use). These assets are measured at their fair value[4].

Scope of work

4. I am instructed to determine the most appropriate and reliable information to use as a starting depreciable tax base, including using the 'prime cost' method suggested by the ERA to depreciate the depreciable tax base to 1 July 2012.

Assumptions

5. I have been instructed to make the following assumptions:

    a. The data provided to me in respect of the assets held by Western Power as at 1 April 2006, and subsequent acquisitions and disposals to 28 February 2012, contained in the tax fixed asset registers is a complete record. Further, I have assumed that all assets listed in the schedules provided existed as at this date and were the property of Western Power for the period they are shown as being owned by Western Power. I have assumed, except where otherwise stated, that the cost data and acquisition date provided to me for these assets is accurate.

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[1] ERA Draft Decision, para 623.
[2] ERA Draft Decision, paras 625-628.
[3] ERA Draft Decision, page 4.
[4] Western Power Financial Report, 30 June 2011, page 83.

b. As at 1 April 2006, Western Power transferred data into the current fixed asset system, Ellipse 6.3. A reconciliation was performed at the time the previous fixed asset register was transferred to Ellipse 6.3 and all assets were transferred with the correct descriptions, cost, acquisition date, accumulated depreciation and written down value. I have not sighted this reconciliation as part of this engagement.

c. The data as at 1 April 2006 is the most reliable data to use as a basis for this exercise. Earlier data cannot be obtained.

d. The estimated additions for the period 1 March 2012 to 30 June 2012 and for each year to the year ended 30 June 2017 that I have been provided with is reasonable and materially accurate.

e. With the exception of the allocated corporate and systems assets, any assets which are shared between the distribution and transmission business are immaterial or insignificant for the purposes of this exercise.

f. As part of determining the opening depreciable starting base, I have reviewed the effective lives applied to the assets by Western Power. I detail the assumptions I have made and the process I have followed at Appendix C.

g. Low cost and low value assets (i.e. assets with either a cost or a written down value less than $1,000) have been allocated to a Low Value Pool. I have assumed these assets are immaterial for the purposes of this review. As such, while I have calculated depreciation on these assets, I have made assumptions around the effective lives of the assets and I have assumed that Western Power has correctly indentified the assets which are eligible to be allocated to the Low Value Pool.

6. To verify that the data I was provided with is a complete record, I have performed the following reconciliations:

a. I have attempted to reconcile the tax and accounting fixed asset registers and the corresponding annual reports for each year. Some discrepancies were noted in this process. Explanations for discrepancies identified in 2010 and 2011 have been given by Western Power. I note there is no detailed reconciliation between the cost of assets, acquisitions and disposals in the accounting and tax fixed asset registers.

b. A reconciliation between the total cost of assets are shown in the tax fixed asset register as at 28 February 2012 and the cost of assets listed as at 1 April 2006 plus the additions and disposals to 28 February 2012 (as detailed in the tax fixed asset register for each year). This reconciliation contained some minor discrepancies, which were less than 1% of the cost of the tax depreciable asset base I have determined at 1 July 2012.

Information

7. The documents I have relied on are listed in Appendix B.

8. I have not conducted an audit or other verification of any information supplied to me. I have assumed that the information supplied to me is accurately stated.

9. Neither Ernst & Young nor I warrant the accuracy or reliability of any of the information supplied to me.

10. The opinions set out in this report may alter if there are any changes to the information supplied to me or assumptions made.

11. I have not been provided with all of the information that I have requested during the course of this engagement. However, I have received substantially all of the material information that I required to complete the engagement. The information missing is:

    - Detailed reconciliations between the tax fixed asset register and the accounting fixed asset register for the years ended 30 June 2006 to 30 June 2011.

    - Reconciliations between the fixed asset register in use prior to 1 April 2006 and the data transferred from this system to the current fixed asset register.

12. To my knowledge, the missing information has not impacted the calculations that I have performed on the data provided, but it does impact my ability to form a view on the integrity of the data provided. Where a requested document has not been provided, I have taken alternative steps (for example, discussions with Western Power personnel) to give myself some assurance over the data integrity.

Qualifications

13. My opinion is based on my interpretation of the relevant regulatory provisions, my experience in the relevant field, and on the information provided to me by Western Power management. Should any of these facts and circumstances change my conclusion may change.

14. This report has been based on the relevant taxation legislation, rulings and case law as it stands at the date of this report. In the event that such legislation, rulings or case law changes over time, the position I have taken may be affected. I am not responsible for updating any advice previously provided for changes in the law or its interpretation.

15. It is important that you ask me to review this report, if any advice contained in it is to be relied upon in the future or in any other context other than this specific engagement. My original advice may no longer be applicable or appropriate in such circumstances.

Reliance on this report

16. This report has been prepared, and may be relied on, solely for the purposes of this assignment. This report has been prepared specifically for Western Power. Neither Ernst & Young nor I accept responsibility to anyone other than Western Power; or to Western Power if they use the report for some other purpose.

17. Neither this report nor any part of it may be published or distributed other than for the specified purpose without obtaining the written consent of Ernst & Young.

Assistance by colleagues

18. In order to arrive at my opinions in this matter, I have selected colleagues to assist me. My colleagues carried out the work that I decided they should perform. I have reviewed their work and original documents to the extent I considered necessary to form my opinions. The opinions expressed in this report are mine.

Conduct of this assignment

19. I understand that my report is to be prepared in respect of the ERA's Draft Decision. I acknowledge that the report will be provided to the ERA by Western Power in response to the Draft Decision.

20. I have been instructed that the report is to be prepared in a form which satisfies the requirements of the guidelines for expert witnesses in proceedings in the Federal Court of Australia. These guidelines are set out in Federal Court of Australia Practice Note CM7.

21. I have read, understood and complied with the Practice Note.

22. I have made all the inquiries which I believe are desirable and appropriate. No matters of significance that I regard as relevant to my opinion have, to my knowledge, been withheld.

Structure of this report

23. The structure of the remainder of this report is as follows.

24. In Section D, I set out a summary of my opinions.

25. In Section E, I discuss my opinion in further detail and outline the reasons for my opinions.

D. Summary of my opinion

26. In this section I summarise the opinions expressed elsewhere in this report. This summary should be read in conjunction with the full report.

27. I have calculated the following is the tax depreciable asset base as at 1 July 2012:

Category of asset	Tax depreciable base ($)
Distribution	3,837,324,920
Transmission	1,807,149,478
Total	5,644,474,398

28. The above asset base excludes IMO-related system management assets and unregulated assets.

29. We have also excluded capital work in progress to 28 February 2012 and estimated capital expenditure from March to June 2012 from the above asset base on the basis that the assets should not be depreciable for tax purposes as at 1 July 2012. We understand these assets will likely not be installed and ready for use on this date. Land has also been excluded on the basis that land is not depreciable for tax purposes.

30. I note the above balances exclude the tax written down value of assets which were previously excluded from Western Power's RAB balance. These assets had a cost of approximately $199m (as at 30 June 2009) and were excluded in the AA2 access arrangement period[5].

31. Contributed and gifted assets are included in the above tax depreciable starting base. Paragraphs 55 to 60 contain a broader discussion on whether the effective tax cost of the associated revenue from these assets should be included in the post-tax WACC calculation. My understanding is that these assets cannot be identified by Western Power in their tax depreciation register with any accuracy. I have made some additional observations about the income tax treatment of contributed assets.

32. The depreciable starting base has been calculated using a prime cost method, as suggested by the ERA in the Draft Decision[6]. I note the prime cost method of depreciation is an election which is generally available under the ITAA97. This method appears reasonable for the purposes of this exercise as prime cost depreciation provides a consistent annual deduction over the life of an asset and it also appears to be consistent with the approach used by other regulatory authorities where a post-tax WACC is adopted.

[5] ERA Draft Decision, page 9.
[6] ERA Draft Decision, page 218.

E. Opinion

Determination of depreciable start base

33. As noted above, the ERA requires a calculation of a post-tax revenue for both the transmission and distribution businesses operated by Western Power. In addition, the ERA has suggested that assets are depreciated in the post-tax revenue calculation using the prime cost method.[7]

34. As such, I have utilised the following process to calculate the depreciable starting base:

    a. Obtained a fixed asset register as at 1 April 2006. This is the earliest date when detailed fixed asset information was available in the current system. Apart from making enquiries of Western Power, I have not been able to verify the quality of this information and the reconciliation of the prior system to the current system information. The quality of this information is listed as an assumption in this report.

    b. I have reviewed the effective lives used for depreciation purposes in that register and confirmed that they are within the range for similar assets in the Commissioner of Taxation's effective life determination which was published in 2006. I have done this on an average basis and investigated exceptions. Due to the quantity of assets and information available, I had to make a number of assumptions during the process. These assumptions are disclosed in Appendix C.

    c. Where an asset had a material written down value at 1 April 2006 and the depreciable effective life of that asset did not match my expectations based on the Commissioner of Taxation's Determination, I made enquiries of Western Power. I have also conducted a sensitivity analysis to determine whether the exceptions that I have identified would materially affect the depreciable asset base. My conclusion is that there should be no material impact from these exceptions.

    d. I obtained the additions and disposals information for the years ended 30 June 2006, 2007, 2008, 2009, 2010 and 2011 to arrive at the total cost of assets held for tax purposes as at 28 February 2012.

    e. Using the effective lives determined by Western Power in the fixed asset register and the total cost of assets held at 1 April 2006, 30 June 2006, 30 June 2007, 30 June 2008, 30 June 2009, 30 June 2010 and 30 June 2011, I was able to calculate the tax written down value for these assets at 28 February 2012. This calculation was done on a prime cost basis.

    f. I did a comparison of Western Power's effective lives for additions in the fixed asset registers from 30 June 2006 to 28 February 2012, compared to the Commissioner's rates for the corresponding years. Again, I did a sensitivity analysis where differences were identified.

    g. The assets can be allocated to the transmission and distribution businesses, either on a direct or an indirect basis. I have allocated assets to the transmission and distribution businesses in a manner which is consistent with Western Power's allocation policy (as documented in the CRAM).

    h. As noted above, I have been advised that any shared assets are insignificant for the purposes of this report. Aside from corporate and systems assets, which have

[7] ERA Draft Decision, page 218.

been allocated to the distribution and transmission businesses, I have not identified any shared assets in the tax fixed asset registers that I reviewed.

35. I have also included an estimate of expenditure from 1 April 2012 to 30 June 2012 in the depreciable starting base. I have assumed Western Power's estimated expenditure is accurate and reliable.

36. The detailed process that I have used to review the Microsoft Excel files provided to me is included at Appendix C.

37. I have relied on the following information, which I understand from my and my colleagues' discussions with Western Power personnel:

- The effective lives for assets acquired after 1 April 2006 were determined based upon the Commissioner's effective lives and will be based on the Commissioner's effective lives going forward. I understand that some older assets may have self-assessed effective lives, however I understand these assets are not material for the purposes of this exercise.

- The negative values in the tax fixed asset register are assets which are work-in-progress and not yet installed ready for use. Around July or August 2010 a large amount of assets recorded as work-in-progress were capitalised for tax purposes. Prior to this date, assets were not being removed from work-in-progress and depreciated in a timely manner. Processes are now in place to identify completed work-in-progress assets and depreciate these assets for tax purposes.

- Contributed and gifted assets cannot be separately identified in the tax fixed asset register.

- Western Power add assets to the tax fixed asset register on a daily basis as each asset is installed and ready for use.

- Interest which is capitalised into the asset balances is expensed for income tax purposes. Labour which is costed to the assets on a timesheet basis is capitalised for income tax purposes. I note that while the ATO's view indicates that the capitalisation of direct labour costs is appropriate (for example, refer to *ATO Interpretative Decision ATO ID 2011/43* regarding labour on-costs). I am aware this position is not free from doubt and there may be some alternative interpretations.

- In July 2011, the Western Power fixed asset register was reduced in size by 'aggregating' a number of assets. This was primarily an administrative measure to reduce the size of the fixed asset register. The effective lives used to depreciate the aggregated assets going forward were calculated as a weighted average of the individual aggregated assets.

- Western Power has no assets which are subject to hire purchases or finance leases. Some assets are subject to operating leases and the lease payments on these assets are expensed as incurred.

- For the purposes of this exercise, work-in-progress assets are generally commissioned within 12 months. This is also documented in the CRAM[8].

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[8] CRAM, page 26.

Ring-fencing assets between the transmission and distribution businesses

38. The Guidelines provide that Western Power disaggregate financial information into the following business segments:

    a. Covered (regulated) transmission services

    b. Covered (regulated) distribution services

    c. IMO-related system management (regulated and ring-fenced)

    d. Unregulated (ring-fenced) services

39. In order to determine a depreciable starting base for tax purposes for the distribution and transmission businesses, Western Power is therefore required to allocate the corporate and systems assets to these two business segments.

40. I understand Western Power has provided the ERA with a copy of the cost and revenue allocation method used for these purposes as Appendix E to the Western Power submission made in September 2011. The cost allocation method provides that the following two step methodology is applied to allocate property, plant and equipment to the business segments:

    - Direct property, plant and equipment is allocated to the business segments.

    - Then, the remaining regulated system management and corporate assets are allocated based on the proportion of direct assets in each business segment to total transmission and distribution direct assets[9]. This is called the "PPE" basis.

41. Essentially the "PPE" basis is an allocation based on each of the direct transmission and distribution assets over the total of both categories of assets.[10] I understand that the ERA has previously accepted this allocation method and I have not reviewed whether this allocation method is appropriate as part of this exercise.

42. The Western Power tax fixed asset register has clearly marked assets which are only attributable to either the transmission or the distribution business. However, corporate and systems assets are required to be allocated between these two businesses. Western Power has allocated the indirect assets as follows:

    - Transmission - 37.21%

    - Distribution - 62.79%

    These figures were calculated based on the Regulatory Financial Statements for the year ended 30 June 2011 and were used as allocation figures in the same financial statements.

43. I have not independently verified the allocation percentages used above. However, The Office of the Auditor General has performed an agreed upon procedures engagement on the 30 June 2011 Regulatory Financial Statements to this effect. One of the procedures which was performed was to check the allocation of assets in the Regulatory Financial Statements to the CRAM. The Office of the Auditor General has concluded that the asset allocation applied in the Regulatory Financial Statements is consistent with the CRAM.

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[9] CRAM, page 26.
[10] CRAM, page 12.

44. I note that this allocation method is calculated based on the 30 June 2011 balances, but is applied in the post-tax revenue modelling for the whole of the AA3 period.

Expenditure to be included in the opening depreciable tax base

Expenditure previously excluded

45. As discussed above, I note the ERA reduced the AA2 asset base for approximately $261m of expenditure that the ERA considered to be inefficient. To the extent that this expenditure is excluded from the AA3 asset base, I have excluded it from the opening tax depreciable base. As such, expenditure of $199m has been excluded. This has been done on an estimated basis using the following assumptions:

- The total amount excluded is $199m (initially included in the tax depreciation register provided by Western Power), which has been removed from the year ended 30 June 2009. This is allocated between transmission and distribution based on the direct expenditure allocations in paragraph 470 of the Draft Decision, with the balance split based on the dissection of expenditure in Table 42 of the Draft Decision[11].

- I have modelled the closing written down value of this exclusion using average effective lives for the transmission and distribution businesses. Using this method, I have excluded $84,430,086 and $101,996,270 from the transmission and distribution starting bases at 1 July 2012.

Replacement assets

46. As noted above, Western Power has deducted all new replacement assets in full for income tax purposes. The assets which have physically been scrapped remain on the fixed asset register and are included in the opening depreciable tax base for income tax purposes. I understand this practice has occurred at Western Power as Western Power are unable to specifically identify the original assets which are later replaced. The opening depreciable base may therefore be understated by this practice.

47. Whether replacement assets are repairs, improvements or separate depreciating assets is a contentious area of the tax law, in particular in relation to infrastructure assets.

48. On the basis that the replacement assets which have been expensed are subsidiary parts of a broader asset, for example, a pole is replaced which forms part of a distribution line to a particular geographic area, I consider the treatment of replacement assets is appropriate. This treatment is consistent with *Taxation Determination TD 2002/5.*

49. I have accepted Western Power's treatment of replacement assets on the basis that replacement assets have been specifically identified as such in the fixed asset register, and new assets (e.g. a distribution network to a new geographic area) are appropriately capitalised for income tax purposes.

Depreciation start times

50. As noted above, Western Power identified a number of assets which should have been capitalised and depreciated for tax purposes in July and August 2010. I understand the tax start time for depreciation of these assets should have been earlier than when the assets began to be depreciated. The opening depreciable base may therefore by overstated due to the late capitalisation of these assets. However, as depreciation will be calculated on a prime cost basis, this over-statement of the opening depreciable tax base should not impact the tax depreciation calculations for AA3.

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[11] Draft Decision, page 109, Table 42.

Redundant assets

51. Further to the issues noted above, the ERA have noted in the ERA Draft Decision[12] that some redundant assets have not been fully depreciated when calculating Western Power's capital base. I am instructed that historically, for income tax purposes, not all redundant assets have been written off in the tax fixed asset register.

52. To the extent that redundant assets are carried forward on the tax fixed asset register, Western Power's tax costs will be understated, as depreciation on the redundant assets will be included in the post-tax WACC calculation.

53. I understand that it is not possible to identify the redundant assets from Western Power's fixed asset records.

Contributions from customers

54. Customer contributions and gifted assets should be taxable to Western Power in the year that the income is derived. I would often see these amounts taxable as a non-cash business benefit[13] or as ordinary income in the hands of Western Power.

55. The income tax treatment for the contributor depends upon how the transaction is structured. In particular, there may be circumstances in which the contributor is not entitled to a deduction for the gifted asset. In considering this issue, it should not be assumed that the contributor is entitled to an income tax deduction for the gifted asset.

56. For Western Power, as the holder of the contributed asset, the corresponding deduction for the asset received should be over time, based on the relevant asset's effective life and nature. Therefore, there is a timing difference between when the income is assessed to Western Power and when the corresponding deduction (where available) can be claimed by Western Power.

57. As noted above in Western Power's 30 June 2011 Financial Report, I understand that contribution revenue and the corresponding asset received are recorded at an equal value, which is the fair value[14].

58. As stated above, I understand that Western Power is not able to separately identify contributed and gifted assets in the tax fixed asset register.

59. I make the following observations about contributed and gifted assets:

    - Provided the revenue recorded and capitalised value of the gifted asset are equal, the 'effective tax cost' resulting from the contributed assets is a time value of money cost. While tax is paid in full in the year that a contribution is received, the corresponding deduction for holding the gifted asset is spread over its effective life.

    - As noted above, the contributor is not always entitled to a deduction for the gifted asset. Negotiations to pass the 'effective tax cost' onto the contributor will not always be successful, especially in the case of marginal projects.

    - A requirement for a contributor to compensate Western Power for the time value of money tax cost of the gift will create a circular problem, as the contribution is then increased (in turn leading to more tax payable).

[12] ERA Draft Decision, page 105.
[13] Section 21A *ITAA36*.
[14] Western Power Financial Report, 30 June 2011, page 83.

- Currently, according to Western Power's Financial Report for the year ended 30 June 2011, the fair value of gifted assets is capitalised and included as revenue. I understand that, consistent with this accounting policy, the assessable amount from a contribution is equal to the overall tax deduction for the contributed asset. If the contributions are increased to incorporate an effective tax cost, there would be a permanent difference (i.e. the assessable amount would be more than the fair value of the associated asset).

- In practice, negotiations to pass on the tax cost may be difficult as there are numerous assumptions which impact the calculation. These assumptions can be subjective.

- A contributor is likely to be especially unwilling to pay the effective tax costs when an asset is contributed (i.e. a non-cash contribution is made) but a cash payment is required in relation to the associated effective tax costs. This requirement would necessitate an incremental cash outflow.

- Over time, where contributions are received each year, the tax paid on the revenue received is negated by accumulating deductions for prior year gifted assets, the accumulation of prior year depreciation deductions may exceed the amount of assessable income from gifted assets in any one year, such that including gifted assets in the post-tax revenue modelling for that particular year may produce a lower overall tax cost for that year. Although, as discussed above, over time, the tax cost should equalise such that the only real cost is the time value of money the upfront payment of tax and receiving corresponding deductions over time.

  For example, assume all assets are depreciated over 5 years and there are gifted assets of $500 in each of year 1 and 2, with a gifted asset of $100 in year 3. Assuming each asset is acquired at the start of each year, the tax profile would be as follows:

	Year 1	Year 2	Year 3
Assessable ($)	500	500	100
Deductible ($)	100	200	220

  In the above table, there is a net assessable amount from the contributions in Year 1 (of $400). However in Year 3 the depreciation on the prior year gifted assets has accumulated to provide a net deduction of $120. Over time, the assessable and deductible amounts should be equal (i.e. $1,100), however there is an associated cost due to the timing mismatch on the assessable and deductible amounts.

- Spreading the effective tax cost across the a broader range of users also has the effect of not substantially increasing either the upstream or downstream costs and, as such, the effective tax cost is more appropriately distributed among a broader user base.

60. Accordingly, I have not removed the contributed assets from the opening depreciable tax base.

Determination of effective lives of assets

61. For income tax purposes, usually the effective lives of assets can either be based on the Commissioner of Taxation's effective life for that asset, or the effective life can be self-assessed.

62. I understand that Western Power determines the effective lives of assets based on the effective lives which are published by the Commissioner of Taxation.

63. I have been provided with a register of the depreciation rates and methods used for the various categories of assets which are usually acquired by Western Power. This register is effectively Western Power's tax depreciation policy. From this information, I have calculated the effective lives which are used to depreciate each category of assets.

64. Notably, the schedule of depreciation rates and methods that I have been provided with is current. I have not reviewed the corresponding registers for prior years. However, I have reviewed the effective lives for the additions added to the depreciation register for the years ended 30 June 2007, 2008, 2009, 2010, and 2011. I have also reviewed the effective lives for assets added from 1 April 2006 to 30 June 2006 and 1 July 2011 to 28 February 2012.

65. When reviewing prior year additions, I have compared the effective lives used to depreciate each asset to an average of the Commissioner of Taxation's effective lives for that broader asset category. For example, the rate used to depreciate an item of furniture has been compared to an average of the Commissioner of Taxation's effective lives for specific items of furniture.

66. Where the effective lives used to depreciate assets with a written down value that was not insignificant at 1 July 2012 differ to the Commissioner of Taxation's effective lives, I have made enquiries with Western Power. I am satisfied that the amount of any variances is either not significant or can be explained. A common explanation for these variances provided by Western Power is that the asset category used to analyse the asset in the depreciation register does not fully describe the underlying asset. An example of this is the use of a broader asset category, such as "Buildings" for a depreciable item installed in the building (e.g. a floor).

Asset disposals

67. My analysis of the fixed asset registers provided shows that there were no disposed assets that should have a tax written down value as at 1 July 2012.

68. Due to the insignificant impact on the opening depreciable tax base, I have not excluded the disposed assets from the opening depreciable tax base.

Conclusion

69. Based on the above analysis and process, I have calculated the following tax depreciable asset base as at 1 July 2012:

Category of asset	Tax depreciable base ($)
Distribution	3,837,324,920
Transmission	1,807,149,478
Total	5,644,474,398

70. The above tax depreciable base above excludes the capital work-in-progress as at 28 February 2012 and the estimated capital spend to 30 June 2012. This is on the basis that work-in-progress assets generally take 12 months (on average) to be installed ready for use. As such, the work-in-progress and estimated capital spend should not be depreciated from 1 July 2012.

71. The above tax depreciable base also excludes land as land is not depreciable for tax purposes.

72. Below is the total capital asset value at 1 July 2012, including capital work in progress and land:

	Category of asset		Total
	Distribution	Transmission	
Tax depreciable base ($)	3,837,324,920	1,807,149,478	**5,644,474,398**
CWIP at 28 February 2012 ($)	228,996,979	186,728,671	**415,725,650**
Estimated spend to 1 July 2012 ($)	171,192,768	67,862,023	**239,054,791**
Land	25,442,632	217,625,425	**243,068,057**
Total	**4,262,957,299**	**2,279,365,597**	**6,542,322,896**

73. I have addressed the tax depreciation of the above amounts in Phase 2 of this engagement, which concerns the income tax calculations over AA3. As noted in the cover letter to this report, Phase 2 will be addressed in a separate report.

Appendix A My curriculum vitae

Vaughan Lindfield
Partner, Business Tax Advisory

Tel: +61 8 9429 2261
Email vaughan.lindfield@au.ey.com

Vaughan has recently joined Ernst & Young as a Partner after spending the last three years in the executive management team of Alinta Energy Limited in Sydney. Vaughan brings significant commercial experience with respect to infrastructure projects and is highly regarded for his ability to manage complex assignments with multiple stakeholders associated with such projects.

A qualified chartered accountant with more than 17 years tax experience, Vaughan is highly regarded for his working knowledge of key tax issues impacting energy and infrastructure companies and projects.

Vaughan has extensive experience in dealing with all financing arrangements associated with integrated mining infrastructure projects from both a commercial and tax perspective.

Vaughan has also advised Government with respect to Infrastructure matters under the NTER. For example, Vaughan was a key member of the EY tax team that advised the Office of Energy on the disaggregation of Western Power and, most recently, he has advised the WA Treasury on the income tax treatment of capital contributions.

Client / Project	Value to client
Department of Treasury (WA)	Most recently, Vaughan has advised WA Treasury regarding the income tax treatment of gifted property, including the resulting assessable and deductible amounts to WA Treasury.
Alinta Ltd Scheme of Arrangement	Vaughan provided advice in structuring the Alinta Limited Scheme of Arrangement on behalf of Alinta Energy Ltd. Alinta Energy was a member of a consortium that comprised Prime Infrastructure (now owned by Brookfield), and Singapore Power. The consortium acquired Alinta Ltd (a Top 40 ASX listed company at that time) and subsequently split up the assets of Alinta. This was considered a highly complicated transaction from both a commercial, legal and tax perspective given the shared vehicle acquisition structure adopted. Vaughan was also involved in settling the outstanding obligations under the Umbrella document with both Prime and Singapore Power in his capacity as a member of the Alinta Energy Management team.
WA Office of Energy	Vaughan was a key member of the tax advisory team associated with the disaggregation of Western Australia's leading energy infrastructure business, Western Power into 4 separate entities.

Professional background and qualifications

- Institute of Chartered Accountants Program (Admitted 11 February 2002)
- CPA Program (Admitted 25 July 1995)
- Edith Cowan University Bachelor of Commerce

Appendix B Documents I have relied on

1. Microsoft Excel documents provided by Western Power:

    - FAR T1 2006-10.xls by Raymond Isaac on 13 April 2012
    - Asset profiles new.xls by Nelly Simon on 17 April 2012
    - Asset profiles old.xls by Nelly Simon on 17 April 2012
    - Asset Depreciation Rates - Tax by Nelly Simon on 17 April 2012
    - WE_n9214920_v1_TEMPLATE_FOR_TAX_ASSET_BASE.xls by Raymond Isaac on 18 April 2012
    - TAR Feb 2012.xls by Raymond Isaac on 18 April 2012
    - TAR 2007.xls by Raymond Isaac on 19 April 2012
    - TAR 2008.xls by Raymond Isaac on 19 April 2012
    - TAR 2009.xls by Raymond Isaac on 19 April 2012
    - TAR 2010.xls by Raymond Isaac on 19 April 2012
    - TAR 2011.xls by Raymond Isaac on 19 April 2012
    - TAR Feb 2012.xls by Raymond Isaac on 19 April 2012
    - RECONCILIATION OF PRIOR YEARS.xls by Raymond Isaac on 19 April 2012
    - RECONCILIATION_OF_ASSETS_REGISTERS_FEBRUARY_2012.xls by Raymond Isaac on 19 April 2012
    - WE-8176080v2.xlsx by Kym Lilleyman on 27 April 2012

2. The following PDF documents provided by Western Power:

    - FAR Recs 30 June 2007 by Nellie Simon on 2 May 2012
    - FAR Recs 30 June 2008 by Nellie Simon on 2 May 2012
    - FAR recs 30 June 2009 by Nellie Simon on 2 May 2012

3. Advice on aspects of equity beta estimation, Craig Mickle, Ernst & Young, 9 September 2011

4. Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network, Economic Regulation Authority, 29 March 2012

5. Cost and Revenue Allocation Method 2010/2011, Western Power, August 2011

6. Western Power Regulatory Financial Statements for the year ended 30 June 2011

7. Western Power Financial Statements for the years ended 30 June 2011, 30 June 2010, 30 June 2009, 30 June 2008, 30 June 2007 and 30 June 2006

8. National Tax Equivalent Regime Manual, Version 5

9. Legislation:

    a. Income Tax Assessment Act 1936 (Cth)

    b. Income Tax Assessment Act 1997 (Cth)

10. ATO guidance publications:

    a. ATO Interpretive Decision ATO ID 2011/43

    b. Taxation Determination TD 2002/5

Appendix C Fixed asset register analysis

I have made the following changes and performed the following calculations on the data which was supplied to me.

Effective lives of assets

When reviewing the effective lives of the assets on the depreciation schedule, I compared Western Power's effective lives for particular assets (or classes of assets) to the effective lives adopted by Western Power. Western Power's fixed asset register as at 1 April 2006 has categorised assets into classes of assets and limited detail is at hand for individual assets. I have therefore made a number of assumptions to review the effective lives that Western Power has allocated to these assets.

A number of assets I reviewed were acquired prior to 1 April 2006, however, due to the volume of information, I applied the Commissioner's effective lives that were current as at 1 April 2006 to simplify the process. I note that assets acquired prior to 1 April 2006 are noted as such on the fixed asset register such that all assets are recorded as at their acquisition date.

I have taken the following steps to verify the effective lives used by Western Power:

- Reviewed the effective lives adopted by Western Power for each category of assets and compared these to the Commissioner's effective lives (or, where applicable, an average of the Commissioner's effective lives). Where the effective life applied by Western Power was within the Commissioner's range for similar assets, I have accepted the life applied by Western Power. I have also accepted Western Power's effective life where there was a prima facie discrepancy, but the discrepancy was explainable.

- When considering the difference between the closing written down values using Western Power's effective lives compared to the closing written down values based on the Commissioner's effective lives on a year by year basis, my analysis produced variances of less than 6% of the written down tax values of additions for each year.

- Low Value Pool assets are assets with a tax cost or written down value of less than $1,000. These assets can be pooled as one asset and depreciated using the diminishing value method. In relation to Low Value Pool assets, I have converted the diminishing value rate applied into a prime cost rate.

Assets excluded from the fixed asset register

I have excluded certain asset categories from the tax fixed asset register to ensure that the appropriate assets are included in the income tax calculations in the post-tax revenue model.

My analysis has excluded the following assets listed in the fixed asset register:

- All assets with a District Code of 7200. I understand these assets were associated with a business, Bright Communications, which is no longer owned by Western Power.

- All assets with the Profile of Motor Vehicle. I understand these assets are unregulated assets and should be excluded from the post-tax WACC calculation.

- IMO-system related assets, as identified by Western Power. I understand these assets are outside of the regulated ring-fenced assets.

- All assets with an "M" depreciation method. I understand these assets are generally land and, as such, should not be depreciated.
- In my analysis, I have also removed all other assets with no capital cost.

Fixed asset register reconciliations

I have been provided with a summary of movements in the accounting and tax fixed asset registers for the years ended 30 June 2010 and 30 June 2011. In this regard, I have made the following observations:

- The opening cost as 1 July 2009 in the work papers I was provided with is consistent with the comparable information in the Note 10 to the Financial Statements for the year ended 30 June 2010.
- The closing cost in the work papers I was provided with at 30 June 2010 did not reconcile to the comparable information in Note 10 to the Financial Statements for the year ended 30 June 2010. There was a discrepancy in this information of $9.6m. I understand the difference related to 'strategic spares'. This difference has not been investigated as it would have an immaterial difference on the post-tax revenue modelling.
- There was a minor discrepancy between the work papers that I reviewed and the closing cost of assets in Note 11 to the Financial Statements for the year ended 30 June 2011.
- Discrepancies were also noted between the financial statements and the accounting fixed asset registers for earlier years (prior to 30 June 2009). I have not queried Western Power regarding these discrepancies as I note they were corrected as at 30 June 2009.
- The work papers that I reviewed documented a considerably higher tax cost of assets compared to the accounting cost of assets. For both years (30 June 2010 and 30 June 2011 and as at 1 July 2009), this discrepancy was in excess of $1,200m. From my discussions with Western Power, I understand that this discrepancy has occurred because the accounting written down value of assets was included in the fixed asset register on 1 April 2006 as the total cost of assets. However, the tax fixed asset register correctly recorded the total cost of assets. This discrepancy has also resulted in a higher cost of asset disposals being recorded for tax purposes.
- I note the total cost of assets as at 1 April 2006, plus additions and less disposals to 28 February 2012 does not reconcile to the total cost of assets detailed on the 28 February 2012 depreciation register. However, I note the discrepancy is less than 1% of total cost of assets and, as such, I do not consider this is a material reconciliation issue.

I have performed the following reconciliation of the total cost of assets included in the tax fixed asset registers provided (the source data) to the total cost of assets used in my calculations:

	$
Total cost of assets included in 1 April 2006 fixed asset register	3,643,475,203
Total cost of additions from 1 April 2006 to 28 February 2012	5,008,742,630
Less assets removed from total cost data:	
Bright Communications assets (labelled as 7200 assets)	(25,586,311)
Motor Vehicles	(223,783,947)
Land	(243,068,057)
Capitalised Interest	(130,508,732)
Replacement Assets	(465,055,082)
IMO assets	(3,774,897)
Inefficient assets	(199,100,000)
Total cost of assets included in the tax depreciable base	7,361,340,807
Less: depreciation to 1 July 2012	(1,716,866,409)
Adjustable value as at 1 July 2012	5,644,474,398

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Appendix Q. Ernst & Young – Recovering the tax costs flowing from the receipt of capital contributions

Recovering the tax costs flowing from the receipt of capital contributions

Western Power Electricity Networks Corporation

18 May 2012

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18 May 2012

Expert report on recovering the tax costs flowing from the receipt of capital contributions

Dear Noel

Please find attached my report prepared in accordance with the Federal Court of Australia expert witness guidelines.

If you have any queries, please contact me on (02) 9248 5196 or craig.mickle@au.ey.com.

Yours sincerely

Craig Mickle
Partner
Ernst & Young

Advice on recovering the tax cost flowing from the receipt of capital contributions

Contents

Introduction

1. I am a Partner of Ernst & Young, working in its Economics, Regulation and Policy practice. My curriculum vitae is at Appendix A.

2. In this report, I have adopted the acronyms and abbreviations set out in Appendix B.

The assignment

3. I understand that this report has been prepared in respect of the ERA's Draft Decision on Western Power's Proposed Revised Access Arrangement.

4. I have been instructed to consider whether it is reasonable, with respect to the requirements of the Access Code, to recover the tax costs (or liabilities) flowing from the receipt of capital contributions from all users of Western Power's network rather than specifically from those making the contribution.

5. I have also been instructed to have particular regard to the following requirements in the Access Code:

    - The Code objective
    - The objectives within section 6.4
    - Section 6.64(b)
    - Section 6.66
    - Chapter 7.

6. In completing this report, I have been instructed by Noel Ryan – Principal Economic Regulatory Advisor – Western Power.

7. I have been instructed to prepare an expert report that satisfies the Federal Court Guidelines (see Appendix D).

Background

8. Western Power owns and operates the transmission and distribution networks in South-West Western Australia, which form the Western Power Network.

9. On 30 September 2011, Western Power submitted to the ERA a Proposed Revised Access Arrangement for the Western Power Network.[1] The Proposed Revised Access Arrangement relates to AA3, the five year period from 1 July 2012 to 30 June 2017.

10. As part of its Proposed Revised Access Arrangement, Western Power used a real, pre-tax rate of return approach in determining its target revenues in providing covered services (transmission and distribution separately). This approach provides an implicit allowance for tax costs in the return on asset building blocks of the target revenues.

11. On 29 March 2012, the ERA issued its Draft Decision on Western Power's Proposed Revised Access Arrangement.[2] The ERA decided not to accept various aspects of Western Power's proposed revisions, including its rate of return approach. Specifically,

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[1] Western Power, Proposed revisions to the Access Arrangement for the Western Power network for 1 July 2012 to 30 June 2017, 30 September 2011

[2] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network, 29 March 2012

Required Amendment 20 states: *"Western Power's Proposed Revisions must be amended to adopt a real post-tax rate of return…"*[3]

12. A post-tax rate of return approach requires an explicit estimate of tax costs (i.e. as a separate building block), in determining target revenue.

13. The Draft Decision estimates Western Power's tax costs using a real post-tax approach, and Paragraph 940 of the Draft Decision details how the ERA has applied that approach. It makes no comments in relation to capital contributions and therefore does not include them in revenues for the purposes of estimating Western Power's tax costs, and thus does not include tax costs in target revenues.

14. Consistent with this, Draft Decision Required Amendment 21 states that: *"No amounts in relation to tax on capital contributions must be included in Target Revenue."*[4]

15. Instead, the Draft Decision suggests that if Western Power needs to recover such tax costs it should negotiate with the party providing the capital contribution to recover them.

Information

16. The documents that I have relied upon for the purposes of completing this report are listed in Appendix C.

17. I have not conducted an audit or other verification of any information supplied to me. I have assumed that the information supplied to me is accurately stated.

18. Neither Ernst & Young, nor I warrant the accuracy or reliability of any of the information supplied to me.

19. The opinions set out in this report may alter if there are any changes to the information supplied to me.

20. I have received all relevant information requested during the course of preparing this report.

Qualifications

21. My opinion is based on my interpretation of the relevant regulatory provisions, my experience in the relevant field, and on the information provided to me by Western Power management. Should any of these facts and circumstances and/or the relevant accounting pronouncements change, my conclusion may change.

Reliance on this report

22. This report has been prepared, and may be relied on, solely for the purposes outlined in paragraphs 3-7. This report has been prepared specifically for Western Power. Ernst & Young does not take responsibility to any person, other than Western Power, in respect of this report, including any errors or omissions howsoever caused.

Assistance by colleagues

23. Where appropriate, I have sought the assistance of colleagues in preparing this report. The opinions expressed in this report are mine.

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[3] Ibid., page 207
[4] Ibid., page 209

Conduct of this assignment

24. I understand that my report is to be prepared in respect of the ERA's Draft Decision. I acknowledge that the report will be provided to the ERA by Western Power in response to the Draft Decision.

25. I have been instructed that the report is to be prepared in a form which satisfies the requirements of the guidelines for expert witnesses in proceedings in the Federal Court of Australia. These guidelines are set out in Federal Court of Australia Practice Note CM7.

26. I have read, understood and complied with the Practice Note.

27. I have made all the inquiries which I believe are desirable and appropriate. No matters of significance that I regard as relevant to my opinion have, to my knowledge, been withheld.

Structure of this report

28. The structure of the remainder of this report is as follows:

- Paragraphs 29 to 40 contain a summary of my opinion.
- Paragraphs 41 to 82 provide my opinion. Specifically:
    - Paragraphs 41 to 52 restate the provisions of the Access Code I have been specifically instructed to consider, and those relevant to the definition of capital contributions and their estimation
    - Paragraphs 53 to 56 summarise the basis for the ERA's approach to estimating tax costs
    - Paragraphs 57 to 61 summarise the basis for the ERA's approach to recovering the tax costs flowing from the receipt of capital contributions
    - Paragraphs 62 to 82 examine the implications for recovering the tax costs flowing from the receipt of capital contributions.

Summary of my opinion

29. This summary should be read in conjunction with the full report.

30. In my opinion it is reasonable to recover the tax costs flowing from receipt of capital contributions from all users of the Western Power Network rather than specifically from those making the contributions, given the requirements of the Access Code.

31. I observe that that the ERA's decision on tax cost recovery conflates tax cost estimation and recovery issues.

32. In order to address the recovery issues, it is necessary to separate the tax cost estimation issue from the tax cost recovery issue. Specifically, the ERA:

- assumes that tax costs are part of Western Power's efficient costs of service;
- appears to accept that tax costs on capital contributions can be efficient costs, as at no stage does it argue that these costs should not be recovered;
- argues that those tax costs should be recovered from the user making the capital contribution; and
- excludes capital contributions from the process of estimating tax costs.

33. It is, however, necessary to include capital contributions in the process of estimating tax costs because:

- The corporate income tax costs of a particular transaction can only be estimated having regard to the relevant entity's overall tax profile and characteristics. As such, the effective tax rate (i.e. the tax rate taking account the timing of the tax payments) of a transaction can only be considered in the context of the relevant entity's other income, deductions and tax attributes, such as, for example carried forward tax losses.
- I understand that capital contributions and gifted assets should be taxable to Western Power in the year that the income is derived. These are often seen as amounts taxable as a non-cash business benefit or as ordinary income in the hands of Western Power.

34. An objective estimate of the efficient tax costs flowing from the receipt of capital contributions would therefore typically include them in estimating the tax costs of the service provider.

35. The ERA's approach does not do this. It cannot therefore objectively measure efficient tax costs. Nor can the ERA achieve its objectives in moving to a post-tax approach (i.e. to achieve economically efficient pricing by having a more precise estimate of the cost of tax).

36. With the estimation issues addressed, it is possible to consider the issue of recovering the appropriate tax costs flowing from the receipt of capital contributions.

37. There are a number of conceptual and practical reasons why it is reasonable to recover the cost from all users of Western Power's network.

38. There are three key conceptual reasons:

- The nature of tax costs and market dynamics will drive the most appropriate approach to tax cost recovery.

- There is no impediment to Western Power recovering those tax costs now in capital contributions from those making the contribution to the extent it is practical to do so.

- Imposing a requirement on Western Power to recover those tax costs in capital contributions risks having the effect of reducing Western Power's incentive to use capital contributions.

39. There are likely to be several practical issues associated with the recovery of tax costs flowing from the receipt of capital contributions from those making the contribution. Specifically:

    - How they would be estimated and demonstrated to be efficient. This is likely to be problematic as the charges could vary depending on how capital contributions are treated (e.g. how timing differences are measured) and how particular capital contributions are ranked, because the marginal tax cost may vary. They will also vary over time. This is likely to lead to significant issues with the acceptability of the charges (e.g. for equity). For example, the typical treatment of capital contributions under tax law involves paying tax immediately on receipt of the contribution, but also getting a tax deduction over time for depreciation over the life of the asset. Unless separated, this benefit would flow through to all users.

    - How they would be levied. For those making capital contributions in kind, it raises the issue of what would be the physical mechanism for charging. It would also likely create an incentive to 'game' the value of capital contributions in kind.

40. By contrast, there are no practical issues associated with recovering the cost from all users. Given all the above, I understand that there is substantial regulatory precedent for allowing these costs to be recovered from all users.[5]

[5] In the case of the AER, my understanding is that its decisions estimate tax costs at the level of the service provider and provide the business with the flexibility to determine how best to recover them (i.e. the AER makes an allowance for these costs in the overall revenue requirement potentially to be recovered from all users).

Opinion

Background

41. Further relevant background to my opinion includes the Access Code provisions:

- I have been specifically instructed to consider; and
- relevant to the definition of capital contributions and their estimation.

<u>**The Access Code provisions I have been specifically instructed to consider**</u>

42. The relevant provisions of the Access Code that I have been specifically instructed to consider are reproduced below[6]:

<u>The Code Objective (section 2.1)</u>

The objective of this Code is to promote the economically efficient:

(a) investment in; and

(b) operation of and use of,

networks and services of networks in Western Australia in order to promote competition in markets upstream and downstream of the networks.

<u>Section 6.4</u>

The price control in an access arrangement must have the objectives of:

(a) giving the service provider an opportunity to earn revenue ("target revenue") for the access arrangement period from the provision of covered services as follows:

(i) an amount that meets the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved; plus:
(ii) for access arrangements other than the first access arrangement, an amount in excess of the revenue referred to in section 6.4(a)(i), to the extent necessary to reward the service provider for efficiency gains and innovation beyond the efficiency and innovation benchmarks in a previous access arrangement; plus
(iiA) an amount (if any) determined under sections 6.5A to 6.5E; plus
(iii) an amount (if any) determined under section 6.6; plus:
(iv) an amount (if any) determined under section 6.9; plus:
(v) an amount (if any) determined under an investment adjustment mechanism (see sections 6.13 to 6.18); plus:
(vi) an amount (if any) determined under a service standards adjustment mechanism (see sections 6.29 to 6.32); plus
(vii) an amount (if any) determined under section 6.37A;

and

(b) enabling a user to predict the likely annual changes in target revenue during the access arrangement period; and

(c) avoiding price shocks (that is, sudden material tariff adjustments between succeeding years).

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[6] Electricity Networks Access Code 2004, Electricity Industry Act 2004 (unofficial consolidated version as provided by Western Power), 17 April 2012.

Sections 6.64 – 6.66

6.64 An access arrangement must set out the weighted average cost of capital for a covered network, which:

(a) if a determination has effect under section 6.65:

(i) for the first access arrangement for the Western Power Network177— may use any methodology (which may be formulated without any reference to the determination under section 6.65) but, in determining whether the methodology used is consistent with this Chapter 6 and the Code objective, regard must be had to the determination under section 6.65; and

(ii) otherwise - must use the methodology in the determination under section 6.65 unless the service provider can demonstrate that an access arrangement containing an alternative methodology would better achieve the objectives set out in section 6.4 and the Code objective,

and

(b) if a determination does not have effect under section 6.65 - must be calculated in a manner consistent with section 6.66.

6.65 The Authority may from time to time make and publish a determination (which subject to section 6.68 has effect for all covered networks under this Code) of the preferred methodology for calculating the weighted average cost of capital in access arrangements.

6.66 A determination under section 6.65:

(a) must represent an effective means of achieving the Code objective and the objectives in section 6.4; and

(b) must be based on an accepted financial model such as the Capital Asset Pricing Model.

Chapter 7

Is concerned with pricing methods and contains guidance on the objectives of pricing methods, including how reference tariffs should be set (e.g. to cover the incremental cost of service provision and to be below stand-alone cost).

43. I draw the following from the above:

- The Code objective is focussed on ensuring economically efficient activity in the electricity network sector in Western Australia. In respect of pricing, section 6.4 seeks to meet this objective by ensuring target revenues reflect efficient costs. These principles do not appear to be in contention in regard to the issue that is the subject of this opinion, which focuses on (efficient) cost recovery rather than estimation *per se*.

- Section 6.4(c) places weight on avoiding price shocks in the form of material tariff adjustments.

- Section 7 is concerned with setting reference tariffs, but is nevertheless consistent with widely accepted principles of market pricing.

- The ERA previously made a determination on the methodology for calculating the WACC. That methodology prescribed a real pre-tax approach to estimating the

WACC. That determination has expired and the ERA's Draft Decision now prescribes a real post-tax approach.[7]

<u>Capital contributions</u>

44. The Access Code defines at section 1.3 a contribution as *"a capital contribution, a non-capital contribution or a headworks charge"*. It defines a capital contribution *"as a payment or provision in kind made, or to be made, by a user in respect of any new facilities investment in required work"*.

45. The ERA's Draft Decision in discussing tax costs identifies two types of capital contributions: *"gifted assets"* or *"cash contributions"*. I understand that the former relate to assets that are developed by a user typically to facilitate connection to the Western Power Network, who then passes over ownership of those assets to Western Power. Cash contributions are payments made by the user to Western Power to facilitate the development of such assets.

46. The Access Code, at section 5.1(h), requires an access arrangement to contain a contributions policy.

47. Sections 5.12-5.17 outline various requirements in respect of a contributions policy, including the circumstances in which it is applicable. Most relevantly, in respect of the setting of contributions:

5.12 The objectives for a contributions policy must be that:

(a) it strikes a balance between the interests of:

(i) contributing users; and
(ii) other users; and
(iii) consumers;

and

(b) it does not constitute an inappropriate barrier to entry.

5.15 A contributions policy must set out:

(a) the circumstances in which a contributing user may be required to make a contribution; and

(b) the method for calculating any contribution a contributing user may be required to make; and

(c) for any contribution:

(i) the terms on which a contributing user must make the contribution; or
(ii) a description of how the terms on which a contributing user must make the contribution are to be determined.

48. Section 5.16 allows the service provider either to develop their own contributions policy (subject to complying with sections 5.12-5.15) or base it in whole or part on the model contributions policy, outlined in Appendix 4 of the Access Code. Under the former approach, the ERA must have regard to the model contributions policy in determining whether the contributions policy is consistent with sections 5.12 to 5.15 and the Code objective.

49. The model contributions policy states, at section A4.6 that:

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[7] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network, 29 March 2012, para. 609.

"A contribution must not exceed the amount that would be required by a prudent service provider acting efficiently, in accordance with good electricity industry practice, seeking to achieve the lowest sustainable cost of providing the new services."

50. A contributions policy is contained in Appendix 3 of Western Power Network's current access arrangement. At Section 3, Appendix 3 makes a similar statement as contained in the model contributions policy, in respect of setting contributions.

    "A contribution with respect to covered services sought by an applicant must not exceed the amount that would be required by a prudent service provider acting efficiently, in accordance with good electricity industry practice seeking to achieve the lowest sustainable cost of providing the covered services."[8]

51. Western Power submitted certain proposed revisions to its contributions policy as part of AA3, but these, and the ERA's Required Amendments in its Draft Decision, do not relate to matters that go to the intent of the contributions policy in respect pricing matters.

