Inquiry into the Funding Arrangements of Horizon Power

Draft Report

16 December 2010

Economic Regulation Authority
WESTERN AUSTRALIA

Executive Summary

The inquiry into the funding arrangements of Horizon Power was given to the Authority, by the Treasurer, on 17 May 2010. Its purpose is to consider the level of Horizon Power's efficient operating and capital expenditure and determine cost reflective tariffs for each year of the inquiry period (2009/10 to 2013/14).

Horizon Power's Services and History

Horizon Power is the regional electricity service provider for the majority of Western Australia, excluding the South West and Kalgoorlie. This is an area of 2.3 million square kilometres stretching from Kununurra in the East Kimberley, through the Mid West towns to Esperance in the South. Horizon Power is a vertically integrated company responsible for generating, transmitting, distributing and retailing electricity services across its supply area. Population and hence demand for electricity is concentrated in a few key areas, the North West Interconnected System (**NWIS**) (50 per cent of electricity sent out) and the main towns of Kununurra, Broome, Carnarvon and Esperance (33 per cent of electricity sent out). The remainder of Horizon Power's supply area is characterised by small, isolated towns served by local generation and islanded distribution systems.

Upon disaggregation from the former Western Power Corporation, Horizon Power inherited an ageing asset base and support systems better suited to a larger, centrally managed business model. Consequently, over the last four years, Horizon Power has undertaken asset management planning and renegotiation of service level agreements for metering and customer service functions. It has 33 discrete distribution systems in addition to the NWIS, which are subject to harsh environmental conditions such as cyclones in the north, storms in the south and dry hot conditions in the interior. Furthermore, Horizon Power's staff are often required to travel long distances to correct faults and maintain systems, which impacts upon repair times and service performance. Horizon Power's customer base ranges from remote aboriginal communities such as Ardyaloon and Bidyadanga in the West Kimberley to large commercial mining and resource customers in the NWIS.

The Tariff Equalisation Contribution (TEC)

Given these environmental and operational conditions and the Government's current policy to charge uniform electricity retail tariffs[1] across the entire State, the cost to supply customers across much of Horizon Power's area is greater than the revenue collected from its customers. Therefore, Horizon Power receives subsidies in the form of Customer Service Obligation (**CSO**) payments, funded through general taxation and the Tariff Equalisation Contribution (**TEC**) which is funded from the network charges to Western Power's wholesale distribution customers. At the current gazetted levels ($122.1m in 2009/10, $175.7m in 2010/11 and $181.2m in 2011/12), the growth in the TEC is increasing Western Power's network distribution charges by CPI plus 15.7 per cent (over three instalments, March 2010, July 2010 and July 2011).[2]

[1] Uniform tariffs do not apply to large commercial customers with usage above 4.38 GWh, these customers pay commercial tariff rates

[2] ERA Media release (4 December 2009), ERA releases final decision on Western Power's revisions.

The Authority's Approach to the Inquiry

Across the majority of its area of supply, Horizon Power provides an essential service and does not charge cost reflective tariffs, which in turn deters competitors from entering the market. This inquiry into the funding arrangements of Horizon Power seeks to simulate the beneficial aspects of a competitive market by:

- determining Horizon Power's efficient cost of supplying electricity for a given level of service delivery; and
- ensuring a benchmark return on the appropriate level of investment in capital assets.

This process encourages increased efficiency in electricity service provision and the prudent use of public funds.

In carrying out this inquiry, the Authority has adopted the following approach.

- The Authority first reviewed Horizon Power's service levels and confirmed that, whilst three towns did not currently meet the required service standards for the average length of interruption to customers, Horizon Power expects all systems to meet the required standards by July 2011.
- The Authority then applied the "building block" approach to determine Horizon Power's efficient costs of delivering its services to the required standard. This involved separately calculating and then summing: efficient operating costs; depreciation; and a return on the appropriate regulatory asset base to give Horizon Power's efficient cost of service (or cost reflective revenue requirement).
- In determining the efficient levels of operating and capital expenditure the Authority sought advice from technical consultants, Parsons Brinckerhoff Australia Pty Ltd (**PB**).[3]
- The data collection and financial modelling exercise resulted in the calculation of the costs of service, broken down by functional cost driver (i.e. generation, transmission, distribution, retail or overhead), for each town, the NWIS and for Horizon Power as a whole.
- The financial modelling was conducted first using Horizon Power's forecast inputs and then using the Authority's recommended efficient operating and capital expenditure levels.
- An average cost reflective tariff was calculated for each town and the NWIS.
- Horizon Power's tariff revenue was deducted from the efficient cost of service to leave a balancing revenue item to be met through CSO and TEC funding.
- Finally, the Authority compiled a set of statutory accounts for Horizon Power to ensure that the recommended variations in the costs of service provide for Horizon Power to remain financially viable, assuming Horizon Power operates in accordance with the Authority's efficient level of costs.

Price Escalation Factors

One issue of difference between the Authority and Horizon Power is in the use of price escalation factors in estimating costs. Horizon Power has used alternative price

[3] This report is available on the Authority's website www.erawa.com.au.

escalators[4] to the Consumer Price Index (**CPI**)[5] as it is of the view that CPI does not reflect the underlying inflation it faces, particularly in the North West of the State, where competition for resources can drive prices higher than in other parts of the State. Whilst the Authority recognises that regional prices have probably risen at a higher rate than CPI in the past, there is no indication that this trend will continue, especially as Horizon Power's preferred inflator has fallen since June 2008. Therefore, with the exception of any inflation fixed by contractual terms, the Authority has concluded that the use of a historically based index to predict future escalation is inappropriate. The Authority's proposed reductions to operating and capital costs outlined below have been applied in real terms, which for this inquiry are prices as at 30 June 2009 (the beginning of the inquiry period).

Operating Costs

Horizon Power has forecast average operating costs of $329.3m (real at 30/6/2009) per annum over the inquiry period compared to a historical annual average of $237.7m (real at 30/6/2009). These operating costs are predominantly driven by the cost of purchasing electricity from Independent Power Producers (88 per cent of the electricity sent out in 2009/10). As a consequence, generation operating costs are fixed in the short-term. The Authority has therefore concentrated on the level of controllable operating costs (an average of $116.8m per annum, real at 30/6/2009) in seeking potential efficiency gains in operating costs.

If this controllable operating cost expenditure is divided by the number of connections supplied, Horizon Power's forecast unit operating costs increase by six per cent over the inquiry period. Of these controllable operating costs, the main drivers are costs deemed as "overheads" by Horizon Power. However, this partly results from Horizon Power's practice of forecasting at the district and central level and not at the individual town or system level.

The Authority recognises that Horizon Power has gone through a period of adjustment and consolidation following disaggregation. However, the Authority considers there is scope for efficiency savings in Horizon Power's controllable operating costs over the inquiry period. To eliminate the effect of any additional costs resulting from growth in demand, the Authority is recommending a compounding efficiency target of one percent per connection per annum be applied to Horizon Power's controllable operating cost base in 2009/10.[6] This has the effect of reducing Horizon Power's controllable unit operating costs by six per cent over the inquiry period.

In total operating cost terms this is a reduction of $105.8m in total across the five years of the inquiry period and reduces the average annual operating cost from $329.3m to $308.2m (real at 30/6/2009).

Valuation of the Initial Asset Base

The determination of Horizon Power's cost of service required the valuation of the initial asset base and the increase in the asset base due to new capital additions. Horizon

[4] The historical, long run Buildings Construction Index.

[5] The weighted average of eight cities CPI.

[6] The 2009/10 base year operating costs have been adjusted to account for certain items, this is explained in more detail in section 7.7.

Power did not propose an asset valuation based on a current cost valuation of its assets[7] and instead supplied information on the historical cost valuation of assets at disaggregation, new capital additions to date and forecast capital expenditure for the inquiry period. The Authority has valued Horizon Power's initial capital base in historic cost terms at $264.1m at 30 June 2009. This takes into account Horizon Power's new capital assets, which have been recognised at cost, and Horizon Power's calculation of the remaining lives of the assets that were taken over at disaggregation.

Capital Expenditure

Expenditure on new capital assets was reviewed on a project-by-project basis by PB and the Authority has accepted its recommended reductions to the capital program.

However, the main driver of the capital expenditure program over the inquiry period relates to Horizon Power's strategy to build, own and operate its own power stations in Marble Bar, Nullagine, Carnarvon and South Hedland.

The Authority has reviewed, and accepted, Horizon Power's demand forecasts which drive the need for additional generation capacity across the supply area. However, the Authority is concerned that, based on the information available, the decision to bring some generation capacity in-house is not the optimal business model for Horizon Power to adopt. Consequently, in addition to specific project-related capital expenditure reductions, the Authority also proposes to exclude, from the determination of efficient costs, any outturn costs from these generation projects over and above the budgeted amounts. This ensures that any cost overruns for the generation projects are borne by Horizon Power and not passed onto South West Interconnected System (**SWIS**) network customers through the TEC.

The combined effect of the Authority's recommendations to specific projects and to generation capital expenditure generally is to reduce Horizon Power's proposed capital expenditure from $841.6m (real at 30/6/2009) over the inquiry period to $764.2m, a reduction of $77.4m (real at 30/6/2009).

Return on Capital

In determining a return on capital, the Authority reviewed the underlying parameters that Horizon Power proposed and where appropriate amended these to reflect current market conditions. This has resulted in a real pre-tax return on capital of 6.49 per cent. However, if Horizon Power's actual cost of debt is used in the return on capital calculation, the real pre-tax return reduces to 4.89 per cent.

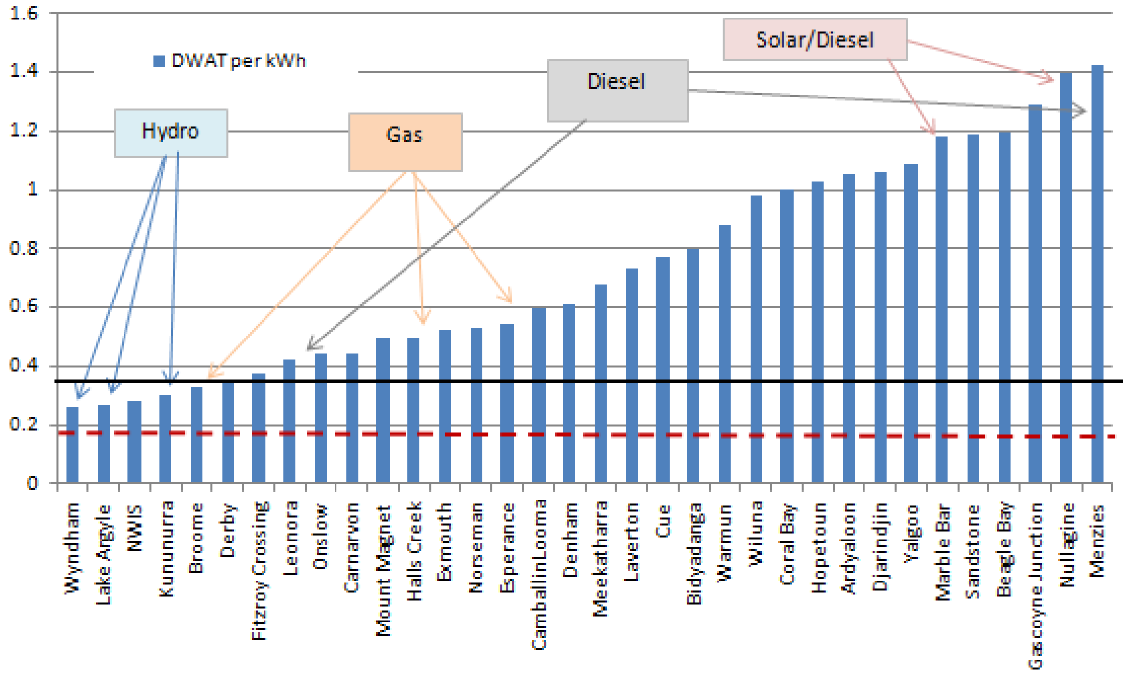
Cost Reflective Tariffs

The combination of the above elements determines the efficient cost of service for each town for each year of the inquiry period. This is then translated into an average cost reflective tariff for each town. These tariffs range from $0.26 per kWh for Wyndham in East Kimberley to $1.43 per kWh for Menzies in the Mid West. The NWIS is $0.28 per kWh and the consolidated tariff for Horizon Power is $0.36 per kWh (solid black line in Figure 1.1 below). The equivalent figure for the SWIS is $0.19 per kWh (broken red line in Figure 1.1 below). The difference in tariff levels is largely due to the type of fuel

[7] Horizon Power did submit a Depreciated Optimised Replacement Cost for the NWIS and Modern Equivalent Asset values for the rest of its assets. This information was used to inform the Authority's decision on the initial capital base.

used to generate electricity, the capacity of the generator and the distance between the town and its main fuel supply.

Figure 1.1 Simple cost reflective tariffs for each town and the NWIS compared to the equivalent tariff for the SWIS ($ per kWh)



Source: ERA analysis

- Hydro is the least expensive source (as evidenced by Lake Argyle, Wyndham and Kununurra at the low end of the tariff range), followed by gas (used in towns such as Broome, Derby and Esperance), then diesel only (a fairly wide range from Onslow to Menzies), then solar and diesel combined (Marble Bar and Nullagine).
- The larger the generation capacity, the lower the cost to supply (the NWIS has the largest installed capacity and a low tariff compared to towns such as Gascoyne Junction, Menzies, Yalgoo and Ardyaloon, which have installed capacity at less than 1MW).
- Also, the greater the distance of the town from support infrastructure, the higher the diesel transport costs (as evidenced by the higher costs of supplying more remote towns such as Ardyaloon, Djarindjin and Beagle Bay in the West Kimberley).

All of the cost reflective tariffs generated are above the equivalent figure for the SWIS, which indicates that all of Horizon Power's towns and systems receive a subsidy.

Impact on the TEC

The impact of the Authority's recommendation on the TEC is that it reduces to $105.9m in 2009/10, $123.9m in 2010/11 and $145.3m in 2011/12. This is a total saving of $103.9m on the current gazetted TEC levels for those three years (all prices are nominal).

Figure 1.2 Comparison of TEC values ($m nominal)

Scenario	2010	2011	2012	2013	2014
Gazetted TEC	122.1	175.7	181.2	n/a	n/a
TEC using Authority recommended efficient levels of operating and capital expenditure	105.9	123.9	145.3	162.4	158.6

Source: ERA analysis

The Authority's preferred position is that the TEC is funded by a CSO payment paid directly to Horizon Power. However, if the Government continues to choose to fund the TEC via network charges in the SWIS then the Authority considers that lower TEC payments would be expected to pass through to lower distribution network tariffs for the benefit of all Western Power's customers.

Future Regulatory Arrangements

The Authority recommends that this inquiry be repeated in three years to ensure a continued path towards efficiency. It is the Authority's experience that as more efficiency reviews are undertaken, confidence in the underlying data quality and regulatory methodology increases, which drives further improvements in performance.

Submissions Invited

Submissions are invited on this draft report, as outlined in section 1.3 below. The Authority will consider these submissions when preparing the final report, which will be delivered to the Treasurer by 18 March 2011. The Treasurer then has 28 days to table the report in Parliament.

Draft Recommendations

1. The service level standards for Horizon Power be retained, unchanged from their existing form, for the inquiry period.

2. A historic cost valuation of $264.1 million (in real prices as at 30/6/2009) be used for Horizon Power's initial capital base as at 1 July 2009.

3. The forecast operating costs incurred as a result of the delay in obtaining funding approval for the South Hedland power station project be borne by Horizon Power. Consequently, the Authority proposes that $35m (real as at 30/6/2009) be removed from the non-controllable generation operating costs in the NWIS in 2012/13 for the purpose of determining cost reflective tariffs.

4. An efficiency target of one per cent compounded per annum be applied to the 2009/10 level of controllable unit operating costs per connection.

5. Horizon Power submit in response to the draft report individual business cases for any additional operating expenditure requests over and above the recommended profile as outlined in Table 7.8. The Authority will then consider each request on a case by case basis and include any additions to the efficient level of operating costs in the final report

6. Horizon Power's actual and forecast capital expenditure programme be reduced by $77.4m (real at 30/6/2009) from $841.6m (real at 30/6/2009) to $764.2m (real at 30/6/2009) as detailed in Table 8.2.

7. A real pre tax benchmark WACC of 6.49 per cent be used for regulatory modelling and calculation of cost reflective tariffs for this inquiry.

8. A real pre tax alternative WACC of 4.89 per cent, reflecting Horizon Power's actual cost of debt, be used for determining TEC levels in this inquiry.

9. The TEC be funded by a CSO paid directly to Horizon Power.

10. Should the Government continue to subsidise Horizon Power through a TEC payment funded by SWIS network customers, the lower TEC should be gazetted. This will provide for the lower TEC to be passed through to lower distribution network tariffs in the SWIS.

11. A second inquiry into the funding arrangements of Horizon Power be undertaken in three years time to further review Horizon Power's actual costs and to set new efficiency targets.

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1 Introduction

The Treasurer of Western Australia gave written notice to the Economic Regulation Authority (**Authority**), on 17 May 2010, to undertake an inquiry into the funding arrangements of Horizon Power, pursuant to Section 32(1) of the *Economic Regulation Authority Act 2003* (**Act**)[8] and in accordance with section 129E(1) of the *Electricity Industry Act 2004*.

This section of the Electricity Industry Act provides for the Treasurer to seek advice from the Authority prior to making a determination on the level of the Tariff Equalisation Contribution (**TEC**) payable to Horizon Power.

1.1 Terms of Reference

The Terms of Reference for the inquiry are presented in Appendix A. The Terms of Reference require the Authority to consider and develop findings on:

- The cost reflective retail tariff that would apply in the areas of operation of Horizon Power, for the purpose of determining the efficient expenditure required to supply customers on regulated retail tariffs located in these areas. This will inform the setting of the amount of the Tariff Equalisation Contribution, which will be determined by Government.
- The cost reflective retail tariffs should be determined for the period 2009/10 to 2013/14.
- A cost reflective tariff should be determined for each of the retail tariffs currently provided by Horizon Power, being the A2, K2, L2, L4, M2, N2, W2 and Streetlight tariffs (as detailed in the *Energy Operators (Regional Power Corporation) (Charges) By-laws 2006*).
- The Authority is to determine whether the area that Horizon operates in should be separated into sub-areas, given the different cost structures of the systems that Horizon Power operates, for the purpose of determining cost reflective retail tariffs. If this is the case, the Authority is to:
  - define the sub-areas (minimising the number of sub-areas as much as possible); and
  - determine a different cost reflective retail tariff (for each tariff class) for each sub-area.
- The Authority is also to consider and incorporate incentives for Horizon Power to develop and implement efficiency measures, such as gain sharing mechanisms between customers and Horizon Power, in determining cost reflective retail tariffs if the Authority considers this would minimise costs within the area that Horizon Power operates in.
- The efficiency of Horizon Power's procurement processes.

[8] Section 32 (1) of the Economic Regulation Authority Act 2003 provides for the Treasurer to refer to the Authority inquiries on matters relating to regulated industries. This excludes inquiries governed by operation of the Gas Pipelines Access (Western Australia) Law or Code in force under section 4 of the *Railways (Access) Act 1998*.

- The efficiency of Horizon Power's operating and capital expenditure programmes, including opportunities for alternative arrangements for service delivery in remote regions.
- The Authority must give consideration to, but will not be limited to the following costs when determining retail tariffs:
  - the efficient generation costs applicable in the area Horizon Power operates in or each sub-area, if applicable, taking into account the current and committed stock of generation;
  - the efficient network costs applicable in the area Horizon Power operates in or each sub-area, if applicable, taking into account the current network infrastructure;
  - the level of efficient retail costs that would be applicable in the area that Horizon Power services (both operating and capital costs);
  - the efficient net retail margin that would apply;
  - the efficient costs related to the national Mandatory Renewable Energy Target (**MRET**), including the expanded MRET if applicable; and
  - the efficient costs related to the proposed Carbon Pollution Reduction Scheme (**CPRS**), including carbon intensity that should be applied in determining CPRS costs that would be incorporated into the cost reflective retail tariffs.

In undertaking the inquiry, the Authority recognises section 26 of the Act, which requires the Authority to have regard to:

- the need to promote regulatory outcomes that are in the public interest;
- the long-term interests of consumers in relation to the price, quality and reliability of goods and service provided in relevant markets;
- the need to encourage investment in relevant markets;
- the legitimate business interests of investors and service providers in relevant markets;
- the need to promote competitive and fair market conduct;
- the need to prevent abuse of monopoly or market power; and
- the need to promote transparent decision making processes that involve public consultation.

1.2 Review process

The recommendations of this inquiry will be informed by the following public consultation process.

- The Authority published an issues paper on 4 June 2010 and invited submissions from industry, government, other stakeholder groups and the general community on the matters in the Terms of Reference. Four submissions were received in response to the issues paper. The issues paper and submissions are available on the Authority's website, www.erawa.com.au.
- The Authority invites further written submission on the draft report (see below).

- The final report for the inquiry will be delivered to the Treasurer by 18 March 2011, and the Treasurer will, in accordance with the Act, have 28 days to table the report in Parliament.

In accordance with section 45 of the Act, the Authority will act through the Chairman and members in conducting this inquiry.

1.3 How to make a submission

Submissions on any matter raised in this draft report or in response to any matter in the Terms of Reference should be in both written and electronic form (where possible) and addressed to:

Inquiry into the Funding Arrangements of Horizon Power
Economic Regulation Authority
PO Box 8469
Perth Business Centre
PERTH WA 6849

Email: publicsubmissions@erawa.com.au
Fax: (08) 9213 1999

Submissions must be received by 28 January 2011.

Submissions made to the Authority will be treated as in the public domain and placed on the Authority's website unless confidentiality is claimed. The submission, or parts of the submission in relation to which confidentiality is claimed, should be clearly marked. Any claim of confidentiality will be dealt with in the same way as is provided for in section 55 of the Act.

The receipt and publication of a submission shall not be taken as indicating that the Authority has knowledge, wither actual or constructive, of the contents of a particular submission. No duty of confidence will arise for the Authority where the submission, in whole or part, contains information of a confidential nature.

Further information regarding this inquiry can be obtained from:

Sara O'Connor
Analyst
Economic Regulation Authority
Ph: (08) 9213 1900

Media inquiries should be directed to:

Ms Sue McKenna
The Communications Branch Pty Ltd.
Ph: 61 8 9254 4077
Mb: 0424 196 771 (Sue McKenna)

2 Inquiry Approach

2.1 Review of the aim of the inquiry

The unit cost of supplying electricity to people living in remote areas, outside the South West, is high because of specific variables associated with these regions, such as climatic conditions, transport distances, fuel costs, limited economies of scale and regional factors affecting labour and material costs. The Government's uniform tariff policy however, ensures that all residential and small business customers pay the same electricity tariffs regardless of where they live. Therefore, the electricity tariffs of customers living in remote Western Australia are subsidised by taxpayers and South West electricity network customers.

The inquiry aims to establish Horizon Power's efficient level of costs to supply electricity to regional Western Australia. From this information the Government can determine the Tariff Equalisation Contribution (**TEC**), which is partly funded from the retail tariffs paid by electricity customers living in the more densely populated areas of the State. The current gazetted TEC figures are given in Table 2.1 below.

Horizon Power also receives additional funds in the form of Community Service Obligation (**CSO**) payments to cover revenue shortfalls. These arise from the smoothing of uniform tariff increases up to cost reflective levels for the South West, from providing rebate schemes to some groups of customers such as Seniors and to support some ongoing State funded projects. The CSOs received by Horizon Power over the inquiry period 2009/10 to 2013/14 are also shown in Table 2.1 below.

Table 2.1 Current gazetted TEC values and CSO payments for the inquiry period ($m nominal)

Funding source	2010	2011	2012	2013	2014
Gazetted TEC amount	**122.1**	**175.7**	**181.2**	**n/a**	**n/a**
CSO payments					
Aboriginal and Remote Community Power Supply Project (Stages 1 and 2)	10.9	12.2	12.8	12.6	13.3
Coral Bay electricity supply	2.6	2.5	2.5	2.6	2.8
Pensioner, Senior, Concession rebates	0.6	0.8	1.0	1.1	1.1
Senior air-conditioning rebate	0.2	0.3	0.3	0.4	0.4
Tariff migration	8.8	7.8	7.5	7.7	7.6
Tariff adjustment payment	13.9	12.6	0	0	0
Total CSO payments	**37.0**	**36.3**	**24.2**	**24.3**	**25.2**
Total combined subsidy	**159.1**	**212.0**	**205.4**	**n/a**	**n/a**

Source: Government Gazette No. 153, 25 August 2009, p3325 and Government Gazette No. 208, 17 November 2009, p4639 and 2010/11 Budget Paper No. 3, Appendix 8, p237

The combined subsidy, shown in Table 2.1 above, represents approximately 40 per cent of Horizon Power's total income over 2009/10 to 2011/12.

2.2 Responses to the issues paper

The Authority received four submissions in response to the issues paper published in June 2010, from Griffin Energy, Alinta Energy, the Office of Energy and Horizon Power. Both Griffin Energy and Alinta Energy commented that the TEC was an inappropriate funding mechanism to subsidise service provision outside of the SWIS, and should be replaced by a CSO. They suggest that the competitive markets within the SWIS are being distorted with regards the true cost to supply because of the TEC element within network charges. It is also the Authority's preferred position that the TEC should be replaced by a CSO. Alinta further comments that a subsidy, such as the TEC is:

> "..facilitating an operating environment where Horizon Power chooses service delivery models without due consideration to the most efficient option"

Alinta also welcomes the opportunity for Horizon Power's costs to be reviewed by an external third party so that appropriate efficiency targets can be set and that ultimately:

> "..the need for the TEC is driven by structural cost differences and not inefficient practises."

The Office of Energy's submission was broadly supportive of the approach being taken by the Authority and the proposed methodology to determine cost reflective tariffs. However the submission does recognise Horizon Power's specific operating conditions and encourages the Authority to account for this when developing cost reflective tariffs. The Office of Energy also suggests that sub-sets of cost reflective tariffs could be derived to reflect similar operating conditions or cost profiles.

Horizon Power's submission in response to the issues paper requests that the Authority recognises Horizon Power's social and environmental responsibilities, including the provision of essential infrastructure to enhance state and regional development when looking at efficient levels of expenditure. Horizon Power also requests that the return on capital recognises the increased level of risk it perceives as a result of its exposure to the variability of commodity prices, cost inflation and demand fluctuations. Horizon Power also states that it considers there is limited scope for further efficiencies other than those it has already identified.

2.3 How Horizon Power operates

2.3.1 Supply characteristics

Horizon Power supplies electricity to customers living in and working over a 2.3 million square kilometre area from Kununurra in the East Kimberley, through the central Mid West towns to Esperance in the South. Horizon Power's 43,000 electricity connections range from large industrial and resource companies in the Pilbara, to residents and businesses in district towns such as Broome and Esperance and to remote indigenous communities. The distribution of energy supplied and total population is given by town in Table 2.2 below.

Combining together the figures for Karratha and Port Hedland from Table 2.2 gives information for the North West Interconnected System (**NWIS**); this system accounts for just over 50 per cent of electricity supplied by Horizon Power and 36 per cent of connections. The larger district towns of Kununurra, Broome, Carnarvon and Esperance are responsible for a further 33 per cent of electricity supplied and 40 per cent of connections, with the smaller towns and remote communities making up the remainder. This illustrates the concentration of demand in the NWIS and key towns. The other 29 towns are characterised by relatively low numbers of connections and/or small, islanded network systems.

Table 2.2 Energy supplied and population by town across Horizon Power's area of supply

District	Town/system	Percent of total electricity supplied by town in 2009/10	Percent of population by town in 2009/10
East Kimberley	Halls Creek	1.1%	1.3%
	Kununurra	6.2%	5.3%
	Lake Argyle	0.0%	0.0%
	Warmun	0.3%	0.3%
West Kimberley	Ardyaloon	0.2%	0.2%
	Beagle Bay	0.2%	0.2%
	Bidyadanga	0.3%	0.3%
	Broome	14.1%	13.0%
	Camballin/Looma	0.3%	0.1%
	Derby	3.4%	5.3%
	Djarindjin	0.2%	0.3%
	Fitzroy Crossing	1.3%	0.9%
East Pilbara	Marble Bar	0.3%	0.3%
	Nullagine	0.1%	0.1%
	Port Hedland	24.1%	17.0%
West Pilbara	Onslow	0.6%	0.9%
	Karratha	26.1%	19.0%
Gascoyne/Mid West	Carnarvon	4.8%	5.4%
	Coral Bay	0.3%	0.0%
	Denham	0.6%	1.8%
	Exmouth	2.6%	2.9%
	Gascoyne Junction	0.1%	0.1%
	Cue	0.2%	0.4%
	Laverton	0.4%	0.7%
	Leonora	1.0%	0.9%
	Meekatharra	0.8%	1.1%
	Menzies	0.1%	0.2%
	Mount Magnet	0.4%	0.6%
	Sandstone	0.1%	0.2%
	Wiluna	0.3%	0.3%
	Yalgoo	0.1%	0.2%
Esperance	Esperance	7.5%	16.5%
	Hopetoun	0.5%	1.8%
	Norseman	0.5%	1.2%

Source: Horizon Power

Horizon Power's operating conditions are in contrast to those in the South West where customers are relatively more densely populated and supplied with electricity through the South West Interconnected System (**SWIS**).[9]

2.3.2 Operating structure

In its submission in response to the issues paper, Horizon Power explains its adoption of a decentralised business operating model. This translates to six district offices managing the generation, transmission and distribution operations in regional towns and remote communities. Horizon Power advises that this enables it to better focus service provision in remote and regional areas and also to cluster a sufficient mass of services at the district level to deliver cost saving via economies of scale.[10] Horizon Power's retail functions (metering, billing and customer contact) are predominantly dealt with centrally via third party service contracts.

The downside of the decentralised business operating model is that it introduces an additional layer of overheads at the district level in addition to the traditional corporate overhead services such as knowledge and technology, financial services, governance, and human resources that are operated as centralised services. The level of overheads is discussed in more detail in section 7.3.5 below.

For purposes of transparency and to better reflect how the company actually operates, the assets and operating and capital expenditure costs associated with each district office and the corporate head office have been modelled separately to produce district level and head office costs of service. These district and corporate costs of service have then been allocated back to the appropriate town (by kWh) to give an adjusted cost of service for each town and the NWIS. This method transparently identifies the contribution of overhead costs to each town.[11] This is explained in more detail in section 10. Appendices D, E, F and G show the percentage contribution of each cost function and total overhead to overall cost of service, by town, for the NWIS and for all non-NWIS towns.

In anticipation of future additional inquiries requiring similar information, Horizon Power has revised its internal procedures and embarked on a more focused approach to reporting costs and revenues at the activity level, which was introduced in February 2010.

2.3.3 Legacy issues

Upon disaggregation, Horizon Power inherited existing Power Purchase Agreements (**PPAs**) with Independent Power Providers (**IPPs**) from Western Power Corporation (**WPC**). These contracts emerged following a funding-driven decision by WPC in the late 1990's not to replace its non-compliant[12] power stations but to outsource electricity generation to third parties through a public power procurement process. Long-dated contracts were awarded to IPPs on demonstration of least cost generation.[13]

[9] The SWIS is the largest interconnected electricity transmission and distribution network in Western Australia and stretches from Kalbarri in the north to Kalgoorlie in the east to Albany in the south.

[10] Horizon Power 2010, Submission to the ERA issues paper, p8.

[11] The use of kWh to allocate overhead may understate the overhead costs for small towns with low demand.

[12] New noise abatement regulations were introduced in the late 1990s resulting in a number of the existing power stations becoming non-compliant.

[13] Horizon Power 2010 – Fact sheet No. 10 – Western Power Legacy Power Purchase Agreements.

Overall, this has resulted in Horizon Power purchasing the majority of its electricity via PPAs (88 per cent in 2009/10), which contributes over $1,003.4m (real at 30/6/09), or 60 per cent to its total operating costs over the five year inquiry period. The level of operating costs and cost escalation associated with these contracts are fixed over the contract period. This unusually high and fixed level of operating costs relative to capital expenditure has the effect of driving the majority of the company's cost of service as calculated in section 10 below.

As PPA's expire, Horizon Power competitively tenders for new contracts from a panel of four IPPs. Parsons Brinckerhoff Australia Pty Limited (**PB**) was asked by the Authority to review the efficiency of this competitive tender process as part of the Authority's assessment of efficient costs for this inquiry.

