Amended Access Arrangement Information

Western Power's amended proposed Access Arrangement for the Network of the South West Interconnected System

Submitted by Western Power
2 April 2007

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Executive summary

Purpose and scope of this document

In accordance with the Electricity Networks Access Code 2004 ("the Code"), Western Power must propose an access arrangement which describes the terms and conditions on which users (typically retailers and generators) can obtain access to Western Power's South West Interconnected Network. The Economic Regulation Authority ("the Authority") is the regulator responsible for ensuring that Western Power's proposed access arrangement complies with the Code.

The development of the Code and independent economic regulation is the latest step in the reform of the electricity industry in Western Australia that commenced 10 years ago. The objective of industry reform is clear – it is to provide Western Australians with safe and reliable electricity at competitive prices – and is strongly supported by Western Power. Western Power's proposed access arrangement builds on the existing open access arrangements, which have provided transmission and distribution network access services since 1997.

To explain and substantiate Western Power's proposed access arrangement, the company must also submit to the Authority a document called the "access arrangement information". In August 2005, Western Power submitted its access arrangement documents for approval by the Authority. The Authority published its Draft Decision in March 2006 (Draft Decision) in relation to Western Power's proposed access arrangement for the South West Interconnected Network. The Draft Decision was not to approve Western Power's proposed access arrangement. The Draft Decision explained the Authority's reasoning for each of 193 Required Amendments to the access arrangement or the access arrangement information.

In May 2006, Western Power submitted a revised proposed access arrangement, together with a revised access arrangement information in response to the Draft Decision. Western Power also submitted a comprehensive response[1] to each Required Amendment.

In March 2007, the Authority published its Final Decision, in which the Authority determined that it would not approve Western Power's revised proposed access arrangement. The Final Decision sets out the Authority's reasoning for 26 Required Amendments that must be adequately addressed in the amended proposed access arrangement before the Authority will approve it.

This document is Western Power's amended access arrangement information, which explains and justifies the company's amended proposed access arrangement[2]. In accordance with the Code, the access arrangement information enables users and applicants to:

(a) understand how Western Power derived the elements of the proposed access arrangement; and

1 Western Power's response to the Required Amendments, dated 19 May 2006.

2 In accordance with section 4.20 of the Code, references to "access arrangement", "proposed access arrangement" and "access arrangement information" when used throughout this document should be read as referring to "amended proposed access arrangement" and "amended access arrangement information" respectively, which are submitted in response to the Final Decision published by the Authority on 2 March 2007.

(b) form an opinion as to whether the proposed access arrangement complies with the Code.

This document also contains references to the Draft Decision, and Western Power's responses to the Required Amendments contained therein, where Western Power believes that this information will assist users and applicants in understanding the derivation of the proposed access arrangement.

In addition to this access arrangement information and the proposed access arrangement submitted with it, Western Power also submits a comprehensive response[3] to the 26 Required Amendments contained in the Final Decision. Western Power believes that this further document will assist the Authority in its assessment of the proposed access arrangement.

As noted in previous submissions, in developing the access arrangement and the access arrangement information, Western Power has sought to meet the requirements of all the relevant provisions of the Code. In guiding the development of its access arrangement Western Power has had particular regard to the Code objectives, as defined in section 2.1 of the Code, as follows:

> "The objective of this Code is to promote the economically efficient:
>
> (a) investment in; and
>
> (b) operation of and use of,
>
> *networks* and *services* of *networks* in Western Australia in order to promote competition in markets upstream and downstream of the *network*s."

The access arrangement is effective from 1 July 2006 or a later date as specified by the Authority in accordance with section 4.26 of the Code.

Western Power's network business and recent performance

As part of the State Government's program to reform how energy is produced, distributed and sold in the electricity sector in Western Australia, Western Power Corporation was separated into four new stand-alone energy businesses in April 2006:

- Synergy: The specialist energy retailer that is the point of contact for customers' day-to-day energy needs. Synergy is the name that appears on energy bills.

- Horizon Power: Customers with premises supplied with power from the North West Interconnected System and regional non-interconnected systems are now Horizon Power customers.

- Verve energy: The new competitive generation business that produces electricity reliably at its power stations using a variety of fuel sources.

- Western Power: The 'new' Western Power manages the 'poles and wires' network that transports electricity from power generators to customers.

3 Western Power's Response to the Required Amendments in the Authority's Final Decision, dated 2 April 2007.

These four specialist businesses can now focus solely on the standard and efficiency of their delivered services. The changes to the State's electricity industry are part of the Government's reform program aimed at improved accountability, greater network investment, greater focus on core activities and improved service and reliability standards. It also demonstrates further that the networks business is fair and impartial about the use of its network by retailers and generators. This is important in Western Australia's new electricity market.

Western Power operates a large and expansive electricity network servicing the majority of the Western Australian population. A geographical map of the South West Interconnected System (SWIS), of which the SWIN is the network element, has been included in section 2 of this Part A of this document. The SWIS network contains:

- over 140 transmission substations;
- 6,750 kilometres of transmission lines and cables; and
- 83,000 kilometres of overhead and underground distribution networks.

It covers vast areas in the South West of Western Australia and the Eastern Goldfields which are heavily dominated by remote mining loads. The physical environment in which Western Power operates presents additional challenges, for example:

- the identification and rectification of faults may involve significant travel time; and
- coastal exposure, an arid interior and prevailing on-shore winds contribute to salt and dust pollution.

Unlike networks in the Eastern states, Western Power is virtually unable to call on additional resources from its neighbours, or to share a large pool of independent contractors. The relative isolation of the SWIS from other networks also contributes to a relatively challenging operating environment.

Together, all of these factors suggest that Western Power's recent cost performance should compare unfavourably with other network businesses across Australia. Contrary to this expectation, however, recent studies undertaken by Meyrick & Associates and Benchmark Economics have identified Western Power as a better-than-average cost performer.

In fact, Western Power's view is that the current level of expenditure is not sustainable, and will need to increase in the forthcoming access arrangement period. Further details of the reasons for the increase are provided below.

Future service levels and compliance obligations

In broad terms, Western Power's key cost drivers are:

- the **standards** or **quality** of services and other outputs which Western Power plans to deliver over the forthcoming access arrangement period; and
- the **quantity** of the services to be delivered over the period.

Accordingly, the expenditure forecasts must reflect:

- the planned transmission and distribution service standards, including compliance with mandatory health, safety and environmental standards; technical standards; and service performance targets; and

- the forecast demand on the transmission and distribution networks, and the forecast of new generation developments.

Western Power has examined each of these cost drivers in detail in developing its capital and operating expenditure forecasts for the transmission and distribution elements that comprise the network business.

In terms of importance, expenditure required to satisfy the company's compliance obligations is mandatory and cannot be avoided or deferred. It is noted that the sources of these obligations include:

- the Electricity Industry (Network Quality and Reliability of Supply) Code 2005, which sets targets for outage duration and frequency;

- the Technical Rules, which deal with all the matters listed in Appendix 6 of the Access Code, including the standards, procedures and planning criteria governing the construction and operation of an electricity network, and the standards for the connection of new users;

- Environmental Protection (Noise) Regulations; and

- Electricity Regulations 1947.

The cost of meeting these obligations is substantial and is also forecast to increase over the forthcoming access arrangement period and beyond.

In addition, in accordance with the Code, Western Power proposes to adopt service standard benchmarks for the transmission and distribution networks. As noted in further detail below, Western Power will be accountable for delivering service standards in accordance with these benchmarks. Meeting these service standard benchmarks will also affect Western Power's future capital and operating expenditure but to a lesser extent than the compliance obligations noted above.

In relation to service standard benchmarks for the distribution network, Western Power has had regard to the current level of SAIDI performance; the recent trend of deterioration in performance; and the competing demands on resources which are expected to be present over the forthcoming access arrangement period. Taking all of these matters into consideration, Western Power has adopted a target of achieving a 25% improvement in SAIDI (compared to actual performance for the year ended in June 2004) over the forthcoming access arrangement period. Following the Authority's Draft Decision and Final Decision Western Power is also proposing:

- corresponding network performance benchmarks in relation to SAIFI;

- separate network performance benchmarks for feeder categories of Rural Short and Rural Long, in lieu of the previous single Rural feeder category.

It should be noted that all feeder classification definitions are now identical to those adopted by the Steering Committee on National Regulatory Reporting Requirements (SCNRRR). As a result, Western Power has made consequential changes to the urban performance benchmarks in the access arrangement. Collectively, the revised service standard benchmarks are statistically equivalent to those in the revised proposed access arrangement and equate to the same overall service standard benchmark for the SWIN.

The company also proposes a service standard adjustment mechanism, under which the company will be required to deliver services in accordance with the service standard benchmarks. In particular, the company will be required to submit an annual report to the Authority where its performance does not fall within a pre-defined range of *normal performance*, for each of the service standard benchmark measures.

The service standard benchmarks for the distribution and transmission networks for each year of the first access arrangement period are shown in the tables below.

Table E1(a): SAIDI service standard benchmarks (expressed as system minutes per annum)

SAIDI	SWIN total	CBD	Urban	Rural Short	Rural Long
June 2007	277	21.4	222	425	741
June 2008	259	20.0	208	398	693
June 2009	224	17.3	179	343	598

Table E1(b): SAIFI service standard benchmarks (expressed as supply interruptions per annum)

SAIFI	SWIN total	CBD	Urban	Rural Short	Rural Long
June 2007	3.44	0.32	3.12	4.89	5.58
June 2008	3.22	0.30	2.91	4.58	5.22
June 2009	2.78	0.26	2.51	3.95	4.50

Table E2: Service standard benchmarks for transmission reference services (Circuit Availability expressed as percentage of total possible hours available, and System Minutes Interrupted)

	First access arrangement period		
	Year ending June 2007	Year ending June 2008	Year ending June 2009
Transmission circuit availability (% of total time)	98.2	98.2	98.2
System minutes interrupted (meshed network)	7.8	7.8	7.8
System minutes interrupted (radial network)	3.9	3.9	3.9

Where Western Power is responsible for the repair of faulty streetlights, the service standard benchmark ser out in table E3 below will apply in relation to repair times for reported faults.

Table E3: Service standard benchmarks relating to repair of faulty streetlights

	First access arrangement period		
	Year ending June 2007	Year ending June 2008	Year ending June 2009
Perth Metropolitan area	5 days	5 days	5 days
Major regional towns	5 days	5 days	5 days
Remote and rural towns	9 days	9 days	9 days

Operating and capital expenditure forecasts

The operating and capital expenditure plans should achieve the following outcomes:

- network asset condition and service performance should comply with all relevant legislation and regulations;
- service performance should comply with the established benchmarks and therefore satisfy customers' expectations in terms of reliability and quality of supply;
- generation connections should be facilitated to ensure that security of supply is maintained;
- assets must be renewed to ensure that service performance is not compromised in the medium term;

- asset management strategies should be aligned with industry best practice;
- the life-cycle costs of providing transmission services should be minimised by appropriately balancing operating and capital expenditure; and
- sustainable efficiency gains, in terms of improved performance, increased output and lower cost should be delivered over time.

In addition, it is essential that expenditure plans are feasible given the availability of internal and external resources, and the need to ensure that expenditure is executed efficiently.

For the transmission and distribution networks, there are a number of high-level cost drivers that will cause expenditure to increase above present levels in the forthcoming access arrangement period. There are 14 principal cost drivers, which are briefly described below:

Table E4 Principal cost drivers for the transmission and distribution networks

1. The impacts of previous budget constraints	In the recent past, Western Power's capital expenditure has been budget-constrained. Given the substantial growth in new customers over the same period, the consequence of the budget constraints has been to defer expenditure in relation to replacement and maintenance of the existing assets. This resulting backlog in works now needs to be addressed
2. Facilitation of market reform	It is important that Western Power fully supports the implementation of market reforms, including the facilitation of competition and the full disaggregation of the former Western Power Corporation business entity. The market reforms will have the most significant impact upon Western Power in the Information Technology area, although structural changes will impact all areas of the business.
3. Asset replacement	The advancing age of Western Power's network means within the next 10 to 15 years, there will be a need to replace much greater volumes of assets than has been the case in the last ten years.
4. Facilitating forecast increases in generation capacity	In recent years the extent to which generation capacity exceeds consumer demand has fallen to a historically low level. Western Power is therefore expecting an increase in generation capacity over the access arrangement period, which in turn will affect network expenditure.
5. The application of new design standards	In the 1990s the company allowed certain substations to be loaded to 90% of the normal cyclic rating (NCR), providing that a rapid response spare transformer (RRST) was available in the event of a transformer failure. Although the adoption of this policy has been successful in managing the capital expenditure restrictions noted above, it has resulted in an increasing utilisation of the substations. As the average loading level of substations across the system increases, it is becoming increasingly difficult to operate the network under contingency conditions, and the risk of loss of supply is increasing.
6. Optimisation of maintenance expenditure	To assist the company to optimise its future maintenance expenditure, Western Power intends to develop a more comprehensive maintenance strategy. Western Power believes that an increased focus on strategic asset management will enable the business to identify efficiency and network performance improvement opportunities that will ultimately lead to improvements in services for customers.

7.	**Insurance**	Western Power's insurance costs have increased over the past 2 years, and are projected to escalate further over the forthcoming access arrangement period. Increases occurring in 2004 and 2005 reflect the difficult climate for utility insurances following 9/11 and the general tightening of policy availability and conditions. The continued increases reflect the expected industry trends for insurance premiums following careful analysis of the market.
8.	**Compliance with more onerous safety, health, and environment regulations;**	Western Power has identified the following specific transmission capital expenditure projects that are required in order to ensure the company's compliance with existing regulations: o substation fencing and security upgrades; o transmission line river crossings; o replacement of 216 22 kV bus disconnectors; o transmission substation safety upgrades; and o transformer neutral earthing resistors. In relation to the distribution network, the following compliance issues have been identified as requiring additional capital expenditure: o Overhead service wires with twisties; o Conductive metal streetlight poles; o Distribution conductive power poles step and touch potential mitigation; o Streetlight switch wires; o URD cable pits; o Henley cable boxes; o Pole top switch (PTS) earthing mats; o Live-frame shrouding; o Wrapped copper LV neutral service connections; o Inadequate reinforcing of transformer poles; o Padmount transformer noise; and o Bushfire mitigation. The completion of these non-discretionary projects will require additional capital expenditure compared to recent historic levels.
9.	**Reliability**	Additional expenditure is required to meet Western Power's distribution service standard benchmarks. Network maintenance programs have been developed to facilitate the achievement of the significant reductions in interruptions required to meet the proposed reliability targets.
10.	**Whole of life efficiencies**	Improved preventative maintenance programs have been introduced to achieve an optimal balance between maintenance and capital expenditure. These programs are expected to allow Western Power to extend the operational lives of some assets whilst minimising service interruptions and corrective maintenance costs, thus leading to a reduction in overall lifecycle costs.
11.	**Increasing asset Base**	Additional operating expenditure will arise as a result of the growth in network assets under the company's capital expenditure program.
12.	**Increasing Resource Costs**	Increases in average unit costs for maintenance are expected, due to competition for resources and contractors within WA and nationally.
13.	**Metering services**	Metering inspections will increase in line with the projected increase in customer connections. In addition, installation and data management costs are expected to increase, as increasing numbers of customers request interval meters.
14.	**Call centre costs**	Historically, there was no recognition of the cost of fault call handling in network tariffs. However, Western Power has now entered into a formal contract with Synergy for the provision of these services.

The impact of these cost drivers on Western Power's preferred level of capital and operating expenditure has been assessed with the assistance of the respected industry consultant PB Associates. Overall, the cost drivers imply that operating and capital expenditure will need to increase substantially compared to historic levels.

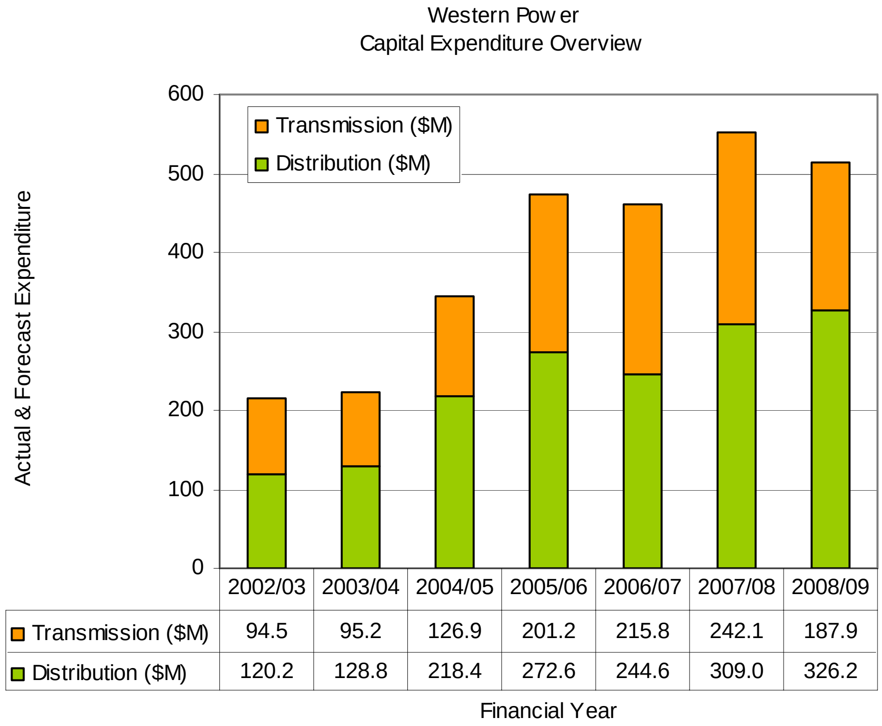
In developing its expenditure proposals, however, Western Power has also had regard to the resource constraints, both internally and within the broader contractor market. The consideration of resource constraints has led Western Power to adopt a number of strategies to ensure that expenditure can be increased above existing levels of expenditure, whilst maintaining value for money in terms of efficient project execution. Notwithstanding these strategies, Western Power believes that the external contractor market has limited capacity to deliver the increased work program, and therefore Western Power's expenditure proposals have been scaled back accordingly.

A further consideration in establishing expenditure proposals is the financing constraints that must also apply, and a consideration of the impact of higher expenditure on the network prices that will be paid by customers. Following discussions with Government in its role as shareholder, Western Power has further reduced its proposed level of expenditure for this forthcoming access arrangement period in the light of these financing and pricing considerations.

With the assistance of PB Associates, Western Power has undertaken a detailed and comprehensive assessment of its capital and operating expenditure necessary to deliver all the required performance outcomes (safety, new customer connections, reliability, prudent asset management, etc.). The expenditure report (attached to this document at Appendix 6) details Western Power's expenditure plans taking into account the resource constraints faced by the company, and the need to manage the transition to higher and more sustainable expenditure levels. The revised expenditure plans take account of the Authority's findings in the Draft Decision, including the reports from consultants Wilson Cook, and Western Power's subsequent expenditure submission[4] to the Authority. Importantly, the revised expenditure plans also reflect recent cost information, which indicates that unit capital prices and tenders from contractors have both been subject to substantial increases.

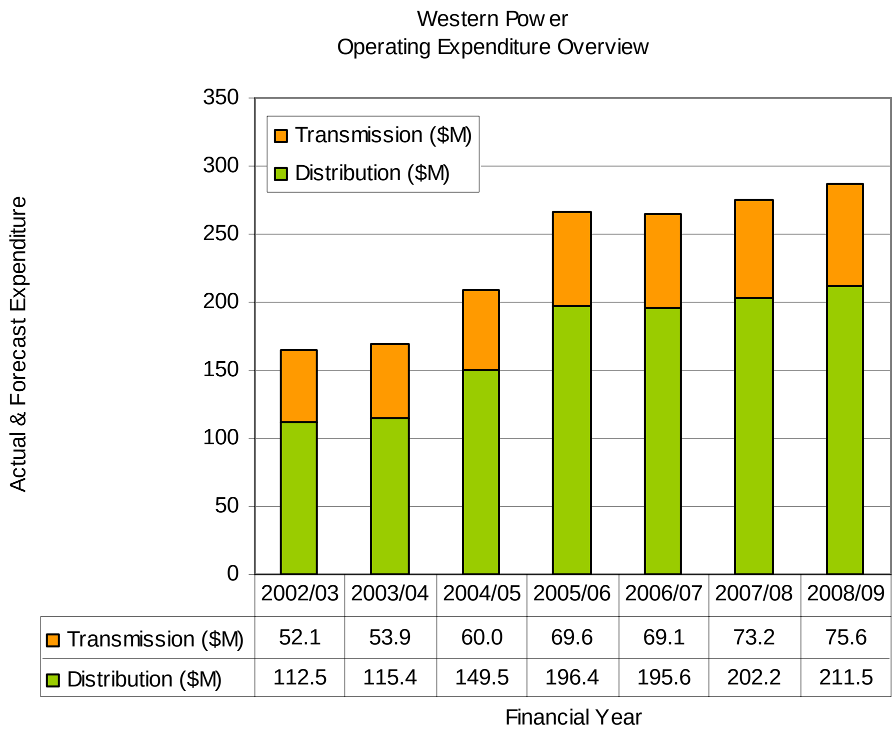
[4] Western Power, Revised Regulatory Expenditure Forecasts, Supporting Information, 26 September 2006.

Figure E1



	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
Transmission ($M)	94.5	95.2	126.9	201.2	215.8	242.1	187.9
Distribution ($M)	120.2	128.8	218.4	272.6	244.6	309.0	326.2

Figure E2



	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
Transmission ($M)	52.1	53.9	60.0	69.6	69.1	73.2	75.6
Distribution ($M)	112.5	115.4	149.5	196.4	195.6	202.2	211.5

Overview of price control arrangements

Under the Code, Western Power's total annual revenue requirement is calculated as the sum of a series of cost "building blocks", as described briefly below.

Table E5 Summary of the building block components of target revenue

Target revenue component	Brief description
Operations and maintenance costs	This is Western Power's annual cost of operating the network, and maintaining the assets used in the delivery of services covered under the Code.
Return of capital	This is the annual depreciation charge on the assets used in the delivery of covered services.
Return on capital	This is the product of the required rate of return (the weighted average cost of capital, or WACC) and the capital base. (The capital base for a covered network means the value of the network assets that are used to provide covered services on the covered network determined under sections 6.44 to 6.63 of the Code.) The capital base value over the access arrangement period is, in turn, a function of the depreciated value of assets at the start of the period, the level of annual depreciation recovered during the period, and the level of efficient new capital expenditure (new facilities investment) that is assumed to be required over the course of the access arrangement period.
Taxation	The pre-tax approach to WACC provides an allowance for company tax in the WACC.

The total annual revenue requirement (termed "target revenue") under the Code is used to calculate the revenue control which will apply to Western Power. Separate revenue controls will apply to the transmission and distribution networks.

The return on assets and other financing issues

As noted above, the calculation of Western Power's target revenue in the forthcoming access arrangement period requires an assessment of the value of the assets used in the delivery of regulated services (the "capital base").

In accordance with Required Amendments 37 and 38 of the Authority's Draft Decision, Western Power proposed that the initial distribution capital base will be the optimized deprival value (ODV) of assets as at 30 June 2004 (determined in accordance with the independent valuation commissioned by the WA Government's Electricity Reform Implementation Unit (ERIU)) adjusted for inflation, depreciation, asset acquisitions and capital expenditure updated for the latest capital expenditure and depreciation forecasts.

The Authority states in paragraph 312 of its Final Decision that it is satisfied that the revised proposed access arrangement incorporates or otherwise addresses the reasons for Draft Decision Required Amendments 37 and 38. The Authority also notes in paragraph 308 of the Final Decision that, following its submission of the revised proposed access arrangement, Western Power updated the value of the capital base to reflect actual new facilities investment up to 30 June 2006. In paragraph 312 of the Final Decision, the Authority concludes that the value proposed by Western Power for the capital base at 30 June 2006 meets the requirements of the Access Code.

The initial capital base is net of accumulated capital contributions received by Western Power to 30 June 2006. The tables below show the derivation of the transmission and distribution capital base value.

The table below shows the derivation of the capital base value as at 30 June 2006.

Table E6: Derivation of Transmission Initial Capital Base (net)
($ million real as at 30 June 2006)

Financial year ending:	30 June 2004	30 June 2005	30 June 2006
Opening capital base value		1,205.9	1,274.6
less Depreciation		43.4	45.7
plus Capital Expenditure (net)		112.2	149.5
less Redundant Assets		0.0	0.0
plus Corporate Assets allocated to Western Power		0.0	8.1
Closing capital base value	**1,205.9**	**1,274.6**	**1,386.6**

Table E7: Derivation of Distribution Initial Capital Base (net)
($ million real as at 30 June 2006)

Financial year ending:	30 June 2004	30 June 2005	30 June 2006
Opening capital base value		1,401.5	1,470.0
less Depreciation		86.5	91.0
plus Capital Expenditure (net)		158.2	209.1
less Redundant Assets		3.2	1.8
plus Corporate Assets allocated to Western Power		0.0	8.1
Closing capital base value	**1,401.5**	**1,470.0**	**1,594.5**

Western Power's approach to determining the depreciation charge (or "return of capital" allowance) is to adopt a straight-line approach to depreciation and it is proposing accelerated depreciation in relation to existing distribution assets that will be decommissioned as a result of the retrospective undergrounding project undertaken by Western Power on behalf of the Western Australian government.

The WACC is the final critical determinant of the level of Western Power's capital-related costs. The product of WACC and the capital base determines the "return on capital" component of the revenue requirement. This component comprises a substantial proportion of the company's total costs, and hence its target revenue.

Western Power's view is that the estimated WACC should be the same for Western Power's transmission and distribution networks that comprise the SWIN.

In its Draft Decision, the Authority estimated the reasonable parameter values and ranges that should be used to determine Western Power's WACC. The Authority calculated a narrower "reasonable range" for the WACC by removing the upper and lower 10% from the wider range implied by the parameter values. As Western Power's proposed WACC was outside the reasonable range estimated by the Authority, the Draft Decision included Required Amendment 52, which stated that:

> "Western Power to amend its proposed access arrangement to reflect a pre tax real weighted average cost of capital of 6.0 per cent."

In response to the Draft Decision, Western Power did not incorporate Draft Decision Amendment 52 in its revised proposed access arrangement. Rather, Western Power proposed a WACC of 6.76% which reflected:

- the Authority's WACC methodology and parameters as set out in the Draft Decision, but updated to reflect the latest market data in relation to the risk free rate; and
- the value at the upper bound of the reasonable WACC range thus determined.

In its Final Decision, the Authority further considers the determination of the reasonable range for the WACC, taking into account the parameter values in its Draft Decision and recent observations from capital markets on risk free rates. The Authority estimates the reasonable range in table 56 of the Final Decision (reproduced below).

Table 56 Authority's Final Decision assessment of reasonable WACC range

Estimated WACC (per cent)	Nominal	Real
Post-Tax	6.19 – 7.11	3.00 – 3.89
Pre-tax	8.84 – 10.16	5.57 – 6.85

Western Power's proposed pre-tax real WACC of 6.76% as set out in its revised proposed access arrangement is within the reasonable range that the Authority estimates in its Final Decision. Therefore, the Authority's Final Decision accepts Western Power's proposed WACC of 6.76%, and concludes (in paragraph 453) that:

> "The WACC incorporated by Western Power in the revised proposed access arrangement (6.76 per cent pre-tax real) lies within the reasonable range determined by the Authority for the purposes of this Final Decision. Accordingly, the Authority accepts that this value meets the requirements of the Access Code."

In accordance with the Final Decision, Western Power will apply a pre-tax real WACC of 6.76% in its access arrangement.