52. I draw the following from the above:

    - the contributions policy seeks to achieve a balance between the different types of users (and consumers); and

    - in respect of setting contributions, it relies on a similar principle as section 6.4; namely efficient cost recovery

The basis for the ERA's approach to estimating tax costs

53. The ERA's approach to estimating tax costs is summarised in paragraphs 8-13.

54. The basis for the ERA's approach appears to be that:

    - *"there is a growing precedent that the post-tax form of the WACC being used."*[9]

    - the pre-tax approach *"tends to over-compensate service providers for their tax liabilities"*, and that *"this over compensation does not meet the objectives of the Code, as it does not result in economically efficient pricing."*[10] Elsewhere, the ERA notes that tax costs are part of the *"the service provider's efficient costs of service."*[11]

    - the ERA now *"considers that the use of an explicit post-tax approach allows a regulated entity's effective tax liabilities to be estimated more precisely – overcoming shortcomings with the pre-tax approach – thereby meeting the objectives of the Code."*[12]

55. The basis the ERA shifting to the post-tax approach therefore appears to be:

    - the objectives of the Access Code;

    - economically efficient pricing. In the context of setting target revenues this means ensuring target revenues are estimated in a manner that avoids systematic error (to avoid over or under-compensation) and more precisely; and

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[8] Western Power, Proposed Revised Contributions Policy, DM: 8548834, 30 September 2011, page 12.
[9] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network, 29 March 2012, para. 623
[10] Ibid., para. 625
[11] Ibid., para 937
[12] Ibid., para. 628

- regulatory precedent.

56. The basis for the ERA's decision to adopt a post-tax approach appears to have implications for the ERA's approach to recovering the tax costs flowing from the receipt of capital contributions. Those implications are discussed in paragraphs 62 to 73.

The basis for the ERA's approach to recovering the tax costs flowing from the receipt of capital contributions

57. The ERA's approach to recovering the tax costs flowing from the receipt of capital contributions is summarised in paragraphs 14-15.

58. The basis for the ERA's approach appears to be described in paragraphs of 889-897 of the Draft Decision. In particular, the ERA argues that it *"does not consider taxation costs relating to gifted assets or cash contributions should be borne by customers who do not make use of those assets."*[13]

59. The ERA also notes that:

    - it understands that the party providing the gifted asset receives a tax benefit as a result of writing off the asset (although I understand that this is not always the case); and

    - its approach would be consistent with the treatment of the economic depreciation for these contributed assets (i.e. depreciation is not included in target revenue because the assets are not included in the regulated asset base).

60. The ERA's approach to the recovery of the tax costs flowing from the receipt of capital contributions appears therefore to be based on the "user pays" principle, although no specific mention is made of this principle. The principle basically holds that those who benefit from a good or service should pay the full cost of their provision.

61. This has some similarities to the economically efficient pricing principle used by the ERA, as discussed in paragraph 53. In this case, however, its application relates to who should pay, rather than how much should be paid.

Recovering the tax costs flowing from the receipt of capital contributions

62. Paragraphs 53 to 61 cover two, at least in principle, separate issues:

    - how to estimate tax costs; and

    - who should pay those costs, particularly those flowing from the receipt of capital contributions.

    The basis for the ERA's decisions on estimating and recovering tax costs, however, conflates these two issues.

63. In practice, the issues may become somewhat interrelated when actually pricing and seeking to recover tax costs from the receipt of capital contributions from those making the contribution (as paragraphs 79 to 81 discuss).

Disaggregating tax cost estimation and recovery issues

64. The way in which the basis for the ERA's decision on tax costs recovery conflates tax cost estimation and recovery issues is outlined below.

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[13] Ibid., para. 897.

65. In the first instance:

- the ERA accepts that tax costs are part of Western Power's efficient costs of service (see paragraph 52)[14];
- the ERA appears to accept that tax costs on capital contributions can be efficient costs (see paragraph 56[15]), as at no stage does it argue that these costs should not be recovered;
- but argues that those tax costs should be recovered from the user making the capital contribution; and
- therefore excludes capital contributions from the process of estimating tax costs.

66. In the process, however, the ERA does not address the issue of how to estimate the tax costs flowing from the receipt of capital contributions - which it has decided should be recovered from the user making the contribution. Specifically:

- The corporate income tax costs of a particular transaction can only be estimated having regard to the relevant entity's overall tax profile and characteristics. As such, the effective tax rate (i.e. the tax rate taking account the timing of the tax payments) of a transaction can only be considered in the context of the relevant entity's other income, deductions and tax attributes, such as, for example carried forward tax losses.

  For example, an entity which is in a tax loss position at the time of receiving a contribution and over the life of depreciation of the associated asset would have no effective tax cost from receiving the contribution. This is because there would be no cash timing difference between when the tax is paid on the assessable contribution and the timing of the associated deductions (as no tax is paid). On the other hand, the same transaction for an entity which is in a constant tax-paying position, would have an associated effective tax cost. Whether tax is payable or not can only be considered at the entity level.

- Tax costs, for the purposes of setting target revenues, are estimated using a benchmarking approach. This involves, amongst other things, estimating the tax costs of the service provider, as opposed to the tax-paying entity. The objective of this approach is to provide an estimate of the efficient tax costs of the service provider. For Western Power it also involves estimating tax costs for transmission and distribution services.
- I understand that capital contributions and gifted assets should be taxable to Western Power in the year that the income is derived.[16] These are often seen as amounts taxable as a non-cash business benefit[17] or as ordinary income in the hands of Western Power. The typical treatment of capital contributions under tax law involves paying tax immediately on receipt of the contribution, but also getting a tax deduction over time for depreciation over the life of the asset, which would normally flow through to all users.
- Capital contributions are therefore relevant to the estimation of efficient tax costs.

67. An objective estimate of the efficient tax costs flowing from the receipt of capital contributions would therefore typically include them in estimating the tax costs of the service provider.

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[14] See also Ibid., paras. 148, 187, 190.

[15] See also Ibid., paragraphs 895-897. The ERA does not appear to dispute that the tax costs flowing from capital contributions are efficient costs.

[16] Vaughan Lindfield, Tax liabilities for regulated revenue purposes, 18 May 2012.

[17] Section 21A of the *income Tax Assessment Act 1936*.

68. The ERA's approach does not do this. It cannot therefore objectively measure either the tax costs:

- of Western Power as a service provider under the Access Code; or
- those flowing from the receipt of capital contributions.

69. Even if the correct approach to estimating of the tax costs flowing from the receipt of capital contributions were adopted, it would reflect the overall circumstances of the business (i.e. by estimating tax costs with and without capital contributions to estimate the impact on tax costs). In effect, this approach assumes that capital contributions are its marginal activity from a tax cost perspective. I am unaware of what the basis for such an assumption would be. If this assumption were made, however, it would provide an estimate of the marginal impact of capital contributions on the tax costs of the service provider (and the relevant services, namely transmission and distribution).

70. The ERA's current approach is therefore inconsistent with:

- my understanding of the typical treatment of capital contributions;
- fulfilling the objective of economically efficient pricing in applying the post-tax approach, including developing a more precise estimate;
- the Code objective; and
- regulatory precedent. The AER estimates tax costs including capital contributions.[18]

71. Indeed, tax costs derived on the basis outlined by the ERA are likely to either under- or over-recover efficient tax costs both in respect of:

- the tax costs attributable to Western Power excluding capital contributions; and
- the tax costs attributable to capital contributions.

72. The extent of any under- or over recovery could only be determined by undertaking the relevant analysis. The typical treatment of capital contributions under tax law involves paying tax immediately on receipt of the contribution, but also getting a tax deduction over time for depreciation over the life of the asset.[19]

73. With the estimation and recovery issues separated, and with appropriate estimation, it is then possible to address the cost recovery issue.

<u>Addressing cost recovery</u>

74. With the estimation issues addressed, it is possible to consider the issue of recovering the appropriate tax costs flowing from the receipt of capital contributions. Specifically, whether it is reasonable to recover the cost from all users of Western Power's network rather than specifically from those making the contribution.

75. There are a number of conceptual and practical reasons why it is reasonable to recover the cost from all users of Western Power's network.

76. There are three key conceptual reasons why it is reasonable to recover the cost of from all users of Western Power's network:

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[18] AER, Electricity distribution network service providers: Post-tax revenue model handbook, June 2008.
[19] So the net impact from the up-front treatment of the capital contribution compared to not treating it this way is a timing issue.

- The nature of tax costs and market dynamics will drive the most appropriate approach to tax cost recovery.

- There is no impediment to Western Power recovering costs those tax costs now in capital contributions to the extent it is practical to do so.

- Imposing a requirement on Western Power to recover those tax costs in capital contributions risks having the effect of reducing Western Power's incentive to use capital contributions.

77. The estimated tax costs are not directly related to provision of capital contributions, for the reasons outlined in paragraph 64. The tax cost is a function of the overall tax position of the taxpaying entity, not just capital contributions. The tax costs are more like indirect corporate overheads than they are like incremental costs that can be directly (i.e. causally) related to a particular user. Specifically:

    - A commercial business would normally seek to recover such costs in a way that minimised the level of disruption to its business (i.e. had the minimal impact on demand). In other words, tax costs would be recovered from the services with the most inelastic demand. This is also consistent the pricing objectives outlined in Chapter 7 of the Access Code, although these relate to reference tariffs.

    - In the case of Western Power, this is likely to be all users of Western Power's network rather than those making contributions (e.g. land developers).[20] The ERA appears to acknowledge this as it argues: *"If Western Power needs to recover such costs, a better approach would be for it to negotiate with the party providing the capital contribution to recover these tax costs."*[21]

78. I am unaware of any existing impediment to Western Power seeking to recover tax costs flowing from the receipt of capital contributions from those making the contribution. In other words, Western Power could do this now and is likely to have an incentive to do so, within the constraints imposed by the nature of the cost and the market. The risk of imposing the ERA approach is that:

    - If Western Power sought to recover the tax costs flowing from the receipt of capital contributions from those making the contributions, it might not be able to do so.

    - A failure to do so would mean that Western Power might not be able to recover its efficient costs. This would be inconsistent with the Code objective, section 6.4 and the contributions policy. It is not the intent of the contributions policy to enable either under- or over-recovery, it is to allocate costs to be recovered.

    - The risk of a failure to do so, would likely distort Western Power's decision about whether to use capital contributions. The risk is that Western Power would rely on them less to avoid, as far as would be practical, the possibility that it would not recover its efficient tax costs.

79. There are likely to be several practical issues associated with recovery of the tax costs flowing from the receipt of capital contributions from those making the contribution.

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[20] This is likely to be true even for a business subject to a revenue cap, such as Western Power, as this approach will typically lessen the overall upward impact on its prices (and may even allow it to recover additional revenue in some circumstances). It is also worth noting that those making capital contributions are potential new users of the network. The contribution is to ensure that the direct costs of their connection are recovered from them. In this sense, they are a marginal user because if they are not prepared to pay the contribution they will generally not connect to the network.

[21] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network, 29 March 2012, para. 897

Specifically, charging those making the capital contribution would raise the following issues:

- How they would be estimated and demonstrated to be efficient. This is likely to be problematic as the charges could vary depending on how capital contributions are treated (e.g. how timing differences are measured) and how particular capital contributions are ranked, because the marginal tax cost may vary. They will also vary over time. This is likely to lead to significant issues with the acceptability of the charges (e.g. for equity).

- How they would be levied. For those making capital contributions in kind, it raises the issue of what would be the physical mechanism for charging. It would also likely create an incentive to 'game' the value of capital contributions in kind.

- Assuming it were possible to levy such charges, it might create potential for price shock. For example, if the statutory rate was merely applied to the value of the capital contribution, in principle the cost of capital contributions would increase by 30%.

80. By contrast, there are no practical issues associated with recovering the cost from all users. Given all the above, I understand that there is substantial regulatory precedent for allowing these costs to be recovered from all users.[22]

81. It is perhaps worth noting that, in justifying its decision to impose that Western Power recover the tax costs flowing from the receipt of capital contributions from those making the contribution, the ERA makes no reference to:

- the Code objective;

- economically efficient pricing (as required under section 6.4 and the contributions policy) or the pricing methods under Chapter 7 of the Access Code.

- the potential for price shock; or

- regulatory precedent.

82. For these reasons, in my opinion, it is reasonable to recover the tax costs flowing from receipt of capital contributions from all users of the Western Power Network rather than specifically from those making the contributions, given the requirements of the Access Code.

[22] In the case of the AER, my understanding is that its decisions estimate tax costs at the level of the service provider and provide the business with the flexibility to determine how best to recover them (i.e. the AER makes an allowance for these costs in the overall revenue requirement potentially to be recovered from all users).

Appendix A: Curriculum vitae

Craig Mickle
Partner, Economics, Regulation and Policy

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Background

Craig has over 15 years experience in providing strategic advice and economic analysis across a range of infrastructure industries that are subject, or potentially subject, to economic regulation of the services they offer and the charges they impose.

He has particular experience working with infrastructure businesses across the energy, water and industrial transport sectors on:

- ► Infrastructure asset transactions; and
- ► Regulatory issues, such as the risk of regulation and its potential impacts on value, the cost of capital, the treatment of risk, ‘related party’ transactions, cost benchmarking, pricing, the form of price control, incentive mechanisms and the economic aspects of legal challenges to regulation. He has also addressed competition policy (e.g. merger) issues.

Prior to professional advisory services, Craig was previously Chief Economist at TXU Australia (now SP AusNet and TRUenergy).

Selected experience

Client/task	Value to client
Infrastructure asset transactions	Provided regulatory due diligence (VDD and buy side) and advised on how to optimise the value of those potential acquisitions for numerous (well over a dozen) infrastructure asset transactions. This includes: ► The Expression of Interest for the Abbott Point Coal Terminal T4-T7 (2011) ► The sale of the Abbot Point Coal Terminal X50 (2011) ► APA Group - proposed sale of assets to the Energy Investment Trust (2010) ► Spark Infrastructure - strategic review (2010) ► Sydney Water - issues pertaining to the potential sale of the desalination plant (2010) ► Queensland Government - Provided regulatory advice on the sale of Queensland Rail (2010) ► North Queensland Gas Pipeline (2008) ► Spark Infrastructure - UK water asset due diligence (2009) ► Origin Energy Networks (2007) ► Allgas (2006) ► Murraylink (2006) ► Duke Energy’s Australasian energy assets (2003) ► Advised the DUET Group on several acquisitions opportunities (2003-2005) ► Advised SP AusNet on its IPO (2006) ► Advised AMP Henderson/Alinta on the acquisition/ownership reorganisation of United Energy, MultiNet and AlintaGas (2003)

	► CitiPower (2001) ► Advised on the sale of several energy retailers.
Regulatory issues	► Advised on regulatory issues to clients including: Alinta, AGL Energy, APA Group, Aurora Energy, the Australian Gas Association, Brookfield, CKI, CitiPower, Country Energy, DUET, ElectraNet, Energex, EnergyAustralia, Envestra, Ergon, ETSA Utilities, Goldfields Gas Pipeline, Hastings Funds Management, HKE, Horizon Power, Integral Energy, Multinet, Origin Energy, PAWA, Powercor, Spark Infrastructure, SP AusNet, TransGrid, United Energy and Western Power.
Financial Investor Group	► Advised the eight major energy asset owners in Australia (APA Group, Brookfield, CKI, DUET, Hastings Funds Management, Hong Kong Electric, Singapore Power, Spark Infrastructure) on the AER's first review of the cost of capital to apply to regulated energy network businesses, particularly in light of the Global Financial Crisis. ► Undertaken several engagements on the cost of capital for this group.
Financial Investor Group	► Advised on the performance of the AER in respect of merits appeals.
Five Victorian electricity network businesses	► Advised on the long term performance of these businesses in respect of network charges in light of the recent debate on increasing electricity prices.
Energy industry reforms in Australia, Oman, Israel and Korea	Australian examples include: ► Better Place: advised the business on the policy and regulatory reform needed to facilitate the penetration of electric vehicles in the NEM. ► Victorian Department of Primary Industries (DPI): Policy advice into Large-Scale Solar Electricity Feed-In tariff design. ► Ministerial Council on Energy: Advised on the retail market impacts associated with rolling-out 'smart' electricity meters for small customers. ► Energy Reform Implementation Group: Advised on the potential impediments in the capital markets to greater investment in the market.

Professional qualifications

- Bachelor of Business, Curtin University, Western Australia
- Diploma in Applied Finance and Investment, FINSIA
- MBA (hons) Middlesex University Business School, London UK

Appendix B: Glossary

Reference	Description
AA3	Western Power's third access arrangement (i.e. for the period 2012/13 to 2016/17)
AER	Australian Energy Regulator
ERA	Economic Regulation Authority
the Access Code	*Electricity Networks Access Code 2004 (WA)*
Western Power	Western Power Electricity Networks Corporation
WACC	Weighted Average Cost of Capital

Appendix C: Documents I have relied on

Documents:

1. Australian Energy Regulator, Electricity distribution network service providers: Post-tax revenue model handbook, June 2008

2. Electricity Networks Access Code 2004, Electricity Industry Act 2004 (unofficial consolidated version as provided by Western Power), 17 April 2012

3. Economic Regulation Authority of Western Australia, Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network, 29 March 2012

4. Vaughan Lindfield, Tax liabilities for regulated revenue purposes, 18 May 2012.

5. Western Power, Proposed Revised Contributions Policy, DM: 8548834, 30 September 2011.

6. Western Power, Proposed revisions to the Access Arrangement for the Western Power network for 1 July 2012 to 30 June 2017, 30 September 2011

Appendix R. Energy Forecast 11/12 - 16/17 - Energy & Customer Numbers

Energy Forecast 11/12 - 16/17

Energy & Customer Numbers

System Forecasting

October 2011

westernpower

Document Control

Endorsement Approvals

	Name	Title	Signature
Prepared by	Ben Jones	Forecasting Analyst	
Approved by	Raphael Ozsvath	System Forecasting Manager	
	David Bones	Branch Manager, Network Planning & Development	
	Gavin Hobbs	Branch Manager, Corporate Accounting & Taxation	
	Peter Mattner	Branch Manager Regulation	
	Mark McKinnon	Revenue & Pricing Manager	

Record of Revisions

Revision number	Date	DM version	Revised by	Description
V1	22 / 09 / 11	8655584	Ben Jones	Draft
V1A	17 / 10 / 11	8655584	Ben Jones	Includes Customer Type and Load Factors
V2	25 / 10 /11	8655584	Ben Jones	Labelled tables, figures. Updated method for Customer Type Calculation & Customer Connections Calculation.
V2A	03/11/11	8655584	Ben Jones	For Distribution

Documents Referenced In This Document

DM#	Title of Document
6296884	System Forecasting Section - Operation Manual
7976363	Photovoltaic Forecast
8638340	Study on Price & Income Elasticity in the Western Power Network
8785338	Energy and Customer Number Forecasts - Spreadsheet Output

Other Documents That Reference This Document

DM#	Title of Document

Stakeholders (people to be consulted when document is updated)

Position / Branch / Section
Ben Jones | Forecast Analyst| System Forecasting
Raphael Ozsvath | Manager | System Forecasting

Notification List (people to be notified when document is updated)

Position / Branch / Section
Ben Jones | Forecast Analyst| System Forecasting
Raphael Ozsvath | Manager | System Forecasting
Mark McKinnon |Revenue and Pricing Manager
Matthew Veryard | Network Pricing Analyst
John Hatton | Access Billing Manger

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1 Introduction

Western Power is required to accurately forecast energy demand and customer numbers per tariff class within the Western Power Network. The forecasts are used for Access Arrangement submissions, for pricing determination, income budgets and accounting. Monthly forecasts are required for accounting purposes, whereas financial year totals are required for most other purposes.

Western Power currently earns the majority of its revenue under a revenue cap. The forecast energy consumption determines the relevant price charged to customers, to meet pre determined revenue. If actual energy usage or customer numbers vary from forecasts, an adjustment is made in the following year, resulting in higher or lower revenue being recouped in that year. It is financially beneficial to reduce these yearly adjustments by ensuring Western Power has better yearly forecasts. At present, Western Power is considering the benefits of moving to a price cap for certain tariffs. Under a price cap energy forecasts become even more critical to the financial success of the business.

Since disaggregation, Western Power has used simple annual energy predictions derived internally for pricing and budget purposes. However for Access Arrangement 3 (AA3) Western Power engaged Deloitte to derive more accurate forecasts. The purpose of this document is to discuss and have approved the proposed methodology for Western Power to internally derive accurate monthly forecasts for energy consumption and customer numbers by tariff.

1.1 Business Integration

System Forecasting is a division in Network Planning and Development that produces fit for purpose forecasts for peak demand and ad-hoc analysis to meet various needs throughout the business. System Forecasting has an established track record in producing statistically valid models and analysis that meet the needs of the business, auditors and regulators. The drivers behind energy consumption are similar to those for peak demand forecasting; therefore energy forecasting is a natural fit for System Forecasting to complete.

Originally, Deloitte was engaged to provide annual energy forecasts for the AA3 submission. System Forecasting will review this forecast and complete further forecasts beyond this initial submission. An additional need was identified after the initial submission, whereby Corporate Accounting and Taxation require monthly energy forecasts per tariff for budgeting and cash flow forecasting.

System Forecasting has worked closely with the relevant stakeholders within the business to develop forecasts that capture all key drivers and meet the needs of the business. Below is a diagram that illustrates the internal and external stakeholders for energy forecasting.

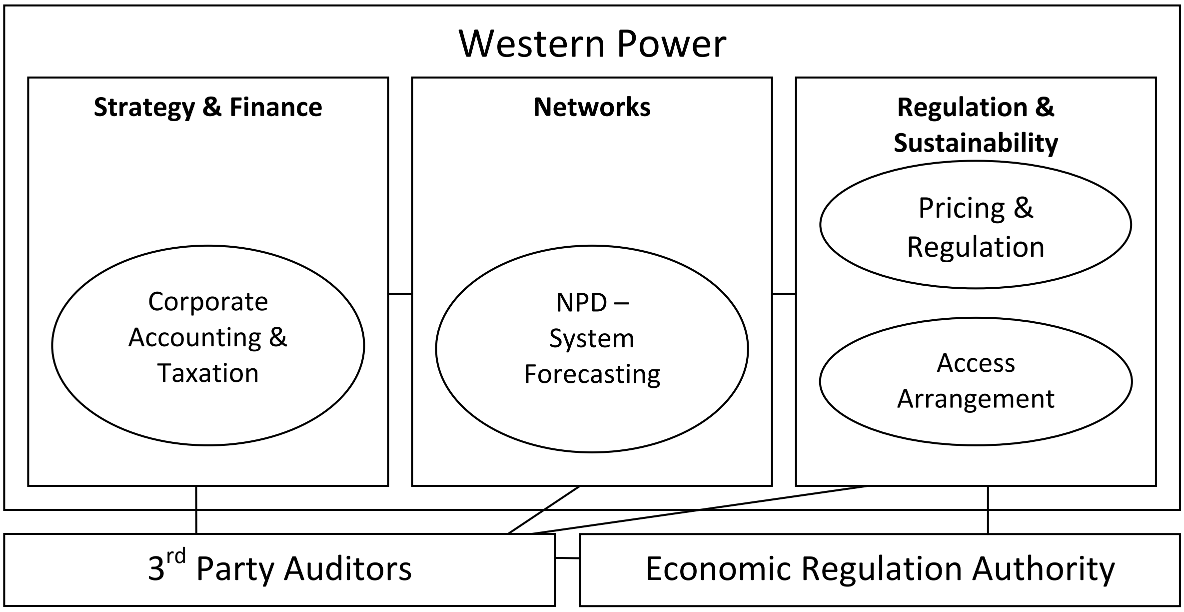


Figure 1: Internal and External Stakeholders

1.2 Network Tariffs

Tariff	MBS Codes	Description
RT1	AER AERP	Anytime Energy (Residential) Exit Service (Prepaid)
RT2	AEB	Anytime Energy (Business) Exit Service
RT3	TOUS	Time of Use Energy (Residential) Exit Service
RT4	TOUL	Time of Use Energy (Business) Exit Service
RT5	HVMD	High Voltage Metered Demand Exit Service
RT6	LVMD	Low Voltage Metered Demand Exit Service
RT7	HVCMD HVCMDZ	High Voltage Contract Maximum Demand Exit Service (Zone Substation Connected)
RT8	LVCMD	Low Voltage Contract Maximum Demand Exit Service
RT9		Street lighting Exit Service
RT10		Un-Metered Supplies Exit Service
RT11	DEN	Distribution Entry Service
RT12	TOUB	Time of Use (Residential) Bidirectional Service
TRT1	TREX	Transmission Exit Service
TRT2	TREN	Transmission Entry Service

Table 1: List of Network Tariffs

Western Power currently has 14 network tariffs, of which 10 are distribution export (consumption) tariffs, two are import (generation) tariffs and one is a bidirectional tariff. The bidirectional tariff (RT12) has never been used and all bidirectional customers currently use one of the export tariffs.

As part of the AA3 submission, Western Power has proposed the creation of four new tariffs specifically for bidirectional customers. These new tariffs will be exact replicas of RT1-RT4 in structure and pricing. At this point it is too premature to predict the acceptance and movements to these new tariffs and this report does not aim to specify the consumption volumes associated with the movements. Because the new tariffs will be identical to the existing four, such movements are immaterial to the total forecast.

As import (generation) tariffs, RT11 and TRT2 are not part of the scope of the forecasts and are therefore excluded.

In addition to network tariffs Western Power earns revenue from other services such as Firm Backup Capacity (FBC). FBC represents a standby capacity service (that is, usually a second feeder) with actual energy consumption reported against the respective network tariff. Including consumption against the FBC service would constitute ‘double counting’. Because it is primarily a demand service, consumption is deemed immaterial against total consumption per tariff and is therefore ignored for the purposes of forecasting.

2 Methodology

The Australian Energy Regulator (AER) has developed the following best practice energy forecasting principles, which Western Power strives to implement fully. The principles are listed below:

Forecasts should:

- be accurate and unbiased
- be transparent and repeatable
- incorporate all key drivers
- withstand scrutiny of models and assumptions
- use the most recent input information
- incorporate weather variability

Western Power is an active member in the Energy Networks Association (ENA) Forecasting Working Group for energy forecasting. Together the group aims to address the AER principles by developing best practice approaches and by identifying key considerations. The methodology proposed is expected to exemplify best practice as defined by this group.

2.1 Review

The Deloitte forecast submitted as part of Access Arrangement 3 is best described as an argument based economic / econometric model. Correlations were established between consumption trends and economic variables. Reputable economic forecasts were then used to derive forecasts of consumption and customer numbers. Since the Deloitte model was developed, Western Power has developed its systems considerably, making data available for complex analysis unachievable at the time of the original report.

System Forecasts aims to retain and enhance the model developed by Deloitte by:

- Retaining the macro-economic model of consumption
- Incorporating new research and learning, including:
  - An improved understanding of the customer network tariff changes that have occurred over the historically available data
  - An improved understanding of the impact of temperature and seasonality
- An improved understanding of the impact of changes in price DM# 8638340 (Study on Price & Income Elasticity in the Western Power Network)

- An improved understanding of the impact of PV's on the network DM# 7976363 (Photovoltaic Forecast)
- Any other new research that affects energy consumption
- Aggregating to the lower level of monthly consumption rather than annual consumption. (Can be rolled up to annual as required)
- Aggregating to the lower level of tariff rather than business classification.
- Present business classification forecasts from tariff forecasts.
- Consistently employing an econometric approach rather than argument based approach.
- Retain the use of reputable 3rd party macro-economic forecasts.

2.2 Data Sources

Available data sources for consumption and customer numbers include Metering Business System (MBS) Warehouse, NetCIS and PI. 2005 to current MBS Warehouse data has been made available and proven the most reliable source for energy data. NetCIS has proven most reliable for the type of customer number forecasts required.

For most tariffs, an accurate forecast can be derived from the analysis of historic metering information; however transmission and major customer tariffs require an understanding of discrete customer activity. System Forecasting already has a detailed understanding these activities for the purpose of peak demand forecasting.

Macro-economic data is often available from the Australian Bureau of Statistics (ABS) or the State Treasury (DTF). Macro-economic forecasts are available from multiple sources so the most reliable and consistent should be chosen.

Temperature is measured continuously at the East Perth Control Centre and is immediately available. For long-term weather, the Bureau of Meteorology has a station in Perth metropolitan area which can be compared to the temperature at East Perth.

2.3 Model

For each tariff, a low, central and high forecast has been developed using appropriate and transparent scenario planning. An econometric model has been selected and applied to historical data based on research already conducted, and the statistical significance of the model. The three forecasting scenarios have been applied to the model producing 60 months of consumption and customer number forecasts.

For each tariff, the following key drivers for consideration are:

- Temperature / Seasonality
- Gross State Product
- Price
- Market Intervention (ie PV's, curtailment)

The Central scenario includes the most probable future values for each of the variables included, whereas the Low and High scenarios can take values that are less probable.

2.4 Customer Groups

The process used for determining tariff pricing requires an understanding of peak demand relative to consumption. As such, pricing has developed a set of customer groups based on the peak demand of each customer. The customer list is presented below:

Transmission connected:

- Transmission Generation
- Transmission Loads

Distribution connected:

- High Voltage >1 MVA maximum demand
- High Voltage <1 MVA maximum demand
- Low Voltage >1 MVA maximum demand
- General Business Large (300-1,000 kVA maximum demand)
- General Business Medium (100-300 kVA maximum demand)
- General Business Small (15-100 kVA maximum demand)
- Small Business (<15 kVA maximum demand)
- Residential
- Streetlights
- Unmetered Supplies

For each tariff, the make up of customer groups is presented, including a forecast derived from the tariff forecast. Where appropriate other relevant metrics to the tariff are included. All load factor forecasts assume a power factor of 0.9.

2.5 Adjustments

Customer movements between tariffs have the ability to skew the trends within the customer numbers and consumption data. In some cases there are reliable trends within the movements whereby customers will move from one tariff month by month in a dependable way. Most cases however are the result of structural adjustments of the tariffs by either Western Power or a retailer and have been removed prior to analysis. In some cases, post analysis adjustments may also be required to include any expected customer movements.

Months have different number of days which reduces the predictive capacity of the model if not addressed. The regression model therefore includes average daily consumption per month as the dependant variable instead of total consumption per month. The regression output can then be multiplied by the number of days in the month to return it to a total monthly forecast.

For detail on the operational implementation of the adjustments and the model please refer to DM# 6296884 (System Forecasting Section - Operation Manual)

3 Annual Implementation

Official energy forecasts will be released annually by March, to coincide with the annual pricing review. They include a minimum of 60 month forecasts for each export (consumption) tariff expected to be used during the relevant financial years.

The forecasts released annually will include:

- Scenario inputs and data sources
- Model inputs, coefficients and significance per tariff
- Forecast future energy consumption by month as well as annual summaries
- Forecast customer connections by month as well as annual summaries
- Forecast 'energy consuming customers' (connected retail customers with consumption > 0) by month as well as annual summaries
- Comparison to IMO and previous forecasts
- Commentary on variances, changes and emerging issues

Forecasts will also available in tabular format: DM# 8785338 (Energy and Customer Number Forecasts - Spreadsheet Output)

4 Explanatory Variables

For each tariff, the following key drivers are considered:

- Temperature / Seasonality
- Gross State Product
- Price
- Market Intervention (ie PV's, Curtailment)

To incorporate the drivers, the following variables may be included as appropriate

- TEMP_C – Mean Monthly Temperature (As observed at EPCC)
    - o To capture a cooling response to heat
- TEMP_C_SQ – Mean Monthly Temperature Squared
    - o To capture a polynomial response to both heat and cool
- GSP_C – Gross State Product
- PR_DUM – A Dummy variable (0 in Nov – Apr, 1 in May – Oct)
- PR_DUM_RES_C – The Price Dummy multiplied by Residential Unit Price
    - o To capture a winter only response to price
- PR_BUS_C – The Business Unit Price
- INDEX – An index variable for where macro-economic variables cannot explain consumption trends
- PVMW_C – The approved MW capacity of PV's in the network
- const – The intercept

In the recent regulatory submission (AA3), and WACC calculation Western Power used a variable inflation rate with a geometric mean of 2.7%. In all analysis used for energy and customer number forecasting, a long term fixed inflation rate of 2.75% has been selected.

4.1 Scenario Design

Three scenarios have been developed to designate 'low', 'central' and 'high' forecasts. The variables specified in each scenario are listed below:

Variable	Low	Central	High
Summer Temperature	80 PoE	50 PoE	20 PoE
Autumn Temperature	50 PoE	50 PoE	50 PoE
Winter Temperature	20 PoE	50 PoE	80 PoE
Spring Temperature	50 PoE	50 PoE	50 PoE
GSP Growth	3.5% p.a.	4% p.a. [1]	4.5% p.a.
2012/13 Price Growth[5]	12% + Carbon Tax[3]	5%[2] + Carbon Tax[3]	5%
2013/14 Price Growth[5]	12% + Carbon Tax[3]	12%[2] + Carbon Tax[3]	5%
2014/15 Price Growth[5]	12% + Carbon Tax[3]	12%[2] + Carbon Tax[3]	5%
2015/16 Price Growth[5]	12% + Carbon Tax[3]	5% + Carbon Tax[3]	5%
2016/17 Price Growth[5]	12% + Carbon Tax[3]	5% + Carbon Tax[3]	5%
PV Uptake[5]	3000 applications p/Month[4]	1500 applications p/Month[4]	1000 applications p/Month[4]

PoE Probability of Exceedance
1 As per Department of Treasury and Finance Forecast
2 As per assumed price glide path in WA State Budget
3 100% price pass through of federal treasury modelled carbon price / MWh
4 As per DM# 7976363 (Photovoltaic Forecast) – updated to current data – Central case revised downward to 1,500 applications per month.
5 High values are used in the 'low' scenario and low values in the 'high' scenario because PV's and price are negatively correlated with consumption.

Table 2: Assumptions used for Scenario Design

The following charts plot the historic and future values for the explanatory variables over the study period.

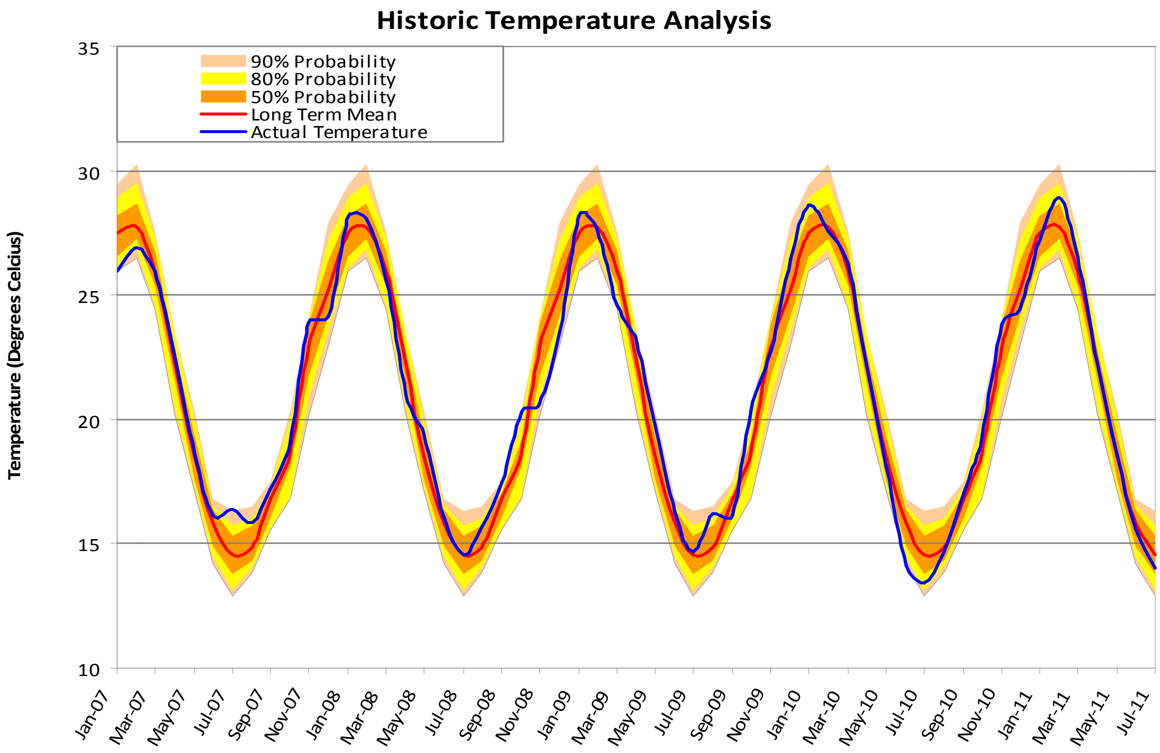


Figure 2: Analysis of Observed Mean Monthly Temperature

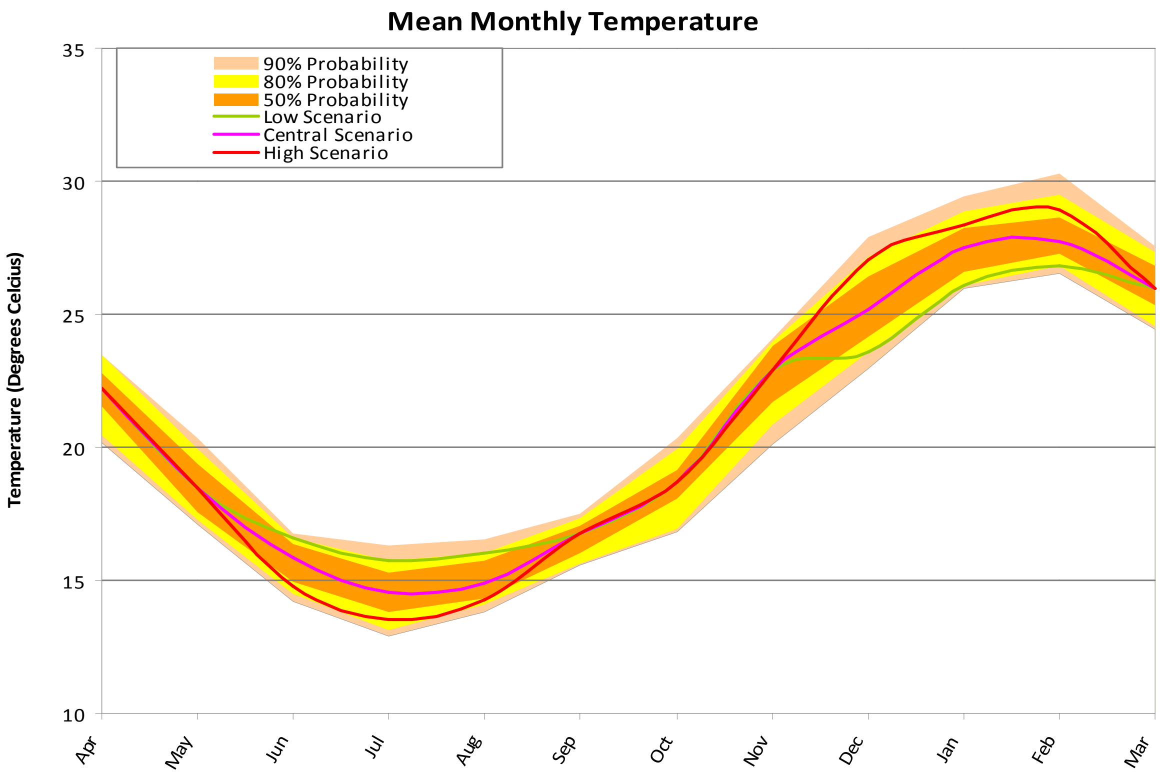


Figure 3: Forecast Mean Monthly Weather

Figure 4: Forecast Residential Retail A1 Unit Price

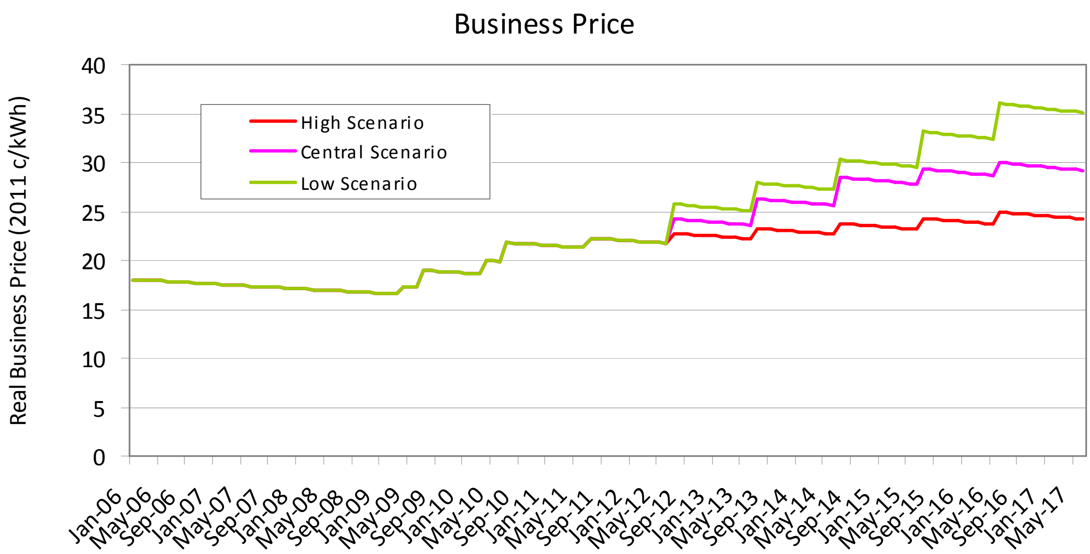


Figure 5: Forecast Business Retail L1 Unit Price

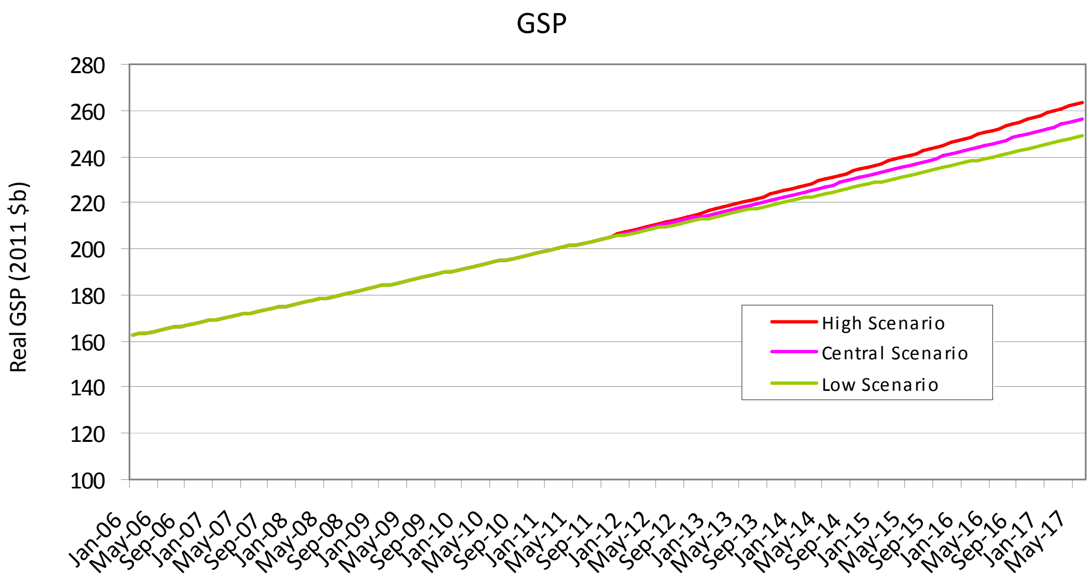


Figure 6: Forecast GSP

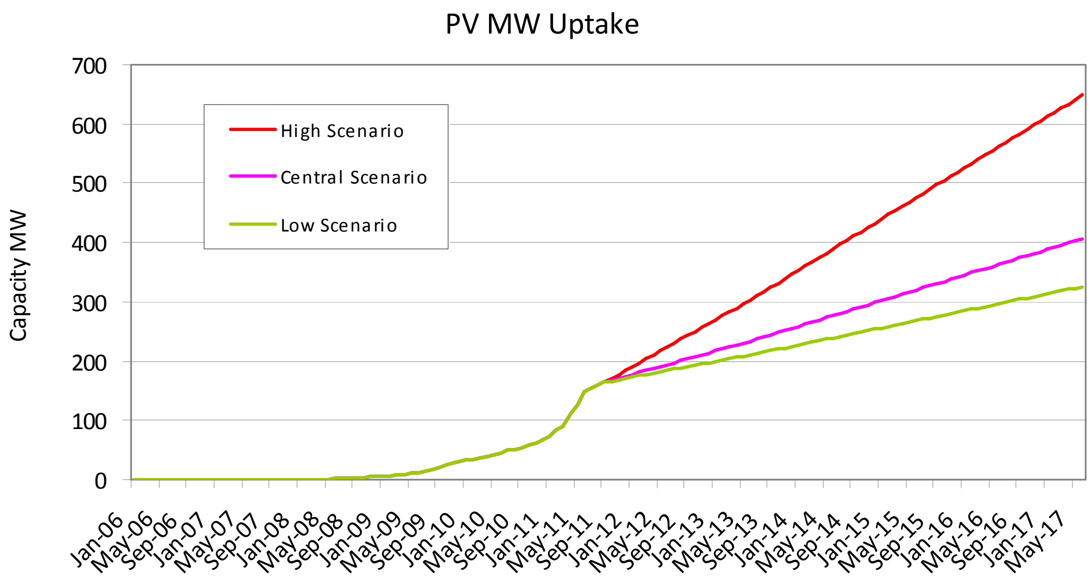


Figure 7: Forecast Photovoltaic Uptake

5 RT1 – Anytime Energy Residential

This network tariff is appropriate for the majority of residential customers and currently includes over 850,000 consumers. This tariff is the default tariff for most customers so it is affected by many customer transfers. The effects of these tariff movements are visible in the difference between actual and adjusted consumption. As with all tariffs, the regression is conducted on the adjusted figures to remove the impact of customer reclassification and incorrect placement. Unlike other tariffs however RT1 has a predictable trend within the tariff movements; approximately 105 customers reliably move to RT3 monthly. These estimated customers are expected to continue to move to RT3 and are therefore removed after modelling.

The model for total consumption on this tariff follows:

```
OLS, using observations 2006:01-2011:06 (T = 66)
Dependent variable: RT1_DAILY
HAC standard errors, bandwidth 3 (Bartlett kernel)

                coefficient     std. error      t-ratio p-value
  -----------------------------------------------------------------
  const          2.14132e+07    1.96763e+06     10.88   9.83e-016 ***
  GSP_C          102.778        8.68831         11.83   3.28e-017 ***
  PVMW_C         -7145.74       3232.58         -2.211  0.0310    **
  PR_DUM         4.42960e+06    845811          5.237   2.28e-06  ***
  PR_DUM_RES_C  -275532         48075.2         -5.731  3.59e-07  ***
  TEMP_C         -2.59952e+06   158788          -16.37  1.31e-023 ***
  TEMP_C_SQ      60891.7        3715.87         16.39   1.25e-023 ***

R-squared            0.883958   Adjusted R-squared   0.872157
F(6, 59)             61.65076   P-value(F)           1.39e-23
```

Figure 8: RT1 Consumption Regression Output

The model for customer numbers is as follows:

```
OLS, using observations 2006:01-2011:06 (T = 66)
Dependent variable: RT1_CUSTOMER
HAC standard errors, bandwidth 3 (Bartlett kernel)

                    coefficient     std. error    t-ratio     p-value
  -----------------------------------------------------------------
  const         275671       8792.82      31.35    1.48e-040  ***
  GSP_C         2.91308      0.0485199    60.04    5.42e-058  ***

R-squared            0.990084   Adjusted R-squared   0.989929
F(1, 64)             3604.667   P-value(F)           5.42e-58
```

Figure 9: RT1 Customers Regression Output

5.1 Comments

The models reveal a great deal about residential consumption in WA. Firstly, the PVMW_C coefficient reveals that 7.145MWh of daily energy reduction is associated with every MW of PV capacity in the network. Given that PV's can generate energy for approximately 8 hours per day this values fits expectation. The three forecasts differ significantly given the potentially large uptake of PV's

A study on the impact of price elasticity per month was conducted that indicated that residential customers have responded to price during winter only. It is expected that price will affect consumption during summer also, but has been excluded from this model due to the lack of observable evidence. The annual model presented in the study suggested that price elasticity was -0.1. The price variable is Figure 8 indicates that during winter, WA domestic consumers have a price elasticity of -0.4. Because these price elasticity coefficients are calculated via correlation, they do not imply immediate causation; only that medium term increases in price have been negatively associated with medium term decreases in consumption.

RT1 customers have been growing reliably at 20,000 new energy consuming customers per year, which has a strong correlation to GSP in WA. This trend is expected to continue. The GSP coefficient implies an income elasticity of 1.5222.

An estimate of customer connections was taken from NetCIS billing data. The data revealed that there were approximately 29,000 more connected properties than there were consuming customers, implying 3.4% of available housing is unoccupied or inactive. The customer connection forecast assumes that 3% of available properties will remain unoccupied or inactive in the future.