Similarly, retail and customer services, such as customer contact, meter reading and billing, are provided by third parties through Service Level Agreements (SLAs). This is after Horizon Power reviewed the SLAs in place following disaggregation and renegotiated new agreements with alternative providers. For example, meter reading and billing services were initially provided by Western Power, through its Metering Business System (**MBS**). Horizon Power has found this system to be inflexible for meeting its needs with limited ability to influence the forward development of MBS. These problems prompted Horizon Power to develop a new tender and contract award for its metering services.[14]

2.3.4 Assets

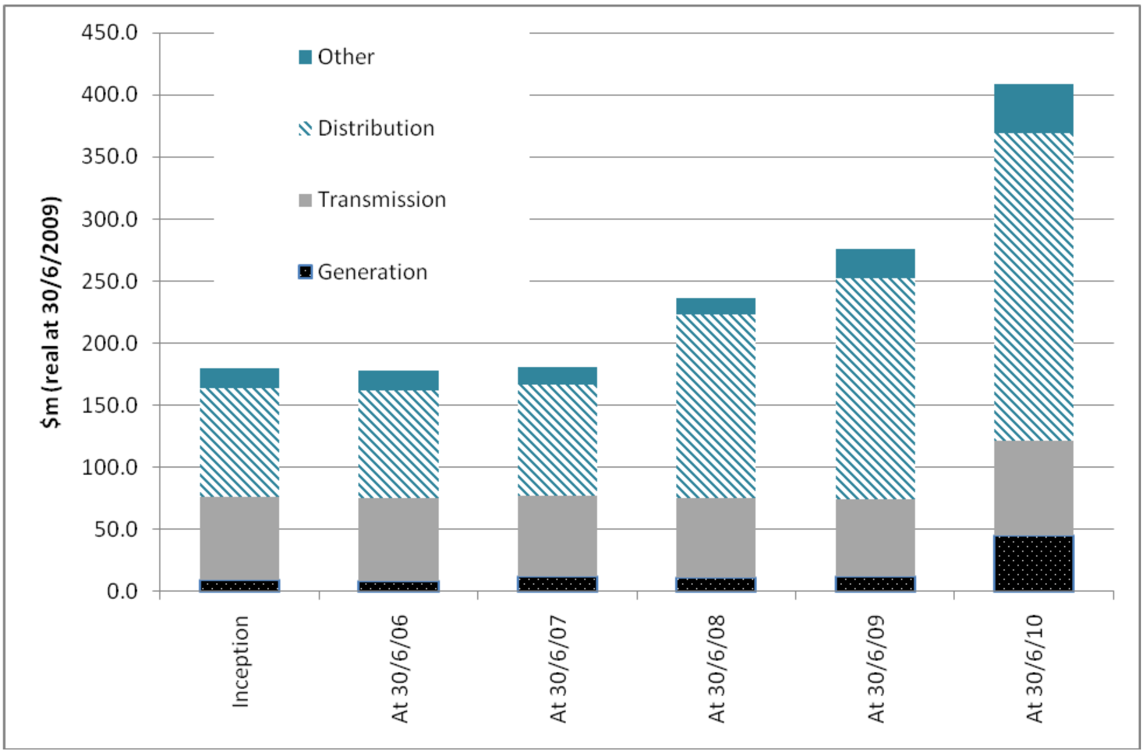
Horizon Power's organisational structure and its new policies concerning which services are provided in-house and which are contracted out, has influenced the structure of its capital base.

Horizon Power's regulated assets[15] are concerned with generation, transmission, distribution and business support, e.g. buildings, furniture and IT systems. Horizon Power owns a minimal amount of assets directly connected with its retail activities. Figure 2.1 below shows the distribution of assets across these different functions and how this distribution changes historically.

[14] Horizon Power 2010, Meter Data Management System Replacement Business Case, DMS 3217795, pp15-16.

[15] This excludes any assets or cash gifted by third parties, such as the Government, customers or developers.

Figure 2.1 Distribution of assets by function by year ($m real at 30/6/2009)



Source: ERA analysis and Horizon Power spreadsheet 3262769 ERA Fixed Asset Register 20101005vFinal

Figure 2.1 demonstrates the changing nature of the asset base with Horizon Power, at inception, being predominantly a distribution-led business. From then, as the company has gone through a period of establishment and restructuring, this change is shown in the increasing levels of support assets (shown as 'other' in the table above), particularly as the district offices, head office and Bentley office were created. Later on, Horizon Power's strategy of bringing some generation in-house is shown through an increase in the value of assets associated with generation. This is discussed in more detail in section 8 below.

2.3.5 Commerciality

Under the *Electricity Corporations Act 2005*, Horizon Power is required to:

> "…supply electricity to consumers and services which improve the efficiency of supply.." [16]

and:

> "…act in accordance with prudent commercial principles and endeavour to make a profit consistent with maximising its long term value." [17]

whilst:

> "…ensuring, as far as is practicable, that the reasonable cost of performing the function does not exceed its revenue from doing so." [18]

Horizon Power has opportunities to operate on a commercial basis, such as in competitively negotiating contracts with large electricity users or commodity supply and trading. However, across some of the areas in which Horizon Power operates the

[16] Electricity Corporations Act 2005, Section 50 (d).

[17] Electricity Corporations Act 2005, Section 61 (1)(a) and (b).

[18] Electricity Corporations Act 2005, Section 61 (2)(b).

opportunities to operate commercially are limited and this lack of an opportunity to earn a commercial return on investment deters competitors from entering the market. For example, in many remote areas Horizon Power operates predominantly as an essential service provider, where the cost of providing essential infrastructure and services exceeds the uniform tariff revenue received for those services.

This has implications for the regulation of Horizon Power. A competitive market normally has desirable outcomes such as downward pressure on prices to reflect the cost of supply and a normal rate of return on the value of assets after allowing for risk. Where there is a lack of competition, such as across much of Horizon Power's operating area, regulation attempts to strengthen the incentive to operate efficiently by imposing pressures similar to those that would be present in a competitive market. Consequently, when determining cost reflective tariffs, operating and capital costs are assumed at an 'efficient' level, to simulate the downward pressure on costs that competition would bring. Similarly, a benchmark return[19] is calculated for Horizon Power to simulate an environment were the return on investment decisions is the same as would be present in a competitive market.

In reality however, Horizon Power has access to debt funding from the State Government, at a favourable rate, so its cost of borrowing is less than that assumed in the benchmark return on its investment. This transfers an element of cost (representing the difference between the two different costs of borrowing, at the benchmark rate and alternative rate (based on the actual cost of debt) into the cost reflective revenue requirement and ultimately into the TEC. The impact upon the TEC of using a rate of return based on actual debt costs is significant (the TEC decreases by $49.8m (nominal) over the inquiry period) and is explained and quantified in section 9 and section 12.3 below.

2.4 Methodology

Economic regulation generally seeks to:

- determine an efficient level of operating and capital expenditure (to simulate the influence of competitive pressure); and
- value the asset base and then apply an appropriate return on this capital (again to reflect a commercial environment and ensure that Horizon Power makes commercially sound investment decisions).

As listed in Appendix A, the Terms of Reference require the Authority to determine cost reflective tariffs for the inquiry period 2009/10 to 2013/14. To be able to determine cost reflective tariffs, the Authority firstly determines the efficient cost of supplying electricity, or 'revenue requirement' and then translates this into retail tariffs.[20] The structure of these cost reflective retail tariffs is discussed in more detail in section 11 below. The Terms of Reference also ask the Authority to consider possible gain-sharing mechanisms for Horizon Power; this is covered in section 13 below.

The regulatory approach taken for this inquiry constructs a 'virtual company' which simulates the business model of a regional power corporation, such as Horizon Power, and estimates efficient levels of costs. These are the costs that would be incurred by a prudent service provider acting efficiently and in accordance with good industry practice. The methodology is referred to as the 'building block' approach as the cost components are calculated individually and then summed together to determine the total revenue

[19] Weighted Average Cost of Capital (WACC) – see Appendix H.

[20] In this draft report, only a simple Discounted Weighted Average Tariff is presented. More tariff options will be presented in the final report.

requirement. This is the typical methodology adopted in most regulated industries including water, gas and electricity.

The revenue requirement is calculated as follows:

Revenue requirement	=	return on capital *plus*
		return of capital (depreciation) *plus*
		operating and maintenance costs
where the return on capital	=	rate of return *multiplied by*
		the regulated asset base

The regulated asset base for this inquiry period is required for the period 1 July 2009 to 30 June 2014. To generate this, the initial capital base at 30 June 2009 is rolled forward by adding efficient new capital expenditure and subtracting asset disposals and depreciation. This is covered in section 6.

The calculation of a benchmark rate of return for Horizon Power is outlined in section 9, with a more detailed technical review in Appendix H. The rate of return is determined by calculating the Weighted Average Cost of Capital (**WACC**), a combination of the cost of debt and equity for Horizon Power, compared to market rates.

As Horizon Power has access to borrowing at below market rates, the Authority has also determined a WACC based on these actual borrowing rates. Holding all other items equal within the cost of service model, the difference in the TEC values calculated using the two alternative WACC values, represents the additional cost of allowing Horizon Power a benchmark return on its assets. If a benchmark WACC is used, the additional cost is ultimately met by network customers in the SWIS. Section 10 below discusses this issue in more detail.

The determination of the efficient levels of operating and capital expenditure, historically and forecast, for the inquiry period are covered in sections 7 and 8 respectively. The Authority engaged technical consultants, Parsons Brinckerhoff Australia Pty Limited (**PB**) to undertake a review of Horizon Power's historical and proposed expenditures and then make recommendations as to the efficient levels of costs for the company. PB's report is published and available on the Authority's website.[21]

Excluded from actual and forecast total capital expenditure are those projects and activities that are requested by and funded by third parties such as the State or Federal Government, developers and customers. These are termed 'gifted assets' or 'gifted cash' provided to fund capital projects and as such are not added to the regulatory asset base and do not earn a return for Horizon Power. Current examples of these projects and their funding sources are shown in Table 2.3 below.

[21] www.erawa.com.au.

Table 2.3 Examples of externally funded capital projects ($m real at 30/6/2009)

Project/activity	Funding source	Total project value $m (project period)
Pilbara Underground Power Programme (PUPP)	75:25 - State Government (Royalties for Regions) and Local Regional Councils	100.4 (2010/11 to 2012/13)
Customer initiated	100 per cent fully funded from developer and customer contributions	36.6 (2010/11 to 2013/14)
Aboriginal Remote Community Power Supply Programme (ARCPSP)	50:50 – State and Federal Governments	20.3 (2010/11 to 2011/12)

Source: ERA analysis and Horizon Power spreadsheet Capex 020910

Therefore, only the efficient level of 'owners' capital expenditure is included in the regulatory accounts. This is to ensure Horizon Power only earns a return on the level of efficient expenditure it has funded.

The financial model built for this inquiry generates a revenue requirement for each of the towns supplied by Horizon Power and then consolidates these to give an aggregate view of the company as a whole. The revenue requirement for each town indicates the cost of supplying the town with electricity. The determination of the key drivers of the cost to supply is aided by a functional analysis, where the costs of generation, transmission, distribution, retail and overhead are shown separately in the model. Once the key drivers of the cost to supply are identified, reviewed and benchmarked with other electricity suppliers, the scope and focus for potential efficiency savings becomes clearer.

The aggregate cost of supply is then carried forward into a set of forecast statutory accounts created for Horizon Power. The statutory accounts serve several purposes:

- The actual sources of customer revenue for Horizon Power (uniform tariff revenue) are subtracted from the aggregate, cost reflective, revenue requirement to leave a 'balancing revenue' item, from which the subsidy (TEC and CSO) can be derived.
- The financial statements for Horizon Power can be reviewed in advance of any proposed reductions in its operating and capital expenditure programmes so that the company's ability to remain financially sound under the proposed regulatory regime can be assessed.
- Financial indicators, such as net debt as a percentage of total assets or earnings before interest and tax as a percentage of total assets can be reviewed to evaluate the financial viability of the company over the inquiry period.

The cost reflective tariffs for each town, and for Horizon power in aggregate, are determined and compared with the current average regulatory tariff in the SWIS (see section 11).

2.5 Practical issues

The Authority conducts financial modelling in real terms. For this inquiry this is in prices as at 30 June 2009 to coincide with the beginning of the inquiry period. This has the advantages of:

- ignoring the inherent uncertainty around forecasts of inflation during the inquiry period; and
- clarifying any proposed efficiency targets in real terms rather than have these masked by possible inflationary activity.

Consequently any figures in the text, tables or charts contained in this report will be in real prices as at 30 June 2009, unless otherwise stated.

The level of expenditure in many of the towns supplied by Horizon Power is very low, which is in contrast to its expenditure in the NWIS and the consolidated position. To adequately capture expenditure levels in appropriate detail all expenditure and asset information relating to the town level is given in $'000s. For the NWIS and for Horizon Power's consolidated position, expenditure and asset values are given in $m.

The NWIS operates in the north west of the State around the industrial towns of Karratha and Port Hedland and their resource and mining centres and serves approximately one third of Horizon Power's customers. As this is an interconnected system it is treated as a single network for the purposes of this inquiry. Therefore the NWIS cost of service is modelled in place of separate calculations for Karratha and Port Hedland. In doing this the Authority has also combined the East and West Pilbara districts into one and allocated the costs of these combined districts over the NWIS and the other towns in the region (Marble Bar, Nullagine and Onslow).[22]

2.6 Data issues

The Terms of Reference expressly request:

> " that the Authority also take into account the following costs when determining retail tariffs, but is not limited to considering only these costs:
>
> - the efficient generation costs applicable in the area Horizon Power operates in or each sub-area, if applicable, taking into account the current and committed stock of generation;
> - the efficient network costs applicable in the area Horizon Power operates in or each sub-area, if applicable, taking into account the current network infrastructure;
> - the level of efficient retail costs that would be applicable in the area that Horizon Power services (both operating and capital costs)"

Consequently, the Authority requested that Horizon Power submit operating and capital expenditures and asset base information at the town level and then further subdivide this into asset information and expenditures at the functional level - generation, transmission, distribution, retail and corporate overhead. This has enabled the Authority to model the cost of service for each town, the NWIS and a consolidated view of Horizon Power at the functional level to determine the impact of each function or combination of functions on the overall cost of service.

The required level of detail in the data provided by Horizon Power and the number of systems this applies to has meant that a considerable quantity of information has been received and reviewed by the Authority. Furthermore, as Horizon Power currently forecasts at the district and corporate level and has not traditionally collated historical information at the functional level, the data request from the Authority has necessitated a considerable degree of allocation across functions. This process has been further

[22] Based on kWh of energy sent out to these towns.

complicated by multiple and late revisions to operating and capital expenditures, data omissions in some years and a significant reallocation of assets between functions and between asset classes from when PB conducted its technical inquiry to when this draft report is published.

This has caused the Authority some concern as to the accuracy and consistency of some of the data received. Particular issues have emerged which have required further analysis and these are discussed as they occur in the sections on operating costs and capital expenditure costs below.

3 Escalation

In submitting its forecast operating and capital expenditure costs, Horizon Power has used a variety of escalators to reflect the anticipated future costs of labour, materials and services.

As mentioned above in section 2.3, Horizon Power purchases approximately 88 per cent of the electricity it sends out from IPPs, via competitively negotiated PPAs. Each PPA typically has its own individually specified escalators and Horizon Power uses the rates outlined in these contracts to forecast forward costs.[23]

For materials and labour costs, Horizon Power has used alternative escalators to the CPI (weighted average of eight capital cities), as it believes CPI does not reflect the underlying inflation it faces in the markets within which it operates.[24] In the North West of the State, Horizon Power is competing with the resources sector for labour and materials, which drives up prices. The remoteness of the location also adds to increased prices due to the cost of landing goods in the region. The variation in the prices of goods in regional Western Australia compared to Perth is generally recognised. This is evidenced by the publication of a Regional Prices Index in 2007 by the Department of Local Government and Regional Development, and since 1983, Rawlinsons Publishing has produced the Australian Construction Handbook which lists regional indices for all states.[25]

However, no consistent measure of regional prices over time exists. For budgeting purposes, instead of using CPI, Horizon Power claims to add 20 per cent to current Perth-based unit costs to what Horizon Power believes are more reflective of current regional unit costs and applies this to its projects material cost (which include contracted labour). Future prices are estimated by inflating current-day costs by a long run average of the Department of Treasury and Finance Building Construction Index (**BCI**),[26] currently calculated between January 1975 and June 2009.

Horizon Power inflates its labour costs by wage rate increases agreed in enterprise arrangements negotiated with staff. These escalators are shown in Table 3.1 below.

In its investigations, PB observed an error in how Horizon Power had calculated the long term BCI and applied the 20 per cent regional uplift to its forecast costs.[27] Instead of applying a 20 per cent uplift to Perth unit costs to reflect regional unit costs and then rolling this forward by BCI, Horizon Power has also uplifted the BCI index growth by 20 per cent. In doing so Horizon Power has effectively double-counted the impact of the 20 per cent uplift.

[23] Horizon Power 2010, Fact sheet No. 41 – Power Purchase Agreement Escalators.

[24] Horizon Power 2010, Fact sheet No. 31 – Rationale for HP's escalators and regional uplifts.

[25] Rawlinsons Australian Construction Handbook.

[26] Department of Treasury and Finance 2010, a model for forecasting construction cost escalation for non-residential buildings (e.g. hospitals, schools, police stations, etc) with input from various business units within the DTF for use by WA public sector agencies.

[27] Parsons Brinckerhoff 2010, Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 5.4.4, pp 53-56.

Table 3.1 Comparison of Horizon Power's nominated escalators against the Consumer Price Index (CPI)

Item	2009/10	2010/11	2011/12	2012/13	2013/14
Materials escalators					
• Escalated Buildings Cost index	8.22%	8.22%	8.22%	8.22%	8.22%
• Compounding escalator	1.082	1.171	1.267	1.371	1.484
Labour escalators					
• Horizon Power labour cost escalators	7.7%	6.4%	6.5%	6.4%	6.5%
• Compounding escalator	1.077	1.146	1.220	1.229	1.383
Correct BCI escalator	1.064	1.132	1.205	1.282	1.364
Consumer Price Index					
• Annual actual and forecast CPI growth	2.60%	2.60%	2.60%	2.60%	2.60%
• Compounding escalator	1.026	1.053	1.080	1.108	1.137

Source: PB Final report, pp 52-53 and RBA Statement on Monetary Policy (August 2010)

Furthermore, Horizon Power has not had its use of escalators independently reviewed, which is usually the case to support any forecast cost increases above CPI. For example, in Western Power's second access arrangement, it had its proposed escalation factors independently reviewed and supported by Access Economics.[28]

Whilst the Authority recognises that regional prices have probably risen at a faster rate than the eight cities CPI in the past,[29] it has concerns regarding how the long-run average BCI growth figure is calculated and that it is not a like-for-like comparison with the forecast CPI preferred by the Authority.

In particular, the 1975 to 2009 average BCI growth of 6.85 per cent includes periods of high inflation during the 1970s and 1980s. After the recession of the early 1990s, price inflation has been much lower than previously, with the independent Reserve Bank of Australia (RBA) adopting a price (national CPI) target of between 2-3 per cent over the cycle,[30] and has generally been successful in achieving this target.

Comparing the CPI and BCI over long periods indicates that BCI growth was only slightly higher than eight-city CPI growth. From 1975 to 2010,[31] the CPI averaged 5.28 per cent growth per annum, with the BCI averaged 5.67 per cent. Between 1990 and 2010, the CPI averaged 2.62 per cent per annum, while the BCI averaged 2.98 per cent. Such similarity points to using a similar figure for BCI growth as for forecast CPI growth of 2.6 per cent per annum. This is shown in Figure 3.1 below.

However, this long-run similarity masks several periods of divergence between the two series. In particular, between 2002 and 2008, the BCI grew by 9.96 per cent per annum, compared to 3.03 per cent for the CPI. Anecdotal evidence suggests that this may have understated price growth in some regions, especially the Pilbara. Since then, however,

[28] Access Economics 2008, Material and labour cost escalation factors.

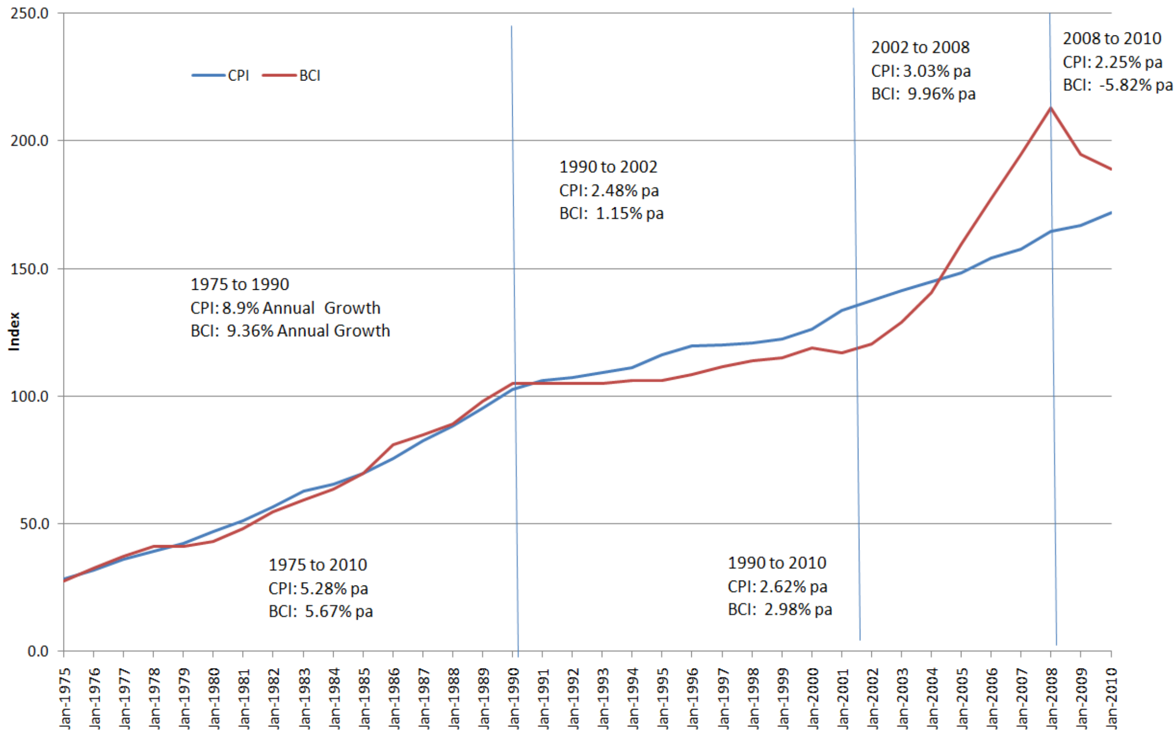
[29] Parsons Brinckerhoff 2010, Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 5.4.4, p56.

[30] http://www.rba.gov.au/monetary-policy/inflation-target.html

[31] The latest data available.

the BCI has fallen 11.3 per cent from its peak in June 2008, which coincided with the onset of the Global Financial Crisis. While Western Australia's economic (and especially investment)[32] prospects may have improved since the peak of the crisis, it is unclear whether rates of escalation of the magnitude experienced between 2002 and 2008 will return.

Figure 3.1 Historical financial year end BCI and CPI (1975 to 2010)



Source: Department of Building and Works, Building Construction Index – Perth.

The Authority accepts that Horizon Power may face materials cost growth higher than the CPI, or even the Perth-based BCI. At this stage, however, Horizon Power has not submitted a credible case that this will occur and has only presented a long-run average.

Therefore, with the exception of the escalators fixed by PPA contracts, any escalation Horizon Power has assumed in its cost forecasts has been ignored and removed on the basis that the use of a historically based index to predict future escalation is inappropriate. Consequently, the reductions to either operating costs or capital expenditure costs have been applied in real terms which, for this inquiry, are in prices as at 30 June 2009, the beginning of the inquiry period.

At this stage the Authority considers that price escalation of the RBA's eight cities CPI forecast is appropriate to inflate real prices into nominal terms. Should Horizon Power wish to submit an alternative escalation forecast between the draft and final reports it should ensure that these forecasts have been independently verified. An alternative might be for Horizon Power to use the Department of Treasury and Finance's forecast for the BCI.[33]

If, however, in later years actual efficient costs do exceed CPI then a future inquiry can correct for this by allowing an uplift to operating costs in the first (or base) year of the inquiry to reflect the actual cost escalation compared to those assumed in the previous

[32] Department of Treasury and Finance 2010/11, Budget Paper No.3 Economic and Fiscal Outlook, p22

[33] This is confidential within Government agencies so cannot be reproduced here.

inquiry. This is a forward looking adjustment and would not retrospectively compensate Horizon Power for the previous inquiry period. This is explored in more detail in section 13 below.

4 Service Standards

The issues paper for this inquiry into the funding arrangements of Horizon Power outlined the current service standards to which Horizon Power has to comply and the actual service standards against which it reports to the Authority.[34]

Standards regarding the reliability of the electricity supply are detailed in the *Electricity Network (Network Quality and Reliability of Supply) Code 2005*. Horizon Power aims, as far as is reasonably practicable to:

- ensure the average interruption length (SAIDI[35]) does not exceed 290 minutes;
- the number of interruptions does not exceed 16 times per year; and
- ensure that any duration does not exceed a continuous 12 hours in length.

One of the key factors affecting Horizon Power's supply interruption measures is the time taken to travel to the source of the problem to affect the repair. This is a result of the size of Horizon Power's area of supply and the remote nature of many towns.

As part of its technical review, PB determined that Horizon Power has established SAIDI targets as follows:[36]

- 160 minutes for its urban areas;[37]
- 290 minutes for its remote areas;[38] and
- Either 350 or 500 minutes (depending upon the characteristics of the supply network) for its remote rural areas.

Based on Horizon Power's 2009/10 performance report, Table 4.1 shows that the average total length of all interruptions to customers (SAIDI) decreased from 336 minutes across the whole system in 2008/09 to 204 minutes in 2009/10. Three towns out of the 36 systems (Esperance, Norseman and Wyndham) had a SAIDI in excess of 290 minutes in 2009/10. In its performance report of May 2010, Horizon Power stated that it expected all systems to meet the required standards by July 2011.[39]

[34] ERA 2010, Inquiry into the funding arrangements of Horizon Power: Issues paper, Section 4, pp 21-27.

[35] SAIDI (System Average Interruption Duration Index) – the total of all customer interruptions in minutes divided by the total number of customer connections averaged over the year.

[36] Parsons Brinckerhoff 2010, Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 5.4.2, p51.

[37] Urban areas means 'economically critical supply areas (NWIS), as defined in the Reliability code for urban areas'. Horizon Power 2010, Submission to the Executive, Differential Electricity Reliability Measure for certain remote areas, p3.

[38] Remote areas means 'other areas of the state with depots, as defined in the Reliability code for "any other area of the state". Horizon Power 2010, Submission to the Executive, Differential Electricity Reliability Measure for certain remote areas, p3.

[39] Horizon Power 2010, Performance report, May 2010 (DMS 3195883), p4.

Table 4.1 Average Total Length of All Interruptions of Supply to Customer Premises in Minutes (SAIDI) for Horizon Power Supply Areas in 2008/09 and 2009/10

	Average Length of Interruption of Supply to Customer Premises (Minutes)	
Town or System	**2008/09**	**2009/10**
NWIS	113	114
Ardyaloon	223	0
Beagle Bay	375	0
Bidyadanga	0	0
Broome	401	61
Carnarvon	207	250
Coral Bay	10	0
Cue	33	173
Denham	85	0
Derby	324	94
Djarindjin	16	0
Esperance	782	611
Exmouth	341	47
Fitzroy Crossing	196	76
Gascoyne Junction	75	0
Halls Creek	333	32
Hopetoun	342	209
Kununurra	372	266
Lake Argyle	325	38
Laverton	520	103
Leonora	30	39
Looma	644	27
Marble Bar	31	38
Meekatharra	173	0
Menzies	0	0
Mount Magnet	667	100
Norseman	384	326
Nullagine	6	110
Onslow	129	217
Sandstone	12	0
Warmun	39	0
Wiluna	175	0
Wyndham	762	327
Yalgoo	9	0
Horizon Power	**336**	**204**

Source: Horizon Power (2010), Network Quality and Reliability of Supply – Performance Report 2009/10, p13.

In January 2009, the Authority issued Horizon Power with a notice of failure to comply with its licence,[40] following the 2008 performance review, which identified 17 contraventions of Horizon Power's operating licence.[41] Since this notice, Horizon Power has fully addressed all but one of these contraventions. The one outstanding compliance relates to the implementation of a customer complaints handling procedure that complies with the *Electricity Code of Conduct.*[42] However, the Authority will not be taking further action as it considers that Horizon has taken adequate measures to rectify the issues identified in the notice.

4.1 Authority comment

The Authority is not proposing a change to existing service level standards at the current time (e.g. to require Horizon Power to report to the same service standards as Western Power does for its Access Arrangement),[43] as this would require a change in legislation away from the Electricity Network Reliability Code, which is outside the terms of this inquiry. Instead the inquiry concentrates on determining the efficient levels of operating and capital expenditure required to deliver service to the existing required standards.

Horizon Power reports regularly to the Authority as part of its licensing requirements and, as such, the Authority is kept informed as to Horizon Power's service performance.

4.2 Recommendation

Recommendation

1) The service level standards for Horizon Power be retained, unchanged from their existing form, for the inquiry period.

[40] *Section 32 Electricity Industries Act 2004 – Notice of Failure to Comply with Licence*, on the Authority web site, under "Horizon Power": http://www.erawa.com.au/2/245/51/electricity_licensing__licence_holders.pm.

[41] Ernst and Young (November 2008), *Integrated Regional Licence (EIRL2) Performance Audit Report.*

[42] Clause 14.4(1) of the *Code of Conduct for the Supply of Electricity to Small Use Customers* requires a distributor to acknowledge and respond to written queries or complaints within a prescribed timeframe. The performance audit identified one instance where a complaint was not acknowledged within the timeframe and two cases where the complaint was not resolved within 20 days.

[43] www.erawa.com.au, Amended proposed revisions to the Access Arrangement for the South West Interconnected System owned by Western Power, pp 5-11.

5 Demand Forecasts

Horizon Power has a five stage process for determining its ten year demand and energy forecasts.[44] These forecasts are used to inform investment decisions and asset management planning concerning network augmentation and generation requirements.

Over the inquiry period Horizon Power is forecasting that overall demand will increase by six per cent for residential customers and just under four per cent for existing commercial customers. This is driven by growth in the numbers of connections of just under three per cent per annum for residential properties and just over two per cent per annum for commercial connections.[45]

In the NWIS, Horizon Power has just over 13,000 commercial and residential customers, including 18 large industrial customers. All customers are covered by the uniform tariff policy with the exception of the 18 large industrial customers as these have commercial supply contracts with Horizon Power. Over the past six years Horizon Power has experienced increasing demand growth of six per cent in the NWIS, driven mostly by population growth.[46]

Horizon Power is forecasting that the demand growth profile for the NWIS will change. Maximum daily demand is expected to increase by 16 per cent in 2010/11 due to increases in demand from major industrial customers, e.g. a new 6.2MW load from the connection of the new bulk commodity export berth by the Port Hedland Port Authority at Utah Point on Finucane Island[47] and an additional discrete load (2.8MW) for a workers accommodation camp for Woodside. This increase in forecast demand is shown in Figure 5.1 below.

The step increase of 25 per cent in maximum demand forecast from 2009/10 to 2010/11 results from the combined effect of lower summer temperatures tempering maximum demand in 2009/10, then the 16 per cent increase from new demand in addition to annual organic growth from residential and small commercial customers.

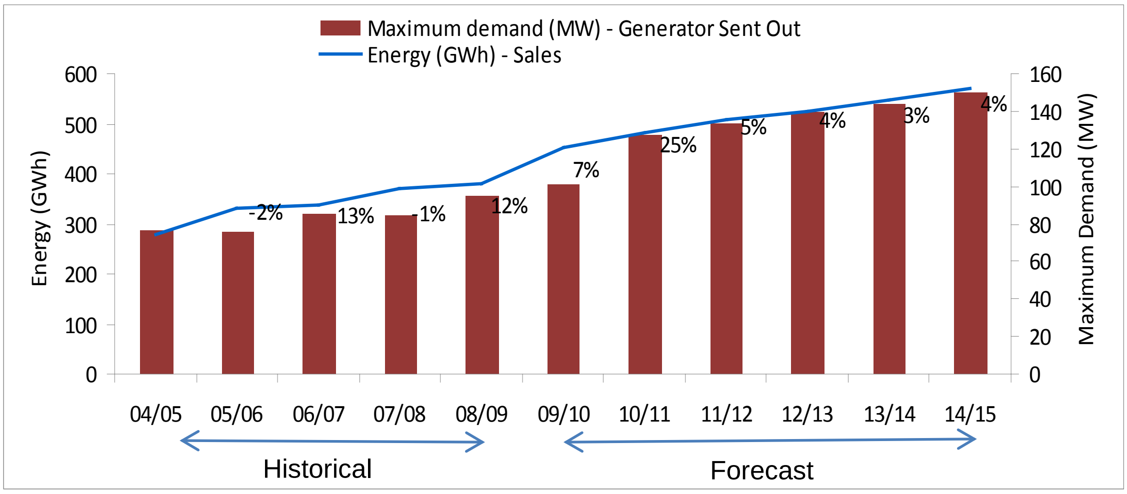
[44] Horizon Power 2010, Fact sheet No. 1 – The demand and energy forecasting process.