Revenue and average price outcomes

Western Power's transmission and distribution revenue and average price path outcomes are described in the tables and figures below.

Table E8 below shows Western Power's forecast for each building block component of the target revenue, together with the target revenue for the transmission business (being the sum of the building block components) for each year of the forthcoming access arrangement period. The table also shows the tariff revenue for the transmission business.

Table E8 – Composition of transmission network revenue ($ million real as at 30 June 2006)

Financial year ending:	30 June 2007	30 June 2008	30 June 2009	Present Value
Operating Costs	67.2	69.4	69.9	181.3
plus Depreciation	48.8	53.1	57.7	139.7
plus Redundant Assets	0.0	0.0	0.0	0.0
plus Return on Assets	93.7	104.6	116.6	275.4
plus Return on Working Capital	0.6	0.6	1.0	1.9
Target Revenue	**210.4**	**227.6**	**245.1**	**598.2**
plus Tariff Equalisation Contribution	0.0	0.0	0.0	0.0
less Non-Reference Services Revenue	-18.4	-18.4	-18.4	-48.5
less Capital Contributions	-16.1	-27.4	-13.4	-50.1
Net Reference Services Revenue	**175.9**	**181.8**	**213.4**	**499.7**
Smoothed Reference Services Revenue	**189.0**	**184.8**	**195.3**	**499.7**

Figures E5 and E6 show the trend in transmission tariff revenues and average transmission tariff prices in nominal dollars for the year ending 30 June 2002 to the end of the first access arrangement period.

Figure E5: Trend in Transmission Tariff Revenue in Real Dollars as at 30 June 2006

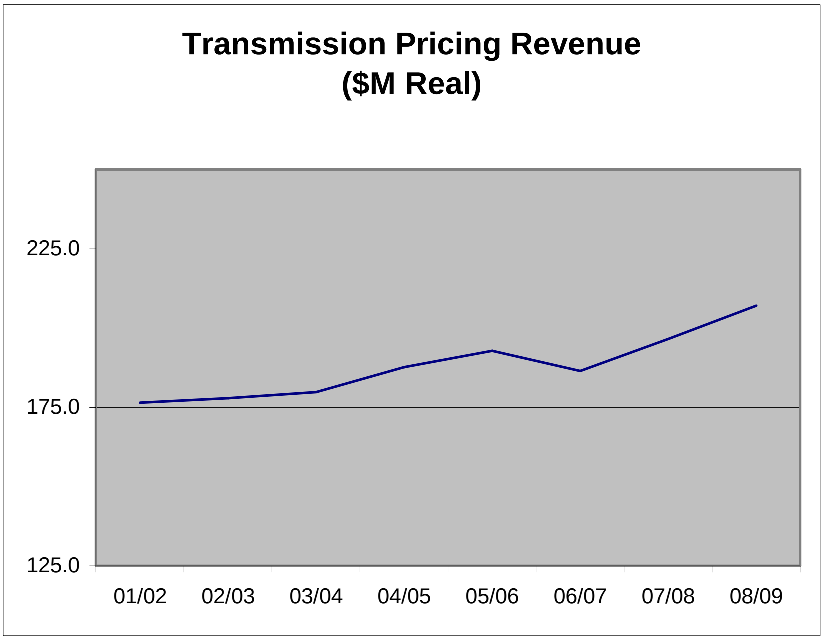


Figure E6: Trend in Transmission Average Price in Real Dollars as at 30 June 2006

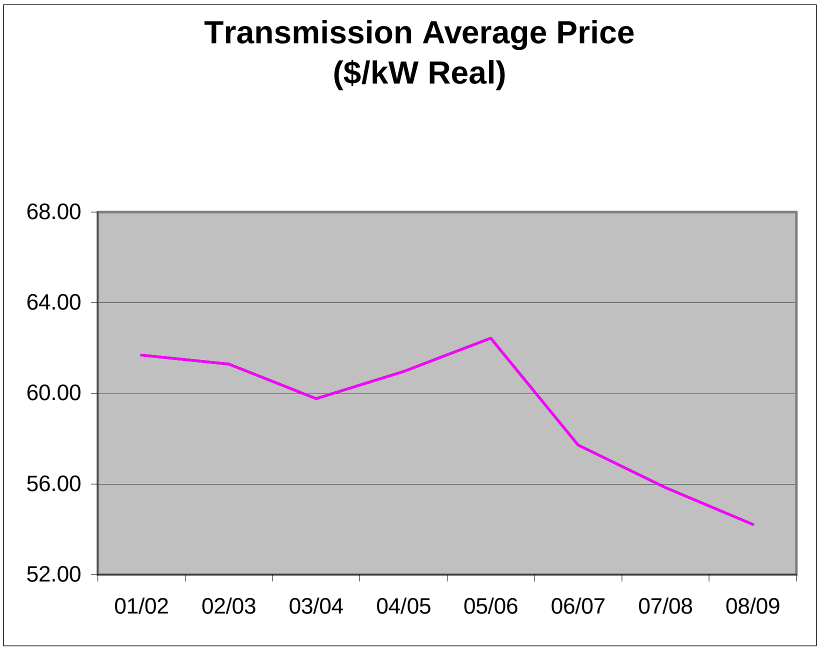


Table E9 below shows the composition of distribution network revenue for the forthcoming access arrangement period.

Table E9– Composition of distribution network revenue
($ million real as at 30 June 2006)

Financial year ending:	**30 June 2007**	**30 June 2008**	**30 June 2009**	**Present Value**
Operating Costs	190.3	191.7	195.4	507.0
plus Depreciation	97.2	101.9	110.5	271.3
plus Redundant Assets	3.8	3.7	3.6	9.8
plus Return on Assets	107.8	118.1	132.0	313.1
plus Return on Working Capital	1.5	1.3	1.3	3.6
Target Revenue	**400.6**	**416.6**	**442.9**	**1,104.7**
plus Tariff Equalisation Contribution	67.8	67.9	66.5	177.7
less Non-Reference Services Revenue	-14.7	-14.7	-14.7	-38.8
less Capital Contributions	-91.6	-106.8	-122.3	-280.0
Net Reference Services Revenue	**362.0**	**363.0**	**372.4**	**963.7**
Smoothed Reference Services Revenue	**313.8**	**384.1**	**404.9**	**963.7**

Figures E7 and E8 show the trend in distribution tariff revenues and average distribution tariff prices in nominal dollars for the year ending 30 June 2002 to the end of the first access arrangement period.

Figure E7: Trend in Distribution Tariff Revenue in Real Dollars as at 30 June 2006

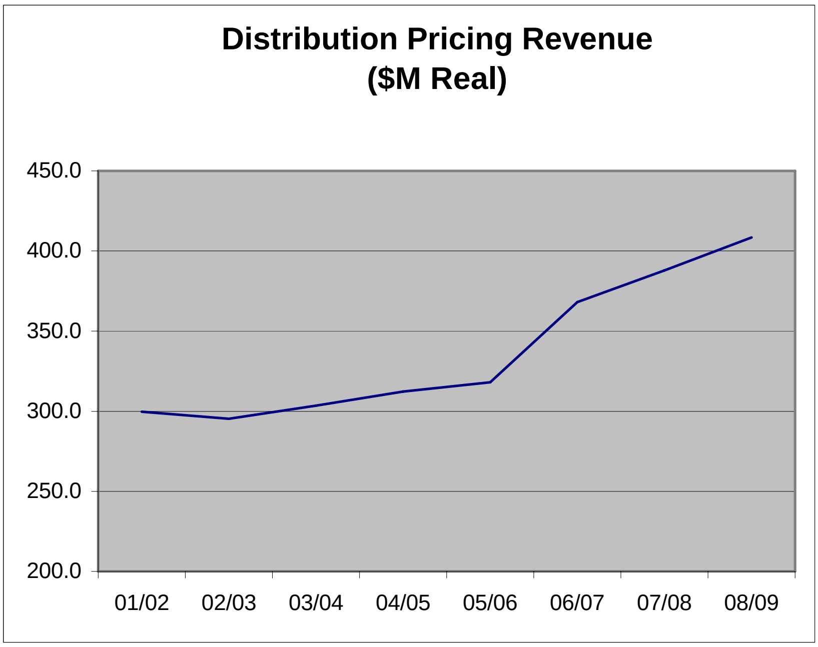
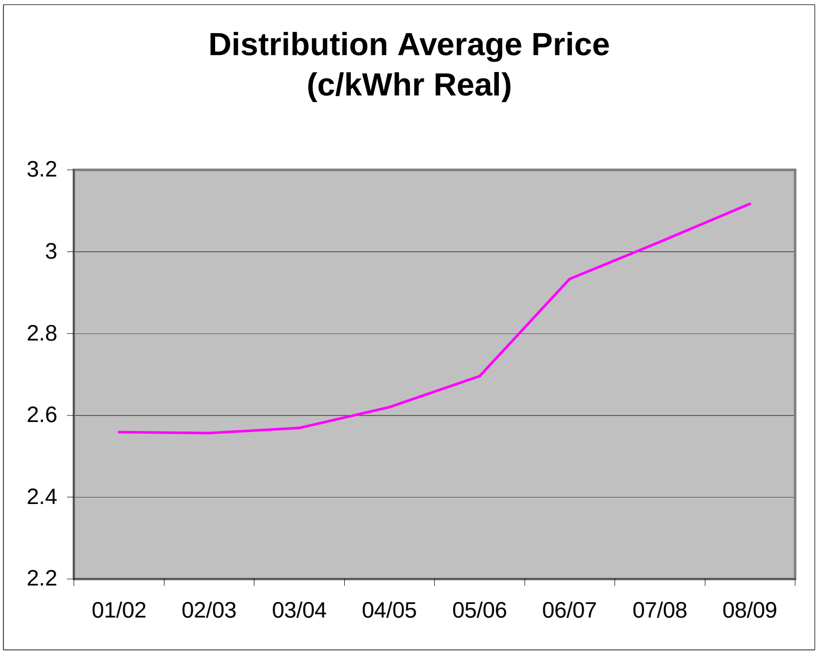


Figure E8: Trend in Distribution Average Price in Real Dollars as at 30 June 2006



Tariffs and service offerings

Under the Code, Western Power is required to offer "reference services"[5], in accordance with the following criteria:

- Reference services are those services that are likely to be sought by a significant number of users and applicants or a substantial proportion of the market for services in the covered network.
- Reference services should be specified in a manner that enables a user to acquire by way of one or more reference services only those elements of a covered service that the user wishes to acquire.
- Reference services should be defined in a way that enables users to acquire entry (or exit) services without having to acquire corresponding exit (or entry) services.

After careful consideration of the Code requirements, Western Power offers 11 *reference services* at *network exit points*:

1. Anytime Energy (Residential) Exit Service	A1
2. Anytime Energy (Business) Exit Service	A2
3. Time of Use Energy (Small) Exit Service	A3
4. Time of Use Energy (Large) Exit Service	A4
5. High Voltage Metered Demand Exit Service	A5
6. Low Voltage Metered Demand Exit Service	A6
7. High Voltage Contract Maximum Demand Exit Service	A7
8. Low Voltage Contract Maximum Demand Exit Service	A8
9. Streetlighting Exit Service	A9
10. Un-Metered Supplies Exit Service	A10
11. Transmission Exit Service	A11

Western Power offers two entry services as *reference service*:

1. Distribution Entry Service	B1
2. Transmission Entry Service	B2

For further detail on each of these reference services, please refer to Appendix 7 of the access arrangement, which provides for each reference service:

- a detailed description;
- user eligibility criteria;

[5] A reference service is a service regulated under the Code for which there is a standard access contract (which forms part of the access arrangement), a reference tariff, and service standard benchmarks which set out the standard of service that users can expect to receive in exchange for payment of the reference tariff.

- the applicable reference tariff;
- the applicable standard access contract; and
- the applicable service standard benchmark.

Regulatory and policy framework

The revenue and price path described above are subject to a regulatory framework that is defined by Western Power's access arrangement in accordance with the Code. In particular, there are a number of adjustment mechanisms that may be applied to Western Power's revenue, to take account of the impact of particular circumstances that may arise during the forthcoming access arrangement period.

The purpose of these various adjustment mechanisms is to properly balance the allocation of risk between Western Power and its customers in the event that expenditure turns out to be higher or lower than forecast for reasons beyond Western Power's control.

The reference tariffs are set at a level that satisfies Western Power's proposed revenue control. The structure of reference tariffs is determined in accordance with Western Power's pricing method, which is also consistent with the Code requirements.

Western Power's access arrangement includes a number of documents that describe the terms and conditions on which Western Power offers to provide covered services to applicants and users. In broad terms, the following list identifies the principal documents and their respective roles in the access arrangement:

- Applications and Queuing Policy processes applications for an access contract in an orderly and fair manner, especially where network capacity is scarce;
- Transfer and Relocation Policy specifies a user's rights to transfer its access rights to another person and relocate capacity from one connection point in its access contract to another connection point in its access contract;
- Capital Contributions Policy describes the circumstances in which a capital contribution will be payable by the applicant and the method for calculating the capital contribution;
- Standard Access Contract describes the standard terms and conditions on which Western Power will offer a user access to its network;
- Policy on Prudent Discounting describes the circumstances in which Western Power will offer discounted charges to particular network users; and
- Policy on Discounts for Distributed Generation describes Western Power's discounts to distributed generators where these generators reduce network costs.

Western Power's standard access contract and policies have had regard to the model contract and policies detailed in the Code, and the Authority's Draft and Final Decisions. In a number of respects Western Power has proposed changes to the model contract and policies in order to facilitate the achievement of the Code objective.

Submission and approval process

The Authority is required by the Code to determine whether a proposed access arrangement meets the Code objective and the requirements set out in Chapter 5 (and Chapter 9, if applicable). As noted above, Western Power has amended its access arrangement to address each of the Required Amendments set out in the Authority's Final Decision. In accordance with section 4.23 of the Code, Western Power's view is that the Authority should approve the proposed access arrangement. It is noted that section 4.28(b) of the Code further clarifies the approach that the Authority must adopt, as follows:

> "to avoid doubt, if the Authority considers that the Code objective and the requirements set out in Chapter 5 (and Chapter 9, if applicable) are satisfied, it must not refuse to approve the proposed *access arrangement* on the ground that another form of *access arrangement* might better or more effectively satisfy the Code objective and the requirements set out in Chapter 5 (and Chapter 9, if applicable)."

PART A: INTRODUCTION AND BACKGROUND

1 Introduction to Part A

In August 2005, Western Power submitted its access arrangement documents for approval by the Authority. The Authority published its Draft Decision in March 2006 (Draft Decision) in relation to Western Power's proposed access arrangement for the South West Interconnected Network. The Draft Decision was not to approve Western Power's proposed access arrangement. The Draft Decision explained the Authority's reasoning for each of 193 Required Amendments to the access arrangement or the access arrangement information.

In May 2006, Western Power submitted a revised proposed access arrangement, together with a revised access arrangement information in response to the Draft Decision. Western Power also submitted a comprehensive response[6] to each Required Amendment.

In March 2007, the Authority published its Final Decision, in which the Authority determined that it would not approve Western Power's revised proposed access arrangement. The Final Decision contains the Authority's reasoning for 26 Required Amendments that must be adequately addressed in the amended proposed access arrangement before the Authority will approve it.

Section 4.19 of the Code provides for Western Power to submit an amended proposed access arrangement to the Authority within 20 business days of the Final Decision. In addition, section 4.4 of the Code states that if a service provider submits an amended proposed access arrangement under section 4.19, the service provider must at the same time submit appropriately amended access arrangement information.

In accordance with these provisions of the Code, this document is Western Power's amended access arrangement information, which explains and justifies the company's amended proposed access arrangement[7]. In accordance with the Code, the access arrangement information enables users and applicants to:

(c) understand how Western Power derived the elements of the proposed access arrangement; and

(d) form an opinion as to whether the proposed access arrangement complies with the Code.

This document also contains references to the Draft Decision, and Western Power's responses to the Required Amendments contained therein, where Western Power believes that this information will assist users and applicants in understanding the derivation of the proposed access arrangement.

6 Western Power's response to the Required Amendments, dated 19 May 2006.

7 In accordance with section 4.20 of the Code, references to "access arrangement", "proposed access arrangement" and "access arrangement information" when used throughout this document should be read as referring to "amended proposed access arrangement" and "amended access arrangement information" respectively, which are submitted in response to the Final Decision published by the Authority on 2 March 2007.

Cost information and other forecast data has been updated where appropriate. It should be noted, however, that particular aspects of the access arrangement will take effect from 1 July 2006. In this context, the 'most recent' relevant data relating to the establishment of performance or cost benchmarks may pre-date the commencement of the access arrangement.

In addition to the access arrangement information and the proposed access arrangement submitted with it, Western Power also submits a comprehensive response[8] to the 26 Required Amendments contained in the Final Decision. Western Power believes that this further document will assist the Authority in its assessment of the proposed access arrangement in accordance with section 4.23 of the Code. In particular, this Code provision states that:

> "If the *Authority's final decision* is to not *approve* a *proposed access arrangement* and the *service provider* submits an *amended proposed access arrangement* and either:
>
> (a) the *amended proposed access arrangement* implements the amendments required under section 4.17(b); or
>
> (b) the *amended proposed access arrangement* does not implement the amendments required under section 4.17(b) but otherwise (in the *Authority's* view) adequately addresses the matters which prompted the *Authority* to require the amendments,
>
> then the *Authority's further final decision* must be to *approve* the *amended proposed access arrangement* unless:
>
> (c) *approving* the *amended proposed access arrangement* would be inconsistent with the *Code objective*; and
>
> (d) the *Authority* determines that the advantages of not *approving* the *amended proposed access arrangement* outweigh the disadvantages, in particular the disadvantages associated with decreased regulatory certainty and increased regulatory cost and delay."

Part A of the document provides important background information and context to Western Power's proposed access arrangement. This Part A comprises four further sections, as follows:

- section 2 explains briefly the development of the Code;
- section 3 provides an overview of Western Power;
- section 4 presents an overview of Western Power's network planning and investment process; and
- section 5 describes Western Power's recent service performance and its planned service outputs for the forthcoming access arrangement period.

The remainder of this document is then presented in three further parts as follows:

- Parts B and C provide detailed information to substantiate the expenditure plans and revenue requirements of the transmission and distribution networks respectively; and

[8] Western Power's response to the Required Amendments in the Authority's Final Decision, dated 2 April 2007.

- Part D sets out information and explanatory material relating to the regulatory framework governing access to Western Power's transmission and distribution networks.

2 Development of the Access Code and Western Power's access arrangement

2.1 Development and purpose of the Access Code

The electricity industry in Western Australia has been the subject of significant reform over the last 10 years. The objective of industry reform is clear – it is to provide Western Australians with safe and reliable electricity at competitive prices. The State Government's plan for reform involves establishing a competitive electricity industry, protecting consumers and keeping the State's electricity assets in government ownership.

In January 1995 the industry reform process commenced with the separation of the State Energy Corporation into two new corporations, Western Power Corporation and AlintaGas. Following this major restructuring, working groups were established under the auspices of the Office of Energy to develop principles and processes for the provision of third party access to Western Power's networks. These working groups successfully developed and published regulations, technical codes and pricing methods. Transmission network access services became available on 1 January 1997, and distribution access services became available on a progressive basis from 1 July 1997.

Despite the significant progress achieved since 1995, the Government decided that further reform is required in order to deliver greater benefits to customers. On 25 November 2002, State Cabinet endorsed the next stage of an electricity reform program including the disaggregation of Western Power Corporation into separate generation, networks, retail and regional businesses. Western Power Corporation was disaggregated into four new stand-alone energy businesses in April 2006. The network company formed from Western Power Corporation is now called Western Power.

In relation to network access, the process of applying for and acquiring network access services had been criticised by market participants for being too slow and complex. In recognition of this, the Electricity Reform Implementation Unit responded by saying that the development of a new access code was an important step in the Government's reform programme for the electricity networks within the State[9].

The Code[10] was gazetted on 30 November 2004 and commenced on the same day. The introduction to the Code explains that:

> "The Code aims to be, where appropriate given conditions prevailing in Western Australia:
>
> - consistent with the National Electricity Code and National Gas Code; and
> - capable of certification as an effective *access* regime under Part IIIA of the *Trade Practices Act 1974*.

[9] ERIU, Steve Edwell's Open letter to interested parties – Public Consultation – WA Electricity Networks Access Code 2004, 5 April 2004

[10] *Electricity Networks Access Code 2004*, made under Part 8 of the Electricity Industry Act 2004.

> This Code establishes a framework for third party *access* to electricity transmission and distribution *networks* with the objective of promoting the economically efficient investment in, and operation and use of, *networks* and *services* of *networks* in Western Australia in order to promote competition in markets upstream and downstream of the *networks*."

To address specifically the criticisms levelled at the previous access regime, the Code requires an approved standard access contract and an approved applications and queuing policy. The intended objective is to provide an improved "balance" between the rights and obligations of the parties seeking access, and those of Western Power as the service provider.

The Code also provides a framework for the independent regulation of certain electricity networks in Western Australia. The Economic Regulation Authority ("the Authority") is now responsible for regulating third party access to electricity networks in Western Australia that are covered by the Code.

At the commencement of the Code, the only networks covered by the Code are the portions of the South West interconnected system (SWIS) that are owned by Western Power. Formally, the SWIS is defined by the Electricity Industry Act 2004 as:

> "the interconnected transmission and distribution systems, generating works and associated works:
>
> (a) located in the South West of the State and extending generally between Kalbarri, Albany and Kalgoorlie; and
>
> (b) into which electricity is supplied by:
>
>   i. one or more of the electricity generation plants at Kwinana, Muja, Collie and Pinjar; or
>
>   ii. any prescribed electricity generation plant."

2.2 Western Power's approach to preparing the access arrangement

The term "access arrangement information" is defined by the Code as follows:

> "In relation to an *access arrangement*, means the information submitted by the *service provider* under section 4.1 as described in sections 4.2 and 4.3, as amended from time to time, and is not part of the *access arrangement*."

Section 4.2 and 4.3 of the Code describe the purpose and content of the access arrangement information in the following terms:

> "4.2 *Access arrangement information* must enable the *Authority*, *users* and *applicants* to:
>
> (a) understand how the *service provider* derived the elements of the *proposed access arrangement*; and
>
> (b) form an opinion as to whether the *proposed access arrangement* complies with the Code.
>
> 4.3 *Access arrangement information* must include:
>
> (a) information detailing and supporting the *price control* in the *access arrangement*; and
>
> (b) information detailing and supporting the *pricing methods* in the *access arrangement*; and

(c) if applicable, information detailing and supporting the measurement of the components of *approved total costs* in the *access arrangement*; and

(d) information detailing and supporting the *service provider's* system capacity and volume assumptions."

In order to comply with the Code requirements, therefore, it is essential that this document addresses the matters set out in sections 4.2 and 4.3. Western Power appreciates that the Authority, users and applicants will be particularly interested in item 4.3(c), which essentially provides information to explain and support Western Power's future expenditure plans. This information will provide the basis for determining the company's total revenue requirement, and hence tariffs, over the forthcoming regulatory period.

In developing the access arrangement and the access arrangement information, Western Power has sought to address all the relevant provisions of the Code. In addition, Western Power has had regard to recent regulatory practice in Australia in order to guide its approach to certain matters. Of particular interest is the ERA's recent decision[11] in relation to AlintaGas' proposed access arrangements, and recent developments in the regulation of transmission businesses in the National Electricity Market.

However, regulatory practice in other sectors and jurisdictions can only guide Western Power's approach to some degree. Above all other considerations, Western Power's access arrangement and the supporting access arrangement information must comply with the Code. In this context, Western Power notes also the importance of the Code objectives, as defined in section 2.1 of the Code, in guiding the development of its access arrangement:

"The objective of this Code is to promote the economically efficient:

(a) investment in; and

(b) operation of and use of,

networks and *services* of *networks* in Western Australia in order to promote competition in markets upstream and downstream of the *network*s."

Western Power also notes that in relation to certain matters the Code is prescriptive in terms of the approach that Western Power must adopt. To assist users and applicants in understanding where the Code mandates a particular approach, this document identifies relevant Code provisions, where appropriate. There are two such matters that are worth highlighting at this stage:

- Section 5.30 of the Code requires that the first access arrangement defines a "target revisions commencement date" that is no more than 3 years after the access arrangement start date. In effect, therefore, the first access arrangement must be no more than 3 years in duration.

- Section 6.3 of the Code requires that the first access arrangement must contain a price control set by reference to Western Power's approved total costs. Essentially, this Code provision means that Western Power's revenues in the first access arrangement period must be justified on the basis of Western Power's cost of service.

11 ERA, Final Decision on the Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution Systems, 12 July 2005.

3 An overview of Western Power

3.1 Introduction

In this section, Western Power provides high-level background information on the company and the operation of its network business. This provides a foundation for more detailed information regarding the performance of the network business and its future expenditure requirements, which is set out in Parts B and C of this document.

The remainder of this section is structured as follows:

- section 3.2 provides a brief overview of Western Power and the network that is covered by the Code;

- section 3.3 presents a summary of Western Power's recent initiatives and achievements; and

- section 3.4 provides a high-level summary of the future challenges facing Western Power in the forthcoming access arrangement period.

3.2 Brief overview of Western Power

As noted in section 2.1 above, as part of the State Government's program to reform the electricity sector in Western Australia, Western Power Corporation was separated into four new stand-alone energy businesses in April 2006:

- Synergy: The specialist energy retailer that is the point of contact for customers' day-to-day energy needs.

- Horizon Power: Customers with premises supplied with power from the North West Interconnected System and regional non-interconnected systems are now Horizon Power customers.

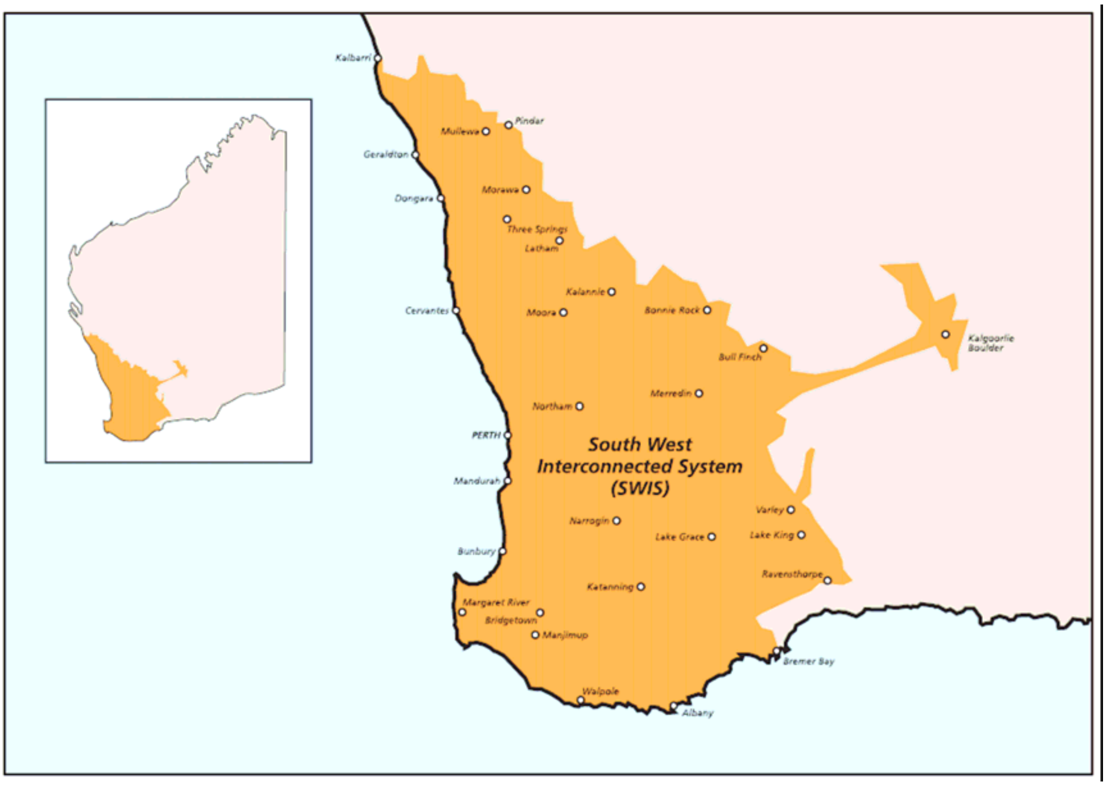
- Verve Energy: The new competitive generation business that produces electricity reliably at its power stations using a variety of fuel sources.