5.2 Energy Consumption

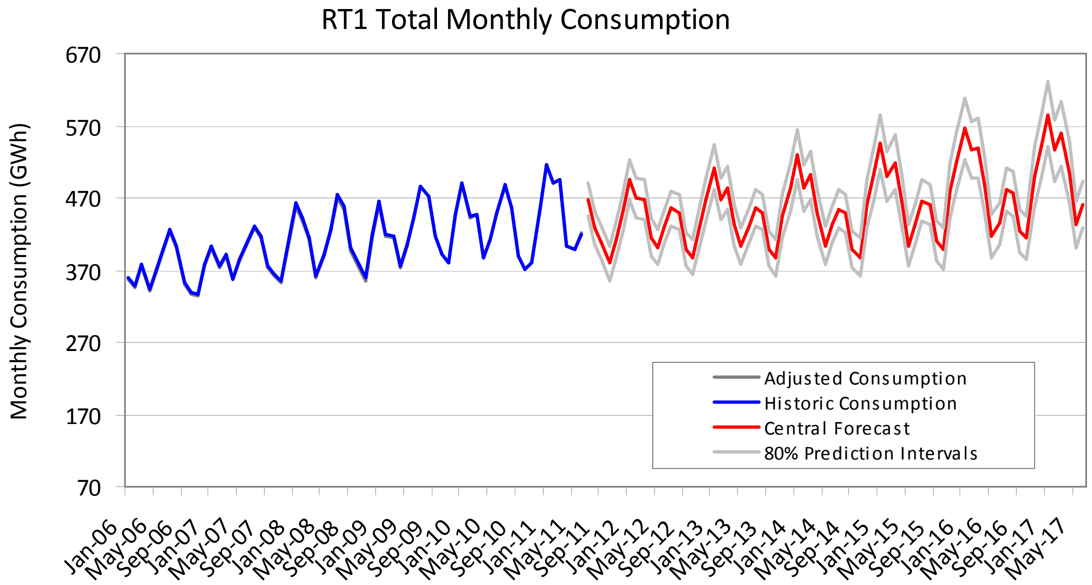


Figure 10: RT1 Monthly Consumption Central Forecast

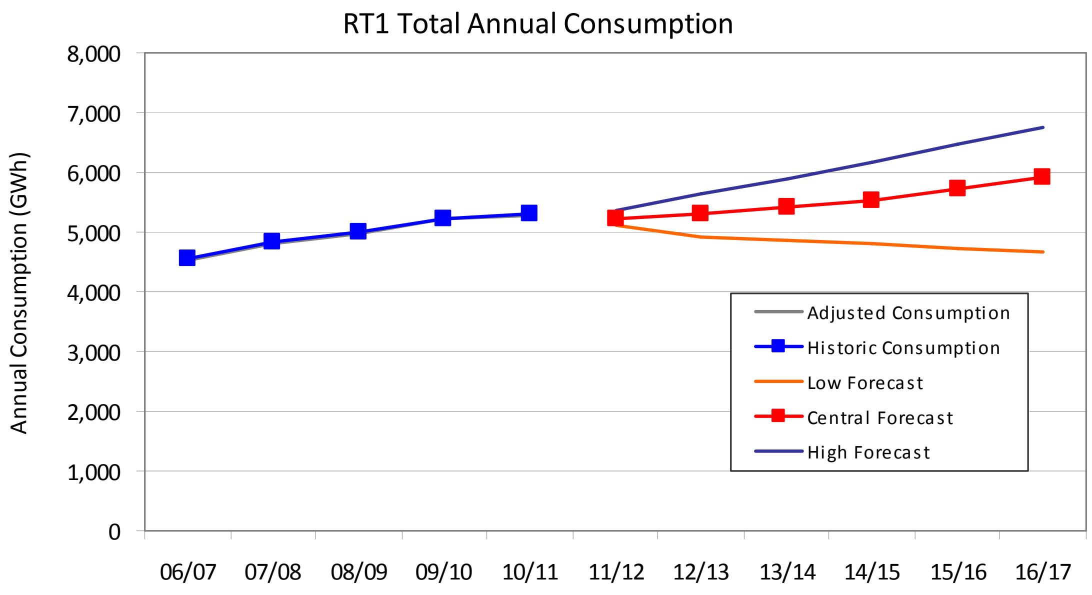


Figure 11: RT1 Annual Consumption Forecast

Gwh	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	4,548	4,839	4,999	5,221	5,293	0	0	0	0	0	0
Adjusted	4,521	4,804	4,961	5,216	5,291	0	0	0	0	0	0
Low	0	0	0	0	0	5,098	4,924	4,870	4,807	4,719	4,670
Central	0	0	0	0	0	5,227	5,319	5,422	5,524	5,715	5,917
High	0	0	0	0	0	5,362	5,643	5,899	6,169	6,466	6,757

Table 3: RT1 Consumption Forecast

5.3 Customer Numbers

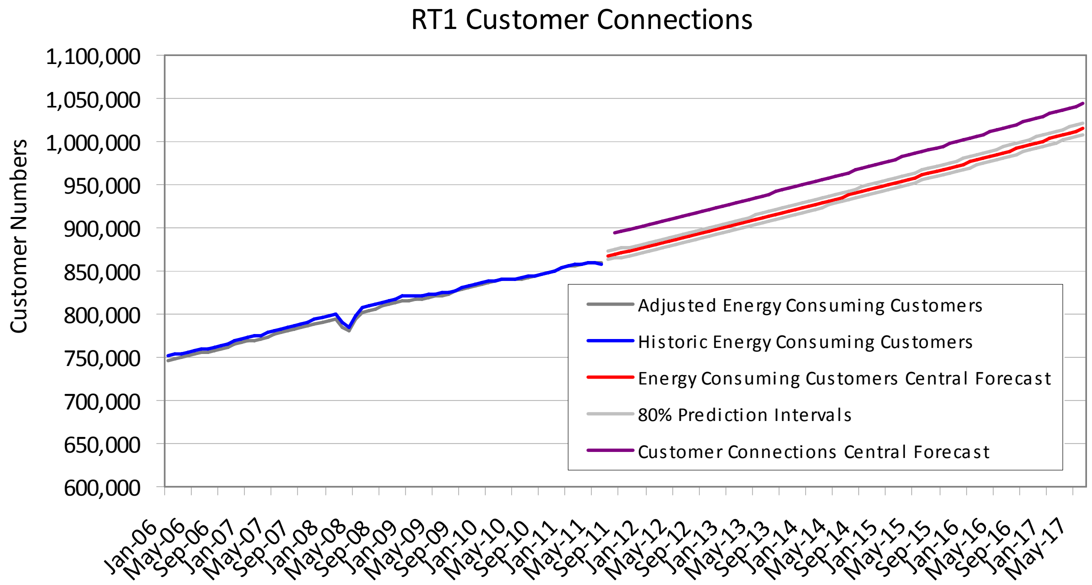


Figure 12: RT1 Monthly Customer Numbers Central Forecast

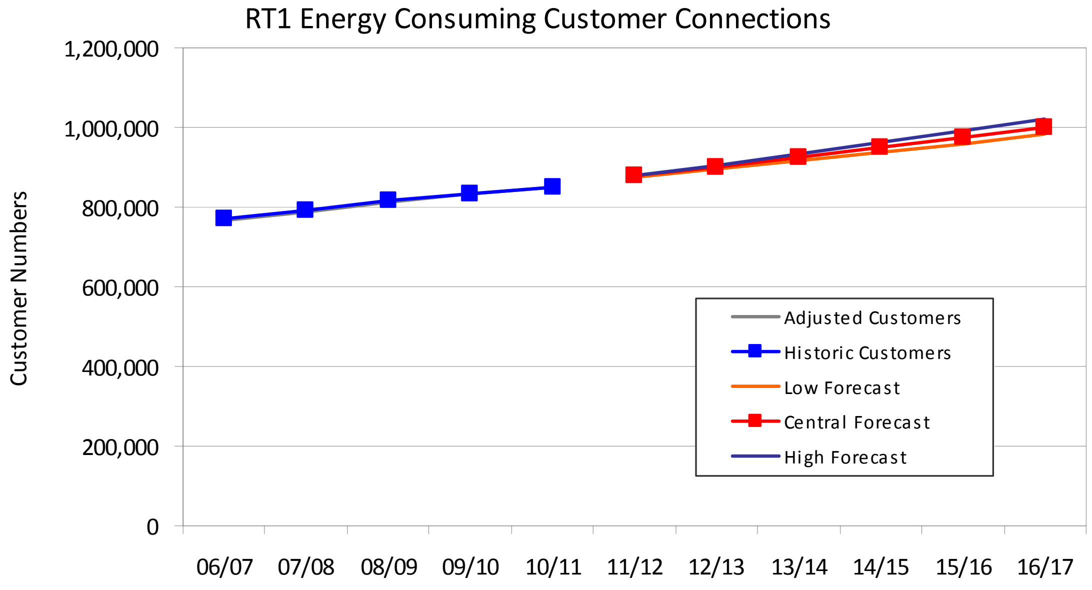


Figure 13: RT1 Annual Customer Numbers Forecast

Thousand Customers	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	769	791	817	834	851	0	0	0	0	0	0
Adjusted	765	787	813	833	851	0	0	0	0	0	0
Low	0	0	0	0	0	876	896	917	938	960	983
Central	0	0	0	0	0	878	901	924	949	975	1,002
High	0	0	0	0	0	879	905	932	961	990	1,021
Connections	0	0	0	0	0	905	928	953	978	1,005	1,033

Table 4: RT1 Customer Number Forecast

5.4 Consumption per Customer

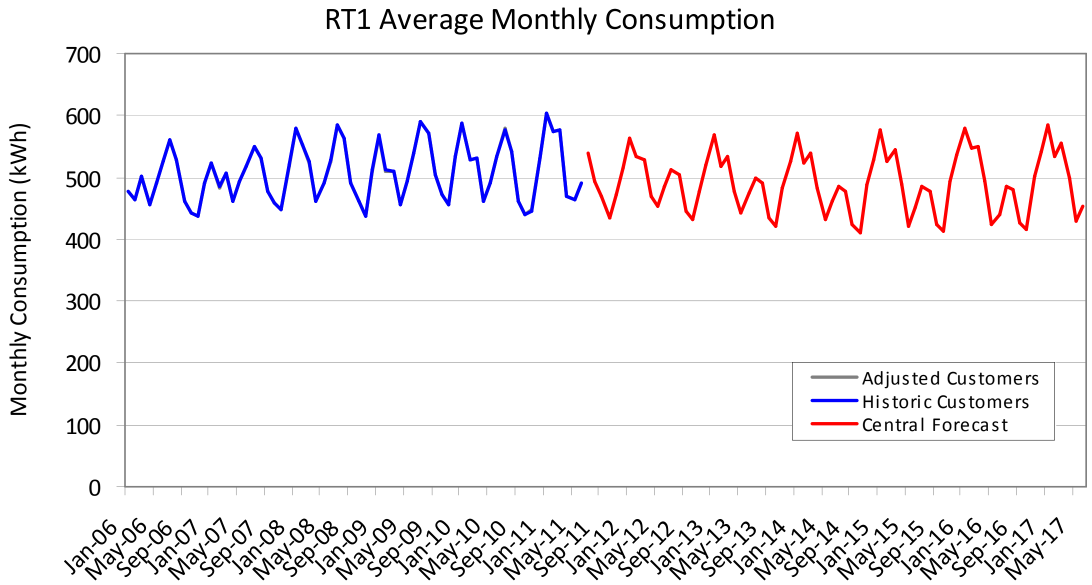


Figure 14: RT1 Monthly Consumption per Customer Central Forecast

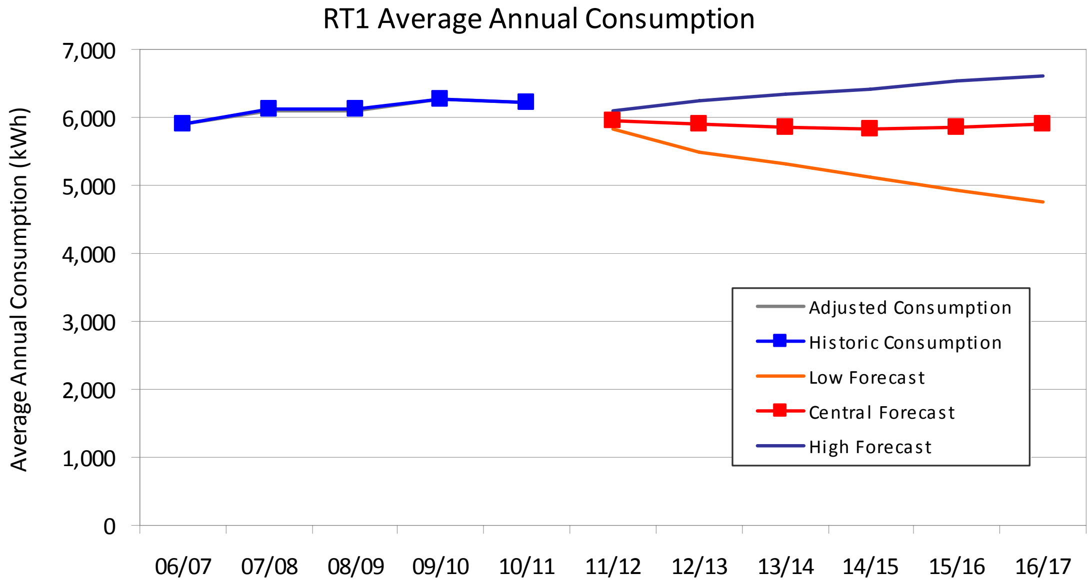


Figure 15: RT1 Annual Consumption per Customer Forecast

kWh	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	5,912	6,113	6,117	6,261	6,217	0	0	0	0	0	0
Adjusted	5,911	6,108	6,106	6,265	6,218	0	0	0	0	0	0
Low	0	0	0	0	0	5,818	5,495	5,312	5,125	4,915	4,751
Central	0	0	0	0	0	5,956	5,907	5,866	5,820	5,861	5,905
High	0	0	0	0	0	6,100	6,236	6,330	6,423	6,529	6,616

Table 5: RT1 Consumption per Customer Forecast

5.5 Customer Groups

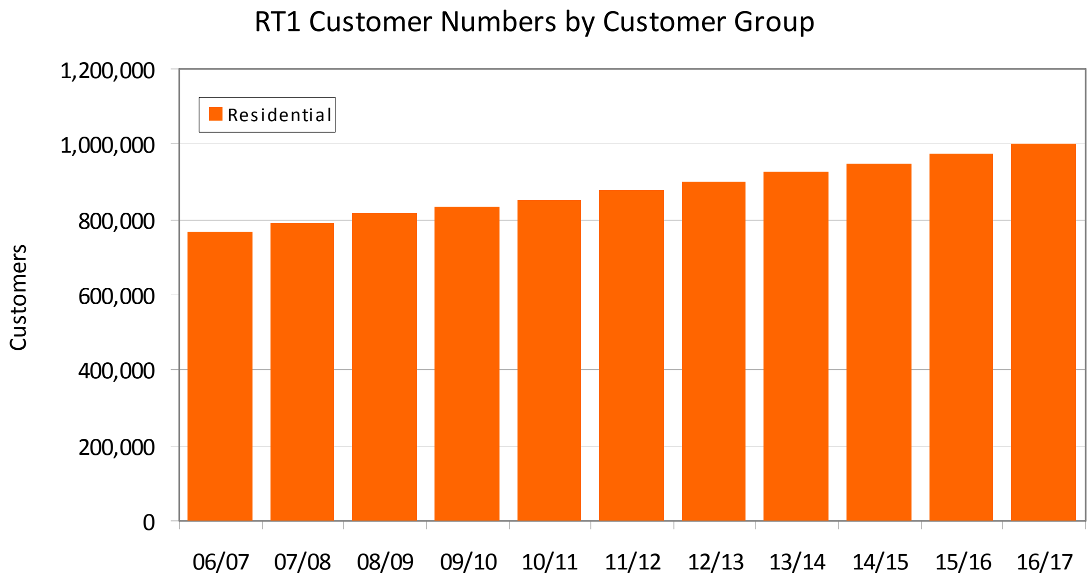


Figure 16: RT1 Annual Consumption by Customer Group

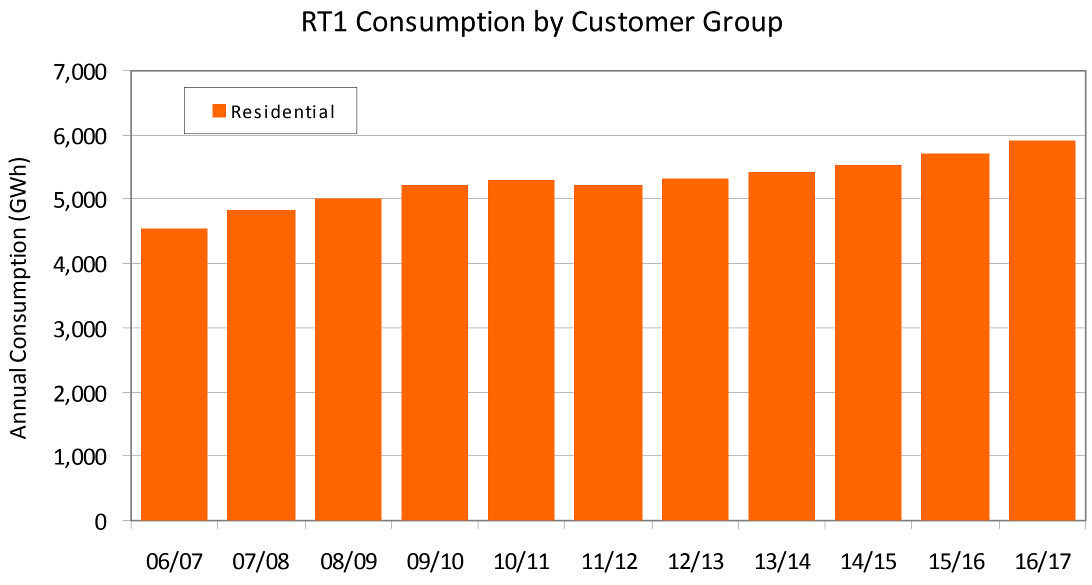


Figure 17: RT1 Annual Customer Numbers by Customer Group

6 RT2 – Anytime Energy Business

This network tariff is appropriate for small sized companies and currently includes 85,000 consumers. This tariff is the default tariff for most business customers so is consequently affected by many customer transfers. The major transfers are listed below:

- Recent years have been inflated by some larger customers now on tariff RT4.
- Early years (Before Sept 09) were deflated by many small customers that were on tariff RT1. They are all now on RT2 and have been stable for 2 years.
- The months March – June 2011 are inflated by two transmission connected customers incorrectly placed on this tariff. It is expected that these customers will be returned to TRT1 in due course.

The effects of these tariff movements are visible in the difference between actual and adjusted consumption. No reliable trends are evident in customer movements therefore no post model adjustments have been made.

The model for total consumption on this tariff follows:

```
OLS, using observations 2006:01-2011:06 (T = 66)
Dependent variable: RT2_DAILY
HAC standard errors, bandwidth 3 (Bartlett kernel)

                coefficient      std. error   t-ratio   p-value
  -------------------------------------------------------------
  Const             3.46460e+06 397237        8.722     2.55e-012 ***
  GSP_C             21.0330     2.07046       10.16     9.73e-015 ***
  PR_BUS_C          -56442.1    16421.1       -3.437    0.0011    ***
  TEMP_C            -259125     31006.7       -8.357    1.07e-011 ***
  TEMP_C_SQ         7043.67     790.014       8.916     1.19e-012 ***

R-squared            0.833038   Adjusted R-squared   0.822090
F(4, 61)             43.89752   P-value(F)           2.63e-17
```

Figure 18: RT2 Consumption Regression Output

The model for customer numbers is as follows:

```
OLS, using observations 2006:01-2011:06 (T = 66)
Dependent variable: RT2_CUSTOMERS
HAC standard errors, bandwidth 3 (Bartlett kernel)

              coefficient     std. error     t-ratio    p-value
  -------------------------------------------------------------
  const       68535.1         3045.83       22.50       4.21e-032 ***
  GSP_C       0.0830937       0.0163120     5.094       3.33e-06  ***

R-squared            0.560625   Adjusted R-squared   0.553760
F(1, 64)             25.94893   P-value(F)           3.33e-06
```

Figure 19: RT2 Customers Regression Output

6.1 Comments

Although there are some PV's on this network tariff, they are negligible against the total energy consumption and were consequently statistically insignificant.

The price coefficient is for an annual response to price and implies an elasticity of -0.29. Conversely the GSP coefficient implies an income elasticity of 1.02.

This tariff has customer number history that is more volatile than others. The ABS has presented GSP figures that are quite smooth; therefore this volatility is not correlated with GSP. This tariff however lost approximately 2,000 customers in 2008 -2009 during the global financial crisis (GFC). The impact of the GFC is not visible in energy consumption, indicating that the customers that were lost were some of the smaller in this tariff. Customer numbers are currently higher than pre-GFC levels.

An estimate of 88,744 customer connections during 10/11 financial year was taken from NetCIS, implying a vacancy rate of approximately 4%. The customer connection forecast assumes an ongoing vacancy rate of 4%.

6.2 Energy Consumption

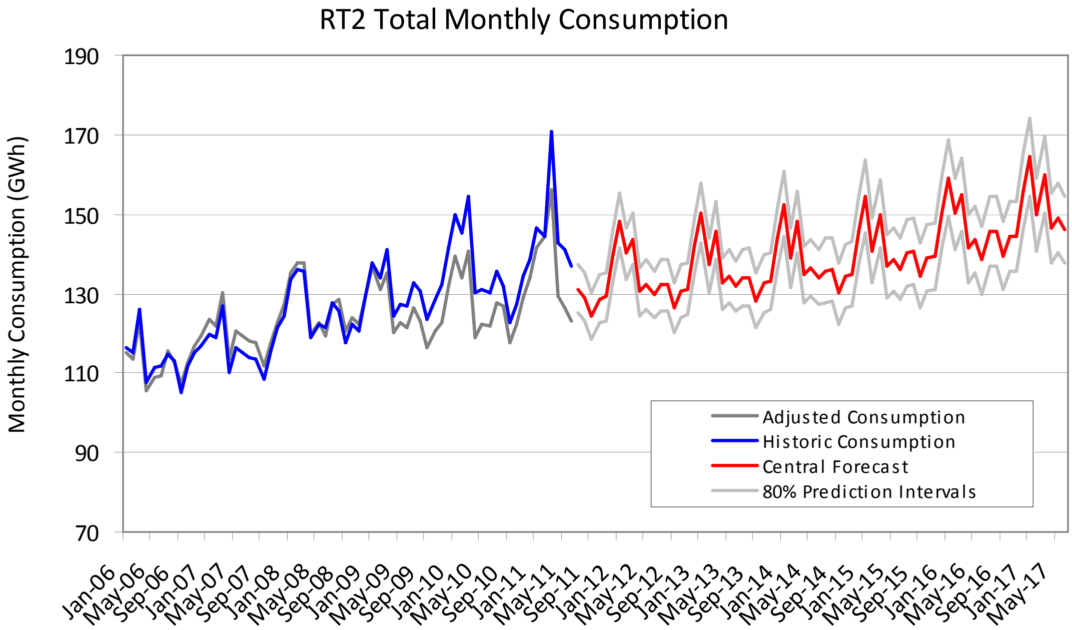


Figure 20: RT2 Monthly Consumption Central Forecast

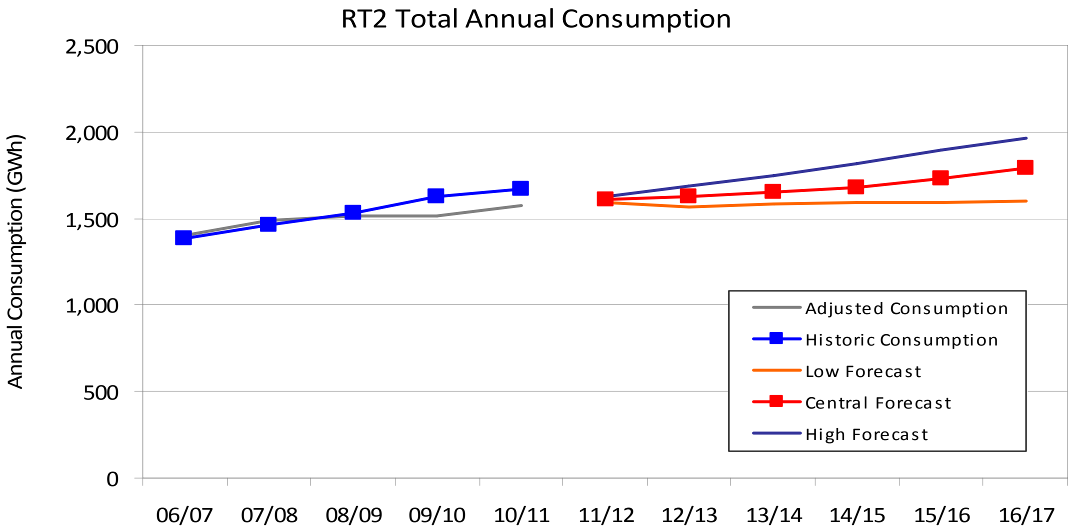


Figure 21: RT2 Annual Consumption Forecast

Gwh	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	1,380	1,459	1,530	1,627	1,666	0	0	0	0	0	0
Adjusted	1,403	1,488	1,517	1,517	1,577	0	0	0	0	0	0
Low	0	0	0	0	0	1,590	1,568	1,581	1,591	1,594	1,601
Central	0	0	0	0	0	1,607	1,627	1,651	1,674	1,731	1,791
High	0	0	0	0	0	1,626	1,686	1,751	1,819	1,894	1,965

Table 6: RT2 Consumption Forecast

6.3 Customer Numbers

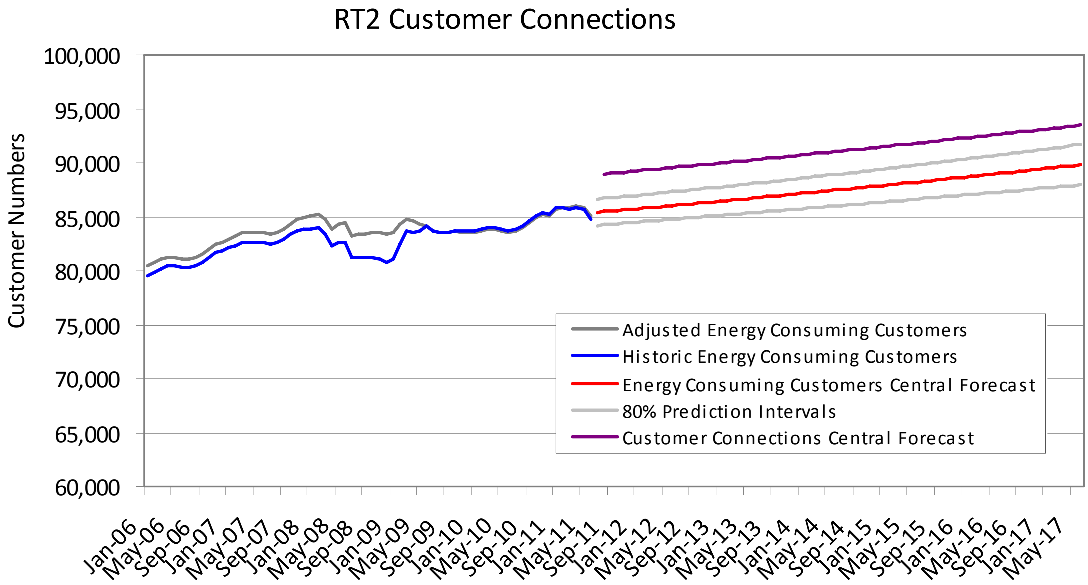


Figure 22: RT2 Monthly Customer Numbers Central Forecast

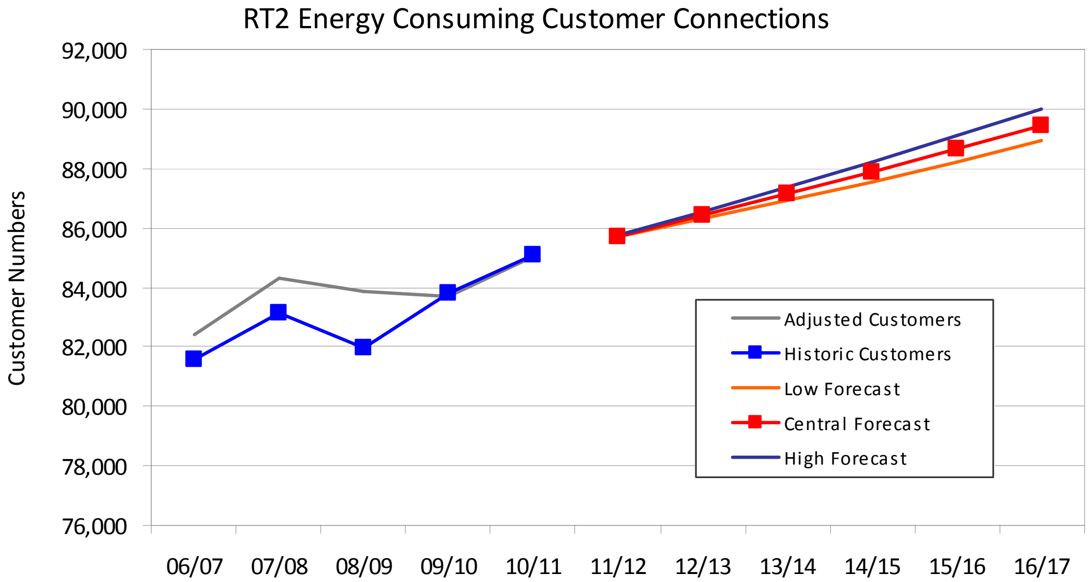


Figure 23: RT2 Annual Customer Numbers Forecast

Customers	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	81,580	83,136	81,963	83,793	85,075	0	0	0	0	0	0
Adjusted	82,400	84,307	83,863	83,690	85,022	0	0	0	0	0	0
Low	0	0	0	0	0	85,687	86,288	86,909	87,552	88,218	88,907
Central	0	0	0	0	0	85,726	86,414	87,129	87,873	88,646	89,451
High	0	0	0	0	0	85,765	86,540	87,350	88,197	89,082	90,006
Connections	0	0	0	0	0	89,298	90,014	90,759	91,534	92,340	93,178

Table 7: RT2 Customer Number Forecast

6.4 Consumption per Customer

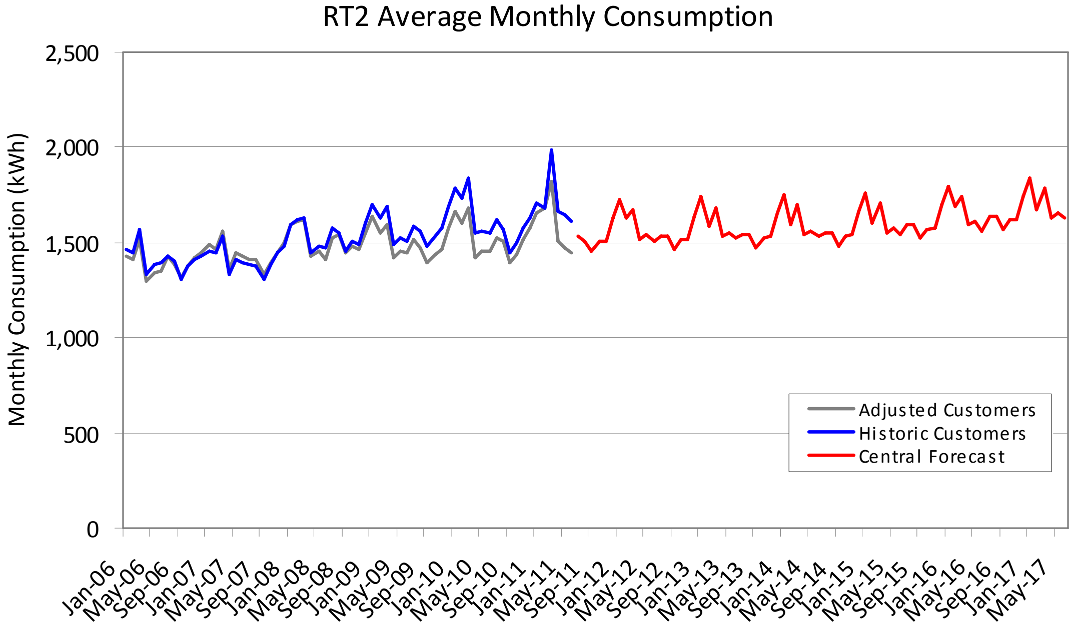


Figure 24: RT2 Monthly Consumption per Customer Central Forecast

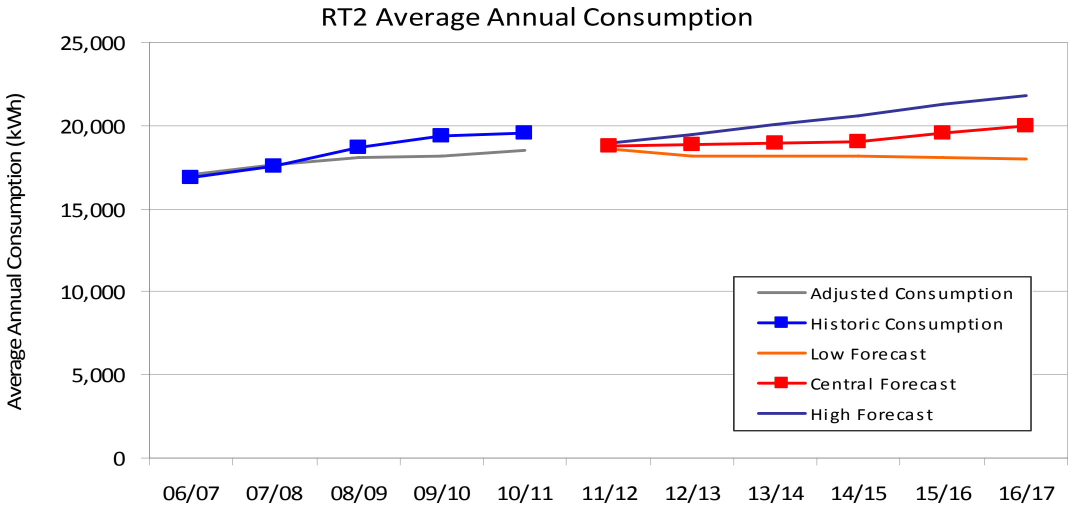


Figure 25: RT2 Annual Consumption per Customer Forecast

kWh	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	16,911	17,543	18,667	19,415	19,576	0	0	0	0	0	0
Adjusted	17,021	17,641	18,087	18,129	18,543	0	0	0	0	0	0
Low	0	0	0	0	0	18,558	18,170	18,187	18,176	18,064	18,012
Central	0	0	0	0	0	18,746	18,824	18,947	19,050	19,531	20,020
High	0	0	0	0	0	18,963	19,487	20,047	20,623	21,259	21,828

Table 8: RT2 Consumption per Customer Forecast

6.5 Customer Groups

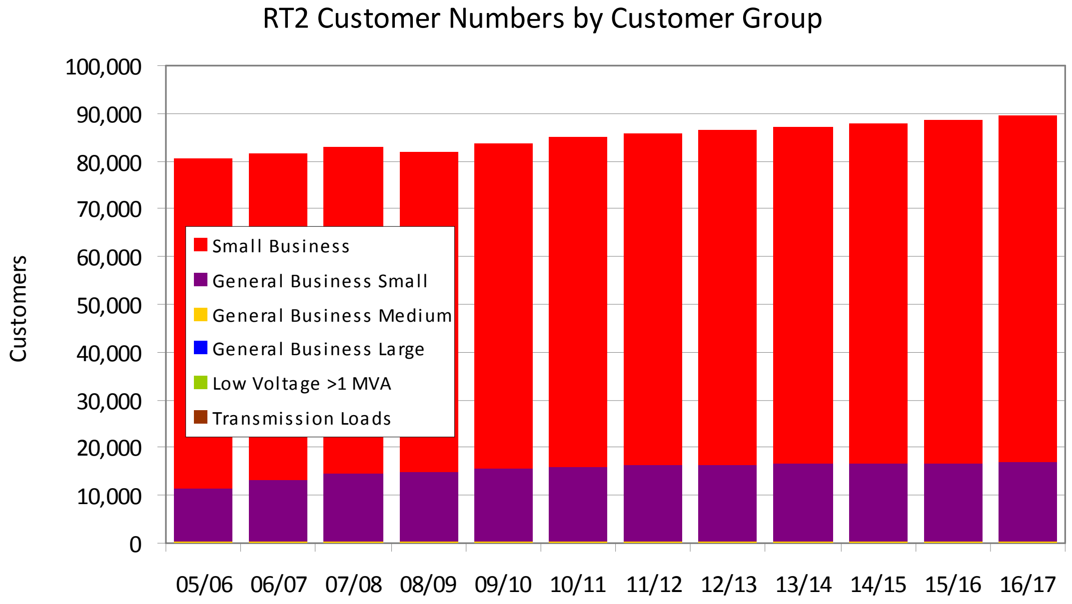


Figure 26: RT2 Annual Consumption by Customer Group

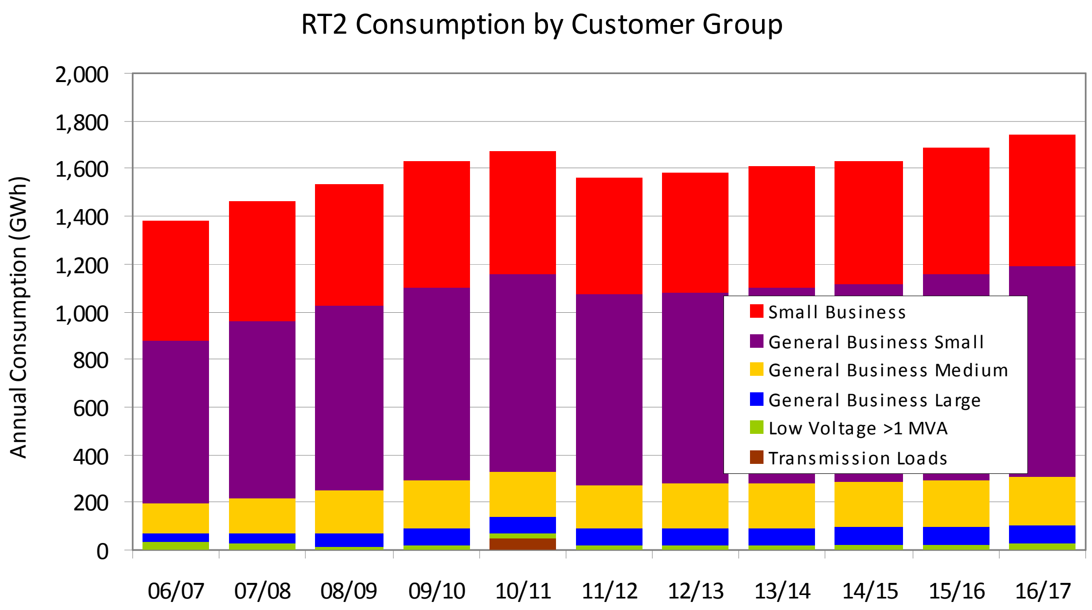


Figure 27: RT2 Annual Customer Numbers by Customer Group

7 RT3 – Time of Use Residential

This network tariff is appropriate for some residential customers and currently includes over 20,000 consumers. This tariff has been reclassified multiple times leading to the movement of customers on and off this tariff, particularly with RT4. The effects of these tariff movements are visible in the difference between actual and adjusted consumption. As noted in RT1, 105 customers have been moving to RT3 reliably since 2008. The forecast assumes that 105 customer per month will continue to move from RT1 to RT3 and will have consumption similar to that of an average RT3 customer.

The model for total consumption on this tariff follows:

```
OLS, using observations 2006:01-2011:06 (T = 66)
Dependent variable: RT3_DAILY
HAC standard errors, bandwidth 3 (Bartlett kernel)

               coefficient    std. error    t-ratio    p-value
  -----------------------------------------------------------------
  Const          814304       112435         7.242     9.65e-010 ***
  GSP_C          2.90770      0.501400       5.799     2.65e-07  ***
  PR_DUM_RES_C   -7127.75     2198.04       -3.243     0.0019    ***
  PR_DUM         103820       40971.5        2.534     0.0139    **
  TEMP_C         -86624.7     6221.26       -13.92     1.88e-020 ***
  TEMP_C_SQ      2040.20      147.209        13.86     2.33e-020 ***

R-squared            0.781651   Adjusted R-squared   0.763455
F(5, 60)             55.61203   P-value(F)           2.96e-21
```

Figure 28: RT3 Consumption Regression Output

The model for customer numbers is as follows:

```
OLS, using observations 2006:01-2011:06 (T = 66)
Dependent variable: RT3_ADJ_CUSTOME
HAC standard errors, bandwidth 3 (Bartlett kernel)

           coefficient    std. error    t-ratio    p-value
  -----------------------------------------------------------
  const     5888.12       462.441       12.73       3.35e-019 ***
  GSP_C     0.0707954     0.00249299    28.40       5.49e-038 ***

R-squared            0.967521   Adjusted R-squared   0.967014
F(1, 64)             806.4354   P-value(F)           5.49e-38
```

Figure 29: RT3 Customers Regression Output

7.1 Comments

Although there are some PV's on this network tariff, they are negligible against the total energy consumption and were consequently statistically insignificant.

The price variable is Figure 28 indicates that during winter, WA domestic consumers on RT3 have a price elasticity of -0.29. Because these price elasticity coefficients are calculated via correlation, they do not imply immediate causation; only that medium term increases in price have been negatively associated with medium term decreases in consumption.

RT3 customers have been growing reliably at 500 new customers per year, which has a strong correlation to GSP in WA. In addition to this 500 customers per year of natural growth, 1260 customer are moved to this tariff from RT1. This trend is expected to continue. The GSP coefficient implies an income elasticity of 0.99.

An estimate of 20,929 customer connections during 10/11 financial year was taken from NetCIS, implying a vacancy rate of approximately 7%. The customer connection forecast an ongoing vacancy rate of 7%.

7.2 Energy Consumption

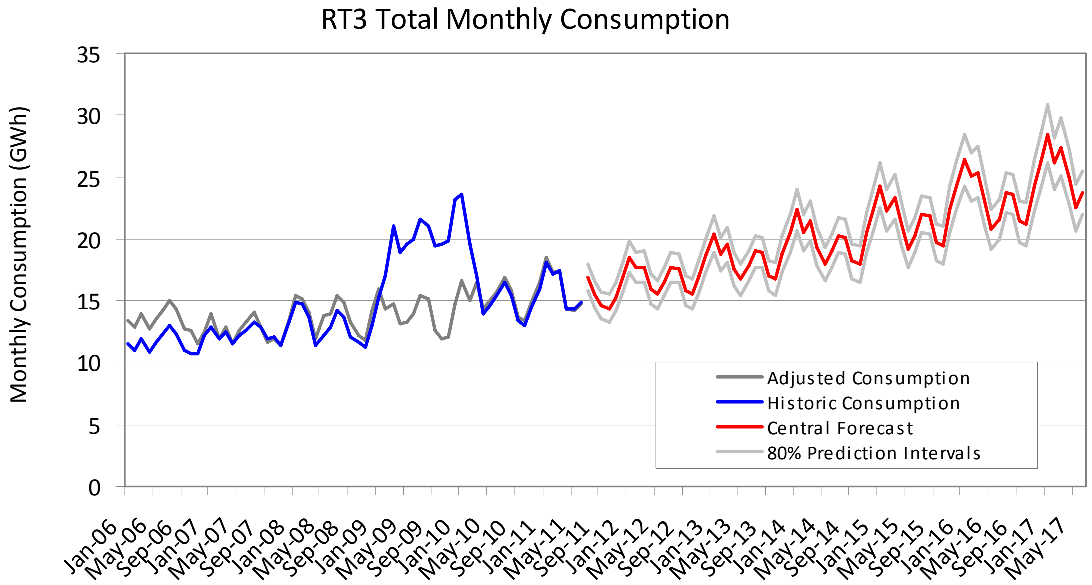


Figure 30: RT3 Monthly Consumption Central Forecast

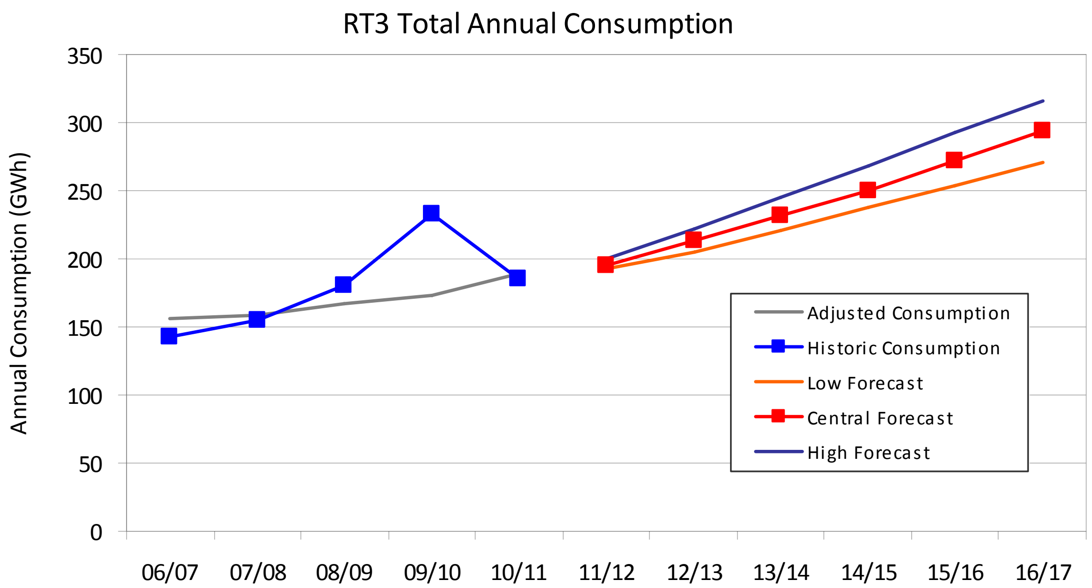


Figure 31: RT3 Annual Consumption Forecast

Gwh	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	143	154	181	233	186	0	0	0	0	0	0
Adjusted	156	159	167	173	189	0	0	0	0	0	0
Low	0	0	0	0	0	192	205	221	238	254	270
Central	0	0	0	0	0	196	213	232	250	272	294
High	0	0	0	0	0	200	222	245	268	292	316

Table 9: RT3 Consumption Forecast

7.3 Customer Numbers

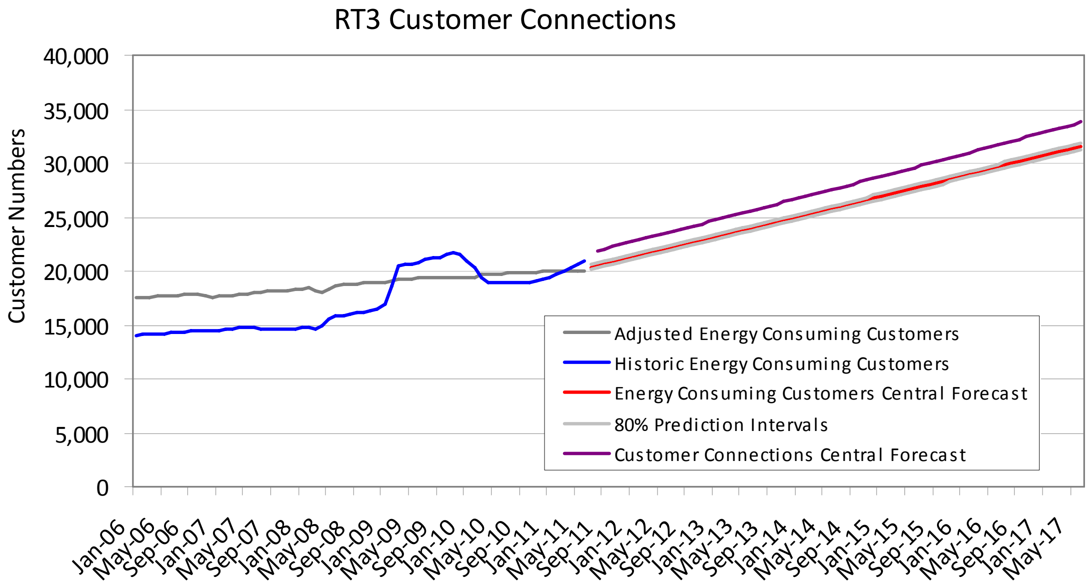


Figure 32: RT3 Monthly Customer Numbers Central Forecast

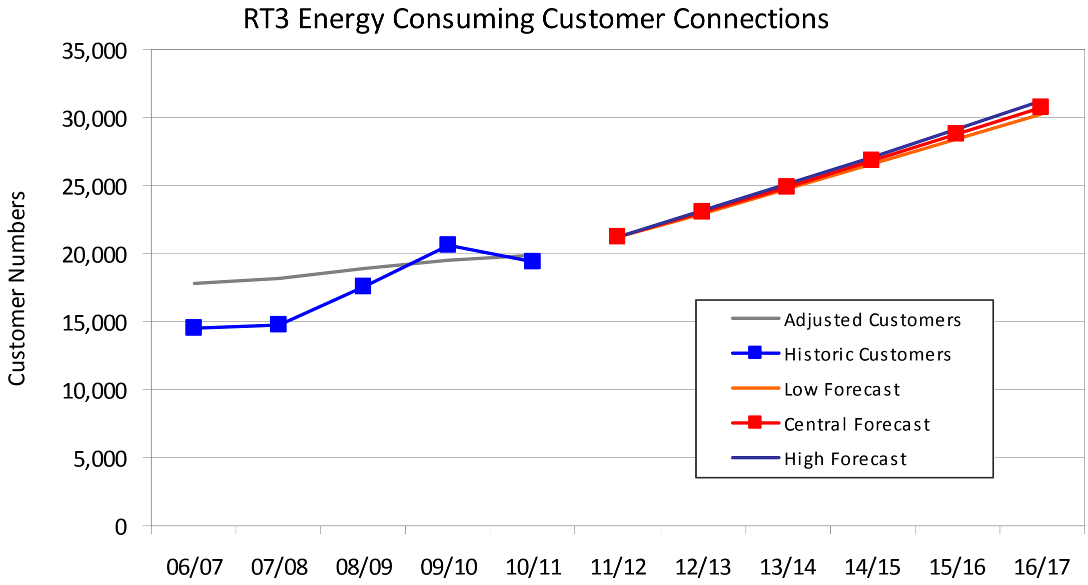


Figure 33: RT3 Annual Customer Numbers Forecast

Customers	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	14,510	14,790	17,514	20,623	19,419	0	0	0	0	0	0
Adjusted	17,759	18,172	18,956	19,477	19,889	0	0	0	0	0	0
Low	0	0	0	0	0	21,185	22,956	24,745	26,553	28,380	30,227
Central	0	0	0	0	0	21,217	23,063	24,932	26,826	28,745	30,690
High	0	0	0	0	0	21,250	23,171	25,121	27,102	29,116	31,164
Connections	0	0	0	0	0	22,814	24,799	26,809	28,845	30,909	33,000