[45] Horizon Power, 2010, Spreadsheet 'HP#3295715v1_connection totals'.

[46] Horizon Power 2010, South Hedland Power Station – Business case for new generation, p7.

[47] Port Hedland Port Authority website http://www.phpa.wa.gov.au/utah_point.asp.

Figure 5.1 Historical and forecast energy demand for NWIS



Source: Horizon Power – South Hedland Power Station, Business Case for New Generation, Figure 4, p8

Horizon Power currently has contractual arrangements for 139MW of capacity (from PPAs with Alinta and ATCO) until the end of December 2012 when its PPA with Alinta expires. At this point available generation capacity falls to 80MW.

The alternatives Horizon Power considered to provide additional generation capacity in the NWIS are discussed in more detail in section 8.2 below.

PB, as part of its review, examined the accuracy and validity of Horizon Power's demand and energy forecasting process and concludes that:

> "Horizon Power approaches its annual demand and energy forecasting using an informed and detailed bottom up approach."

However, PB is concerned that the company does not place much emphasis on incorporating independent 'top-down' analysis, which is typically the case, in PB's experience, for other electricity suppliers.[48]

Where the demand forecast is driving a particular investment project, such as in the proposed augmentation of the Fairway Drive transmission substation in Broome, PB has reviewed Horizon Power's underlying demand projection in more detail. In this particular case, PB proposed reductions to the forecast capital expenditure in line with its own considerations on forecast demand growth and alternative arrangements in the short term. This is explained in more detail in section 8.3 below.

PB does not suggest any revision to Horizon Power's current demand forecast or its energy and demand forecasting methodology and processes.

5.1 Authority comment

The Authority has noted PB's comments on Horizon Power's demand forecasts and does not propose any adjustments to Horizon Power's demand forecasts over the inquiry period.

[48] Parsons Brinckerhoff 2010, Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 5.3.3, p45.

Section 13 below outlines the approach the Authority would take if, at the onset of a future review, Horizon Power's demand forecasts proved to be inaccurate.

6 Initial Capital Base (ICB)

This section outlines the determination of the regulatory asset base for Horizon Power over the inquiry period.

6.1 ICB at 1 April 2006

Assets were transferred to Horizon Power at their written down historic cost value, excluding any accumulated depreciation ($180.1m nominal in Table 6.2 below). Following disaggregation, Horizon Power undertook a review of all inherited assets and assigned a remaining asset life to each asset.

6.2 Net new capital expenditure to 30 June 2009

To reflect the operation of an efficient regional power corporation, the ICB value is only rolled forward by efficient new capital expenditure. PB was asked to review the efficiency of Horizon Power's historical capital expenditure as part of its wider technical advice to the Authority.

6.2.1 PB findings

PB outlined its findings on Horizon Power's historical expenditure in Chapter 6 of its report.[49] In summary, PB found some variance between Horizon Power's actual capital spend when compared to budget; 18 per cent in 2006/07, 13 per cent in 2007/08 and 3 per cent in 2008/09. The majority of these variances could be accounted for and were, in the main, outside the control of Horizon Power. On page 60 of its report, PB comments:

> "With regards to capex, PB has identified a clear trend of underspending against budget. However, as noted above, this has largely been due to factors which were outside the company's control and the underspending is reducing as a percentage of budgeted expenditure."

In its report, PB notes that Horizon Power has been undergoing a period of 'establishment and restructuring' since inception[50] and as such can be expected to show increases in operating costs and staff numbers. Consequently, PB did not recommend any reductions to historical operating and capital expenditure levels. However, PB also expects that the cost increases and staff numbers should start to decrease as the company realises efficiencies. This supports PB recommendation for reductions to future operating costs as detailed in section 7.

6.3 Authority comments

Horizon Power provided the Authority with a copy of its Fixed Asset Register as at 1 April 2006, coinciding with its disaggregation from Western Power Corporation. This Fixed Asset Register data and information was used to determine ICB values and

[49] Parsons Brinckerhoff 2010, Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 6.2, p63.

[50] Parsons Brinckerhoff 2010, Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 8.8, p89.

weighted average asset lives by function and by asset class for each town and for each district. The data for new capital additions, disposals and gifted assets was also sourced from Horizon Power's fixed asset registers. All new capital additions were depreciated using average asset class lives in accordance with Horizon Power's Budget Model.[51]

To calculate an ICB at 1 July 2009, the Authority took the value of Horizon Power's asset base at the point of disaggregation from Western Power Corporation, on 1 April 2006 and then rolled this value forward by adding efficient new capital net of asset disposals and depreciation to give a closing asset value at 30 June 2009. This figure, $264.1m, was then carried forward to become the opening ICB value at 1 July 2009. The figure is not inflated as financial modelling for the five year inquiry period is carried out in real prices as at 30 June 2009.

A list of ICB values at 1 April 2006 and 30 June 2009, for each location, is given in Appendix B.

Assets gifted to Horizon Power either as cash or as physical assets by customers, developers, the State Government or Federal Government have been excluded from the regulatory asset base as they were not directly funded by Horizon Power.

Given PB's comment on and assessment of past expenditures, the Authority does not propose to make any adjustments to net new capital additions between 1 April 2006 and 30 June 2009.

The Authority proposes to use the historic cost valuation of Horizon Power's asset base in the calculation of revenue requirement. This is contrary to the frequent use, in regulatory economics, of a current cost valuation methodology, such as a Depreciated Optimised Replacement Cost (**DORC**) or Optimised Deprival Value (**ODV**), to establish an ICB (e.g. as in Western Power's first access arrangement period, 1 July 2006 to 30 June 2009).

In its response to the issues paper Horizon Power suggests that:

> "..utilisation of the accounting data will significantly undervalue the assets from an economic perspective."

Horizon Power expands on this by stating that, given the age of some of its infrastructure assets, there are some assets have been depreciated to zero, have no value in Horizon Power's regulatory asset base and therefore will not earn a return. [52]

Horizon Power did submit some current cost information on its asset base which was used to inform the Authority's discussion on ICB valuation and its final decision to use a historic cost valuation.[53]

After reviewing the available evidence, the Authority supports the use of a historic cost ICB valuation given that:

- there is insufficient time available for Horizon Power to undertake a complete revaluation of its asset base using an optimised current cost methodology;
- the Authority is aware that some assets have a written down value of zero in Horizon Power's asset register. Typically these assets were commissioned before

[51] Horizon Power 2010, Fact Sheet No. 38 – Asset Classes and Asset Life Expectancy.

[52] Horizon Power 2010, Submission to the ERA Issues Paper, Section B 4.1 Asset Valuation, p23.

[53] SKM 2010, '2009 Horizon Power Asset Valuation of the NWIS' and '2010 Horizon Power Replacement Cost Valuation of the Non-Interconnected System (NIS).

Horizon Power was established and so would have earned a return for the previous owner, WPC, and been fully depreciated. Therefore the Authority suggests that these assets should not earn a further return for Horizon Power;

- the Authority is unable to establish an ODV for Horizon Power using the regulatory methodology because of circularity issues. ODV requires the calculation of anticipated future income streams generated by each asset. The establishment of future income streams is dependant upon the size of the TEC, calculated by the cost of service model, which uses the ODV as an input;
- the calculation of the revenue requirement is relatively insensitive to the ICB, when compared with the other elements of the revenue requirement calculation. This is explained in more detail in section 10 below; and
- a historic cost ICB valuation, and the contribution this makes to the overall revenue requirement, when tested through a model of Horizon Power's statutory accounts is sufficient to maintain Horizon Power's financial fitness over the inquiry period. This 'testing' of financial viability is also explained in more detail in section 10.

The historic cost ICB valuation at 30 June 2009 reconciles back to Horizon Power's statutory accounts for 2008/09 as shown in Table 6.1 below.

Table 6.1 Reconciliation of historic cost valuation to Horizon Power's 2008/09 statutory accounts ($m real at 30/6/2009)

Item	Amount ($m)
Horizon Power Statutory accounts 2008/09	
• Land	7.545
• Leasehold buildings and equipment	18.225
• Plant and equipment	372.172
Sub-total non-current assets	397.942
Less	
• Work in progress	99.060
• Decommissioned assets	5.497
• Gifted assets	22.258
Regulatory asset base from statutory accounts	271.112
ERA calculated regulatory asset base	264.086
Variance in calculated depreciation charge	-3.506
Overall variance between asset bases	3.520

Source: Horizon Power's statutory accounts for 2008/09, spreadsheet HP=326434 and ERA analysis

The roll forward of Horizon Power's ICB, at the aggregate level from 1 April 2006 to 30 June 2009 is shown in Table 6.2 below. The closing ICB value in the preceding year is inflated by CPI to give the opening value ICB in the following year. As mentioned above, the exception is the final year where the closing value at 30 June 2009 is taken forward to 1 July 2009 as from this date all financial modelling data is shown in prices as at 30 June 2009.

Closing ICB values at 1 April 2006 and 30 June 2009 for all towns and the NWIS are shown in Appendix B.

Table 6.2 Derivation of Horizon Power's aggregate ICB to 30 June 2009 ($m nominal)

Item	1 April 2006	30 June 2006	30 June 2007	30 June 2008	30 June 2009
Opening value		182.9	180.4	174.1	232.6
Net additions		-2.7	0.2	64.2	40.7
Depreciation		-3.5	-14.0	-9.0	-9.2
Closing value	180.1	176.7	166.6	229.2	**264.1**

Source: ERA analysis

6.4 Recommendation

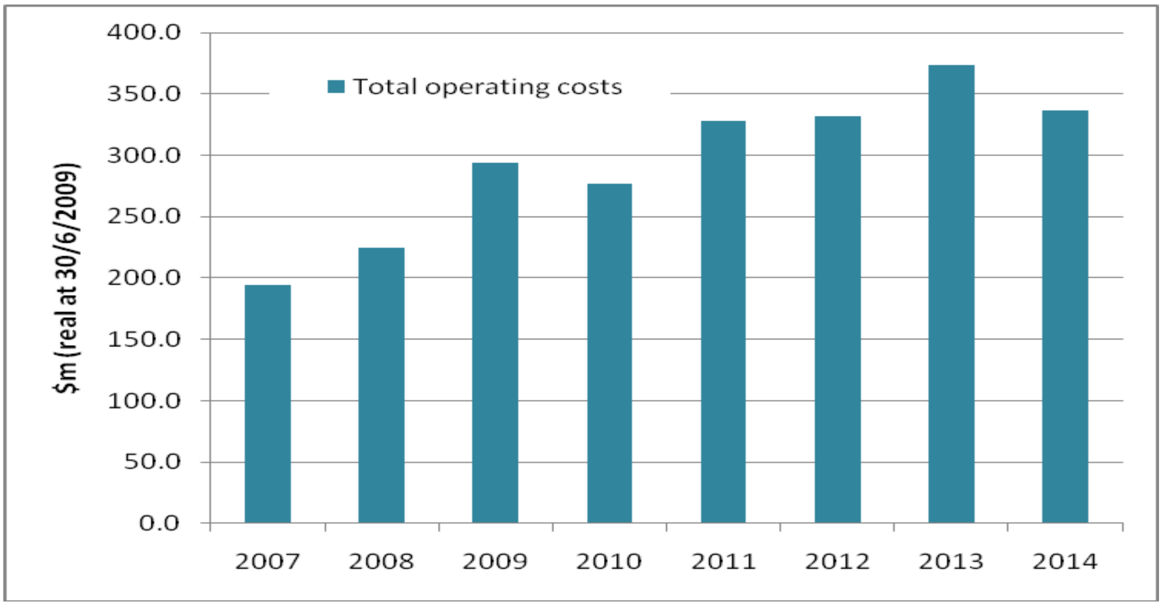
Recommendation

2) A historic cost valuation of $264.1 million (in real prices as at 30/6/2009) be used for Horizon Power's initial capital base as at 1 July 2009.

7 Total Operating Costs

After removing any assumed escalation, Horizon Power incurred average annual operating costs of $237.7m (real at 30/6/09) over the period 2006/07 to 2008/09 and submitted average annual (actual and forecast) operating costs of $329.3m (real at 30/6/09) over the period 2009/10 to 2013/14. This is an increase of 38.5 per cent in the average annual expenditure between the two periods. The annual expenditure is shown in Figure 7.1 below.

Figure 7.1 Actual and forecast total operating cost levels over time ($m real at 30/6/09)



Source: Horizon Power - Consolidated town report data 16/9/2010 and ERA analysis

Horizon Power supplied actual and forecast operating costs by function (generation, transmission, distribution, retail and overhead) for the inquiry period. The Authority reviewed this functional analysis of operating costs to determine which functions or combination of functions is driving operating cost growth. The individual cost functions comprising forecast operating costs are shown in Table 7.1 below, which demonstrates that generation and overhead operating costs are the main drivers of total operating costs and together contribute over 93 per cent of total costs over the inquiry period.

Table 7.1 Drivers of forecast operating costs by function ($m real at 30/6/2009)

Function and main drivers	2010	2011	2012	2013	2014	Total	Per cent of total
Generation	175.0	208.6	212.1	251.5	215.4	1,062.5	64.5
Transmission	1.9	2.4	2.4	2.7	4.4	13.7	0.8
Distribution	18.1	6.4	6.7	7.0	8.7	46.9	2.8
Retail	9.4	10.1	9.9	10.0	10.0	49.3	3.0
Overhead	72.7	100.5	101.1	102.2	97.8	474.3	28.8
Total operating expenditure	277.0	327.9	332.3	373.3	336.3	1,646.7	100.0

Source: Horizon Power - Consolidated town report data (16/9/2010) and ERA analysis

The ‘spike’ in total operating costs in 2012/13 ($373.3m real at 30/6/2009) is associated with additional electricity purchases required to cover demand whilst the new power station in South Hedland is being constructed.[54] Energy costs increase from $71.8m in 2011/12 to $106.7m in 2012/13 then reduce back to $66.6m in 2013/14 (all real as at 30/6/2009). Horizon Power has advised the Authority that because of delays in obtaining budget approval for the South Hedland power station project from State Government, Horizon Power’s initial commissioning date for the new power station, November 2012, has been delayed until 1 July 2013. This is on the assumption that budget approval will be forthcoming by the end of 2010. Had the original timeframe been met then additional energy purchases would not have been required.[55]

If Horizon Power does not receive funding approval for the South Hedland power station project by the end of 2010, then Horizon Power is expected to submit alternative costings and generation solutions which will be reflected in the final report for the inquiry.

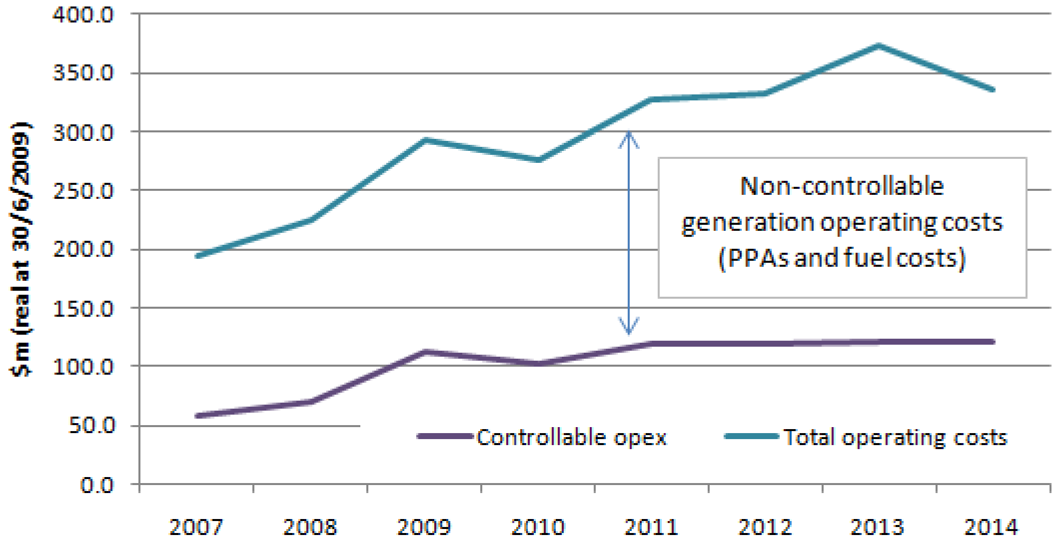
Table 7.1 above also demonstrates a clear increase in overhead operating costs from $72.7m (real at 30/6/2009) in 2009/10 to $100.5m (real at 30/6/2009) in 2010/11, after which overheads remain at around $100m per annum. This illustrates how the functional analysis of operating costs is effected by Horizon Power’s current practise of allocating actual costs (2009/10) at the town/functional level and forecasting (2010/11 onwards) the majority of its operating costs at the district level. District costs and corporate overheads are combined in Table 7.1 as total overhead. A further analysis of overhead is undertaken in section 7.3.5 below.

However, not all of Horizon Power’s operating costs are controllable in the short term. This non-controllable element of operating costs (just over 60 per cent of total operating costs) is predominantly those generation operating costs that relate to PPA agreements and fuel purchases. This is illustrated in Figure 7.2 below and explained in more detail in section 7.2.

[54] Parsons Brinckerhoff 2010, Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 7.4, p74.

[55] Horizon Power 2010, email received 16 November 2010.

Figure 7.2 Horizon Power's total operating costs and controllable operating costs ($m real at 30/6/2009)



Source: Horizon Power town reports at 8 and 16 September and ERA analysis

7.1 Authority comments

The Authority notes the increase in energy purchase operating costs by just under $35m in 2012/13 to cover demand prior to the South Hedland power station being commissioned. The Authority considers that any additional costs incurred by Horizon Power and identified by Horizon Power as resulting from delays in receiving funding approval should not be passed through to the TEC and consequently to SWIS customers. The Authority has removed this forecast expenditure from the generation operating costs included in the cost of service calculation. Furthermore, there is a risk that this increased level of energy purchase costs will continue if the power station project is delayed and so the Authority also recommends that any additional operating cost increases resulting from a delay of the South Hedland generation project are borne by government through a CSO payment funded from general taxation.

7.2 Non-controllable operating costs

All non-controllable operating costs are related to generation activities. This is because the purchase of electricity from IPPs through PPAs and the purchase of fuel for its self-generation activities and tolling arrangements with IPPs, dominates Horizon Power's generation operating costs (just over 94 per cent of total generation operating costs) over the inquiry period. Each IPP has its own set of escalation factors written into the contract terms. Consequently, in the short term, Horizon Power has very limited control over these IPP costs, and their embedded escalation factors. The non-controllable elements of generation operating costs over the inquiry period are given in Table 7.2 below. For comparative purposes all costs are shown in prices as at 30 June 2009, having been deflated by CPI. It should be noted that the embedded inflation factors in IPP contracts may differ from CPI.

Table 7.2 Forecast generation operating costs analysis ($m real at 30/6/2009)

Generation operating cost item	Total 2009/10 to 2013/14	Percent of total generation operating costs
Distillate/Waste Oil	27.0	2.5
Gas transport/Gas purchase	160.5	15.1
Electricity purchase (capacity and energy)	773.9	72.8
Renewable energy (capacity and energy)	41.9	3.9
Sub-total non-controllable generation operating costs	1003.4	94.4

Source: Horizon Power town reports at 8 Sep 2010 and ERA analysis

With the above items removed, Horizon Power's remaining operating costs are considered 'controllable', this amounts to a total controllable operating cost of $584.2m (real as at 30/6/2009) for the inquiry period (or an average controllable operating cost of $116.8m per annum).

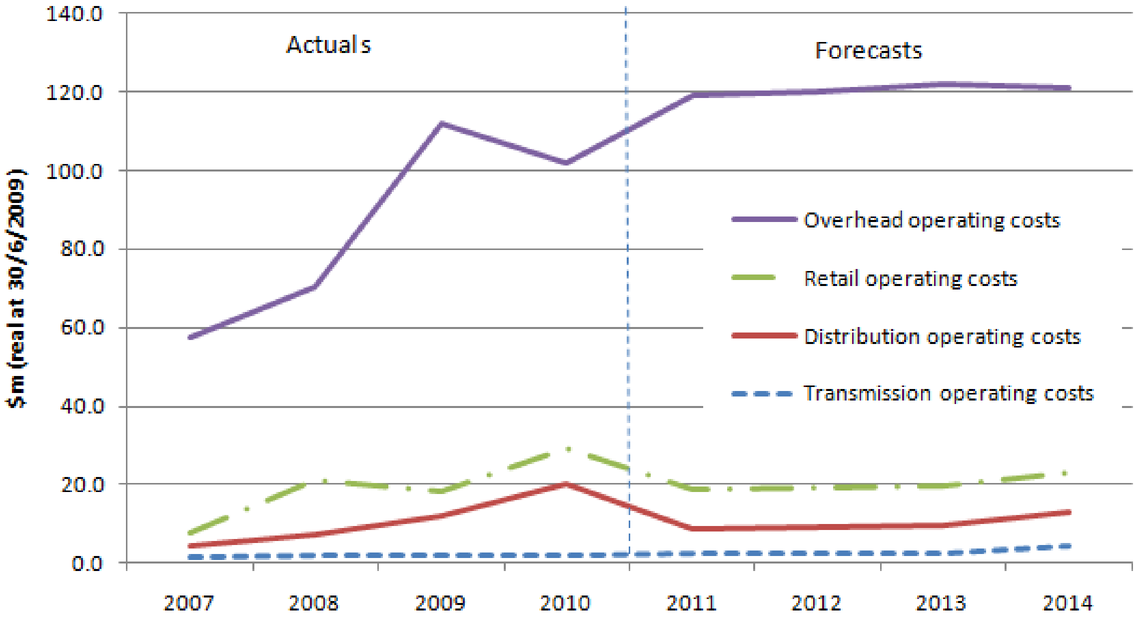
7.2.1 Authority comments

Given that a large proportion (94.4 per cent) of generation operating costs is essentially fixed by contract rates, there is little Horizon Power can do to reduce these costs in the short term. In addition, each PPA has its own cost escalators written into the contract terms. The Authority recognises the fixed nature of the majority of Horizon Power's generation operating costs and does not intend to apply any efficiency factor to this 'non-controllable' element and has retained the escalation factors inherent in these PPAs in the financial modelling for the inquiry.

7.3 Controllable operating costs

The controllable operating costs shown in Figure 7.2 above are analysed by function in Figure 7.3 below. Controllable generation operating costs are not shown in the following chart as they are marginal compared to the other functional elements, however each operating cost element is considered individually in the sections below.

Figure 7.3 Actual and forecast controllable operating costs ($m real at 30/6/2009)



Source: Horizon Power town reports at 16 Sep 2010 and ERA analysis

7.3.1 Generation operating costs

Section 7.2 above explains that, in the short term, the majority of Horizon Power's generation operating costs are fixed because they are defined by the contractual terms of individual PPAs. However, Horizon Power has scope to affect contract costs when PPAs are renegotiated.

Horizon Power competitively tenders its PPA contracts from a panel of four parties. As part of its technical review PB was asked to investigate the efficiency of Horizon Power's procurement processes which include PPA tenders. PB observed that as PPAs expire and are replaced, Horizon Power has improved the terms of its PPA contracts and has looked to drive down costs where possible.[56] PB expressed concerns that, despite a competitive tendering approach, in remote areas there is a lack of competition for outsourcing services as often, there are only single electricity suppliers in remote areas.

Horizon Power informed PB that, in response to the lack of IPPs in remote regions, it has chosen to bring some services in-house such that it is able to form comparisons of its own cost to supply with those of IPPs. Horizon Power generates its own electricity on nine sites, as shown in Table 7.3 below.

[56] Parsons Brinckerhoff 2010, Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 7.4, pp 75.

Table 7.3 Horizon Power self-generation locations

Location	Fuel type	Approximate installed capacity MW
Carnarvon	Gas/diesel	16.5
Coral Bay	Diesel	2.24
	Wind (IPP)	*0.825*
Denham	Diesel	2.55
	Wind (IPP)	*1.02*
Hopetoun	Diesel	2.24
	Wind (IPP)	*1.2*
Kununurra	Standby diesel plant	12.4
	Hydro (IPP)	*30*
Marble bar	Diesel	1.276
	Solar	0.3
Nullagine	Diesel	0.96
	Solar	0.2
Onslow	Standby diesel plant	2.8
	Gas (IPP)	*3.42*
Wyndham	Standby diesel plant	2.0
	Hydro (IPP)	*As per Kununurra above*

Source: Email and attachment from Horizon Power, 15/10/2010

PB investigated the operating cost expenditure for Horizon Power's self-generation and although it observed considerable cost over and underruns with regards fuel purchases and maintenance, these are mostly explained by:

- fuel costs being linked to the generation output, which is variable given that much of the diesel generation in remote locations is used to back up peak demand; and
- the age of mobile plant where emergency or reactive maintenance surpasses any planned or corrective maintenance.

Consequently, PB did not make any specific recommendations regarding generation operating costs.

7.3.2 Transmission operating costs

After removing any assumed inflation, Horizon Power incurred annual average transmission operating costs of $1.8m (real at 30/6/09) over the period 2006/07 to 2008/09 and submitted annual average (actual and forecast) transmission operating costs of $2.7m (real at 30/6/09) over the inquiry period. This is an increase of 50 per cent in the average annual expenditure between the two periods.

Transmission operating costs follow a similar profile to that of historic expenditure, ranging between $1.8m and $2.6m per annum. The exception is an increase of $1.7m (real as at 30/6/2009) in 2013/14. These are operations and maintenance expenditures associated with the commissioning of the proposed new power station in South Hedland. Horizon Power informed PB that as Horizon Power currently has no generation operation and maintenance cost codes for the Pilbara, it has temporarily classified these costs as transmission related.[57]

PB did not make any specific recommendations regarding transmission operating costs.

7.3.3 Distribution operating costs

After removing assumed escalation, Horizon Power incurred annual average distribution operating costs of $6.1m (real at 30/6/09) over the period 2006/07 to 2008/09 and submitted annual average (actual and forecast) distribution operating costs of $9.4m (real at 30/6/09) over the inquiry period. This is an increase of 54.1 per cent in the average annual expenditure between the two periods.

The spike in operating costs in 2009/10 results from an increase in the following costs:

- maintenance (contractors and consultants) $6.4m nominal;
- overhead recovery $6.0m nominal; and
- CSO expense $6.2m nominal.

CSO expense has been removed from the 2009/10 base year (and all other years) for financial modelling purposes because the cost of service model excludes any sources of external funding arrangements for Horizon Power from calculation of the revenue requirement and cost reflective tariffs.

PB did not make any specific recommendations regarding distribution operating costs.

7.3.4 Retail operating costs

Retail operating costs are associated with metering and billing services, customer services and marketing and product development. Horizon Power contracts out its metering, billing and customer service functions through Service Level Agreements (SLAs) as follows:

- Meter reading – AMRS Pty Ltd.
- Data management – Western Power
- Billing and customer contact – Serviceworks Ltd.

After removing assumed escalation, Horizon Power incurred annual average retail operating costs of $7.9m (real at 30/6/09) over the period 2006/07 to 2008/09 and submitted annual average (actual and forecast) retail operating costs of $9.9m (real at 30/6/09) over the inquiry period. This is an increase of 25.3 per cent in the average annual expenditure between the two periods.

There is a large expenditure of $11.7m (nominal) in 2007/08 on 'other' metering and billing costs. Horizon Power has advised the Authority that this is mainly related to CSO expense costs which because of a change in Horizon Power's chart of accounts has been captured in this code in 2007/08.[58]

[57] Parsons Brinckerhoff 2010, Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 8.3, p82.

[58] Horizon Power, 2010, email dated 18 November 2010.

The Authority has not determined a separate retail margin for Horizon Power because the systematic risks faced by Horizon Power as a vertically integrated electricity supplier will be accounted for in the calculation of its return on capital. This also ensures an appropriate return on any retail assets Horizon Power owns, which are minimal.

PB did not make any specific recommendations regarding retail operating costs.

7.3.5 Corporate and district overhead operating costs

After removing assumed escalation, Horizon Power incurred annual average overhead operating costs of $64.2m (real at 30/6/09) over the period 2006/07 to 2008/09 and submitted annual average (actual and forecast) overhead operating costs of $94.9m (real at 30/6/09) over the inquiry period. This is an increase of 47.8 per cent in the average annual expenditure between the two periods.

In real terms overheads contributed 27 per cent to total operating costs over 2006/07 to 2008/09 and 28.8 per cent to total operating costs over 2009/10 to 2013/14. This is partly explained by Horizon Power's practice of forecasting operating costs at the district and corporate level with the consequence that a disproportionate level of cost is held at these levels and not directly allocated to the respective towns.

In its report, PB expressed some concern that Horizon Power appears to have inherited or adopted processes and an organisational structure from a model of the larger legacy business (Western Power Corporation), which is contributing to a 'top heavy' organisational structure and cost loading.

PB also commented on increasing staff levels from inception (193 full-time equivalents) to the current time (388 full-time equivalents) and noted that staffing levels are increasing faster than sales which could suggest that additional personnel are working in a centralised support function.[59]

Three main areas of costs are driving 40.9 per cent of total overheads, these are:

- Labour 22.1 per cent ($104.8m real at 30/6/2009);
- IT services 9.7 per cent ($46.1m real at 30/6/2009); and
- Strategic management 9.1 per cent ($43m real at 30/6/2009)

The additional layer of district overhead resulting from the adoption of a decentralised operating model is increasing the amount of overhead as a proportion of overall operating costs. At the Authority's request PB was asked to investigate this further. In response, Horizon Power prepared a breakdown of overhead, differentiating the traditional overhead items such at IT, finance and people services, from district level overheads.

Historically, Horizon Power's traditional corporate overheads varied from 13 per cent (in 2007/08) to 22 per cent (in 2006/07) as a percentage of total operating expenditure. PB then benchmarked this percentage range of overhead against a number of electricity, gas and water companies. Corporate overhead as a percentage of total operating costs

[59] Parsons Brinckerhoff 2010, Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 8.8, p87.

ranged from 15 to 25 per cent for these companies, with Horizon Power's overhead proportion falling towards the high end of this range.[60]

PB subsequently concluded that, although towards the upper end of the benchmarked range, Horizon Power's level of corporate overhead operating costs is not unusual and so did not recommend any specific reduction to Horizon Power's forecast.

7.4 Renewable energy costs

The Terms of Reference request that the Authority take into account:

- "the efficient costs related to the Mandatory Renewable Energy Target (MRET), including the expanded MRET, if applicable; and
- the efficient costs related to the proposed Carbon Pollution Reduction Scheme (CPRS), including the carbon intensity that should be applied in determining CPRS costs that would be incorporated into the cost reflective retail tariffs."

PB reviewed the impact of MRET and CPRS on Horizon Power's budget forecasts as part of its review.[61] Horizon Power advised PB that, after the Federal Governments statement[62] in April 2010 that the start of the CPRS would be delayed until early 2013 and on direction from the Department of Treasury and Finance it removed the cost of carbon from its budget forecasts.

Horizon Power advises that it has assessed the impact of the Renewable Energy Target on the organisation and has committed to a key performance indicator on reducing the carbon intensity of its operations.[63]

Horizon Power advise that its current Renewable Energy Certificate (REC) liability is around 30,000 certificates and it has a contract in place which will cover half of this requirement through to 2012. Horizon Power intends to purchase the shortfall on the market and with a current market price of around $40 per certificate this gives Horizon Power's REC related expenditure at around $1.2m (nominal) per year. This forecast is included in the generation operating costs for the NWIS.

The Authority intends to review the impact of these two schemes on Horizon Power's cost efficient tariffs in the final report for the inquiry.

7.5 Authority comments

In determining Horizon Power's level of efficient controllable operating costs, the Authority first reviewed PB's recommendation regarding global efficiency savings and recalculated this into an effect upon unit controllable operating costs. From this analysis the Authority considers that the reductions recommended by PB do not sufficiently challenge Horizon Power to operate efficiently and so the Authority is recommending an alternative efficiency

[60] Parsons Brinckerhoff 2010, Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 5.3.5, p48.