- Western Power: The 'new' Western Power manages the 'poles and wires' network that transports electricity from power generators to customers.

These four specialist businesses can now focus solely on the standard and efficiency of their delivered services. The changes to the State's electricity industry are part of the Government's reform program aimed at improved accountability, greater network investment, greater focus on core activities and improved service and reliability standards. It also demonstrates further that the networks business is fair and impartial about the use of its network by retailers and generators. This is important in Western Australia's new electricity market.

Figure 1 below shows the geographic location of the South West Interconnected System ("SWIS")[12] within which the South West Interconnect Network (SWIN) is owned and operated by Western Power.

Figure 1: The South West Interconnected System



The SWIS consists of transmission and distribution assets, and it extends from Kalbarri to Albany and across to the Eastern Goldfields. It contains more than 140 major substations, 6,750 km of transmission lines (operating at voltages of 66 kV and greater) and over 83,000 km of high voltage distribution lines (operating at 33 kV and lower).

Table 1 below provides a summary of the key network assets which comprise the SWIS.

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12 As already noted, under section 3.1 of the Code, the (network) portions of the SWIS which are owned by Western Power are a covered network. Under section 4.1 of the Code, Western Power is required to submit a proposed access arrangement and access arrangement information to the Authority in respect of the covered network.

Table 1: Network Assets of the South West Interconnected System for the 2004/05 financial year

Assets	Overhead	Underground
Transmission Lines		
330 kV (km)	775	
220 kV (km)	655	
132 kV (km)	4,005	16
66 kV (km)	1,130	42
Distribution Network		
High voltage mains (km)	58,956	3,635
Low voltage mains (km)	9,727	8,830
Total transformer capacity (MVA)	5,389	
Street lights	192,643	

3.3 Western Power's recent initiatives and achievements

As noted above, Western Power is the newly formed network business following the disaggregation of Western Power Corporation. Prior to disaggregation, the network business undertook a number of important initiatives aimed at improving services to customers and increasing the efficiency of its operations. These recent achievements, summarised in table 2 below, provide a firm foundation for further improvements during the course of the forthcoming access arrangement period.

Table 2 – Recent achievements and initiatives

Capital works programs to improve networks	Capital works have been targeted to ensure the reliability of supply to customers as well as improving the environmental performance of the company's plant. It is recognised, however, that significantly more needs to be done if recent reliability concerns are to be properly addressed.
Delivering real benefits to rural Western Australia	In May 2004, the State Government launched a $48 million, four-year program to improve country electricity supplies. The program demonstrates both the State Government's and Western Power's commitment to delivering a safe, reliable power supply in country areas. Phase 1 of the program commenced in August 2004 and includes installing reclosers, section switches and remote communications equipment on key distribution lines. This equipment allows faults to be isolated so that fewer customers will be affected and because the location of faults can be pinpointed more rapidly, they can be repaired more quickly. Distribution line upgrades will also be undertaken to reduce the susceptibility of the line to faults. Phase 2 of the program includes works to be undertaken in 2005/06 and 2006/07 and concentrates on upgrading specific unreliable rural lines to improve supply reliability, and provide additional capacity and backup capability to the areas they serve.
Inaugural bushfire management plan	The inaugural bushfire management plan for the SWIS was launched in July 2003. Production of the five-year implementation plan involved extensive consultation with the Fire and Emergency Services Authority of WA and the Department of Conservation and Land Management.
Poletop fire strategy	Network services are affected by the continuing occurrence of poletop fires, caused by electricity arcing across salt and dust built up on insulators. In spite of the company's best efforts to attend to these incidents, poletop fires have been a persistent cause of supply interruption to many thousands of customers in the metropolitan area. In response, new strategies for maintaining pole tops have been developed with the aim of reducing the incidence of these events in future years.
Placing assets underground to improve network efficiency	Since 1996, the State Underground Power Program (SUPP) has led to more than 31,000 homes and businesses moving from overhead power supplies to new underground connections. Round 3 of the program has now commenced, which will underground supplies to a further 5100 lots, including 10 projects in the metropolitan area, plus 9 Localised Enhancement Projects in Balingup, Bunbury, Carnamah, Collie, Geraldton, Guilderton, Lake Grace, Mt Barker and Nannup.

3.4 Challenges ahead

Although Western Power (and its predecessor network business) has embarked upon a number of initiatives to deliver service improvements and enhance operating efficiencies, a number of important challenges need to be addressed in the forthcoming access arrangement period. In particular, the following issues will affect Western Power's expenditure plans:

- complying with more onerous safety, health and environmental obligations;

- maintaining sufficient network capability to meet growing demand in the SWIS, taking into account the much higher level of uncertainty associated with the location decisions of Independent Power Producers entering the wholesale generation market;

- meeting customers' expectations with respect to supply reliability;

- servicing the increasing demand associated with continued urban infill, which is leading to increased pressures on the distribution network;

- timely reinforcement of the network to accommodate both the increasing demand and expected deterioration in system load factor due to increased domestic air conditioning load (which is highly temperature-sensitive);

- timely and efficient renewal of ageing network assets;

- facilitating market reform through the timely development of systems and processes;

- managing the competing demands on internal and external resources, whilst ensuring that customers receive value for money; and

- attracting and retaining specialist staff, and implementing effective succession planning in response to the issues associated with an ageing workforce.

These high-level challenges have important implications for the expenditure requirements of the transmission and distribution networks, and therefore are discussed in more detail in Parts B and C of this document.

4 Network planning and investment process

4.1 Introduction

In this section, Western Power provides an overview of its network planning and investment process. This process drives the company's expenditure plans which are discussed in detail in Parts B and C of this document.

The remainder of this section is structured as follows:

- section 4.2 provides an overview of Western Power's network planning process;
- section 4.3 discusses Western Power's network investment strategy; and
- section 4.4 explains how Western Power's planning and investment processes deliver expenditure plans that satisfy the Code's regulatory requirements.

4.2 Overview of Western Power's network planning process

Western Power's network development plans are based on regional forecasts of peak demand, assumptions about generation developments and a detailed understanding of the capacity of the existing network. These data and assumptions are used in sophisticated network analysis that assesses the ability of each network element to satisfy a number of planning and technical criteria necessary to deliver the required network performance and service standards.

For convenience, the network is considered to be divided into the bulk transmission network and a number of load areas. As a minimum, each load area is studied in detail every two years to ensure that it will continue to meet the relevant planning and technical criteria. Where there have been significant changes in a load area (perhaps due to significant load growth or a new generator connecting), the network will be re-assessed as a matter of priority. The network planning process is, therefore, a continuous one.

Three levels of demand forecast are required for network planning purposes:

- a demand forecast for the bulk transmission system, which is broadly based on the demand forecasts contained in the Independent Market Operator's Statement of Opportunities, and which allows peak network flows across the bulk transmission network to be modelled;
- demand forecasts for each substation, which are developed by extrapolating previous system peaks for each substation, and which allow peak power flows across each substation element to be modelled; and
- demand forecasts for each load area, which allow peak power flows across the network elements in each load area to be modelled. These forecasts are developed using the bulk transmission forecasts and the individual substation forecasts.

In each case, the focus is on understanding the most onerous conditions that will affect each network element. For example, the bulk transmission network's most onerous power flows are at the time of system peak. An individual substation may have its peak load at a different time to the remainder of the network. Simply using a load forecast for the time of system peak would potentially understate the duty on each substation element, and lead to inadequate development plans. The most onerous operating condition for each load area is derived from a combination of the demand at time of system peak and local demand peaks, depending on the characteristics of that load area.

The peak demand for electricity is highly sensitive to temperature. The forecasts used for network planning purposes are based on a 10% Probability of Exceedance: that is, Western Power's peak demand forecast, probabilistically, is likely to be exceeded one year in every ten.

Further information regarding Western Power's demand forecasts for the forthcoming access arrangement period is provided in Parts B and C of this document.

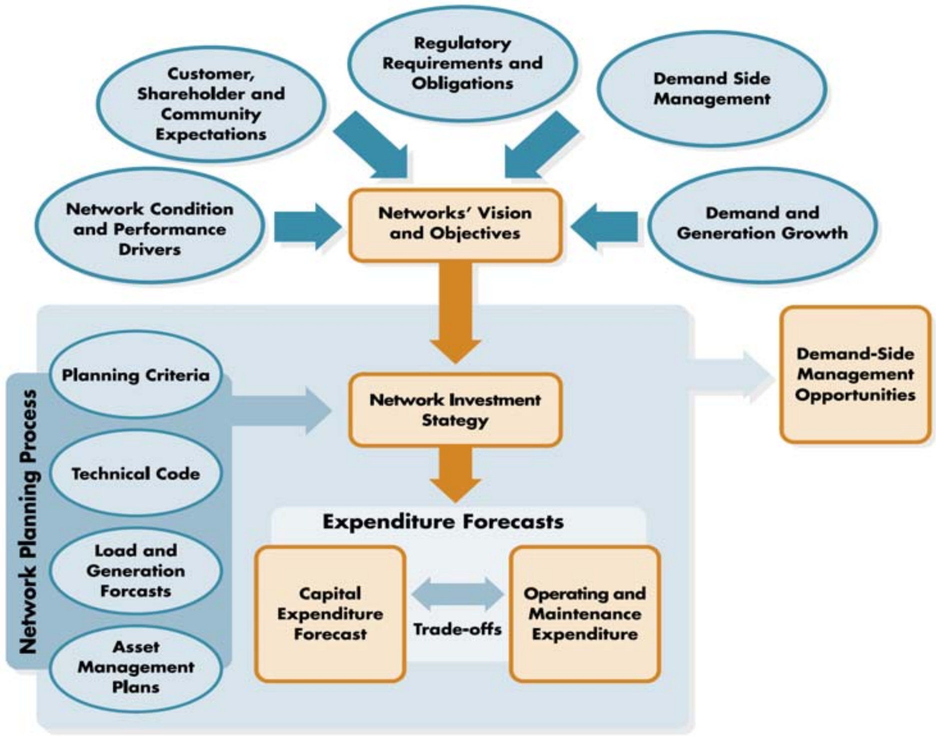
The timing, location and type of generation projects are the other main drivers of network investment. The need for network development is highly sensitive to the location and type of generation development. This is an important source of uncertainty that must be taken into account in developing expenditure forecasts. The role of the investment adjustment mechanism in managing this uncertainty is discussed in more detail in Part D of this document. Further detail in relation to generation capacity forecasts is provided in section 3, Part B of this document.

Western Power's planning process identifies a number of network constraints over the next ten years, based on the network planning assumptions (that is, demand growth and new generation developments) described in this document. Depending on the nature of the network constraints, different solutions may be available. In some cases, it may be possible to avoid network augmentation if demand side or generation solutions are brought forward in the right locations.

Western Power publishes a Transmission and Distribution Annual Planning report, which provides existing and prospective network users and other interested parties with information on emerging constraints and major planned developments on Western Power's South West Interconnected System. An objective of this report is to encourage the development of non-network solutions to emerging network constraints.

Figure 2 below provides a useful summary of the company's network planning and investment process.

Figure 2: Western Power's network planning and investment process



4.3 Network investment strategy

Western Power's network investment strategy is focused on meeting or exceeding customer and community expectations regarding the quality and reliability of the electricity supply, and to deliver outputs that are consistent with sound engineering practice in terms of asset management and stewardship.

The investment strategy is to deliver expenditure plans that balance capital expenditure and operating and maintenance expenditure, with the objective of minimising the total life-cycle costs of delivering services. This trade-off between capital and operating expenditure necessarily requires the exercise of judgment, taking into account issues of risk and prudent asset management.

Risk management is an important consideration in developing any expenditure plans. Western Power identifies risk exposure through due diligence programmes, asset audits, analysis of performance history and other specialised risk analysis processes. Critical assets are treated in a standard risk management procedure. Special contingency plans are developed for significant risk scenarios. This information is taken into account in developing the company's expenditure forecasts.

Western Power applies widely accepted network investment criteria in order to balance network costs against the likely costs to customers of a less reliable supply. In effect, network expenditure is justified with reference to 'value for money' considerations. It is also important, however, that the requirements of the Technical Code are met and that all necessary work is undertaken in a manner that complies with relevant legislation, national standards and industry guidelines (including those relating to occupational health and safety, environment and employment). In other words, a significant proportion of Western Power's forecast expenditure is not discretionary, as the expenditure must be undertaken in order to comply with legislated requirements.

It should also be noted that the planning process must manage the high level of uncertainty associated with the timing, size and location of potential future generation sources. The impact of this uncertainty is exacerbated by the time taken to complete major transmission network augmentation projects, such as the construction of 330 kV transmission lines required to accommodate large new generation sources. The construction phase of a generation project can take as little as two years, whereas establishing a new transmission line can take up to seven years from conception to commissioning. Much of the time required to establish a new transmission line is associated with the environmental processes that need to be completed to identify and gain approval for line routes.

Without the necessary network infrastructure to provide minimum levels of power transfer capability, generator outputs may need to be restricted to maintain network safety and security. Such restrictions may have an adverse impact on the development of a competitive generation market. Consequently, Western Power's planning processes are designed to identify universally required network developments and to commence investment to ensure that the network can respond to market needs in a timely fashion.

At a high-level, any network investment must be justified with reference to one or more of the following objectives:

- achieving and maintaining required service levels;
- reducing servicing and operating costs;
- optimising the economic life of equipment;
- ensuring safe operation of assets; and
- meeting regulatory and environmental requirements.

Ideally, maintenance expenditure should minimise the total life-cycle costs of providing network services, taking into account the future network renewal and development plans. Importantly, however, there are a number of other high-level drivers for maintenance expenditure, which include:

- ensuring the asset condition is kept within acceptable limits;
- operating the equipment at an acceptable level of risk; and
- meeting required performance targets and compliance obligations.

Western Power's asset management plans provide essential information to help guide the company's capital and operating expenditure decisions. The asset management plans are developed from information and analysis relating to:

- asset age and condition;
- the asset's expected role in the system taking into account potential obsolescence;
- the probability and consequence of failure;
- the physical and system environment of the asset;

- realistic asset decay predictions and subsequent life-cycle cost planning; and
- the need to ensure the long-term viability of the business, that is, to avoid reaching a situation where the overall condition of the network has declined to an unmanageable state.

All proposals for major expenditure are prepared using Western Power's economic assessment and project approval processes. These processes include a detailed operating and capital funding requirements review and prioritisation process, which is managed within Western Power's overall budgeting framework.

It is noted that resourcing and financing constraints must be fully considered before any expenditure proposals are finalised. This is an important issue for the forthcoming access arrangement period, which is discussed in detail in Parts B and C of this document.

4.4 Compliance with Code's investment criteria

The Code establishes a "new facilities investment test" and a "regulatory test", with which Western Power's capital expenditure forecasts must comply. The new facilities investment test is defined in section 6.52. In particular, 6.52(b) identifies three separate elements of the test:

> (i) either: the anticipated incremental revenue for the new facility is expected to at least recover the new facilities investment; or if a modified test has been approved under section 6.53 and the new facilities investment is below the test application threshold – the modified test is satisfied; or
>
> (ii) the new facility provides a net benefit in the covered network over a reasonable period of time that justifies the approval of higher reference tariffs; or
>
> (iii) the new facility is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted covered services.

The regulatory test applies only to major augmentations. In the Authority's Draft Decision[13] on Western Power's August 2005 access arrangement submission, the Authority commented (paragraph 871) on the regulatory test as follows:

> "As a threshold issue, the Authority has considered the application of the regulatory test to projects which fall within the definition of "committed" under sections 9.5 and 9.6 of the Access Code during the period prior to the commencement of the access arrangement (prior to 1 July 2006). In the Authority's view, the Access Code does not evince an intention that it be applied retrospectively. That is, to apply the regulatory test to projects which were "committed" to (within the definition of sections 9.5 and 9.6 of the Access Code) prior to the access arrangement period would be inconsistent with, and contrary to, the Access Code."

Western Power concurs with the Authority's interpretation of the Code on this matter. It is also important to note that the Code provides that forecast investment that is reasonably expected to meet the requirements of the new facilities investment test can be included in the capital base for the purposes of determining the company's revenue requirements.

[13] It is noted that the Authority's Final Decision does not specifically address this issue.

Western Power recognises that its current planning and investment process will need to be fine-tuned to accommodate formally the Code requirements in relation to the new facilities investment test and the regulatory test. For the purposes of this document, however, it is pertinent to consider whether the expenditure forecasts that are produced by the existing planning and investment process are reasonably expected to meet the requirements of the new facilities investment test. To address this question, we examine briefly each of the three elements of the new facilities investment test.

In relation to the first element of the new facilities investment test, Western Power's capital contribution policy ensures that investment in relation to new connections will comply with this provision of the test. In particular, a capital contribution will be levied in respect of any connection that does not produce sufficient revenue to cover the incremental costs of that connection.

In relation to the second element of the new facilities investment test, Western Power is proposing to undertake expenditure in relation to improving the reliability of supply. This expenditure is predominantly operating expenditure, and therefore is not subject to the new facilities investment test. In any event, as explained above, Western Power has regard to the likely benefits of improving reliability to ensure that any expenditure is cost-effective. In this sense, Western Power's reliability-related expenditure meets the spirit of the new facilities investment test, even though this test only applies to capital expenditure.

In relation to the third element of the new facilities investment test it is noted that Western Power's planning and investment process takes account of the Technical Rules and other obligations prescribed by regulations and legislation[14]. In essence, the inclusion of these compliance obligations in the current planning and investment process is consistent with meeting this third leg of the test, namely to maintain "the safety or reliability of the covered network or its ability to provide contracted covered services". It is noted that a substantial proportion of Western Power's capital expenditure program is driven by compliance obligations.

In summary, therefore, whilst Western Power's planning and investment process does not specifically incorporate the new facilities investment test, Western Power believes that its investment evaluation process broadly complies with the requirements of the test. It is further noted that the expenditure plans resulting from the planning and investment process will be further constrained by resourcing and financing considerations. The additional constraints on expenditure will ensure that projects will only proceed if they are compliance-related or produce high net benefits. This should provide further confidence that Western Power's capital expenditure program satisfies the requirements of the new facilities investment test.

Further details of Western Power's expenditure forecasts are provided in Parts B and C of this document. This information will further support Western Power's view that the proposed capital expenditure complies with the requirements of the new facilities investment test.

[14] These obligations are described in more detail in section 5.4.4 below.

5 Recent performance and future service levels

5.1 Introduction

This section presents information on Western Power's recent performance, in terms of network costs and reliability. Details of Western Power's future reliability benchmarks and service obligations are also provided. These elements have an important bearing on Western Power's expenditure forecasts that are the subject of Parts B and C of this document.

This section is structured as follows:

- Section 5.2 examines Western Power's recent network performance in terms of costs and service;

- Section 5.3 discusses Western Power's approach to setting future reliability benchmarks; and

- Section 5.4 presents a summary of Western Power's overall service benchmarks and obligations for the forthcoming access arrangement period, including its reliability targets.

5.2 Recent SWIS performance

5.2.1 Recent cost performance

Western Power operates a large and expansive electricity network servicing the majority of the Western Australian population. A geographical map of the SWIS has been included in section 2 of this Part A of this document. Within the SWIS, the SWIN contains:

- over 140 transmission substations;

- approximately 6,750 kilometres of transmission lines and cables; and

- approximately 83,000 kilometres of overhead and underground distribution networks.

It covers approximately 322,000 square km, in the South West and the Eastern Goldfields of Western Australia which are heavily dominated by remote mining loads. The physical environment in which Western Power operates presents additional challenges, for example:

- the identification and rectification of faults may involve significant travel time; and

- coastal exposure, an arid interior and prevailing on-shore winds contribute to salt and dust pollution.

Unlike networks in the Eastern states, Western Power is virtually unable to call on additional resources from its neighbours, or to share a large pool of independent contractors. The relative isolation of the SWIS from other networks also contributes to a relatively challenging operating environment.

Together, all of these factors suggest that Western Power's recent cost performance should compare unfavourably with other network businesses across Australia. Contrary to this expectation, however, recent studies undertaken by Meyrick & Associates and Benchmark Economics have all identified Western Power (and its predecessor network business) as a better-than-average cost performer. For further details of these reports, please refer to appendices 1 and 2.

Notwithstanding the studies conducted by Benchmark Economics and Meyrick and Associates, Western Power recognises that cost benchmarking can only provide a partial indication of company performance. Specifically, benchmarking cannot readily provide definitive conclusions regarding a company's relative efficiency because it is practically impossible to normalise for the cost impacts of each company's unique operating circumstances.

The ACCC noted the challenges of conducting effective comparative benchmark in its Statement of Regulatory Principles – Background Paper, as follows:

> "The key issue in constructing exogenous measures is how they should be calibrated to take account of TNSPs' specific operating conditions. The ACCC is aware of the work undertaken by the Office of Water Services (Ofwat) in the UK and by other European regulators to develop comparative benchmarks and other partially exogenous measures to establish expenditure allowances.
>
> The ACCC considers that the development of comparative benchmarks has considerable merit since it would allow the ACCC to establish expenditure allowances without necessarily having to conduct exhaustive firm-specific cost analyses. The use of benchmarks offers the promise of less intrusive regulation. However, considerable work would need to be done to establish reliable benchmarks that produce fair and balanced comparisons between the TNSPs in the NEM."[15]

Western Power concurs with the ACCC's view that considerable work would need to be done to establish reliable benchmarks that produce fair and balanced comparisons between TNSPs, and network businesses more generally. Nevertheless, the analysis presented by Benchmark Economics and Meyrick and Associates suggests that Western Power appears to be relatively low cost despite their challenging operating environment.

In this light, a key question for the forthcoming access arrangement period and beyond is whether the existing level of expenditure is sustainable. The expenditure forecasts presented in Parts B and C of this document indicate that expenditure must increase if service performance and the reliability of the network are not to deteriorate unacceptably.

5.2.2 Recent service performance

In considering the sustainability of Western Power's existing expenditure levels, it is useful to assess the company's recent performance in relation to service levels. At a high level, it is well understood that service performance will tend to suffer if there is insufficient expenditure over the long-term to maintain and expand the operating capability of the asset base to meet customers' needs.

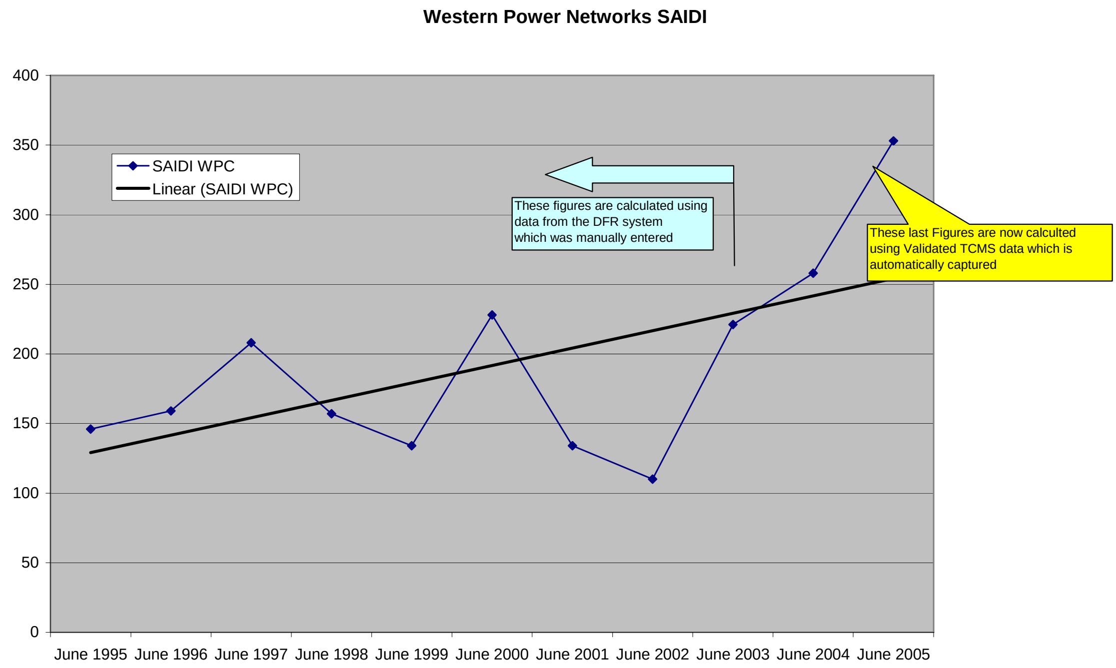
The performance of Western Power's transmission network is broadly comparable with the performance of other transmission networks in Australia. As a general observation, an improvement in the current level of performance of the transmission

[15] ACCC, Statement of Regulatory Principles – Background Paper, December 2004, page 67.

network would only have a modest impact on the standard of service observed by end-customers. Given these observations, Western Power's view is that the current performance of the transmission network is appropriate for the forthcoming access arrangement period. The expenditure forecasts set out in Part B of this document reflect the desire to maintain the existing level of performance.

Although service performance has numerous attributes, the reliability of the network is a principal concern of customers, and Western Power must focus its efforts on improving, or at least maintaining network reliability in accordance with the needs and expectations of its customers. In a recent survey of its customers, 86% identified reliability as a concern. Figure 3 below shows Western Power's SAIDI performance across the SWIS from June 1995 to June 2005.