Table 10: RT3 Customer Number Forecast

7.4 Consumption per Customer

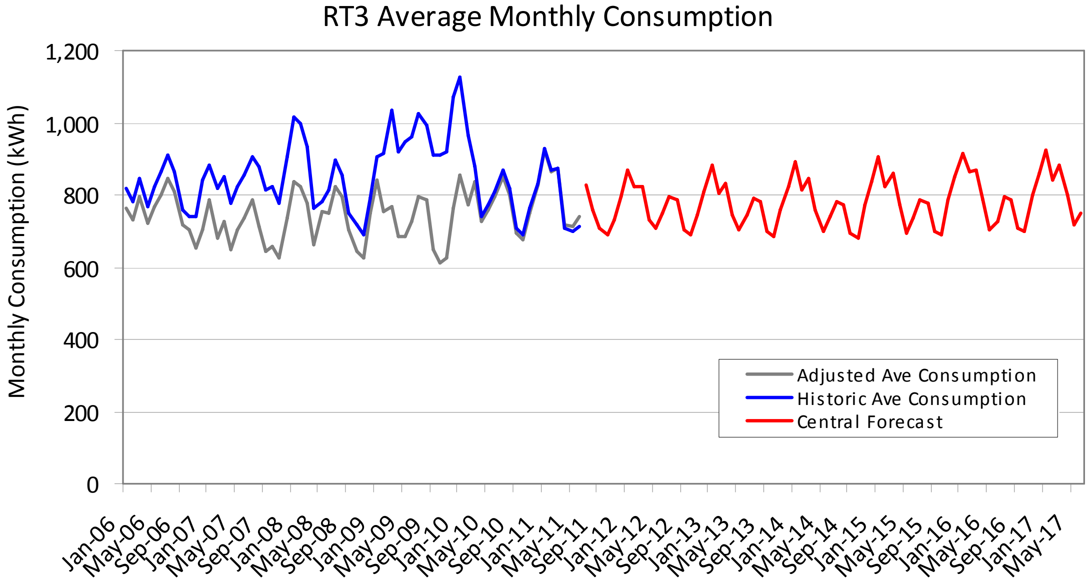


Figure 34: RT3 Monthly Consumption per Customer Central Forecast

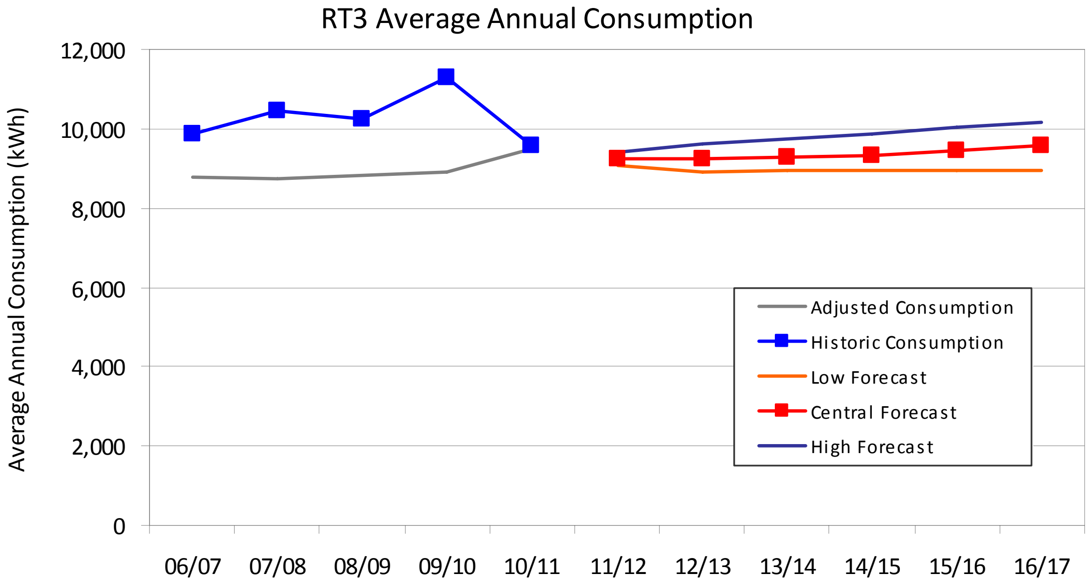


Figure 35: RT3 Annual Consumption per Customer Forecast

kWh	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	9,873	10,446	10,231	11,276	9,564	0	0	0	0	0	0
Adjusted	8,776	8,745	8,820	8,903	9,483	0	0	0	0	0	0
Low	0	0	0	0	0	9,081	8,915	8,936	8,950	8,938	8,943
Central	0	0	0	0	0	9,223	9,247	9,289	9,324	9,458	9,570
High	0	0	0	0	0	9,407	9,603	9,744	9,883	10,040	10,153

Table 11: RT3 Consumption per Customer Forecast

7.5 Customer Groups

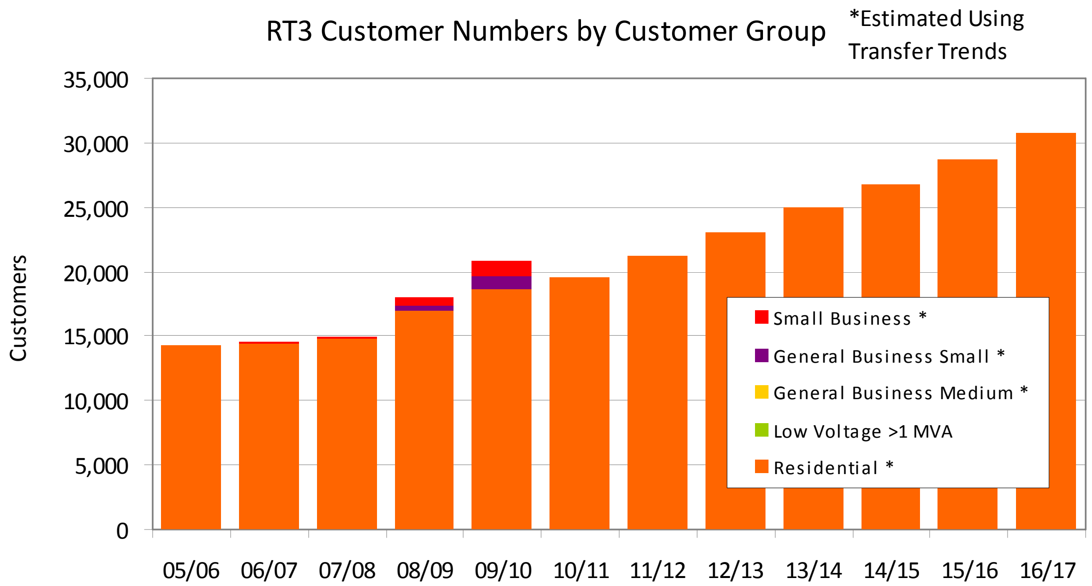


Figure 36: RT3 Annual Consumption by Customer Group

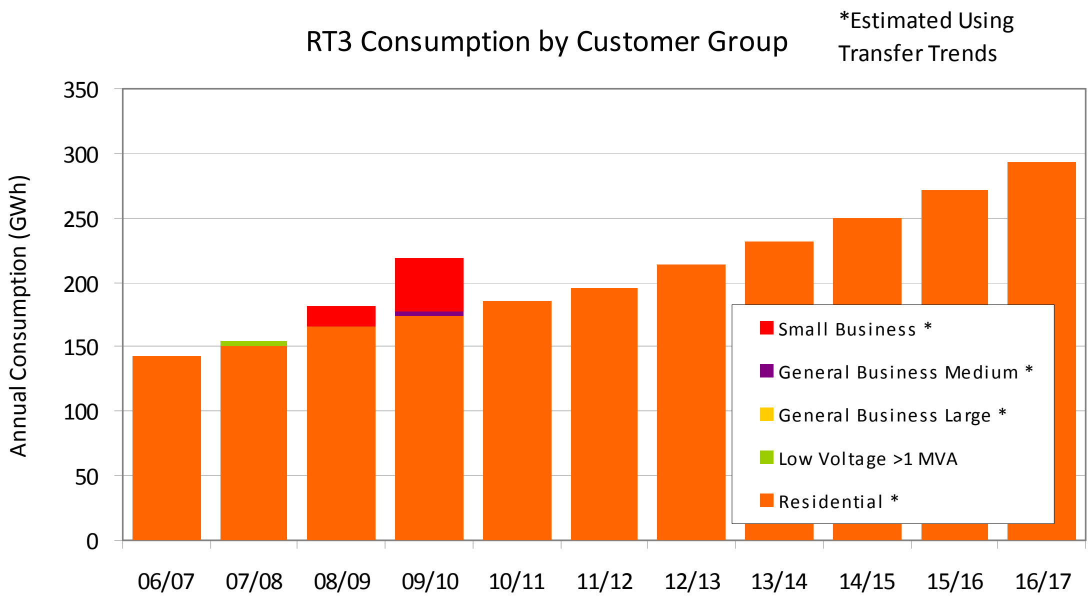


Figure 37: RT3 Annual Customer Numbers by Customer Group

7.6 Time of Use

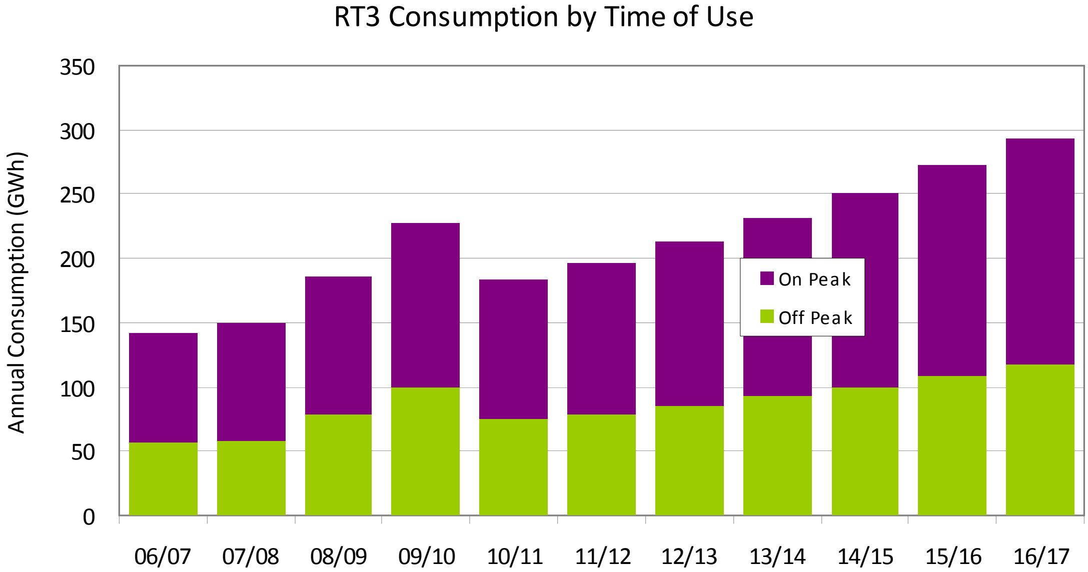


Figure 38: RT3 Consumption by Time of Use Actual

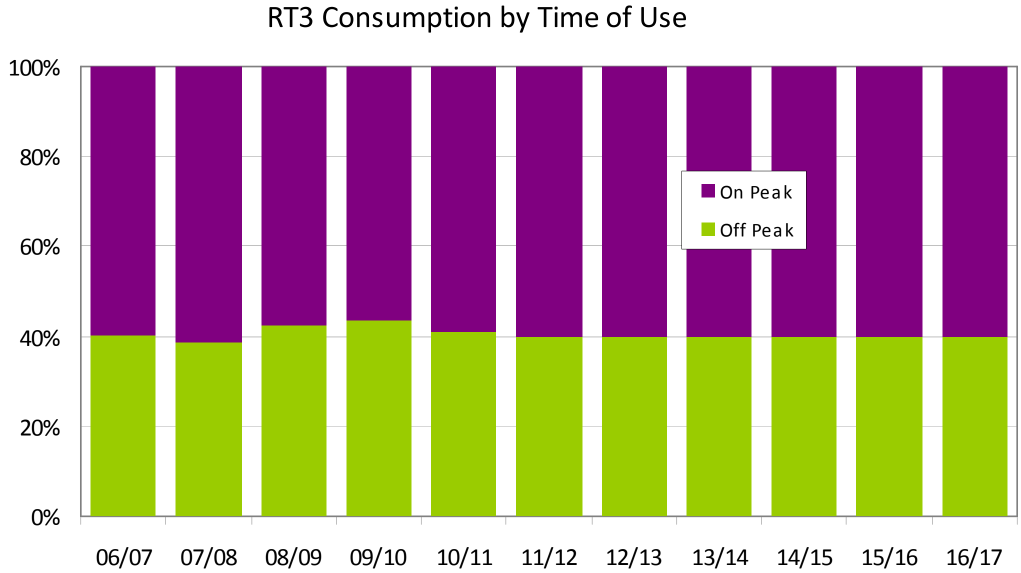


Figure 39: RT3 Consumption by Time of Use Percentage

8 RT4 – Time of Use Business

This network tariff is appropriate for some smaller business customers and currently includes over 12,000 energy consuming customers. This tariff has been reclassified multiple times leading to the movement of customers on and off this tariff, particularly to and from RT3. The effects of these tariff movements are visible in the difference between actual and adjusted consumption. As with the remainder of the tariffs, there are no reliable trends within the customer movements, therefore no post model adjustments have been made.

The model for total consumption on this tariff follows:

```
OLS, using observations 2006:01-2011:06 (T = 66)
Dependent variable: RT4_DAILY
HAC standard errors, bandwidth 3 (Bartlett kernel)

             coefficient       std. error     t-ratio  p-value
  ---------------------------------------------------------------
  Const            6.12231e+06 1.20325e+06   5.088    3.71e-06 ***
  GSP_C            20.8607     7.28406       2.864    0.0057   ***
  PR_BUS_C         -195965     51438.1       -3.810   0.0003   ***
  TEMP_C           -145978     85242.1       -1.713   0.0919   *
  TEMP_C_SQ        5742.17     2080.82       2.760    0.0076   ***

R-squared             0.743230   Adjusted R-squared   0.726393
F(4, 61)              25.56421   P-value(F)           1.83e-12
```

Figure 40: RT4 Consumption Regression Output

The model for customer numbers is as follows:

```
OLS, using observations 2006:01-2011:06 (T = 66)
Dependent variable: RT4_ADJ_CUSTOME
HAC standard errors, bandwidth 3 (Bartlett kernel)

            coefficient     std. error     t-ratio   p-value
  -----------------------------------------------------------
  const     6308.34        1347.35          4.682     1.52e-05 ***
  GSP_C     0.0296463      0.00718104       4.128     0.0001   ***

R-squared             0.513424   Adjusted R-squared   0.505822
F(1, 64)              17.04377   P-value(F)           0.000108
```

Figure 41: RT4 Customers Regression Output

8.1 Comments

The consumption model presented in Figure 40 includes GSP, Price, Temperature and Temperature Squared. Temperature Squared could be excluded given the low significance of Temperature however there is still a small response to winter visible in this tariff that is captured by the two temperature variables. Exclusion of one would exclude the winter response.

Although there are some PV's on this network tariff, they are negligible against the total energy consumption and were consequently statistically insignificant.

The price coefficient implies an elasticity of -0.7. Conversely the GSP coefficient implies an income elasticity of 0.9. This tariff has the highest price elasticity of all of the tariffs. Given the forecast increases in price this tariff has a forecast decline in consumption.

The customer numbers regression has a relatively low r-squared, indicating that the model is only an average fit for the data. No other variables are however correlated with the data, meaning that GSP alone is the best indicator of customer numbers even though it is not as accurate as it is when applied to other tariffs.

An estimate of 10,581 customer connections during 10/11 financial year was taken from NetCIS, which is slightly lower than the customer connections observed in the MBS. It is therefore assumed that there are no vacant connections on this tariff.

8.2 Energy Consumption

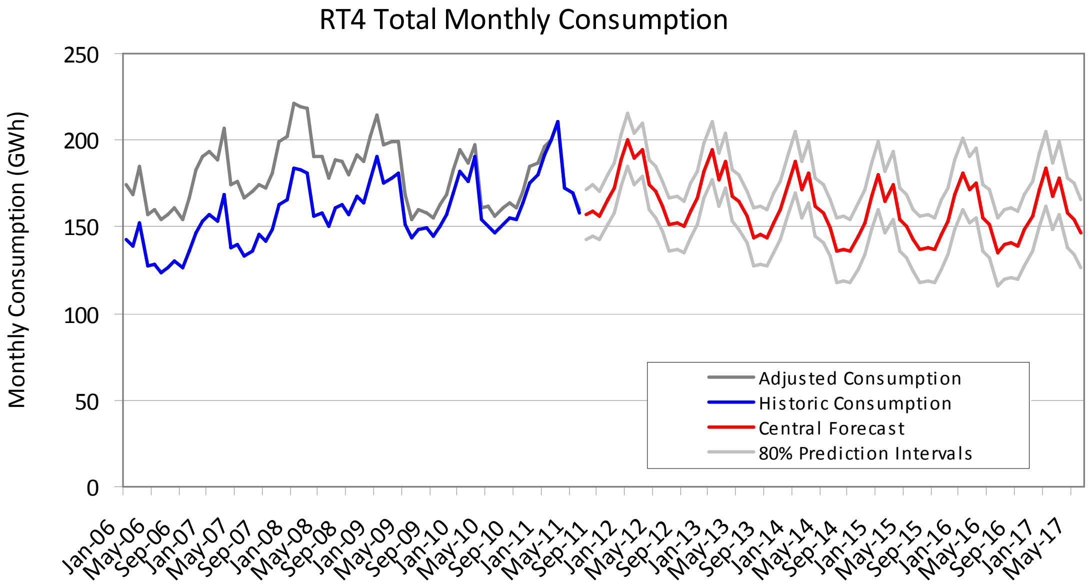


Figure 42: RT4 Monthly Consumption Central Forecast

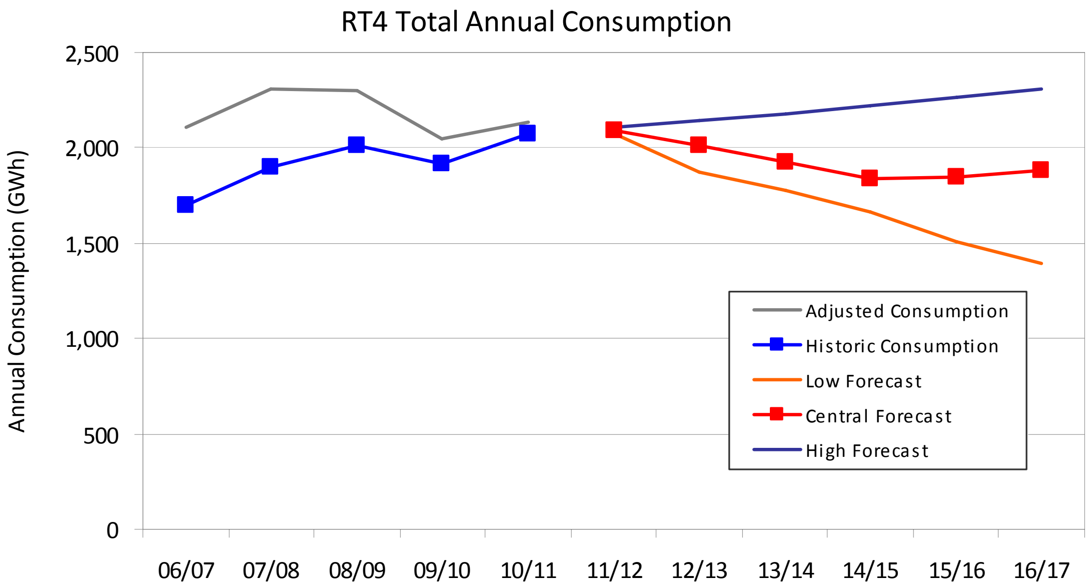


Figure 43: RT4 Annual Consumption Forecast

Gwh	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	1,699	1,895	2,016	1,915	2,070	0	0	0	0	0	0
Adjusted	2,106	2,309	2,295	2,043	2,133	0	0	0	0	0	0
Low	0	0	0	0	0	2,069	1,875	1,777	1,668	1,511	1,392
Central	0	0	0	0	0	2,090	2,009	1,929	1,839	1,849	1,883
High	0	0	0	0	0	2,112	2,140	2,179	2,221	2,265	2,312

Table 12: RT4 Consumption Forecast

8.3 Customer Numbers

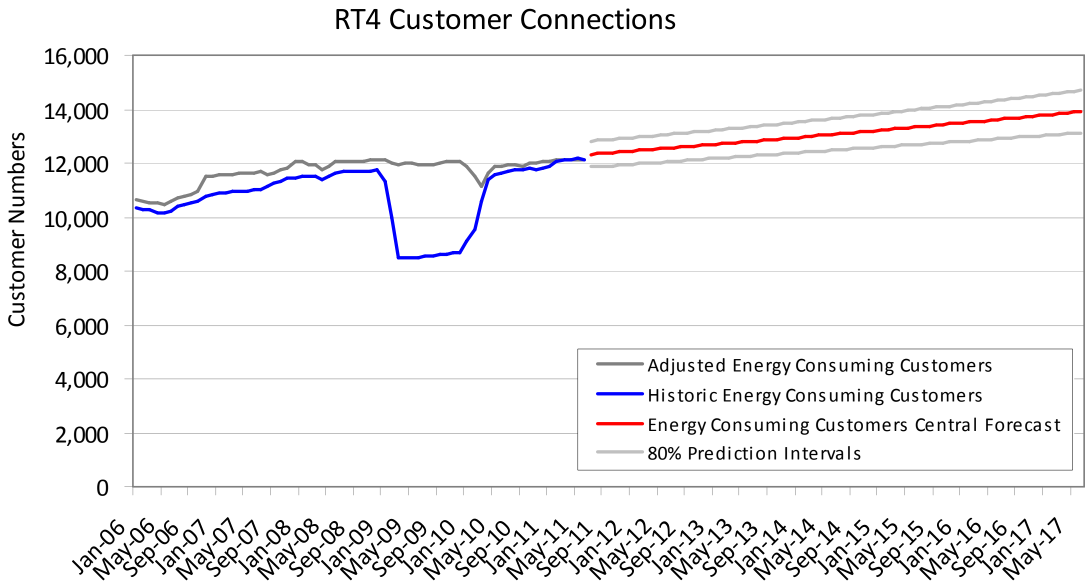


Figure 44: RT4 Monthly Customer Numbers Central Forecast

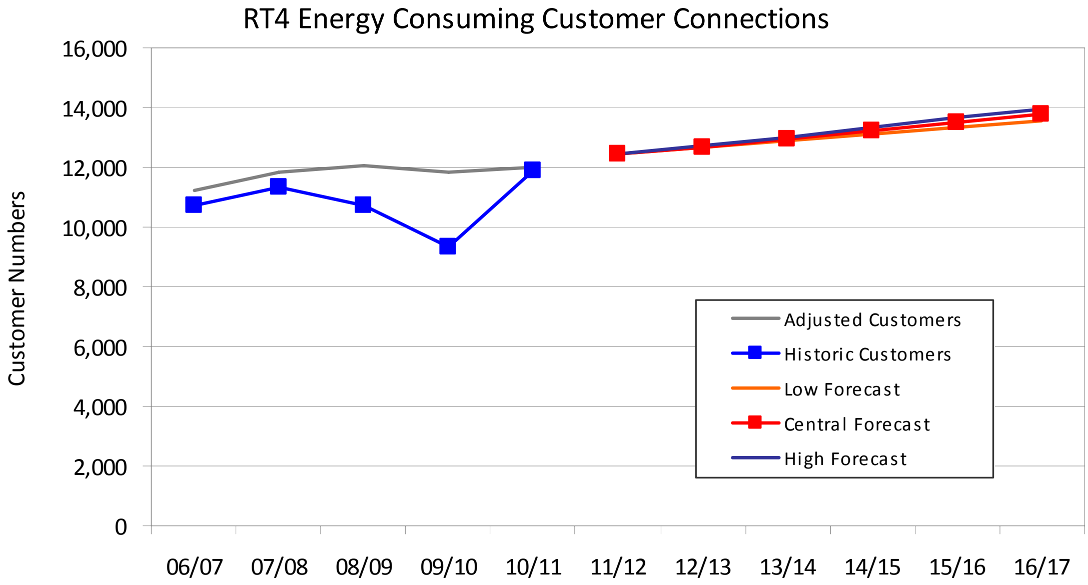


Figure 45: RT4 Annual Customer Numbers Forecast

Customers	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	10,703	11,334	10,724	9,357	11,880	0	0	0	0	0	0
Adjusted	11,239	11,811	12,044	11,845	12,024	0	0	0	0	0	0
Low	0	0	0	0	0	12,428	12,642	12,864	13,093	13,331	13,577
Central	0	0	0	0	0	12,442	12,687	12,942	13,208	13,484	13,771
High	0	0	0	0	0	12,456	12,732	13,021	13,323	13,639	13,969
Connections	0	0	0	0	0	12,442	12,687	12,942	13,208	13,484	13,771

Table 13: RT4 Customer Number Forecast

8.4 Consumption per Customer

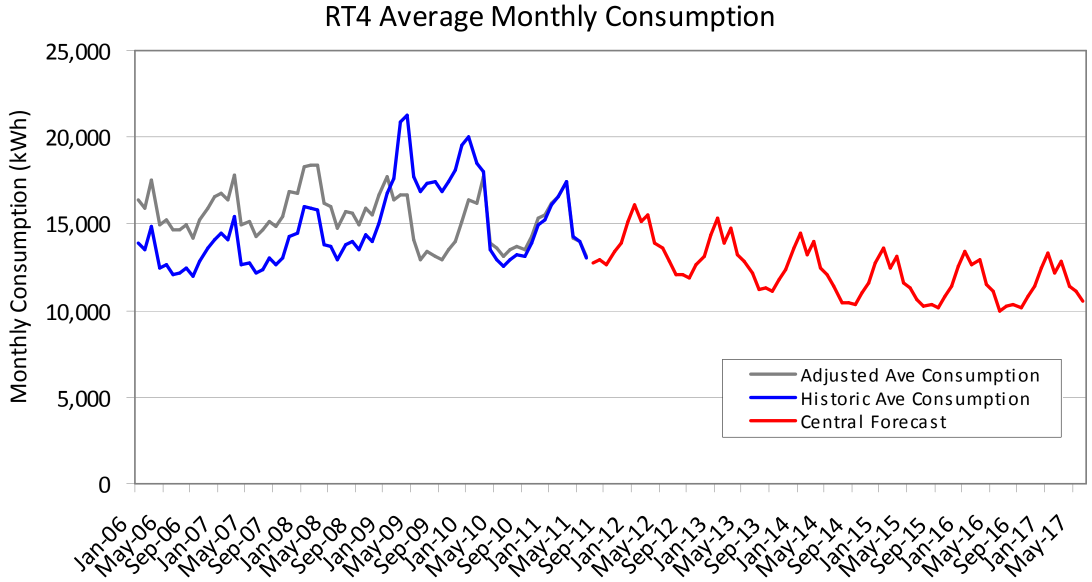


Figure 46: RT4 Monthly Consumption per Customer Central Forecast

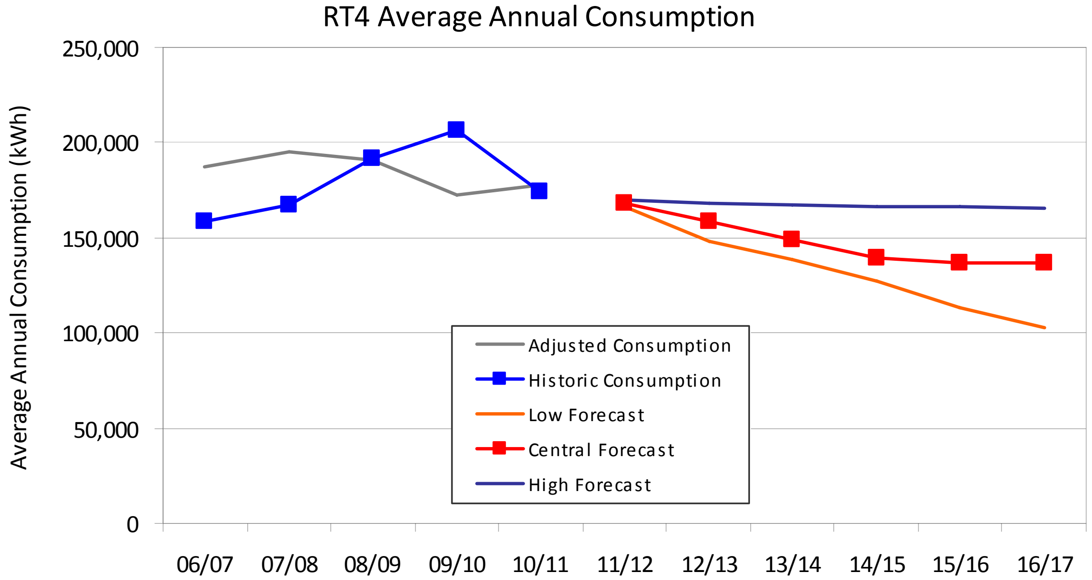


Figure 47: RT4 Annual Consumption per Customer Forecast

MWh	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	159	167	192	207	174	0	0	0	0	0	0
Adjusted	187	195	191	173	177	0	0	0	0	0	0
Low	0	0	0	0	0	166	148	138	127	113	103
Central	0	0	0	0	0	168	158	149	139	137	137
High	0	0	0	0	0	170	168	167	167	166	165

Table 14: RT4 Consumption per Customer Forecast

8.5 Customer Groups

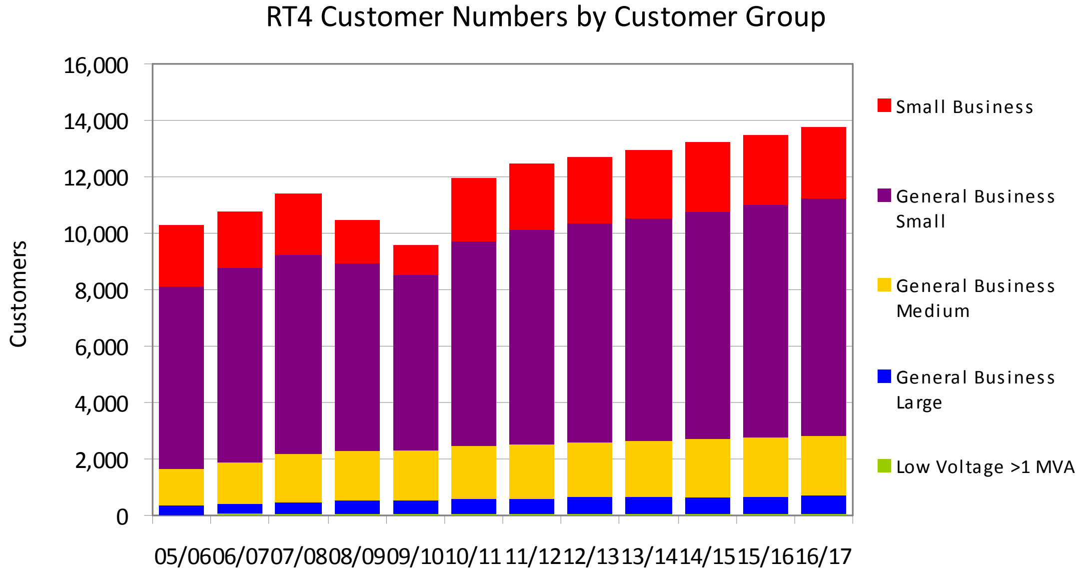


Figure 48: RT4 Annual Consumption by Customer Group

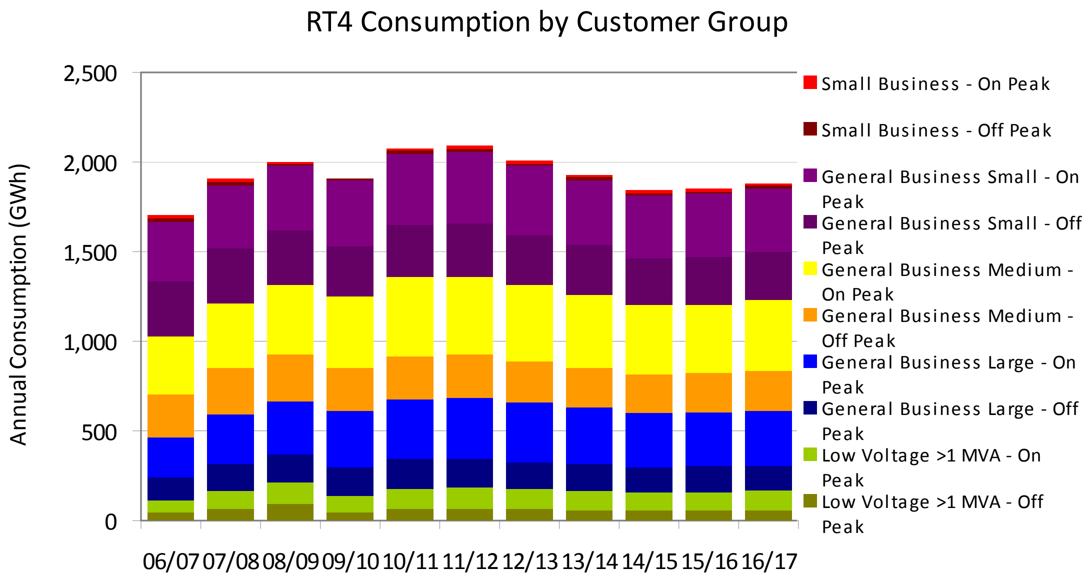


Figure 49: RT4 Annual Customer Numbers by Customer Group

8.6 Time of Use

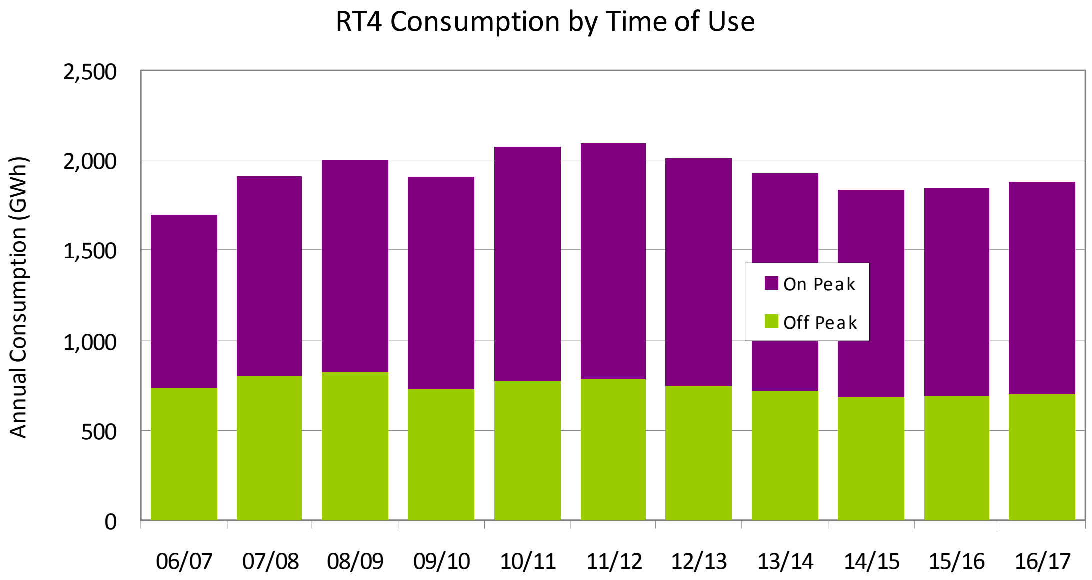


Figure 50: RT4 Consumption by Time of Use Actual

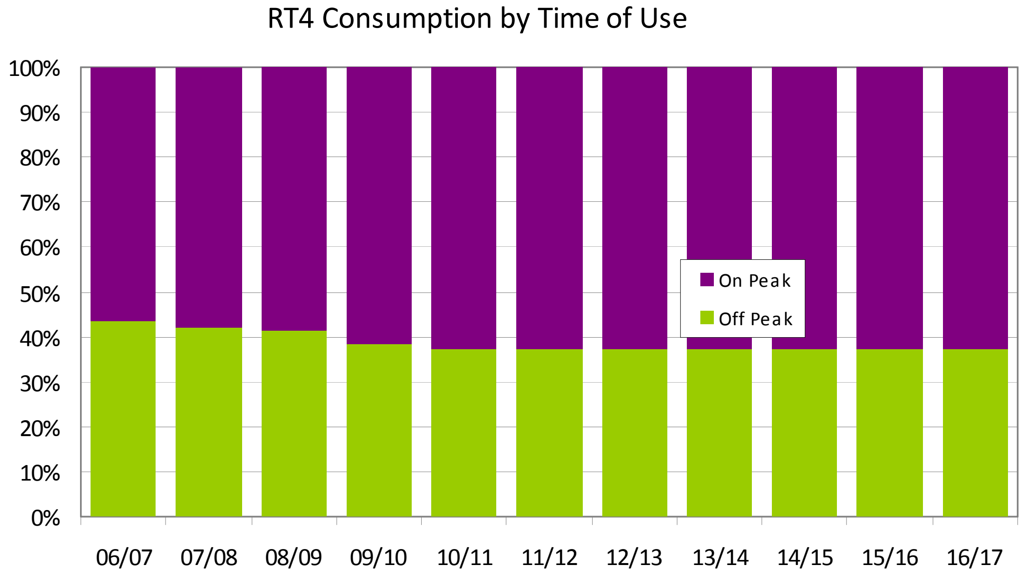


Figure 51: RT4 Consumption by Time of Use Percentage

9 RT5 – High Voltage Metered Demand

This network tariff is appropriate for medium sized business customers and currently includes approximately 120 energy consuming customers.

The model for total consumption on this tariff follows:

```
OLS, using observations 2006:01-2011:06 (T = 66)
Dependent variable: RT5_DAILY
HAC standard errors, bandwidth 3 (Bartlett kernel)

              coefficient     std. error    t-ratio   p-value
  ------------------------------------------------------------
  const      -913372         220820         -4.136    0.0001   ***
  GSP_C      8.59153         1.29822         6.618    9.22e-09 ***
  TEMP_C     8413.63         2297.28         3.662    0.0005   ***

R-squared             0.687086   Adjusted R-squared   0.677152
F(2, 63)              48.29891   P-value(F)           1.92e-13
F(4, 61)              25.56421   P-value(F)           1.83e-12
```

Figure 52: RT5 Consumption Regression Output

The model for customer numbers is as follows:

```
OLS, using observations 2006:01-2011:06 (T = 66)
Dependent variable: RT5_ADJ_CUSTOME
HAC standard errors, bandwidth 3 (Bartlett kernel)

              coefficient     std. error    t-ratio    p-value
  -------------------------------------------------------------
  const      -46.6955        11.7021        -3.990     0.0002    ***
  GSP_C        0.000868892    6.71460e-05   12.94      1.58e-019 ***

R-squared             0.877077   Adjusted R-squared   0.875157
F(1, 64)              167.4524   P-value(F)           1.58e-19
```

Figure 53: RT5 Customers Regression Output

9.1 Comments

The consumption model presented in Figure 52 includes GSP and Temperature only. Temperature squared is excluded because the relationship between consumption and temperature is now linear – cold winter temperatures are not associated with increased consumption. Price is also excluded as there is not statistically significant correlation with consumption.

The GSP coefficient implies an income elasticity of 1.35.

An estimate of 154 customer connections during 10/11 financial year was taken from NetCIS, which implies an average vacancy rate of 24%. It is assumed that this occupancy rate will continue on this tariff.

9.2 Energy Consumption

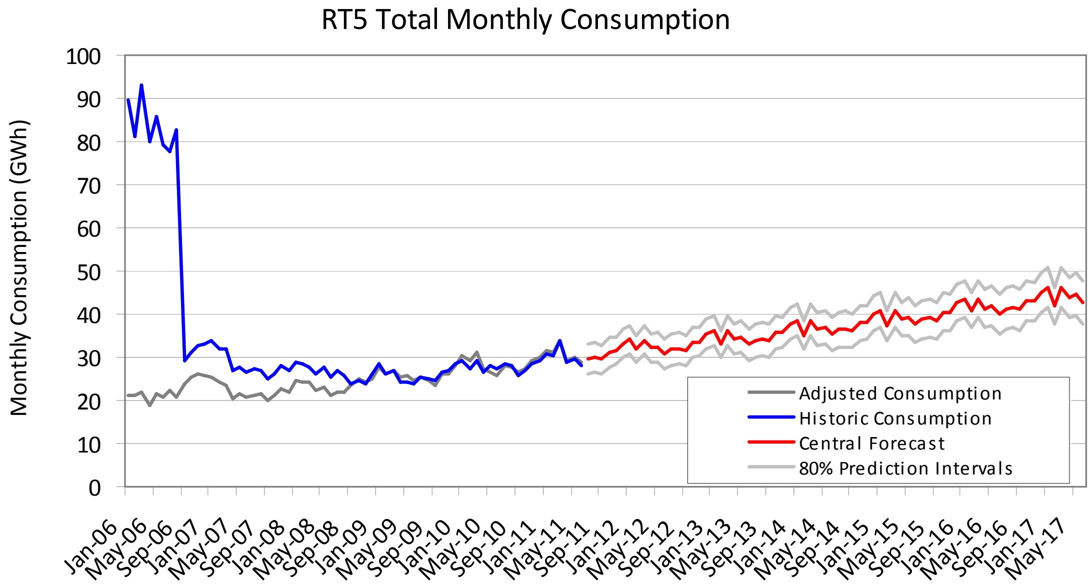


Figure 54: RT5 Monthly Consumption Central Forecast

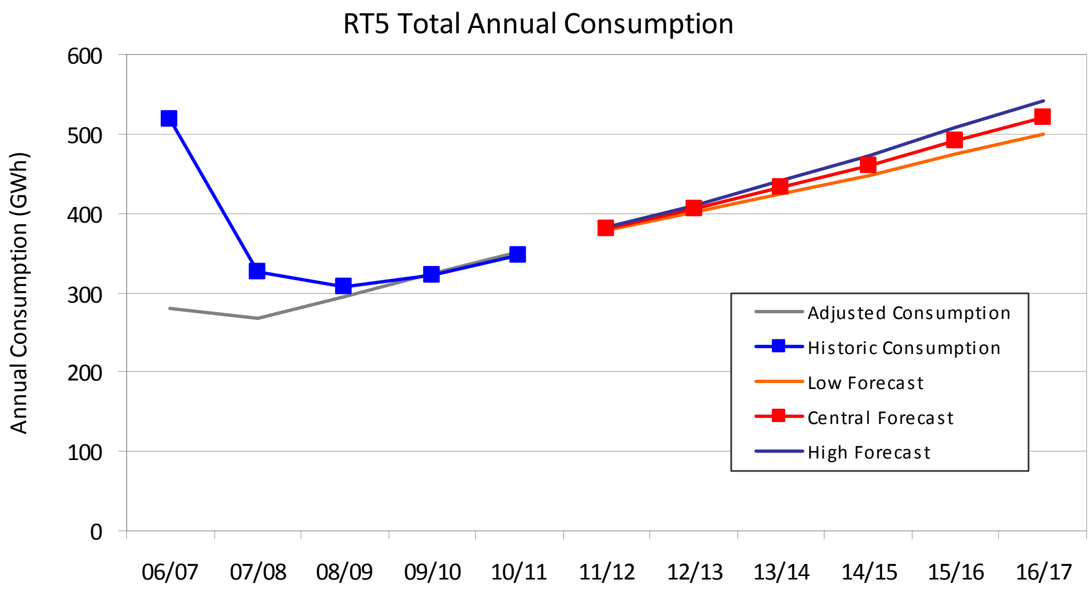


Figure 55: RT5 Annual Consumption Forecast

Gwh	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	518	325	307	322	348	0	0	0	0	0	0
Adjusted	280	267	295	323	350	0	0	0	0	0	0
Low	0	0	0	0	0	378	400	424	448	475	499
Central	0	0	0	0	0	381	405	432	460	491	520
High	0	0	0	0	0	383	410	441	473	508	541

Table 15: RT5 Consumption Forecast

9.3 Customer Numbers

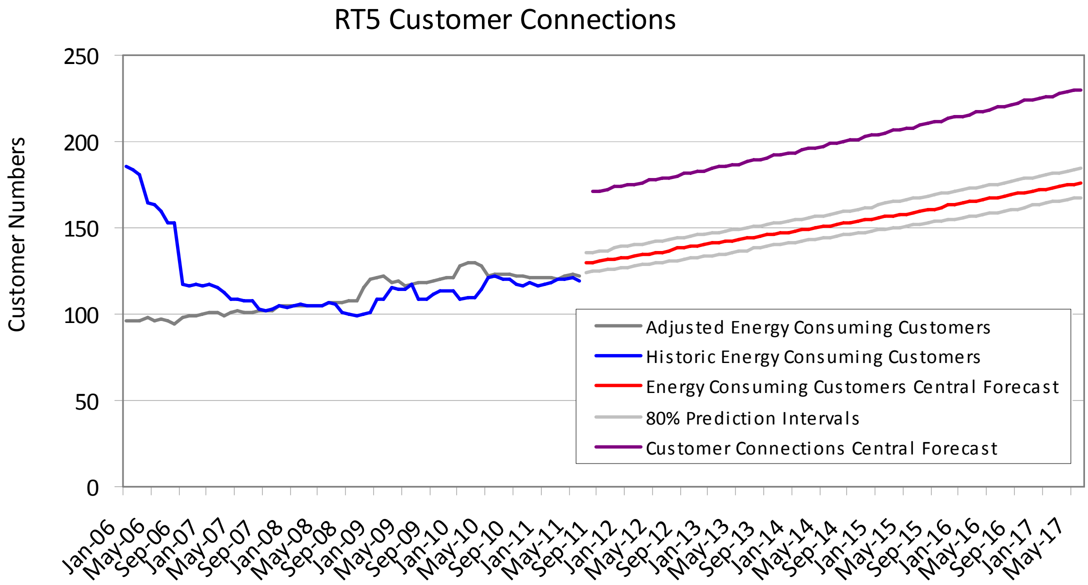


Figure 56: RT5 Monthly Customer Numbers Central Forecast

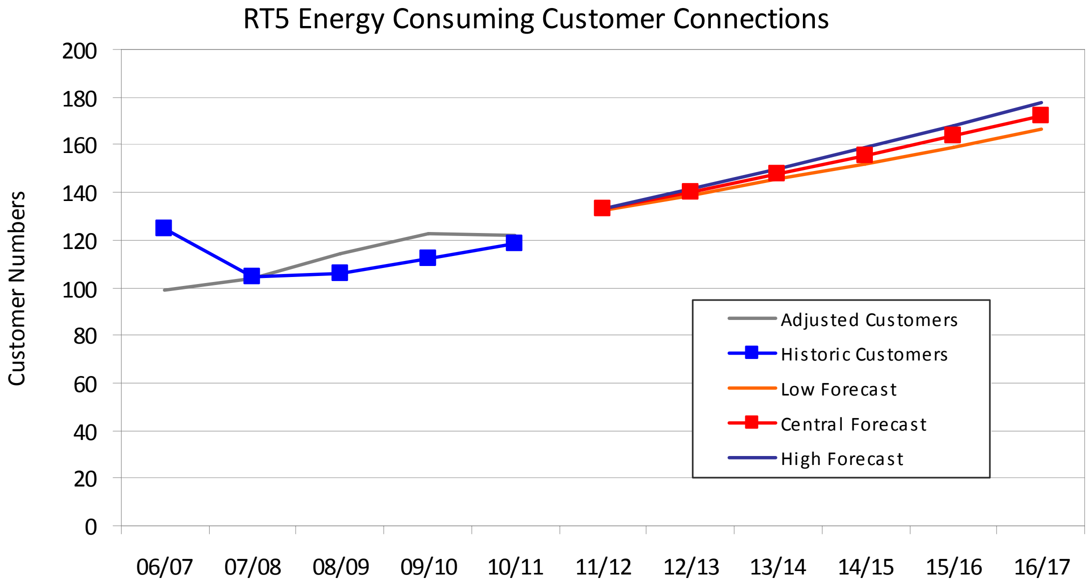


Figure 57: RT5 Annual Customer Numbers Forecast

Customers	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	125	105	106	112	119	0	0	0	0	0	0
Adjusted	99	104	114	123	122	0	0	0	0	0	0
Low	0	0	0	0	0	133	139	145	152	159	166
Central	0	0	0	0	0	133	140	148	156	164	172
High	0	0	0	0	0	133	142	150	159	168	178
Connections	0	0	0	0	0	175	185	194	205	215	226