[61] Parsons Brinckerhoff 2010, Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 5.4.3, p51.

[62] Department of Climate Change and Energy Efficiency website, http://www.climatechange.gov.au/whats-new/cprs-delayed.aspx.

[63] Horizon Power 2010, Fact Sheet No. 12 – CPRS & RET Liabilities – Forecasting, Considerations and Allowances.

target for Horizon Power's operating cost forecasts. The reasons for this are explained in more detail below.

Section 7.2 above explains that 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 gain 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. Unit controllable operating cost data is shown in Table 7.4 below.

Table 7.4 Unit controllable operating costs based on Horizon Power's operating cost forecasts (real at 30/6/09)

Unit controllable operating cost	2010	2011	2012	2013	2014
$ per kWh	0.113	0.121	0.116	0.114	0.109
$ per connection	2,572	2,922	2,862	2,828	2,736

Source: ERA analysis

Over the five year inquiry period unit controllable operating costs initially increase from 2009/10 to 2010/11 then reduce each year. Overall unit controllable operating costs per kWh reduce by three per cent over the inquiry period and unit operating cost per connection increase by six per cent over the inquiry period.

In its report, PB indicates that although Horizon Power is past its initial period of establishment and restructuring, following disaggregation, it is still forecasting average increases in real controllable operating costs of 3 per cent per annum between 2010/11 and 2013/14.[64]

As a relevant case study, PB referenced the experience of the Victorian electricity distribution businesses[65] since they were privatised. PB reported that, in the first year of the second regulatory period, companies were set operating efficiency targets of between 3.1 per cent and 16.4 per cent, followed by an average operating cost efficiency target of 1.2 per cent in each subsequent year. PB calculated that, overall, this represented an annual average reduction of three per cent.

Consequently, PB recommends that the experience of the Victorian electricity distributors could be used as a benchmark for setting an efficiency target to reduce Horizon Power's real controllable operating costs by three per cent per annum. In effect, this would hold

[64] Parsons Brinckerhoff 2010, Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 8.8, p89.

[65] AGL, CitiPower, Powercor, TXU/SP AusNet and United Energy.

Horizon Power's controllable operating costs constant in real terms between 2010/11 and 2012/13.

The Authority has modelled the effect of PB's three per cent efficiency recommendation on Horizon Power's unit controllable operating costs, as shown in Table 7.5 below. Despite the reduction to overall controllable operating costs, the result is an increase in controllable unit costs of 2.5 per cent per annum.

Table 7.5 Comparison of controllable unit operating costs for Horizon Power against PB recommendations (real at 30/6/2009)

Unit controllable operating cost ($ per connection)	2010	2011	2012	2013	2014
Horizon Power proposed	2,572	2,922	2,862	2,828	2,736
Percentage change per annum		13.6%	-2.1%	-1.2%	-3.3%
PB recommends	2,572	2,637	2,702	2,770	2,839
Percentage change per annum		2.5%	2.5%	2.5%	2.5%

Source: ERA analysis

The Authority has reviewed PB's report and Horizon Power's actual and forecast operating cost data and concluded that, whilst recognising the period of adjustment Horizon Power has experienced following disaggregation, there is scope for efficiency savings in Horizon Power's controllable operating costs over the inquiry period.

The Authority notes PB's proposed three per cent reduction to controllable operating costs. However, the Authority considers that the unit operating cost per kWh or per connection should decrease (in real terms) as the company becomes more efficient, not increase as is suggested by PB's recommendation. The application of an efficiency target to unit controllable operating costs removes the impact of increased costs resulting from growth in demand and was the approach followed by the Authority when it recommended efficiency levels for Water Corporation.[66]

Support for the application of efficiency savings on controllable unit operating costs comes from the following observations:

- the high level of corporate overhead as a proportion of controllable operating costs (28.8 per cent is at the top end of the benchmarking range established by PB);
- PB's observation that Horizon Power has adopted processes and an organisational structure from a model of a larger legacy business, which contributes to the apparent 'top heavy' nature of Horizon Power's organisation;
- the operation of two district offices in the Pilbara (West Pilbara district office in Karratha and East Pilbara district office in Port Hedland). Both of these offices are involved in running the NWIS, which is operated as a single system; consequently, there is scope to reduce the two district offices to one;
- PB's recommendation of an annual three per cent reduction in controllable forecast operating costs; and
- Horizon Power is not subject to competitive pressure from the market, as is the case for the Victorian electricity distributors.

[66] ERA 2009, Inquiry into Tariffs of the Water Corporation, Aqwest and Busselton Water.

2009/10 has been selected as the base year on which to apply an operating cost efficiency target because it is the latest year for which actual operating costs are available and for which costs have been allocated across each town, distribution system and cost function.

Information on 2009/10 operating costs was selected from the individual town reports submitted to the Authority on 16 September 2010. The operating expenditure in 2009/10 was adjusted by the Authority to remove certain items (CSO expense, depreciation, interest and amortisation) before this data could be used as a base year for efficiency purposes. A reconciliation of the initial 2009/10 operating cost figure and the base operating cost for 2009/10 is given in Table 7.6 below.

Table 7.6 Reconciliation of starting 2009/10 controllable operating costs and base year 2009/10 controllable operating costs ($m real at 30/6/2009)

Item	2009/10
Initial aggregate operating cost	338.7
Deductions	
• Net Interest	-7.2
• Depreciation	-34.3
• Tax	-7.7
• Amortisation	-2.6
• CSO expense	-10.0
Base year operating costs	277.0

Source: Horizon Power town reports at 16 September 2010 and ERA analysis.

The Authority has taken 2009/10 base year controllable operating costs of $277.0m (real at 30/6/2009) and then applied a compounding reduction in the unit operating cost per connection of one per cent per annum for each year of the inquiry period.

The determination of the one per cent efficiency target is supported by:

- a similar approach taken for the Water Corporation, where the Authority applied a reduction in base real operating expenditure per connection of 1.88 per cent per year;
- a similar operating cost efficiency factor of 10 per cent over a 10 year period recommended for Power and Water in its 2009 Network Pricing Reset;[67] and
- the emergence of operating costs as a clear focus for an efficiency target as they are the predominant driver of the total cost of service for Horizon Power (see section 10);

A comparison of controllable unit operating costs based on the Authority's proposed one per cent efficiency target and controllable unit operating costs based on Horizon Power's operating cost forecasts is given in Table 7.7 below.

[67] Meyrick and Associates 2008, Electricity Distribution X Factors for the NT's Third Regulatory Period, piii.

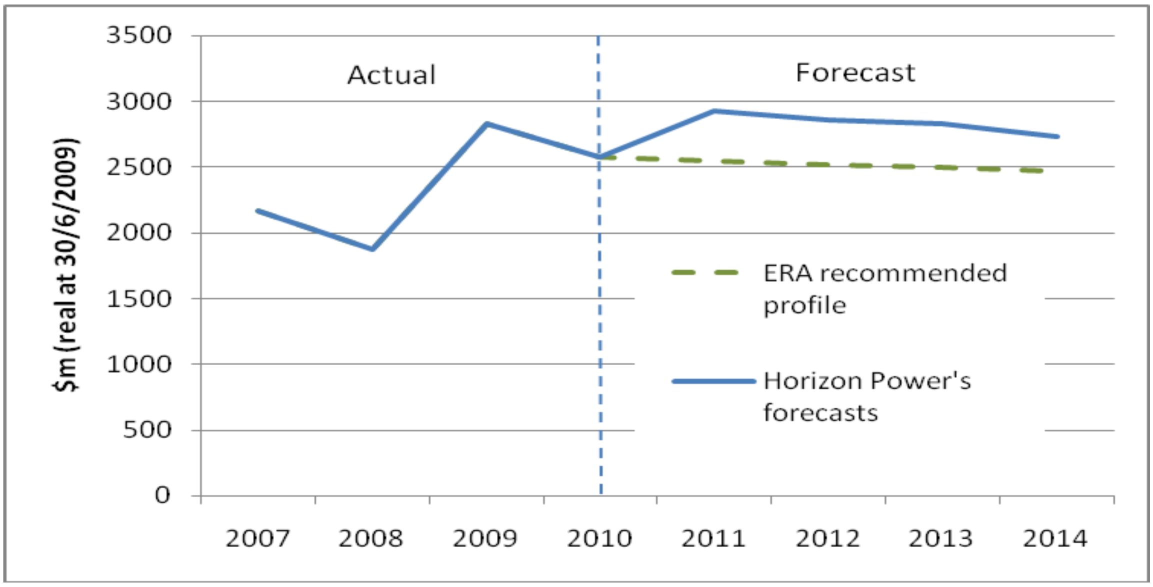
Table 7.7 Comparison of controllable unit operating costs for Horizon Power against ERA recommendations (real at 30/6/2009)

Unit controllable operating cost ($ per connection)	2010	2011	2012	2013	2014
Horizon Power proposed	2,572	2,922	2,862	2,828	2,736
Percentage change per annum		13.6%	-2.1%	-1.2%	-3.3%
ERA recommends (1% efficiency)	2,572	2,545	2,519	2,493	2,468
Percentage change per annum		-1%	-1%	-1%	-1%

Source: ERA analysis

The Authority's recommendation has the effect of reducing controllable unit operating costs for Horizon Power as shown in Figure 7.4 below.

Figure 7.4 Trends in controllable unit costs per connection based on Horizon Power's forecasts and ERA's recommendations ($m real at 30/6/2009)



Source: ERA analysis

If the Authority's recommended controllable operating costs are added back to non-controllable operating costs, Horizon Power's total operating costs reduce from $1,646.7m to $1,540.9m (real as at 30/6/2009) over the inquiry period as shown in Table 7.8 below. The overall reduction in Horizon Power's forecast total operating costs is $105.8m (real as at 30/6/2009).

Table 7.8 Recommended total operating cost from 2009/10 to 2013/14 ($m real at 30/6/2009)

Operating costs	2010	2011	2012	2013	2014	Total
Horizon Power proposed	277.0	327.9	332.3	373.3	336.3	1,646.7
ERA recommended	277.0	309.8	314.8	318.7	320.6	1,540.9
Reduction	0	-18.0	-17.5	-54.6	-15.7	-105.8
As a percentage	0	-5.5%	-5.3%	-14.6%	-4.7%	-6.4%

Source: ERA analysis. The majority of the reduction in 2012/13 ($54.6m) relates to the removal of generation operating costs associated with the delay in the commissioning the proposed South Hedland power station.

In summary, the Authority

- recognises that generation related fuel and electricity purchase costs associated with PPAs are not controllable in the short term and has excluded these costs from any proposed reductions;
- has reviewed the increase in generation operating costs associated with the additional electricity purchased to cover demand whilst the new power station at South Hedland is being built, as detailed in section 7.2, and understands from Horizon Power that delays in the budget approval process with State Government has contributed to the increased costs. However, the Authority does not consider that this additional cost should be passed on to SWIS customers via the TEC; instead, this cost should be borne by Horizon Power. In addition, should the commissioning of South Hedland be delayed, or if the additional electricity costs turn out higher than budgeted, any additional cost should also be borne by Horizon Power; and
- has applied an efficiency target of one per cent compounded per annum to the 2009/10 level of controllable operating costs per connection.

The Authority is aware that the recommended efficiency target does not take account of any specific operational projects or programmes that Horizon Power may have included in its submitted operating cost forecasts. Horizon Power can request, in its response to this draft report, that additional operating costs for new or existing projects or programmes be considered by the Authority as an addition to the recommended total operating cost profile in Table 7.8 above. The Authority will review each request on a case by case basis and include any additions to the efficient level of operating expenditure in the final report. However, Horizon Power would need to demonstrate that the expenditure is efficient and cannot be met from base operating expenditure.

7.6 Recommendation

Recommendations

3) The forecast operating costs incurred as a result of the delay in obtaining funding approval for the South Hedland power station project be borne by Horizon Power. Consequently, the Authority proposes that $35m (real as at 30/6/2009) be removed from the non-controllable generation operating costs in the NWIS in 2012/13 for the purpose of determining cost reflective tariffs.

4) An efficiency target of one per cent compounded per annum be applied to the 2009/10 level of controllable unit operating costs per connection.

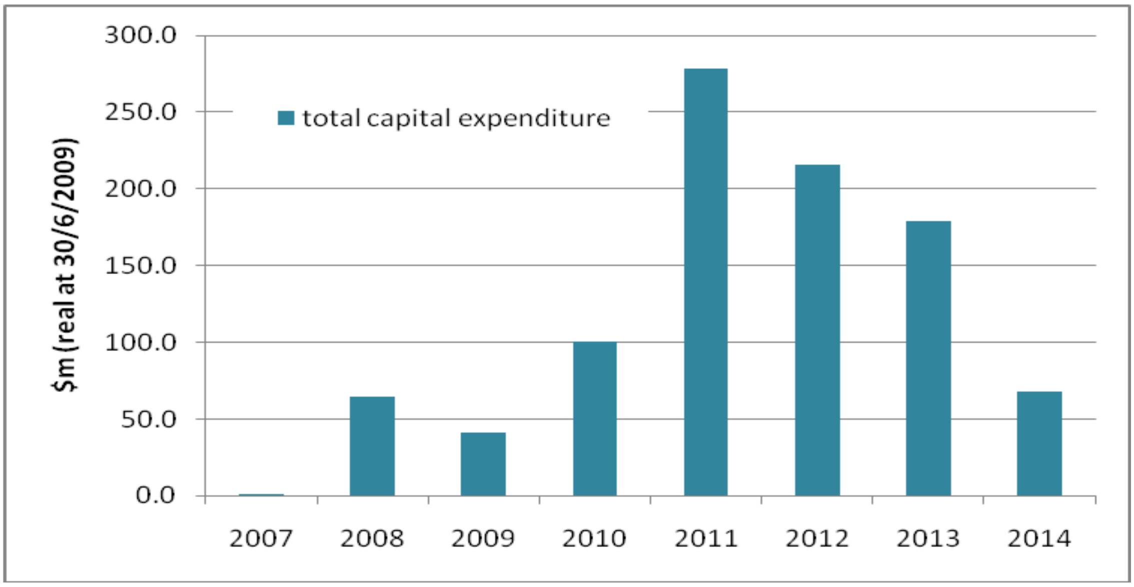
5) Horizon Power submit in response to the draft report individual business cases for any additional operating expenditure requests over and above the recommended profile as outlined in Table 7.8. The Authority will then consider each request on a case by case basis and include any additions to the efficient level of operating costs in the final report.

8 Capital Expenditure

After removing assumed escalation, Horizon Power incurred annual average capital expenditure costs of $35.5m (real at 30/6/09) over the period 2006/07 to 2008/09 and submitted annual average (actual and forecast) capital expenditure costs of $168.3m (real at 30/6/09) over the period 2009/10 to 2013/14. This is an increase of over 350 per cent in the average annual expenditure between the two periods.

The historical and proposed annual capital expenditure profile from 2006/07 to 2013/14 is shown in Figure 8.1 below.

Figure 8.1 Actual and forecast capital expenditure ($m real at 30/6/09)



Source: Horizon Power spreadsheets[68] and ERA analysis

A comparison of Horizon Power's historical capital spend over the period 2006/07 to 2008/09 with actual and forecast expenditure for the period 2009/10 to 2013/14 shows a significant increase. This is predominately driven by a decision by Horizon Power in 2006 to bring some generation capability in-house. Horizon Power's stated reasoning for this is so that it could better understand the cost structure behind electricity generation, which in turn would help inform its negotiations with IPPs.[69] Consequently Horizon Power built, owns and operates (**BOO**) generation capacity at Marble Bar (commissioned in 2009 and capitalised in 2010) and Nullagine (commissioned in 2010 and capitalised in 2011) and has proposed new BOO generators for Carnarvon (under construction) and South Hedland (to be commissioned on 1 July 2013).

This has led to just over half (50.9 per cent) of Horizon Power's forecast capital expenditure programme being driven by generation projects. Dominating these projects is the construction of a new power station at South Hedland to supply electricity into the NWIS ($334.3m at 30/6/2009). More detailed information on the South Hedland generation project is provided in section 8.2 below.

[68] Horizon Power 2010 '20100922 – ERA Capex – Unescalated by funding type'.

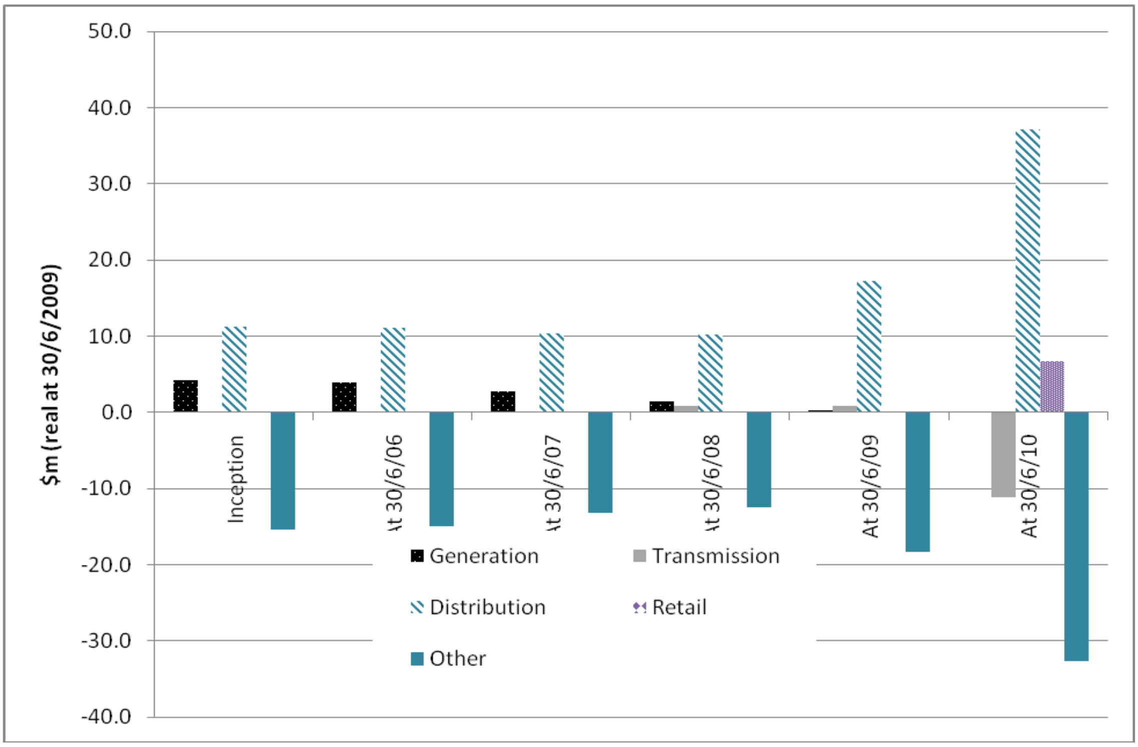
[69] Parsons Brinckerhoff 2010, Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 7.3, p67.

Horizon Power owns only minimal retail assets associated with billing and customer care. These services are provided through Service Level Agreements with third parties and, as these are predominantly operating cost items, are discussed in Section 7.3.4.

8.1.1 Authority comments

The Authority noted that Horizon Power reallocated its capital expenditure between functions and asset classes from the first set of capital expenditure and fixed asset register information sent in August 2010 when compared to the final set of data received in early November 2010. The effect of this is shown in Figure 8.2 below.

Figure 8.2 Horizon Power's reallocation of assets between functions – final fixed asset register compared to initial fixed asset register



Source: Horizon Power spreadsheets and ERA analysis

The effect of this reallocation has been to move the majority of its assets out of the 'other' category and into the 'distribution' category. The result is that no district office capital is dedicated to regional overhead. In particular the Authority noticed that capital expenditure to refurbish houses was part of this reallocation. Horizon Power informed the Authority that the expenditure on refurbishment was for staff housing and that as most of the staff involved were engaged in distribution related work, this prompted the reallocation.[70] The Authority will further examine this allocation of assets in the final report.

8.2 Generation capital costs

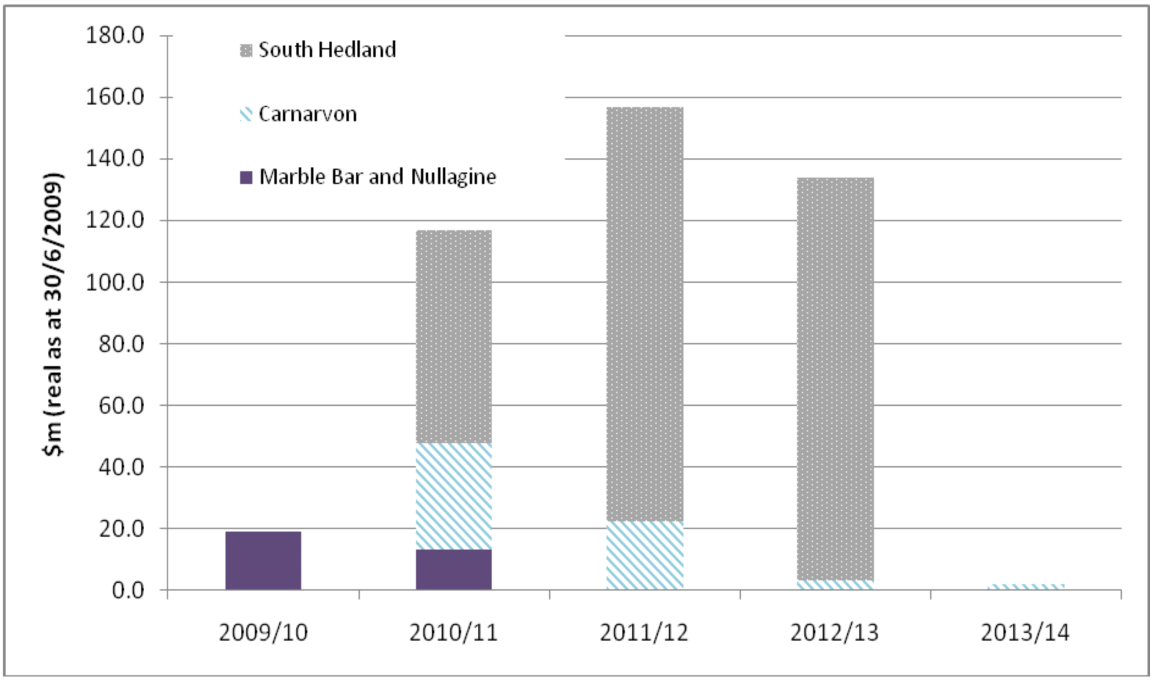
By the end of the inquiry period (30 June 2014), Horizon Power will have commissioned four BOO generation projects, assuming all funding approvals are provided. The total capital expenditure on each project, over the five year inquiry period is as follows (all prices are real as at 30/6/2009):

[70] Horizon Power, 2010, email dated 17 November 2010.

- Marble Bar $18.9m (outturn cost)
- Nullagine (costs are still being considered, a final outturn cost will be shown in the final report)
- Carnarvon $62.1m (budget cost)
- South Hedland $334.3m (budget cost)

These projects are driving the generation capital expenditure profile shown in Figure 8.3 below. As mentioned above, this follows a policy decision by Horizon Power in 2006, to bring some generation in house.

Figure 8.3 Actual and forecast capital expenditure on key generation projects ($m real at 30/6/09)



Source: Horizon Power spreadsheets[71] and ERA analysis

In determining the optimal generation solution for each system, Horizon Power compared contracting with an IPP to supply electricity with the BOO option. As discussed in section 7.2 above, prior to disaggregation WPC embarked on a policy to outsource power procurement for remote regional towns: the Remote Towns Power Procurement Process and for Carnarvon, the Carnarvon Power Procurement Process. By 2006, only Marble Bar, Nullagine and Carnarvon remained without IPP arrangements. The generation projects are discussed individually below.

Marble Bar and Nullagine power station projects

Marble Bar and Nullagine are situated in the East Pilbara district of Western Australia. Both are situated inland; Marble Bar is 218km south east of Port Hedland and Nullagine is 195km north of Newman. The numbers of premises in each town are 124 and 52 respectively. Existing generators on both sites were at the end of their economic life by 2006 and were supplemented by mobile generation units to provide a reliable electricity supply.

[71] Horizon Power 2010, '20100922 – ERA Capex – Unescalated by funding type'

Horizon Power's analysis of the IPP and BOO options (diesel only and diesel/solar combined) for these projects illustrate that the decision to select a solar/diesel option over diesel only was marginal in cost terms. The Authority has sighted this information and as this is commercial in confidence has not included the detail in the draft report.

The Post Implementation Review[72] conducted in June 2010 noted that, whilst the new power station delivered the required level of service for Marble Bar and is expected to provide the anticipated reductions in diesel fuel consumed, the project was executed directly from a preliminary business case status, overran by six months and considerably exceeded budgeted costs. PB's investigation confirmed that the generation projects undertaken at Marble Bar and Nullagine went from the prefeasibility stage to the implementation stage which is in conflict with Horizon Power's own project gating framework.[73]

PB discussed the cost overruns in past generation projects with Horizon Power as part of its investigation. PB is aware that Horizon Power is concerned about the cost management issues with Marble Bar and Nullagine and has taken action to limit the possibility of similar problems happening again.

The outturn costs of each project compared to the budget estimates are given in Table 8.1 below. Horizon Power received partial funding of $4.9m (nominal) from the Commonwealth's Renewable Remote Power Generation Programme.[74]

Table 8.1 Comparison of the actual spend and budgeted spend for Marble bar and Nullagine power station projects ($m real at 30/6/2009)

Project	Budget	Outturn	Variance (%)
Marble Bar power station *(costs capitalised 2009/10)*	12.9	18.9	+50.0
Nullagine power station *(costs capitalised 2010/11)*	10.6	n/a	n/a
Total	23.2	n/a	n/a

Source: 20100922 – ERA Capex – Unescalated by funding type and Horizon Power, Submission to the Board of Directors (August 2006) Generation options for Carnarvon, Nullagine and Marble Bar (DMS 301185)

8.2.1 Authority comments

The Authority is aware of the anticipated outturn cost of the Nullagine power station project. However, some cost discussions between Horizon Power and its suppliers are still continuing and as such the outturn cost is commercial in confidence until these discussions are resolved. The final project outturn costs are expected to be available and published in the final report.

The Authority understands that any additional outturn costs of these generation projects over and above the budgeted amounts would ultimately be funded via the TEC and potentially impact upon the tariffs paid by customers in the SWIS. The Authority considers

[72] LogiCamms Ltd. 2010 – Horizon Power hybrid power station – Marble Bar post implementation review.

[73] PB 2010, Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 7.3.1, p68.

[74] Ministerial Media Statements (Minister for Energy, Training and Workforce Development) 2010 – Boost for renewable energy in regional WA.

that SWIS customers should not be unduly penalised for Horizon Power's chosen strategic direction or poor project and cost management.

The Authority is concerned that the decision to bring some generation in house, or the particular form of the generation chosen, may not be the optimal business model for Horizon Power to adopt. The Authority is particularly concerned that this decision may result in cost overruns, incurred as a result of Horizon Power's inexperience in the self-generation area, and the novel nature of projects (such as the Marble Bar and Nullagine solar generation projects) compared with the standard diesel-only alternatives.

The Authority has calculated that the average capital cost per property connection, based on the budget figures for the solar/diesel generation projects, is $104,255 per property for Marble Bar and $203,846 per property for Nullagine. The outturn cost per property for Marble Bar is $152,419 with an even higher anticipated figure per property for Nullagine.[75]

The Authority has noted Horizon Power's recognition of the problems with Marble Bar and Nullagine and the steps it has taken to address these in later generation projects. However, had the comparison of generation options been conducted on more reliable cost estimates (as is required by Horizon Power's own project gating framework) then, in purely cost terms this may have favoured the IPP option over Horizon Power's decision to bring some generation in house. The Authority will investigate this with Horizon Power in more detail for the final report.

Consequently, the Authority recommends reducing actual and forecast capital expenditure by the amount of the cost overrun at Marble Bar and anticipated cost overrun at Nullagine. Therefore the project costs for Marble Bar and Nullagine power station projects have been modelled at the budgeted amounts.

Carnarvon power station project

Carnarvon, the largest town in the Gascoyne region, lies between Exmouth and Monkey Mia, 904km north of Perth and has a population of approximately 2,500.

Prior to disaggregation WPC had commenced a process to contract with an IPP to supply electricity to Carnarvon. Following its decision to bring some generation in house, Horizon Power compared two IPP bids received during the Carnarvon Power Procurement process in October 2005 with two BOO options. The first BOO option was based on all capital expenditure occurring in the first year and the second BOO option proposed a phased approach to construction. The 2005 IPP bids were escalated by Horizon Power and scaled to match the anticipated demand forecast for Carnarvon to aid the comparison of options in early 2008. Based on its analysis of alternatives, Horizon Power selected the staged BOO approach to the project. First, diesel generation will be installed at the site of the new power station to supply peak demand in the town then the new gas generation plant will be installed. After this, the old power station in Carnarvon will be decommissioned. Available capacity for the Carnarvon area will increase from 15MW to 19MW, an increase of 26.6 per cent.

The forecast capital expenditure for Carnarvon power station is $62.1m (real as at 30/6/2009) and the power station is due to be commissioned in 2013/14.

PB reviewed the business case for the Carnarvon power station development and discussed the lessons learned from Marble Bar and Nullagine. Horizon Power confirmed

[75] The Authority expects outturn information on Nullagine power station project to be available in the final report.

to PB that the cost estimates will be refined to ± 10 percent prior to construction in an attempt to avoid the cost overruns of the previous generation projects.[76] In its conclusion, PB found the capital expenditure forecasts for the project to be prudent and efficient. Horizon Power has subsequently advised the Authority that it has 81 per cent of the cost of the project fixed under contract and that the remaining 19 per cent are comprised of Horizon Power's own internal costs.[77] The use of fixed price contracts helps to ensure project costs do not overrun.

South Hedland power station project

As mentioned in section 5 above, Horizon Power will experience a shortfall in generation capacity in the NWIS when its PPA with Alinta expires in December 2012.

The total generation capacity from Alinta's Port Hedland power station is contracted to a commercial third party. As not all of this contracted generation has been required by the third party, Alinta has been able to enter into a PPA to supply Horizon Power until December 2012. After this time the third party has stated that it will require 100 per cent of Alinta's capacity to fuel its expansion activities in the region.[78] Consequently the PPA between Horizon Power and Alinta cannot be renewed beyond 2012.

This contractual expiration leaves Horizon Power with a shortfall of installed capacity to meet its anticipated future demand of 145MW by 2013/14. Horizon Power has therefore forecast that it needs an additional 105MW of capacity by January 2013. This includes 40MW of spinning reserve[79] and some redundant generation capacity to cover maintenance and plant failure.

This situation is of particular relevance to the inquiry as Horizon Power is proposing the construction of a new power station at South Hedland to be commissioned on 1 July 2013. This single capital project represents just under 40 per cent of the total capital budget over the inquiry period. The development of this new power station project is in response to increasing demand in the NWIS and the expiry of Horizon Power's PPAs with Alinta Energy which combine to give a shortfall in supply capacity towards the end of the inquiry period.[80]

The situation also impacts upon forecast operating costs as Horizon Power intends to cover demand over the period from 31 December 2012 (when the PPA with Alinta expires) to 1 July 2013 (when the new power station is commissioned) with additional electricity sourced through temporary mobile generation.

Horizon Power determined several viable options to meet this additional capacity requirement, to:

- renew or extend existing PPAs;
- contract with an IPP for an additional 100MW of capacity; and
- invest in new generation to build, own, operate (BOO) its own power station.

[76] PB 2010, Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 7.3.1, p69.

[77] Horizon Power 2010, email dated 18 November 2010.

[78] Horizon Power 2010, email dated 18 November 2010.

[79] Spinning reserve is unused capacity which can be activated on the decision of the system operator and which is provided by devices that are synchronised to the network and able to affect the active power. Rebours, Y and Kirschen, D, University of Manchester, 2005. What is spinning reserve?

[80] Horizon Power 2010, South Hedland Power Station – Business case for new generation, p7.

As outlined in section 5 above, the option to renew Horizon Power's existing PPA with Alinta beyond December 2012 is not considered possible on the understanding that after this date all of Alinta's generation capacity will be utilised by another company for its own anticipated expansion activities.