Figure 3 - Western Power Network SAIDI

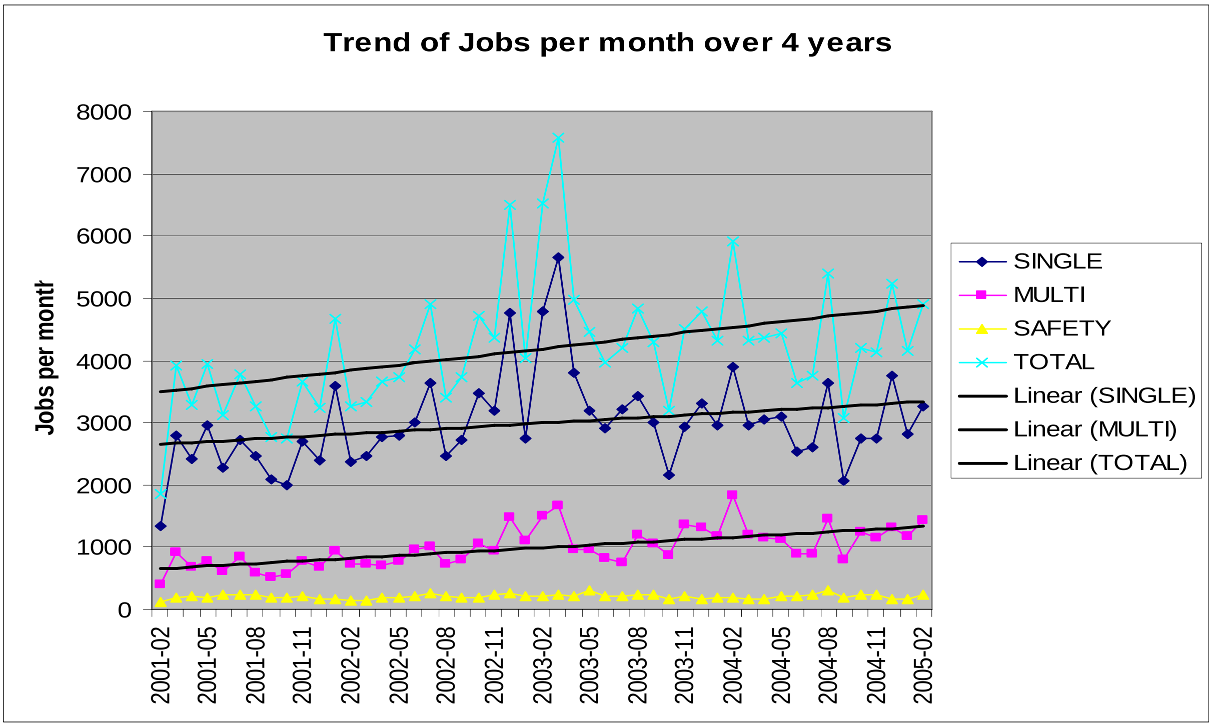


The above figure shows a worsening linear trend performance in relation to SAIDI from 1995 to 2005. Anecdotally, this worsening trend in performance has occurred at a time when customers expect better reliability from network services. The figure also shows significant annual volatility in performance, from a little over 100 minutes in 2002 to more than 200 minutes in 2003. Again, Western Power recognises that this apparent increase in the volatility of network performance falls short of meeting customer expectations.

Some important determinants of reliability performance, such as weather, are not within Western Power's direct control. Nevertheless, a worsening trend in performance such as that shown in Figure 3 above is a cause for concern. In particular, it may indicate that the company's recent expenditure levels and work practices should be enhanced.

Indeed, Figure 4 below lends further support to this view. It provides details of the number of network faults or incidents that the network business has responded to over the previous 4 years. It is evident from this figure that Western Power is attending more network faults with a trend increase over the 4 year period.

Figure 4 - Fault Jobs Trends



Overall, Western Power's recent cost and service performance indicates that expenditure levels will need to increase in order to arrest the recent decline in network reliability.

5.3 Western Power's approach to setting reliability benchmarks

The recent deterioration in reliability performance raises the question of how future reliability benchmarks should be set. Conceptually, network performance should seek to minimise the total costs to customers, which comprises the indirect costs of unreliability plus the direct costs of network services.

In this regard, useful information is available on the value that consumers typically place on marginal improvements in reliability. In particular, a report commissioned by VENCorp[16] estimated the marginal value of customer reliability (measured across all customers) to be approximately $29,600 per MWh as at December 2002. This estimate of the value of customer reliability provides a useful reference point for assessing whether increases in capital and operating expenditure to deliver reliability improvements are warranted.

A further important consideration is that the Electricity Industry (Network Quality and Reliability of Supply) Code 2005 sets standards for outage duration, which Western Power must use best endeavours to meet, however the Code is silent on the timeframe within which these standards are to be attained.[17] These standards are: a

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16 Charles River Associates, *Assessment of the Value of Customer Reliability,* December 2002. A copy of the report is available from VENCorp's web site at: http://www.vencorp.com.au.

17 Refer to Part 2 of the Code.

SAIDI of 30 minutes for CBD, 160 minutes for urban areas and 290 minutes for rural areas.

In setting reliability benchmarks for the forthcoming access arrangement period, Western Power believes that it should have regard to the targets set in the Electricity Industry (Network Quality and Reliability of Supply) Code 2005; the current level of SAIDI performance; the recent trend of deterioration in performance; and the competing demands on resources over the forthcoming access arrangement period. Taking all of these matters into consideration, Western Power has adopted a target of achieving a 25% improvement in SAIDI (compared to actual performance for the year ended in June 2004) over the forthcoming access arrangement period.

Following the Authority's Draft Decision, Western Power also proposed to adopt network performance benchmarks in relation to SAIFI.

As noted in further detail in Part D of this document:

- Western Power plans to incorporate these SAIDI and SAIFI performance benchmarks in relation to the reference services it provides to users connected to the distribution network.

- Western Power also plans to adopt service standard benchmarks for transmission reference services which are consistent with the company's overall SAIDI performance improvement targets.

- Under the service standard adjustment mechanism (also discussed in detail in Part D of this document) the company will be required to submit explanatory reports to the Authority if its performance is materially better or worse than the service standard benchmarks.

Further details of the proposed service standard benchmarks are provided in section 5.4 below, together with a brief description of other key factors that influence the level of service provided by Western Power's network.

5.4 Summary of Western Power's service standards and obligations

This section summarises Western Power's service standards and obligations for the forthcoming access arrangement period. Where detailed obligations are prescribed in regulations or legislation, the title of the relevant document is noted and the scope of the regulation is described briefly. Further details regarding the derivation of the service standard benchmarks are provided in Part D, Section 3 of this document.

The expenditure forecasts set out in Parts B and C of this document reflect Western Power's forecasts of the efficient costs associated with complying with the requirements of all of the applicable statutory instruments, as well as achieving the network performance improvement goals the company has set for the forthcoming access arrangement period.

5.4.1 Proposed service standard benchmarks

The reliability-related service standards to apply during the forthcoming access arrangement period are summarised in Tables 3a, 3b and 4a and 4b below.

Table 3a: SAIDI service standard benchmarks
(expressed as system minutes per annum)

SAIDI	SWIN total	CBD	Urban	Rural Short	Rural Long
June 2007	277	21.4	222	425	741
June 2008	259	20.0	208	398	693
June 2009	224	17.3	179	343	598

Table 3b: SAIFI service standard benchmarks
(expressed as supply interruptions per annum)

SAIFI	SWIN total	CBD	Urban	Rural Short	Rural Long
June 2007	3.44	0.32	3.12	4.89	5.58
June 2008	3.22	0.30	2.91	4.58	5.22
June 2009	2.78	0.26	2.51	3.95	4.50

Table 4a: Service standard benchmarks for transmission reference services
(Circuit Availability expressed as percentage of total possible hours available, and System Minutes Interrupted)

	First access arrangement period		
	Year ending June 2007	Year ending June 2008	Year ending June 2009
Transmission circuit availability (% of total time)	98.2	98.2	98.2
System minutes interrupted (meshed network)	7.8	7.8	7.8
System minutes interrupted (radial network)	3.9	3.9	3.9

Where Western Power is responsible for the repair of faulty streetlights, the service standard benchmark ser out in table 4b below will apply in relation to repair times for reported faults.

Table 4b: Service standard benchmarks relating to repair of faulty streetlights

	First access arrangement period		
	Year ending June 2007	Year ending June 2008	Year ending June 2009
Perth Metropolitan area	5 days	5 days	5 days
Major regional towns	5 days	5 days	5 days
Remote and rural towns	9 days	9 days	9 days

5.4.2 Customer Reliability Payment Scheme

On 31 March 2005, the Government announced that householders affected by power blackouts lasting 12 hours or more will receive a rebate from Western Power. The 'Customer Reliability Payment Scheme', took effect from 1 July 2005, and entitles households to an $80 rebate from Western Power in recognition of the inconvenience caused by blackouts.

The scheme is also aimed at increasing Western Power's accountability for network performance and providing an incentive to the company to improve the reliability of supply to customers. Under the scheme, Western Power will pay a rebate to affected customers regardless of the cause of the supply interruption except where the customer is clearly at fault. The scheme is separate to and does not negate the compensation process currently available to Western Power customers.

The scheme applies to Western Power customers who use less than 50 MWh of electricity per year.

5.4.3 Western Power's Networks Customer Charter

The Customer Charter applies to residential and small business customers using less than 50 MWh of electricity per year. This group of customers comprises some 98% of all customers. The Charter sets out comprehensive information about Western Power's network services and associated standards of service for these customers, along with these customers' rights and obligations in their relationship with Western Power.

5.4.4 Regulations and legislative obligations

The forecasts of expenditure described in Parts B and C include the costs associated with Western Power's compliance with the following mandatory obligations over the forthcoming access arrangement period:

- The Electricity Industry (Network Quality and Reliability of Supply) Code 2005 sets targets for outage duration and frequency.

- The Technical Rules set out the standards, procedures and planning criteria governing the construction and operation of an electricity network, the technical criteria for connection of new users, and deal with all the matters listed in Appendix 6 of the Access Code.

- Environmental Protection (Noise) Regulations 1997 prescribe limits for noise emissions, and methods for noise monitoring and control.

- Electricity Regulations 1947 prescribe network operator service standards; and standards for line worker and electricity worker safety.

- Occupational Safety and Health Act 1984 and Occupational Safety and Health Regulations 1996 promote improvements to working practices and facilitate the coordination of the administration of laws relating to health and safety.

- Environmental Protection Act 1986 provides for the Environmental Protection Authority for the prevention, control and abatement of pollution and environmental harm.

PART B: TRANSMISSION BUSINESS EXPENDITURE PLANS AND TOTAL REVENUE

1 Introduction to Part B

Part B of this document provides detailed information to explain and substantiate the company’s expenditure plans and the total revenue requirements of the transmission network.

In broad terms, the key underlying cost drivers of the transmission business are:

- the **standards** or **quality** of services and other outputs which Western Power plans to deliver over the forthcoming access arrangement period*;* and

- the **quantity** of the services to be delivered over the period.

Accordingly, the expenditure forecasts set out in this Part B reflect:

- the planned transmission service standards, including compliance with mandatory health, safety and environmental standards; technical standards; and performance targets as summarised in section 5 of Part A; and

- the forecast demand on the transmission system and the forecast of new generation developments, which broadly reflect the *quantity* of transmission services that the company is planning to provide.

This Part B is structured as follows;

- section 2 describes and substantiates the transmission system demand forecasts;

- section 3 describes and substantiates the generation capacity forecasts;

- section 4 describes and substantiates the transmission capital expenditure forecasts;

- section 5 describes and substantiates the transmission operating and maintenance expenditure forecasts;

- section 6 provides explanatory information relating to the asset valuation and depreciation costs for the transmission network;

- section 7 sets out the company’s estimate of the cost of capital for the network business; and

- section 8 calculates and describes the total revenue requirement for the transmission network.

In each section, Western Power has taken account of the Authority’s Draft and Final Decisions, submissions made by interested parties and the latest available data and information, where relevant.

2 Transmission system demand and energy forecasts

2.1 Introduction

This section provides an overview of the transmission system demand and energy forecasts for the access arrangement period.

As noted in section 1 of this Part B, Western Power's transmission system demand and energy forecasts reflect the quantity of transmission services that are to be provided in the forthcoming access arrangement period. As such, these forecasts provide a foundation for the company's forecasts of network development capital expenditure (including load and generation-related expenditure[18]). The forecasts also provide the basis for developing the company's proposed tariffs.

In addition, section 4.3(d) of the Code requires that the *access arrangement information* must include information detailing and supporting the *service provider's* system capacity and volume assumptions. This section of the document, together with section 2, Part C, is intended to discharge this Code obligation.

In preparing its August 2005 access arrangement submission Western Power commissioned National Institute of Economics & Industry Research (NIEIR) to review the company's forecasts for energy and demand for the transmission network, for each year of the forthcoming access arrangement period (2006-07 to 2008-09 inclusive). NIEIR was asked to verify whether Western Power's forecasts were suitable for the purpose of establishing the access arrangement. Specifically, it was noted that the transmission energy and demand forecasts should be prepared on a consistent basis, and should be reconcilable to the forecasts contained in the 2004 Generation Status Review (GSR).

Since NIEIR provided its report (in March 2005), the Independent Market Operator (IMO) has released its Statement of Opportunities (SOO) for both 2005 and 2006, which provides more recent energy and demand forecasts.

In the Final Decision issued by the Authority, Required Amendment 3 states that:

> "The access arrangement information should be amended to include substantiated forecasts of forecast maximum demand."

Subsequent discussions clarified that the Authority required Western Power to include a total transmission system maximum demand forecast in tabular form (instead of graphical) and forecasts for each individual substation. It was also agreed with the Authority that all forecasts should be revised and updated where appropriate. In particular, forecasts have been updated to reflect the IMO's 2006 SOO.

Therefore, consistent with the Final Decision, this section of the access arrangement information has been revised and in particular the total system forecasts have been updated and presented in tabular form. Western Power has also provided the Authority with copies of Western Power's "Substation Summer Load Trends (System Peak) 2007-2026" and "Substation Summer Load Trends (Substation Peak) 2007-2026" documents. These documents have been provided on a confidential basis, as they contain data that is specific to individual users. It is noted that in paragraph 208 of the Final Decision the Authority comments that it is willing to accommodate any

18 Further details of generation capacity forecasts are set out in section 3 below.

reasonable requirements for confidentiality in Western Power's submission of forecasts.

The remainder of this section is structured as follows:

- section 2.2 provides an overview of Western Power's methodology for developing transmission demand and energy forecasts;
- section 2.3 presents the transmission demand and energy forecasts;
- section 2.4 summarises NIEIR's comments on Western Power's forecasting methodology; and
- section 2.5 provides concluding comments.

2.2 Western Power's forecasting methodology for transmission demand and energy

2.2.1 Transmission demand forecast methodology

Power is transferred across the SWIN over the 330 kV and 132 kV bulk transmission networks from five major power stations (and a number of smaller inter-connected power stations) to twelve bulk supply terminals for transformation to lower voltages. Electrical energy is then distributed to a host of zone substations supplying localised areas via the sub-transmission networks operating at 132 kV and 66 kV voltages.

Each local area has its own unique growth characteristics, which influence the demand and energy forecasts. For example, the load areas supplying the northern and southern coastal areas are experiencing rapid load growth due to residential housing developments, whereas growth in the Eastern Goldfields area is highly sensitive to the activities of mining companies in response to world metal prices. As might be expected, the greatest distinctions are between load areas that cover urban and rural load areas.

Western Power currently prepares 20-year zone sub-station demand forecasts. These demand forecasts form the foundation of Western Power's network planning and analysis described in the company's Transmission and Distribution Annual Planning Report.

Western Power's forecast methodology produces three different demand forecasts for the network. These are:

1. A coincident summer network peak demand forecast across all zone sub-stations for a 20 year horizon. That is, a coincident forecast when the overall bulk transmission system is at its peak. This would usually be consistent with when the SWIN system peaks on a generation basis and, therefore, the forecasts should approximately match the SOO forecasts;

2. A non-coincident summer peak demand forecast for all zone sub-stations for a 20 year period; and

3. A non-coincident summer peak demand forecast for SWIN terminal stations.

The non-coincident peak forecasting methodology is based on statistical analysis of historic load information for every sub-station and terminal station. Specific ‘out-of-the ordinary’ block loads are also explicitly taken into account.

All data used in the forecasting model is obtained from an IRIS database of 5 minute SCADA readings for every feeder at every zone sub-station on the Network. Logarithmic, linear, exponential and power curve fits are calculated from the historical data for each sub-station and terminal station. The equation with the highest multiple regression coefficient (or fit) is automatically selected. Some trends are adjusted to reflect historical load transfers and past/future block loads at sub-stations. Trends are also adjusted to allow for 1 in 10 year conditions.

Only sub-stations that have at least four years of historical values are trended forward. Sites with less data or new sub-stations are checked against the system peak trend and further adjusted, if required. The forecasts are also compared against the Contracted Maximum Demand (CMD) for particular sub-stations.

2.2.2 Transmission energy forecast methodology

Western Power proposes to adopt the system level forecasts published by the IMO in the Statement of Opportunities (SOO), in accordance with the Authority’s Draft Decision. Western Power understands that the SOO forecasts were prepared by NIEIR.

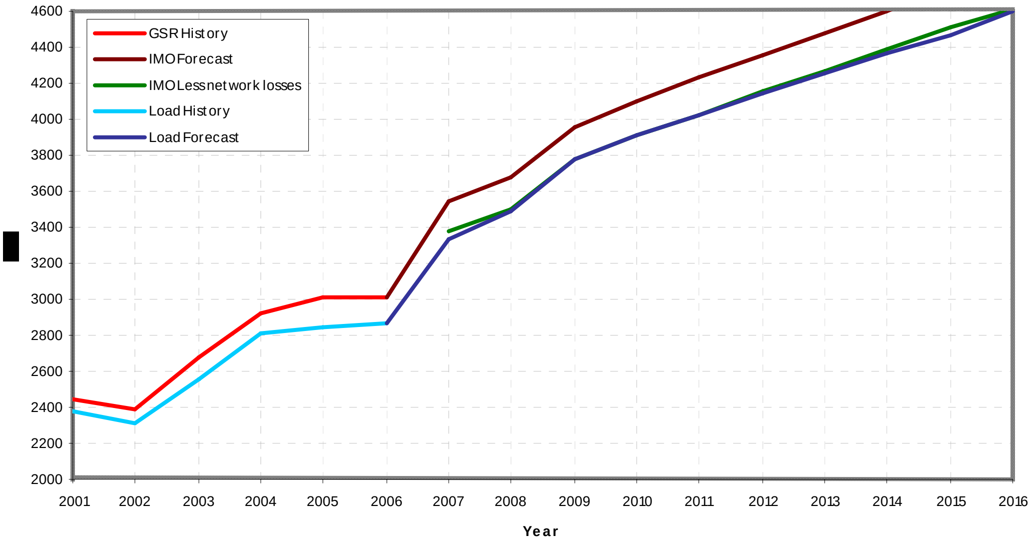
2.3 Western Power’s transmission demand and energy forecasts

Detailed demand forecasts for each substation are presented in the Western Power planning reports “Substation Summer Load Trends (System Peak) 2007-2026” of July 2006 and “Substation Summer Load Trends (Substation Peak) 2007-2026” of July 2006. Figure 5 below (reproduced from the Western Power System Peak report shows the historic and forecast MW demand on the transmission system. In particular, it shows the summated diversified transmission demand forecasts at the zone sub-station level (labelled on the graph as “Load Forecast”) and the system demand forecasts (10% probability of exceedence expected growth scenario) published by the IMO in the 2006 Statement of Opportunities less network losses (labelled on the graph as “IMO Less Network Losses”).

The individual zone sub-station forecasts are more granular than the SOO forecasts and, therefore, provide a more detailed and appropriate foundation for Western Power’s transmission investment plans. The high level of consistency between the summation of the individual zone sub-station forecasts and SOO forecasts provides a high degree of confidence that the individual substation forecasts are robust and fit for purpose.

Figure 5

Comparison of Load Forecasts and Historical Data



Western Power consequently proposes to adopt the system level demand forecasts published by the IMO in the 2006 Statement of Opportunities as follows:

Table 4c: Transmission System Demand Forecast with Expected Growth (MW)

Year	2006 SOO (MW)
2006/07	3541
2007/08	3679
2008/09	3961

Western Power also proposes to adopt the substation demand forecasts as detailed in the Western Power reports “Substation Summer Load Trends (System Peak) 2007-2026” and “Substation Summer Load Trends (Substation Peak) 2007-2026”. As already noted, confidential copies of these reports have been provided to the Authority.

The Authority’s Draft Decision concluded that the IMO’s energy forecasts were preferred to Western Power’s forecasts contained in the August 2005 access arrangement submission. Table 5 below provides details of Western Power’s transmission energy forecast as adopted from the IMO’s 2006 SOO. These forecasts have minimal impact on the company’s transmission investment plan. However, energy forecasts are relevant to the establishment of distribution energy forecasts and the determination of distribution tariffs for the forthcoming access arrangement period.

Table 5: Transmission Energy Forecast with Expected Growth (GWh)

Year	2006 SOO (GWh)
2006/07	15,400
2007/08	15,775
2008/09	16,913

2.4 NIEIR's comments on Western Power's transmission forecasting methodology

As noted in section 2.1, NIEIR examined whether Western Power's original forecasts, as presented the August 2005 access arrangement submission, were reconcilable to the forecasts contained in the 2004 Generation Status Review (GSR). Whilst NIEIR confirmed that Western Power's forecasts were reconcilable to the 2004 GSR, the 2004 GSR forecasts have now been superseded by the IMO's 2005 and 2006 SOO. Western Powers' forecasts have also since been revised, and NIEIR's analysis and comments in relation to Western Power's transmission demand forecasting methodology remain relevant. In particular, NIEIR commented that:

- Overall, based on its meeting with officers of Western Power, NIEIR found the modelling approach applied by Western Power to be sound. Western Power has a good understanding of the input data, which is of high quality and is quality controlled during processing.

- Western Power's purpose-built model for demand forecasting contains a comprehensive framework for forecasting zone sub-station peaks. Of the in-house network demand forecasting models that NIEIR has reviewed for various businesses across Australia, the Western Power model appears to be one of the best.

- NIEIR reinforces and agrees with Western Power's approach that planning should be undertaken at the zone sub-station level, in order to take into account regional specific information.

These comments should provide comfort to the Authority and interested parties that Western Power's forecasting methodology is robust.

2.5 Concluding comments on energy and demand forecasts

This section has explained:

- Western Power's methodology for forecasting transmission system demand and energy over the forthcoming regulatory period;

- Western Power's amended forecasts for transmission demand and energy, which are based on the IMO's 2006 SOO; and

- NIEIR's comments on Western Power's forecasting methodology.

Western Power's view is that the information presented demonstrates that Western Power's transmission demand and energy forecasts are robust and fit for purpose. In particular, the forecasts used are consistent with the IMO's 2006 SOO forecast, taking account of the need for more granular transmission demand forecast in order to inform Western Power's transmission investment plans.

3 Generation capacity forecasts

3.1 Introduction

This section provides an overview of the generation capacity forecasts for the access arrangement period. As noted in section 1 of this Part B, new generation connections and demand together define the quantity of services that must be provided by the transmission business. Without the necessary network infrastructure to provide minimum levels of power transfer capability, generator outputs may need to be restricted to maintain network safety and security. Such restrictions may have an adverse impact on the development of a competitive generation market.

As a consequence of the establishment of a competitive market in generation, Western Power can no longer influence the location, timing, and size of new generation plant connecting to its network. Western Power is therefore entering a period of much greater uncertainty with respect to generation connection capital expenditure, in terms of connection costs, and shared network augmentations.

Western Power seeks to manage this uncertainty through scenario planning.[19] The purpose of this section is to provide a high-level overview of the key drivers for new generation capacity, and to provide an indication of the quantum of new generation projects that are expected to proceed in the forthcoming access arrangement period. The impact of this increased capacity needs to be reflected in Western Power's capital expenditure forecasts for the forthcoming access arrangement period.

The remainder of this section is structured as follows:

- section 3.2 provides a summary of historic and forecast generation connections; and
- section 3.3 provides some concluding comments.

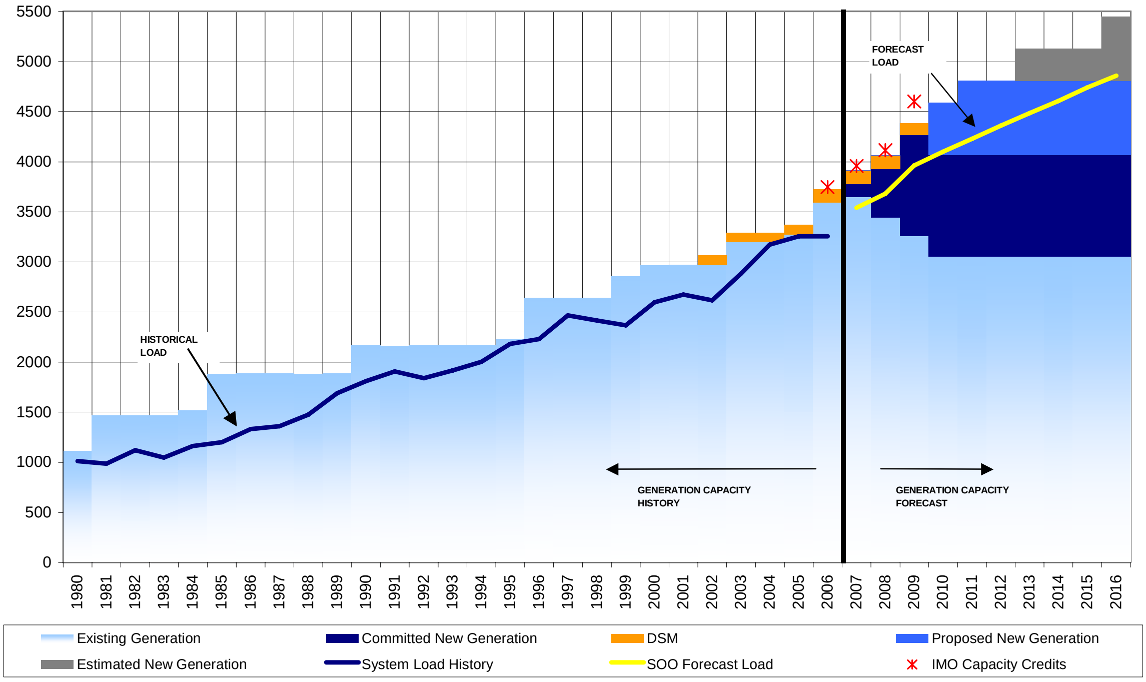
3.2 Historic and forecast generation connections

In order for Western Power Networks to produce its forecast capital expenditure for the transmission network, it must produce a future generation scenario. This scenario must meet the system security criteria such as the minimum reserve margin. The scenario can then be used in planning studies to determine the network augmentations that are required to ensure that supply reliability is maintained.

Historically, generation capacity has tended to be added to the SWIS in large increments every 3 to 5 years. The addition of generation capacity has been necessary given the increasing demand on the transmission system, which has tended to accelerate in recent years. Figure 5a below shows historical and forecast load and generation capacity from 1980 to 2016 and also shows the reserve margin (the gap between generation capacity and maximum system demand).

[19] Further details of Western Power's planning process are provided in section 4 of Part A of this submission.

Figure 5a - Historical and forecast load and generation capacity.



The load forecast in figure 5a and the proposed generation scenario are based on the 2006 Statement of Opportunities (SOO) published by the IMO.

The establishment of a competitive generation market introduces a new dynamic into transmission network planning. At this time it appears that the majority of new generation connections will be of a smaller size and/or in different locations, rather than the more "lumpy" additions of larger generators or multiple generators at the same site. This expectation is reflected in the forecasts of generation capacity for 2007 to 2010 in the Figure 5. The impact of these more numerous and smaller connections is that total connection and network reinforcement costs will be higher than recent historical levels.

A significant proportion of new generation capacity is expected to be located south of the Perth metropolitan area in the region between Pinjarra and Collie. The main factors driving this predominant location are:

- proximity to a developed coal source;
- access to the Dampier-Bunbury gas pipeline;
- the suitability of the area to renewable energy wind and biomass development;
- the presence of major established industries requiring steam with an option for cogeneration;
- the environmental suitability of the area to further power station development; and
- access to suitable land, water and other infrastructure.

Western Power has developed generation scenarios based upon its knowledge of the announced projects, and the relative probabilities of new generation development occurring in particular locations. An important driver of the expected increase in generation capacity is that existing reserve margins need to be maintained.

The general guidelines for the selection of generation proposals for inclusion in the future generation development scenario were as follows:

- Precedence was given to generation proposals contained in the 2006 SOO or well developed proposals that have been made since publication of the 2006 SOO, or which are currently making progress with access studies and applications;

- Precedence was given to generation proposals that are of a size that will provide a substantial portion of the new capacity required to meet the reserve margin each year; and

- Generation proposals not included were either relatively underdeveloped proposals, proposals that were relatively small in size and insignificant to overall generation planning, or proposals with a history of deferral.