Table 16: RT5 Customer Number Forecast

9.4 Consumption per Customer

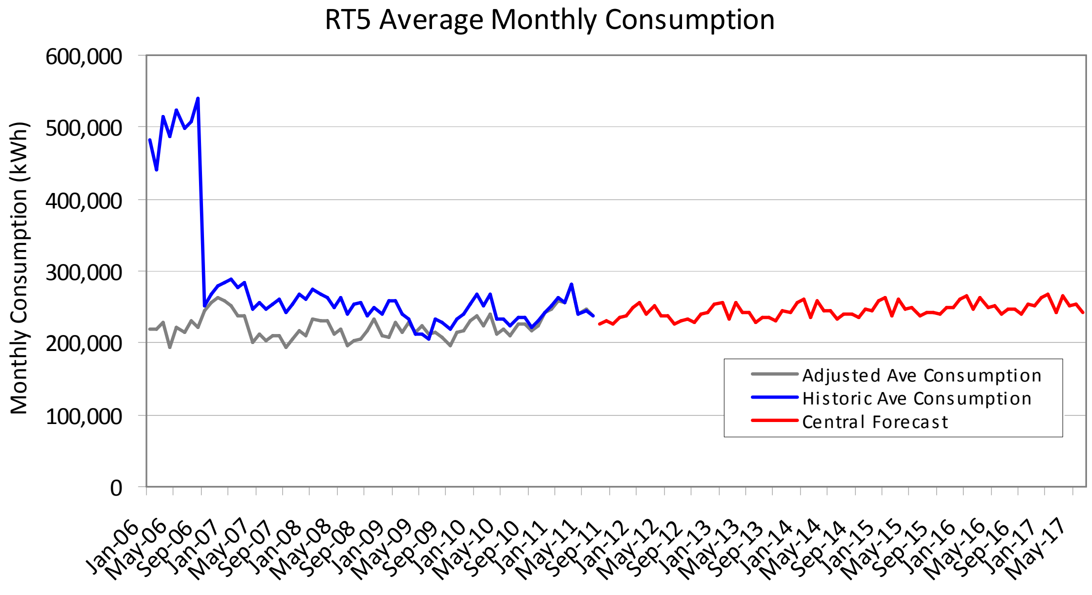


Figure 58: RT5 Monthly Consumption per Customer Central Forecast

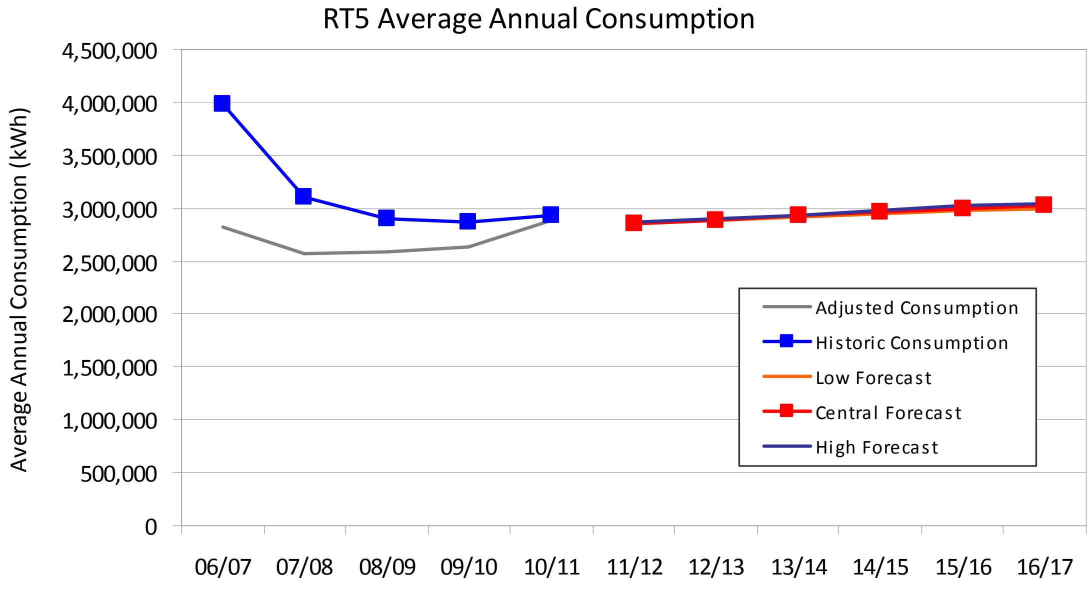


Figure 59: RT5 Annual Consumption per Customer Forecast

MWh	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	3,977	3,107	2,893	2,864	2,927	0	0	0	0	0	0
Adjusted	2,829	2,575	2,581	2,632	2,878	0	0	0	0	0	0
Low	0	0	0	0	0	2,855	2,880	2,914	2,945	2,983	3,001
Central	0	0	0	0	0	2,859	2,888	2,926	2,959	3,000	3,021
High	0	0	0	0	0	2,870	2,898	2,938	2,974	3,019	3,043

Table 17: RT5 Consumption per Customer Forecast

9.5 Customer Groups

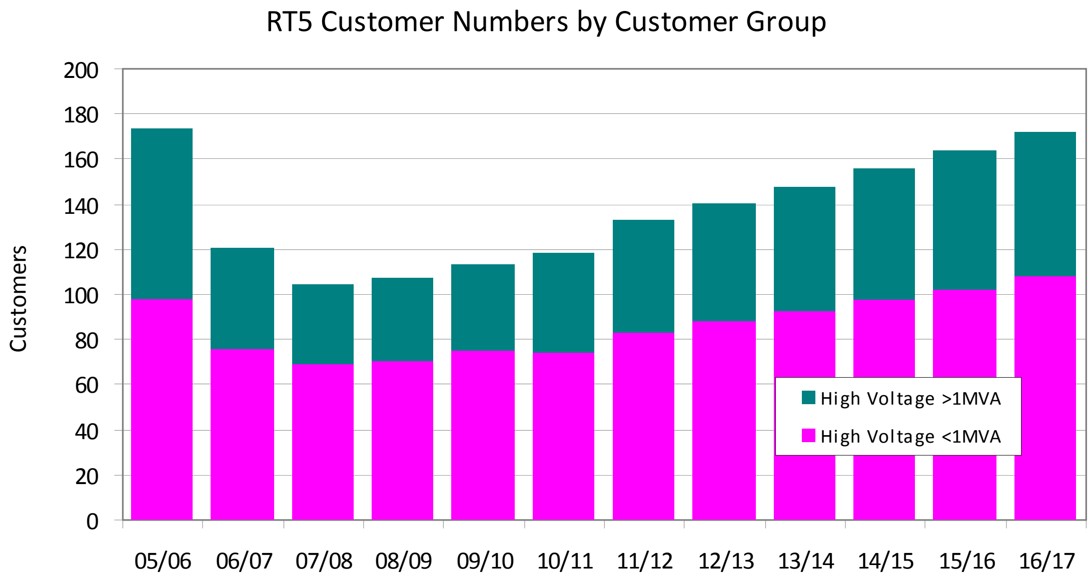


Figure 60: RT5 Annual Consumption by Customer Group

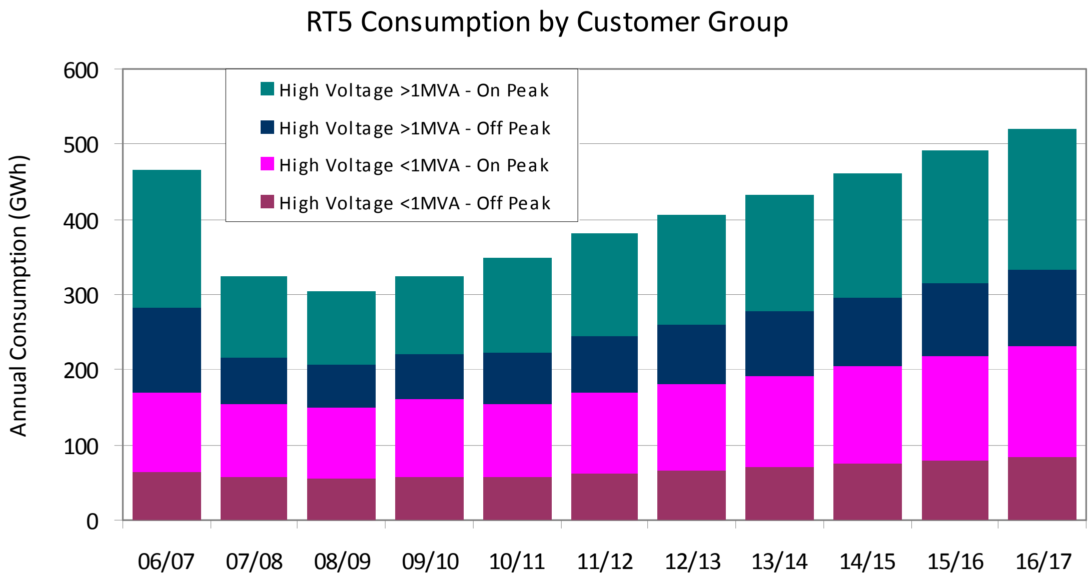


Figure 61: RT5 Annual Customer Numbers by Customer Group

9.6 Time of Use

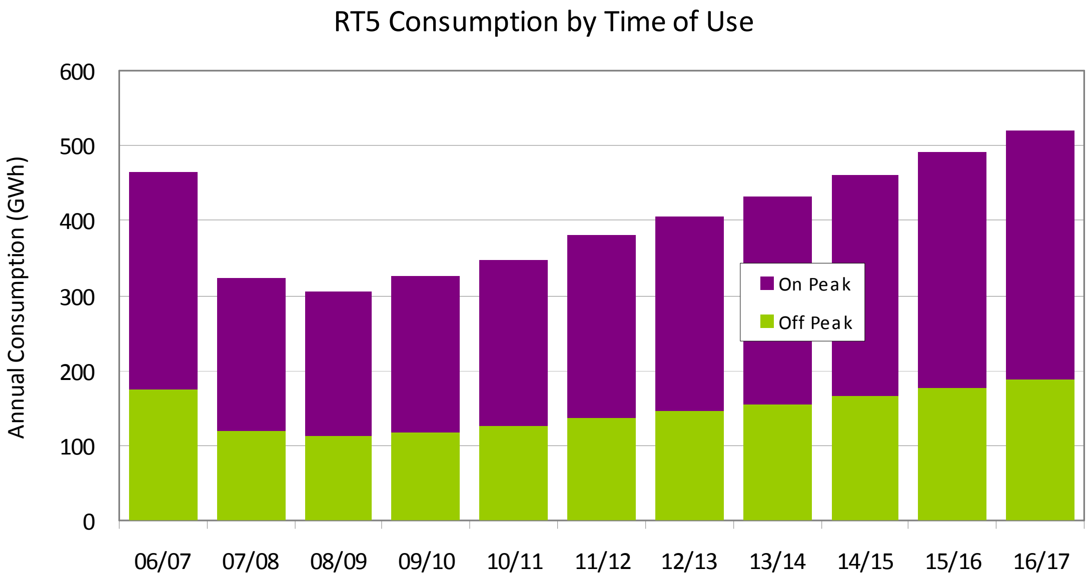


Figure 62: RT5 Consumption by Time of Use Actual

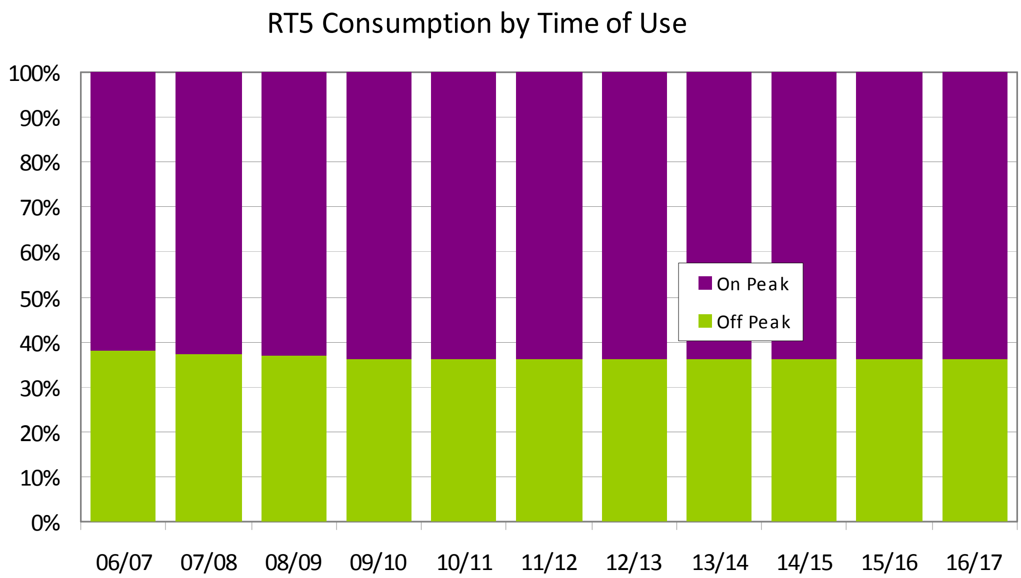


Figure 63: RT5 Consumption by Time of Use Percentage

9.7 Load Factors

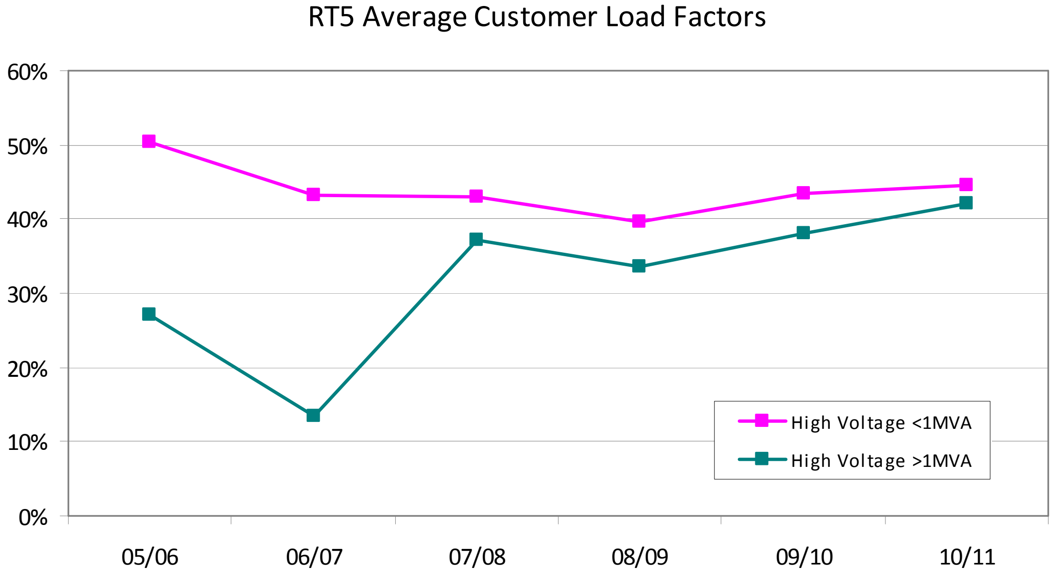


Figure 64: RT5 Average Customer Load Factors

10 RT6 – Low Voltage Metered Demand

This network tariff is appropriate for medium sized business customers and currently includes approximately 1,200 energy consuming customers.

The model for total consumption on this tariff follows:

```
OLS, using observations 2006:01-2011:06 (T = 66)
Dependent variable: RT6_DAILY
HAC standard errors, bandwidth 3 (Bartlett kernel)

              coefficient     std. error    t-ratio    p-value
  -------------------------------------------------------------
  const        -828895        285718        -2.901     0.0052    ***
  GSP_C        26.7505        1.69563       15.78      3.34e-023 ***
  PR_BUS_C     -30137.7       10225.5       -2.947     0.0045    ***
  TEMP_C       -87311.2       21106.9       -4.137     0.0001    ***
  TEMP_C_SQ    2831.61        527.899       5.364      1.33e-06  ***

R-squared            0.953230   Adjusted R-squared   0.950163
F(4, 61)             241.3981   P-value(F)           1.20e-36
```

Figure 65: RT6 Consumption Regression Output

The model for customer numbers is as follows:

```
OLS, using observations 2006:01-2011:06 (T = 66)
Dependent variable: RT6_ADJ_CUSTOME
HAC standard errors, bandwidth 3 (Bartlett kernel)

              coefficient     std. error     t-ratio    p-value
  --------------------------------------------------------------
  const      -1795.60        135.150         -13.29     4.60e-020 ***
  GSP_C      0.0158696       0.000723164     21.94      1.75e-031 ***

R-squared            0.974015   Adjusted R-squared   0.973609
F(1, 64)             481.5712   P-value(F)           1.75e-31
```

Figure 66: RT6 Customers Regression Output

10.1 Comments

The price coefficient implies an elasticity of -0.17. Conversely the GSP coefficient implies an income elasticity of 1.2.

Although the volumes on this tariff is expected to increase, the per customer volumes are expected to decrease.

An estimate of 1,573 customer connections during 10/11 financial year was taken from NetCIS, which implies a vacancy rate of 24%. The customer connection forecast assumes this occupancy rate will continue.

10.2 Energy Consumption

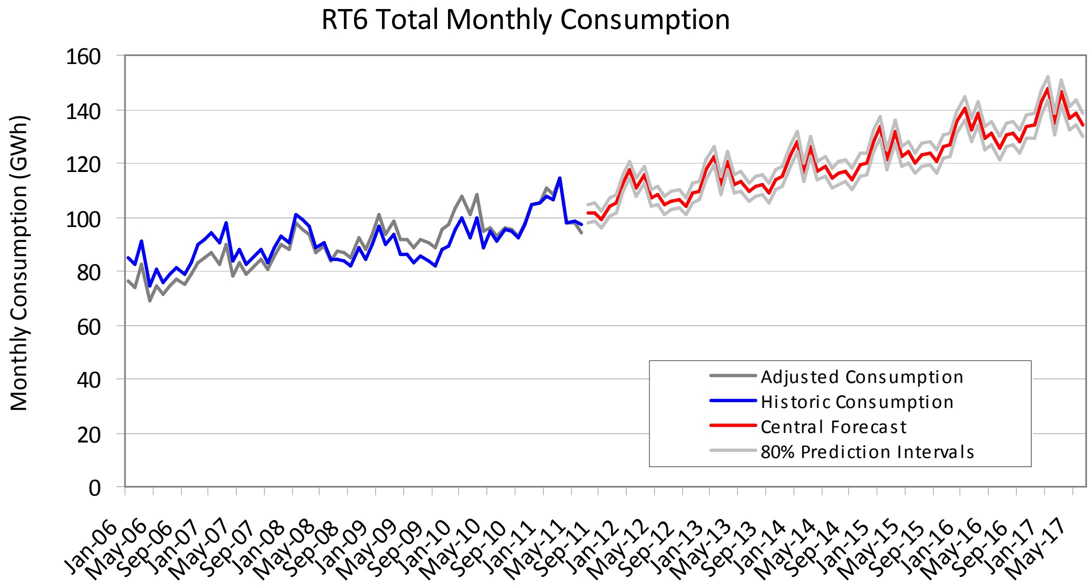


Figure 67: RT6 Monthly Consumption Central Forecast

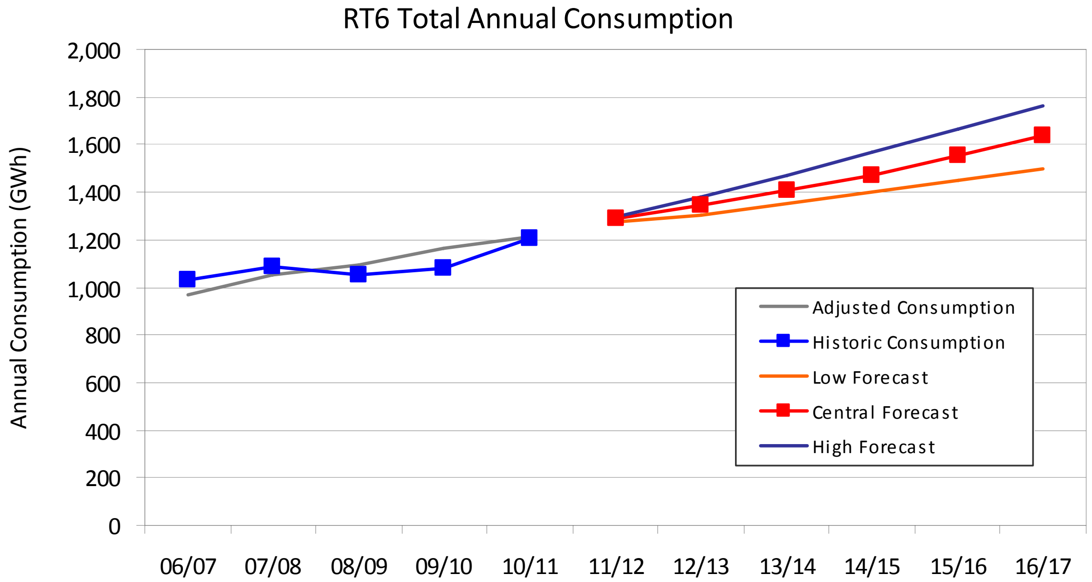


Figure 68: RT6 Annual Consumption Forecast

Gwh	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	1,034	1,086	1,049	1,082	1,207	0	0	0	0	0	0
Adjusted	965	1,052	1,093	1,164	1,214	0	0	0	0	0	0
Low	0	0	0	0	0	1,276	1,305	1,354	1,404	1,452	1,501
Central	0	0	0	0	0	1,287	1,343	1,405	1,468	1,553	1,638
High	0	0	0	0	0	1,299	1,382	1,471	1,565	1,667	1,766

Table 18: RT6 Consumption Forecast

10.3 Customer Numbers

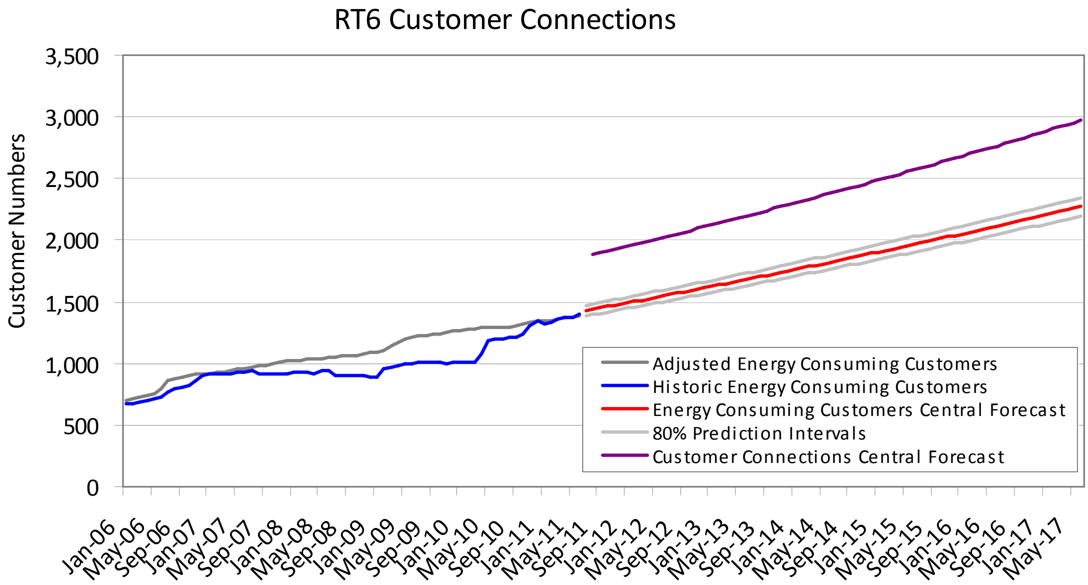


Figure 69: RT6 Monthly Customer Numbers Central Forecast

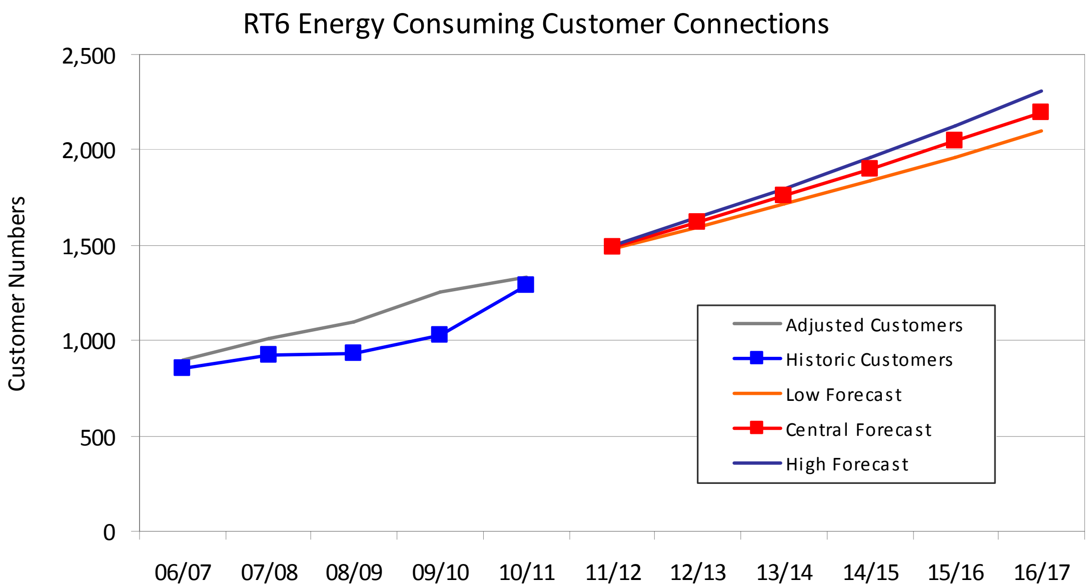


Figure 70: RT6 Annual Customer Numbers Forecast

Customers	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	857	925	928	1,028	1,288	0	0	0	0	0	0
Adjusted	900	1,006	1,096	1,255	1,333	0	0	0	0	0	0
Low	0	0	0	0	0	1,480	1,595	1,714	1,836	1,964	2,095
Central	0	0	0	0	0	1,488	1,619	1,756	1,898	2,045	2,199
High	0	0	0	0	0	1,495	1,643	1,798	1,960	2,129	2,305
Connections	0	0	0	0	0	1,957	2,130	2,310	2,497	2,691	2,893

Table 19: RT6 Customer Number Forecast

10.4 Consumption per Customer

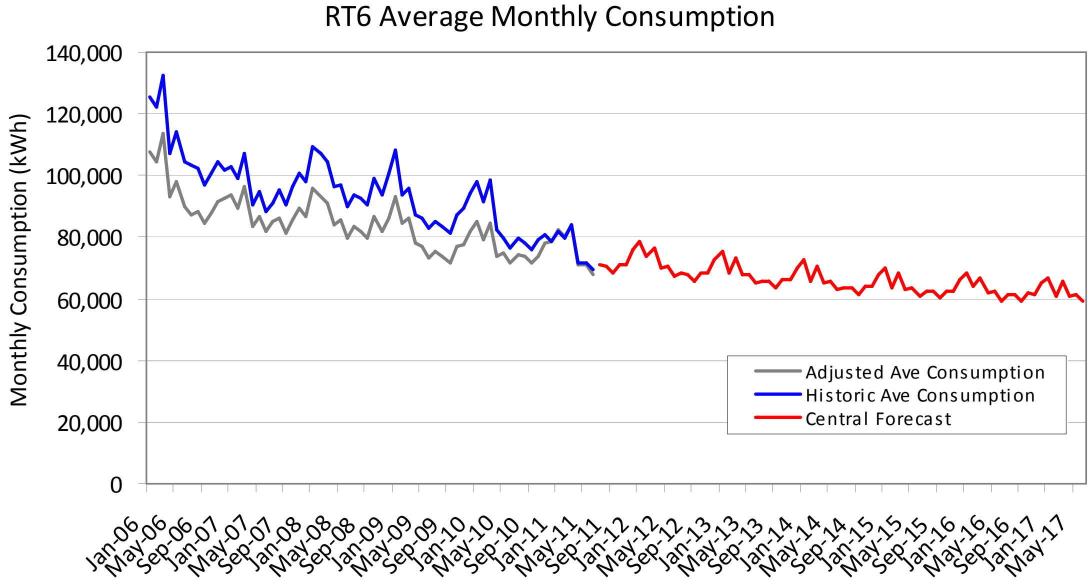


Figure 71: RT6 Monthly Consumption per Customer Central Forecast

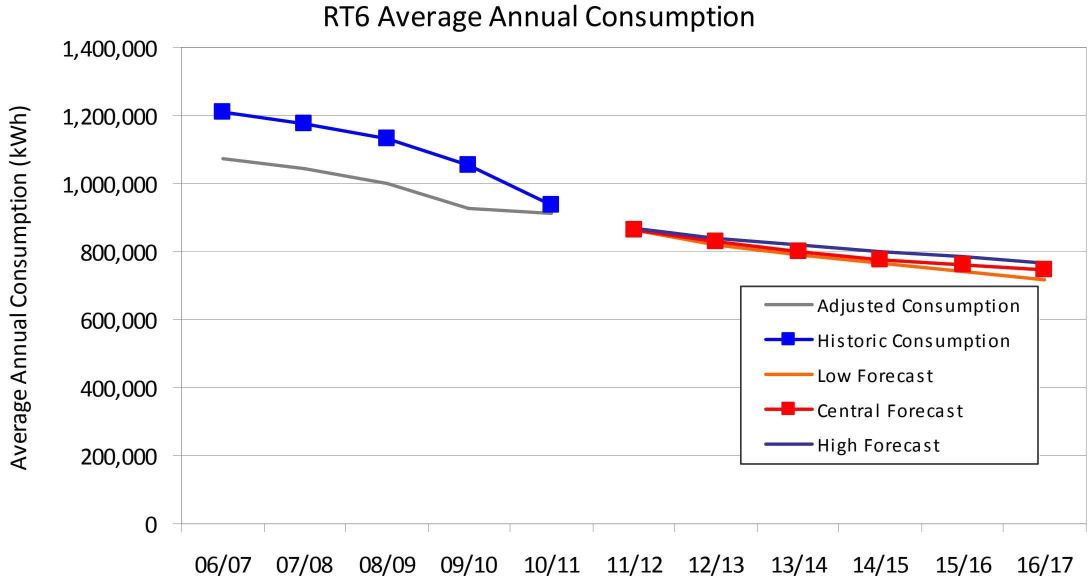


Figure 72: RT6 Annual Consumption per Customer Forecast

MWh	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	1,208	1,174	1,132	1,054	937	0	0	0	0	0	0
Adjusted	1,072	1,044	998	927	911	0	0	0	0	0	0
Low	0	0	0	0	0	862	818	790	764	739	717
Central	0	0	0	0	0	865	830	800	773	759	745
High	0	0	0	0	0	869	841	818	799	783	766

Table 20: RT6 Consumption per Customer Forecast

10.5 Customer Groups

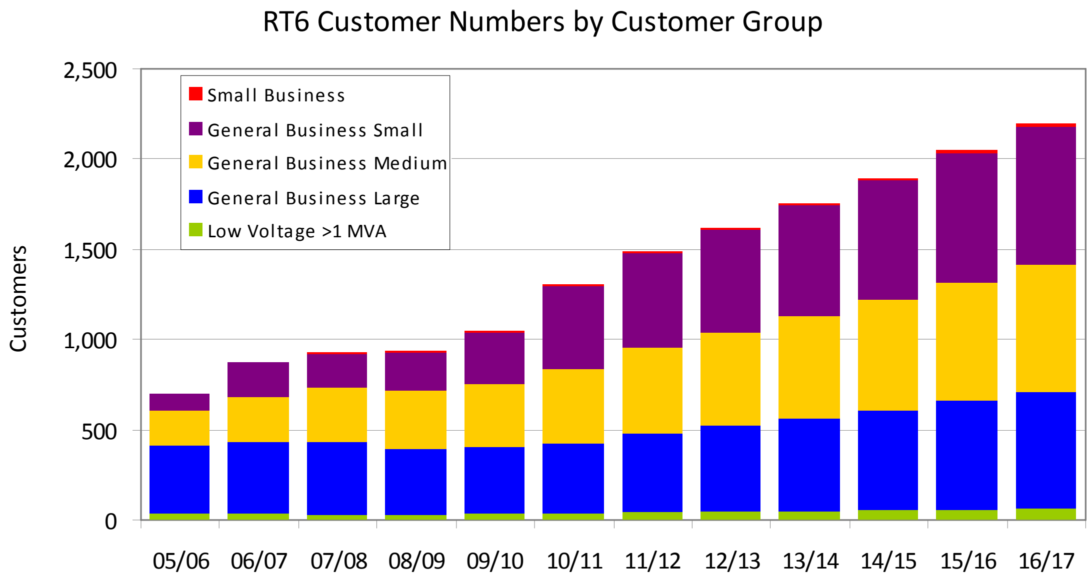


Figure 73: RT6 Annual Consumption by Customer Group

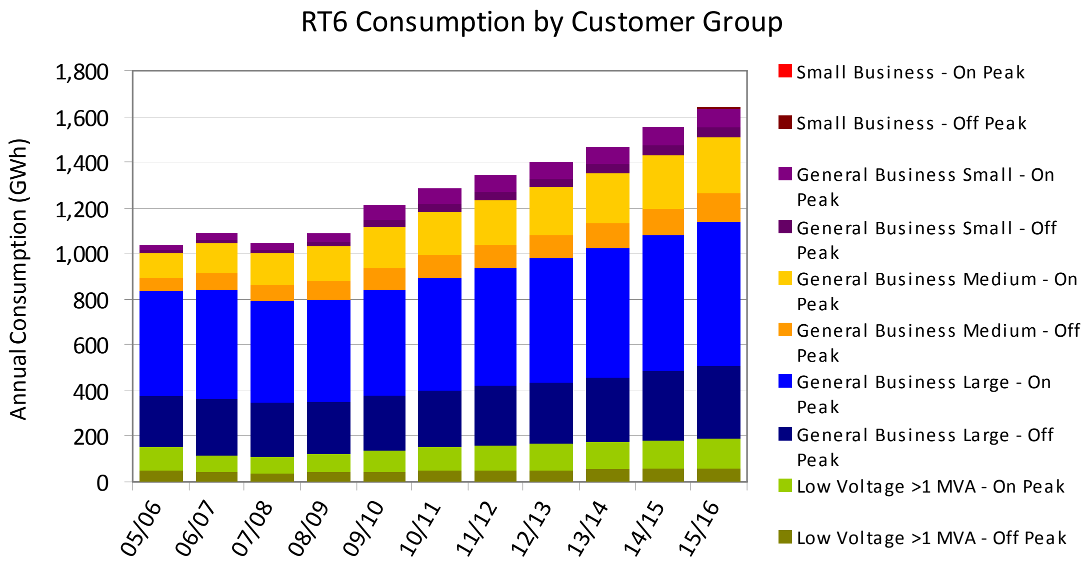


Figure 74: RT6 Annual Customer Numbers by Customer Group

10.6 Time of Use

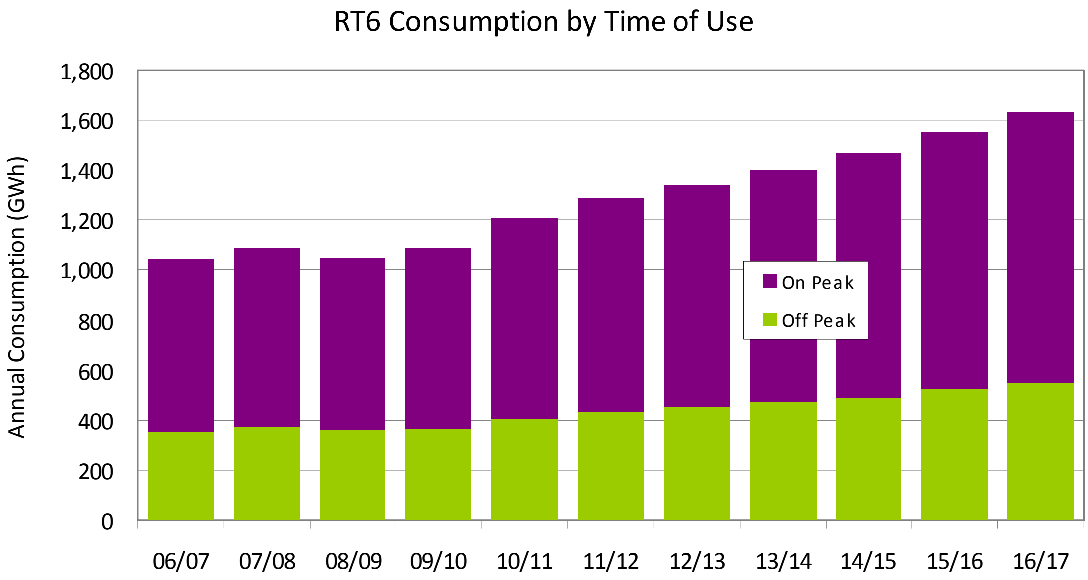


Figure 75: RT6 Consumption by Time of Use Actual

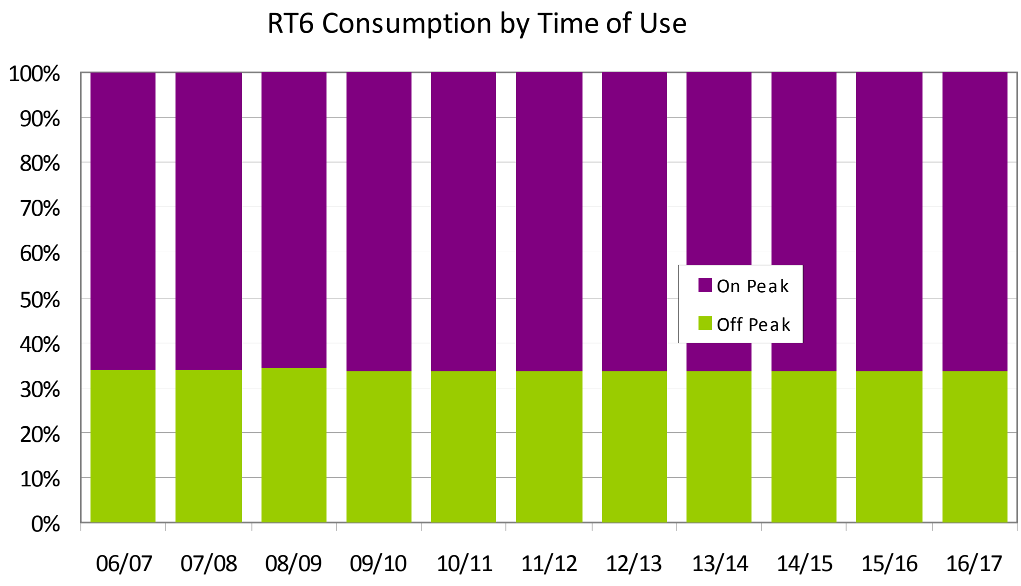


Figure 76: RT6 Consumption by Time of Use Percentage

10.7 Load Factors

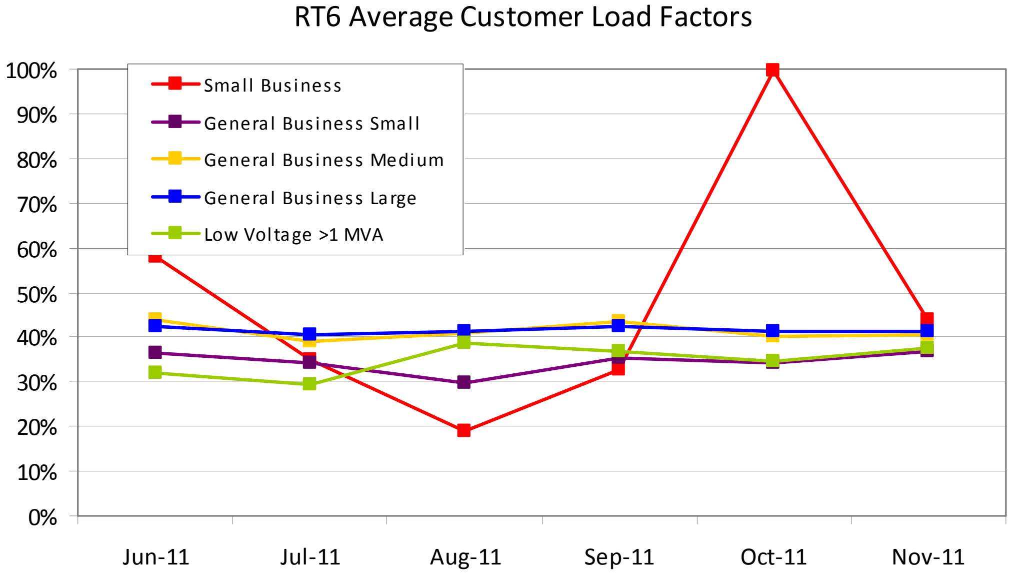


Figure 77: RT6 Average Customer Load Factors

11 RT7 – High Voltage Contract Maximum Demand

This network tariff is appropriate for large high voltage business customers and currently includes approximately 250 energy consuming customers. This tariff has the largest consumption of all the business tariffs. Since deregulation many customers have moved to this tariff, however there is no underlying growth in new customers.

The model for total consumption on this tariff follows:

```
OLS, using observations 2007:01-2011:06 (T = 54)
Dependent variable: RT7_DAILY
HAC standard errors, bandwidth 2 (Bartlett kernel)

              coefficient      std. error    t-ratio    p-value
  ---------------------------------------------------------------
  const        2.31523e+06     613916          3.771    0.0004     ***
  GSP_C        22.2346         2.75439         8.072    1.12e-010  ***
  TEMP_C       65409.0         7104.21         9.207    2.00e-012  ***

R-squared           0.777880   Adjusted R-squared    0.769169
F(2, 51)            47.55216   P-value(F)            2.21e-12
```

Figure 78: RT7 Consumption Regression Output

On this tariff, the customer numbers are assumed as follows:

```
High = 264 Customers
Central = 255 Customers
Low = 248 Customers
```

Figure 79: RT7 Customer Assumptions

11.1 Comments

The consumption model presented in Figure 52 includes GSP and Temperature only. Temperature squared is excluded because the relationship between consumption and temperature is now linear – cold winter temperatures are not associated with increased consumption. Price is also excluded as there is not statistically significant correlation with consumption.

The GSP coefficient implies an income elasticity of 0.45.

An estimate of 339 customer connections during 10/11 financial year was taken from NetCIS, which implies an average vacancy rate of 24%. It is assumed that this occupancy rate will continue on this tariff.

This tariff contains customers that connect to the high voltage distribution network (HVCMD) and customers that connect to the high voltage network at a zone substation (HVCMDZ). There are currently 18 NMI's shared by 8 customers that connect at the zone substation. Although they are RT7 customers, they are charged different network tariffs because they do not use the distribution network. Due to the small number of customers that use this service, all forecast growth is expected to occur on the distribution network (or HVCMD customers). No changes are therefore forecast to the customers connected at the zone substation (HVCMDZ).