Of the two remaining options, Horizon Power has determined that the BOO option is the preferred option on the basis of the highest net present value (NPV). This reasoning has formed the basis for development of the South Hedland Power Station. Whether or not this is the optimal solution depends on several issues such as:

- the accuracy of Horizon Power's comparison of the various options, e.g. if alternatives have been compared on a like for like basis regarding what costs are included and excluded and the rate of return applied to the various options;
- the extent to which options are re-costed and re-compared again as the actual costs of the projects harden;
- what arrangements are assumed and costed, and which party bears the risk of this if the projects are delayed and temporary capacity is required to meet demand in the interim; and
- if Horizon Power's forecast of increased demand prove to be accurate.

Whether BOO or IPP, both options require the construction of a new 80-100MW power station by 1 January 2013. The four companies on Horizon Power's panel all submitted proposals. Two scenarios were proposed.

- Scenario 1 - to retain the current arrangement with ATCO at Karratha (80MW OCGT[81]) and build a new 112MW CCGT[82] power station at South Hedland; and
- Scenarion 2 – upgrade the Karratha power station to 102MW CCGT and build a new 83MW OCGT power station at South Hedland.

Horizon Power selected the option to BOO a CCGT 112 MW power station at South Hedland as this returned the largest NPV. The Authority has sighted this information and as this is commercial in confidence has not included the detail in the draft report.

In its review, PB did note that several of the options were very close, within 8 per cent of each other and any slight amendment to the estimates in any option could alter the ranking.[83] Horizon Power responded by advising PB that a further cost estimation will be carried out prior to construction and, if this estimate exceeds a predetermined amount, it will resubmit the business case for further consideration.[84] However, there is no information submitted by Horizon Power to suggest that it would reverse the decision to build the new power station at South Hedland if costs do increase above the threshold.

8.2.2 Authority comments

The Authority does not intend to recommend any specific reductions to the capital expenditure forecasts for the Carnarvon and Port Hedland power station projects. However, in both cases:

[81] OCGT – Open Cycle Gas Turbine

[82] CCGT – Closed Circuit Gas Turbine

[83] PB 2010, Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Appendix 1, p 121

[84] PB 2010, Email from P Walshe date 11 October 2010, 'Summary of PB's reponse to ERA comments on the draft report', item 20

- the preferred option was selected with a very narrow margin over the next best alternative;
- Horizon's inexperience relative to other providers meant that there was a greater likelihood for budgeting inaccuracies in the BOO options; and
- the occurrence of an actual cost overrun in Marble Bar and anticipated cost overrun in Nullagine suggests improvements are still required in Horizon Power project and cost management processes.

In the case of the larger South Hedland station, an investment decision was made on relatively preliminary costs, and it is unclear what course of action the Board will take if costs do increase.

This means that any cost overrun could mean that the selected alternative is not the efficient solution for generation at these locations. Consequently, should these projects again overrun the capital budget cost then any cost overrun should be borne by Horizon Power and not covered by the TEC.

Additionally, any operational cost implications from cost or time overruns from the power station construction process should not be covered by the TEC. A particular risk would be the extension of the additional mobile generation electricity costs in 2013 if the South Hedland Station did not meet its scheduled completion date.

Horizon Power has submitted forecast cost information on the Port Hedland power station as its preferred and most efficient option for meeting demand in the NWIS by 2013. However, these forecasts are still subject to Government approval. If Horizon Power does not receive the required approval for the South Hedland power station project by the end of 2010 then Horizon Power is expected to submit alternative cost forecasts and generation solutions which will be reflected in the final report for the inquiry.

8.3 Transmission capital costs

After excluding assumed escalation, Horizon Power incurred annual average transmission capital costs of \$1.0m (real as at 30/6/09) over the period 2006/07 to 2008/09 and submitted annual average (actual and forecast) transmission capital costs of \$22.6m (real as at 30/6/09) for the period 2009/10 to 2013/14. The expenditure from 2010/11 to 2013/14 is predominantly driven by four planned transmission projects, which account for the majority (90 per cent) of forecast expenditure. PB reviewed three of these planned capital projects and found a number of problems with each of the projects investigated as follows:

- Karratha to Roebourne 220kV line (\$59.5m real as at 30/6/2009) – the project is contingent on an IPP generator (Rio Tinto Iron Ore) disconnecting from the NWIS. The date for the disconnection is still uncertain and therefore the likelihood that the expenditure on this project will be required over the inquiry period is low.
- Dampier to Karratha 132kV line (\$19.7m real as at 30/6/2009) – the project is also contingent on the RTIO disconnection and the proposed system design following disconnection is not optimal. Therefore the project costs, with the exception of \$0.4m to replace unserviceable transmission poles on the existing line, are deemed inefficient and removed.

- Fairway Drive substation, Broome ($14.5m real as at 30/6/2009) – this project is to augment the existing substation at Fairway Drive to serve a new residential and industrial development north of Broome. PB has noted that:
  - Historically, demand in Broome has been overstated and as such a similar overstatement of forecast demand would have been included in the project specifications;
  - the development is only in its early stages and increased demand is contingent on specific residential development driving demand higher; and
  - there is limited evidence that other options, to the proposed augmentation, have been properly explored.

A more detailed explanation of PB's reasoning behind the proposed reductions can be found in its report.[85]

8.3.1 Authority comments

The Authority is comfortable with PB's reasoning and has adopted the proposed reductions as shown in Table 8.2 at the end of the section.

8.4 Distribution capital costs

After removing assumed escalation, Horizon Power incurred annual average distribution capital costs of $28.9m (real as at 30/6/2009) over the period 2006/07 to 2008/09 and actual and forecast transmission capital costs of $37.6m (real as at 30/6/2009) over the period 2009/10 to 2013/14. This is an increase of over 30 per cent in the average annual expenditure between the two periods.

Horizon Power is proposing distribution capital expenditure across the whole of its supply area, however PB investigated two of the main projects. These are the wood pole reinforcement programme ($6.3m real as at 30/6/2009) mainly occurring around Esperance and Carnarvon and the Esperance Network Rural Upgrade Project (**ENRUP**) ($13.6m real as at 30/6/2009) to replace wooden poles that do not meet the AS1720.2 2006 Timber Structures, Part 2 Timber Properties as required under Electricity (Supply Standards and System Safety) Regulations 2001.

Horizon Power has already conducted a stage one ENRUP programme (completed March 2010) that concentrated on replacing non-compliant wooden poles that supported three phase conductors. Horizon is proposing to extend the ENRUP programme to non-compliant wooden poles that support single phase conductors over the inquiry period. The project will be extended to 2012 and will seek to replace poles that have failed an inspection in order to reduce the risk of fire and faults arising from clashing conductors.

PB suggested that in economic terms the case for the ENRUP programme is:

> "..poorly supported and that rectification of the network should occur during the replacement of assets due to condition."[86]

85 PB 2010, Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 9.3, pp 93-100.

86 PB 2010, Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 9.4.3, p109.

Consequently PB recommends that poles which fail a condition inspection are replaced and other defects can be addressed via the condition based replacement programme Horizon Power is adopting.

Following receipt of PB's final report Horizon Power asked Energy Safety to review the proposed reductions to the ENRUP programme. Energy Safety responded[87] suggesting that:

> " programmes agreed to ensure compliance with AS1720.2 as required under the (regulations) would need to be continued to optimise public safety."

Authority comments

The Authority has noted PB's comments on distribution capital expenditure and has applied PB's proposed reductions to specific distribution projects as shown in Table 8.2 at the end of this section for the draft report. However, the Authority will expect any safety issues around the recommended reductions to the ENRUP programme to be addressed in any submission Horizon Power may publish in response to the draft report.

8.5 Non system capital costs

Horizon Power incurred minimal non-system (not directly relating to the generation or carriage of electricity) capital costs for the period 2006/07 to 2008/09 and submitted annual average actual and forecast non-system capital costs of $12.8m (real as at 30/6/2009) for the period 2009/10 to 2013/14. The majority of forecast capital expenditure in this category is associated with Horizon Power replacing IT and fleet functions, previously supplied by Western Power through SLAs with in-house solutions.

As part of its investigation PB reviewed the proposed expenditure on IT, fleet and buildings management. Of these, PB found the proposed expenditure on IT and fleet appropriate and reasonable.

For proposed building expenditure, PB suggested that the $7.2m (real as at 30/6/2009) proposed for the Esperance depot was based on a building design that had larger capacity than would be required based on forecast staff numbers and so made a reduction accordingly. The Authority supports this reduction and has included it in Table 8.2. PB also suggested that Horizon Power should review its current strategy of providing free housing for regional staff as an alternative 'housing allowance' may prove more economical and reduce ongoing expenditure. However, PB did not quantify the level of any possible savings.

8.6 Authority comments

The Authority has reviewed and adopted PB's recommended reductions to specific transmission, distribution and non-system capital expenditure, as outlined in Table 8.2 below.

Also in its report PB noted that Horizon Power has a contingency of 10-30 per cent in project estimates to cover unforseen project risks. PB recommends reducing the 10 per cent contingency to 4.6 per cent in line with recent regulatory decisions by the Australian Economic Regulator (**AER**). The AER agreed the following risk contingencies; ElectraNet,

[87] Email dated 8 November 2010

2.6 – 4.6 per cent depending upon the size of the project, Transgrid, 2.8 per cent and Powerlink, 2.6 per cent.[88]

The Authority accepts PB's suggested reduction in project risk contingency from 10 per cent to 4.6 percent for non-generation projects. This decision is based on the Authority's analysis and comparison of the size of the capital programmes underlying the allowed risk contingencies for transmission service providers in the Eastern states. The forecast capital programmes for Powerlink and Transgrid are around $475m to $490m per annum, against which the AER allowed the lower risk contingency of 2.6 to 2.8 per cent. Electranet has a forecast capital programme of around $155.6m per annum and an upper risk contingency of 4.6 per cent. This capital programme is much closer in magnitude to Horizon Power's ($168.2m per annum) and consequently the Authority considers that the project risk contingency be reduced in line with that agreed for Electranet.

The Authority also reviewed the contingencies implicit in the BOO generation projects and found these to be consistent with a 10 per project risk contingency. Notwithstanding PB's advice the Authority has also applied the reduced project contingency to generation projects and included the reductions in the total reductions line in Table 8.2 below.

The Authority's recommended reductions to Horizon Power's forecast capital programme are shown in Table 8.2 below.

Table 8.2 Recommended reductions to Horizon Power's actual and forecast capital programme ($m real at 30/6/2009)

Item	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Horizon Power submitted capital programme	100.1	278.4	216.0	179.2	67.8	841.6
Reductions by project						
TRANSMISSION						
• Karratha to Roebourne line	-	-	-	-	-9.2	-9.2
• Dampier to Karratha line	-	-	-12.1	-8.1	0.1	-20.0
• Fairway Drive substation	-	-	-	-1.2	-8.7	-9.9
DISTRIBUTION						
• Pole management programme	-	-	-0.8	-0.8	-1.7	-3.2
• ENRUP	-	-2.2	-3.6	0.2	2.3	-3.3
NON-SYSTEM						
• Esperance depot	-0.6	-	-	-	-	-0.6
ERA recommended capital programme	92.1	258.5	195.6	169.7	48.3	764.2
Total reductions[89]	-8.0	-20.0	-20.4	-9.5	-19.5	-77.4

Source: ERA analysis and PB Final report

The Authority has also noted PB's comment on the incorrect escalators being applied to expenditure relating to the PUPP, which results in a proposed reduction of $25.7m (real at 30/6/2009) on a capital project total of $103.0m real at 30/6/2009). However, for regulatory purposes, the reductions PB has recommended regarding the PUPP concern

[88] PB 2010, Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 9.2.3, p96.

[89] This includes the specific reductions to projects and a 5.6 per cent reduction on all capital expenditure to reduce the risk contingency from 10 per cent to 4.6 percent in line with PB's recommendations.

capital expenditure that is outside of the regulatory base as this programme is externally funded.

8.7 Recommendation

Recommendations

6) Horizon Power's actual and forecast capital expenditure programme be reduced by $77.4m (real at 30/6/2009) from $841.6m (real at 30/6/2009) to $764.2m (real at 30/6/2009) as detailed in Table 8.2.

9 Return on Capital

Investors have a right to expect a return on the value of their assets equal to the cost of capital associated with the regulated activities. As assets are often financed by a combination of debt and equity, so the return on assets should compensate both providers of debt and equity holders. For this reason the Weighted Average Cost of Capital (WACC) is often used to refer to the average cost of debt and equity capital, weighted by the proportion of debt and equity that reflects the financing arrangements for the assets.

For this inquiry, Horizon Power has proposed a WACC following a study conducted on its behalf by Deloitte. This information is given in section 9.1 below. The Authority has considered Horizon Power's proposed WACC and the underlying parameters from which it was calculated and has recommended an alternative WACC as outlined in section 9.2 below. More detailed technical information on the WACC methodology and calculation is given in Appendix H.

However, the WACC proposed for Horizon Power and modelled for this draft report is likely to change prior to publication of the final report. This is because the Authority has just released a discussion paper on the intended method to estimate the debt risk premium (debt margin)[90] and is inviting public submissions. Subject to the Authority's consideration of feedback on this discussion paper, it is the intention of the Authority to use this proposed method for calculating the debt risk premium in its regulatory roles and also when undertaking inquiries referred to the Authority by the State Government.

As a result, the calculation of the rate of return detailed for the Horizon Power inquiry will be informed by the submissions received on and conclusions drawn from the cost of debt discussion. Therefore, a revised rate of return, from that proposed below, will be included in the final report for the inquiry into the funding arrangements of Horizon Power.

9.1 Horizon Power's proposal

Horizon Power commissioned Deloitte to prepare the report on the Weighted Average Cost of Capital (**WACC**) in November 2009. Based on Deloitte's advice, Horizon Power submits the following estimates of its WACC for the purpose of the Inquiry into the funding arrangements of Horizon Power.

[90] Economic Regulation Authority 1 December 2010, Measuring the Debt Risk Premium: A Bond Yield Approach, available on the ERA website www.erawa.com.au

Table 9.1 Horizon Power's proposal for the cost of capital

Parameter	Estimate	
	Low	**High**
Market Risk Premium	6.0%	7.0%
Cost of equity (post-tax)	11.23%	13.93%
Cost of debt (pre-tax)	7.23%	7.43%
Gearing: equity to total value	40%	40%
Gearing: debt to total value	60%	60%
Beta	0.8	1.0
Tax rate	30%	30%
Specific Company Risk Premium	1.0%	1.5%
Weighted Average Cost of Capital (WACC)		
Nominal Post Tax WACC	7.5%	8.5%

Source: Deloitte 2009, "Horizon Power: Weighted Average Cost of Capital Analysis"

9.2 The Authority's rate of return summary

The main points of difference between Horizon Power's WACC parameters and the Authority's WACC parameters are listed below. A full discussion of the individual parameters is given in Appendix H.

- Cost of Debt – the Deloitte report recommends a debt margin of 180 to 200 basis points above the risk free rate to reflect Horizon Power's mix of government subsidised and commercially available debt. Deloitte uses a mix of Australian and US bonds (with credit ratings of A and BBB) to determine credit spreads. Deloitte's suggested debt margin over the nominal risk free rate gives a cost of debt of between 7.23 per cent and 7.43 per cent (pre tax). The Authority suggests that only Australian corporate bonds with a credit rating of BBB-, BBB and BBB+, and terms to maturity of two year or longer, should be used to derive the debt margin for regulated businesses. Using different weighted average approaches, the Authority then calculated the debt margin for the sample of 15 bonds that fitted its criteria over the 20 trading day period to 31 October 2010 which gives a benchmark debt margin of 330.5 basis points over the nominal risk free rate of 5.10 per cent, plus an allowance for debt raising costs of 12.5 basis points to give an overall nominal cost of debt of 8.53 per cent (pre tax). The Authority has also used Horizon Power's actual nominal cost of debt (5.73 per cent) to calculate an alternative WACC to determine TEC levels.
- Value of imputation credits (Gamma) – Deloitte suggest that the WACC should not be adjusted for gamma as Horizon Power is government owned and tax benefits attached to frank dividends cannot be realised by government. The Authority does not agree with this suggestion and has set a gamma of 0.535.
- Equity beta – The Deloitte's paper and a later paper by consultants Economic Insights supported a higher equity beta (0.8 to 1.04) to accommodate the extra risk associated with a smaller company such as Horizon Power. The Authority does not support the consultants' use of US and other countries data to calculate beta. Instead as Australian data has been used to calculate all other parameters in the

WACC it should also be used for beta. The Authority considered other estimates of equity beta from recent regulatory determinations (range 0.4 to 0.7) and considers a point estimate of 0.7 for beta to be appropriate.

The point estimates that the Authority considers may reasonably be applied to the parameters of the CAPM in estimating the rate of return for Horizon Power are as shown in Table 9.2 below.

Table 9.2. Authority's Required Amendments to Horizon Power's Proposed Parameter Values for Determination of a Rate of Return at 30 October 2010

Parameter	Value
Nominal Risk Free Rate $\left(R_f\right)$	5.10%
Real Risk Free Rate $\left(R_f^r\right)$	2.42%
Inflation Rate π_e	2.62%
Debt Proportion (D)	60%
Equity Proportion (E)	40%
Cost of Debt: Debt Risk Premium (DRP) (BBB+)	330.5
Cost of Debt: Debt Issuing Cost (DIC)	12.5
Cost of Debt: Risk Margin (RM)	343.0
Australian Market Risk Premium (MRP)	6.0%
Equity Beta $\left(\beta_e\right)$	0.7
Corporate Tax Rate $\left(T_c\right)$	30%
Franking Credit (γ)	0.535
Nominal Cost of Debt $\left(R_d^n\right)$	8.53%
Real Cost of Debt $\left(R_d^r\right)$	5.76%
Nominal Pre Tax Cost of Equity $\left(R_e^{n,\text{pre-tax}}\right)$	10.81%
Real Pre Tax Cost of Equity $\left(R_e^{r,\text{pre-tax}}\right)$	7.98%
Nominal After Tax Cost of Equity $\left(R_e^{n,\text{post-tax}}\right)$	9.30%
Real After Tax Cost of Equity $\left(R_e^{r,\text{post-tax}}\right)$	6.51%

Source: ERA analysis

Inputting the parameters shown above into the WACC equation results in the pre-tax WACC values as shown in Table 9.3 below.

Table 9.3. Estimates of WACC (Per cent)

WACC	Value
Nominal Pre Tax WACC $\left(WACC_n^{\text{pre-tax}}\right)$	9.44%
Real Pre Tax WACC $\left(WACC_r^{\text{pre-tax}}\right)$	6.49%

Source: ERA analysis

As noted in section 2.4 above, the Authority has assumed a benchmark rate of return for Horizon Power even though Horizon Power has access to debt funding, at favourable rates, from the State Government. Using a benchmark rate of return in the cost of service model will result in a higher 'balancing revenue' item than if Horizon Power's actual rates of borrowing are used to determine the WACC. The impact upon the balancing revenue item of using a benchmark return or return based on actual borrowing costs has been determined by:

- calculating cost reflective tariffs using a benchmark return on capital (6.49 per cent); and
- calculating the cost of service (used to determine the balancing revenue item) again but by using Horizon Power's actual borrowing characteristics to determine an alternative return on capital (4.89 per cent)

The alternative return on capital is calculated using Horizon Power's actual nominal cost of debt funding and with all other WACC parameters unchanged, the real pre-tax alternative WACC is 4.89 per cent.

The overall effect of these two alternative rates of return on the balancing revenue item is considerable.

Based on the Authority's assumptions using efficient levels of operating costs and capital cost and ICB value, the cost of service model was run with the benchmark WACC of 6.49 per cent and then run again with the alternative WACC of 4.89 per cent. All other parameters were unchanged.

TEC values were derived from each run of the cost of service model and compared. By substituting a WACC based on actual cost of debt for a benchmark WACC, this results in a reduction in the TEC of $49.8m (nominal) over the inquiry period.

This is explained in more detail in section 12.3 below.

9.3 Recommendation

Recommendations

7) A real pre tax benchmark WACC of 6.49 per cent be used for regulatory modelling and calculation of cost reflective tariffs for this inquiry.

8) A real pre tax alternative WACC of 4.89 per cent, reflecting Horizon Power's actual cost of debt, be used for determining TEC levels in this inquiry.

10 Cost of Service Model

The cost of service model is used to calculate the revenue requirement for an efficient regional power corporation. The revenue requirement is determined by the sum of return on capital, return of capital (depreciation) and efficient operating costs. The calculation of the amount of each of these three elements is as follows:

- return on capital – regulatory asset base, net of depreciation multiplied by the rate of return, where;
  - the regulatory asset base is the initial capital base at 1 July 2009 (as determined in section 6.4) rolled forward by net, new, self-funded efficient capital additions (as determined in section 8.7); and
  - the rate of return as determined in section 9.3;
- return of capital – depreciation is calculated on the regulatory asset base, which is, in turn, calculated as straight line depreciation on;
  - the initial capital base utilising remaining weighted asset lives per asset class; and
  - on new capital additions utilising asset lives per asset class in line with the Horizon Power's Fact Sheet No. 38 – Asset Classes and Asset Life Expectancy
- efficient operating expenditure as determined in section 7.6.

A revenue requirement is calculated for each town's network system in Horizon Power's supply area (35), five districts plus Bentley head office, the NWIS and also in aggregate for Horizon Power as a whole.

The cost of service model for the aggregate business has a set of statutory accounts included. This enables the Authority to determine whether the revenue forecast (including revised TEC amounts) delivers sufficient funds for Horizon power to be able to finance its function to a required level of service delivery and remain financially sound. Details of the annual financial indicators under each scenario are given in Table 10.2 and Table 10.4 below. The financial analysis assumes Horizon Power does not pay a dividend to Government during the inquiry period.

10.1 Using Horizon Power's actual and forecast data

The cost of service model has produced a revenue requirement, based on Horizon Power's submitted cost information for each town, the NWIS and a consolidated position for Horizon Power.

The revenue requirement for Horizon Power's consolidated position is given in Table 10.1 below. The revenue requirements for all towns have not been listed in this report, at Horizon Power's request as these are considered commercial in confidence and as such may influence Horizon Power's future price negotiations.[91].

[91] Horizon Power, letter received 19 November 2010 – Confidentiality arrangements – Inquiry into the funding arrangements of Horizon Power.

The operating cost and capital expenditure data used to calculate the consolidated revenue requirement for Horizon Power is from Horizon Power's actual and forecast data. However, the depreciation and return on asset lines are outputs from the Authority's financial modelling and utilise the Authority's assumptions on ICB and the calculation of depreciation.

WACC values as calculated by Horizon Power and the Authority are very similar. Consequently, the Authority's calculated real pre tax WACC figure of 6.49 per cent has been used in both scenarios.

Table 10.1 ERA determination of cost of service for using Horizon Power's own forecast cost inputs ($m real at 30/6/2009)

Item	2010	2011	2012	2013	2014
Opex	277.0	327.9	332.3	373.3	336.3
Depreciation	10.3	17.3	35.7	43.5	41.3
Return on Asset	17.1	23.0	40.0	52.2	61.6
Total Cost of service	304.4	368.1	408.1	469.0	439.2

Source: ERA analysis. Numbers may not add due to rounding.

Operating costs, again largely a result of the uncontrollable IPP and contract fuel costs account for between 91 per cent of total cost of service in 2009/10 to 76.6 per cent of total cost of service in 2013/14.

The Authority also tested the sensitivity of the cost of service model to different values of ICB and because the majority of Horizon Power's revenue requirement is driven by operating costs, as can be seen from Table 10.1 above, increases in the ICB value have little impact upon the overall cost of service.

The functional analysis of cost of service has been calculated for each town however because of the variance in the overall size of the cost of service, (from small remote towns to the large NWIS) the functional contributions have been normalised as percentages of total cost of service for each town in Appendix E.

Using Horizon Power's forecast operating costs and capital expenditure combined with the Authority's proposed ICB value, the forecast statutory accounts modelled for the inquiry period are shown in Table 10.2 below.

Table 10.2 Key financial indicators for Horizon Power using its own forecast cost inputs ($m nominal unless otherwise stated)

Indicators	2010	2011	2012	2013	2014
Net Profit	11.9	11.8	-1.3	2.7	5.5
Interest bearing liabilities	654.7	955.1	1,181.6	1,372.8	1,437.7
Net Assets	142.7	159.6	162.4	169.4	179.3
Total Asset	915.1	1,234.1	1,466.6	1,668.0	1,746.1
Interest bearing liabilities/Total Assets	71.5%	77.4%	80.6%	82.3%	82.3%
Net cash from operating activities	22.8	22.8	41.7	53.1	52.5

Source: ERA analysis

Horizon Power's net profit remains positive for the majority of the inquiry period although it does fall slightly negative in 2011/12. Interest bearing liabilities as a percentage of total assets rises initially then remains constant over the remainder of the inquiry period.

10.2 Using the Authority's recommendations

The revenue requirements generated from the cost of service model using the Authority's recommended operating cost and capital expenditure forecasts are given for Horizon Power in Table 10.3 below.

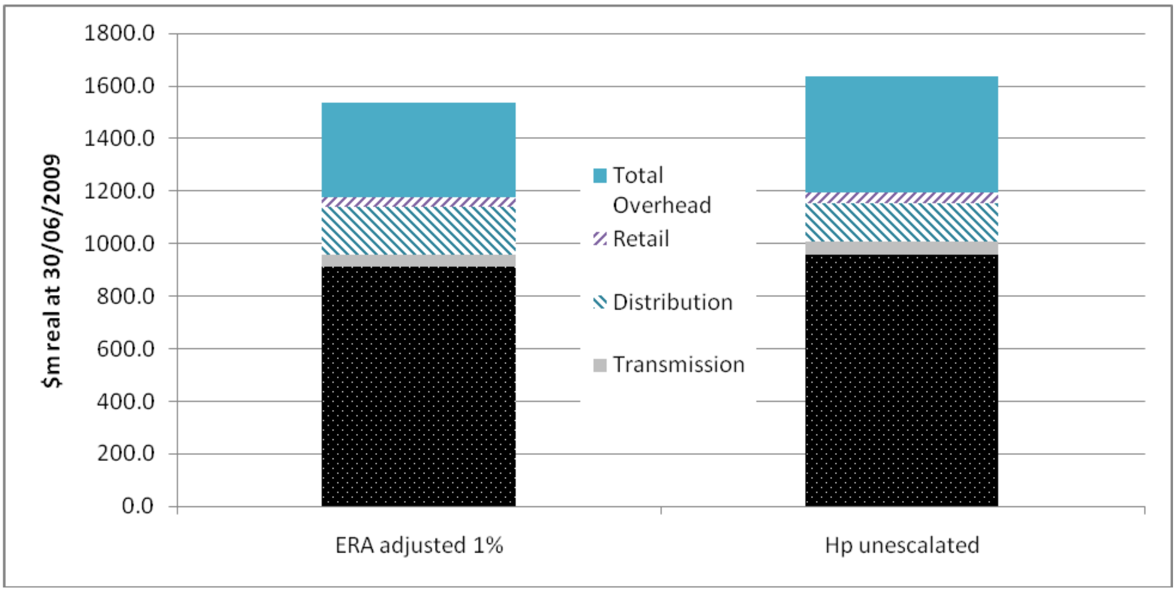
Table 10.3 Determination of cost of service for Horizon Power using ERA recommended forecast inputs ($m real at 30/6/2009)

Item	2010	2011	2012	2013	2014
Opex	277.0	309.8	314.8	318.7	320.6
Depreciation	10.3	16.8	33.9	40.5	38.0
Return on Asset	17.1	22.4	38.1	48.6	57.0
Total Cost of service	304.4	349.0	386.9	407.8	415.6
Comparison from Table 10.1	*304.4*	*368.1*	*408.1*	*469.0*	*439.2*

Source: ERA analysis. Numbers may not add due to rounding.

The contribution of each functional area of expenditure to the overall cost of service is shown in Figure 10.1 below.

Figure 10.1 NPV comparison of the functional analysis under the two different scenarios (Using Horizon Power proposed inputs and ERA recommended forecasts) ($m real at 30/6/2009)



Source: ERA analysis

The contribution of each function to the cost of service for Horizon Power as a whole under each of the two scenarios is shown above and the equivalent (normalised) analysis for each town is given in Appendix G. The total ERA adjusted cost of service under Horizon Power's assumptions is $1,633.8m (real at 30/6/2009) and for the ERA recommendations is $1,534.7m (real at 30/6/2009).

The dominance of generation and total overhead occurs in both scenarios but the NPV of the ERA cost of service is lower by $99.1m (real as at 30/6/2009). Reductions are shown in all cost functions because the one per cent efficiency adjustment is applied consistently to all controllable operating costs.

Under the ERA proposed forecasts of the efficient revenue requirement, Horizon Power's statutory accounts, as shown in Table 10.4 below show that net profit remains positive until 2011/12 when it dips slightly negative and then recovers well towards 2013/14. The percentage of interest bearing liabilities over total assets also increases through to 2012/13 then begins to recover in 2013/14.

Table 10.4 Key financial indicators for Horizon Power using ERA recommended forecast inputs ($m nominal unless otherwise stated)

indicators	2010	2011	2012	2013	2014
Net Profit	11.1	11.4	-1.6	2.2	4.9
Interest bearing liabilities	646.2	923.8	1,122.3	1,294.2	1,339.1
Net Assets	141.9	158.5	161.0	167.4	176.7
Total Asset	905.8	1,201.7	1,405.8	1,587.4	1,644.9
Interest bearing liabilities/Total Assets	71.3%	76.9%	79.8%	81.5%	81.4%
Net cash from operating activities	22.0	21.7	39.4	49.3	48.0

Source: ERA analysis

11 Cost Reflective Tariffs

The Terms of Reference requires the Authority to determine cost reflective retail tariffs for the inquiry period for each of the retail tariffs currently provided by Horizon Power. The Authority has considered this request and will address this in more detail in the final report. The issues paper for the inquiry also discussed cost reflective tariff design.[92] However, the quantity and quality of data reviewed in preparing the draft report has necessitated a more simplified approach to the derivation of cost reflective tariffs at this stage in the inquiry.

One representation of a cost reflective tariff is the Discounted Weighted Average Tariff (DWAT) as this divides the discounted cost of service from the regulatory model by the discounted kWh over the five year inquiry period. The simple DWAT is a combination of direct town costs of service plus district and head office overheads allocated to each town by the appropriate amount of electricity sent out to each town/system as measured by kWh.

The Authority has calculated DWAT for all the towns in Horizon Power's supply area and the NWIS for comparative purposes. The DWAT values range from $0.2588 for Wyndham to $1.5460 for Nullagine. The results for all towns are given in Figure 11.1 below.

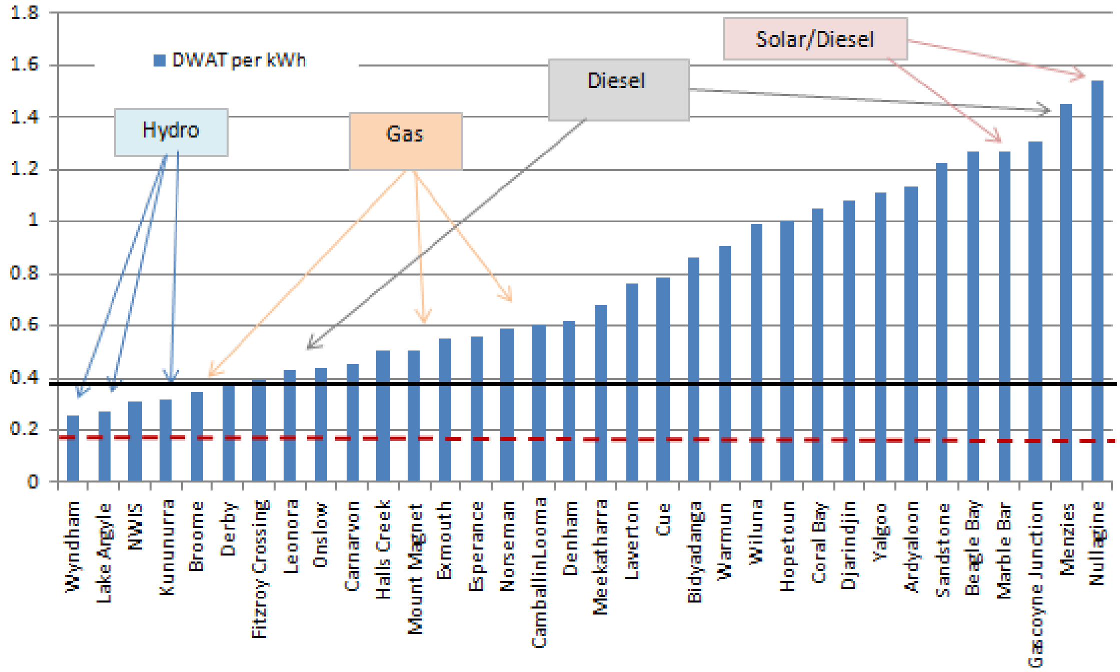
The equivalent DWAT for the SWIS is approximately $0.19 per kWh. This level is shown as a red dotted line in Figure 11.1 below.