Based upon this assessment, Western Power considers the following projects constitute a reasonable generation development scenario for the forthcoming access arrangement period.

Old and inefficient generating plant will be de-commissioned as follows (as published in the IMO's 2006 Statement of Opportunities):

- 2006/07: Muja A/B is approximately 40 years old and has a sent-out capacity of 202 MW;

- 2007/08: Kwinana B is approximately 35 years old and has a sent-out capacity of 212 MW; and

- 2008/09: Kwinana A is approximately 35 years old and has a sent-out capacity of 194 MW.

At this point in time, the committed generation projects are (as per IMO's July 2006 SOO):

- 2006: Alinta 2, with 129 MW of capacity;

- 2006: Emu Downs Windfarm, with total capacity of 80 MW (note: intermittent capacity – 31.1 MW allocated by the IMO);

- 2007: Muja D Upgrade, with 52 MW of capacity;

- 2007: Alinta Wagerup, with 351 MW of capacity;

- 2008: Bluewaters 1, with 204 MW of capacity; and

- 2008: Newgen, with 320 MW of capacity.

Table 5a below shows the assumed generation connections, which are in addition to the committed projects listed above.

Table 5a: Assumed generation connections

Generation Connection	Access Agreement Signed?	Target Date	MW
Bluewaters 2	No	Nov 2009	220
Collie 2	No	Nov 2010	320
Collie 3	No	Nov 2012	320

3.3 Concluding comments in relation to generation capacity forecasts

This section has briefly outlined the expected increase in generation capacity that the transmission system must accommodate over the forthcoming access arrangement period. As noted in section 1 of this Part B, the forecast generation capacity together with the forecast demand on the transmission system effectively define the quantity of services that the transmission network must provide.

The generation reserve margin has narrowed in recent years, and this is expected to be addressed in the forthcoming access arrangement period by the addition of new generation capacity. However, the introduction of competition in the generation market means that Western Power will have little influence on the location, scale and timing of the new generation capacity. In addition, the transmission business expects the increments of generation to be smaller, and therefore the number of new connections is also expected to increase compared to historic levels.

Western Power expects that much of the additional generation capacity will seek connection in the South West area of the SWIS. This enables the transmission business to anticipate some of the network investment that will be required to facilitate the connection of the new generation capacity. However, the uncertain nature of the transmission costs raises important regulatory issues in relation to whether Western Power or its customers should bear the risk of cost forecast errors. This issue is discussed in more detail in Part D of this submission, in relation to the Investment Adjustment Mechanism.

4 Transmission capital expenditure

4.1 Introduction

This section describes and substantiates the capital expenditure forecasts for the transmission network. As noted earlier, the information presented in this section takes account of the Authority's Draft Decision, including reports from consultants Wilson Cook, and the revised forecasts provided by Western Power on 26 September 2006 in response to the Section 51 request for information issued by the Authority on 22 August 2006.

The capital expenditure requirements of the transmission network should achieve the following outcomes:

- network asset condition and service performance should comply with all relevant legislation and regulations;
- service performance should also meet customers' expectations in terms of reliability and quality of supply;
- generation connections should be facilitated to ensure that security of supply is maintained;
- assets must be renewed to ensure that service performance is not compromised in the medium term; and
- the life-cycle costs of providing transmission services should be minimised by appropriately balancing operating and capital expenditure.

In addition, it is essential that expenditure plans are feasible given the availability of internal and external resources, and the need to ensure that expenditure is executed efficiently. Furthermore, the resulting prices to Western Power's customers must be acceptable – taking into account the competing demands for better service and the desire to minimise price increases where practicable.

The purpose of this section is to provide information on the cost pressures in the forthcoming access arrangement period, noting the key changes from the recent past that must be addressed. Western Power accepts, however, that it is not practical or desirable to accommodate all of the pressure to increase expenditure in the forthcoming access arrangement period. Instead, the company intends to propose expenditure that is compatible with improving service delivery, whilst recognising the constraints that must be applied to ideal levels of expenditure in order to ensure that plans can be met without substantially compromising efficiency or long-term price stability.

The remainder of this section is structured as follows:

- section 4.2 summarises the drivers for increased expenditure in the forthcoming access arrangement period;
- section 4.3 explains the strategies and initiatives adopted by Western Power to improve the business' capacity to deliver an increased quantity of projects in the face of resource constraints, and without compromising cost efficiencies; and

- section 4.4 presents Western Power’s transmission network capital expenditure proposals.

4.2 Drivers for increased transmission capital expenditure

In relation to transmission network capital expenditure, there are six principal drivers for increased expenditure from historic levels. These are:

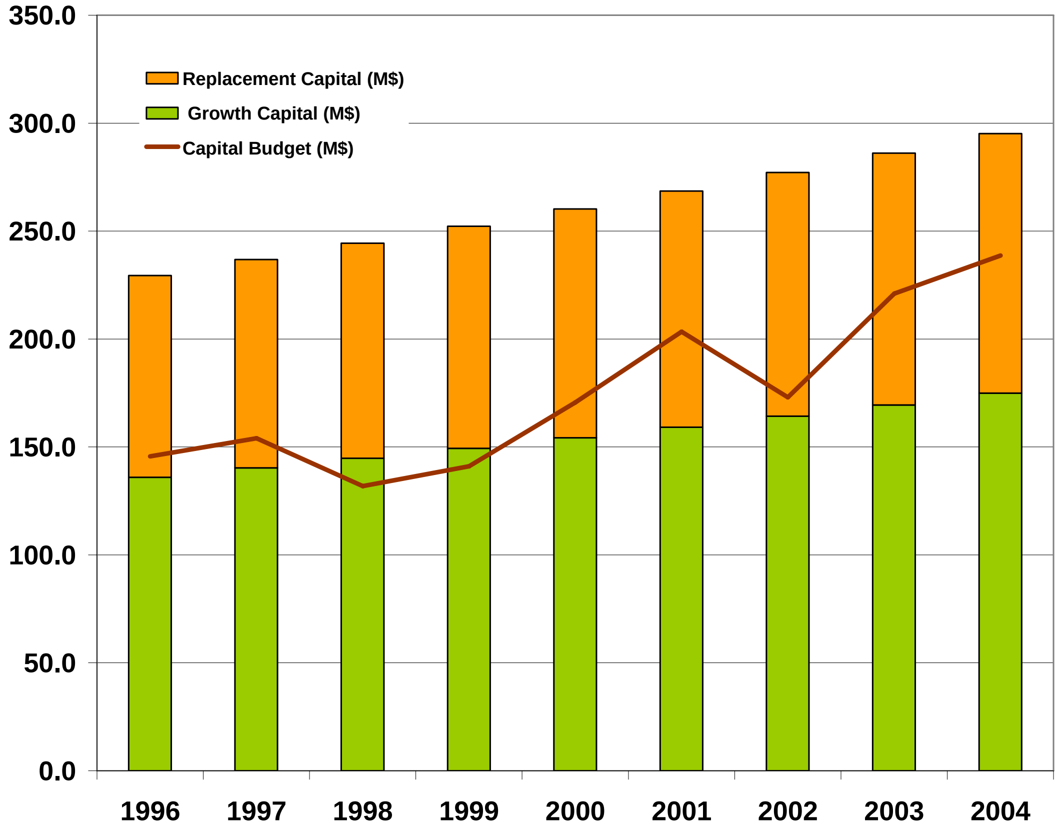
- the impacts of previous budget constraints;
- facilitation of market reform;
- asset replacement;
- facilitate the connection of additional generation capacity;
- achieving and maintaining network performance in accordance with approved planning criteria; and
- compliance with more onerous safety, health, and environment regulations.

The first two of these drivers affect both the transmission and distribution networks, whereas the latter four drivers specifically relate to the transmission network. For ease of reference, all six drivers are discussed in the remainder of this section.

4.2.1 Impact of previous budget constraints

Over recent years, Western Australia has continued to enjoy a period of high economic and population growth. Unfortunately, Western Power’s capital expenditure budget for its predecessor network business has remained at a level that has barely allowed the business to undertake new customer works. Figure 6 below shows that a substantial amount of replacement capital expenditure has not been undertaken as a result.

Figure 6 – Growth and replacement capital requirements and budget (Nominal dollars)



At current levels of capital expenditure, Western Power is replacing less than 0.5% of its system per year. This level of capital expenditure is unsustainable given that a typical network business with asset lives of 40-50 years would expect on average to replace between 2% and 2.5% of its capital base per annum. Unsurprisingly, therefore, Western Power has a growing backlog of assets that are identified for repair and replacement. Western Power has identified $40 million of backlog replacement capital expenditure in the transmission network.

Whilst it is not unusual for a network business to operate with some element of backlog expenditure, in Western Power's view it is important that the current level of backlog is not allowed to increase further. Arresting the growth in the replacement backlog will itself require an increase in replacement capital expenditure in the forthcoming access arrangement period. Of course, the extent of the increase is a matter of judgement, given the age profile of the asset base; the condition of the assets; and the overarching need to ensure that expenditure remains at a manageable level both from the perspective of Western Power's customers and in terms of ensuring efficient execution of projects.

4.2.2 Facilitation of market reform

Western Power is required to support the implementation of market reforms including the enablement of competition and the disaggregation of Western Power Corporation. The market reforms will have the most significant impact upon Western Power in the Information Technology area, although structural changes will impact all areas of the business.

The projects that have been identified by Western Power as being required to facilitate competition or disaggregation include:

- **Standalone business systems** - Configuration of the corporate systems adopted by Western Power after corporate ring-fencing is complete. Works include Internet, Intranet, MIMS, Financial modelling, Treasury, DMS, Messaging.

- **Networks Customer Information System** - Replacement of current systems and processes with an off-the-shelf package that supports access billing, and provides Western Power with capability to manage customers (retailers and non-energy customers) in a de-regulated environment as an independent business unit.

- **Metron** – A Metering Business System to enable the dissemination of metering data to the Western Australian Energy Market participants.

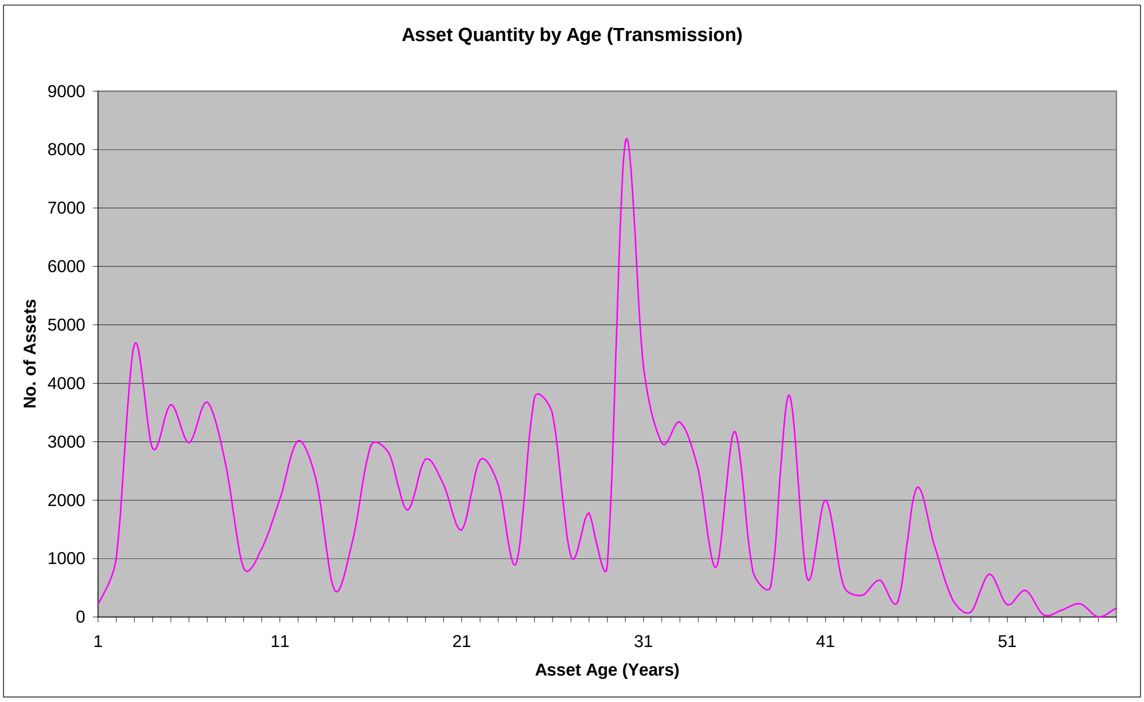
- **Compliance reporting** – Works include determining compliance reporting needs and the implementation of a solution to best meet the needs of Networks and the Regulator.

The projected Western Power expenditures associated with market reforms include costs associated with disaggregation and competition reforms. Notwithstanding this, Western Power's forecast expenditure of less than $50 per customer compares favourably with per-customer costs incurred in other Australian states where expenditures in those states primarily relate to competition reforms only.

4.2.3 Asset replacement

The advancing age of Western Power's transmission network means within the next 10 to 15 years, there will be a need to replace much greater volumes of assets than has been the case in the last ten years. Figure 7 below shows an installation age profile for the transmission assets. This figure indicates the large number of assets that were installed around 30 years ago. Noting that transmission asset economic lives are generally in the order of 40-60 years, this data clearly shows that Western Power is entering a period of increasing need for asset replacement.

Figure 7: Transmission asset age profile



The ageing asset base reinforces the view expressed in section 4.2.1 above that the existing level of replacement expenditure is not sustainable, even in the short to medium term.

4.2.4 Facilitate the connection of additional generation capacity

In section 3 of this Part B, it was noted that increases in forecast generation capacity will have an impact on network expenditure. The precise location and quantity of new generation capacity cannot be known with certainty. Therefore, it is difficult to forecast the precise impact of new generation capacity on transmission network capital expenditure.

As noted elsewhere in this document, without the necessary network infrastructure to provide minimum levels of power transfer capability, generator outputs may need to be restricted to maintain network safety, reliability and security. Such restrictions may have an adverse impact on the development of a competitive generation market. They may also lead to undue increases in the overall cost of electricity supply within the SWIS. It is therefore imperative that sufficient capital expenditure is allowed to facilitate connection of new generation capacity.

In Western Power's view, the bulk transmission network will require a significant level of network investment to allow the system to accommodate the expected increase in generation capacity and still comply with the performance levels specified in the Technical Rules. Generation scenario analysis, combined with power system modelling, assist Western Power in identifying the network investment likely to be necessary to meet existing planning criteria.

It is also noted that the increasing demand and energy requirements of customers, as described in section 2 of this Part B of the document, will also drive future network capital expenditure. It is noted, however, that whilst these increased demand and energy requirements will affect capital expenditure, this particular driver is not expected to result in a material increase in expenditure over historic levels. Notwithstanding this observation, connection of bulk loads to the transmission system can lead to significant and lumpy network capital expenditure.

*4.2.5 Achieving and maintaining network performance in accordance with approved pl***anning criteria**

In the 1990s the company allowed certain substations to be loaded to 90% of the normal cyclic rating (NCR), providing that a rapid response spare transformer (RRST) was available in the event of a transformer failure. It is now recognised, however, that this approach is not consistent with current engineering best practice.

Although the adoption of this policy has been successful in managing the capital expenditure restrictions noted in section 4.2.1, it has resulted in an increasing utilisation of the substations. As the average loading level of substations across the system increases, it is becoming increasingly difficult to operate the network under contingency conditions, and the risk of loss of supply is increasing.

This problem is accentuated by the fact that the lower margins of spare capacity do not cater for the less predictable surges in demand growth that are now being experienced due to the unprecedented use of air conditioners. In addition, the implementation of the NCR criteria has now reached a stage where deferral of capex is more difficult as the criteria is fully implemented in many substations. This means that a natural point has been reached where transmission expenditure will need to ramp up to meet even normal load growth.

Following a number of widespread outages in Queensland, the state government commissioned a report into the electricity networks operated by Energex and Ergon Energy. This report[20] highlighted substation planning practices and high levels of utilisation as contributory factors in the outages. It is important for Western Power to learn from the findings in Queensland, and in this regard the company now believes that a more conservative NCR criterion should be adopted.

In Western Power's view, it is important that the capital expenditure in the forthcoming access arrangement period winds back the loadings on Western Power's substations. The rate and extent of this 'wind back' is a matter of engineering judgement. It is important to note that increasing the level of system utilisation has enabled the company to meet its capital expenditure budget constraints. As a minimum, however, system utilisation cannot continue to increase without unacceptably compromising supply reliability. Moreover, as demonstrated by the recent experience in Queensland, it would be prudent and efficient to undertake expenditure that facilitates some reduction in the presently high levels of utilisation across the network.

4.2.6 Compliance with more onerous safety, health, and environment regulations

As noted in section 5 of Part A of this document, Western Power's expenditure in relation to safety, health and environmental regulations is not discretionary. In the forthcoming access arrangement period, and in consultation with the relevant authorities, Western Power has identified the following specific capital expenditure

[20] Electricity Distribution and Service Delivery for the 21st Century, prepared for the Queensland Government, July 2004.

projects that are required in order to ensure the company's compliance with existing regulations:

- noise mitigation;
- transmission line river crossings;
- transformer neutral earthing resistors and bunding;
- transmission substation safety upgrades; and
- step and touch potential mitigation.

The completion of these non-discretionary projects will require additional capital expenditure compared to recent historic levels.

4.3 Western Power's approach to delivering capital expenditure

In Section 4.2, six principal drivers for increases in transmission network capital expenditure were identified. With the assistance of PB Associates, Western Power has undertaken a detailed and comprehensive assessment of its capital and operating expenditure necessary to deliver all the required performance outcomes (safety, new customer connections, reliability, prudent asset management, etc.). The expenditure report (attached to this document at Appendix 6) details Western Power's expenditure plans taking into account the resource constraints faced by the company, and the need to manage the transition to higher and more sustainable expenditure levels.

The revised expenditure plans take account of the Authority's findings in the Draft Decision, including the reports from consultants Wilson Cook, and the revised forecasts provided by Western Power on 26 September 2006 in response to the Authority's Section 51 request for information issued on 22 August 2006. Importantly, Western Power's response to the Authority's Section 51 request considered the impact of the latest available cost information, which indicates that unit capital prices and tenders from contractors have both been subject to substantial increases.

Western Power has adopted two key strategies for meeting the resourcing challenges in the forthcoming access arrangement period and beyond:

1. **Extend the capability of the in-house resources** to deliver more projects using in-house resources and out-sourcing, and

2. **Encourage the external market to progressively build its capacity** to assist the business to deliver the total project workload by:

   (i) immediately increasing the number of projects (or part projects) that are out-sourced, and

   (ii) giving clear signals to the market about the type and extent of project workload that will be outsourced over the next four to five years.

These strategies require several complementary initiatives (all of which are underway) to reduce the risk of poor project outcomes and/or delivery failure:

1. **The Program Management Office** has been established to efficiently manage the program of work (that is, to set priorities, allocate work to in-house and outside resources, confirm aggregated materials requirements as early as possible for the ensuing financial year, and report progress to management);

2. **The Flexible Resourcing Office** has been established to focus on managing the portfolio of out-sourced work and to assist with building the skills needed to successfully out-source large packages of work, and

3. **The Works Management System** has been implemented, the two key purposes of which are to: (i) provide a dynamic view of the status of the program of work in order to facilitate the efficient management of work; and (ii) provide an integrated view of resource capability, facilitating optimum resource allocation.

These initiatives are aimed at improving the business' capacity to deliver an increased quantity of projects without compromising cost efficiencies.

Western Power's capability to undertake the increased expenditure required over the forthcoming access arrangement period is dependent on the ability of its suppliers and contractors to provide the necessary resources (including materials, labour and plant). The capability of suppliers and contractors will be limited because most other network businesses in Australia are also commencing similar increased investment programs. Consequently, Western Power's assessment of capability is somewhat more conservative than industry's advice in this regard.

Western Power's detailed expenditure plan, which is presented in Appendix 6 of this document, represents Western Power's realistic assessment of what can be achieved in relation to meeting the transmission network's capital expenditure needs over the forthcoming access arrangement period.

4.4 Western Power's capital expenditure proposals

Table 6 below provides a summary of actual and forecast transmission capital expenditure, by category, for the period 2002/03 to 2008/09. For further details of Western Power's expenditure plans please refer to Appendix 6 of this document.

Table 6: Forecast Transmission Capital Expenditure by expenditure type
($ million real as at 30 June 06)

	Actual	Actual	Actual	Actual	Forecast	Forecast	Forecast
	Historical				First access arrangement period		
	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
DEMAND RELATED							
System Capacity	90.6	83.1	68.8	81.9	79.0	101.9	98.9
Customer Driven - Bulk Loads	0.3	2.2	2.2	7.9	28.4	52.4	11.2
Customer Driven - Generation	0.3	3.1	44.6	82.4	66.4	38.7	22.8
NON DEMAND RELATED							
Asset Replacement	3.6	5.6	5.7	7.0	13.8	14.2	18.4
Safety, Environmental & Statutory	0.1	0.3	1.5	3.4	8.0	13.5	14.0
Reliability Driven	1.0	1.4	0.7	1.1	1.5	0.3	0.0
OTHER							
SCADA & Communications	4.9	4.0	2.1	4.1	5.6	1.4	3.1
IT (inc. Market Reform)	0.6	0.4	1.2	0.8	2.1	2.8	2.5
Support	1.8	1.4	5.1	2.8	5.1	4.3	2.7
Transmission Total ($M)	**103.1**	**101.5**	**131.9**	**191.6**	**210.0**	**229.6**	**173.6**

Table 7 below shows the forecast capital expenditure by asset class.

Table 7 – Forecast Transmission Capital Expenditure by asset class
($ million real as at 30 June 06)

	Forecast	Forecast	Forecast
	First access arrangement period		
	2006/07	2007/08	2008/09
Transmission transformers	35.9	33.9	28.3
Transmission reactors	1.0	1.0	1.6
Transmission capacitors	4.7	14.4	9.3
Transmission circuit breakers	38.3	39.4	41.7
Transmission lines - steel towers	79.0	78.3	46.3
Transmission lines - wood poles	4.8	5.9	22.5
Transmission cables	4.8	6.5	0.4
Transmission metering	0.0	0.0	0.0
Transmission SCADA and Communications	5.6	1.4	3.1
Transmission IT&T	2.1	2.8	2.5
Transmission Other, non-network assets	13.9	16.4	9.8
Transmission Land & Easements	19.9	29.5	8.2
TOTAL	**210.0**	**229.6**	**173.6**

5 Transmission operating and maintenance expenditure

5.1 Introduction

This section describes and substantiates the operating expenditure forecasts for the transmission network. As noted earlier, the information presented in this section takes account of the Authority's Draft Decision, including reports from consultants Wilson Cook, and the revised forecasts provided by Western Power on 26 September 2006 in response to the Section 51 request for information issued by the Authority on 22 August 2006.

The operating expenditure requirements of the transmission network should achieve the following outcomes:

- satisfaction of future demand for Western Power's services, including new connection enquiries from generators and loads;
- alignment of asset management strategies with industry best practice;
- ensuring that benchmark service standards for the transmission network are achieved;
- ensuring compliance with health, safety and environmental obligations;
- minimization of total life-cycle costs by optimising operating and maintenance (O&M) and capital expenditures; and
- delivery of achievable and sustainable efficiency gains, in terms of improved performance, increased output and lower cost.

The remainder of this section is structured as follows:

- section 5.2 summarises the drivers for increased operating expenditure in the forthcoming access arrangement period;
- section 5.3 explains Western Power's approach to determining its operating expenditure for the forthcoming access arrangement period; and
- section 5.4 presents Western Power's transmission network operating expenditure proposals.

5.2 Drivers for increased operating expenditure

In a number of respects, the drivers for increased operating expenditure are similar to those identified in relation to capital expenditure. In particular, future transmission operating expenditure will be affected by:

- the impact of previous budget constraints;
- facilitation of market reform;
- facilitating the connection of additional generation capacity; and
- compliance with more onerous safety, health, and environment regulations.

In addition to these factors (which drive operating and capital costs), two cost drivers relating specifically to operating expenditure are:

- optimisation of maintenance expenditure; and
- insurance.

Each of these cost drivers are discussed in turn, but for more detailed discussion of the first four cost drivers listed above, please refer to section 4.2.

5.2.1 Impact of previous budget constraints

In recent years, Western Power Corporation's network business operated within budget constraints that have required expenditure to be reduced below optimal levels. This has affected both capital and operating expenditure, and will have an impact on future operating expenditure.

To some extent, rectifying the backlog in replacement capital expenditure over forthcoming years will reduce the pressure on operating expenditure. In particular, expenditure in relation to corrective emergency maintenance expenditure should reduce as asset failure rates decline. However, Western Power also needs to address a growing backlog in preventative routine maintenance in order to arrest the recent increase in failure rates (see section 5.2.2 of Part A of this document for details).

It is noted that increases in preventative routine maintenance will have a number of positive impacts in terms of business performance. In particular, it will assist the transmission business in meeting its service benchmarks in relation to circuit availability and customer minutes off supply. In addition, preventative maintenance will assist the business in minimising the risk of non-compliance with its health, safety and environmental obligations.

The key preventative maintenance activities that will be enhanced in the forthcoming access arrangement period are summarised in Table 8 below.

Table 8: Key preventative activities for the transmission network

Substation Primary Plant Maintenance	This activity includes maintenance of switchgear, disconnectors, transformers and other associated transmission primary plant, in accordance with good electricity industry practice.
Line Patrol / Pole Top Inspection	These patrols are necessary to ensure that Western Power meets its regulatory requirements as well as reducing the potential risks of fire, outages or injury to staff and the public. These inspections help detect sagging or aged conductors or poor condition pole tops so that action can be taken prior to equipment failure. These inspections are likely to lead to additional follow-up work.
Substation HV Equipment Testing	This activity includes routine maintenance and electrical testing of CTs, VTs, CVTs, SAs and indoor switchboards in order to meet the defined asset mission criteria.
Line Washing / Insulator Silicone	This activity includes the washing of line insulators from elevated platform vehicles or helicopters. This activity covers the most critical transmission lines located close to the coast, to reduce the number of outage incidents due to salt build-up.
Line Easement Vegetation Maintenance	This program is intended to reduce exposure to bushfires and reduce the number and severity of system interruptions.
Plant Modification & Refurbishment	This activity includes works to bring plant up to an acceptable condition and meet new compliance requirements, as identified from reviews and inspections. Some examples include re-clamping windings on specific transmission power transformers, removal of redundant transmission lines and refurbishment of 66 kV transformers.

5.2.2 Facilitation of market reform

In relation to capital expenditure, the following market reform projects were noted (in section 4.2.2 above) as key cost drivers in the forthcoming regulatory period:

- **Standalone business systems** - Configuration of the corporate systems adopted by Western Power after corporate ring-fencing is complete. Works include Internet, Intranet, MIMS, Financial modelling, Treasury, DMS, Messaging.

- **Networks Customer Information System** - Replacement of current systems and processes with an off-the-shelf package that supports access billing, and provides Western Power with capability to manage customers (retailers and non-energy customers) in a de-regulated environment as an independent business unit.

- **Metron** – A Metering Business System to enable the dissemination of metering data to the Western Australian Energy Market participants.

- **Compliance reporting** – Works include determining compliance reporting needs and the implementation of a solution to best meet the needs of Networks and the Regulator.

Each of these projects will have an operating expense component, and therefore these cost drivers are equally relevant to future operating expenditure. A particular area where costs are likely to increase is in relation to compliance and regulatory reporting, as the new regulatory arrangements are implemented.