11.2 Energy Consumption

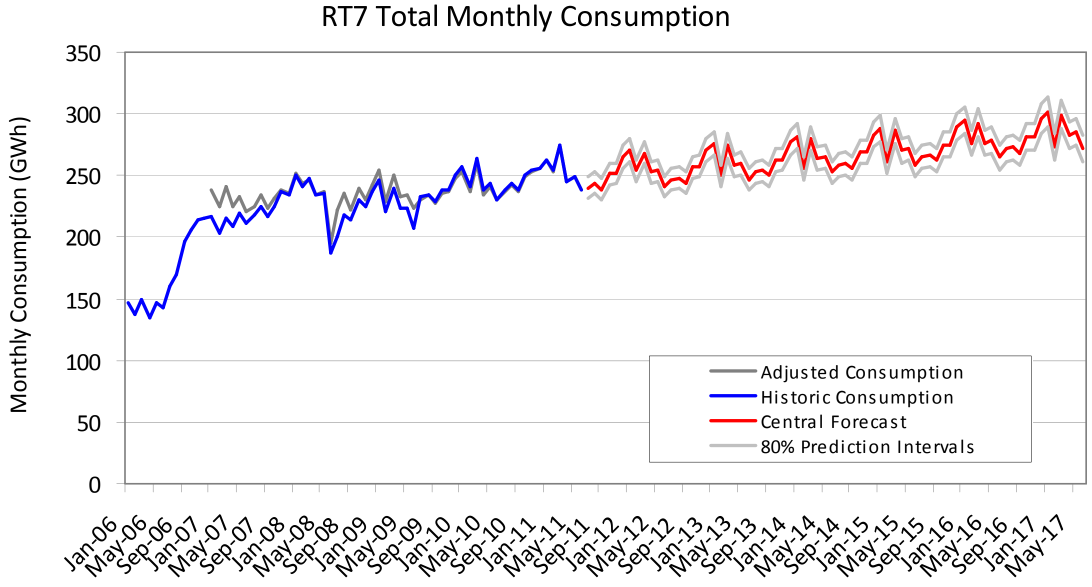


Figure 80: RT7 Monthly Consumption Central Forecast

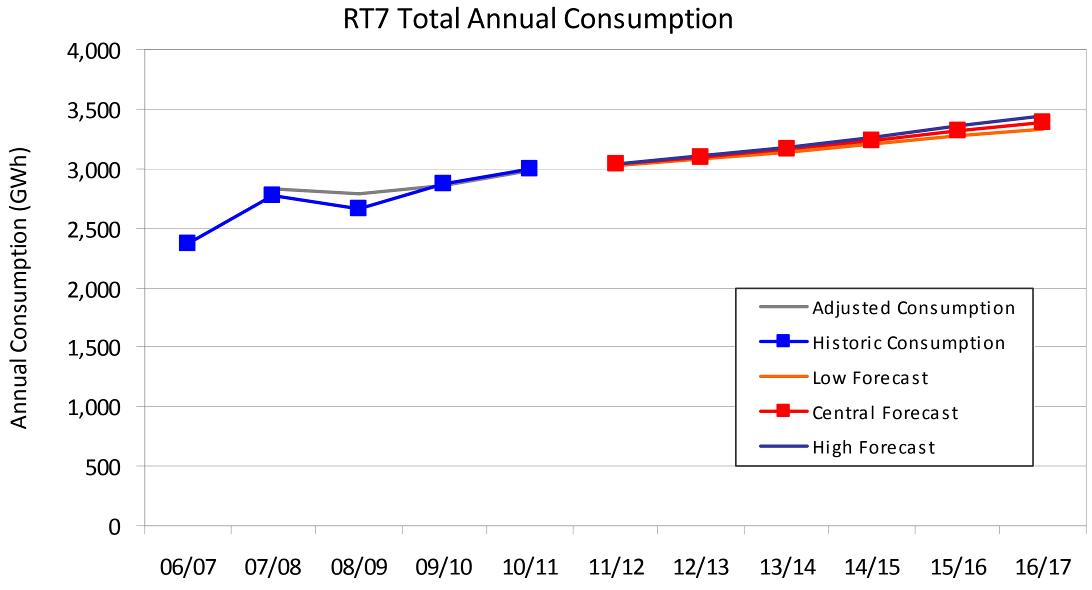


Figure 81: RT7 Annual Consumption Forecast

Gwh	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	2,371	2,775	2,664	2,874	2,996	0	0	0	0	0	0
Adjusted	0	2,824	2,787	2,859	2,987	0	0	0	0	0	0
Low	0	0	0	0	0	3,021	3,075	3,136	3,199	3,273	3,331
Central	0	0	0	0	0	3,031	3,089	3,159	3,232	3,317	3,386
High	0	0	0	0	0	3,041	3,103	3,183	3,265	3,361	3,442

Table 21: RT7 Consumption Forecast

11.3 Customer Numbers

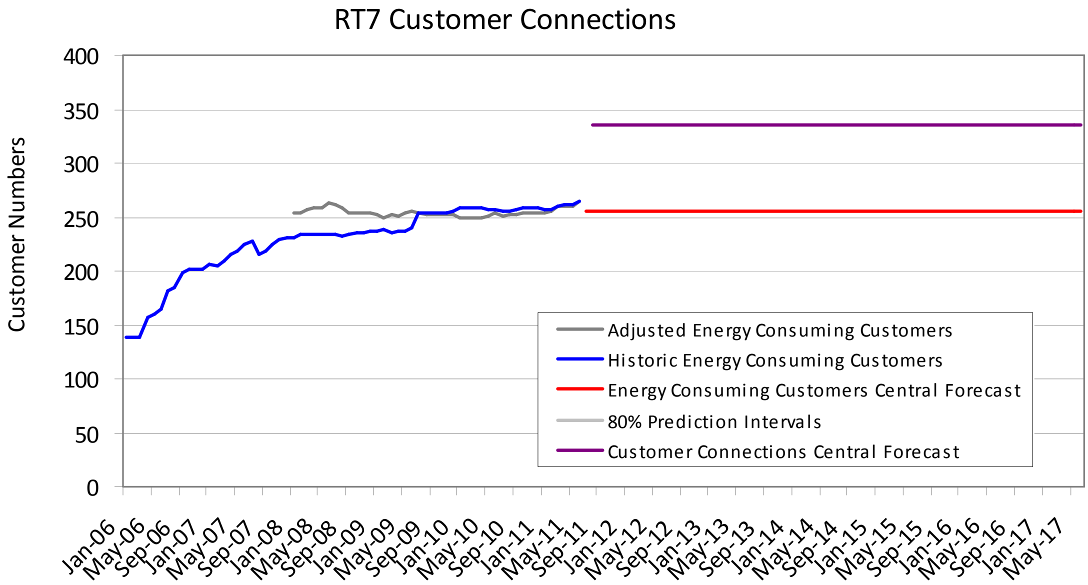


Figure 82: RT7 Monthly Customer Numbers Central Forecast

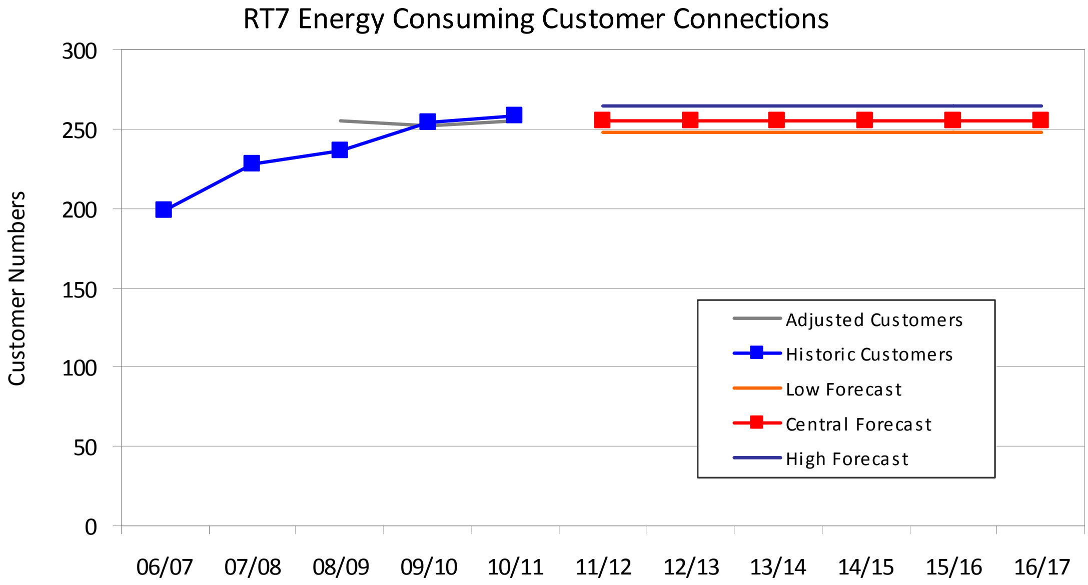


Figure 83: RT7 Annual Customer Numbers Forecast

Customers	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	199	228	236	254	258	0	0	0	0	0	0
Adjusted	0	0	255	252	255	0	0	0	0	0	0
Low	0	0	0	0	0	248	248	248	248	248	248
Central	0	0	0	0	0	255	255	255	255	255	255
High	0	0	0	0	0	264	264	264	264	264	264
Connections	0	0	0	0	0	336	336	336	336	336	336

Table 22: RT7 Customer Number Forecast

11.4 Consumption per Customer

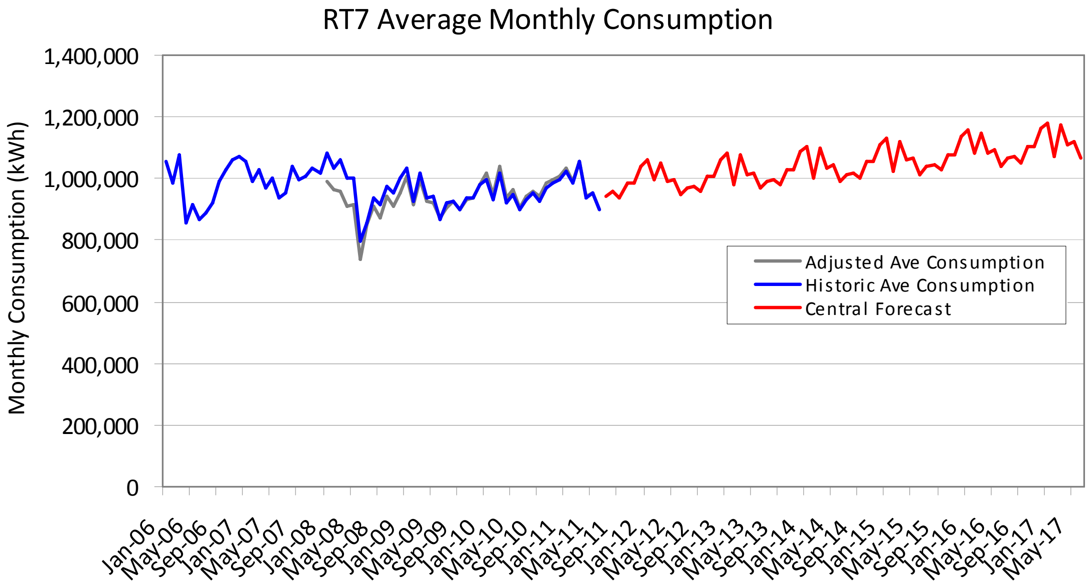


Figure 84: RT7 Monthly Consumption per Customer Central Forecast

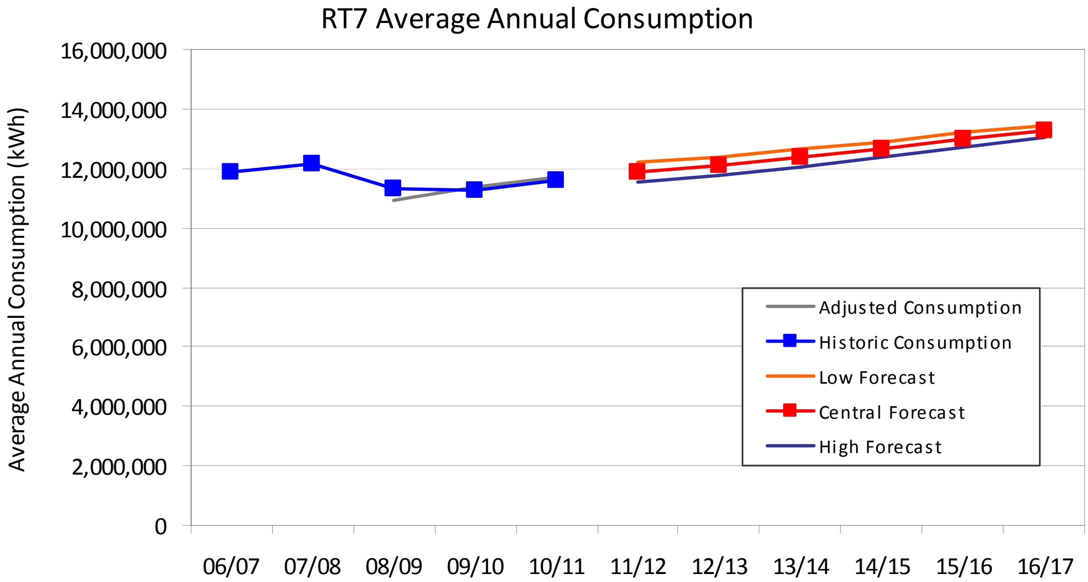


Figure 85: RT7 Annual Consumption per Customer Forecast

MWh	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	11,871	12,165	11,299	11,288	11,614	0	0	0	0	0	0
Adjusted	0	0	10,950	11,357	11,707	0	0	0	0	0	0
Low	0	0	0	0	0	12,182	12,400	12,644	12,898	13,198	13,431
Central	0	0	0	0	0	11,888	12,114	12,388	12,673	13,006	13,277
High	0	0	0	0	0	11,518	11,755	12,055	12,368	12,732	13,038

Table 23: RT7 Consumption per Customer Forecast

11.5 Customer Groups

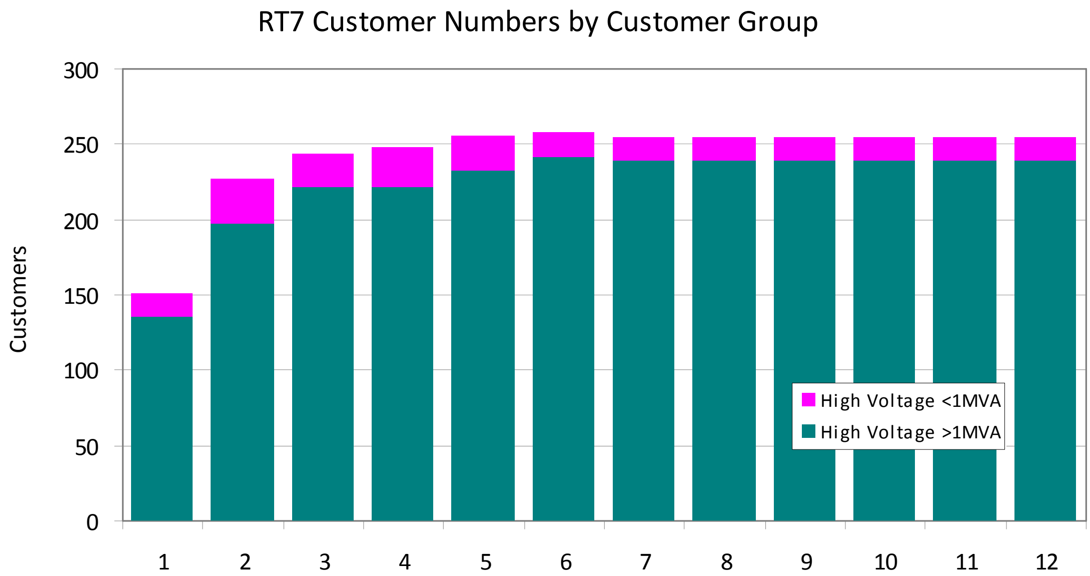


Figure 86: RT7 Annual Consumption by Customer Group

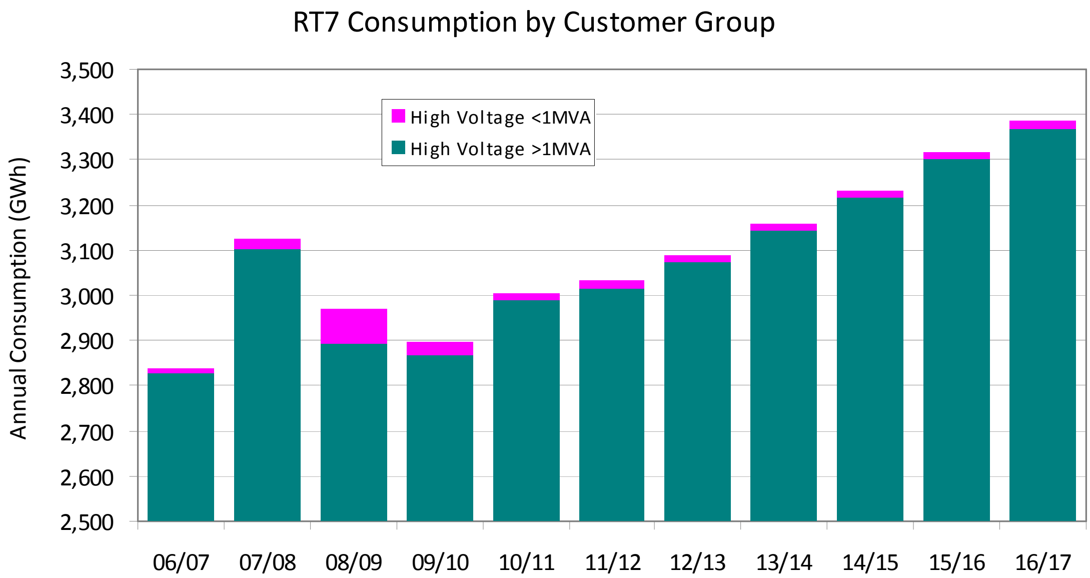


Figure 87: RT7 Annual Customer Numbers by Customer Group

11.6 Load Factors

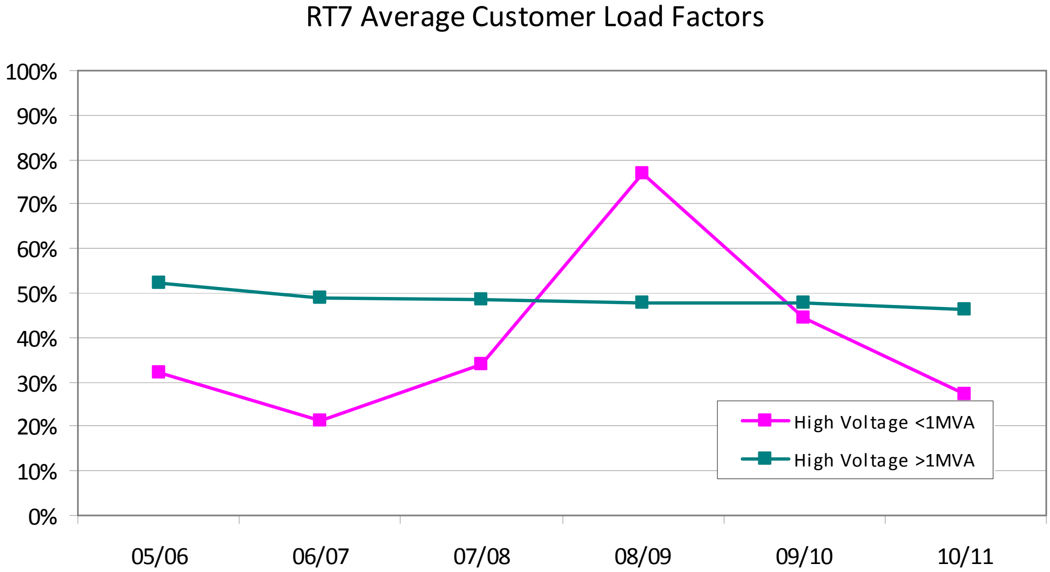


Figure 88: RT7 Average Customer Load Factors

12 RT8 – Low Voltage Contract Maximum Demand

This network tariff is appropriate for large low voltage business customers and currently includes approximately 60 energy consuming customers. This tariff has a long term decline in energy consumption per customer and in total. The decline is not correlated with any macro-economic variables. There is no underlying growth in new customers.

The model for total consumption on this tariff follows:

```
OLS, using observations 2006:01-2011:05 (T = 65)
Dependent variable: RT8_DAILY
HAC standard errors, bandwidth 3 (Bartlett kernel)

             coefficient   std. error   t-ratio    p-value
  --------------------------------------------------------
  const        586207        46821.6     12.52     1.26e-018 ***
  INDEX        -675.216      328.179     -2.057    0.0439    **
  TEMP_C       8065.56       987.046      8.171    2.00e-011 ***

R-squared            0.622722   Adjusted R-squared   0.610552
F(2, 62)             64.16549   P-value(F)           7.93e-16
```

Figure 89: RT8 Consumption Regression Output

On this tariff, the customer numbers are assumed as follows:

```
High = 65 Customers
Central = 63 Customers
Low = 61 Customers
```

Figure 90: RT8 Customer Assumptions

12.1 Comments

The consumption model presented in Figure 52 includes Temperature and an Index variable only because RT8 consumption was not appropriately correlated with any other macro economic variables. It is the only tariff that is showing long term decline in total and average consumption.

An estimate of 87 customer connections during 10/11 financial year was taken from NetCIS, which implies an average vacancy rate of 25%. It is assumed that this occupancy rate will continue on this tariff.

12.2 Energy Consumption

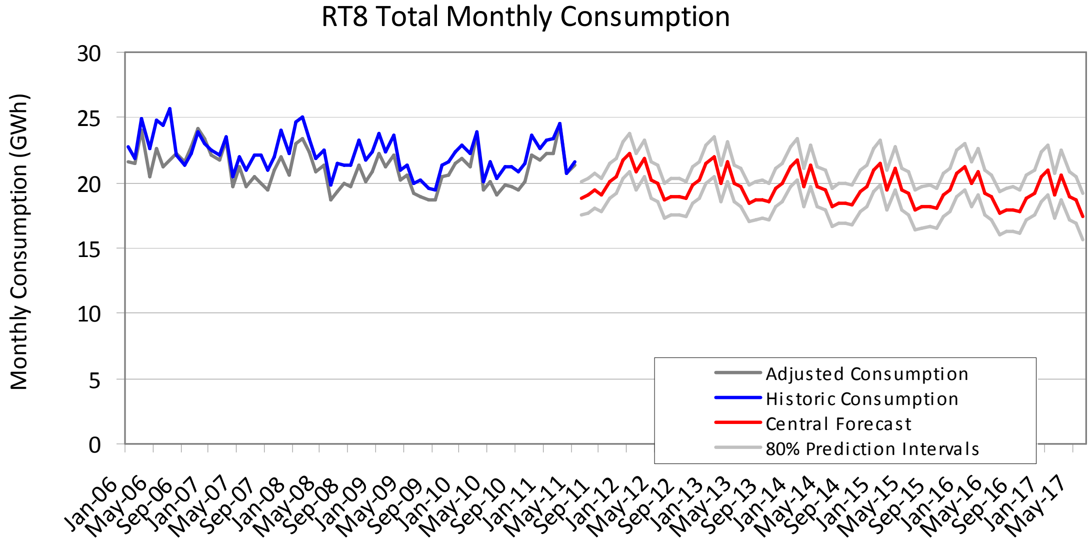


Figure 91: RT8 Monthly Consumption Central Forecast

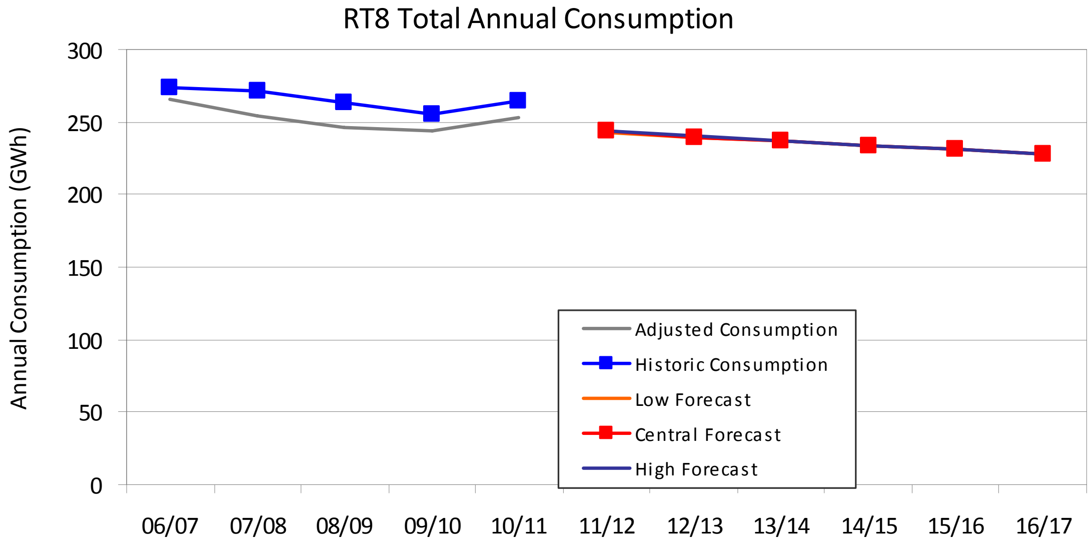


Figure 92: RT8 Annual Consumption Forecast

Gwh	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	273	272	263	255	265	0	0	0	0	0	0
Adjusted	265	254	246	244	253	0	0	0	0	0	0
Low	0	0	0	0	0	243	240	237	234	232	228
Central	0	0	0	0	0	244	240	237	234	232	228
High	0	0	0	0	0	244	240	237	234	232	228

Table 24: RT8 Consumption Forecast

12.3 Customer Numbers

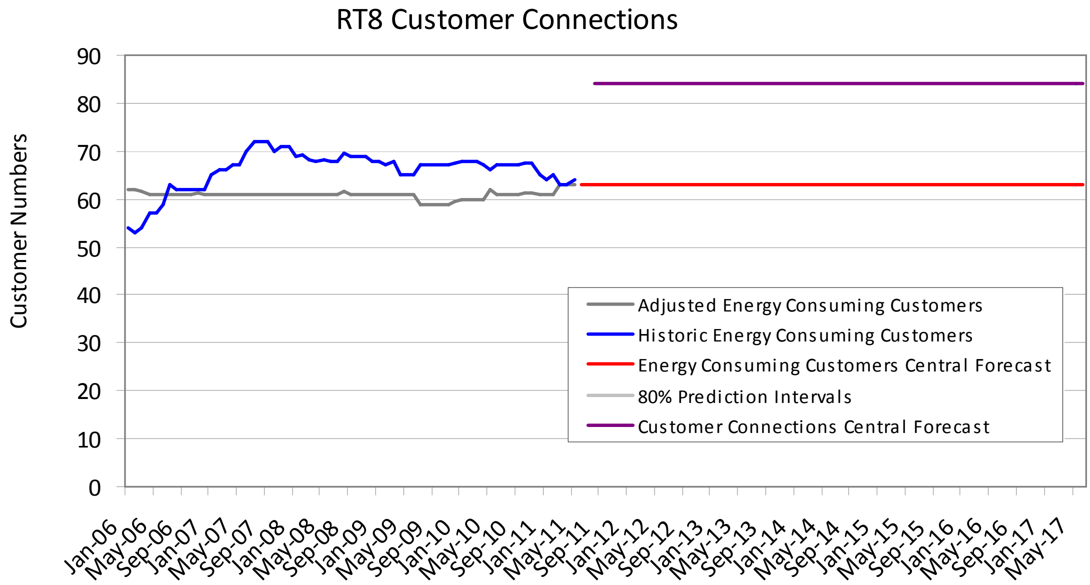


Figure 93: RT8 Monthly Customer Numbers Central Forecast

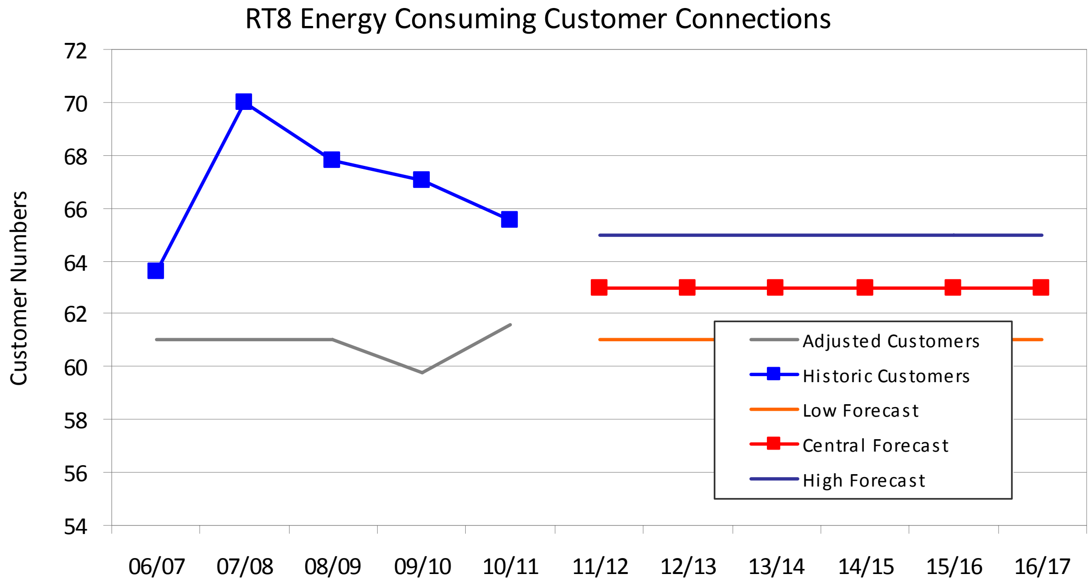


Figure 94: RT8 Annual Customer Numbers Forecast

Customers	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	64	70	68	67	66	0	0	0	0	0	0
Adjusted	61	61	61	60	62	0	0	0	0	0	0
Low	0	0	0	0	0	61	61	61	61	61	61
Central	0	0	0	0	0	63	63	63	63	63	63
High	0	0	0	0	0	65	65	65	65	65	65
Connections	0	0	0	0	0	84	84	84	84	84	84

Table 25: RT8 Customer Number Forecast

12.4 Consumption per Customer

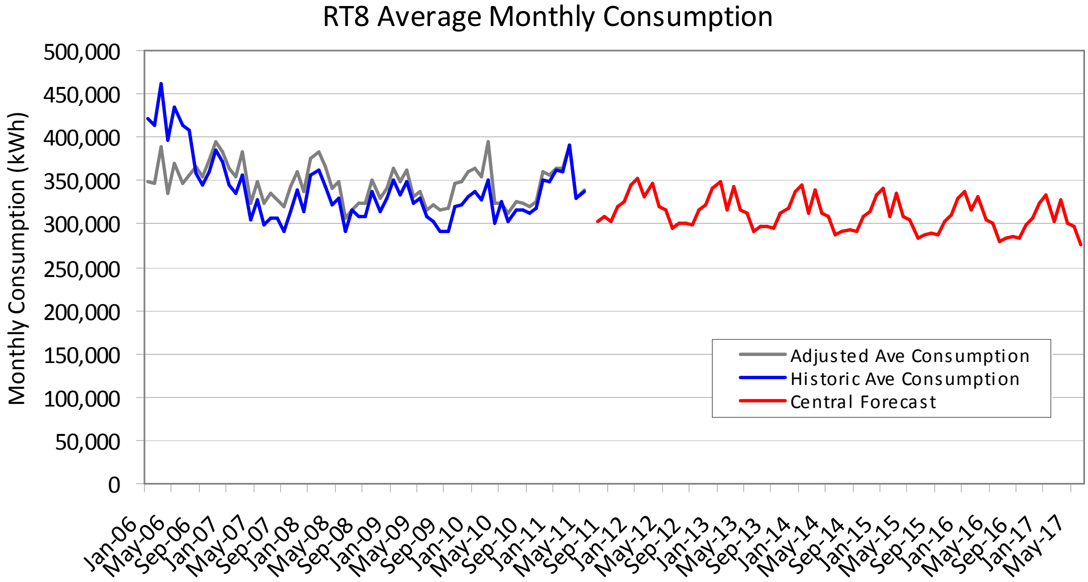


Figure 95: RT8 Monthly Consumption per Customer Central Forecast

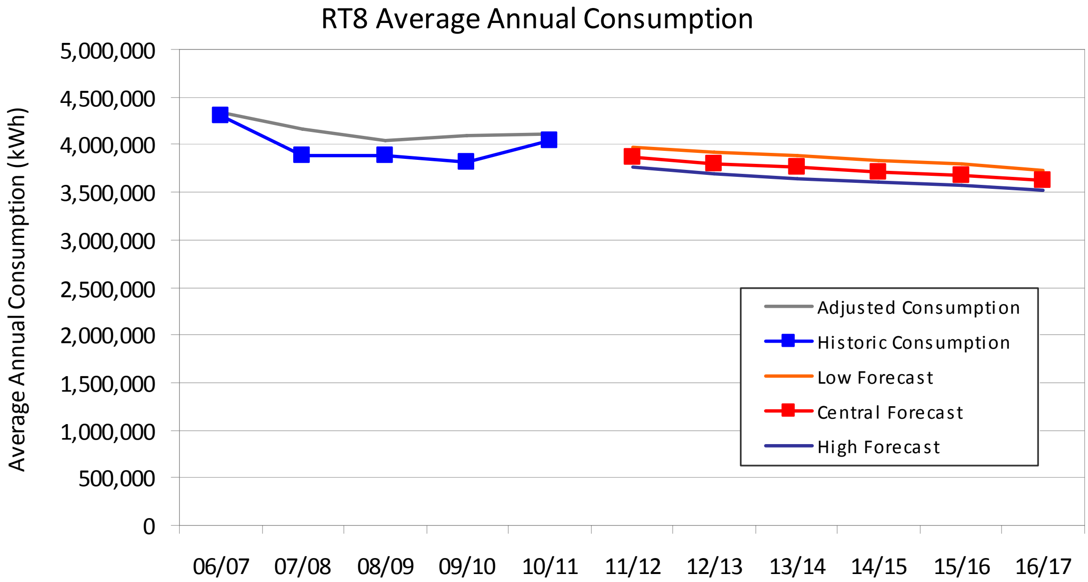


Figure 96: RT8 Annual Consumption per Customer Forecast

MWh	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	4,309	3,884	3,888	3,808	4,045	0	0	0	0	0	0
Adjusted	4,346	4,162	4,038	4,088	4,109	0	0	0	0	0	0
Low	0	0	0	0	0	3,980	3,931	3,883	3,835	3,797	3,738
Central	0	0	0	0	0	3,866	3,806	3,759	3,712	3,676	3,618
High	0	0	0	0	0	3,757	3,693	3,647	3,602	3,567	3,511

Table 26: RT8 Consumption per Customer Forecast

12.5 Customer Groups

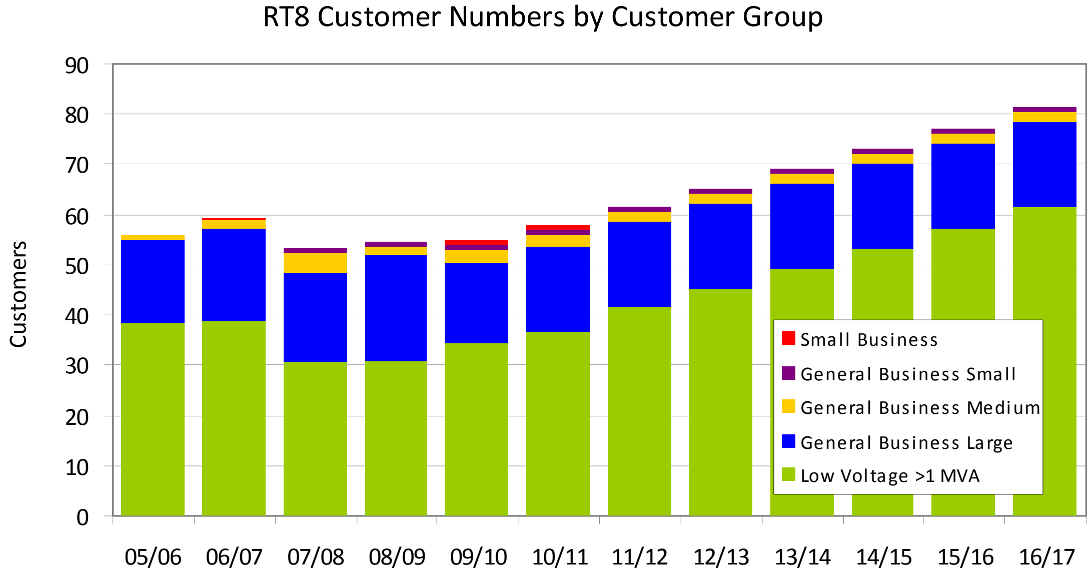


Figure 97: RT8 Annual Consumption by Customer Group

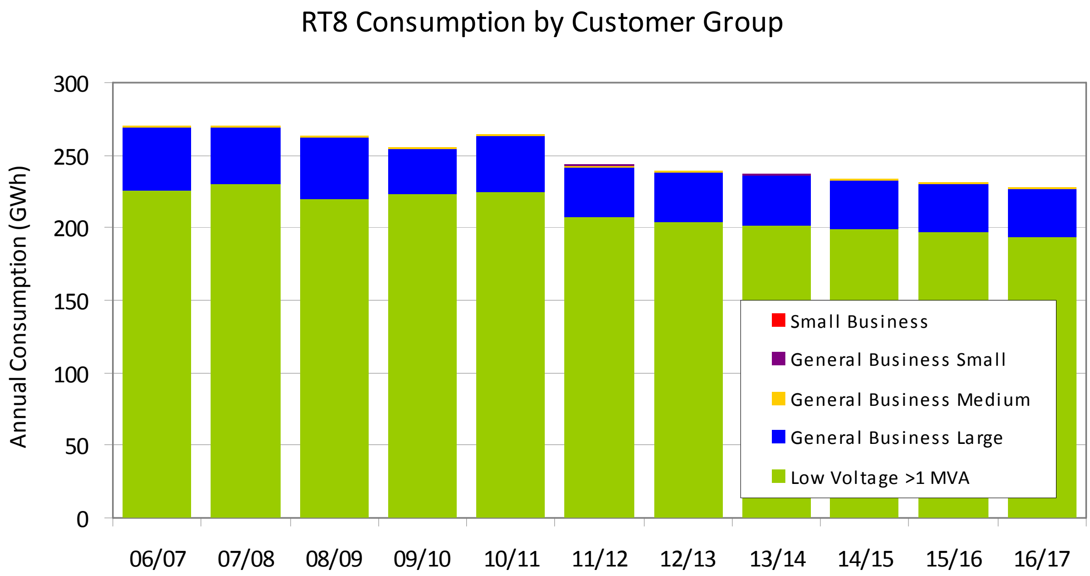


Figure 98: RT8 Annual Customer Numbers by Customer Group

12.6 Load Factors

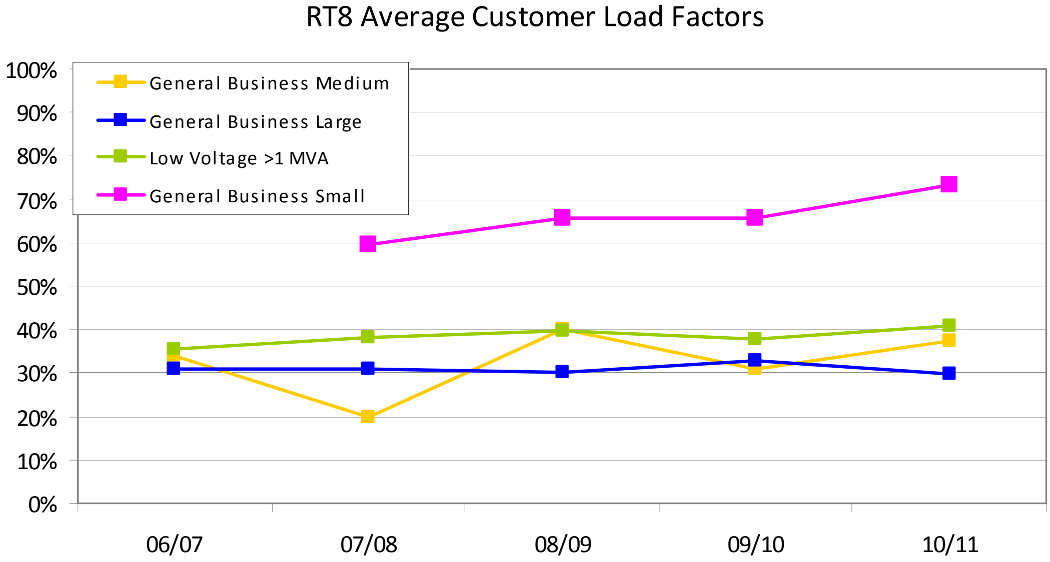


Figure 99: RT8 Average Customer Load Factors

13 RT9 – Streetlights Exit Service

This network tariff is appropriate for streetlights only. There are currently 226,828 streetlights in service for 114 distinct local governments.

The model for total consumption on this tariff follows:

```
OLS, using observations 2009:12-2011:09 (T = 22)
Dependent variable: RT9_DAILY
HAC standard errors, bandwidth 2 (Bartlett kernel)

             coefficient    std. error    t-ratio    p-value
  ---------------------------------------------------------------
  const      29848.1       22509.0         1.326    0.1998
  GSP_C      1.40970       0.112873        12.49    6.69e-011 ***

R-squared            0.918257   Adjusted R-squared   0.914170
F(1, 20)             155.9798   P-value(F)           6.69e-11
```

Figure 100: RT9 Consumption Regression Output

The model for streetlight numbers on this tariff follows:

```
OLS, using observations 2009:12-2011:09 (T = 22)
Dependent variable: RT9_COUNT
HAC standard errors, bandwidth 2 (Bartlett kernel)

             coefficient     std. error     t-ratio   p-value
  ------------------------------------------------------------
  const      66711.2        15468.5          4.313    0.0003    ***
  GSP_C      0.805832       0.0773771        10.41    1.59e-09 ***

R-squared            0.891060   Adjusted R-squared   0.885613
F(1, 20)             108.4585   P-value(F)           1.59e-09
```

Figure 101: RT9 Customers Regression Output

13.1 Comments

Since an adjustment in 2009 streetlight numbers have been growing steadily. Contrary to expectation, consumption per light has also been going up, driven by an increase in the average wattage of installed bulbs.

13.2 Energy Consumption

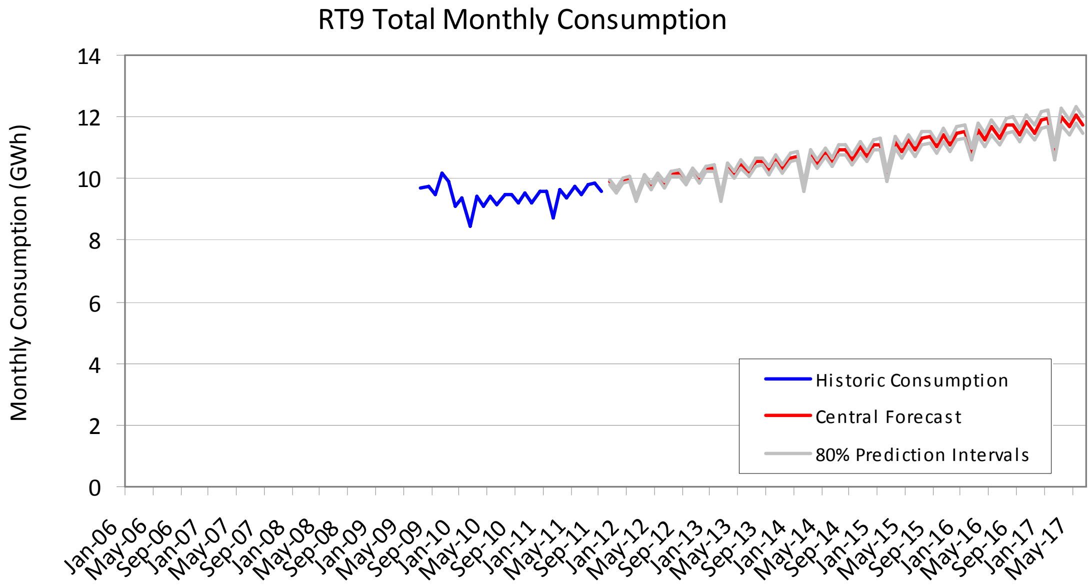


Figure 102: RT9 Monthly Consumption Central Forecast

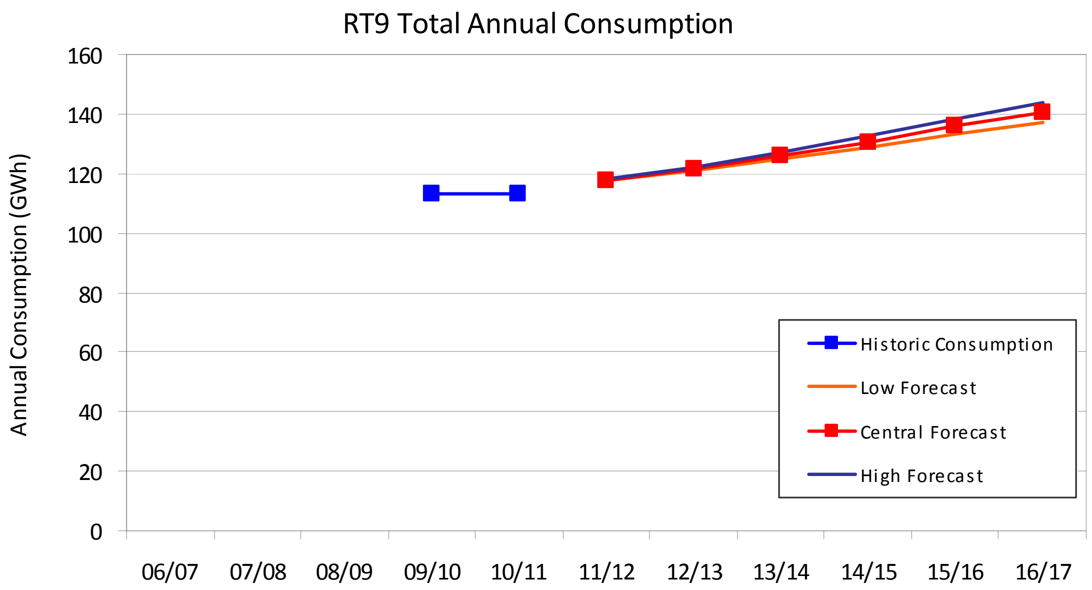


Figure 103: RT9 Annual Consumption Forecast

Gwh	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	0	0	0	113	113	0	0	0	0	0	0
Low	0	0	0	0	0	118	121	125	129	133	137
Central	0	0	0	0	0	118	122	126	131	136	140
High	0	0	0	0	0	118	122	127	133	138	144

Table 27: RT9 Consumption Forecast

13.3 Customer Numbers

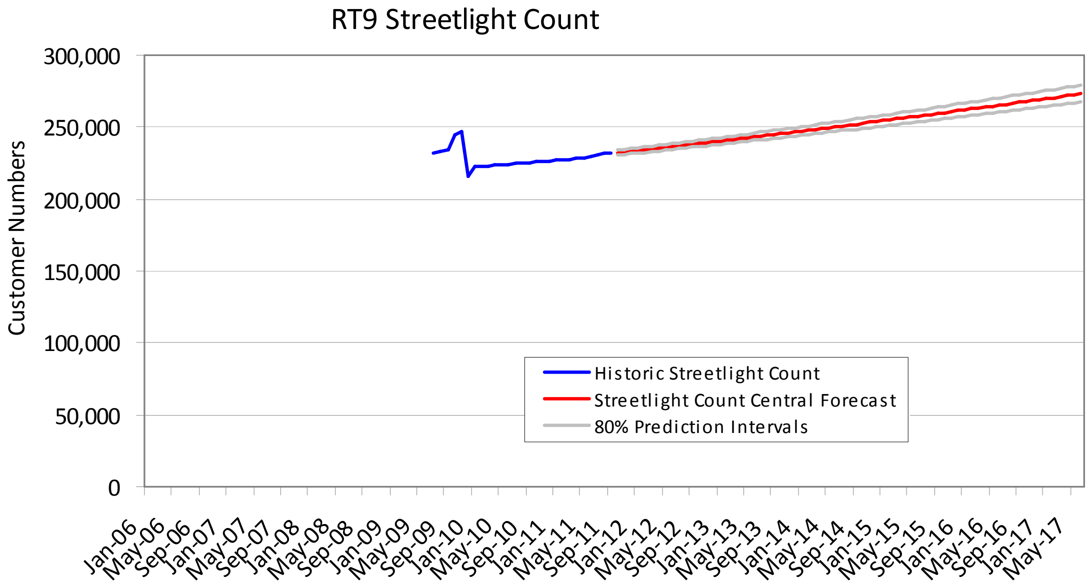


Figure 104: RT9 Monthly Streetlights Central Forecast

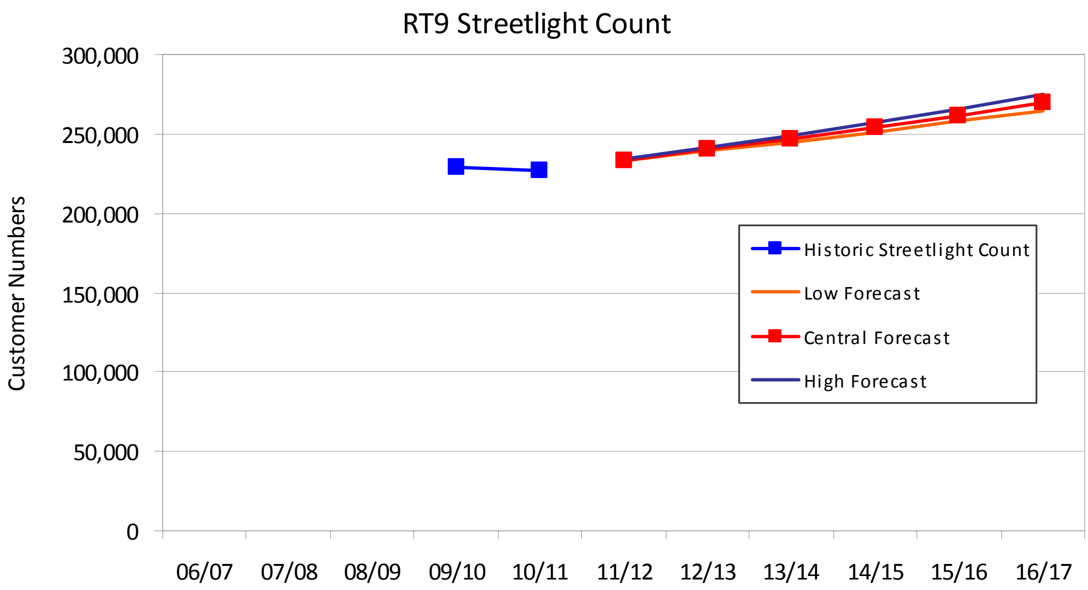


Figure 105: RT9 Annual Streetlights Forecast

Streetlights	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	0	0	0	228,811	226,828	0	0	0	0	0	0
Low	0	0	0	0	0	233,193	238,936	244,986	251,249	257,730	264,439
Central	0	0	0	0	0	233,520	240,095	247,030	254,243	261,744	269,546
High	0	0	0	0	0	233,843	241,247	249,071	257,247	265,791	274,720

Table 28: RT9 Customer Number Forecast

13.4 Consumption per Customer

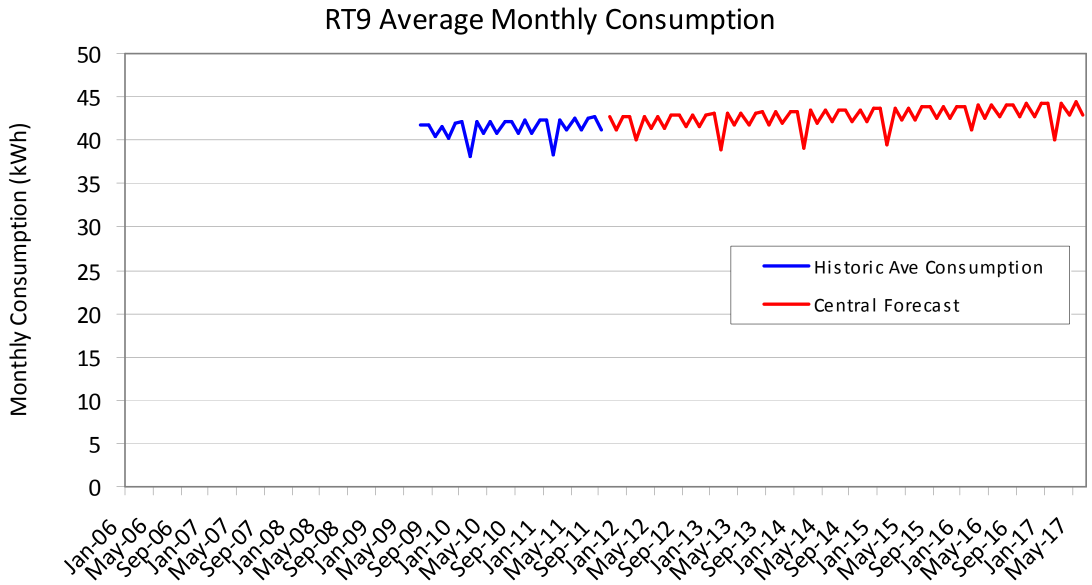


Figure 106: RT9 Monthly Consumption per Customer Central Forecast

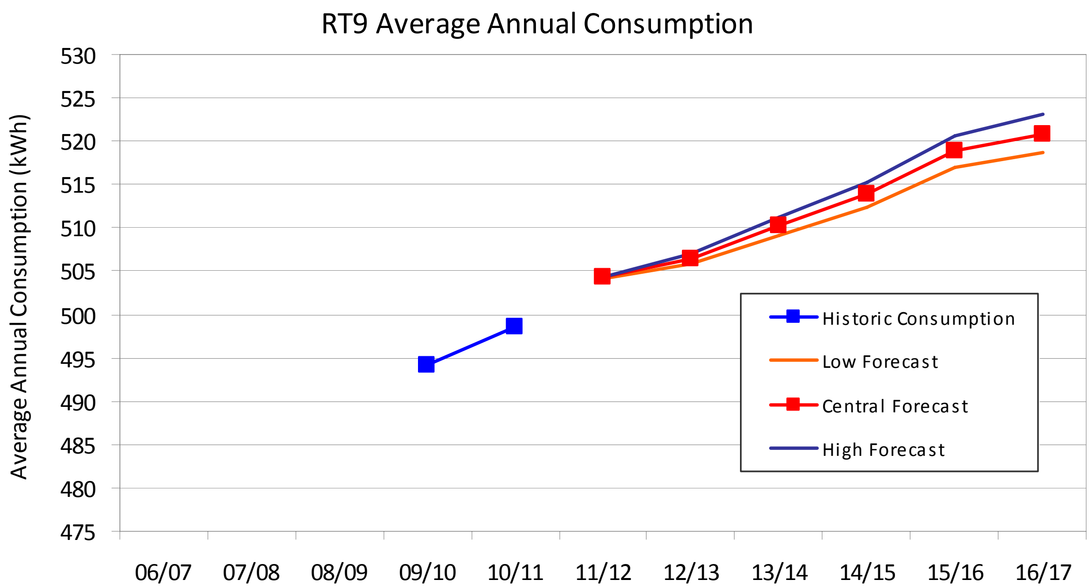


Figure 107: RT9 Annual Consumption per Customer Forecast

kWh	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	0	0	0	494	498	0	0	0	0	0	0
Low	0	0	0	0	0	504	506	509	512	517	519
Central	0	0	0	0	0	504	506	510	514	519	521
High	0	0	0	0	0	504	507	511	515	521	523

Table 29: RT9 Consumption per Customer Forecast

13.5 Customer Groups

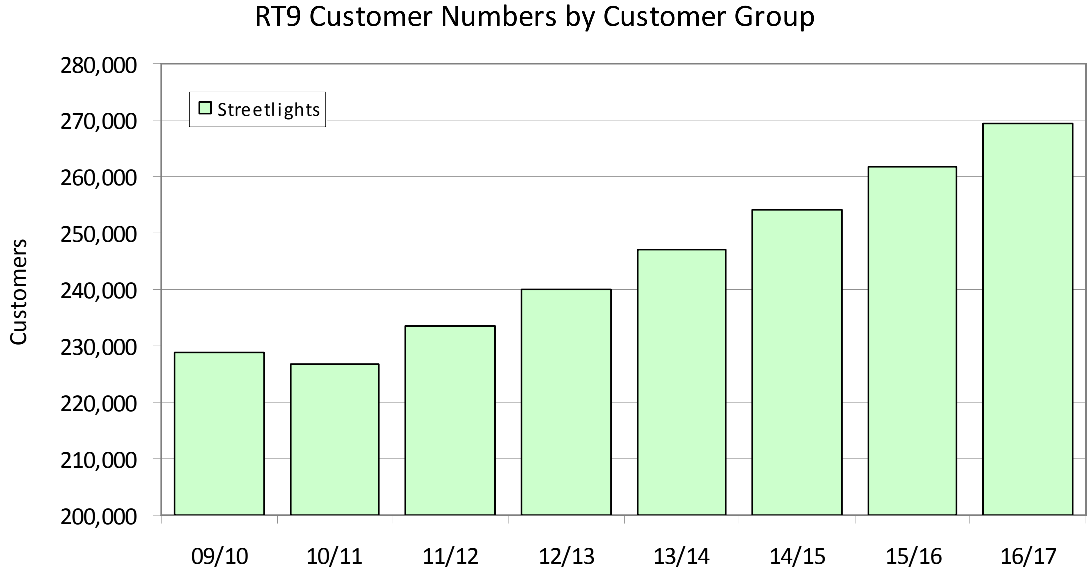


Figure 108: RT9 Annual Consumption by Customer Group

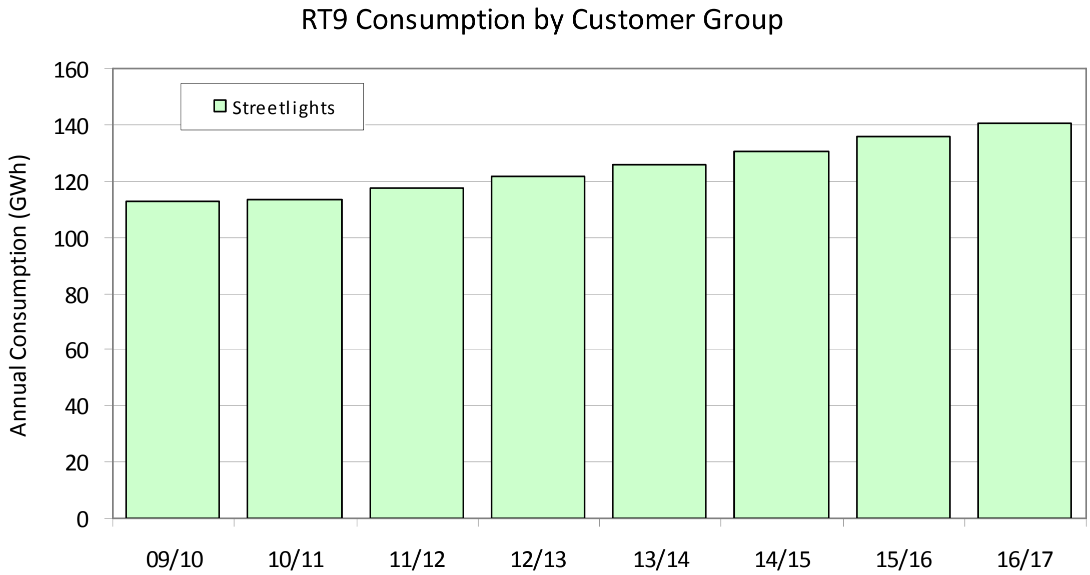


Figure 109: RT9 Annual Customer Numbers by Customer Group

14 RT10 – Unmetered Exit Service

This network tariff is appropriate for unmetered supplies including traffic lights and public telephones. There are currently 15,472 unmetered supplies in the Western Power network.