11.1 DWAT

The DWAT for Horizon Power as a whole based on Horizon Power's unescalated forecasts of operating costs and capital expenditure $0.3880 per kWh. This is shown as the solid black line in Figure 11.1 below.

[92] Economic Regulation Authority 2010, Inquiry into the Funding Arrangements of Horizon Power: Issues Paper, p 18.

Figure 11.1 Simple DWAT by town (Horizon Power's forecasts) ($/kWh)



Source: ERA analysis

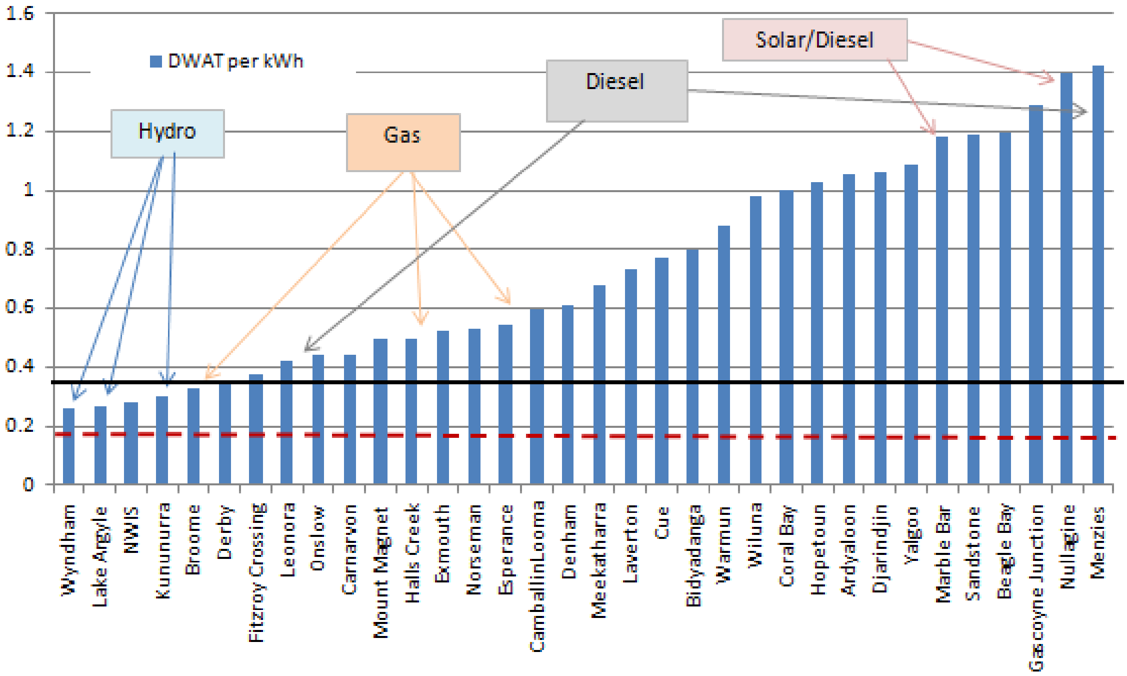
There are reasonably strong relationships between the DWAT for a town and:

- the type of fuel used to generate electricity – hydro is the least expensive source (as evidenced by Lake Argyle, Wyndham and Kununurra at the low end in the above figure), followed by gas (used in towns such as Broome, Derby and Esperance), then diesel only (a fairly wide range from Onslow to Menzies), then solar and diesel combined (Marble Bar and Nullagine);
- generator capacity – the larger the generation capacity the lower the cost to supply (the NWIS has the largest installed capacity and a low DWAT compared to towns such as Gascoyne Junction, Menzies, Yalgoo and Ardyaloon which have installed capacity at less than 1MW); and
- distance from infrastructure – in particular for diesel generators, as the further away a town is from a major town the higher the diesel transport costs (as evidenced by the higher costs of supplying more remote towns such as Ardyaloon, Djarindjin and Beagle Bay in the West Kimberley).

Horizon Power's DWAT under the Authority's 1 per cent efficiency target for controllable operating costs and stated capital expenditure reductions is $0.3645 per kWh. This level is shown as the solid black line in Figure 11.2 below.

Overall this is a reduction in the DWAT of -$0.0235 per kWh or 6.1 per cent compared to Horizon Power's DWAT.

Figure 11.2 Simple DWAT by town (ERA recommended forecasts) ($/kWh)



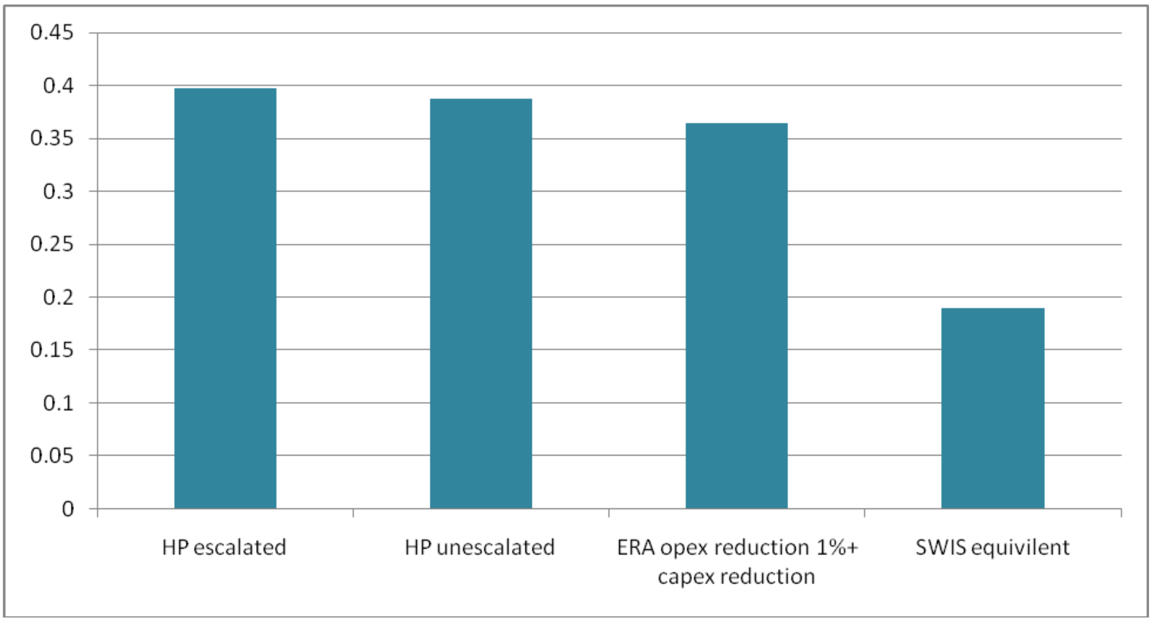
Source: ERA analysis

The one per cent efficiency adjustments to the controllable 2009/10 base operating year cost has been applied uniformly across the individual towns, district and head office. However, to achieve the required operating cost savings, Horizon Power can seek to achieve the efficiency gains in whatever way it chooses. Consequently actual DWAT may vary from those shown in Figure 11.2 above.

11.2 Reduction of DWAT

The effect on the DWAT of the various assumptions used by the Authority in conducting the inquiry and the proposed reductions to forecast operating and capital expenditures is shown in Figure 11.3 below and compared to the equivalent figure for the SWIS.

Figure 11.3 The incremental effect of Authority's proposed reductions on DWAT



Source: ERA analysis

Across the first three DWATs above there is an overall reduction of $0.0330 per kWh, from Horizon Power escalated $0.3975 per kWh to the ERA recommended position (with operating and capital cost reductions) $0.3645 per kWh. The other value is for HP unescalated at $0.3880 per kWh. These calculated DWATs are compared with an equivalent figure for the SWIS.

12 Tariff Equalisation Contribution (TEC)

As outlined at the beginning of the draft report, the unit cost of supplying electricity to people living in remote areas, outside the South West, is high because of specific operating circumstances associated with these regions. The Government's uniform tariff policy however, ensures that all residential and small business customers pay the same electricity tariffs regardless of where they live. The electricity tariffs of customers living in remote Western Australia are subsidised by taxpayers and South West electricity network customers. This subsidy takes two forms, CSO payments and the TEC.

CSO payments can cover the funding of specific projects or programmes such as the Aboriginal and Remote Community Power Supply Project or rebate schemes for specific groups of customers. Horizon Power and Synergy also currently receive a CSO payment to cover the revenue shortfall arising from the transition of existing tariff levels to cost reflective tariffs levels in the SWIS.

The shortfall between the income Horizon Power receives from the sum of its existing income sources (e.g. uniform tariff revenue, commercial customer revenue, non-regulated revenue and gifted cash in the form of CSO payments) and the cost reflective revenue requirement as determined from the regulatory modelling above will inform the setting of the TEC by the State Government.

Horizon Power informed the Authority that it was engaged by the Department of Treasury and Finance and Office of Energy in September 2009 to set TEC for the 2009/10 year and the following two financial years.[93] Horizon Power has advised the Authority that the TEC is calculated from projected notional profit after tax and a capital charge.

The Authority has used the efficient level of costs reported in sections 7 and 8 to determine the overall revenue required by Horizon Power to perform its functions at the required levels of service. From this total revenue requirement, uniform tariff revenue and commercial customer revenue are deducted to leave a 'balancing revenue' item equivalent to the TEC and CSO.

12.1 Using Horizon Power's actual and forecast data

The Authority has taken the revenue requirement determined in section 10.1 above and converted to nominal prices, then deducted Horizon Power's income. This then determines the 'balancing revenue' from which Horizon Power's TEC subsidy is derived. This is shown in Table 12.1 below.

[93] Horizon Power 2010, Powerpoint presentation to ERA Secretariat.

Table 12.1 Derivation of the 'balancing revenue' item and TEC ($ nominal) using Horizon Power's forecast operating and capital cost inputs

Balancing revenue calculation	2010	2011	2012	2013	2014
CoS	312.4	387.7	441.0	520.1	499.8
Commercial customer revenue (Tier 3&4)	-18.3	-29.6	-28.0	-26.2	-26.8
Unit tariff revenue (Tier 1&2)	-152.5	-182.2	-222.0	-241.5	-265.2
Required 'balancing revenue'	141.6	175.9	190.9	252.4	207.7
Net CSO	-35.7	-31.8	-22.8	-22.2	-22.3
Derived TEC	**105.9**	**144.0**	**168.1**	**230.2**	**185.5**

Source: ERA analysis. Numbers may not add due to rounding.

The output from the cost of service model is the revenue required to fund the cost of service based on Horizon Power's forecast operating and capital costs and the Authority's assumption for ICB. As mentioned in section 10.1 above, Horizon Power's calculated WACC and the Authority's calculated WACC are very similar so the Authority's real pre tax WACC of 6.49 per cent has been used in both scenarios.

From this, all other sources of income are deducted to calculate the amount of balancing revenue that needs to be met by the subsidy. The net CSO payment is deducted from balancing revenue to give derived TEC values.

The Table 12.2 compares this derived TEC value, determined from Horizon Power's proposed forecasts, with the gazetted TEC values for 2009/10 to 2013/14.

The NPV of the gazetted TEC figures is $397.7m (real at 30/6/2009) for year 2009/10 to 2011/12 and the comparable NPV over the same three years from Table 12.2 is $346.4m (real as at 30/6/2009), a reduction of $51.3m (real NPV as at 30/6/2009).

Table 12.2 Comparison of derived TEC (Horizon Power's forecast cost inputs) with gazetted TEC ($m nominal)

Item	2010	2011	2012	2013	2014
Gazetted TEC	122.1	175.7	181.2	n/a	n/a
Derived TEC - adjusted 09/10 base year then Horizon Power's forecasts	105.9	144.0	168.1	230.2	185.5

Source: Government Gazette No. 153, 25 August 2009, p3325 and Government Gazette No. 208, 17 November 2010, p4639 and ERA analysis.

The derived TEC determined by the financial modelling is considerably lower than the current gazetted TEC figures. This results from the influence of the following items:

- a lower asset base - in the last gazetted TEC calculation Horizon Power used an average asset value of $452m (nominal) which includes those assets gifted by third parties. Any gifted assets are excluded from the regulatory asset base on the assumption that Horizon Power should not receive a return on assets it has not funded itself. The closing regulatory asset base determined by the Authority in 2009/10 is $346.0m;
- different depreciation charges – any difference in the value of the asset base will also result in a different depreciation charge between that which was used to

calculate the gazetted TEC and the depreciation charge calculated by the cost of service model; and

- a lower operating cost value – at the time the gazetted TEC was calculated Horizon Power only had budgeted operating costs available ($300m nominal). In the calculations below, Horizon Power has submitted actual operating costs information for 2009/10 of $284.3 (nominal). As the main driver of overall cost of service, lower operating costs reduce the balancing revenue item and result in a lower overall TEC requirement.

12.2 Using Authority's recommendations

The process was then repeated but using the cost efficient revenue requirement based on the Authority's recommended levels of operating and capital costs. Values for ICB and WACC remained constant for both scenarios.

At the consolidated level, the derived TEC resulting from the ERA recommended revenue requirement less Horizon Power's forecast income is also shown compared to the gazetted TEC in Table 12.2 above.

Table 12.3 Derivation of the 'balancing revenue' item and TEC ($ nominal) using ERA recommended forecasts

Balancing revenue calculation	2010	2011	2012	2013	2014
CoS	312.4	367.6	418.1	452.3	472.9
Commercial customer revenue (Tier 3&4)	-18.2	-29.6	-28.0	-26.2	-26.8
Unit tariff revenue (Tier 1&2)	-152.5	-182.2	-222.0	-241.5	-265.2
Required 'balancing revenue'	141.6	155.8	168.0	184.6	180.9
Net CSO	-35.7	-31.8	-22.8	-22.2	-22.3
Derived TEC	**105.9**	**123.9**	**145.3**	**162.4**	**158.6**

Source: ERA analysis. Numbers may not add due to rounding.

The balancing revenue figure, and hence derived TEC is further reduced when using the Authority's recommended forecasts to calculate the efficient cost of service. This is predominantly because of:

- the Authority's recommended reductions to operating costs over the inquiry period ($105.8m real as at 30/6/2009); and
- the Authority's recommended reductions to capital expenditure over the inquiry period ($77.4m real as at 30/6/2009).

Table 12.4 Comparison of derived TEC (ERA recommended forecasts) with gazetted TEC ($m nominal)

Item	2010	2011	2012	2013	2014
Gazetted TEC	122.1	175.7	181.2	n/a	n/a
Derived TEC - adjusted 09/10 base year then ERA recommended forecasts	105.9	123.9	145.6	162.4	158.6

Source: ERA analysis

Table 12.4 compares the derived TEC, determined from the ERA proposed forecasts, with the gazetted TEC values for 2009/10 to 2011/12.

The NPV of the TEC from the ERA scenario is $312.1m (real as at 30/6/2009) for years 2009/10 to 2011/12, a reduction of $85.6m (real as at 30/6/2009) when compared to the NPV of the gazetted TEC of $397.7m (calculated over the same three years).

This greater reduction in the TEC largely results from the one per cent compounding efficiency factor applied to the base year controllable unit operating costs per connection of Horizon Power. This has resulted in a reduction in Horizon Power's total operating cost of $105.8m (real as at 30/6/2009) over the inquiry period as demonstrated in Table 7.8 above.

Operating costs are the major contributor to the cost of service and revenue requirement. Therefore if operating costs are reduced then the cost of service reduces and less funding is required to be met by the TEC.

12.3 Using an alternative WACC

Section 9 outlines the potential impact upon the derived TEC of using a benchmark WACC or a WACC based on Horizon Power's actual borrowing costs. The results of that comparison are shown in Table 12.5 below.

Table 12.5 Comparison of derived TEC with ERA forecasts but using a benchmark WACC and alternative WACC ($m nominal)

Item	2010	2011	2012	2013	2014
Derived TEC - calculated with benchmark WACC (6.49%)	105.9	123.9	145.3	162.4	158.6
Derived TEC - calculated with alternative WACC (4.89%)	101.6	118.1	135.1	149.0	142.6
Variation	4.3	5.8	10.2	13.4	16.0

Source: ERA analysis. Numbers may not add due to rounding.

This indicates the impact upon SWIS network customers (who ultimately fund the TEC) of applying a benchmark WACC for Horizon Power when it has access to borrowing from the State Government, at favourable rates. This amounts to $49.8m (nominal) over the inquiry period.

12.4 Authority comments

The Authority considers that the TEC should be funded by a CSO payment directly to Horizon Power. This approach is supported by Alinta Energy and Griffin Energy in their submissions in response to the issues paper. Furthermore, the Office of Energy in its response to the issues paper also encouraged the Authority to:

> "..examine what is an appropriate funding mechanism for Horizon Power, including whether the TEC should be funded through a direct CSO from Government instead of from network tariffs paid by South West consumers."[94]

The main cause for concern with the current funding of TEC though network charges in the SWIS is that the funding of the TEC subsidy rests with a specific group of electricity customers instead of being funded by all Western Australian consumers via general taxation. By limiting the funding of the TEC subsidy to a subset of electricity consumers this effectively inhibits the move toward fully cost reflective pricing within the SWIS.

Alinta Energy and Griffin Energy are particularly concerned that the TEC is negatively influencing that part of the electricity supply market in the SWIS that is considered competitive. This concerns the partial deregulation of the electricity market in the SWIS to enable customers whose annual demand is greater than 50 MWh per annum on a single site to choose their electricity supplier. These are called 'contestable customers'. Alternative retailers to these contestable customers, such as Alinta Energy, are concerned that because the network charges they pay to Western Power to access the SWIS include an element intended to cover the TEC, this distorts the competitive nature of the contestable customer market.

The Authority recognises that the form of funding for the TEC ultimately rests with the Government. However, should the Government continue to fund the TEC though Western Power's network access charges then the Authority considers that this should be reflected in lower distribution network access charges for Western Power so that all Western Power's wholesale customers benefit.

Recommendations

9) The TEC be funded by a CSO paid directly to Horizon Power.

10) Should the Government continue to subsidise Horizon Power through a TEC payment funded by SWIS network customers, the lower TEC should be gazetted. This will provide for the lower TEC to be passed through to lower distribution network tariffs in the SWIS.

[94] Office of Energy 2010, Submission to the inquiry into the funding arrangements of Horizon Power, Attachment 1, p5.

13 The Future Regulatory Approach

The current inquiry gives an initial analysis of Horizon Power's operating efficiency. The assumptions and recommendations drawn in the draft report are based on data that the Authority has some concerns about, in terms of its accuracy and consistency (see section 2.6).

In the Authority's experience it takes time for a company to adapt to the data requirements associated with economic regulation and the level of supporting information required by a regulator when analysing operating and capital expenditure. Consequently the Authority recommends that a second inquiry be undertaken in three years time.

Horizon Power has recently changed its chart of accounts to forecast and more correctly allocate data to the town level. Therefore, for the second review there will be several years of actual data available at required level of detail for the Authority to better investigate trends in expenditure and performance.

A second or ongoing series of inquiries enables the Authority to make corrections for incorrect assumption made at the previous review. For example, if, when reviewing actual costs, Horizon Power has been faced with inflation greater than CPI inflation, the Authority can consider adjusting for this in a subsequent inquiry, if the expenditure is deemed efficient.

Furthermore at a later review the Authority would be able to review Horizon Power's demand forecasting performance and if this were to result in Horizon Power having received more of a subsidy than necessary, the additional subsidy could be recouped in future periods.

Horizon Power publishes service performance data annually, which is also reviewed by the Authority as part of its licensing functions. By incorporating the review of service standards into subsequent Horizon Power inquiries this enables the Authority to compare historical service performance data and use this to set service standard benchmarks against which Horizon Power's future performance is measured. This, in turn introduces the opportunity for incentive mechanisms, related to service performance, to be incorporated into the inquiry recommendations. Such incentive mechanisms would compare over or under performance against an agreed benchmark and rewards and penalties determined, such as is the case for Western Power.

At the current time however, the Authority believes the setting of incentive mechanisms is inappropriate. This is because retail tariffs to customers are already subsidised and Horizon Power does not predominantly operate in a commercial environment. Furthermore the Authority prefers that the data quality and consistency issues be resolved before they are used in setting incentives.

Recommendation

11) A second inquiry into the funding arrangements of Horizon Power be undertaken in three years time to further review Horizon Power's actual costs and to set new efficiency targets.

APPENDICES

Appendix A: Terms of Reference

INQUIRY INTO THE FUNDING ARRANGEMENTS OF HORIZON POWER

FINAL TERMS OF REFERENCE

I, COLIN BARNETT, Treasurer, pursuant to Section 32(1) of the *Economic Regulation Authority Act 2003*, and in accordance with section 129E(1) of the *Electricity Industry Act 2004*, request that the Economic Regulation Authority (the Authority) undertake an inquiry into the funding arrangements, and operating and capital expenditure programmes of the Regional Power Corporation (Horizon Power).

In doing so, the Authority is expected to consider and develop findings on:

- The cost reflective retail tariffs that would apply in the areas of operation of Horizon Power, for the purpose of determining the efficient expenditure required to supply customers on regulated retail tariffs located in these areas. This will inform the setting of the amount of the Tariff Equalisation Contribution (TEC), which will be determined by Government.

- The cost reflective retail tariffs should be determined for the period 2009/10 to 2013/14.

- A cost reflective retail tariff should be determined for each of the retail tariffs currently provided by Horizon Power, being the A2, K2, L2, M2, N2, W2 and Streetlight tariffs (as detailed in the Energy Operators (Regional Power Corporation) (Charges) By-laws 2006).

- The Authority is to determine whether the area that Horizon Power operates in should be separated into sub-areas, given the different cost structures of the systems that Horizon Power operates, for the purpose of determining cost reflective retail tariffs. If this is the case, the Authority is to:

  - define the sub-areas (minimising the number of sub-areas as much as possible); and

  - determine a different cost reflective retail tariff (for each tariff class) for each sub-area.

- The Authority is also to take into account the following costs when determining the retail tariffs, but is not limited to considering only these costs:

  - the efficient generation costs applicable in the area Horizon Power operates in or each sub-area, if applicable, taking into account the current and committed stock of generation;

  - the efficient network costs applicable in the area Horizon Power operates in or each sub-area, if applicable, taking into account the current network infrastructure;

  - the efficient level of retail costs that would be applicable in the area that Horizon Power services (both operating and capital costs);

  - the efficient net retail margin that would apply;

  - the efficient costs related to the national Mandatory Renewable Energy Target (MRET), including the expanded MRET if applicable; and

  - the efficient costs related to the proposed Carbon Pollution Reduction Scheme (CPRS), including the carbon intensity that should be applied in determining CPRS costs that would be incorporated into the cost reflective retail tariffs.

- The Authority is also to consider and incorporate incentives for Horizon Power to develop and implement efficiency measures, such as gain sharing mechanisms between customers and Horizon Power, in determining cost reflective retail tariffs if the Authority considers this would minimise costs within the area that Horizon Power operates in.

- The efficiency of Horizon Power's procurement processes.

- The efficiency of Horizon Power's operating and capital expenditure programmes, including opportunities of alternative arrangements for service delivery in remote regions.

The Authority should note the following:

- The TEC refers to the amount payable by the Electricity Networks Corporation (Western Power) to the Tariff Equalisation Account to contribute towards maintaining the financial viability of Horizon Power, as set out in part 9A of the *Electricity Industry Act 2004*.

- The Department of Treasury and Finance and the Office of Energy are currently in the process of developing a revised framework for determining the TEC amount, including a post adjustment mechanism to vary the TEC set for 2009/10 to 2011/12.

The Authority will release an issues paper as soon as possible after receiving the reference. The paper is to facilitate public consultation in the basis of invitations for written submissions from industry, government and all other stakeholder groups, including the general community.

A draft report is also to be made available for public consultation.

The Authority will complete a final report on the findings of the inquiry no later than 18 March 2010.

COLIN BARNETT MLA
PERMIER; TREASURER

Appendix B: ICB values by location at 1 April 2006 and 30 June 2009

Location	2006 ICB value ($'000s)	2009 ICB value ($'000s)
Ardyaloon	-	-4,890
Beagle Bay	-	1,464,881
Bidyadanga	-	-4,595
Broome	12,316,553	36,941,764
Camballin/Looma	168,271	527,632
Carnarvon	12,307,627	14,388,414
Coral Bay	-	1,036,774
Cue	594,345	1,662,505
Denham	1,362,102	1,891,918
Derby	2,089,672	4,688,393
Djandinjin	-	-82,526
Esperance	17,836,984	29,473,745
Exmouth	2,637,077	4,178,093
Fitzroy Crossing	1,363,869	3,813,365
Gascoyne Junction	-	-8,038
Halls Creek	854,049	2,137,623
Hopetoun	707,500	5,136,982
Kalumburu	-	-
Kununurra	12,977,573	20,263,235
Lake Argyle	152,003	118,352
Laverton	526,082	1,466,149
Leonora	1,209,249	1,215,516
Marble Bar	324,463	492,332
Meekatharra	6,364,182	1,996,607
Menzies	153,005	531,789
Mount Magnet	762,264	1,267,897
Norseman	857,497	786,143
Nullagine	193,142	170,857
Onslow	2,843,705	2,514,857
Sandstone	429,140	455,131
Warmun	-	335,215
Wiluna	652,715	779,373
Wyndham	955,631	1,127,237
Yalgoo	261,283	412,005

Location	2006 ICB value ($'000s)	2009 ICB value ($'000s)
Yungngora	-	-
NWIS	95,428,866	113,669,045
Bentley	1,338,271	7,293,942
East Kimberley	-	2,096
Esperance(Goldfields)	-	30,298
Gascoyne Midwest	-	9,558
Pilbara	680,006	574,855
West Kimberley	1,727,688	1,332,059
Aggregate	180,074,815	264,086,589

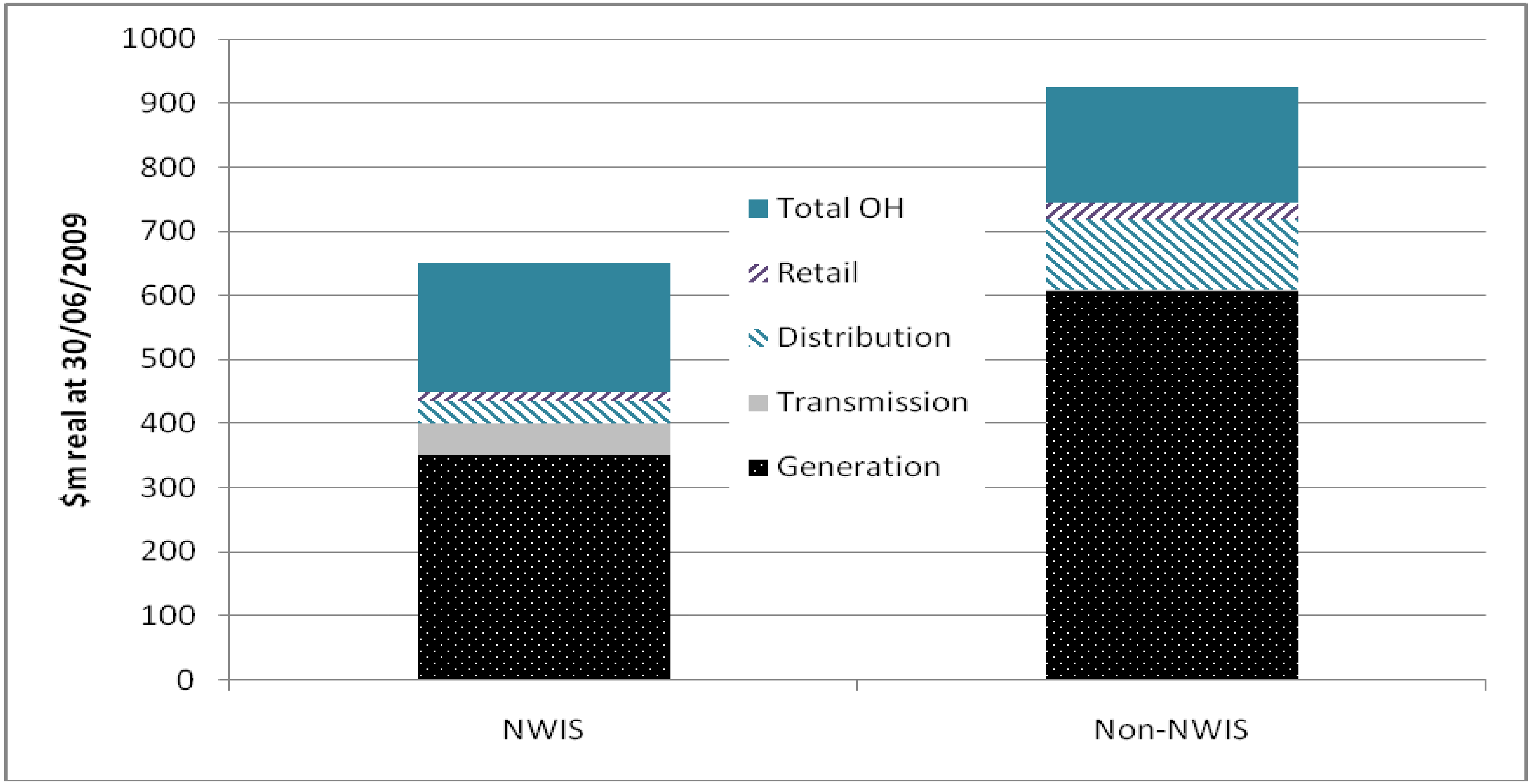
Appendix C: DWAT comparisons under different modelling scenarios

Location	Town DWATS from Horizon Power's forecasts	ERA DWATS
Ardyaloon	1.3372	1.0568
Beagle Bay	1.2682	1.1963
Bidyadanga	0.8584	0.8017
Broome	0.3509	0.3296
Camballin/Looma	0.6072	0.5967
Carnarvon	0.4571	0.4463
Coral Bay	1.0538	0.9988
Cue	0.7837	0.7741
Denham	0.6163	0.6087
Derby	0.3706	0.3438
Djandinjin	1.0797	1.0611
Esperance	0.5612	0.5434
Exmouth	0.5546	0.5239
Fitzroy Crossing	0.3965	0.3771
Gascoyne Junction	1.3068	1.2937
Halls Creek	0.5081	0.4993
Hopetoun	1.0047	1.0263
Kalumburu	n/a	n/a
Kununurra	0.3176	0.3040
Lake Argyle	0.2683	0.2660
Laverton	0.7626	0.7322
Leonora	0.4329	0.4257
Marble Bar	1.2690	1.1812
Meekatharra	0.6835	0.6753
Menzies	1.4486	1.4270
Mount Magnet	0.5098	0.4943
Norseman	0.5895	0.5340
Nullagine	1.5460	1.3963
Onslow	0.4385	0.4451
Sandstone	1.2214	1.1907
Warmun	0.9059	0.8781
Wiluna	0.9901	0.9794