5.2.3 Facilitate the connection of additional generation capacity

As noted in section 3 above, Western Power expects a substantial increase in generation connections in the forthcoming regulatory period. As a result, Western Power will need to address an increased number of connection inquiries and connection agreements (operating expenditure) in addition to the physical connection of the generators (capital expenditure).

5.2.4 Compliance with safety, health, and environment regulations

It was noted in section 4 above, that the company must comply with more onerous safety, health, and environment regulations in the forthcoming regulatory period.

In relation to operating expenditure, the key compliance issues relate to the need for additional network inspections and associated follow-up maintenance work to meet prescribed maintenance standards. Bushfire mitigation programs also necessitate increased vegetation management activities. These operating expenditure are non-discretionary and cannot be deferred to later periods.

5.2.5 Optimisation of maintenance expenditure

In addition to the specific impact of budget constraints, Western Power also recognises that further work needs to be undertaken in order to optimise maintenance expenditure. The purpose of this optimisation is to better balance expenditure between operating and capital, but also to direct operating expenditure in an effort to minimise its total life-cycle costs.

To assist the company to optimise its future maintenance expenditure, Western Power intends to develop a more comprehensive maintenance strategy. Western Power believes that an increased focus on strategic asset management will enable the business to identify efficiency and network performance improvement opportunities that will ultimately lead to improvements in services for customers.

5.2.6 Insurance

Western Power’s insurance costs have increased over the past 2 years, and are projected to escalate further over the forthcoming access arrangement period. Increases occurring in 2004 and 2005 reflect the difficult climate for utility insurances following 9/11 and the general tightening of policy availability and conditions. The continued increases reflect the expected industry trends for insurance premiums following careful analysis of the market.

5.3 Western Power’s approach to determining transmission operating expenditure

In section 4.3, Western Power explained that its proposed capital expenditure has addressed the issue of resource constraints, so that the expenditure plan is achievable. Similar considerations also apply in relation to operating expenditure. In particular Western Power has sought to minimise the required increase in expenditure, recognising the cost drivers in the forthcoming regulatory period and the resource constraints that are expected to apply.

Taking all of these matters into account, Western Power believes it is appropriate for operating expenditure in the forthcoming regulatory period to be somewhat higher than historic levels. In evaluating the extent to which future operating expenditure needs to be increased, Western Power has sought to contain price increases, recognising that the application of onerous constraints to operating expenditure would expose the company and its customers to excessive risk in terms of the long-term performance of the network. It is therefore essential that all reasonable endeavours are made to increase preventative maintenance to levels that are consistent with good electricity industry practice. It is also essential that the company has available to it sufficient resources to enable it to comply with all health, safety and environmental obligations within reasonable timeframes.

In this context, Western Power has undertaken an analysis of its business and operations to identify opportunities to increase its efficiency and performance. Consequently, a change program was initiated to secure efficiencies and other benefits across a number of areas relating to:

- cost effective purchasing and procurement strategies for materials and services;
- improvements to the way work is planned, given priority, schedules and resource; and
- improvements in the methods and standards for undertaking operational, maintenance and capital works.

Efficiency benefits are being sought in both capital and operating expenditure. However, the primary focus is currently on opportunities in the operating expenditure area. A range of business cases have been approved for implementation and these have a potential yield of $17m of operating expenditure efficiency benefits commencing in the financial year commencing 1 July 2006.

As well as implementing existing initiatives, Western Power is still looking to identify a further $3-4m of efficiency changes to ensure its efficiency target of $20m is achieved. Efficiency benefits, once achieved, are expected to recur each financial year through to 2008/09 and beyond.

5.4 Western Power's forecast transmission operating expenditure

Table 9 below provides details of actual and forecast transmission maintenance expenditure over the period from 2003 to 2009.

Table 9 – Forecast Transmission Operating and Maintenance Expenditure by expenditure type ($ million real as at 30 June 06)

	Actual	***Actual***	***Actual***	***Forecast***	***Forecast***	***Forecast***	***Forecast***
	Historical			**Interim**	**First access arrangement period**		
	2002/03	**2003/04**	**2004/05**	**2005/06**	**2006/07**	**2007/08**	**2008/09**
Maintenance Strategy	2.7	4.0	3.9	3.6	4.1	3.9	3.9
Preventative Condition	6.4	6.2	7.2	10.0	6.9	6.9	6.9
Preventative Routine	8.4	7.0	8.1	10.1	8.2	9.0	9.4
Corrective Deferred	3.3	3.0	3.8	4.0	4.5	3.8	4.1
Corrective Emergency	2.2	0.7	1.2	1.4	1.0	0.9	0.8
Maintenance (Total)	**23.0**	**20.9**	**24.2**	**29.1**	**24.7**	**24.4**	**25.1**
SCADA & Communications	2.0	3.3	2.5	3.2	5.3	5.3	5.3
Misc Network Services	0.0	0.0	3.4	6.4	4.2	4.3	4.3
Network Operations	8.3	9.4	8.4	9.5	9.7	10.4	10.1
IT&T	5.2	6.0	4.8	6.3	7.3	7.8	8.1
Network Support	17.7	17.3	21.9	15.1	13.3	14.4	14.3
Energy Safety Levy	0.0	0.0	0.0	0.0	2.8	2.8	2.8
TRANSMISSION TOTAL	**56.3**	**56.9**	**65.2**	**69.6**	**67.2**	**69.4**	**69.9**

6 Asset valuation and depreciation

6.1 Introduction

The calculation of Western Power's target revenue in the forthcoming access arrangement period requires an assessment of the value of the capital base[21]. The assets that comprise the capital base over the course of the first access arrangement period can be divided into two categories:

- assets employed at the access arrangement start date, which is scheduled to be 1 July 2006; and
- assets employed throughout the duration of the first access arrangement period, which is scheduled to be from 1 July 2006 to 30 June 2009.

[21] The *capital base* is defined in the Code as the value of the network assets that are used to provide covered services on the covered network determined under sections 6.44 to 6.63. The capital base value is an input into the calculation of Western Power's target revenue, in accordance with section 6.4(a) of the Code.

The first category of assets is sometimes referred to as “sunk assets” because it consists of investments already undertaken at the access arrangement start date. Once the value of the assets in existence at the access arrangement start date is determined, the value of assets employed during the access arrangement period largely depends on the company’s capital expenditure program[22], and regulatory depreciation[23].

The Authority’s Draft Decision examined Western Power’s proposed approach to valuing its capital base as at 30 June 2006, as described in Western Power’s access arrangement information document submitted on 24 August 2005. The Authority considered submissions from interested parties, including the Office of Energy, in addition to a report from its consultants Wilson Cook. Required Amendments 37 and 38 of the Authority’s Draft Decision established a valuation for Western Power’s capital base as at 30 June 2006.

Western Power accepts the Authority’s valuation of its capital base as being in accordance with the Code, and therefore the company has adopted this valuation for the purposes of this access arrangement, updated for asset acquisitions associated with the restructuring of the former Western Power Corporation in April 2006 and the actual capital expenditure and depreciation to 30 June 2006, as noted in paragraph 308 of the Final Decision.

The Authority states in paragraph 312 of its Final Decision that it is satisfied that the revised proposed access arrangement incorporates or otherwise addresses the reasons for Draft Decision Amendments 37 and 38, and that the value proposed by Western Power for the capital base at 30 June 2006 (as set out in Table 27 of the Final Decision) meets the requirements of the Access Code.

This remainder of this section presents the following information regarding asset valuation and regulatory depreciation:

- section 6.2 examines the Code provisions relating to the valuation and depreciation of Western Power’s assets for the purpose of determining target revenue;

- section 6.3 describes the valuation of the transmission capital base as at 30 June 2006 (the proposed access arrangement start date) in light of the Code provisions and the Authority’s Draft and Final Decisions;

- section 6.4 summarises Western Power’s approach to depreciation of the transmission capital base in the light of the Authority’s Draft and Final Decisions; and

- section 6.5 provides details of the calculations of the transmission capital base value from 1 July 2006, and for each subsequent year of the first access arrangement period.

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22 Western Power’s capital expenditure program is described in section 2, Part B (transmission) and section 2, Part C (distribution) of this document.

23 In this context, the term “regulatory depreciation” means the depreciation charge adopted for the purpose of determining the company’s target revenue and the value of its capital base. This measure of depreciation may differ from that disclosed in the company’s statutory financial statements.

6.2 Code provisions relating to the valuation of the capital base

Section 6.43 of the Code states that:

> "The *capital-related costs* component of *approved total costs* for a covered network must be calculated by:
>
> (a) determining a *capital base* under sections 6.44 to 6.63; and
>
> (b) calculating a return on the *capital base* of the *covered network* by applying the w*eighted average cost of capital* calculated under section 6.64 to the *capital base*; and
>
> (c) calculating the depreciation of the *capital base* under section 6.70."
>
> The Code's definition *of capital-related costs* and *capital base* are as follows:
>
> "capital-related costs in relation to *covered services* provided by a *service provider* by means of a *covered network* for a period of time, means:
>
> (a) a return on the *capital base* of the *covered network*; and
>
> (b) depreciation of the *capital base* of the *covered network.*"
>
> "capital base for a *covered network* means the value of the network assets that are used to provide *covered services* on the *covered network* determined under sections 6.44 to 6.63."

Sections 6.46 and 6.47 of the Code specify the asset valuation methodology that is to be employed at the commencement of the access arrangement period as follows:

> "6.46 For the start of the *first access arrangement period*, the *capital base* for a *covered network* must be determined using one of the following asset valuation methodologies:
>
> (a) depreciated optimised replacement cost ("DORC"); or
>
> (b) optimised deprival value ("ODV").
>
> 6.47 If under section 6.46 the *ODV* asset valuation methodology is used to determine the *capital base* at the start of the *first access arrangement period* for the *covered network* that is *covered* under section 3.1, the valuation must utilise, to the extent possible, any ministerial valuation under section 119 of the Act of the *network assets* which comprise the *covered network*."

For subsequent years of the access arrangement period, section 6.51 of the Code provides for forecast capital expenditure to be recognised in the calculation of target revenue, providing that the forecast expenditure is reasonably expected to meet the new facilities investment test, as follows:

> "6.51 For the purposes of section 6.4(a)(i) and subject to section 6.49, the forward-looking and efficient costs of providing *covered services* may include costs in relation to *forecast new facilities investment* for the *access arrangement period* which is reasonably expected to meet the *new facilities investment test* when the *forecast new facilities investment* is forecast to be made."

Section 6.48 of the Code describes how the capital base is to be determined at the start of subsequent access arrangement periods.

"6.48 For the start of each *access arrangement period* other than the *first access arrangement period,* the *capital base* for a *covered network* must be determined in a manner which is consistent with the *Code objective*."

Sections 6.61 to 6.63 enable the Authority to remove an amount from the capital base to take account of any redundant capital. Section 6.62 of the Code provides guidance to the Authority in terms of the approach that it must take in determining if any capital is redundant, whilst section 6.63 allows the Authority to take account of its decision in relation to redundant capital in making other determinations:

"6.61 Subject to section 6.62, the *Authority* may in relation to a determination under section 6.44(a) require an amount ("redundant capital") to be removed from the *capital base* to the extent (if any) necessary to ensure that *network assets* which have ceased to contribute in any material way to the provision of *covered services* are not included in the *capital base*.

6.62 Before requiring a removal under section 6.61, the *Authority* must have regard to:

(a) whether the *service provider* was *efficiently minimising costs* when it developed, constructed or acquired the *network assets*; and

(b) the uncertainty such a removal may cause and the effect which any such uncertainty may have on the *service provider*, *users* and *applicants*; and

(c) whether the cause of the *network assets* ceasing to contribute in any material way to the provision of *covered services* was the application of a *written law* or a *statutory instrument*; and

(d) whether the *service provider* was compelled to develop, construct or acquire the *network assets*:

(i) by an award by the *arbitrator*; or

(ii) because of the application of a *written law* or a *statutory instrument*; and

(e) whether the depreciation of the *network assets* should be accelerated instead of or in addition to a *redundant capital* amount being removed from the *capital base* under section 6.61.

6.63 If the *Authority* requires a removal under section 6.61, then when making other determinations under this Chapter 6 the *Authority* may have regard to the removal."

The Code provides limited guidance in relation to the regulatory depreciation that should be applied to the capital base. Section 6.70 places a requirement on the service provider to set out its approach in the access arrangement, as follows:

"6.70 An *access arrangement* must provide for the depreciation of the *network assets* comprising the *capital base*, including the economic lives of each *network asset* or group of *network assets*, the depreciation method to be applied to each *network asset* or group of *network assets* and the circumstances in which the depreciation of a *network asset* may be accelerated."

6.3 The valuation of the transmission capital base as at 30 June 2006

In broad terms, the Code provisions require that:

- The target revenue properly reflects the capital-related costs of providing covered services;

- The capital-related costs comprise the return on capital (namely, WACC multiplied by the capital base value) plus the return of capital (namely, depreciation);

- The capital base value as at the commencement of the first access arrangement period must be set on the basis of a DORC or ODV valuation, and utilise any ministerial valuation made under section 119 of the Act;

- The Authority may remove assets or that part of an asset from the capital base that is considered to be redundant. However, the Authority must also consider whether the investment was prudent at the time it was undertaken, and the possible adverse consequences of removing redundant capital expenditure in terms of its impact on incentives to invest in the future;

- The capital-related costs for an access arrangement period may include forecast capital expenditure, providing that this is a prudent estimate;

- There should be no 'double-charging' in relation to assets whose initial construction costs are funded by capital contributions; and

- The service provider must propose a reasonable approach with regard to the depreciation of the capital base (for the purpose of determining target revenue) over time.

In accordance with Required Amendments 37 and 38 of the Authority's Draft Decision, Western Power proposes that the initial transmission capital base will be the optimized deprival value (ODV) of assets as at 30 June 2004 (determined in accordance with the independent valuation commissioned by the WA Government's Electricity Reform Implementation Unit (ERIU)) adjusted for inflation, depreciation, asset acquisitions and capital expenditure updated for the actual capital expenditure and depreciation to 30 June 2006. The initial transmission capital base is net of accumulated capital contributions received by Western Power to 30 June 2006. For information purposes, the ERIU valuation is attached to this document at Appendix 10.

As noted in section 6.1 above, the Authority states in paragraph 312 of its Final Decision that it is satisfied that the revised proposed access arrangement incorporates or otherwise addresses the reasons for Draft Decision Amendments 37 and 38, and that the value proposed by Western Power for the capital base at 30 June 2006 (as set out in Table 27 of the Final Decision) meets the requirements of the Access Code.

Table 10 below sets out details of the ERIU valuation.

Table 10 – Net ODV valuation of transmission assets as at 30 June 2004 ($ million real as at 30 June 2006)

Asset Group	Remaining Life as at 30 June 2004 (years)	Value
Transmission transformers	24.6	133.7
Transmission reactors	26.5	3.5
Transmission capacitors	23.3	69.2
Transmission circuit breakers	27.7	398.8
Transmission lines - steel towers	41.1	324.8
Transmission lines - wood poles	19.8	144.9
Transmission cables	37.8	10.5
Transmission metering	26.6	2.0
Transmission SCADA and Communications	11.9	33.3
Transmission IT&T	3.4	1.8
Transmission Other, non-network assets	9.8	15.4
Transmission Land & Easements	N/A	68
TOTAL		**1,205.9**

Details of the calculation of the transmission capital base value as at 30 June 2006 are set out in table 11 below.

Table 11 - Derivation of Transmission Initial Capital Base (net) ($ million real as at 30 June 2006)

Financial year ending:	30 June 2004	30 June 2005	30 June 2006
Opening capital base value		1,205.9	1,274.6
less Depreciation		43.4	45.7
plus Capital Expenditure (net)		112.2	149.5
less Redundant Assets		0.0	0.0
plus Corporate Assets allocated to Western Power		0.0	8.1
Closing capital base value	**1,205.9**	**1,274.6**	**1,386.6**

At the time of separation of Western Power Corporation into separate businesses, the transfer order gifted the following corporate assets to Western Power. These assets have been included within the initial capital base of both transmission and distribution with the value split 50%-50%. Table 11a below details the assets and their value at 30 June 2006.

Table 11a – Corporate Assets Transferred to Western Power
($ million real as at 30 June 2006)

Asset	Asset Value
Head Office Land	4.0
Head Office Building	9.3
Jandakot Land	2.7

For the avoidance of doubt, it is noted that the capital base valuation reflects actual capital expenditure for the year ending 30 June 2006.

6.4 Western Power's approach to depreciation – transmission assets

Under the approach to calculating target revenue set out in Subchapter 6.2 of the Code[24], depreciation (as defined in sections 6.43 and 6.70 of the Code) represents a return of accumulated capital to investors. In this sense, it is necessary to distinguish between the depreciation charge that is applied in the calculation of target revenue pursuant to Subchapter 6.2 of the Code, and the depreciation charge that may appear in the company's statutory financial accounts, or in its tax return.

In accordance with the Draft Decision's Required Amendment 46, Western Power adopts the economic lives set out in Table 12 for depreciation purposes. It is noted that in its Final Decision[25], the Authority concludes that Table 12 below satisfies the Authority's Required Amendment 46.

Table 12 - Transmission asset groupings and economic lives for depreciation purposes

Asset group	Economic Life (years) for depreciation purposes
Transmission transformers	50 years
Transmission reactors	50 years
Transmission capacitors	40 years
Transmission circuit breakers	50 years
Transmission lines - steel towers	60 years
Transmission lines - wood poles	45 years
Transmission cables	55 years
Transmission metering	40 years
Transmission SCADA and Communications	34.15 years
Transmission IT&T	16.85 years
Transmission Other, non-network assets	16.85 years

Furthermore, in accordance with the Draft Decision's Required Amendment 47, Western Power confirmed that it is adopting a straight-line approach to depreciation and is not proposing any accelerated depreciation in the first access arrangement

24 "Calculation of Service Provider's Costs".

25 ERA, Final Decision on the Proposed Access Arrangement for the South West Interconnected Network, March 2007, paragraph 420.

period in relation to transmission assets. It is noted that in its Final Decision[26], the Authority concludes that Western Power has satisfied the Authority's Required Amendment 47.

6.5 Proposed transmission capital base and depreciation values

As noted in section 6.3 above, Western Power has adopted a transmission capital base of $1,404.5 million as at 30 June 2006, which has been updated for the latest capital expenditure and depreciation forecasts.

Table 13 below provides details of the composition of the transmission capital base as at 30 June 2006, by asset group.

Table 13 – Transmission Initial Capital Base (net) as at 30 June 2006
($ million real as at 30 June 2006)

Asset Group	Remaining Life as at 30 June 2006 (years)	Value
Transmission transformers	25.5	154.9
Transmission reactors	27.0	3.9
Transmission capacitors	23.1	76.3
Transmission circuit breakers	28.2	455.3
Transmission lines - steel towers	41.3	365.2
Transmission lines - wood poles	20.9	172.7
Transmission cables	38.1	12.1
Transmission metering	26.1	2.1
Transmission SCADA and Communications	11.4	33.9
Transmission IT&T	4.2	2.7
Transmission Other, non-network assets	12.0	24.5
Transmission Land & Easements	N/A	83.0
TOTAL		**1,386.6**

Table 14 below provides an overview of the forecast transmission capital base values for each year of the forthcoming access arrangement period.

Table 14 – Assessment of transmission asset values
($ million real as at 30 June 2006)

Financial year ending:	30 June 2006	30 June 2007	30 June 2008	30 June 2009
Opening capital base value		1,386.6	1,547.7	1,724.2
less Depreciation		-48.8	-53.1	-57.7
plus Capital Expenditure		210.0	229.6	173.6
less Redundant Assets		0.0	0.0	0.0
Closing capital base value	1,386.6	1,547.7	1,724.2	1,840.2

26 Ibid, paragraph 421.

7 The cost of capital

7.1 Introduction

The weighted average cost of capital (WACC) is a critical determinant of the level of Western Power's capital-related costs. These capital-related costs, in turn, comprise a substantial proportion of the company's total costs, and hence its target revenue.

There is a significant degree of imprecision and subjectivity involved in the estimation of the WACC, and there is certainly no one objectively determinable "correct" estimate of the WACC. It is universally recognised however, that very large costs to society as a whole would arise over the long term if regulators set the WACC at a level that is insufficient to encourage adequate on-going investment in infrastructure over the long term.

This section of the document describes the methods and assumptions applied by Western Power to estimate its WACC for the purpose of calculating the target revenue attributable to the SWIS[27]. In particular, the information presented in this chapter is intended to assist interested parties in understanding Western Power's derivation of the WACC, and the process that led Western Power to propose a pre-tax WACC of 6.76%.

Specifically, it should be noted that sections 7.2 to 7.9 below repeat Western Power's analysis of the WACC as presented in its access arrangement information submitted on 24 August 2005. In reiterating this information, Western Power believes that the information presented remains valid (notwithstanding subsequent changes to the risk free rate) in assessing a reasonable point estimate for the WACC for the purposes of determining Western Power's target revenue.

Notwithstanding Western Power's view that its original submission in relation to the WACC remains valid, Western Power fully accepts the Authority's findings in its Final Decision. Specifically, the Authority concluded in paragraph 453 that:

> "The WACC incorporated by Western Power in the revised proposed access arrangement (6.76 per cent pre-tax real) lies within the reasonable range determined by the Authority for the purposes of this Final Decision. Accordingly, the Authority accepts that this value meets the requirements of the Access Code."

On the basis of the Final Decision, Western Power has adopted a pre-tax WACC of 6.76% in its access arrangement.

This section is therefore structured as follows:

- section 7.2 examines the Code provisions and other relevant regulatory instruments relating to WACC;
- section 7.3 broadly outlines Western Power's approach to estimating the WACC;
- section 7.4 examines the statutory framework under the Code that governs the Authority's decision making in relation to WACC;

[27] The methodology and assumptions described here are the same for Western Power's transmission and distribution networks that comprise the SWIS.

- section 7.5 examines the key practical issues which arise when estimating WACC in a regulatory context;

- section 7.6 examines the costs and risks which arise if WACC is set at too low a level;

- section 7.7 details the approach adopted by Western Power's specialist advisers to quantify the estimation errors inherent in establishing the regulatory WACC;

- section 7.8 quantifies the plausible range for the regulatory WACC;

- section 7.9 outlines the approach applied, and considerations taken into account by Western Power to select a point estimate of the WACC from the plausible range; and

- section 7.10 sets out Western Power's conclusion on the WACC to be applied for the purpose of calculating the company's target revenue for the first access arrangement period, having regard to the above analysis and the Authority's Draft Decision and Final Decision.

7.2 Code and other regulatory provisions relating to WACC

Section 6.65 of the Code states:

> "The *Authority* may from time to time make and *publish* a determination (which subject to section 6.68 has effect for all *covered networks* under this Code) of the preferred methodology for calculating the *weighted average cost of capital* in *access arrangements*."

On 25 February 2005, the Authority made and published a determination of the preferred WACC methodology to apply to networks which are covered under the Code.[28]

Section 6.64(a) of the Code states:

> "An *access arrangement* must set out the *weighted average cost of capital* for a *covered network*, which if a determination has effect under section 6.65:
>
> (i) for the *first access arrangement* for the *covered network* that is *covered* under section 3.1 - may use any methodology (which may be formulated without any reference to the determination under section 6.65) but, in determining whether the methodology used is consistent with this Chapter 6 and the *Code* objective, regard must be had to the determination under section 6.65; and
>
> (ii) otherwise - must use the methodology in the determination under section 6.65 unless the *service provider* can demonstrate that an *access arrangement* containing an alternative methodology would better achieve the objectives set out in section 6.4 and the *Code objective*."

Section 6.69 of the Code states:

> "For the *covered network* that is *covered* under section 3.1, a determination under section 6.65 has effect in relation to the *approval* of the *first access arrangement* if it is *published* at least 3 months before the *submission deadline*."

For the avoidance of doubt, paragraph 7 of the Authority's WACC determination states:

> "Pursuant to section 6.69 of the Access Code, this determination is effective for the first access arrangement submitted for Western Power Corporation's South West Interconnected Network (SWIN) within the South West Interconnected System."

Paragraph 5 of the WACC determination states:

> "The Authority's determination, pursuant to section 6.65 is that:
>
> - the capital asset pricing model (CAPM) be the methodology used for calculating the return on assets;
> - financial modelling be applied in real terms;

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[28] A copy of the Authority's *Determination of a preferred WACC methodology for covered electricity networks* is available from the Authority's web site at: http://www.era.wa.gov.au/electricity/library/WACC_Methodology_Determination_23Feb05.pdf

- the weighted average cost of capital (WACC) be formulated on a pre-tax basis, using the Officer formula with the taxation adjustment calculated using a forward transformation;
- the debt premium be based on market evidence of debt costs for businesses with a credit risk profile consistent with a BBB or BBB+ credit rating (sources of relevant market evidence may include CBASpectrum and Bloomberg estimates of corporate bond yields);
- nominal risk free rates to be derived from Commonwealth 10 year bond rates with terms of 10 years, calculated on the basis of a 20 trading day average of the yields, taken at the final day of the month prior to a decision on an access arrangement;
- real risk free rates to be derived from a 20 trading day average of the yields on Commonwealth index-linked bonds with terms of 10 years, taken at the final day of the month prior to a decision on an access arrangement;
- the inflation forecast for the relevant period is the difference between the nominal risk free rate and real risk free rate (calculated using the Fisher equation); and
- an appropriate benchmark gearing assumption be adopted to encourage efficient financing decisions."

Importantly, paragraph 8 of the determination states:

> "It is noted that the figures in Appendix 1 to this determination do not represent a pre-determination of the WACC by the Authority, but are intended to represent a reasonable depiction of the cost of capital at the time of publication of this determination. Appendix 1 sets out the inputs into the WACC calculation considered by the Authority to be an effective means of achieving the objectives in sections 2.1 and 6.4 of the Access Code for the SWIN."

7.3 Western Power's approach to estimating the WACC

Western Power appointed KPMG and the Strategic Finance Group (SFG) to provide specialist assistance in estimating the WACC. The reports provided by KPMG and SFG form part of this access arrangement information, and are attached as Appendices 3 and 4, respectively.

KPMG's report sets out detailed analysis that identifies and describes the feasible or plausible range of values for each of the individual WACC parameters, namely:

- the real risk free rate;
- equity beta;
- market risk premium;
- capital structure;
- debt margin and cost of debt; and
- the value of imputation credits.

SFG then undertook an analysis which translated the plausible range of values for each WACC parameter into a point estimate of the WACC. To do this, SFG developed and applied a simple framework based on well-accepted statistical procedures to quantify the statistical imprecision associated with estimating WACC parameter values and the WACC itself.

KPMG's report sets out the key results of SFG's analysis. That report also states that KPMG is of the view that the overall approach applied by Western Power in developing its point estimate of the WACC is consistent with the Authority's WACC determination made on 25 February 2005.

7.4 Framework for the Authority's decision making under the Code

In its report to Western Power, KPMG expresses concern regarding the Authority's interpretation of its obligations under the Code, and certain aspects of the Authority's approach to determining the WACC methodology.

As already noted, there is significant uncertainty and estimation error involved in determining a point estimate of the WACC. This necessarily leads to a need for reasonable judgement to be exercised when selecting a point estimate of WACC from a plausible range. In this context, it is worth noting that section 4.28 of the Code is a significant provision as it attempts to clarify the nature of the Authority's functions in carrying out its decision making process. The section provides that the Authority must determine whether a proposed access arrangement meets the Code objective and the requirements set out in chapter 5. If the Authority considers that the Code objective and the requirements set out in chapter 5 are satisfied, it must approve the proposed access arrangement.