The model for total consumption on this tariff follows:

```
OLS, using observations 2009:07-2011:09 (T = 27)
Dependent variable: RT10_DAILY_kWh
HAC standard errors, bandwidth 2 (Bartlett kernel)

              coefficient     std. error    t-ratio    p-value
  -------------------------------------------------------------
  const       83262.3         6062.33       13.73      3.78e-013 ***
  GSP_C       0.0520698       0.0306184     1.701      0.1014

R-squared            0.183057   Adjusted R-squared   0.150379
F(1, 25)             2.892054   P-value(F)           0.101426
```

Figure 110: RT10 Consumption Regression Output

The model for supply numbers on this tariff follows:

```
OLS, using observations 2009:07-2011:09 (T = 27)
Dependent variable: RT10_COUNT
HAC standard errors, bandwidth 2 (Bartlett kernel)

              coefficient     std. error    t-ratio    p-value
  -------------------------------------------------------------
  const       11603.4         321.093        36.14     4.22e-023 ***
  GSP_C       0.0195107       0.00163201     11.95     7.79e-012 ***

R-squared            0.836819   Adjusted R-squared   0.830292
F(1, 25)             142.9212   P-value(F)           7.79e-12
```

Figure 111: RT10 Customers Regression Output

14.1 Comments

Unmetered supply numbers have been growing steadily. Unlike streetlights however, consumption per unit has been decreasing, perhaps reflecting a move towards more energy efficient lighting and appliances.

The energy regression has a very low r-squared which is sometimes an indication of a poor fitting model. The r-squared is also low when consumption is not growing or declining as is the case with this tariff. Although the r-squared is low the model proposed is still believed to provide the most explanatory power.

14.2 Energy Consumption

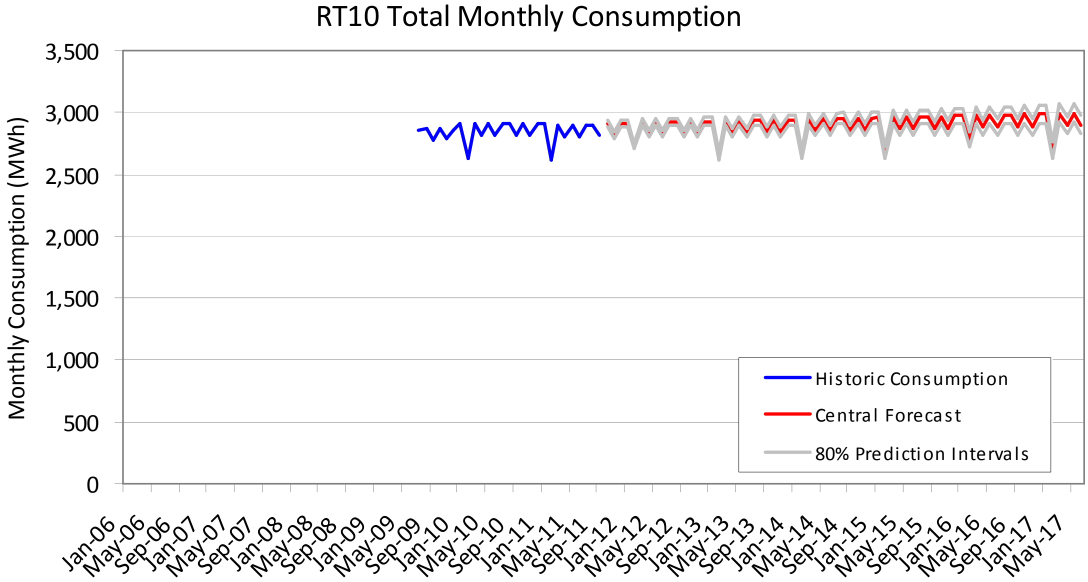


Figure 112: RT10 Monthly Consumption Central Forecast

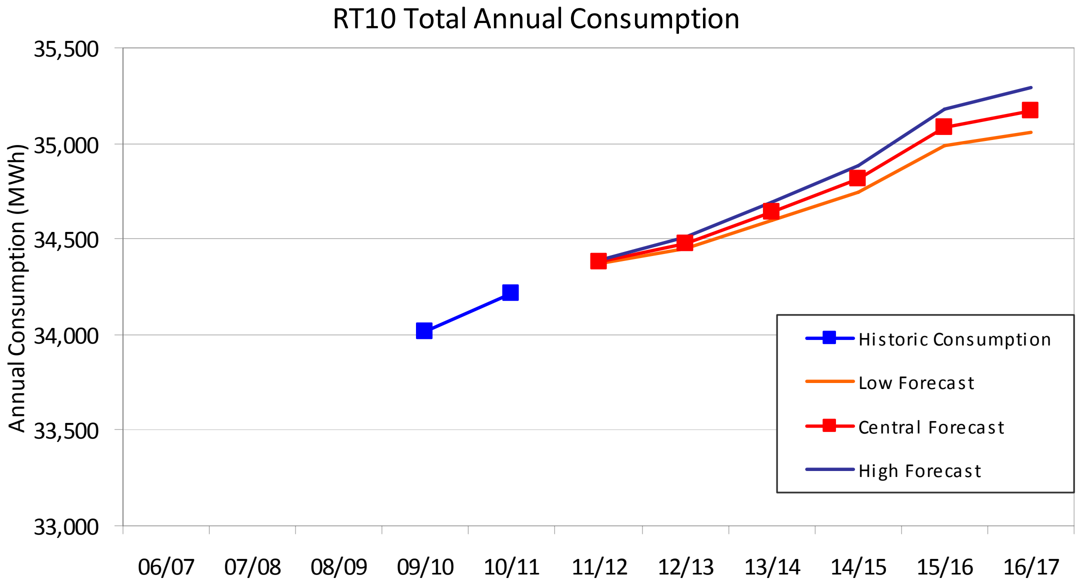


Figure 113: RT10 Annual Consumption Forecast

Gwh	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	0	0	0	34	34	0	0	0	0	0	0
Low	0	0	0	0	0	34	34	35	35	35	35
Central	0	0	0	0	0	34	34	35	35	35	35
High	0	0	0	0	0	34	35	35	35	35	35

Table 30: RT10 Consumption Forecast

14.3 Customer Numbers

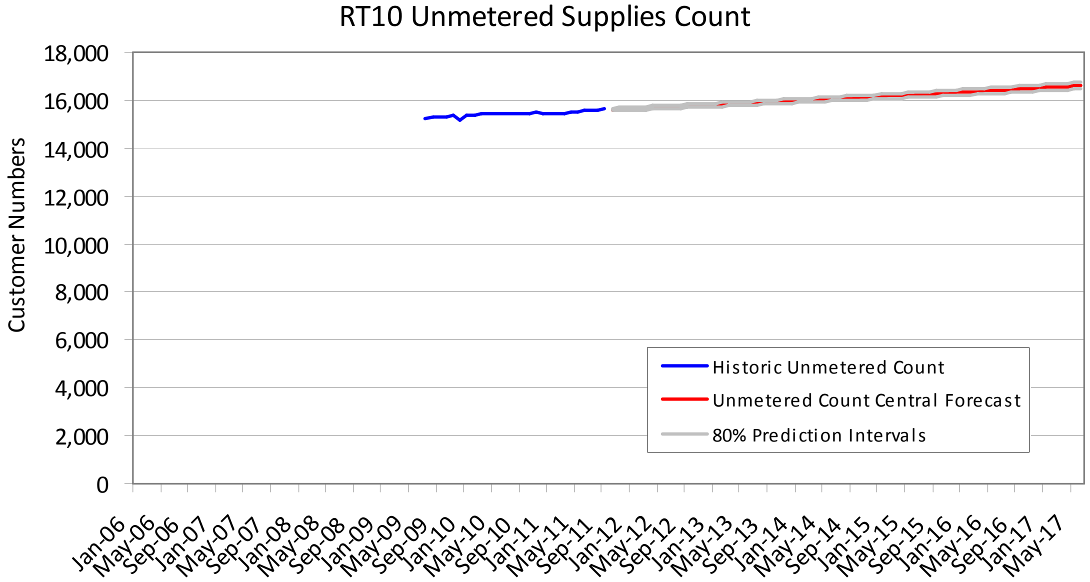


Figure 114: RT10 Monthly Streetlights Central Forecast

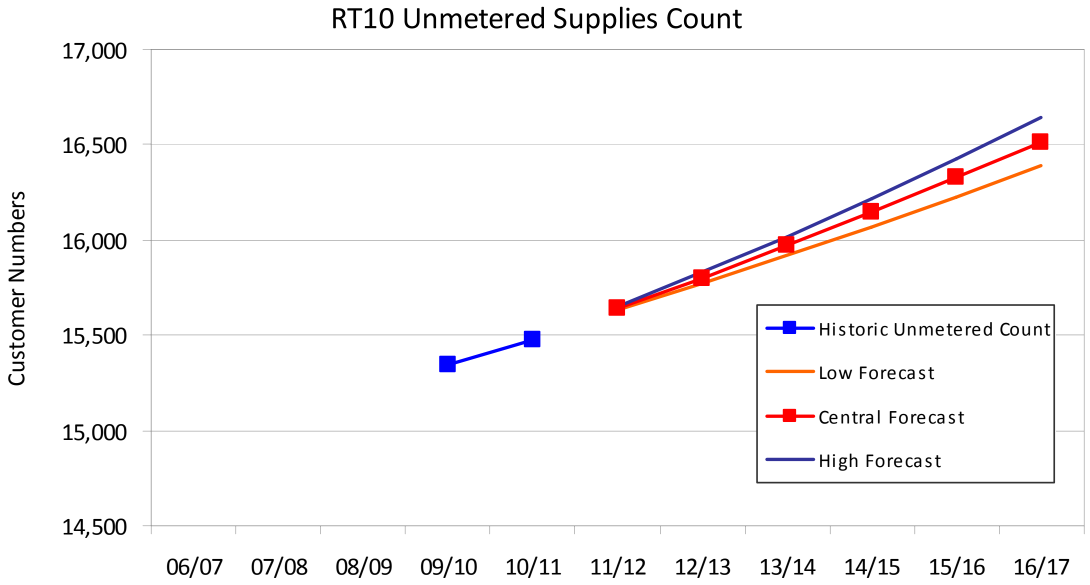


Figure 115: RT10 Annual Streetlights Forecast

Unmetered	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	0	0	0	15,343	15,472	0	0	0	0	0	0
Low	0	0	0	0	0	15,637	15,773	15,919	16,070	16,227	16,389
Central	0	0	0	0	0	15,645	15,801	15,969	16,144	16,326	16,514
High	0	0	0	0	0	15,653	15,830	16,020	16,218	16,425	16,642

Table 31: RT10 Customer Number Forecast

14.4 Consumption per Customer

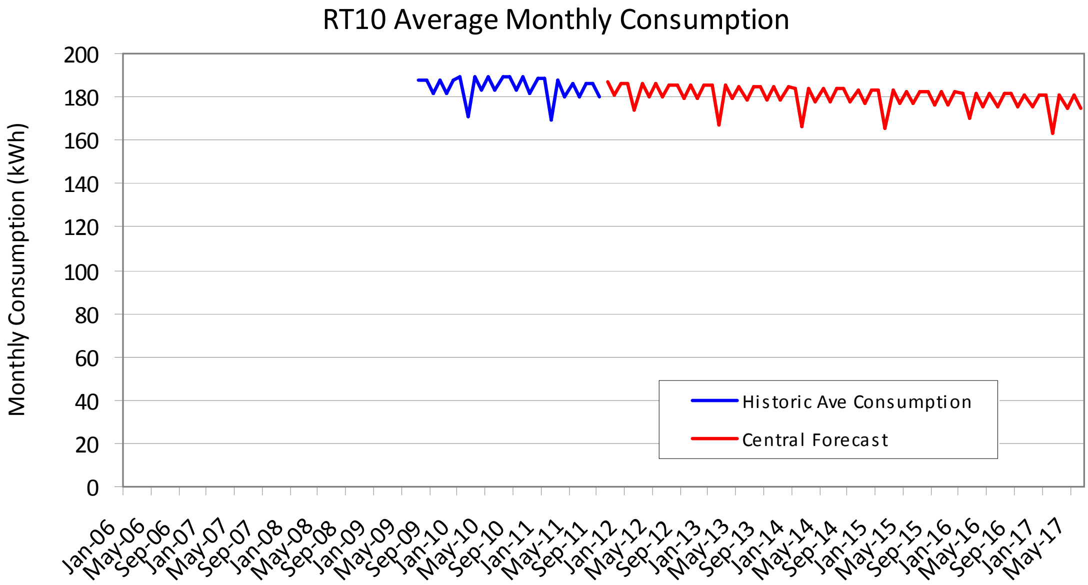


Figure 116: RT10 Monthly Consumption per Customer Central Forecast

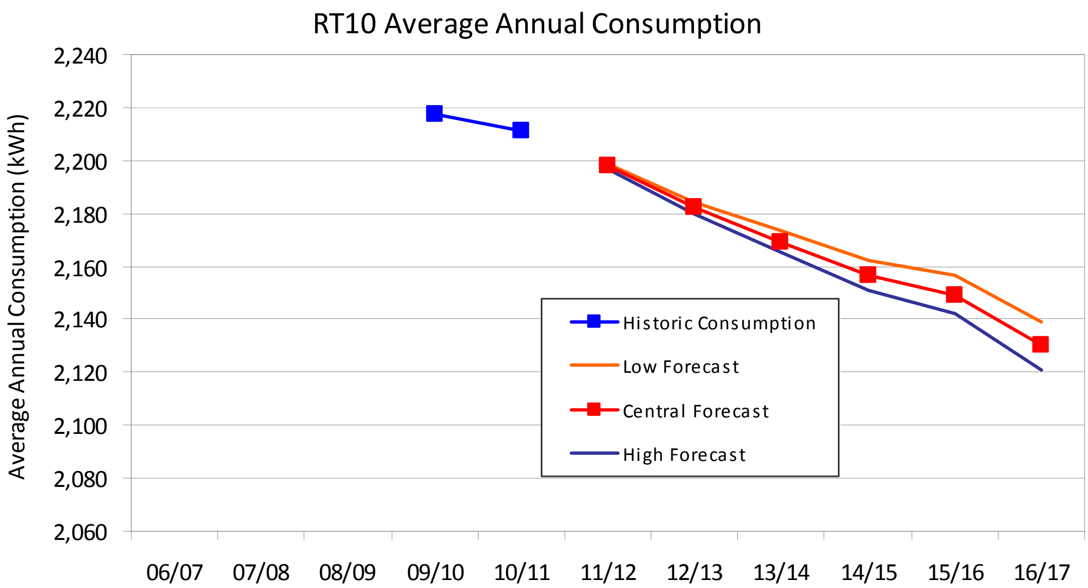


Figure 117: RT10 Annual Consumption per Customer Forecast

kWh	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	0	0	0	2,217	2,211	0	0	0	0	0	0
Low	0	0	0	0	0	2,198	2,184	2,173	2,162	2,156	2,139
Central	0	0	0	0	0	2,198	2,182	2,169	2,156	2,149	2,130
High	0	0	0	0	0	2,197	2,180	2,166	2,151	2,142	2,121

Table 32: RT10 Consumption per Customer Forecast

14.5 Customer Groups

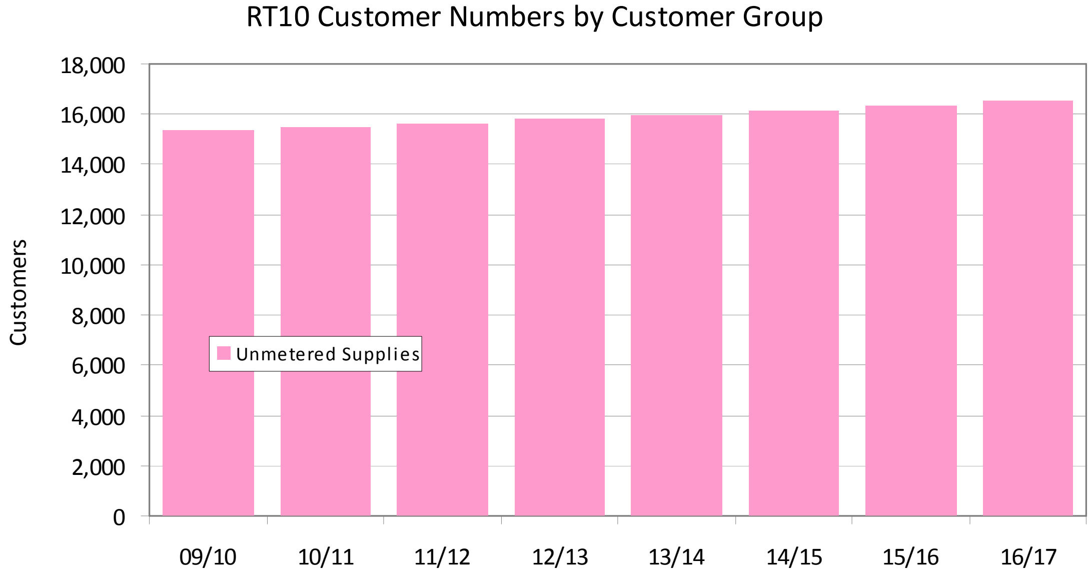


Figure 118: RT10 Annual Consumption by Customer Group

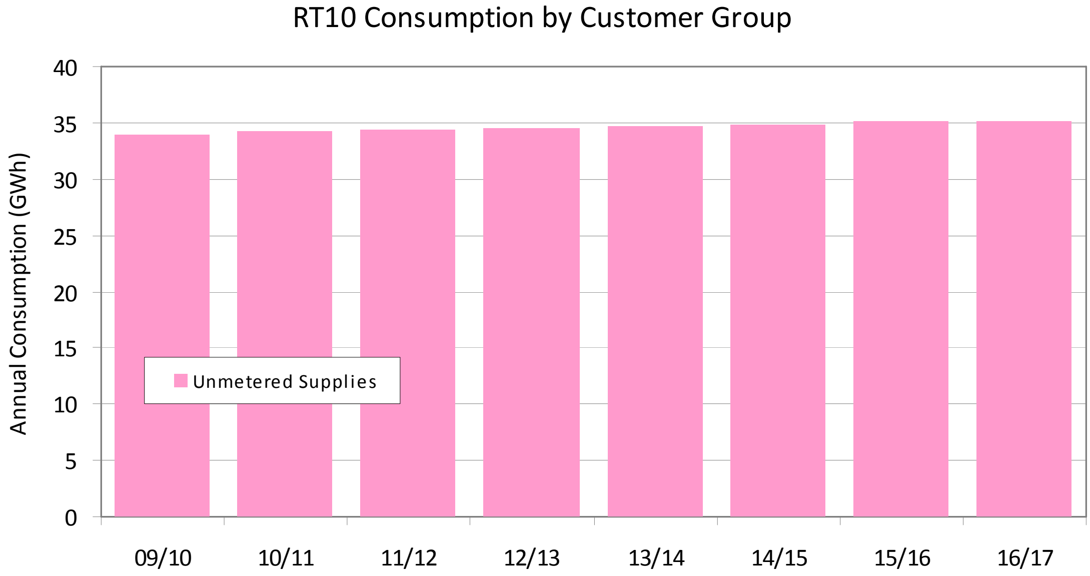


Figure 119: RT10 Annual Customer Numbers by Customer Group

15 TRT1 – Transmission Connected Exit Service

This network tariff is appropriate for large transmission connected customers. These customers typically own their own network infrastructure and are very large in scale and consumption. There are currently approximately 33 energy consuming customers, each with unique consumption profiles. As such this tariff is best forecast using an understanding of the consumption pattern of each customer, whether existing or new.

Existing customers:

ALCOA	PUBLIC TRANSPORT AUTHORITY OF WA
ALCOA OF AUSTRALIA LIMITED	SIMCOA
AUST FUSED MATERIALS PTY LTD	SIMCOA OPERATIONS PTY LTD
BGM	SOUTH WEST COGENERATION JV
BRADKEN PTY LIMITED	SOUTHERN CROSS ENERGY
BURSWOOD RESORT CASINO	SOUTHERN SEAWATER JOINT VENTURE
COCKBURN CEMENT LIMITED	TIWEST JOINT VENTURE
CSBP LIMITED	VERVE ENERGY
DORAL FUSED MATERIALS PTY LTD	WATER CORPORATION
HISMELT (OPERATIONS) PTY LIMITED	WESFARMERS PREMIER COAL LIMITED
ILUKA RESOURCES LIMITED	WMC RESOURCES LTD
PARKESTON POWER STATION	WORSLEY ALUMINA
PUBLIC TRANSPORT AUTHORITY	WORSLEY ALUMINA PTY LTD

Table 33: Existing Transmission Connected Customers

The existing customers draw a collective load of 211 GWh per month. This load is expected to continue.

Western Power system forecasting maintains forecasts for all large projects as part of peak demand forecasting. For energy forecasting, the same criteria have been used to determine the projects that are deemed ‘central’ and those that are ‘high’ and the timing that will apply. An expected load factor of 0.8 was applied to determine energy consumption. Below is a list of the expected new projects in Central and High cases.

Expected new customers for the Central Case:

Simcoa 3rd Furnace	Southern Seawater Desal Plant Stage 1 & 2
kararra Stage 1.1 & 1.2	Port of Oakajee Stage 1

Expected new customers for the High Case:

Grange Resources Southdown Mine	HMAS Stirling Garden Island, Stage 2
GPA – Asia Iron Export	Asia Iron Slurry Pump
Port of Oakajee Stage 1 & 2	Oakajee Industrial Estate
Oakajee Industrial Estate Heavy (Smelter)	Wickepin Kaolin Mine and WRS
Kwinana Ethanol Plant	Kararra Stage 1.1 – 2.4
Asia Iron Ltd – Extension Hill Mine Site	Ewington Coal Mine
Simcoa 3rd and 4th Furnace	Southern Seawater Desal Plant Stage 1 & 2
Port and Pumping for Grange Resources	Jack Hills
Black Swan Nickel Mine	

Table 34: Central and High Forecast Transmission Connected Customers

15.1 Energy Consumption

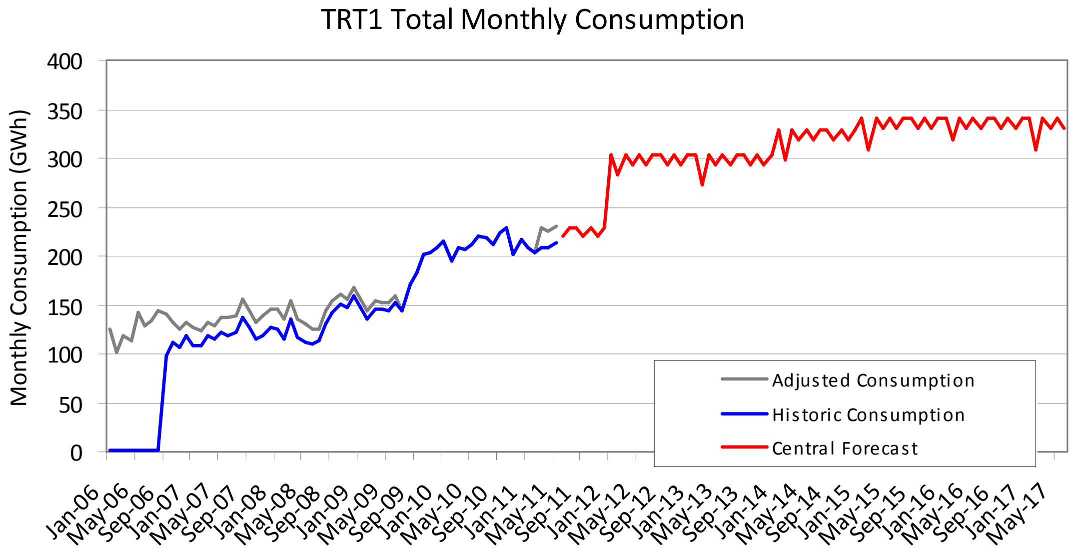


Figure 120: TRT1 Monthly Consumption Central Forecast

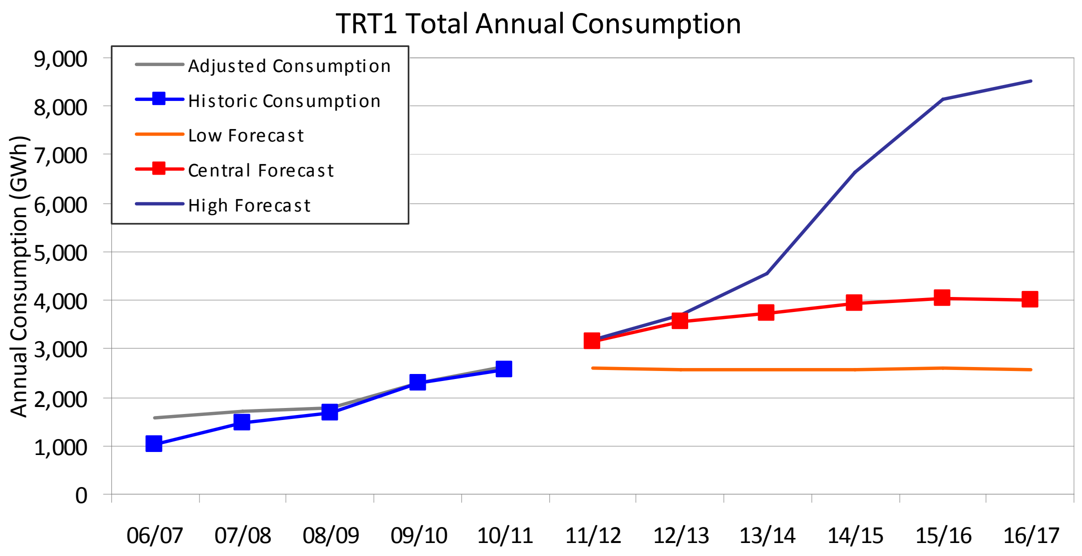


Figure 121: TRT1 Annual Consumption Forecast

Gwh	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	1,016	1,472	1,672	2,300	2,566	0	0	0	0	0	0
Adjusted	1,587	1,696	1,792	2,308	2,618	0	0	0	0	0	0
Low	0	0	0	0	0	2,585	2,578	2,578	2,578	2,585	2,578
Central	0	0	0	0	0	3,134	3,565	3,721	3,950	4,031	4,020

Table 35: TRT1 Consumption Forecast

15.2 Customer Numbers

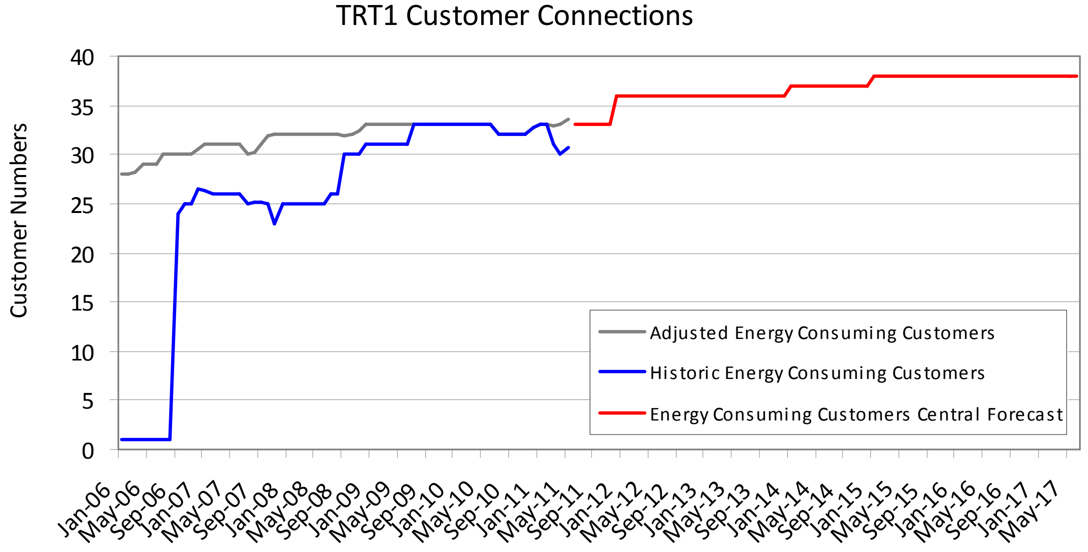


Figure 122: TRT1 Monthly Customer Number Central Forecast

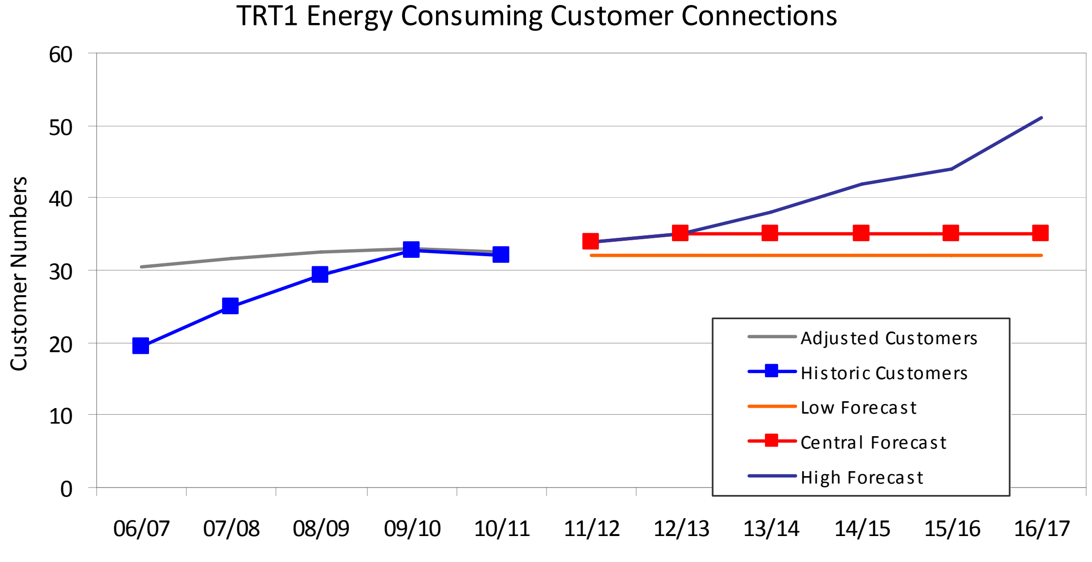


Figure 123: TRT1 Customer Number Forecast

Customers	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	19	25	29	33	32	0	0	0	0	0	0
Adjusted	30	32	33	33	33	0	0	0	0	0	0
Low	0	0	0	0	0	32	32	32	32	32	32
Central	0	0	0	0	0	34	35	35	35	35	35
High	0	0	0	0	0	34	35	38	42	44	51

Table 36: TRT1 Customer Number Forecast

15.3 Consumption per Customer

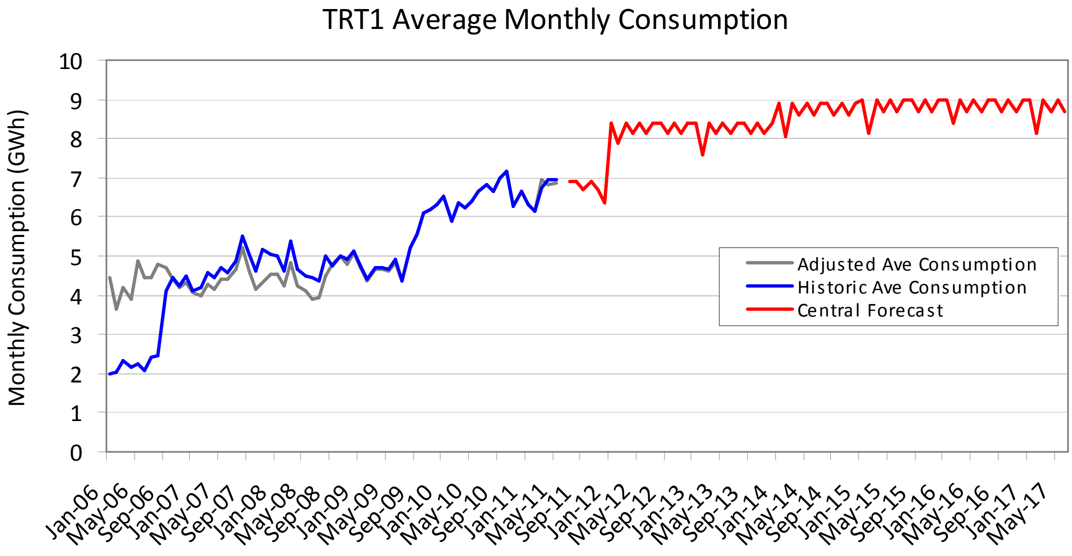


Figure 124: TRT1 Monthly Consumption per Customer Central Forecast

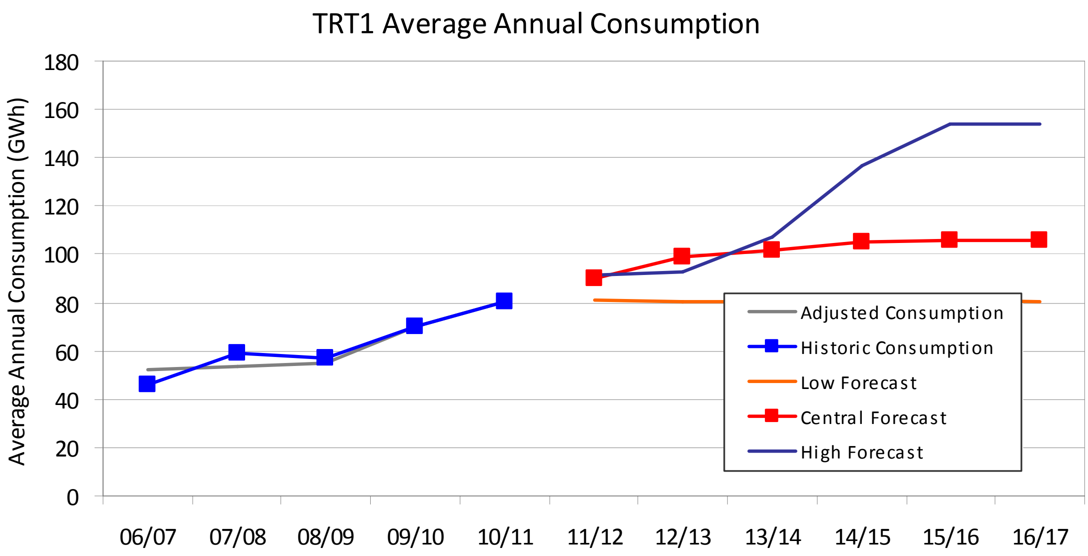


Figure 125: TRT1 Annual Consumption per Customer Forecast

MWh	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Actual	46,222	59,073	56,774	69,998	80,360	0	0	0	0	0	0
Adjusted	52,253	53,861	55,051	69,938	80,283	0	0	0	0	0	0
Low	0	0	0	0	0	80,788	80,567	80,567	80,567	80,788	80,567
Central	0	0	0	0	0	89,897	99,025	101,924	105,332	106,090	105,800

Table 37: TRT1 Consumption per Customer Forecast

15.4 Customer Groups

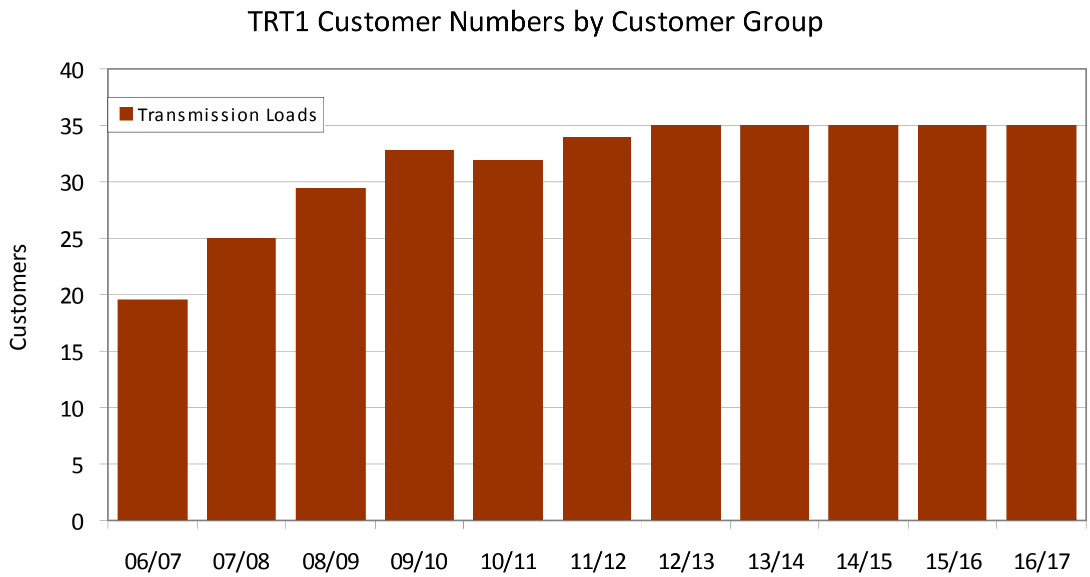


Figure 126: TRT1 Annual Consumption by Customer Group

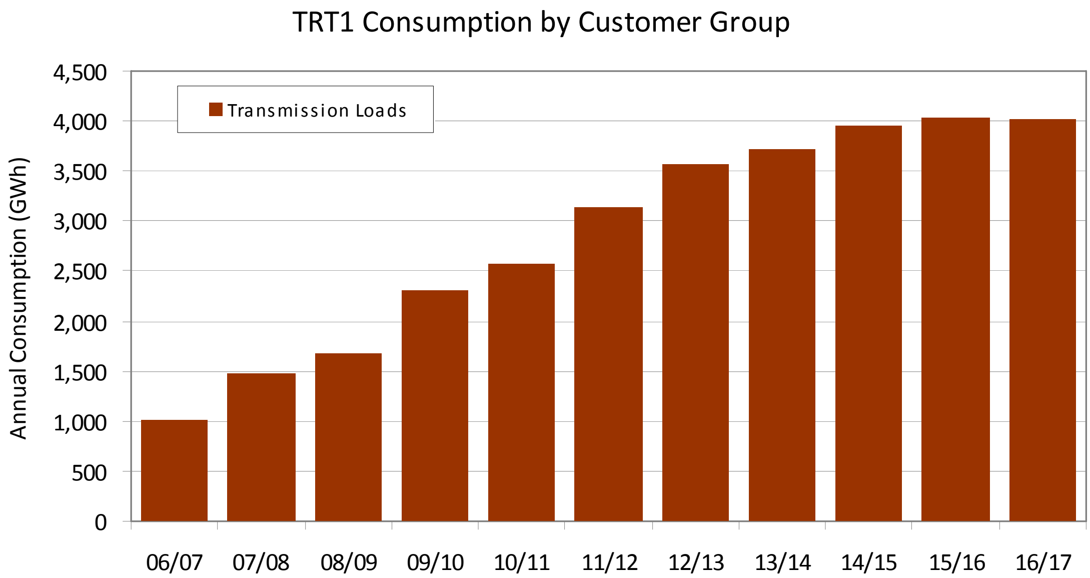


Figure 127: TRT1 Annual Customer Numbers by Customer Group

16 Summary by Customer Type

Below are the graphs that summarise the trends within customer and consumption data by customer type.