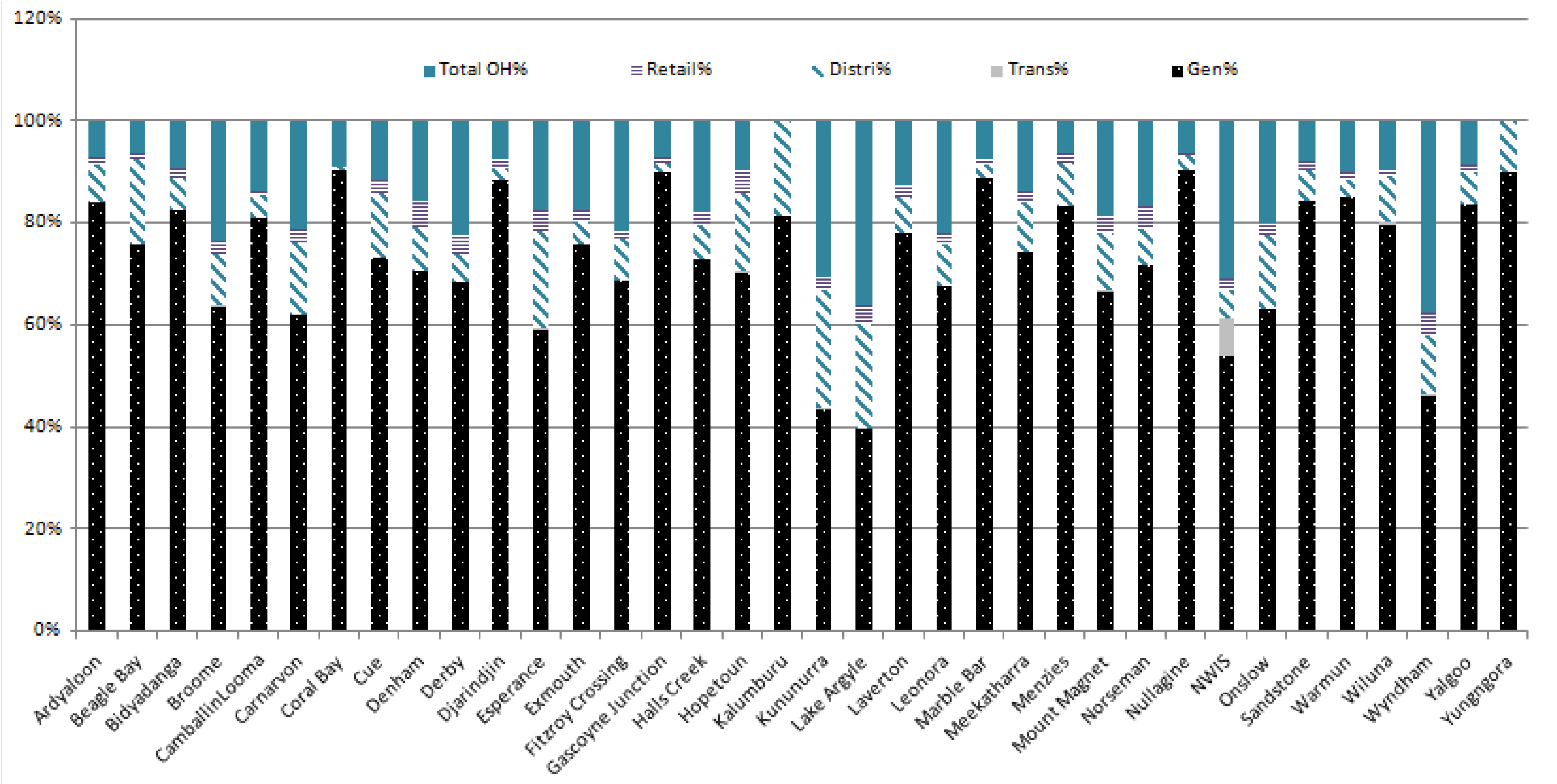
Location	Town DWATS from Horizon Power's forecasts	ERA DWATS
Wyndham	0.2588	0.2602
Yalgoo	1.1098	1.0902
Yungngora	n/a	n/a
NWIS	0.3126	0.2847
Aggregate	0.3880	0.3645

Source: ERA analysis

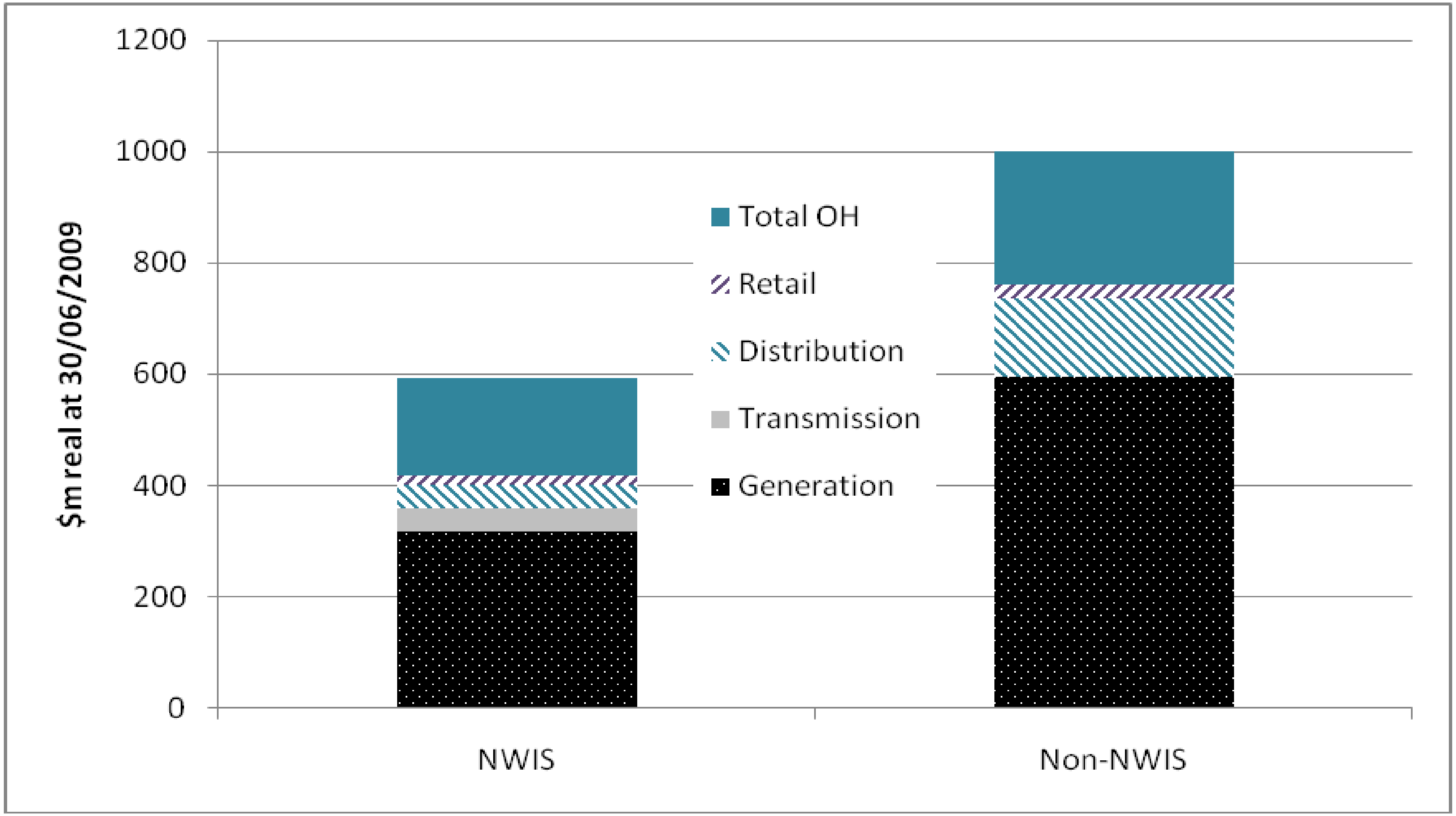
Appendix D: Cost of service by function for NWIS and non-NWIS (Horizon Power's forecasts)



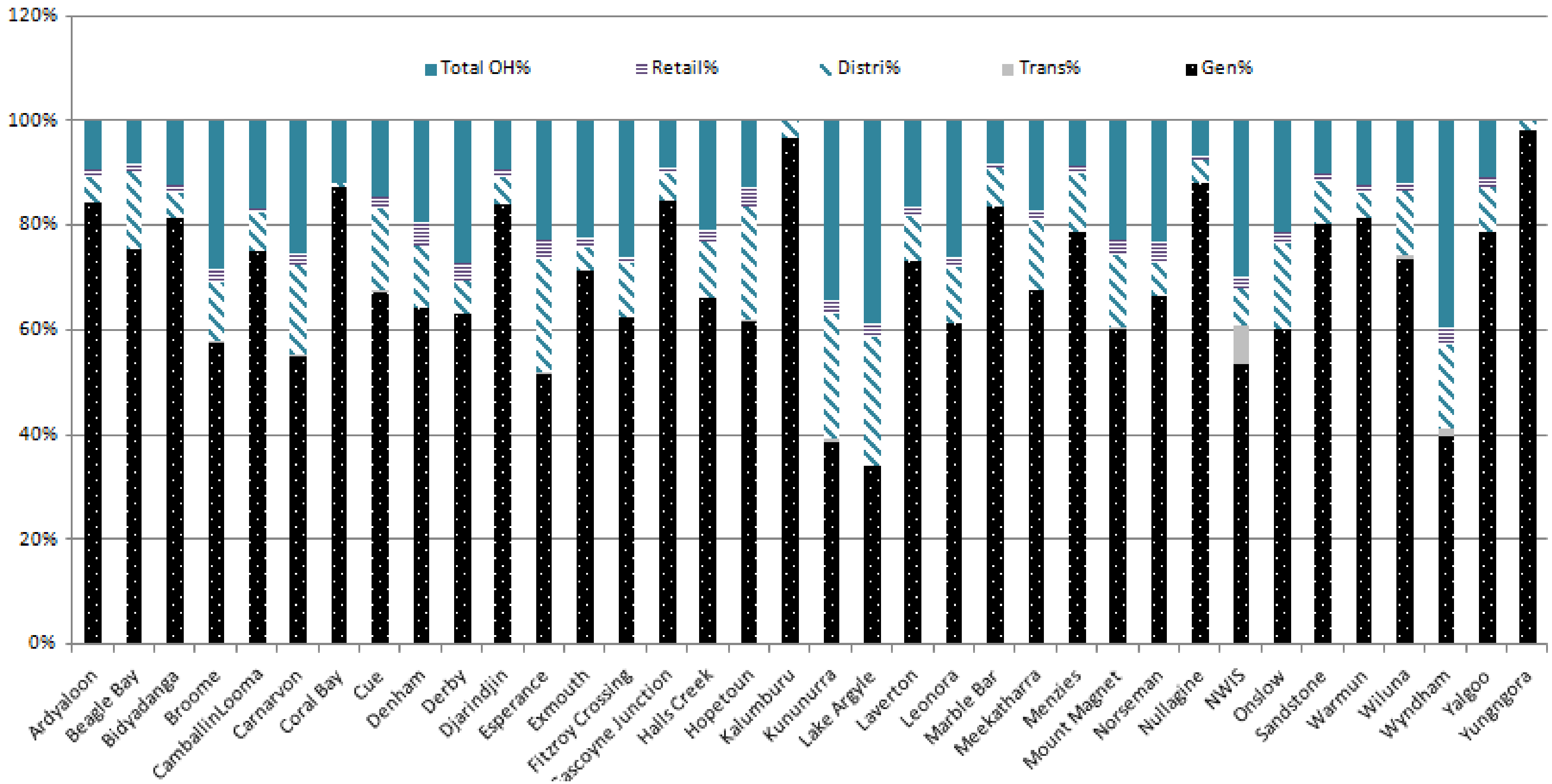
Appendix E: The percentage contribution of each function to total cost of service for each town (%) (Horizon Power's forecasts)



Appendix F: Cost of Service by function for NWIS and non-NWIS (ERA forecasts)



Appendix G: The percentage of each function to the total cost of service for each town (ERA forecasts)



Appendix H: Technical information on WACC

Method for Calculation of Rate of Return

The Nominal Post-Tax WACC Formula:

In the absence of an imputation tax system, the nominal post-tax form of the Weighted Average Cost of Capital (WACC) is expressed as below:

$$WACC_{\text{nominal post-tax}} = E\left(R_e\right) \times \frac{E}{V} \times + E\left(R_d\right) \times \frac{D}{V}\left(1 - T_c\right)$$

where:

- $E\left(R_e\right)$ is the nominal post-tax expected rate of return on equity - the cost of equity;
- $E\left(R_d\right)$ is the nominal pre-tax expected rate of return on debt - the cost of debt;
- E/V is the proportion of equity in the total financing (which comprises equity and debt);
- D/V is the proportion of debt in the total financing; and
- T_c is the tax rate.

The Australian tax system provides credits to shareholders for tax already paid at the corporate level, to avoid double taxation of the same income stream. In this circumstance, the nominal post-tax WACC formula needs to be modified to reflect the additional element of shareholders' return available through the taxation system. This is an estimate of the post-tax return on assets in the presence of an imputation credit tax system:

$$WACC = E\left(R_e\right) \times \frac{E}{V} \times \frac{1 - T_c}{\left(1 - T_c\left(1 - \gamma\right)\right)} + E\left(R_d\right) \times \frac{D}{V}\left(1 - T_c\right)$$

where γ (gamma) is the value of franking credits created (as a proportion of their face value).

The Nominal Pre-Tax WACC Formula:

This is an estimate of the pre-tax return on assets, which can be obtained by dividing the right hand side of the formula for the above nominal post-tax return on assets by the component $\left(1 - T_c\right)$, which can be expressed as:

$$WACC = E\left(R_e\right) \times \frac{E}{V} \times \frac{1_c}{\left(1 - T_c\left(1 - \gamma\right)\right)} + E\left(R_d\right) \times \frac{D}{V}$$

The Real Pre-Tax WACC Formula:

A real pre-tax WACC is obtained by removing expected inflation π_e from the nominal pre-tax WACC:

$$WACC_{\text{real pre-tax}} = \frac{\left(1 + WACC_{\text{nominal pre-tax}}\right)}{1 + \pi_e} - 1$$

Authority's Assessment

While all regulators of utility industries in Australia use the CAPM to estimate the cost of capital, there is no clear precedent on the form of the WACC to be used (i.e. pre-tax or post-tax, real or nominal).

- A pre-tax real WACC has been generally preferred by the Independent Pricing and Regulatory Tribunal of New South Wales (**IPART**) and the Independent Competition and Regulatory Commission (**ICRC**) of the Australian Capital Territory.
- The Australian Competition and Consumer Commission (**ACCC**) and the Australian Energy Regulator (**AER**) have used a post-tax nominal form of the WACC in recent decisions.
- The Essential Services Commission of Victoria (**ESC**) has used a post-tax real form of the WACC in recent decisions.

The Authority notes that Deloitte's proposed method of ascertaining a rate of return using a real pre-tax WACC is appropriate and this proposal is also consistent with the Authority's preference. The Authority is therefore satisfied that the proposed method of calculating the rate of return using a real pre-tax WACC formula meets the requirements of the NGL and NGR.

The Authority also prefers a real pre-tax WACC approach, as this method:

- simplifies financial modelling;
- is consistent with the preferences of major utilities in Western Australia (e.g. Water Corporation and Western Power); and
- allows consistency across regulated utilities in Western Australia.

Methods for Estimating the Cost of Equity

Horizon Power's Proposal

Horizon Power proposes to use the Capital Asset Pricing Model, on the advice of Deloitte, to estimate the cost of equity. However, an extra element, known as specific company risk premium, is added.

$$K_e = R_f + \beta \times \left(R_m - R_f\right) + \alpha$$

where:

- K_e is required return on equity
- R_f is the risk free rate of return
- R_m is the expected return on the market portfolio
- β is beta, the systematic risk of a stock; and
- α is specific company risk premium

Authority's Assessment

The Authority agrees with Horizon Power's proposal to use the standard CAPM (known as Sharpe-Litner CAPM) to estimate the cost of equity.

The central implication of CAPM is that the contribution of an asset to the systematic risk (also known as beta risk) is the correct measure of the asset's risk and the only systematic determinant of the asset's return. There are two main components of CAPM: the market portfolio M, and beta risk β of a portfolio, which correlates the portfolio to the rise and fall of the market.

Under the CAPM model, the total risk of an asset can be divided into systematic and non-systematic risk. Systematic risk is a function of broad macroeconomic factors (such as interest rates) that affect all assets and cannot be eliminated by diversification of the businesses asset portfolio. In contrast, non-systematic risk relates to the attributes of a particular asset, with this risk managed by portfolio diversification.

In estimating the cost of equity, Horizon Power proposes to take into account both systematic and non-systematic risks which are in contrary with the standard CAPM and regulatory practices: only systematic risk is compensated for regulated businesses. As such, the Authority is of the view that the cost of equity is estimated by using the standard CAPM.

$$K_e = R_f + \beta \times \left(R_m - R_f\right)$$

Nominal Risk Free Rate of Return

Horizon Power's Proposal

Horizon Power has approximated the risk free rate of return using the proxy of daily yield data for Commonwealth Government securities with terms to maturity of 10 years, reported by the Reserve Bank of Australia.

Horizon Power proposes a nominal risk free rate of return of 5.43 per cent.[95] This is the average of 10-year Commonwealth Government Securities for the 20 trading days to 8 September 2009 as reported by the Reserve Bank of Australia.

Authority's Assessment

The risk free rate is the rate of return an investor receives from holding an asset with guaranteed payments (i.e. no risk of default). The Commonwealth government bond is

95 Deloitte, "Horizon Power: Weighted Average Cost of Capital Analysis", 2 November 2009, p4.

widely used as a proxy for the risk free rate in Australia.[96] CAPM theory does not provide guidance on the appropriate proxy for the risk free rate. In Australia, regulators' current practice is to average the yield on the indexed 10-year Commonwealth government bond for a period of 20 trading days as close as feasible before the day the decision is made.

Recent decisions by economic regulators in Australia generally use the implied yields on 10-year nominal government bonds as a proxy for the risk free rate. The Authority prefers to use a 20-day moving average[97] of observed rates of return on 10-year Commonwealth government bonds as an estimate of the risk free rate.

The Authority agrees that Horizon Power's proposed approach to determining the nominal risk free rate of return is appropriate. It is a method which has been adopted by most Australian economic regulators (e.g. the AER, ESC and IPART). The data adopted by Horizon Power for the calculation of the nominal risk free rate was current as at 8 September 2009 which is quite outdated now.

For the purpose of this draft report, the Authority adopts the updated values, as at 31 October 2010. Adopting these updated values and the calculation approach proposed by Horizon Power, the Authority calculates a nominal risk free rate of 5.10 per cent.

Based on an estimated nominal risk free rate of return of 5.10 per cent and an assumed inflation rate of 2.62 per cent, the Authority estimates a real risk free rate of 2.42 per cent.

The Authority notes that these values will need to be updated at the time of the Final Report, so as to be commensurate with prevailing market conditions at the time.

Market Risk Premium

Horizon Power's Proposal

On the advice from Deloitte, Horizon Power submits that the market risk premium (MRP) of 6 per cent to 7 per cent[98] has been arrived at on a reasonable basis, and represents the best estimate possible in the circumstances.

Authority's Assessment

The market risk premium is the required return, over and above the risk free rate, on a fully diversified portfolio of assets.

It is the current practice of regulators across Australia to estimate the MRP using the historical data on equity premia.

[96] Although Blanco *et al* consider swap rates as superior to Government bonds as a proxy for the risk free rate and state that "it is well known that government bonds are no longer an ideal proxy for the unobservable risk free rate". See Blanco, Brennan, and Marsh, "An Empirical Analysis of the Dynamic Relation between Investment-Grade Bonds and Credit Default Swaps", *The Journal Of Finance*, Vol. LX, no. 5 October 2005, p2261, for details.

[97] There are three different types of moving averages: (i) Simple Moving Average; (ii) Exponential Moving Average; and (iii) Weighted Moving Average, and they are all calculated slightly differently. However, all have a similar smoothing effect on the data, so that any unexpected changes on rates are removed, and, as a result, the overall direction is shown more clearly. For simplicity, the Authority adopts the simple moving average in its calculations.

[98] Deloitte, "Horizon Power: Weighted Average Cost of Capital Analysis", 2 November 2009, page 5.

Australian regulators have consistently applied a MRP of 6 per cent in their decisions, except for the AER's decisions after its review of WACC parameters released in May 2009. It is noted that a MRP of 6 per cent was first adopted in Australia by the ACCC[99] and the Victorian Office of the Regulator General. A MRP range of 4.5-7.5 per cent was derived on the basis of consultant work prepared by Professor Davies at the University of Melbourne, where the upper bound of this range was based on historical estimates and the lower bound was based on cash flow measures.[100] As such, the mid-point of that range (6 per cent) was adopted. Subsequently, Australian regulators have consistently applied a MRP of 6.0 per cent, which is estimated using historical data on equity premia.

In its review of WACC parameters for electricity distribution and transmission networks in May 2009, the AER commissioned Associate Professor Handley at the University of Melbourne to update historical excess returns using full year data for 2008. The estimates for this study covered the periods of 1883-2008, 1937-2008, 1958-2008, 1980-2008 and 1988-2008, were relative to 10-year Commonwealth Government Securities, were grossed-up for a theta[101] of 0, 0.28, 0.5, 0.65 and 1.0 and included standard errors and 95 per cent confidence intervals. The results are presented in Table H 1 below.

Table H 1 Historical Excess Returns (Arithmetic Average, Relative to 10-Year Bonds, 'Grossed-up' for Value of Imputation Credits Distributed, Per cent)

Utilisation rate	0.00	0.28	0.5	0.65	1.00
1883-2008	5.9*	6.0*	6.1*	6.1*	6.2*
1937-2008	5.4*	5.5*	5.6*	5.7*	5.9*
1958-2008	5.7	5.9	6.1	6.2*	6.4*
1980-2008	5.0	5.3	5.6	5.8	6.3
1988-2008	3.8	4.3	4.7	5.0	5.6

*Indicates estimates are statistically significant at the five per cent level based on a two-tailed t-test.

Source: Handley (2009).[102]

The above estimates reveal that the most recent long-term historical average excess returns estimated over a range of long-term estimation periods (1883-2008, 1937-2008, 1958-2008), once 'grossed-up' for a utilisation rate of 0.65 and estimated relative to the yield on 10-year Commonwealth Government Securities, is close to 6 per cent (between 5.7 and 6.2 per cent).

An estimate of MRP of 6 per cent, from the AER's view, was the best estimate of a forward-looking long-term value for MRP prior to the onset of the global financial crisis under relatively stable market conditions with the assumption that there is no structural break which has occurred in the market. However, given the state of the international

99 ACCC, Access arrangement by Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Principal Transmission System – Access arrangement by Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Western Transmission System – Access arrangement by Victorian Energy Networks Corporation for the Principal Transmission System, Final Decision, 6 October 1998.

100 ORG, Access arrangements – Multinet Energy Pty Ltd and Multinet (Assets) Pty Ltd – Westar (Gas) Pty Ltd and Westar (Assets) Pty Ltd – Stratus (Gas) Pty Ltd and Stratus Networks (Assets) Pty Ltd , Final decision, October 1998.

101 Theta is the value of a franking credit to investors at the time they receive it.

102 J. C. Handley, *Further comments on the historical market risk premium*, Report prepared for the AER, 14 April 2009, pp.6-9.

financial market at that time (May 2009), when relatively stable market conditions did not exist, and taking into account the uncertainty surrounding the global economic crisis, the AER considered that a MRP of 6.5 per cent was reasonable.

> "The AER considers that prior to the onset of the global financial crisis, an estimate of 6 per cent was the best estimate of a forward looking long term MRP, and accordingly, under relatively stable market conditions - assuming no structural break has occurred in the market - this would remain the AER's view as to the best estimate of the forward looking long term MRP." [emphasis added] 103

The current state of the Australian financial market has significantly improved, as evidenced by six consecutive increases in the cash rate by the Reserve Bank of Australia since 7 October 2009. In its recent Statement on Monetary Policy Decision in August 2010, the Reserve Bank stated that:

> "The Australian economy continued to expand at a solid pace over the first half of 2010. The economy is benefiting from elevated commodity prices and high levels of public investment. Employment growth has been strong and confidence remains generally positive. Over the period ahead, some rebalancing of growth is expected, with public investment likely to decline as stimulus projects are completed, while private demand is expected to strengthen. The outlook for investment in the resources sector remains especially positive and the high level of the terms of trade is boosting incomes and demand." [104]

[and]

> "Since the *Statement* in May, the Reserve Bank Board has maintained its target for the overnight cash rate at 4.50 per cent. An intensification in pressures in global financial markets over recent months saw domestic yields move to price in some probability that the cash rate target could be reduced later in 2010. More recently, as global conditions have stabilised and domestic indicators have pointed to a reasonably buoyant domestic outlook, money market yields have shifted to imply a small chance that monetary policy may be tightened in the year ahead." [105]

[and]

> "The strong growth in Asia over the past year has led to large rises in the contract prices of iron ore and coal, which are Australia's two largest exports. As a result, Australia's terms of trade are back around the historically very high levels that they reached in 2008. While the spot prices for many commodities have fallen over the past few months – reflecting the concerns in Europe and signs of growth moderating in China – Australia's terms of trade seem likely to remain very high over the next couple of years." [106]

The Authority also observes that 6.0 per cent is the market risk premium value most commonly used by market practitioners. Surveys of market risk practice show that 47 per cent of market practitioners apply a MRP of 6.0 per cent, while 69 per cent apply a value of 6.0 per cent or less. Only 26 per cent of market practitioners apply values of MRP

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[103] Australian Energy Regulator, May 2009, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, p175.

[104] The Reserve Bank of Australia, (August 2010), Monetary Policy Decision, accessed at http://www.rba.gov.au/publications/smp/index.html, p29.

[105] The Reserve Bank of Australia, (August 2010), Monetary Policy Decision, accessed at http://www.rba.gov.au/publications/smp/index.html, p39.

[106] The Reserve Bank of Australia, (August 2010), Monetary Policy Decision, accessed at http://www.rba.gov.au/publications/smp/index.html, p1.

more than 6.0 per cent.[107] However, the Authority is aware that this information preceded the global financial crisis in 2008.

IPART has used a market risk premium range of 5.5 per cent to 6.5 per cent in its recent determinations, such as for metropolitan and outer metropolitan bus services in December 2009, the CityRail determination, and recent determinations on prices charged by Sydney Catchment Authority and Hunter Water. IPART argues that MRP derived from a long-term historical time series remains appropriate. IPART also considers that relying on a long-term historical time series adequately takes into account any impact on excess returns of recent market events such as the global financial crisis.

The Queensland Competition Authority has also used 6.0 per cent for MRP in the Draft determination for Queensland Rail in December 2009. QCA argued that it did not lower the MRP when the market conditions at the time led some stakeholders to seek a reduction – therefore increasing the MRP now would be inconsistent with its past practice that sets the MRP at a level to encourage investment over the medium term and not in response to short-term market fluctuations.

The Authority has considered the data on market returns for the periods detailed in Table H 2 below. The Authority has had regard to the analysis by the AER in its WACC determination. However, the Authority does not have access to the data set to the end of 2008 prepared by Associate Professor Handley, the AER's consultant on the market risk premium, on which the AER has derived its conclusions on the issue. The Authority has also had regard to its own data set with an update to the end of 2009.

Table H 2 Estimates of the Market Risk Premium Over a Range of Different Periods[108]

Value of Imputation Credits	1958 - 2009	1980 - 2009	1988 - 2009
0%	6.2	5.7	4.6
60%	6.7	6.4	5.7

Source: Economic Regulation Authority

Table H 2 shows that the range of estimates of the market risk premium over the various periods, using the Authority's data set and including an adjustment for the value of imputation credits (60 per cent), is 5.7 per cent to 6.7 per cent. This range of estimates does not provide any convincing evidence for the Authority to depart from a widely adopted value of 6 per cent per year for the MRP by many Australian regulators.

The Authority adopts the same approach it took in its Final Decisions on the Proposed Revisions to the Access Arrangement for the South West Interconnected Network in December 2009; and on Proposed Revisions to the Access Arrangement for the Goldfields Gas Pipeline in May 2010, for the same reasons as applied in those decisions. This approach is consistent with historical regulatory practice. In these two final decisions, the Authority has adopted the range of 5 per cent to 7 per cent with the view

[107] G. Truong, G. Partington and M. Peat, 'Cost of capital estimation and capital budgeting practices in Australia', *Australian Journal of Management*, Vol. 33, No. 1, June 2008, p155.

[108] The adjustments for the value of imputation credits of 60 per cent have been interpolated using the values of imputation credits at 50 per cent and 65 per cent made by the AER in its WACC review, p209. It is immaterial to make the adjustment for the value of imputation credits for one more year (from the ending year of 2008 in the AER's analysis to the ending year of 2009 as calculated using the Authority's data set).

that the point estimate of 6 per cent as the reasonable estimate for the MRP is to be adopted.

The Authority is of the view that a MRP of 6 per cent will be within the reasonable range of values. This is consistent with the view with some other Australian regulators, including IPART and QCA. The estimate of the MRP of 6 per cent also reflects the view by the AER that this is the best estimate of a forward-looking long-term MRP.

In conclusion, the Authority considers that a reasonable point estimate for the MRP is 6 per cent.

Cost of Debt

Horizon Power's Proposal

On the advice of Deloitte, Horizon Power submits that Horizon Power has historically received funds at 70 to 80 basis points above the risk free rate and that the cost of debt for Horizon Power should reflect the split between the source of its debt funding, such that it reflects a mix of government subsidised and commercially available debt.[109]

Deloitte submits the following estimates of credit spreads of A rated and BBB rated corporate bonds from both Australian financial market and the US market: [110]

- current credit spreads for A rated Australian and US corporate bonds are in the range of 160 to 205 basis points and 140 to 200 basis points respectively over the equivalent risk free rate;
- current credit spreads for BBB rated Australian and US corporate bonds are in the range of 250 to 350 basis points and 280 to 305 basis points respectively over the equivalent risk free rate;
- current credit spreads for A rated US corporate bonds of utilities are in the range of 110 to 140 basis points over the equivalent risk free rate; and
- current credit spreads for BBB rated US corporate bonds of utilities are in the range of 195 to 255 basis points over the equivalent risk free rate.

Based on the above information, Deloitte argues that debt margin of 180 to 200 basis points on the basis that Horizon Power will continue to secure subsidised debt funding.[111]

Authority's Assessment

The debt margin (also referred to as the debt premium) is a margin above the risk free rate reflecting the risk in provision of debt finance to the regulated activity.

Debt Risk Premium

Methodology

The Authority considers that the approach taken in its recent determinations on the access arrangement for the South West Interconnected Network (SWIN) in December

[109] Deloitte, "Horizon Power: Weighted Average Cost of Capital Analysis", 2 November 2009, p10.

[110] Deloitte, "Horizon Power: Weighted Average Cost of Capital Analysis", 2 November 2009, p11.

[111] Deloitte, "Horizon Power: Weighted Average Cost of Capital Analysis", 2 November 2009, p10.

2009, the Proposed Revisions to the Access Arrangement for the Goldfields Gas Pipeline in May 2010, and the recent Draft Decision on Proposed Revisions to the Access Arrangement for the Western Australian Gas Networks in August 2010, is no longer appropriate to be considered as the approach to estimate debt risk premium for this Report due to data unavailability.

Given data on fair yields for 10-year BBB/BBB+ Australian corporate bonds are not available from Bloomberg service provider, the Authority is of the view that *observed* debt risk premiums for Australian corporate bonds currently trading in the Australian financial market are appropriate to be used in estimating debt risk premiums for regulated businesses. The average of these debt risk premiums from a sample of Australian bonds will be a good proxy for regulated businesses.

The Authority is of the view that any bond included in the set of securities to derive the debt risk premium for regulated businesses should ideally satisfy three criteria. The security must:

1. have the same credit rating as the regulated businesses (BBB/BBB+ in this case because a credit rating of BBB+ is applied for DBP). However, the Authority is aware that Bloomberg has used all BBB-/BBB/BBB+, known as “BBB band”, to estimate the fair value curve for the so-called BBB fair value curve. As such, bonds with credit rating of BBB+ are also included in the sample of the bonds;
2. be in the same industry (the utility sector in this Report); and
3. have a maturity of two years and longer to ensure that there are enough numbers of bonds in the sample for the analysis. This criterion has been used by the AER and IPART.

Given that the current market for bonds in Australia is very thin at the moment, the Authority has made the following observations:

- When the credit rating of BBB-/BBB/BBB+ is targeted, 15 bonds satisfy Criterion 1 (the same credit rating) and Criterion 3 (maturity of two years and longer), but not Criterion 2 (the same industry as the regulated business);
- When the industry-based criterion is targeted, together with Criterion 3, only a few bonds are found (e.g. APT Pipelines, Snowy Hydro, and Santos).

Based on the above analyses, the Authority considers that it is appropriate to include all bonds which satisfy Criteria 1 and 3 in the set of securities. This means that criterion 2 is effectively ignored.

For transparency, the following criteria have been applied to determine the sample of Australian corporate bonds to be used to estimate the debt risk premium, using the “search” function from Bloomberg:

- Credit rating of BBB-/BBB/BBB+ by Standard & Poor’s;
- Time to maturity of 2 years or longer;
- Bonds must be issued in Australia by Australian entities and denominated in Australian dollars;
- Inclusion of both fixed bonds[112] and floating bonds[113]; and both Bullet[114] and Callable/ Putable[115] redemptions are included.

[112] This is a long term bond that pays a fixed rate of interest (a coupon rate) over its life.

The Authority notes that bonds issued by individual companies change over time, together with the credit rating of the company. As a result, the set of securities will be frequently updated as soon as the new bond is issued and satisfies the criteria set out above. In addition, it is noted that only bonds in the sample which are currently traded in the averaging period are included in the sample of bonds used to derive the debt risk premium.