Section 4.28(b) of the Code states:

> 'To avoid doubt, if the *Authority* considers that the *Code objective* and the requirements set out in chapter 5... are satisfied, it must not refuse to *approve* the *proposed access arrangement* on the ground that another form of *access arrangement* might better or more effectively satisfy the *Code objective* and the requirements set out in chapter 5...'

The note accompanying this provision in the Code states that the effect of section 4.28 is to make the Authority's decision in relation to a proposed access arrangement a 'pass or fail' assessment. The policy behind this provision is consistent with the reasoning of the Australian Competition Tribunal in the decision in Re: GasNet Australia (Operations) Pty Ltd [2003] A CompT 6 where it was found (in the context of equivalent provisions of the National Gas Access Code) that the Regulator was required to approve a proposed access arrangement if the proposed access arrangement falls within the range of choice reasonably consistent with the Code principles.

Notwithstanding the apparently clear terms of section 4.28, paragraph 27 of the Authority's WACC determination notes that section 2.1 of the Code requires the service provider's proposal to promote an economically efficient outcome, and that "this objective is not necessarily achieved by the service provider making proposals which fall within a [reasonably open] range of choice". In Western Power's view, the Authority's statement runs counter to the proper approach to be taken to assessing a proposed access arrangement as required by section 4.28.

7.5 Estimating WACC in a regulatory context

The discussion paper published by the Authority in January 2005 noted:

> "The cost of capital for an asset or activity is not unilaterally determined by the owner of the asset, the provider of the capital or, in the case of regulated utilities, by a regulator – it is a market price for investment funds [and is] dependent upon a supply and demand for capital funds. As with the market price for any good or service, the market price for capital cannot be calculated a priori, but is determined by transactions within the market. In judging what the cost of capital might be for a particular project, the best source of information is historical evidence on costs of capital for other, similar, projects and businesses."[29]

The Authority subsequently determined (pursuant to section 6.65 of the Code) that the capital asset pricing model (CAPM) shall be the methodology used for calculating the return on assets.

The practical application of the CAPM to estimate the cost of equity in a regulatory context must recognise the following important considerations:

- Whilst various tests of the CAPM have generally lent support to the broad concepts of risk that underpin the model, empirical testing has also shown that the CAPM does not fully explain security pricing and the cost of equity[30].

- There are significant information constraints, estimation challenges and uncertainties in applying the CAPM in practice. The potentially detrimental impacts of these challenges and methodological limitations are magnified in a regulatory context, where a substantial proportion of revenues and profitability is dependent on the Authority's estimate of WACC.

- In theory, a number of parameters underpinning the CAPM should reflect forward-looking estimates, which are unobservable in practice.

In Western Power's view, the most significant practical consideration arising in the application of the CAPM is that estimating the cost of capital necessarily involves a very significant degree of uncertainty. This practical reality has been recognised by the Productivity Commission in its final report on its review of the gas access regime, as follows:[31]

> "While the debt costs of a service provider are relatively straightforward to assess, the return required by equity investors is not. The return on equity is typically estimated using the capital asset pricing model (CAPM). This method depends on the measurement of two contentious variables — a service provider's 'beta' (a measure of its risk relative to that of the total market for risky investments) and the market risk premium…

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29 Allen Consulting Group, *Advance Determination of a WACC Methodology: Report to Economic Regulation Authority*, January 2005, pages 7 and 9.

30 See, for instance, Richard Roll (1997) "A critique of the asset pricing theory's test", *Journal of Financial Economics, 4*. The Roll critique also highlights the difficulties of testing the theory. Similarly, in its May 2004 *Gas Control Inquiry Draft Report*, the New Zealand Commerce Commission stated: "The Commission acknowledges that a number of the assumptions underlying the CAPM violate real world conditions".

31 Productivity Commission (2004) *Review of the Gas Access Regime*, Report no. 31, Canberra. pages 297, 299, 302.

> Implementing the WACC/CAPM approach is not a precise science, given the numerous debatable assumptions involved. There is even disagreement on the precise formulas to use, due to different views on how issues such as tax should be treated. Hence, a range of plausible values can be generated for the regulatory rate of return using the WACC/CAPM approach…
>
> This debate highlights the fact that regulatory rates of return are set on the basis of many assumptions. Such assumptions are used because regulation is applied in a world of uncertainty...
>
> There is disagreement among technical experts about how regulatory rates of return (WACC) in Australia compare to those in other countries. This illustrates the inevitable imprecision and subjectivity that occurs when regulators are required to approve reference tariffs…"
>
> Given that the CAPM is a theoretical model based on debatable assumptions, the Commission is concerned that the model has become a de facto requirement under the regime. This situation might have been facilitated by s.8.31 of the Gas Code, which describes the CAPM as a 'well accepted financial model'. The comments of the leading financial experts quoted by Allgas Energy would suggest otherwise. The Commission considers that it needs to be made more explicit that there is no single correct method to calculate a rate of return and there can be a range of plausible values used in applying a method. It is recommended that s.8.31 be reworded to reflect this."

SFG's report to Western Power describes and analyses in some detail the practical limitations of using CAPM in a regulatory setting. For instance, page 10 of the SFG report states:

> "It is safe to say that the CAPM does not provide any degree of comfort in being able to state precisely and without reservation what the cost of equity actually is. Confidence intervals around the estimated cost of equity are extremely wide. Furthermore, firm specific estimates would have even greater uncertainty than the industry results that are reported. The merits of the asset pricing approach to cost of equity estimation are perhaps best summed up by Fama and French (1997) themselves:
>
> > '…uncertainty of this magnitude about risk premiums, coupled with the uncertainty about risk loadings [betas], implies woefully imprecise estimates of the cost of equity'."

Given the challenges involved in the application of theoretical asset pricing models such as the CAPM, the paucity and uncertainty of the available data, and the impact that the Authority's WACC determination will have on incentives for on-going investment, it is clear that:

- a considerable amount of careful judgment - based on robust analysis - is required in developing a point estimate of the WACC; and
- the WACC must be set at a level that takes due account of the estimation error involved, and minimises the risk of damaging investment incentives.

Before examining how the estimation error can be taken into account (in section 7.7 of this Part of the document), section 7.6 below examines the significant potential costs that may arise in the event that estimation error leads to the adoption by the Authority of a regulated WACC that is below the true cost of capital.[32]

7.6 Costs and risks involved in setting WACC at too low a level

The Authority will be well aware that one of the major themes of the Productivity Commission's recent review of the national access arrangements was the risk of "regulatory error", and the realisation that the potential costs associated with too little infrastructure investment are far greater than those associated with too much investment. The Productivity Commission found that there is asymmetry in the consequences of regulatory errors:

> "Given that precision is not possible, access arrangements should encourage regulators to lean more towards facilitating investment than short term consumption of services when setting terms and conditions …
>
> [and] given the asymmetry in the costs of under- and over-compensation of facility owners, together with the informational uncertainties facing regulators, there is a strong in principle case to 'err' on the side of investors".

It is in this vein that the Productivity Commission provided a clear warning against an excessive focus on the removal of so-called "monopoly rents" from the revenue streams of facility owners, quoting a submission to the review by National Economics Consulting Group Pty Ltd (NECG), which stated:

> "In using their discretion, regulators effectively face a choice between (i) erring on the side of lower access prices and seeking to ensure they remove any potential for monopoly rents and the consequent allocative inefficiencies from the system; or (ii) allowing higher access prices so as to ensure that sufficient incentives for efficient investment are retained, with the consequent productive and dynamic efficiencies such investment engenders.
>
> There are strong economic reasons in many regulated industries to place particular emphasis on ensuring the incentives are maintained for efficient investment and for continued productivity increases. The dynamic and productive efficiency costs associated with distorted incentives and with slower growth in productivity are almost always likely to outweigh any allocative efficiency losses associated with above-cost pricing. (sub. 39, p. 16)"

Given these important considerations, the Productivity Commission's review of the national access regime made 33 recommendations to improve the operation of the regime. The review identified as a "threshold issue":

> "… the need for the application of the regime to give proper regard to investment issues…[and] the need to provide appropriate incentives for investment".[33]

The Productivity Commission's views were supported by the Australian Government's response, which signalled the Government's intention to make changes to the Trade Practices Act which "endorse the thrust" of the Productivity Commission's recommendations.[34] In particular, the Government will modify the

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32 The notion of the distinction between the true cost of capital and the regulatory WACC is explored in further detail in section 7.7 below.

33 Productivity Commission (2001), *Review of the National Access Regime: Inquiry Report 28*, page xxii.

34 Commonwealth Government (2002), *Government Response to Productivity Commission Report on the Review of the National Access Regime: Interim Response*, page 1.

regime to require the ACCC to have regard to pricing principles, which specify that regulated access prices should:

- be set so as to generate expected revenue for a regulated service or services that is at least sufficient to meet the efficient costs of providing access to the regulated service or services;
- include a return on investment commensurate with the regulatory and commercial risks involved.

It is noteworthy that these requirements are broadly reflected in section 6.4(a)(i) of the Code, which sets out the objectives of price control in an access arrangement.

The Productivity Commission's 2004 review of the gas access regime also recommended the adoption of an objects clause and pricing principles that are essentially the same as those proposed by the Australian Government for the national access regime. In relation to the issue of regulatory error, regulatory risk and WACC, the Productivity Commission stated:[35]

> "The Commission also considers that there is a potential for *regulatory error* under the regime due to the complex issues involved in determining a reference tariff, including the need to make a subjective judgment about the risk faced by a service provider… In addition, recent appeal decisions suggest that regulators err towards imposing lower returns…
>
> … There is also uncertainty about the values of various parameters a regulator might apply in approving reference tariffs (such as the weighted average cost of capital)…"

The method prescribed in section 6.2(a) of the Code for determining Western Power's target revenue for the purpose of establishing its price control for the first access arrangement period necessarily requires that a point estimate of the WACC be applied. As already noted, the WACC is probably the single most important and uncertain variable in the calculation of Western Power's target revenue. In view of these considerations, the point estimate of the WACC used to determine Western Power's price control must take into account:

- the potential cost of getting it "wrong" (as described in the Productivity Commission's recent reviews);
- the uncertainties associated with estimating the WACC and its constituent parameters; and
- the need to ensure that in practice, investors are adequately remunerated for all risks involved in the provision of infrastructure (including the regulatory and commercial risks, as required by the Government's proposed modifications to the national access regime).

With these considerations in mind, Western Power engaged SFG to undertake a robust analysis aimed at quantifying the estimation error involved in establishing the regulatory WACC. The approach applied by SFG in its analysis, and the key conclusions of that analysis are discussed in detail below.

35 Productivity Commission (2004), *Review of the Gas Access Regime*, Report no. 31, page xxx.

7.7 Quantifying estimation error in regulatory WACC

SFG's report to Western Power explains that in a regulatory setting, the regulator seeks to estimate the true cost of capital. In this context, it is important to note that the regulator cannot observe or measure or compute the true cost of capital, nor does the regulator know the firm's true cost of capital. The regulator can only estimate it. This is because the true cost of capital is a forward-looking expectation or required return and is simply not observable. Importantly therefore, the allowed return (or "regulatory WACC") is likely to be different from the true cost of capital.

SFG's report cites evidence demonstrating that generally:

- regulators are well aware of the distinction between the firm's true cost of capital, and the regulator's estimate of this; and
- regulators recognise that their estimates of WACC are statistically imprecise.

The SFG report then proceeds to:

- identify the sources of uncertainty in estimating WACC parameters;
- quantify the uncertainty around the estimation of each WACC parameter;
- demonstrate how uncertainty around each parameter aggregates into uncertainty about the true cost of capital of an efficiently financed firm, and quantify the uncertainty around the estimated WACC; and
- develop and apply a framework for determining an appropriate regulatory WACC in light of estimation uncertainty.

The key conclusions of SFG's analysis are as follows:

- There is significant uncertainty and estimation error involved when estimating a firm's cost of capital. This uncertainty has been clearly and systematically documented in authoritative studies (such as those undertaken by Fama and French, for instance), the results of which are examined in some detail in the SFG report. The source of this uncertainty is that WACC parameters cannot be estimated with great precision.
- A firm's WACC is estimated, not computed. The true cost of capital of an efficiently financed firm may be higher or lower than this estimate.
- It is particularly important in a regulatory setting to not just recognise the existence of uncertainty and estimation error, but also to quantify it as precisely as is reasonably possible. That is, it is important to quantify the probability that the true cost of capital is higher or lower than the estimated WACC, and by how much.

7.8 Quantification of the plausible range for WACC

Based on its analysis, KPMG concludes that the WACC for Western Power's network should be set by reference to values that fall within a specified plausible range for each of the underlying parameters, as set out in Table 15 below.

Table 15: Pre-tax real WACC parameter estimates

Parameter	Basis of estimate	Plausible range	
		Low	**High**
Real risk free rate *	Yield on 10 year Government indexed bond (20 day average)	2.69%	2.69%
Equity beta	Comparables and regulatory decisions	0.90	1.10
Market risk premium	Historical stock returns and 10 year government yields; Regulatory decisions	6.0%	8.0%
Capital structure (equity to total value)	Comparables and regulatory decisions	40%	40%
Debt margin *	BBB and BBB+ spreads from CBA Spectrum, and other allowances	1.49%	1.68%
Value of imputation credits	Empirical evidence and regulatory decisions	50%	0%
** Estimate will be subject to change to reflect prevailing interest rates at the time of Authority's final authorisation*			

SFG has applied parameter values drawn from the plausible ranges identified by KPMG to construct a full probability distribution of the WACC estimate using standard Monte Carlo simulation techniques. Table 16 below lists the assumptions applied by SFG regarding the probability distributions of each of the parameter values.

Table 16: Assumptions adopted in SFG's Monte Carlo simulation

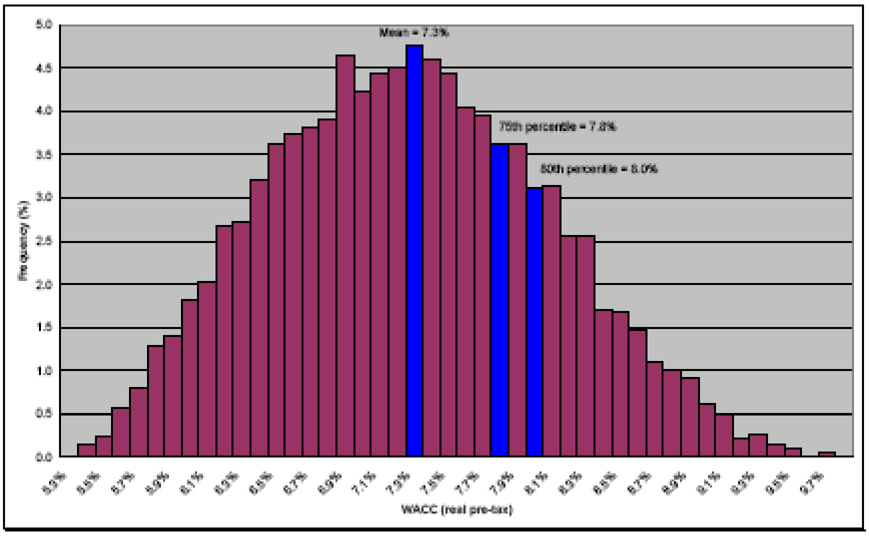
Parameter	Estimate of value	Probability Distribution
Real risk free rate	2.69%	None
Equity beta	0.9 – 1.1	Uniform
Market risk premium	Mean = 6% Standard deviation = 1.8%	Normal
Capital structure	60%	None
Debt margin	1.49% – 1.68%	Uniform[36]
Value of franking credits	0.0 – 0.5	Uniform

Applying the assumptions set out in Table 16, SFG took a random draw from the distribution for each uncertain parameter, and computed the resulting pre-tax real

36 A uniform distribution indicates that the parameter value has an equal probability of being at any point within the range indicated.

WACC. This process was repeated 10,000 times, yielding a histogram of WACC estimates, which is shown in Figure 8 below.

Figure 8: Distribution of pre-tax real WACC estimates for 10,000 simulations



This probability distribution of the pre-tax real WACC has the following characteristics:

- a mean value of 7.3%;
- a standard deviation of 0.8%;
- a 90% chance the true value falls between 6.0% and 8.6%;
- a 75th percentile value of 7.8%; and
- an 80th percentile value of 8.0%.

In interpreting the output of this analysis, the SFG report notes:

> "The fact that a number of input parameters cannot be estimated precisely but can only be narrowed to a reasonable range, inevitably means that it is impossible to express the WACC estimate (which is a mathematical aggregation of the input parameters) as a single point estimate. The estimated WACC must be expressed as a reasonable range. The width of this range depends on the aggregated uncertainty of the imprecisely estimated input parameters."

Pages 17 to 19 of the SFG report set out further explanatory material to provide guidance regarding the interpretation of the WACC probability distribution.

7.9 Considerations relevant to selecting a point estimate of the WACC

The approach developed by SFG provides the Authority with a useful aid to decision-making: the ability to explicitly measure the probability that a particular regulatory WACC will be insufficient to meet the cost of capital of an efficiently financed firm.

The SFG report notes:

> "This information will be useful to the regulator in setting an allowed return to balance (i) whether the costs paid by consumers are higher than they need to be, with (ii) whether the returns earned are sufficient to ensure the viability of the regulated entity and provide the appropriate incentives for future investment. Clearly, a key piece of information to be considered by the regulator when assessing these competing objectives is the probability that the allowed WACC will be insufficient to meet the true cost of funds. This, of course, is directly related to the ongoing viability of the business and to the incentives for future investment.
>
> This non-recovery probability would be set at 50% if these two considerations were ranked equally. But they are not. Setting the non-recovery probability at 20-25% for example, would reflect the fact that it is more important to ensure the viability of the business than to ensure that customers pay the minimum possible cost…
>
> Quantifying the probability that the assigned regulatory WACC is sufficient to meet the true cost of funds is central to the implementation of the objectives of regulation. For example, a regulatory WACC that provides a 75% chance of meeting the true cost of funds is likely to be sufficient to provide a sustainable commercial revenue stream, [in accordance, for instance, with the requirements implied by the Australian Government's response to the Productivity Commission's report on the national access regime] but a WACC that provides only a 25% chance does not…
>
> Indeed, the Authority is required to exercise its judgment to achieve an appropriate balance between the interests of all stakeholders. The proposed approach provides a framework for quantifying exactly this trade-off - if prices (and returns) are to be lowered, how (quantitatively) will this impact the ability of the firm to meet its cost of funds and provide adequate returns to its investors?"

SFG notes that the New Zealand Commerce Commission (NZCC) has recently recognised the uncertainty and statistical imprecision in its regulatory WACC estimates in a formal probabilistic manner.[37] Rather than producing a single point estimate, the NZCC constructs a probability distribution for the WACC and recognises that the firm's true cost of funds could come from anywhere within that distribution. The NZCC also notes the asymmetric consequences of regulatory error – that the costs of setting the regulatory WACC too low are much more severe than the costs of setting it too high. For this reason, the NZCC adopts the 75th percentile from the probability distribution as the appropriate regulatory WACC estimate. This reflects the statistical uncertainty of its WACC estimate and the balancing of the risks of regulatory error.

SFG's report concludes by suggesting that the regulatory WACC should be set so that there is a 75% to 80% chance that it will be sufficient to cover the true cost of funds of the regulated entity. The basis of this conclusion is summarised in the following excerpt from the SFG report:

[37] New Zealand Commerce Commission, *Gas Control Enquiry: Final Report*, 29 November 2004, www.med.govt.nz/ers/gas/control-inquiry/final-report/final-report.pdf.

> “Setting a 75-80% probability of being able to earn a return sufficient to cover the true cost of funds is consistent with the notion that ensuring the ongoing viability of the business and creating the right incentives for future investment is more important than keeping prices to a minimum, a view that is supported by the Productivity Commission. Note that if consumer prices and business viability are weighted equally, there is a 50% chance that the WACC will be insufficient to cover the entity’s cost of funds.”

After examining the lessons from the Productivity Commission’s recent reviews of access regimes in Australia (summarised in section 7.5 above), SFG states:

> “We argue that the views [expressed by the Productivity Commission regarding the need for regulatory decision-making to focus on providing incentives for more rather than less investment] are consistent with the notion that the regulatory WACC should be set so that there is a better than even chance of the entity recovering its cost of funds.”

Western Power strongly concurs with the specialist advice provided by KPMG and, in particular, the conclusions of SFG’s analysis, which collectively provide a compelling case for an estimated real pre-tax WACC in the range of 7.8 to 8.0% (for a real risk free rate of 2.69%).

7.10 Conclusion: Western Power’s proposed WACC following the publication of the Draft Decision and Final Decision

Notwithstanding the case for applying a real pre-tax WACC in the range of 7.8% to 8.0%, Western Power recognises the need for pragmatism to be applied in selecting a point estimate of the WACC, having regard, in particular to:

- the need to moderate anticipated price increases at the commencement of the new access arrangement (in comparison to those that would be associated with a WACC of 7.8% to 8.0%);
- policymakers’ expectations regarding the outcomes of electricity industry reform in Western Australia;
- the need to ensure that Western Power remains a financially viable business;
- the views expressed by the Authority on the issue of WACC, including those set out in the Draft Decision; and
- KPMG’s further advice on WACC in the light of the Authority’s Draft Decision (appendix 5 of this document).

In responding to the Authority’s Draft Decision in relation to WACC, Western Power carefully reviewed table 43 of the Draft Decision (reproduced below), which set out the Authority’s view on the reasonable range for the WACC at that time.

Table 43 Authority's assessment of reasonable WACC range

Estimated WACC (per cent)	Nominal	Real
Post-Tax	5.80 – 6.70	2.76 – 3.64
Pre-tax	8.28 – 9.57	5.18 – 6.43

In the Draft Decision, the Authority explained its assessment of the reasonable WACC range in paragraph 674 as follows:

> "The Authority considers that the range of values that different minds acting reasonably could attribute to the cost of equity and WACC is narrower than the ranges that the extremes of ranges in CAPM parameters would suggest. An approach by a service provider to determine the WACC that adopted the highest value within the reasonable range for each of the relevant CAPM parameters would not, in the Authority's view, result in a value for the WACC that different minds, acting reasonably, would attribute to the WACC. Also, such an approach would be inconsistent with the nature of regulatory oversight because the incentive throughout the process of consideration of a WACC would be for the service provider to contend for those values for each of the underlying parameters that would produce the highest WACC. The process would be reduced to a consideration of what would be the highest possible WACC rather than determining a best estimate of the WACC on a reasonable basis."

Western Power questions as a matter of logic whether the Authority's application of a narrower WACC range is appropriate. In Western Power's view, selecting a range of 'reasonable' parameter values must deliver a reasonable overall WACC range, and any number within the reasonable WACC range must, by definition, also be reasonable. Nevertheless, for expediency, Western Power is willing to accept the Authority's approach to selecting the narrower WACC range for the purposes of this access arrangement.

Western Power also strongly questions the Authority's assessment of the reasonable range for gamma. As a matter of logic, a gamma of zero is a valid parameter value on the basis that the marginal investor may well attach a value of zero to imputation credits. In fact, KPMG's advice in its Further Report (Appendix 5, page 15) in relation to this parameter is as follows:

> "KPMG continues to maintain that a value of zero is likely to be the most valid assumption for gamma. However, based on the evidence that the ERA has considered, the uncertainties with respect to measurement of gamma, and noting the need for internal consistency between the values adopted for the MRP and gamma, we believe that it would be reasonable to conclude that the value of gamma lies in the range of zero to 50%. This range of values is consistent with an MRP in the range of 6% to 8%."

Western Power also strongly believes that the lower bound parameter values selected by the Authority for the Market Risk Premium and equity beta are unreasonably low.[38] In making this observation, Western Power notes that a WACC calculation based on these lower bound parameter values would be insufficient to attract the investment in electricity network infrastructure and would therefore have a seriously damaging effect on investment in the transmission and distribution networks across Australia.

In paragraph 679 of the Draft Decision, the Authority concluded that the range of values that would comply with the Access Code should not include the values that lie within the lower 10 per cent or upper 10 per cent of the range that may be derived by the application of the extremes of values for each of the parameters of the CAPM. At the time of the Draft Decision, the Authority considered that the pre-tax real WACC should fall within the range of 5.18 per cent to 6.43 per cent.

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38 KPMG's Further Report (at appendix 4) provides a detailed substantiation of this view.

As Western Power's proposed WACC of 6.76% was outside the reasonable range estimated by the Authority at that time, the Draft Decision included Required Amendment 52, which stated that:

> "Western Power to amend its proposed access arrangement to reflect a pre tax real weighted average cost of capital of 6.0 per cent."

In response to the Draft Decision, Western Power did not incorporate Draft Decision Amendment 52 in its revised proposed access arrangement. Rather, Western Power proposed a WACC of 6.76% which reflected:

- the Authority's WACC methodology and parameters as set out in the Draft Decision, but updated to reflect the latest market data in relation to the risk free rate; and
- the value at the upper bound of the reasonable WACC range thus determined.

In its Final Decision, the Authority further considers the determination of the reasonable range for the WACC, taking into account the parameter values in its Draft Decision and recent observations from capital markets on risk free rates. The Authority estimates the reasonable range for the WACC in table 56 of the Final Decision (reproduced below).

Table 56 Authority's Final Decision assessment of reasonable WACC range

Estimated WACC (per cent)	Nominal	Real
Post-Tax	6.19 – 7.11	3.00 – 3.89
Pre-tax	8.84 – 10.16	5.57 – 6.85

Western Power's proposed pre-tax real WACC of 6.76% as set out in its revised proposed access arrangement is within the reasonable range the Authority estimates in its Final Decision. Therefore, the Authority's Final Decision accepts Western Power's proposed WACC of 6.76%, concluding (in paragraph 453) that:

> "The WACC incorporated by Western Power in the revised proposed access arrangement (6.76 per cent pre-tax real) lies within the reasonable range determined by the Authority for the purposes of this Final Decision. Accordingly, the Authority accepts that this value meets the requirements of the Access Code."

As noted in section 7.1 above, Western Power fully accepts the Authority's findings in its Final Decision. In accordance with the Final Decision, Western Power will apply a pre-tax real WACC of 6.76% in its access arrangement.

8 Total Revenue Requirement

8.1 Introduction

Section 6.2(a) of the Code states that:

> "Without limiting the forms of *price control* that may be adopted, *price control* may set *target revenue* by reference to the *service provider's approved total costs*."

Furthermore, in respect of the first access arrangement period, section 6.3 of the Code requires that the first access arrangement must contain the form of control described in section 6.2(a).

The earlier sections of this Part B provide a detailed explanation of Western Power's cost forecasts for the transmission network. Together, these cost forecasts comprise the approved total costs for the transmission network, for the purpose of determining target revenue. This approach to determining the annual revenue requirement of a regulated company is often referred to as the "building block" approach.

The purpose of this section of the document is to explain how the cost elements discussed in the earlier sections of this Part B are combined to determine the target revenue in each year of the first access arrangement period. A similar calculation is explained in section 7, Part C of this document in relation to the distribution network.

The remainder of this section is structured as follows:

- section 8.2 provides an overview of the building block method for determining the target revenue for the transmission network; and
- section 8.3 provides details of the composition of the target revenue, including figures showing the trend of transmission revenue and average prices from 2002 to the end of the first access arrangement period.

8.2 Overview of "Building Block" Revenue Determination Method

The revenue requirements (target revenue) are calculated as the sum of a series of "building blocks" which are described briefly in Table 17, below. As already noted, the earlier sections of this Part of the document provide detailed analysis of each building block element.