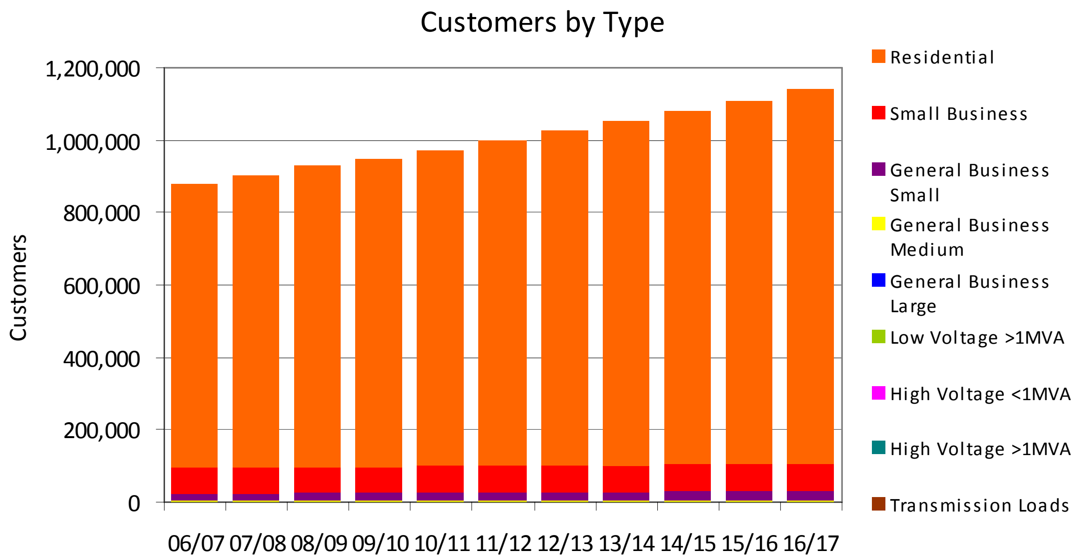


Figure 128: Customer Numbers by Customer Type

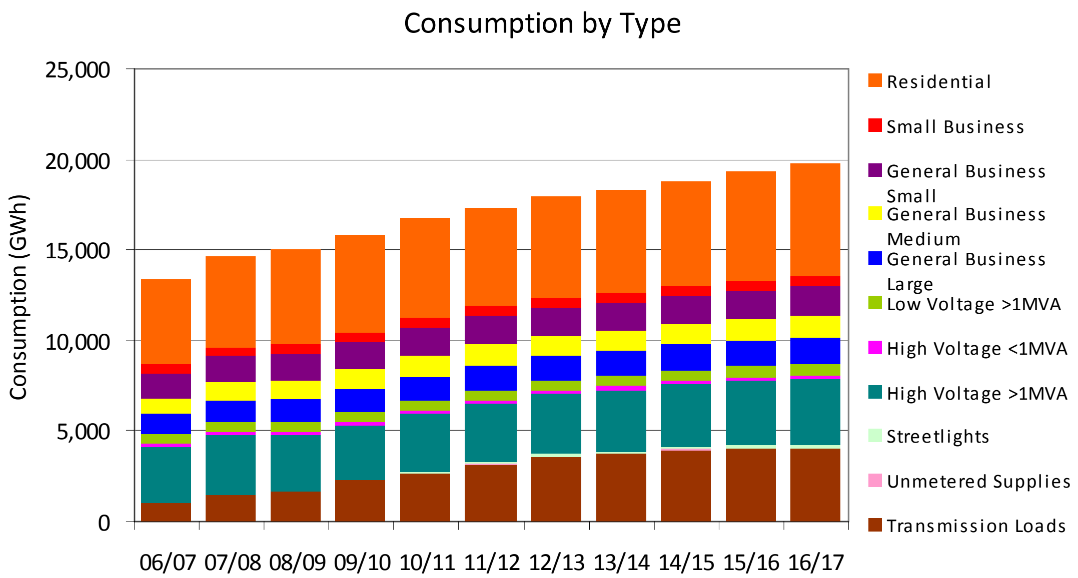


Figure 129: Consumption by Customer Type

16.1 Residential

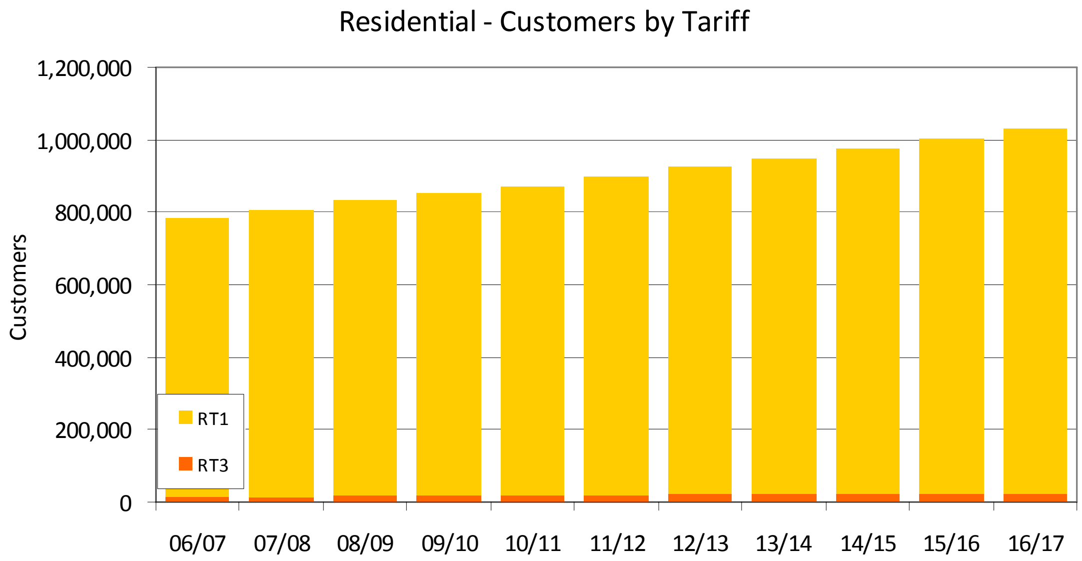


Figure 130: Residential Customer Numbers by Tariff

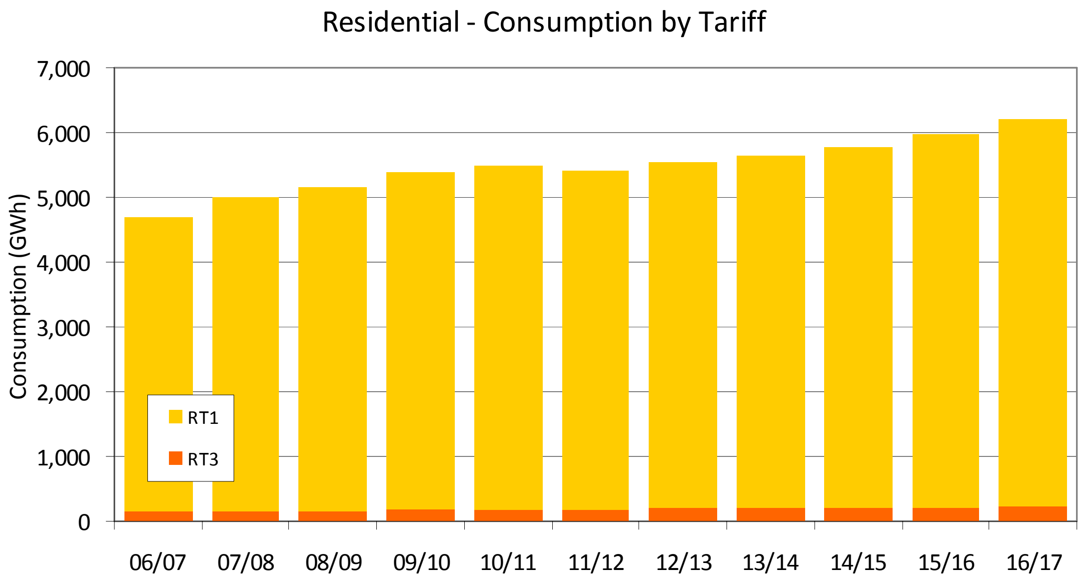


Figure 131: Residential Consumption by Tariff

16.2 Small Business

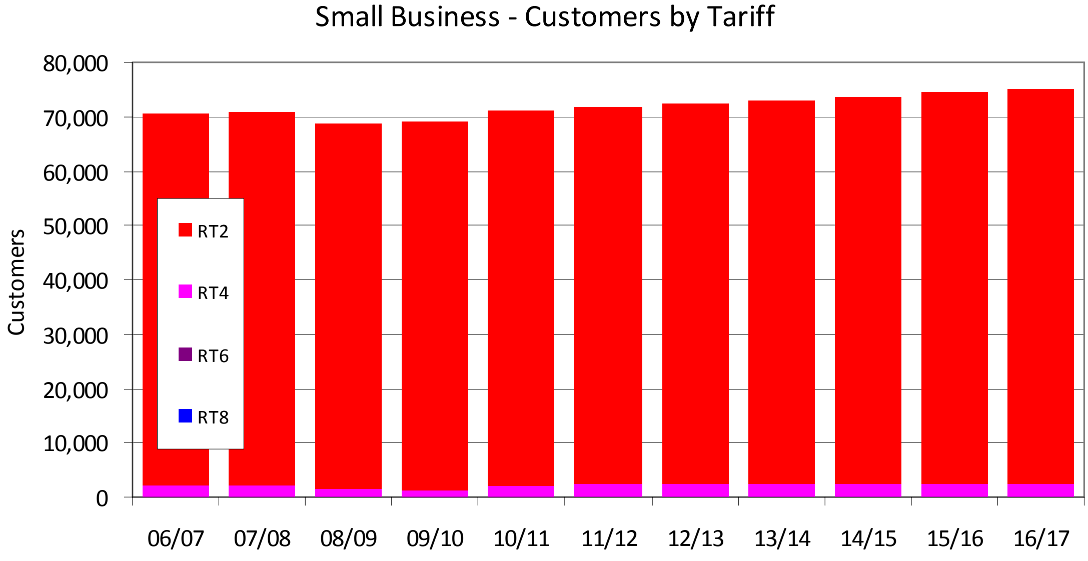


Figure 132: Small Business Customer Numbers by Tariff

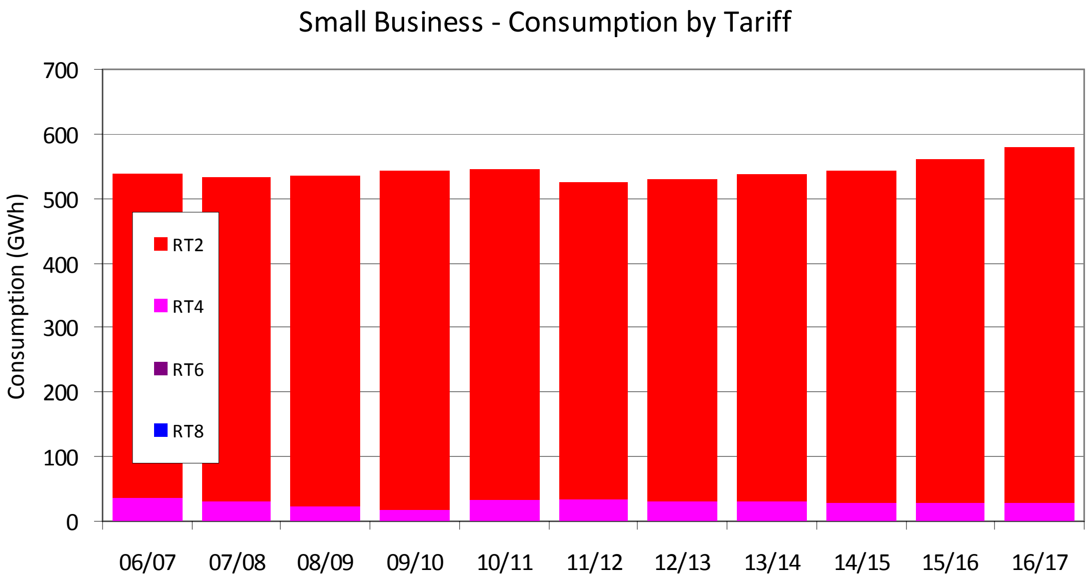


Figure 133: Small Business Consumption by Tariff

16.3 General Business Small

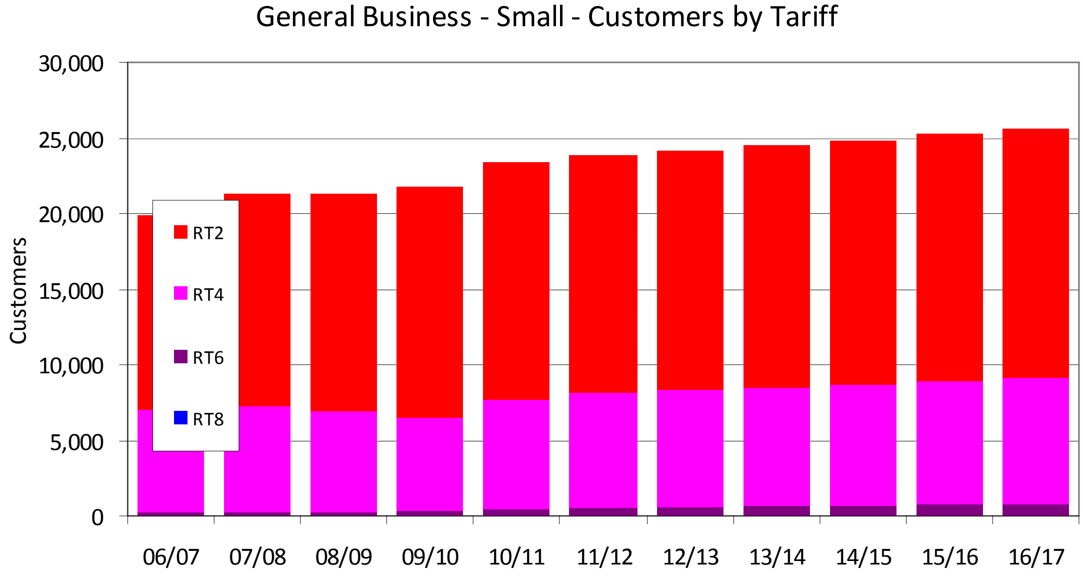


Figure 134: General Business Small Customer Numbers by Tariff

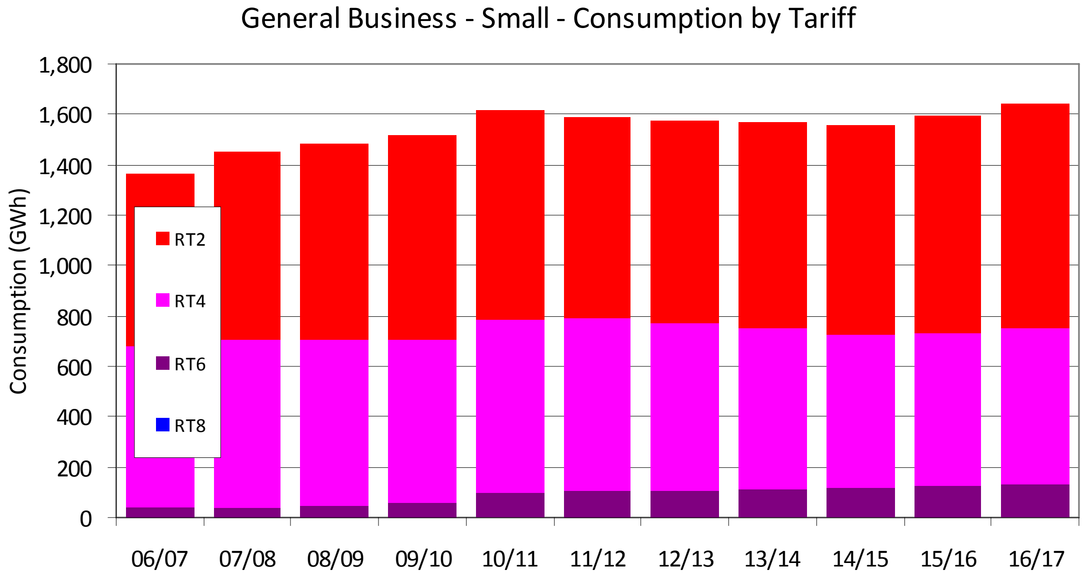


Figure 135: General Business Small Consumption by Tariff

16.4 General Business Medium

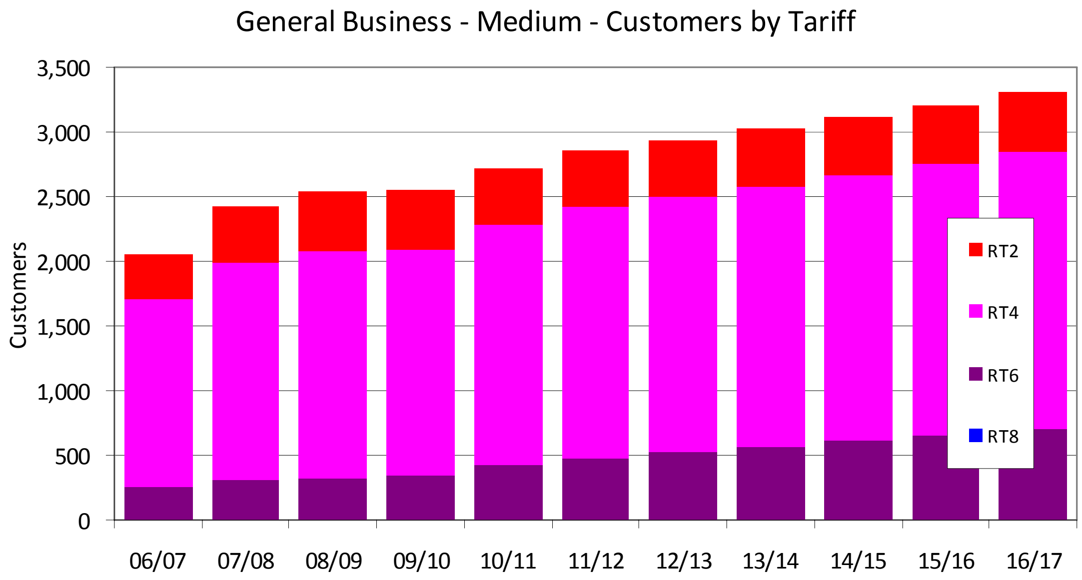


Figure 136: General Business Medium Customer Numbers by Tariff

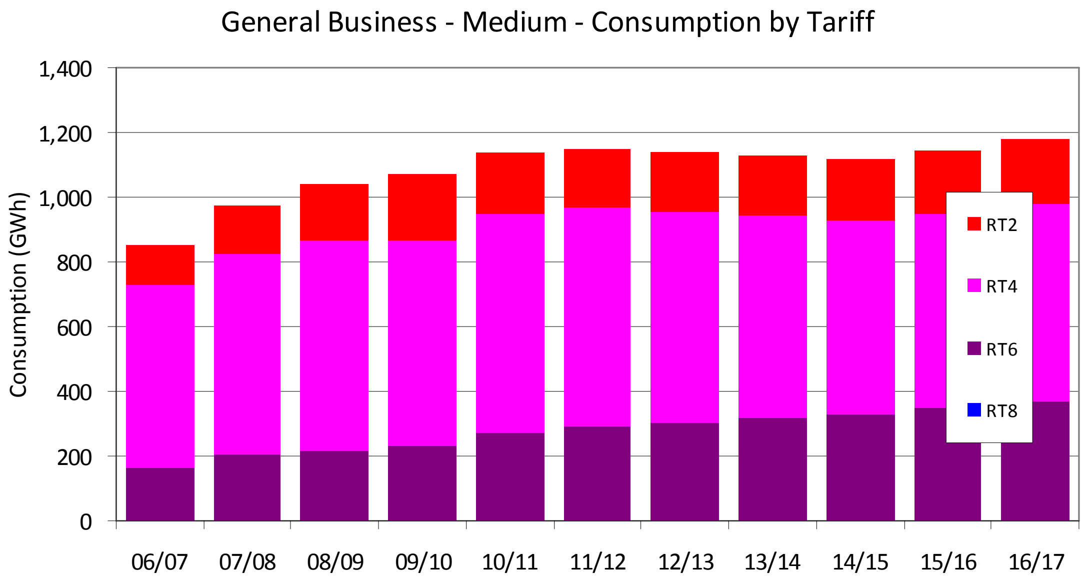


Figure 137: General Business Medium Consumption by Tariff

16.5 General Business Large

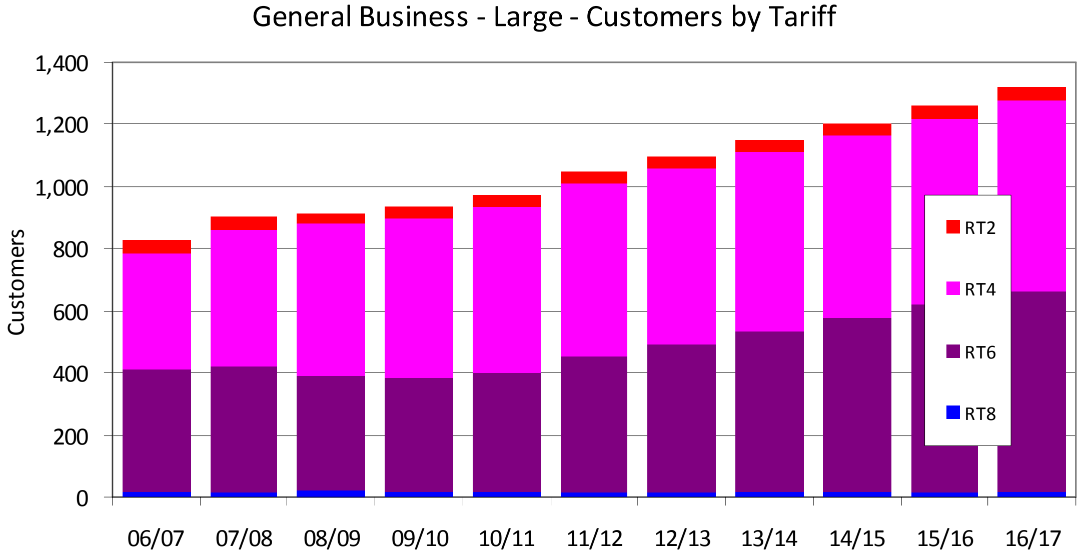


Figure 138: General Business Large Customer Numbers by Tariff

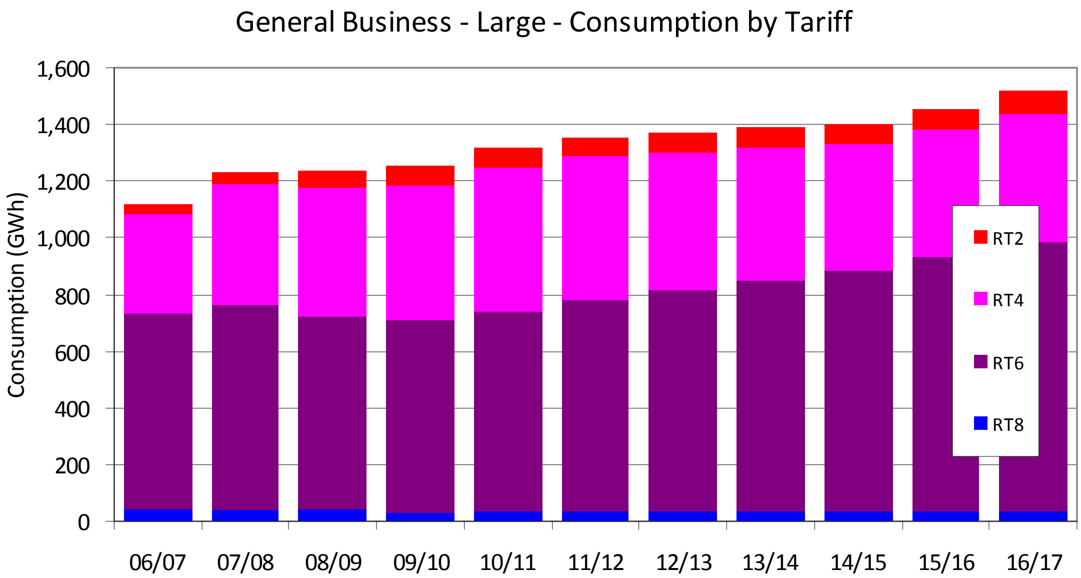


Figure 139: General Business Large Consumption by Tariff

16.6 Low Voltage > 1 MVA

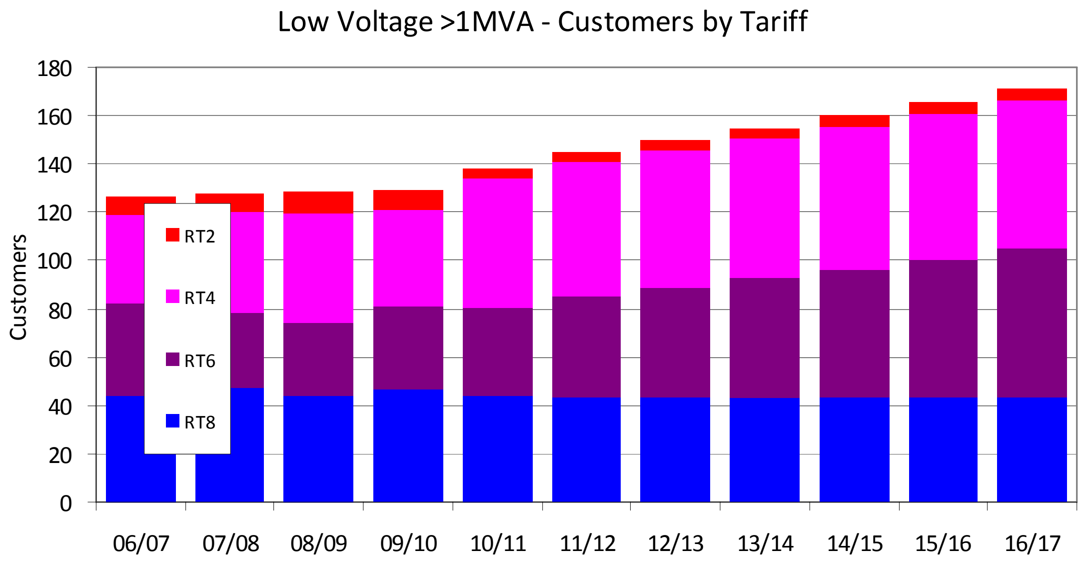


Figure 140: Low Voltage >1 MVA Customer Numbers by Tariff

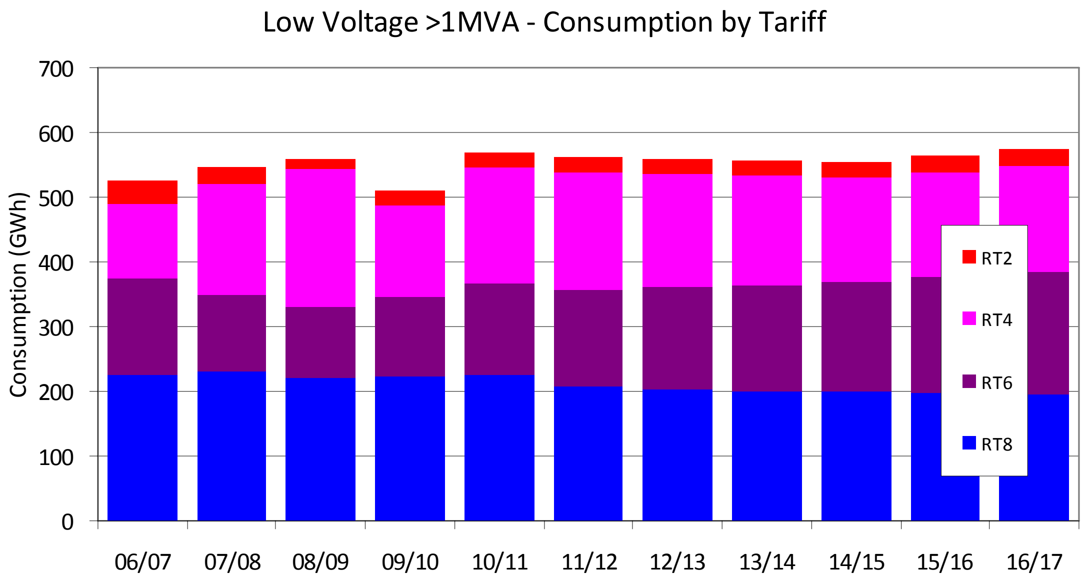


Figure 141: Low Voltage >1 MVA Consumption by Tariff

16.7 High Voltage < 1 MVA

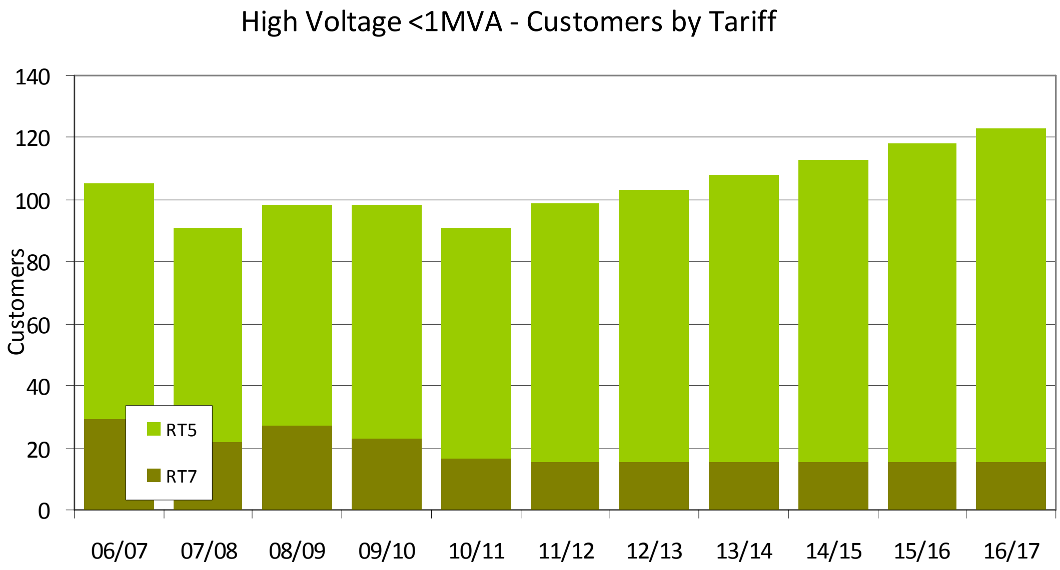


Figure 142: High Voltage < 1 MVA Customer Numbers by Tariff

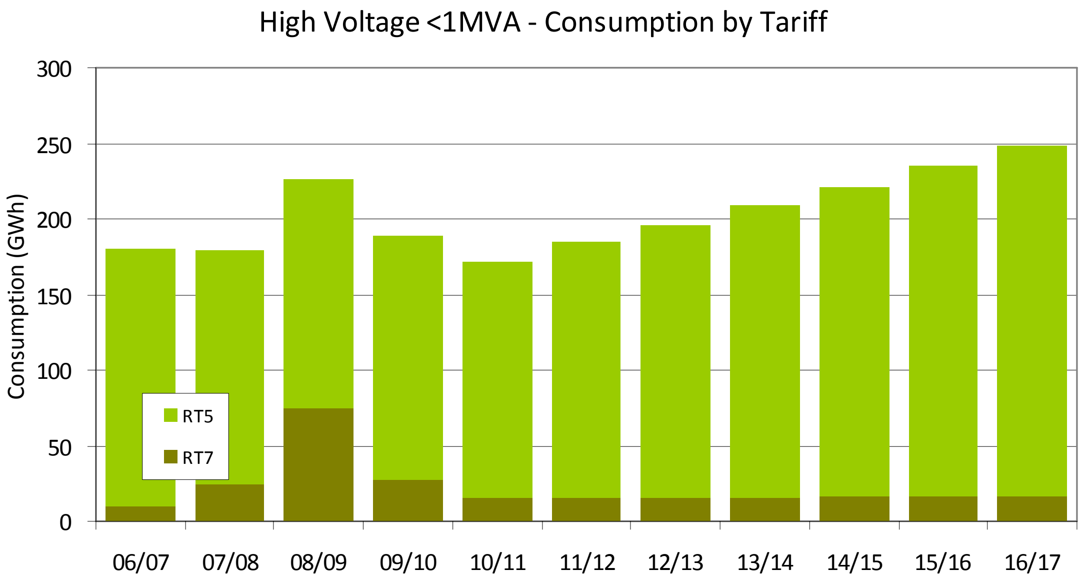


Figure 143: High Voltage < 1 MVA Consumption by Tariff

16.8 High Voltage > 1 MVA

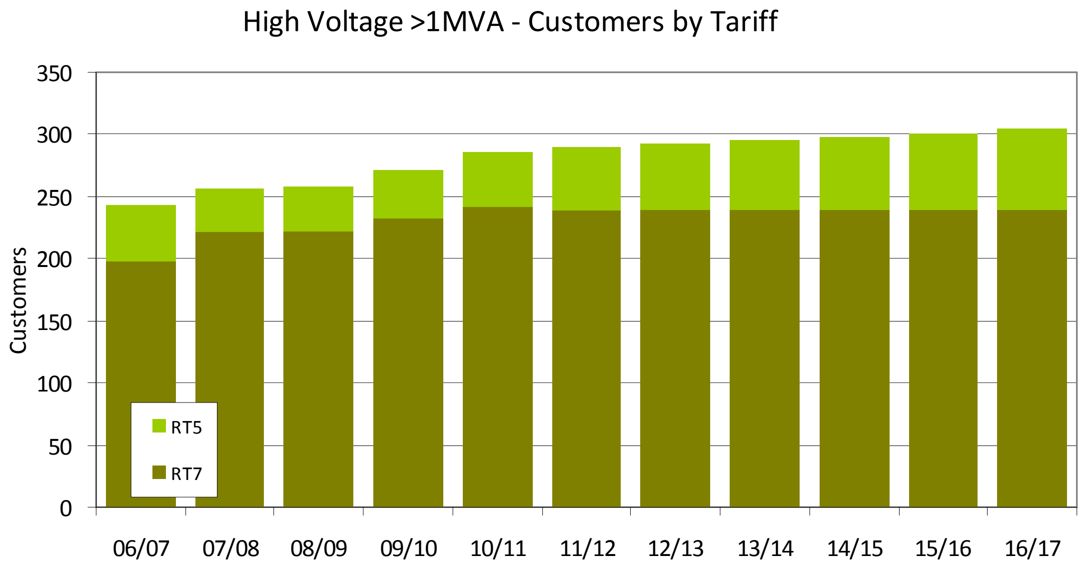


Figure 144: High Voltage > 1 MVA Customer Numbers by Tariff

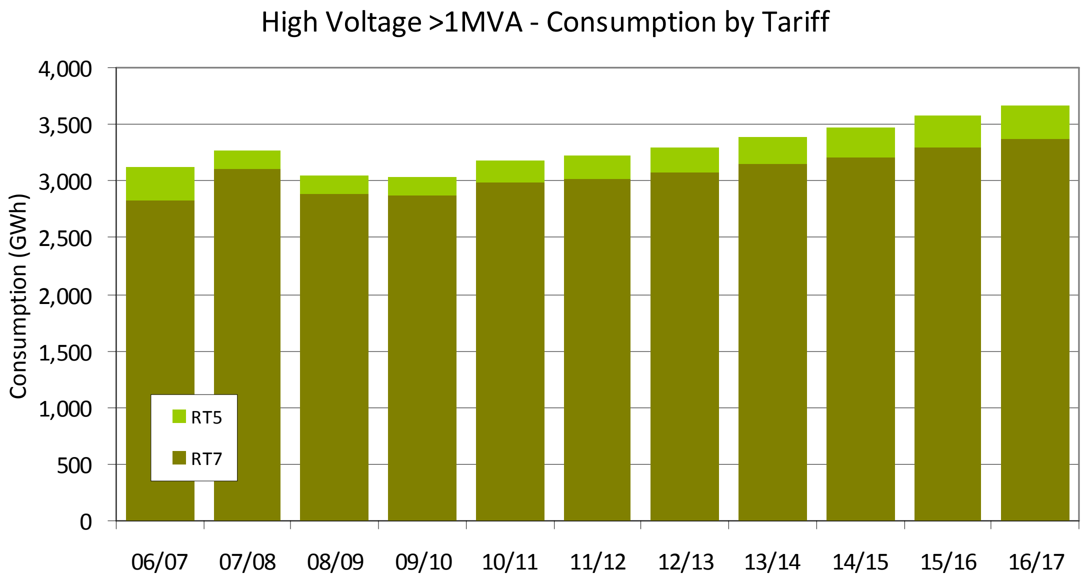


Figure 145: High Voltage > 1 MVA Consumption by Tariff

17 Comparison - Residential Customers

Population forecasts were sourced from the ABS and WA Planning Commission. The following chart compares the ABS(32220, 2004) ‘B’(central) forecast disaggregated to Perth and Non-Perth (ABS) with the regional analysis presented in WA Tomorrow (WAT). The two forecasts match very closely.

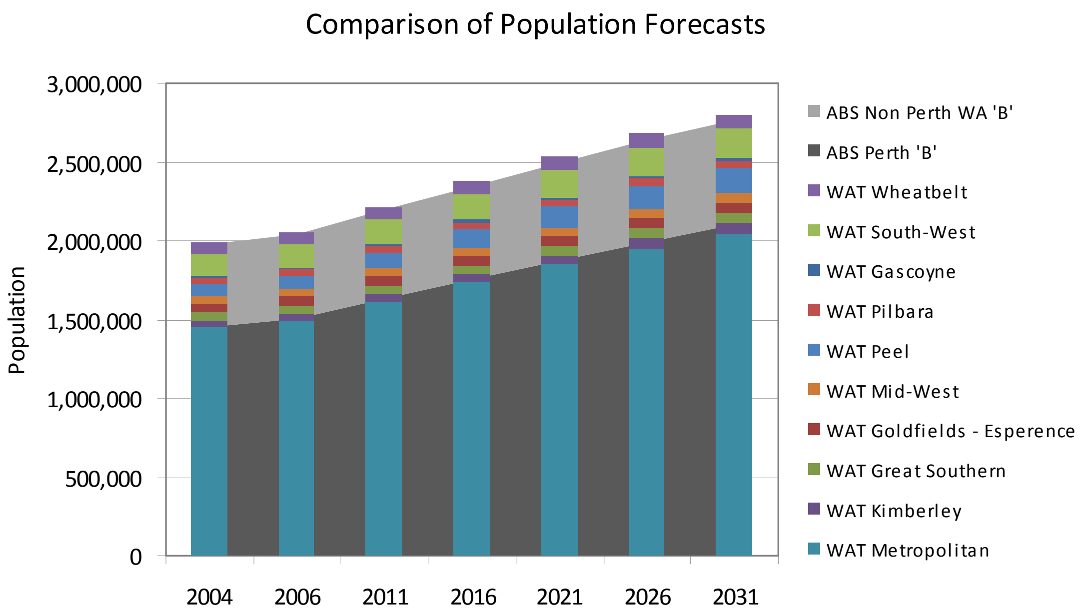


Figure 146: Comparison of Population Forecasts

The population of the area supplied by the Western Power network was derived by summating the relevant WA Tomorrow regions. Over the forecast period, the Western Power network is consistently expected to supply 93% of the state’s population.

Given the above population forecasts for the Western Power network region, the following occupancy rates can be implied from the residential customer number forecasts presented under RT1 and RT3. For comparison, the ABS (4130.0.55) reports that the average occupancy Australia wide in 2002 was 2.68.

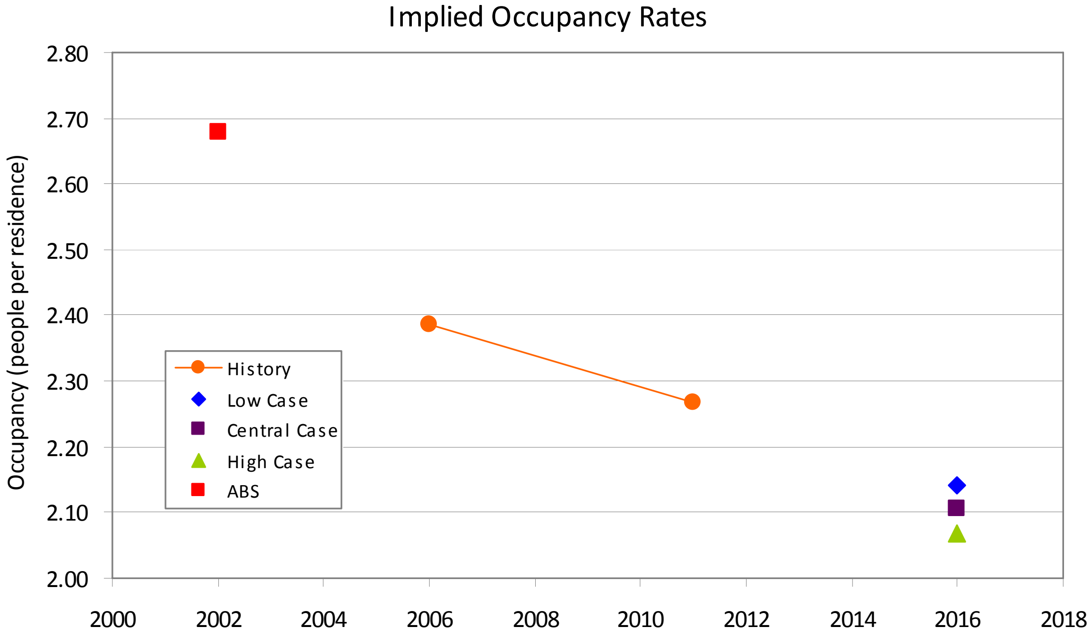
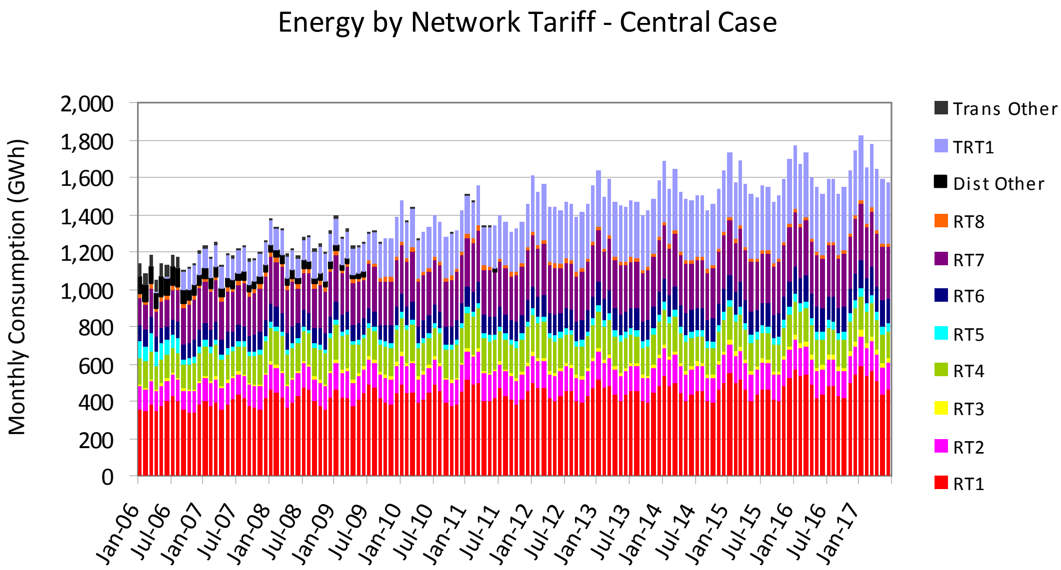


Figure 147: Comparison of Occupancy Rates

Given that the occupancy rate has been in decline, it is reasonable to assume that the average occupancy will continue to decline. This confirms that the residential customer connection forecasts are reasonable when compared to other population forecasts.

18 Comparison - Energy

The following charts illustrate the forecasts per tariff against historically metered consumption data.



*Trans and Dist other categories represent customers that were on network tariffs no longer in use.

Figure 148: Energy by Network Tariff – Central Forecast

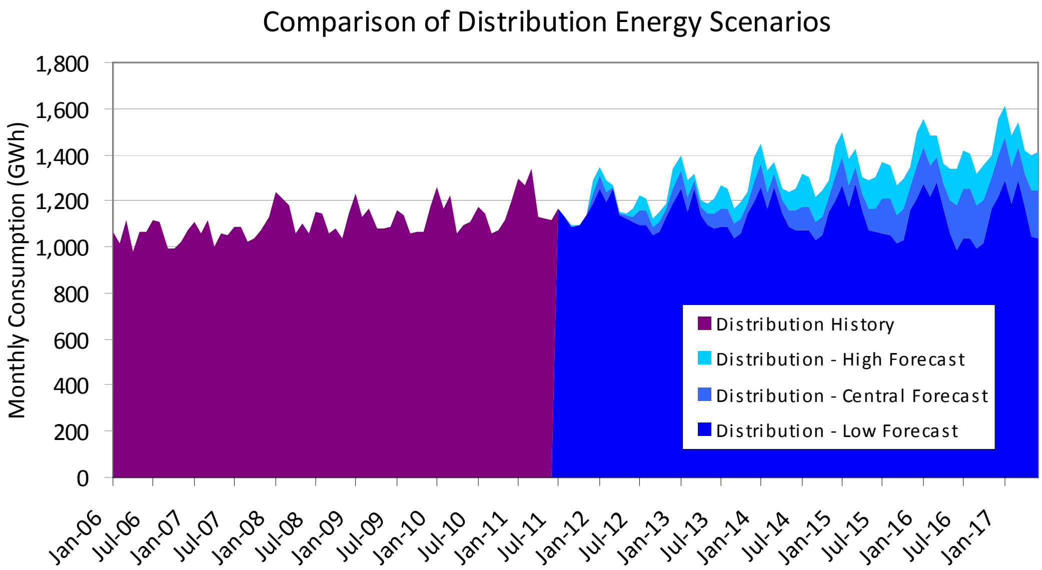


Figure 149: Comparison of Distribution Connected Energy Scenarios

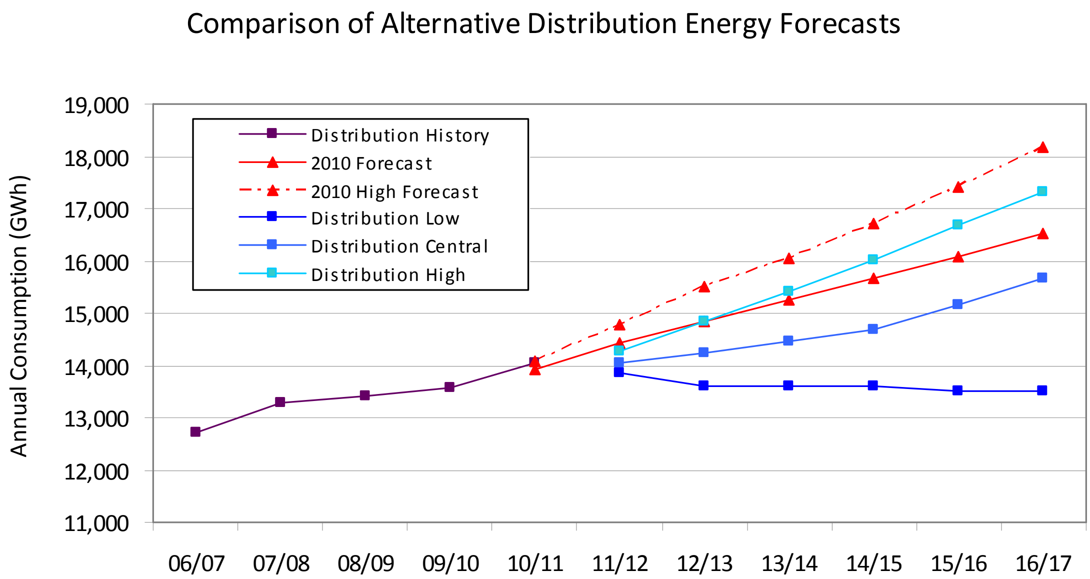


Figure 150: Comparison of Distribution Energy Forecasts

Figure 150 compares the three distribution energy forecasts against the 2010 forecasts prepared by Deloitte and the history. The 2011 distribution energy forecasts are lower in volume compared to the 2010 forecasts for both central and high cases. This variation is caused by the inclusion of new research and drivers of consumption, namely:

- Weather Normalisation
- Price Elasticity
- PV Installations.

Although the forecasts now include new drivers, the old and new forecasts are still directly comparable. As such the 2010 forecast is validated by its forecasting accuracy for FY 10/11.

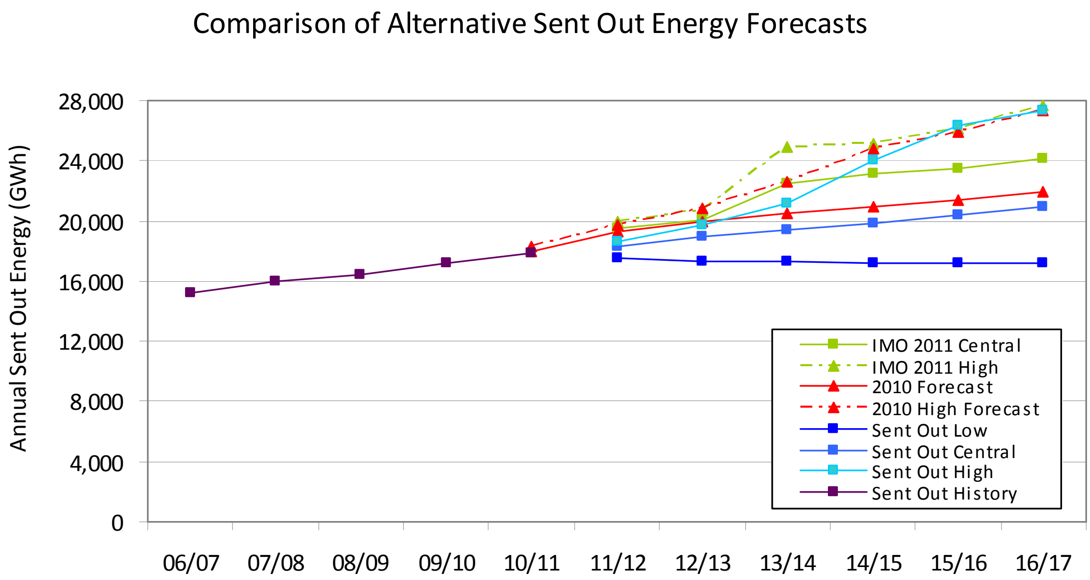


Figure 151: Comparison of Sent Out Energy Forecasts

The chart above compares the three sent out forecasts against the 2010 Deloitte forecasts, 2011 IMO forecasts and history. Sent out sales include distribution consumption, distribution losses and unmetered consumption, transmission consumption and transmission losses. The losses are estimated using Western Power 2011 official loss factors, distribution: 4.66%, transmission: 2.69%.

When distribution losses, transmission sales, and transmission losses are included the two forecasts differ more substantially. Beyond 2013/14 the high cases are much closer, due to the similar inclusion of block loads.

The forecasts prepared by the IMO are included for comparison, although IMO forecasts are almost always higher than consumption forecasts. The IMO and WP forecasts vary most in 2013/14, where the IMO presumably expects new block loads to connect that WP expects in 2015/16 (High Case Only).

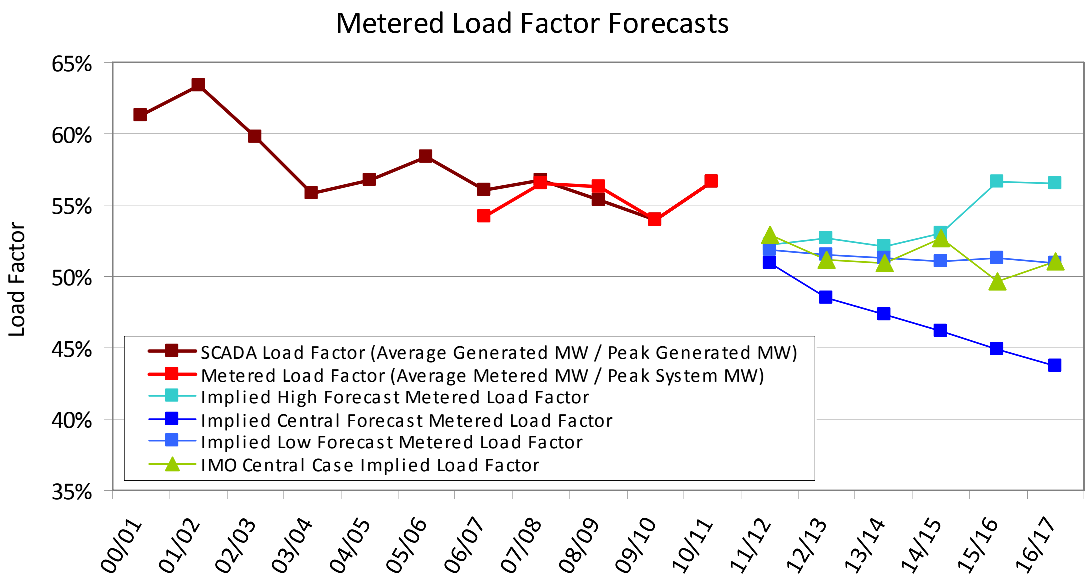


Figure 152: Comparison of Metered Load Factor Forecasts

Figure 152 plots the historic metered load factors against the three implied load factors for the scenarios. Although the IMO has forecast higher than Western Power, the IMO load factor has also been included. The IMO load factor is comparable, indicating that the IMO peak demand and energy forecasts both differ from the Western Power forecasts at a consistent ratio.

In 2011 the load factor bucked the long term historic trend downwards due to a moderate peak with an extended hot summer. All forecasts however match the long term downward expectation.

19 Conclusion

Western Power has a need to accurately forecast energy consumption and customer numbers per tariff for several uses within the business. As presented earlier, the following are considered best practice principles for energy forecasting. Forecasts should:

- be accurate and unbiased,
- be transparent and repeatable,
- incorporate all key drivers,
- withstand scrutiny of models and assumptions,
- use the most recent input information,
- incorporate weather variability.

The methodology and results presented in this document are expected to comply with the best practice principles as defined by the AER in the following ways:

- the forecasts are statistically derived and are applied consistently,
- the model inputs, statistics and results are readily available for critique and analysis,
- all key drivers were tested for correlation and statistical significance, including weather,
- are compared to other forecasts and are reasonably similar,
- all model inputs are up to date at the time of analysis.

System Forecasting will produce forecasts by March annually based on the template and methodology provided above. The process proposed provides Western Power with forecasts that will meet the needs of all internal stakeholders while incorporating best practice principles thereby meeting external requirements.

Appendix S. SKM - CBD 25 year strategy (Confidential) - Review of Planning Philosophies

This document is not available for public release and has been supplied separately as confidential supplementary information and forms a part of this submission.

Appendix T. SKM - CBD 25 year strategy (Confidential) - Load Area Development Report

This document is not available for public release and has been supplied separately as confidential supplementary information and forms a part of this submission.

Appendix U. SKM - Western Terminal Area Long Term Strategic Option (Confidential)

This document is not available for public release and has been supplied separately as confidential supplementary information and forms a part of this submission.

Appendix V. Project list - Response to draft decision

This document is not available for public release and has been supplied separately as confidential supplementary information and forms a part of this submission.

Appendix W. Current Wood pole management position (confidential)

This document is not available for public release and has been supplied separately as confidential supplementary information and forms a part of this submission.

Appendix X. Alliance Power & Data - Wood pole testing facility presentation to Energy Safety - 15 March 2012 (Confidential)

This document is not available for public release and has been supplied separately as confidential supplementary information and forms a part of this submission.

Appendix Y. Draft Business Case - Field Survey Data Capture Project

This document is not available for public release and has been supplied separately as confidential supplementary information and forms a part of this submission.

Appendix Z. Explanation of negotiation process with distribution delivery partners (confidential)

This document is not available for public release and has been supplied separately as confidential supplementary information and forms a part of this submission.