The Authority considers the set of Australian corporate bonds currently traded in the Australian financial market, provided from Bloomberg data services as at 31 October 2010, which is summarised in Table H 3 below.

[113] This is a bond whose interest payment fluctuates in step with the market interest rates, or some other external measure. Price of floating rate bonds remains relatively stable because neither a capital gain nor capital loss occurs as market interest rates go up or down. Technically, the coupons are linked to the bank bill swap rate (BBSW), but this is highly correlated with the RBA's cash rate. As such, as interest rates rise, the bondholders in floaters will be compensated with a higher coupon rate.

[114] A bond that is not able to be redeemed prior to maturity. The bondholders are protected against the possibility of the bond being called when the market interest rates fall. As such, a bullet bond is usually more expensive than a callable bond because the interest rate (the yield) is lower.

[115] A callable (putable) bond includes a provision in a bond contract that give the issuer (the bondholders) the right to redeem the bonds under specified terms prior to the normal maturity date.

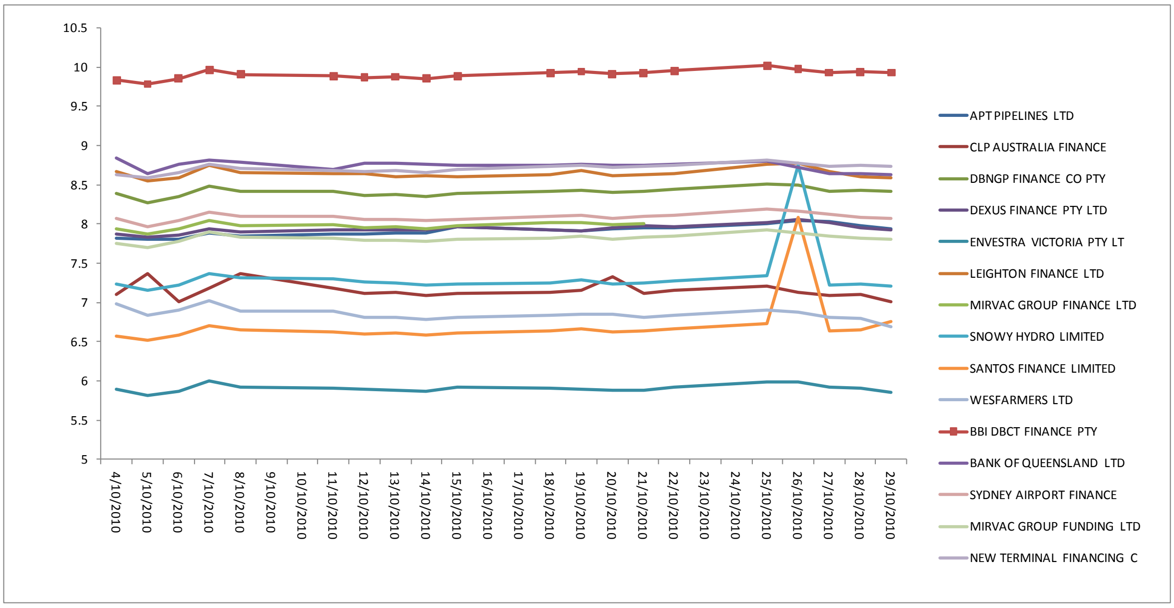
Table H 3 The list of BBB/BBB+ Australian Corporate Bonds

No.	Name of business	Bloomberg ticker	Coupon	Maturity	Main industry
1	APT PIPELINES	E1325336 Corp	7.75	22/07/2020	Electric transmission
2	BBI DBCT FINANCE PTY	EF461870 Corp	6.25	9/06/2016	Diversified Financial Services
3	BANK OF QUEENSLAND LTD	EH390789 Corp	10.75	4/06/2018	Commercial Banks Non-US
4	CLP AUSTRALIA	EF167960 Corp	6.25	16/11/2012	Finance commercial
5	DBNGP FINANCE CO PTY	EI414656 Corp	8.25	29/09/2015	Gas transportation
6	DEXUS FINANCE	EI223256 Corp	8.75	21/04/2017	Mortgage
7	ENVESTRA VICTORIA PTY LT	EC866427 Corp	6.25	14/10/2015	Gas distribution
8	LEIGHTON FINANCE	EH911249 Corp	9.5	28/07/2014	Diversified financial service
9	SYDNEY AIRPORT FINANCE	EI308853 Corp	8	6/07/2015	Finance-Other Services
10	MIRVAC GROUP FUNDING LTD	EI195249 Corp	8.25	15/03/2015	Real Estate Oper/Development
11	MIRVAC GROUP FINANCE LTD	EI414696 Corp	8	16/09/2016	Real Estate Oper/Development
12	NEW TERMINAL FIN	EF641357 Corp	6.25	20/09/2016	Special Purpose entity
13	SNOWY HYDRO LTD	EC870795 Corp	6.5	25/02/2013	Energy - alternate sources
14	SANTOS FINANCE	EF102609 Corp	6.25	23/09/2015	Oil Comp-Exploration & Production
15	WESFARMERS LTD	EH964875 Corp	8.25	11/09/2014	Retail-Misc/Diversified

Source: Bloomberg

The yields for the 20 trading days period, from 4th October to 29th October 2010, for the above 15 bonds are as below.

Table H 4 Yields for BBB-/BBB/BBB+ Australian Corporate Bonds, Oct 2010



The Authority is of the view that a simple average (or equally weighted average) should be used for simplicity. This practice is also used by IPART in its decision to estimate the debt risk premium using a sample of Australian bonds. However, since bonds in the sample exhibit different characteristics, such as different industries and different days until maturity, the Authority considers that it may be appropriate to give different weights to different bonds, to reflect the different relative importance of each bond in the sample. This is known as the weighted average approach.[116] The weighting approaches currently being investigated are:

- A “number-of-years-until-maturity” approach; and
- An “amount-issued” approach.

The Authority notes the average of yields for the 20-trading days to 31 October 2010 from the sample of 15 bonds above can be calculated as:

- A simple average (or equally weighted average);
- A years-until-maturity weighted average;
- An amount-issued weighted average; and
- A median approach.

116 The weighted average of yields (WAY) is defined as:

$$\text{WAY} = \frac{1}{n}\sum_{i=1}^{n} w_i \overline{Y}_i;$$

where:

n is the number of bonds in the sample;

w_i is the weight assigned to bond i in the sample; and

$\overline{Y}_i$ is the average of the fair yields for bond i in the averaging period.

Table H 5 The debt risk premium for the 20-trading days average to 31 October 2010 (Per cent)

A simple average	A years-until-maturity weighted average	An amount-issued weighted average	Median approach
2.775	2.885	2.768	2.837

Source: The Authority's calculations

The average term to maturity of the above sample of 15 bonds is 5.126 years. For the 20-trading days period to 31 October 2010, the average of the debt risk premium for the above sample of 15 bonds, is 3.305 per cent.

For the purpose of this Draft Report, the Authority has adopted the estimate of 3.305 per cent as the debt risk premium for a BBB+ rated company for the 20-trading day period to 31 October 2010. This decision reflects a conservative position taken by the Authority on the following three grounds:

- First, this debt risk premium of 3.305 per cent is higher than any approach using a sample of 15 bonds observed from the market at the time when this Draft Report is made;
- Second, a sample of 15 bonds observed from the market includes bonds with the feature of "Callable" redemption which, in principle, requires a higher yield to compensate the holders of the bonds. This conclusion is evident from the above sample of bonds with some callable bonds, such as bonds issued by Bank of Queensland Ltd and BBI DBCT Finance Pty. It is also noted that there is no bond with the feature of "Putable" redemption the sample.
- Third, a sample of the Australian corporate bonds includes BBB and BBB- bonds which, in principle, have higher yields in comparison with BBB+ credit rating bonds for regulated business.

The Authority acknowledges that the debt risk premium will have to be updated for the purpose of the Final Report to reflect the most up-to-date estimates available.

An allowance for debt raising costs

The Authority considers that an inclusion of 12.5 basis points as an increment to the debt margin is generally acknowledged as a conservative allowance for all related costs of debt issuance.

In conclusion, the Authority considers that an appropriate credit rating for Horizon Power is BBB+. This is consistent with the Authority's recent Final Decision on the proposed access arrangement for the Goldfields Gas Pipeline in May 2010 and also in the Draft Decision on Proposed Revision to the Access Arrangement for the Western Australian Gas Networks in August 2010.

The Authority considers that a reasonable cost of debt is 8.53 per cent, including the debt risk premium of 3.305 percent for BBB+ at 31 October 2010 derived using observed yields for a sample of Australian corporate bonds from Bloomberg; an allowance for debt raising costs of 0.125 per cent; and the nominal risk free rate of 5.10 per cent.

Gearing

Horizon Power's Proposal

Deloitte considers that the gearing level of 60 per cent is the efficient level of gearing for Horizon Power. [117]

Authority's Assessment

Gearing refers to the proportions of the value of the regulated business assumed to be financed by debt and equity. Financial gearing refers to the ratio of debt to total asset value. The relative proportions of debt and equity that a firm has outstanding constitute its capital structure. The capital structure choices differ across industries, as well as for different companies within the same industry.

The benchmark gearing ratio is considered to be the capital structure of a benchmark efficient utility business. The Authority assumes that the regulated business tends towards the benchmark gearing level in long-run. As the optimal level of gearing is not directly observable, the 60/40 gearing level is derived from the average of actual gearing levels from a group of comparable firms.[118] The actual proportion of debt and equity for each business is dynamic and depends on a number of business-specific factors.

The Authority agrees that Horizon Power's proposed the gearing level of 60 per cent is consistent with the approach taken in relation to the current Access Arrangement and the approach taken in the AER electricity WACC Review, as well as being otherwise consistent with regulatory precedent and with observed levels of gearing of Australian pipeline companies.

The Authority approves Horizon's proposal that the appropriate debt to total assets ratio (gearing level) is 60 per cent and the equity to total assets ratio is 40 per cent.

Corporate Tax Rate

Horizon Power's Proposal

Horizon Power proposes to adopt the current corporate tax rate of 30 per cent to calculate a pre-tax WACC.[119]

Authority's Assessment

There has been some debate amongst regulators as to whether WACC determinations should use the statutory corporate tax rate (30 per cent), or effective tax rates.[120] Many companies have effective tax rates that are well below the statutory rate and there is a risk that using the statutory tax rate will overestimate the returns required by companies to meet tax obligations. However, verifying an individual company's effective tax rate would require modelling of taxation cash flows. The benefit of using the statutory rate as a benchmark assumption is that it is simple to apply.

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117 Deloitte, "Horizon Power: Weighted Average Cost of Capital Analysis", 2 November 2009, p11.

118 Australian Energy Regulator, May 2009, Final Decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters

119 Deloitte, "Horizon Power: Weighted Average Cost of Capital Analysis", 2 November 2009, p11.

120 IPART, 2002, The weighted average cost of capital (WACC): Discussion paper

The Authority has in previous WACC determinations assumed the effective taxation rate of the utility businesses to be equal to the statutory rate of corporate income tax.

The Authority agrees with Horizon Power's proposal with respect to the corporate tax rate of 30 per cent.

Value of Imputation Credits (Gamma)

Horizon Power's Proposal

Deloitte is of the view that the WACC for Horizon Power should not be adjusted for the impact of imputation credits because Horizon Power is a government owned entity.[121] As such, tax benefits attached to frank dividends cannot be realised by the government.

Authority's Assessment

A full imputation tax system for companies has been adopted in Australia since 1 July 1987. While Australia and New Zealand have full imputation tax systems (which are discussed below), many other countries have a partial imputation system, where only partial credit is given for the company tax.

Under the tax system of dividend imputation, a franking credit is received by Australian resident shareholders, when determining their personal income taxation liabilities, for corporate taxation paid at the company level. In a dividend imputation tax system, the proportion of company tax that can be fully rebated (credited) against personal tax liabilities is best viewed as personal income tax collected at the company level. With the full imputation tax system in Australia, the company tax (corporate income tax) is effectively eliminated if all the franking values are used as credits against personal income tax liabilities.

It is widely accepted that the approach adopted by regulators across Australia to define the value of imputation credits, known as "gamma" (γ), is in accordance with the Monkhouse definition.[122] There are two components of gamma:

- the payout ratio (F); and
- theta (θ).

As a result, the actual value of franking credits, represented in the WACC by the parameter 'gamma', depends on the proportion of (i) the franking credits that are created by the firm and that are distributed (the payout ratio, F); and (ii) the value that the investor attaches to the credit (theta), which depends on the investor's tax circumstances (that is, their marginal tax rate). As these will differ across investors, the value of franking credits may be between nil and full value (i.e. a gamma value between zero and one). A low value of gamma implies that shareholders do not obtain much relief from corporate taxation through imputation credits and therefore require a higher pre-tax income in order to justify investment.

In considering the value of imputation credits, the Authority has had regard to the detailed consideration given by the AER to this element of the WACC calculation.[123]

121 Deloitte, "Horizon Power: Weighted Average Cost of Capital Analysis", 2 November 2009, p10.

122 Monkhouse, P. 'Adapting the APV Valuation Methodology and the Beta Gearing Formula to the Dividend Imputation Tax System', *Accounting and Finance*, 37, vol. 1, 1997, pp. 69-88.

Payout Ratio (F)

The AER has previously adopted a distribution rate (F) of 1.0, reflecting advice that this assumption is consistent with a standard assumption of valuation practice that all free cash flows are paid out to investors.[124] On this basis, the AER has rejected the use of empirically observed market average distribution ratios. Advice to the AER also indicates that an assumed distribution rate of 1.0 is consistent with the Officer WACC.[125]

In addition, the AER noted that the Officer WACC framework is a perpetuity framework, which includes a simplifying assumption that cash flows occur in perpetuity and are therefore fully distributed at the end of each period. The AER accepted the advice of its consultant, Associate Professor Handley, and noted that it would be inconsistent to assume that there is a full distribution of a service provider's free cash flow but not a full distribution of the imputation credits associated with that free cash flow.

The AER considers that the assumption of a zero value for retained imputation credits is inconsistent with the Officer WACC framework.

The AER is also of the view that the actual payout ratio is unlikely to be significantly less than 100 per cent, based on an observed payout ratio from tax statistics of 71 per cent and the assumption that retained imputation credits have a positive value.[126]

In its recent Final Decision in October 2010 on Victorian electricity distribution network service providers, the AER adopted the range of 0.7 and 1.0 for the payout ratio.[127]

Based on the above analyses, the Authority considers that the payout ratio of 0.7 and 1.0 is appropriate.

Estimates of theta (θ)

The AER has considered two sources of information on the utilisation rate.

First, the AER has placed significant weight on an estimate of the utilisation rate (θ) of 0.57, derived in a dividend drop-off study over the period 2001 to 2004,[128] taking into account that this study:

- is directly relevant to the current imputation tax regime, assessing the value of imputation credits over the post-2000 period after changes in tax law that

[123] Australian Energy Regulator, December 2008, *Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters*, pp. 287 – 340. Australian Energy Regulator, May 2009, *Final decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters*, pp. 393 – 469.

[124] Australian Energy Regulator, December 2008, *Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters*, p302.

[125] Australian Energy Regulator, December 2008, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, Attachment G: John C Handley, 12 November 2008, A note on the valuation of imputation credits.

[126] The Australian Energy Regulator, May 2010, Final Decision, South Australia Distribution Determination, 2010-11 to 2014-15, p150.

[127] Australian Energy Regulator, October 2010, Victorian electricity distribution network service providers: Distribution determination 2011 – 2015, p583.

[128] Australian Energy Regulator, December 2008, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, p327, citing Beggs, D. and Skeels C.L., 2006, Market arbitrage of cash dividends and franking credits, *The Economic Record* vol 82 no.258, p247. AER, May 2009, Final decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, pp. xix, 466.

allowed Australian taxpayers to claim a full cash rebate for unused imputation credits;

- is able to be verified on the basis of statistical tests presented in the paper; and
- is an independent and credible published study that has been through the academic peer review process.

Second, the AER has had regard to estimates of the utilisation rate from taxation statistics, indicating a range of values of the utilisation rate, θ, from 0.67 (pre-2000) to 0.81 (post-2000) and a point estimate of 0.74.[129]

In addition, in its Final Decision on the South Australia Distribution Determination, the AER considers that the utilisation rate of 0.65, based on an estimate from tax statistics as well as an estimate from market prices, is better than a market-based estimate alone.[130]

The mid-point estimate of theta θ is 0.65, together with the payout ratio F of 1.0. This provides an estimate of 0.65 for gamma in all determinations after the 2009 WACC Review by the AER. In its most recent Final Decision on Victorian Electricity, the AER adopted the payout ratio of the range of 0.70 and 1.0. As such, the AER adopted the gamma of 0.50 for its Final Decision on Victorian Electricity.

The Authority has determined a value of theta on the basis of the two empirical studies: (i) the 2006 Beggs and Skeels study; and (ii) the 2008 Handley and Maheswaran study. A range of 0.37 to 0.81 was used in its Final Decision on the Proposed Revision to the Access Arrangement for the South West Interconnected Network in December 2009; and on the Proposed Revisions to the Access Arrangement for the Goldfields Gas Pipeline in May 2010.

However, a more recent study by SFG Consulting in 2009, compared with the 2006 Beggs and Skeels, produced an estimated lower utilisation rate of 0.37.[131] This study used the same data as Beggs and Skeels in 2006 (which analysed data up to 10 May 2004) but analysed a further period of 28 months of data (up to 30 September 2006). This estimate was verified by one of the authors, C. Skeels, in the 2006 study by Beggs and Skeels. Skeels concluded that:

> "the only reasonable conclusion to be drawn is that the extended data set should yield more accurate parameter estimates for the 1 July 2000 onwards sub-sample than does the shorter data set." [132]

The Authority notes that the AER's view is that the 2009 SFG study is subject to methodological concerns. In its recent Final Decision for South Australia Distribution Determination in May 2010, after taking account of the advice of its consultants, Professor Michael McKenzie, Associate Professors Graham Partington (University of Sydney) and

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129 Australian Energy Regulator, December 2008, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, p 333, citing Handley, J. C. and Maheswaran, K., A measure of the efficacy of the Australian Imputation Tax System, *The Economic Record* vol. 84 no. 264 p.91. Australian Energy Regulator, May 2009, Final decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, pp. xix, xx, 466, 467.

130 The Australian Energy Regulator, May 2010, Final Decision, South Australia Distribution Determination, 2010-11 to 2014-15, p.xxiv.

131 SFG Consulting, 2009, The value of imputation credits as implied by the methodology of Beggs and Skeels (2006), p3.

132 Skeels, C. 2009, A Review of the SFG Dividend Drop-Off Study. A report prepared for Gilbert and Tobin, p11.

Associate Professor John Handley (University of Melbourne), the AER considers that market-based estimates of theta in the form of dividend drop-off studies are subject to significant concerns due to noise in the data and the likely effects of multi-collinearity on the regression results. Nevertheless, the Authority notes that the AER does make use of information from previous dividend drop-off studies in coming to its position on a reasonable value for the utilisation rate.

Given the uncertainty about the estimates of the utilisation rate using dividend drop-off studies and tax studies, the Authority's position is to take a wide range of estimates of the utilisation rate. Overall, the Authority considers that a reasonable range for the value of utilisation rate is 0.37 to 0.81.

As a result, based on a payout ratio of a range of 0.7 and 1.0; and a theta of 0.37 and 0.81, the Authority concluded that a reasonable value of gamma, being the product of a payout ratio and theta, for this Draft Report is 0.535.

The Authority does not agree with Deloitte's proposal that the cost of capital for Horizon Power will not be adjusted for the impact of imputation credits due to the nature of regulatory regime in which a benchmark company, not a specific entity, is regulated. As such, the Authority considers that a reasonable point estimate for gamma of 0.535 should also be incorporated into the estimate of its cost of capital.

Expected Inflation

Horizon Power's Proposal

No proposal on expected inflation can be found on the Deloitte's advice on WACC to Horizon Power.

Authority's Assessment

The Authority's approach to estimate the expected inflation is to use the geometric mean of the Reserve Bank of Australia's inflation forecasts for the next ten years. The inflation forecasts for the next two years are in the RBA's Monetary Statement which are published quarterly and the forecasts for the last eight years being the midpoint of the RBA's inflation target of 2 per cent to 3 per cent, being the midpoint of 2.5 per cent.

In the Authority's recent Final Decisions on the Proposed Access Arrangement for the Goldfields Gas Pipeline in May 2010 and on its Proposed Revisions to the Access Arrangement for the South West Interconnected Network in December 2009, the same general approach was adopted.

The Authority proposes to adopt the same approach for this Report. The forecasts on which the Authority relies for its calculations are all from the RBA's August 2010 *Statement on Monetary Policy:*[133]

- 3.25 per cent for the year to June 2011;
- 3.00 per cent for the year to June 2012; and
- 2.50 per cent (being a mid-point estimate of the RBA's long term inflation forecasts) for each year from July 2013.

[133] Reserve Bank of Australia, August 2010, *Statement on Monetary Policy*, available at http://www.rba.gov.au/publications/smp/2010/aug/pdf/0810.pdf p56.

Using the above forecasts, the Authority has calculated the forecast inflation rate for this draft report of 2.62 per cent.

Specific company risk premium (α)

Horizon Power's Proposal

Deloitte submits that the cost of equity for Horizon Power needs to be adjusted for company specific risk factors such as company size; depth and quality of management; reliance on key customers and suppliers; product diversity; and capital structure among many others.

Deloitte argues that empirical studies do show that on average, smaller companies have higher rates of return than larger companies, which is referred to as the size premium.[134] Using the returns for different size categories from 1926 to 2007 for companies on the New York Stock Exchange (NYSE), the American Stock Exchange (AMEX) and the National Association of Securities Dealers Automated Quotation System (NASDAQ), Deloitte argues that a specific risk premium of 1.0 per cent to 1.5 per cent is appropriate for Horizon Power.

Authority's Assessment

The Authority does not accept it as reasonable to provide for non-systematic risks within the CAPM. This is because, under the CAPM, risks associated with returns to a particular asset could be eliminated through the holding of a well diversified portfolio of assets, and hence there is no reason to compensate for these risks. The Authority notes that appropriate parameters to the WACC calculation will be selected to give the service provider the opportunity to earn a return commensurate with the commercial risk involved.

As such, the Authority does not agree that the standard CAPM, which is used to estimate the cost of equity for Horizon Power, should be extended to take into account specific risk premium for Horizon Power. The Authority is of the view that the standard CAPM was developed on the view that only systematic risks, which cannot be diversified, are compensated. As such, the Authority considers that any modification to the standard CAPM's formula is inappropriate.

Cost of Equity

Horizon Power's Proposal

On the advice from Deloitte, Horizon Power submits that standard CAPM is used to estimate the cost of equity.

Deloitte is of the view that the betas of listed companies, from both Australia and the US, that are comparable to Horizon Power are appropriate to be used in estimating beta for Horizon Power. Deloitte submits that the betas, from these selected comparable companies to Horizon Power, have been calculated based on weekly returns over a two year period and monthly returns over a four year period, compared to the relevant local accumulation index.

[134] Deloitte, "Horizon Power: Weighted Average Cost of Capital Analysis", 2 November 2009, p9.

The main findings from Deloitte's study can be summarised as follows:

- the average unlevered beta for the Australian comparables in the distribution and transmission sector is 0.19 over two years on a weekly basis and 0.25 over four years on a monthly basis, compared with the average for the international comparables of 0.41 and 0.24 respectively;
- Horizon Power is involved in the distribution and transmission of electricity; however a number of the comparable companies such as APA Group, DUET Group, Envestra, AGL Resources, Enbridge, Plains All American and TransCanada are involved in the distribution and transmission of natural gas. The average unlevered beta for these companies over two years on a weekly basis and four years on a monthly basis is 0.33 and 0.28 respectively;
- the distribution and transmission comparable companies which have electricity, as well as natural gas operations, include SP Ausnet, Spark Infrastructure, Consolidated Edison, National Grid and Northeast Utilities. The average unlevered beta for these companies over two years on a weekly basis and over four years on a monthly basis is 0.29 and 0.20 respectively; and
- the average unlevered beta for the Australian comparables in the diversified energy sector is 0.61 over two years on a weekly basis and 0.49 over four years on a monthly basis, compared with the average for the international comparables of 0.45 and 0.51 respectively

In July 2010, Horizon Power commissioned another consultant, Economic Insights, to advise it on the WACC issues in responses to the Authority's issue paper. Economic Insights argues that with reference to the size of HP, there is considerable empirical evidence that supports the use of a higher value of Beta for small firms. Using a work by Booth and Smith (1985),[135] Economic Insights submits that the implied size premium could range from 0.15 to 0.24.[136]

Using the above implied size premium, Economic Insights is of the view that an equity beta of between $0.8+0.15=0.95$; and $0.8+0.24=1.04$; could be an appropriate way to accommodate the extra risk associated with the small size of Horizon Power.

Authority's Assessment

The Authority is of the view that using the US and other countries data in estimating the equity beta for Horizon Power is not appropriate. In addition, if the equity beta to be estimated using data from the US and other countries capital markets, all other WACC parameters such as nominal risk free rate, MRP, and inflation would also need to be derived using these data sources for consistency. This is contrary to current practices applied by Australian regulators. As such, the Authority is of the view that only Australian data should be used to estimate the equity beta.

[135] Booth, J.R. and R.L. Smith (1985), "The Application of Errors-in-Variables Methodology to Capital Market Research: Evidence on the Small-Firm Effect", *Journal of Financial and Quantitative Analysis*, 20, 501-515.

[136] Economic Insights, "WACC Advice to Horizon Power", 20 July 2010, p7.

The Authority considers that only the group of Australian companies, including APA Group; DUET Group; Envestra; SP Ausnet; and Spark Infrastructure, can be considered comparable to Horizon Power. From Deloitte's estimate, the average of unlevered beta using weekly and monthly data, for the period of June 2007 to September 2009, is 0.19 to 0.25. With the corporate tax rate of 30 per cent and debt to equity ratio of 60:40, a levered beta for these estimates will be in the range of 0.4 to 0.5 which can be used the equity beta for Horizon Power.

The Authority also rejects the estimates provided by Economic Insight. The Authority considers that only one academic paper does not constitute a significant body of evidence given this study used the US data and was conducted 25 years ago. As such, its relevance to the current context of Australia is very limited. In addition, the Authority is of the view that evidence and/or data used should be for Australia.

In addition, recent estimate of equity beta reveals that equity beta of 0.4 to 0.7 is considered appropriate. In the 2009 review of WACC parameters, the AER concluded that a beta value of 0.8 is appropriate for both transmission and distribution businesses in the National Electricity Market.[137]

The Authority adopted the range of equity beta of 0.8 and 1.0 in its Final Decision on the proposed access arrangement for Goldfields Gas Pipeline in May 2010 and a point estimate of equity beta of 0.8 in its most recent Draft Decision on the proposed access arrangement for Western Australia Gas Networks.

For the government-owned entities, a range of equity beta of 0.5 to 0.8 was adopted in the Authority's Final Decision on the Proposed Revisions to the Access Arrangement for the South West Interconnected Network in December 2009. In addition, the Authority adopted an equity beta of 0.65 for Water Corporate and Water Boards in its Final Report on the Inquiry into Tariffs of the Water Corporation, Aqwest and Busselton Water in June 2009.

Therefore, the Authority considers that a reasonable point estimate for equity beta is 0.7, at a gearing level of 60 per cent debt to total assets, to be adopted for Horizon Power.

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Therefore, the Authority considers that a reasonable point estimate for equity beta is 0.7, at a gearing level of 60 per cent debt to total assets, to be adopted for Horizon Power.

[137] Australian Energy Regulator, May 2009. Electricity transmission and distribution network service providers, Statement of the revised WACC parameters (transmission), Statement of the revised WACC parameters (transmission), Statement of regulatory intent on the revised WACC parameters (distribution), p6.

Appendix I: Glossary

Act	Economic Regulation Authority Act 2003
AER	Australian Economic Regulator (for the Eastern States)
AMP	Asset Management Plan
Authority	Economic Regulation Authority (Western Australia)
BCI	Building Construction Index
Biomass	Renewable organic materials, such as wood, agricultural crops or wastes, and municipal wastes, especially when used as a source of fuel or energy. Biomass can be burned directly or processed into biofuels such as ethanol and methane.
CNG	Compressed Natural Gas
Cost Reflective Tariffs	Tariffs applying to a certain class of customers that generate revenue that exactly covers the cost of supplying electricity to that class of customers.
CPI	Consumer Price Index
CPRS	Carbon Pollution Reduction Scheme
CSO	Community Services Obligation
DAMPs	Horizon Power's District Asset Management Plans
Distribution	Distribution generally relates to the electricity network that extends from the zone sub-station to the customer's premises.
DORC	Depreciated Optimised Replacement Cost
DTF	Department of Treasury and Finance
DWAT	Discounted Weighted Average Tariff
ENRUP	Esperance Network Rural Upgrade Project
ERA	Economic Regulation Authority (Western Australia)
Gifted Assets	Those assets owned by the service provider but which were funded through an external source, such as developer contribution or government funding.
GSL	Guaranteed Service Level – generally these are accompanied by a penalty payment, payable to customers, who have experienced performance from an electricity supplier, below a given level.
GST	Goods and Services Tax
GTE	Government Trading Enterprise
GW	Gigawatt, 1 billion watts or 1000 megawatts
GWh	Gigawatt hour
IPART	Independent Pricing and Regulatory Tribunal (in New South Wales)
kW	Kilowatts, 1000 watts
kWh	Kilowatt hour
LNG	Liquid Natural Gas
LRMC	Long Run Marginal Cost - the change in the long-run total cost of producing a good or service resulting from a change in the quantity of output produced. There are no fixed inputs in the long run. As such, there is only variable cost. This means that long-run marginal cost is the result of

	changes in the cost of all inputs.
MRET	Mandatory Renewable Energy Target
MW	Megawatts, 1 million watts or 1000 kilowatts
MWh	Megawatt hour
Network charges	The fees charged by a network operator and paid by generators and retailers for use of the network operator's network to transport electricity.
NWIS	North West Interconnected System – the system of generation, network and distribution centring around Karratha and Port Hedland in the far north west of Western Australia.
ODV	Optimised Deprival Value
OoE	Office of Energy
PPAs	Power Purchase Agreements – between Horizon Power and independent generators of electricity.
PB	Parsons Brinckerhoff Australia Pty Ltd
Pre-payment meters	Electricity meters that allow customers to purchase credit and load this credit onto the pre-payment meter. The prepayment meter then allows the customer to consume electricity up to the value of the amount of the credit. Once the amount of the credit is exhausted, the pre-payment meter discontinues the supply of electricity.
RBA	Reserve Bank of Australia
REC	Renewable Energy Certificate
Renewable energy	Energy that is generated from renewable sources such as wind, solar or water (hydro).
Revenue requirement	A level of revenue, to be collected from regulated tariffs, that covers the efficient costs of providing a utility service to a required performance standard.
SAIDI	System Average Interruption Duration Index – the total of all customer interruptions in minutes divided by the total number of customer connections averaged over the year.
SAIFI	System Average Interruption Frequency Index – the total number of interruptions divided by the total number of customer connections averaged over the year.
SWIS	South West Interconnected System – the system of generation, networks and distribution supplying the area between Kalbarri in the north and Albany in the south and stretching out to Kalgoorlie in the east.
Synergy	The state-owned Electricity Retail Corporation, operating in the SWIS.
Transmission	Transmission generally relates to the electricity network from the generating power station to zone sub-stations, which are located at key points around the supply area.
TEC	Tariff Equalisation Contribution − paid by Western Power's customers through their network charges, to Horizon Power to fund the shortfall between the uniform tariff revenue and the cost of supplying electricity to customers.
Uniform Tariff	A state government policy which ensures all small use customers pay the same tariffs regardless of where they live in Western Australia.
Verve	Verve Energy − the state-owned Electricity Generation Corporation, operating in the SWIS.
WACC	Weighted Average Cost of Capital - is the minimum return that a company

	must earn on existing asset base to satisfy its creditors, owners, and other providers of capital, or they will invest elsewhere. It is generally calculated as the proportion of debt and equity funding used by the company compared to market risk free rates.
Watt	the SI (International System of Units) unit of power, equivalent to one joule per second and equal to the power in a circuit in which a current of one ampere flows across a potential difference of one volt.
WEM	Wholesale Electricity Market – for the trading of electricity between generators and retailers in the SWIS.
Western Power	The state-owned Electricity Networks Corporation, operating in the SWIS.