Table 17 – Summary of the building block components of target revenue

Target revenue component	Brief description	Cross-references for further details
Operations and maintenance costs	This is Western Power's annual cost of operating the transmission network, and maintaining the assets used in the delivery of covered services.	Section 4, Part B
Return of capital	This is the annual depreciation charge on the transmission assets used in the delivery of covered services.	Section 5, Part B
Return on capital	This is the product of the required rate of return (the weighted average cost of capital, or WACC) and the capital base. (The capital base for a covered network means the value of the network assets that are used to provide covered services on the covered network determined under sections 6.44 to 6.63 of the Code.) The capital base value over the access arrangement period is, in turn, a function of the depreciated value of assets at the start of the period, the level of annual depreciation recovered during the period, and the level of efficient new capital expenditure (new facilities investment) that is assumed to be required over the course of the access arrangement period.	Sections 5 and 6, Part B
Taxation	The pre-tax approach to WACC provides an allowance for company tax in the WACC.	Section 6, Part B

Target revenue is calculated using a model developed by the Authority which adopts an end of year timing assumption for modelling revenues and expenses[39] in real terms. That model calculates target revenue for each year of the access arrangement period in accordance with the following formula:

$TR_t = r.RAB_{t,open} + Dep_t + O\&M_t$

where

TR_t = target revenue in year t.

r = WACC (in real pre-tax terms).

$RAB_{t,open}$ = opening value of the regulatory asset base (which takes into account forecast new facilities investment over the access arrangement period).

Dep_t = depreciation in year t (which takes into account forecast new facilities investment over the access arrangement period).

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

A copy of the revenue model outputs is provided in Appendix 11.

39 The calculations assume that all forecast capital expenditure occurs at the end of each relevant year. The effect of this assumption is to align the timing of forecast capital expenditure with that of all other costs and revenues, which are assumed to occur at the end of each relevant year.

8.3 Forecast target revenue for the transmission network

Table 18 below shows the composition of transmission network revenue for the forthcoming access arrangement period.

Table 18 – Composition of transmission network revenue
($ million real as at 30 June 2006)

Financial year ending:	**30 June 2007**	**30 June 2008**	**30 June 2009**	**Present Value**
Operating Costs	67.2	69.4	69.9	181.3
plus Depreciation	48.8	53.1	57.7	139.7
plus Redundant Assets	0.0	0.0	0.0	0.0
plus Return on Assets	93.7	104.6	116.6	275.4
plus Return on Working Capital	0.6	0.6	1.0	1.9
Target Revenue	**210.4**	**227.6**	**245.1**	**598.2**
plus Tariff Equalisation Contribution	0.0	0.0	0.0	0.0
less Non-Reference Services Revenue	-18.4	-18.4	-18.4	-48.5
less Capital Contributions	-16.1	-27.4	-13.4	-50.1
Net Reference Services Revenue	**175.9**	**181.8**	**213.4**	**499.7**
Smoothed Reference Services Revenue	**189.0**	**184.8**	**195.3**	**499.7**

Table 19 below shows the transmission capital base depreciation by asset class.

Table 19 – Transmission Capital Base depreciation by asset class
($ million real as at 30 June 2006)

Financial year ending:	**30 June 2007**	**30 June 2008**	**30 June 2009**
Transmission transformers	6.1	6.1	6.1
Transmission reactors	0.1	0.1	0.1
Transmission capacitors	3.3	3.3	3.3
Transmission circuit breakers	16.1	16.1	16.1
Transmission lines - steel towers	8.8	8.8	8.8
Transmission lines - wood poles	8.3	8.3	8.3
Transmission cables	0.3	0.3	0.3
Transmission metering	0.1	0.1	0.1
Transmission SCADA and Communications	3.0	3.0	3.0
Transmission IT&T	0.6	0.6	0.6
Transmission Other, non-network assets	2.0	2.0	2.0
Transmission Land & Easements	0.0	0.0	0.0
TOTAL	**48.8**	**48.8**	**48.8**

Table 20 below shows transmission capital expenditure depreciation by asset class.

Table 20 – Transmission capital expenditure depreciation by asset class ($ million real as at 30 June 2006)

Financial year ending:	**30 June 2007**	**30 June 2008**	**30 June 2009**
Transmission transformers	0.0	0.7	1.4
Transmission reactors	0.0	0.0	0.0
Transmission capacitors	0.0	0.1	0.5
Transmission circuit breakers	0.0	0.8	1.6
Transmission lines - steel towers	0.0	1.3	2.6
Transmission lines - wood poles	0.0	0.1	0.2
Transmission cables	0.0	0.1	0.2
Transmission metering	0.0	0.0	0.0
Transmission SCADA and Communications	0.0	0.2	0.2
Transmission IT&T	0.0	0.1	0.3
Transmission Other, non-network assets	0.0	0.8	1.8
Transmission Land & Easements	0.0	0.0	0.0
TOTAL	0.0	4.2	8.8

Table 21 below shows the forecast transmission capital contributions.

Table 21 – Forecast Transmission Capital Contributions by expenditure type ($ million real as at 30 June 06)

	First access arrangement period		
	2006/07	**2007/08**	**2008/09**
Customer Driven	16.1	27.4	13.4
Transmission Total ($M)	**16.1**	**27.4**	**13.4**

Figures 9 and 10 show the trend in transmission tariff revenues and average transmission tariff prices in real dollars for the year ending 30 June 2002 to the end of the first access arrangement period.

Figure 9: Trend in Transmission Tariff Revenue in real dollars as at 30 June 2006

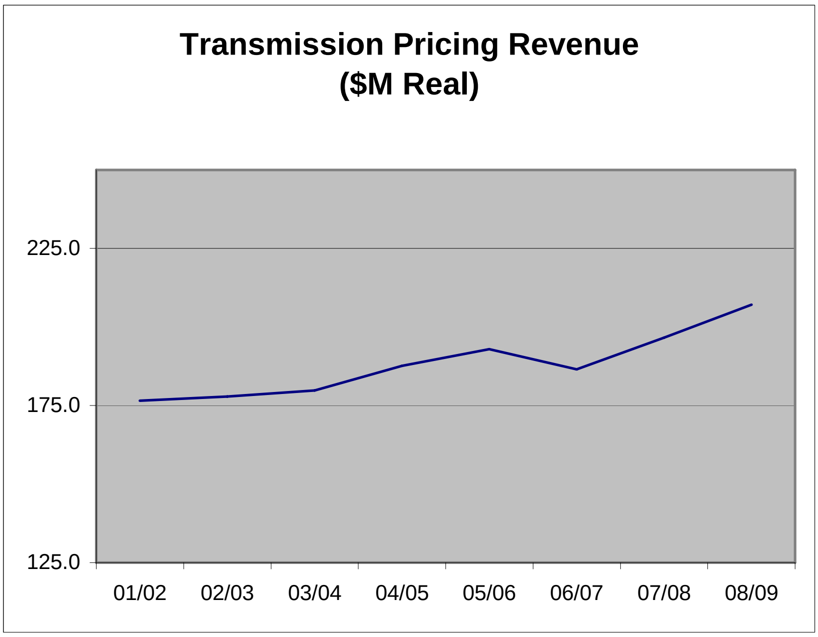
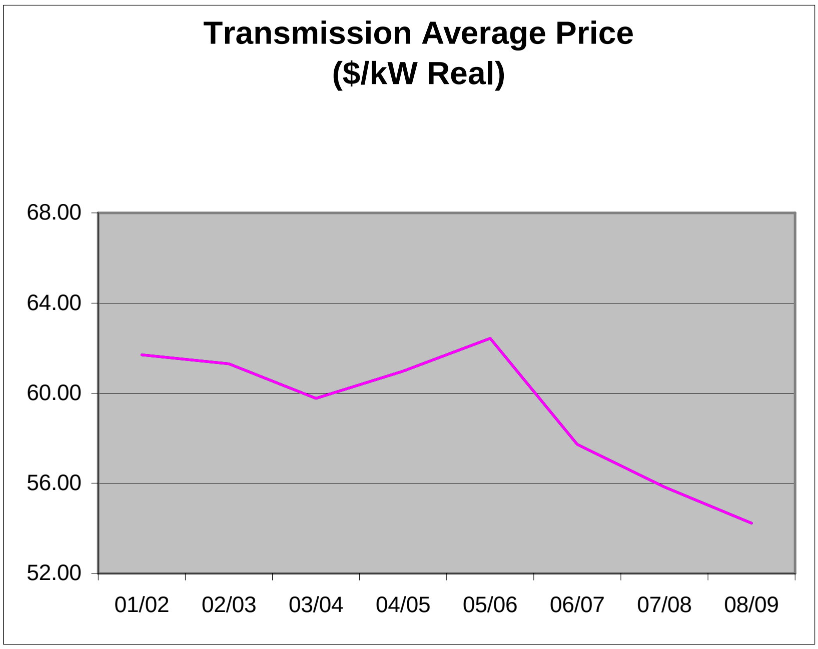


Figure 10: Trend in Transmission Average Price in real dollars as at 30 June 2006



PART C: DISTRIBUTION BUSINESS EXPENDITURE PLANS AND TOTAL REVENUE

1 Introduction to Part C

This Part C provides detailed information to explain and substantiate the expenditure plans and total revenue requirements of the distribution business.

The key underlying cost drivers of the distribution business are:

- the standards or quality of services and other outputs which Western Power plans to deliver over the forthcoming access arrangement period; and
- the quantity of the services to be delivered over the period.

The development of robust expenditure programs must be based on a comprehensive consideration of these two fundamental cost drivers. Accordingly, the expenditure forecasts set out in this Part C reflect:

- the key distribution business outputs, in terms of planned distribution service standards, and other outcomes such as compliance with mandatory health and safety standards, environmental standards and technical standards, as summarised in section 5 of Part A; and
- the demand forecasts set out in section 2 below, which, among other things, are key determinants of the expected quantity of services that the company is planning to provide.

Once the underlying cost drivers have been defined and described in this manner, section 3 of this Part C proceeds to describe and substantiate the capital expenditure forecasts for the distribution business. The remainder of this Part C is then structured as follows;

- section 4 describes and substantiates the operating and maintenance expenditure forecasts;
- section 5 provides explanatory information relating to the asset valuation and depreciation costs;
- section 6 sets out the company's estimate of the cost of capital for the distribution business; and
- section 7 calculates and describes the total revenue requirement of the distribution business.

For each section, Western Power has taken account of the Authority's Draft Decision, submissions made by interested parties and the latest available data and information, where relevant.

2 Distribution system energy forecasts

2.1 Introduction

This section provides an overview of the distribution system energy forecasts for the access arrangement period. In relation to the distribution network, energy forecasts are used to set tariffs.

It was noted in relation to the transmission system that Western Power initially commissioned NIEIR to review the company's forecasts for energy and demand for the SWIN, for each year of the forthcoming access arrangement (2006-07 to 2008-09 inclusive). The IMO subsequently produced updated forecasts in its 2005 Statement of Opportunities (SOO). The Authority's Draft Decision concluded that the IMO's forecasts are to be preferred to Western Power's initial forecasts as presented in its access arrangement information, which was submitted on 24 August 2005. In light of discussions with the Authority following publication of the Final Decision, this section has been updated to reflect the IMO's 2006 SOO.

The remainder of this section is structured as follows:

- section 2.2 provides an overview of Western Power's methodology for distribution energy forecasting;
- section 2.3 presents the distribution system energy forecasts; and
- section 2.4 provides concluding comments.

2.2 Western Power's forecasting methodology for distribution energy

The first step in Western Power's methodology for forecasting distribution energy is to determine the actual sales for total distribution energy based on the most recent available data. Total distribution energy sales are defined as:

Total distribution energy = Synergy Retail sales

+ Third Party Retail sales

- Direct transmission sales

Sales to direct transmission customers are removed from retail sales because these customers are not connected to the distribution system.

The second step in Western Power's forecasting methodology is to 'roll forward' the latest available actual total distribution energy sales, in order to forecast sales in the forthcoming access arrangement period. In essence, the forecasts of distribution energy to 2008-09 were developed by growing the total distribution energy with the same underlying energy growth rate of 2.2% as used in the IMO's 2006 SOO.

2.3 Western Power's distribution system energy forecasts

Western Power's distribution energy sales forecast are summarised in table 22 below. These forecasts have been developed using the forecast methodology described in section 2.2 above.

Table 22: Forecast Distribution Energy Sales (GWh)

Year	Forecast Sales (GWh)
2005/06 (Actual)	12,276
2007/08	12,822
2008/09	13,104

2.4 Concluding comments

This section has explained:

- Western Power's methodology for forecasting distribution system energy over the forthcoming regulatory period; and
- Western Power's forecasts for distribution system energy.

Western Power's view is that the information presented demonstrates that the distribution energy forecasts are consistent with the requirements of the Authority's Draft Decision, and are robust and fit for purpose.

3 Distribution capital expenditure

3.1 Introduction

This section describes and substantiates the capital expenditure forecasts for the distribution network. As noted earlier, the information presented in this section takes account of the Authority's Draft Decision, including reports from consultants Wilson Cook, and the revised forecasts provided by Western Power on 26 September 2006 in response to the Section 51 request for information issued by the Authority on 22 August 2006.

The capital expenditure requirements of the distribution network should achieve the following outcomes:

- network asset condition and service performance should comply with all relevant legislation and regulations;

- service performance should also meet customers' expectations in terms of reliability and quality of supply;

- new customer connections should be provided in a timely manner;

- assets must be renewed to ensure that service performance is not compromised in the medium term; and

- the life-cycle costs of providing distribution services should be minimised by appropriately balancing operating and capital expenditure.

In addition, it is essential that expenditure plans are feasible given the availability of internal and external resources, and the need to ensure that expenditure is executed efficiently. Furthermore, the resulting prices to Western Power's customers must be acceptable – taking into account the competing demands for better service and the desire to minimise price increases where practicable.

In relation to transmission capital expenditure (which is described in section 4 of Part B of this document), Western Power noted a number of important cost drivers in the forthcoming access arrangement period that suggest that capital expenditure will need to increase. It was also noted that the need for increased capital expenditure as a result of these drivers must be tempered by resource and pricing constraints.[40]

A similar set of challenges arise in relation to the capital expenditure needs of the distribution network. The remainder of this section is structured in a similar manner to the section on transmission capital expenditure, and where appropriate, references to that earlier section are noted.

- section 3.2 summarises the drivers for increased expenditure in the forthcoming access arrangement period; and

- section 3.3 presents Western Power's distribution network capital expenditure proposals.

[40] In particular section 4.3 of Part B explained the strategies and initiatives adopted by Western Power to improve the business' capacity to deliver an increased quantity of projects in the face of resource constraints, and without compromising cost efficiencies. These strategies and initiatives have been deployed across the whole of Western Power's business.

3.2 Drivers for increased distribution capital expenditure

In relation to distribution network capital expenditure, there are six principal drivers that lead to a need to increase expenditure from historic levels. These are:

- the impact of previous budget constraints;
- facilitation of market reform;
- load growth;
- review of design standards;
- reliability;
- asset condition; and
- safety, environment and statutory compliance obligations.

The first two drivers relate to both the transmission and distribution networks, and have already been discussed in relation to the transmission network capital expenditure (refer to sections 4.2.1 and 4.2.2 of Part B of this document). Whilst the precise detail of their impact on each network is different, the general observations regarding their impact on future costs is the same for each network. Therefore, the focus of the discussion in this section is the remaining five principal distribution-specific drivers for increased capital expenditure. Each of these five remaining drivers is discussed in turn.

3.2.1 Load growth

Western Power currently designs and constructs a large proportion of the connection assets for new residential, industrial and commercial customers. Connection assets constructed by external contractors are "gifted" to Western Power and are not included in this category.

As a result of Western Australia's unprecedented high levels of population growth and the high levels of load growth generated primarily by new air conditioning load (including its deleterious effect on load factor) Western Power has a substantial amount of new distribution assets to construct and commission now and over the course of the forthcoming access arrangement period. In addition there is a substantial amount of augmentation work required on existing distribution feeders, as well as zone substation integration to cater for the additional load. This augmentation work includes a substantial amount of backbone feeder conductor replacement to improve both capacity and fault level rating.

3.2.2 Review of design standards

The development of the new Technical Rules, and the recent enactment of new environment protection legislation require a number of changes to Western Power's design policies and standards. These changes include:

- reduction of padmount substation noise;
- reduction in the number of customers on radial feeders;

- increased design loads for commercial and industrial customers;
- underground pole to pillar connections;
- installation of remote monitoring and control of ring main switches (RMU);
- changes to street light designs; and
- fireproof construction in fire risk areas.

Compliance with these changed standards necessitates changes in Western Power's design standards, and associated an associated increase in the costs of some distribution capital works.

3.2.3 Reliability

As noted in section 4 of Part A of this document, Western Power's assessment is that customers expect, and should receive an improvement in reliability performance from recent historic levels. In particular, Western Power is committed to delivering a 25% improvement in SAIDI performance for customers in the SWIS over the next 4 years. This service performance improvement has implications primarily for distribution operating expenditure (discussed in section 4 of this Part C below) but it also has some implications for distribution capital expenditure.

It is noted that some distribution capital expenditure that primarily caters for increased load growth or increased fault levels also has an impact on network performance. The contributions made by these works to meeting the target reduction in SAIDI and SAIFI have been acknowledged and identified. In addition, two specific capital expenditure projects have been identified which can provide cost-effective contributions to achieving the SAIDI target:

- Distribution Automation Strategies; and
- Worst Performing Feeder Program.

In relation to Distribution Automation Strategies, the objective of the project is to introduce smart mechanisms and remote control methodologies for the prompt identification of faulted network sections, and rapid supply restoration to un-faulted sections. A pilot project will be commissioned, followed by a Distribution Automation Rollout. The project will considerably enhance Western Power's ability to respond to faults quickly, thus minimising average outage duration, particularly for those customers connected to sections of a feeder not affected by a fault.

In relation to the Worst Performing Feeder Program, the objective is to substantially improve the SWIN SAIDI by identifying and implementing technical solutions for the 40 worst performing feeders. The work will include activities such as targeted siliconing, bird-proofing, fitting tightening, surge arrestor installation, spreader installation, line patrol, line thermographic surveys, spreader/spacer installation, vegetation control, and other similar measures. In addition the work will include targeted conductor replacement, including undergrounding and the use of covered conductors as appropriate. This program will target the worst 20 Metropolitan, worst 10 North Country and the worst 10 South Country feeders. The cost is expected to be $30.5 million per year over the next three years, which should deliver a 21 minute improvement in SAIDI over that three year period.

3.2.4 Asset condition

In order to determine a soundly-based forecast of distribution infrastructure investment required, Western Power engaged PB Associates to develop an age, condition and risk based replacement model. This model has been populated with Western Power's distribution asset data and the replacement capital expenditures determined by the model have been used as the basis of the projected expenditures for asset replacement for the forthcoming access arrangement period.

The model has been used to predict distribution asset replacement expenditures over the regulatory period, as well as the weighted average remaining life of these assets. The model has indicated that Western Power's distribution assets have a weighted average remaining life of 55% in 2005.

The model incorporates the current backlog of assets identified for replacement in the MIMS data base and has predicted total asset replacement expenditures over the regulatory period of approximately $145 million. The model has also predicted that these levels of investment will result in the average remaining life decreasing to 52% over the forthcoming access arrangement period. This outcome represents a reasonable balancing of the constraints that limit investment over the forthcoming access arrangement period, and the need to ensure that the average age of the asset base does not deteriorate over time to unsustainable levels. Issues relating to the level of renewals and replacement investment required to efficiently manage Western Power's ageing asset base will need to be examined in further detail over the forthcoming access arrangement period and at subsequent access arrangement reviews.

Replacement capital expenditure of the level predicted by the model would represent a very substantial increase compared to historic levels of expenditure. This observation indicates that the current level of expenditure is almost certainly unsustainably low in the medium term. The challenge facing Western Power is to propose a reasonable approach for ramping up replacement capital expenditure towards its long-term sustainable level, given the inevitable resource and financing constraints that apply.

3.2.5 Safety, environment and statutory requirements

This cost driver relates to Western Power's compliance with directives and remedial actions agreed with the Energy Safety Directorate (ESD), and compliance with statutes, acts, regulations, codes and standards, in particular the Electricity Industry (Network Quality and Reliability of Supply) Code 2005.

Some of the remedial actions agreed with the ESD have been instigated in accordance with recommendations made by the State Coroner and others have been instigated by Western Power to minimise safety and environmental risks in accordance with good industry practice. All the projects included in this category directly relate to the achievement of mandated safety, environmental, and compliance outcomes or industry accepted good practice employed to prudently manage risk and avoid adverse outcomes. In this sense, the proposed expenditure is not discretionary.

The expenditure requirements necessary for Western Power to comply with its safety, environmental and statutory obligations are very substantial. The required capital expenditure is estimated to be approximately $39 million per annum. In view of this substantial level of expenditure, it is helpful to provide some details of the remedial actions that are considered necessary in the forthcoming access arrangement period. The principal items of capital expenditure are described briefly in Table 23 below.

Table 23: Principal capital expenditure items: Distribution network

Overhead service wires with twisties	The recent double fatality in Wyndham prompted a capital replacement program to replace services with twisty connections. Western Power has decided to replace all existing PVC services with Cross Linked Polyethylene insulated service cable terminated with approved wedge type clamps.
Conductive metal streetlight poles	A number of electric streetlight shock incidents have been experienced by members of the public from contact with metal streetlight structures. These incidents seem to have been due to inadequate earthing and/or deterioration or damage of insulation through abrasion inside the metal streetlight arm or luminare thereby energizing the metal structure. There are approximately 60,000 existing metal streetlight poles in the SWIN which will be inspected and where necessary maintained.
Distribution conductive power poles step and touch potential mitigation	This risk was highlighted during the investigation of the suspected electrocution of a dog in Derby and 3 potentially fatal electric shocks to members of the public in the Perth metropolitan area. An estimated 51,000 poles in the SWIN are at special or frequented locations that need to meet the ESAA C(b))1 limits for touch and step potential.
Streetlight switch wires	There have been 2 fatalities in the last 10 years and 2 potentially fatal electric shock incidents in the past 4 years to the public from fallen streetlight wires.
URD cable pits	There are 5711 below-ground cable pits with insulated piercing connectors (IPCs) used to supply power mainly to residential customers which have been installed in the SWIN as part of the Retrospective Underground Power program. A number of electric shock incidents have been reported by the public and Western Power Network employees resulting from such installations. A program to replace these URD cable pits with above ground pillars has commenced and up until March 2005 approximately 25% of these pits had been replaced in accordance with the solution agreed with the ESD.
Henley cable boxes	There has been a number of Henley cable box explosive failures in public areas resulting in shrapnel (metal) spread over a wide area. Such failures could have serious consequences, especially in high traffic areas (e.g. shopping centre car parks) where there is a high risk of injury to the public or damage the vehicles. There are an estimated 2,000 Henley cable boxes, which need to be replaced based on site location and traffic with the more critical known sites being resolved first.
Cattle care	The aim of the project is to restrict cattle access to the Aldrin/Dieldrin that was applied to the base of wooden poles of power lines that were built prior to 1986. The project has been initiated to comply with prudent avoidance requirements of Quality Assurance Accreditation Schemes and mitigate the risk of potential contamination of beef with chlorinated hydrocarbon pesticides. The consequences of not taking action include potential loss of shipments of beef at market door (e.g. USA) and potentially disastrous flow-on effects for the export market in this commodity and possibly other farm produce.

Pole top switch (PTS) earthing mats	Five years ago a Western Power Network operator received a near fatal electric shock. Temporary measures have been taken until a permanent solution is implemented. About 3,000 pole-top switches in the metro area have ineffective earthing mats and so pose a significant risk of injury to switching operators.
Live-frame shrouding	Many of the LV frames in district substations have exposed bare live copper busbars. This has been recognised as hazardous to personnel accessing the site and must be rectified so as to protect switching operators and substation inspectors from risk of electrocution.
Inadequate reinforcing of transformer poles	Recently a transformer pole with limited reinforcement fell over into the middle of a suburban street. Western Power has engaged GHD to re-evaluate the strength of its pole top substation structures and GHD has indicated that these structures need to be reinforced by installing additional ground line reinforcements. It is estimated that around 3,000 poles may not be suitable for carrying the weight of 50 kVA or larger transformers, and need to be refurbished.
Padmount transformer noise	This project consists of the construction of noise barriers around padmount substation transformers to reduce noise emissions so that they comply with the requirements of the Environmental Protection (Noise) Regulations. The program of noise mitigation work is to be completed at 26 substations over a 4-year period which is expected to conclude by the end of 2008.
River crossings	The ESD has advised Western Power that it requires all bare conductor river crossings to be either placed underground or in some agreed circumstances replaced with Hendrix cables installed with substantially increased height above MHW. Western Power has commenced a program to replace the river crossings in the SWIS.
Bushfire mitigation	This project has been instigated as a result of a desire of both the West Australian Government and Western Power to reduce the potential for loss of life and/or property as a result of bush fires initiated by either the transmission or distribution network infrastructure.

3.3 Western Power's distribution capital expenditure proposals

Western Power explained in Part B, section 4 that it has taken measures to ensure that the proposed increase in Transmission capital expenditure can be achieved within the expected resource constraints and without compromising efficiency. The same considerations have been factored into Western Power's capital expenditure plans for the distribution network. For a detailed explanation of these plans, please refer to Appendix 6 of this document.

Table 24 below sets out a summary of actual and forecast distribution capital expenditure, by category, for the period 2002/03 to 2008/09.

Table 24 – Forecast Distribution Capital Expenditure by expenditure type ($ million real as at 30 June 06)

	Actual	*Actual*	*Actual*	*Actual*	*Forecast*	*Forecast*	*Forecast*
	Historical				**First access arrangement period**		
	2002/03	**2003/04**	**2004/05**	**2005/06**	**2006/07**	**2007/08**	**2008/09**
DEMAND RELATED							
Distribution Capacity	18.8	19.3	23.4	40.7	30.5	32.2	37.2
Customer Driven	74.0	90.1	107.8	156.4	90.2	104.7	119.3
Customer Driven – Vested Assets	9.8	14.7	16.8	16.9	15.5	18.9	22.1
NON DEMAND RELATED							
Asset Replacement	9.0	4.3	11.5	14.3	17.1	28.4	28.7
Reliability Driven	0.0	0.4	0.1	5.6	9.2	18.8	12.6
Safety, Environmental & Statutory	0.0	4.5	26.1	25.2	26.9	43.6	43.1
OTHER							
SCADA & Communications	5.0	2.7	2.3	2.4	2.1	1.7	1.8
IT (inc. Market Reform)	0.7	1.2	5.4	9.9	18.7	16.1	14.2
Metering	4.9	4.8	14.1	11.9	4.3	7.7	9.2
State Undergrounding Power Program (SUPP)	17.5	8.7	20.1	14.1	16.6	15.4	15.8
Rural Power Improvement Program (RPIP)	0.0	0.0	10.8	6.7	10.0	10.1	11.1
Support	1.3	1.3	5.6	5.9	12.3	14.1	8.3
Distribution Total ($M)	**141.0**	**152.0**	**243.9**	**309.9**	**253.4**	**311.9**	**323.5**

Table 25 below provides details of Western Power's forecast distribution capital expenditure by asset class.

Table 25 – Forecast Distribution Capital Expenditure by asset class ($ million real as at 30 June 06)

	Forecast	*Forecast*	*Forecast*
	First access arrangement period		
	2006/07	**2007/08**	**2008/09**
Distribution lines - wood poles	53.1	72.4	82.1
Distribution lines - steel poles	0.0	0.0	0.0
Distribution underground cables	101.8	118.4	117.9
Distribution transformers	27.9	34.8	37.5
Distribution switchgear	21.8	32.7	38.5
Street lighting	11.2	13.1	13.8
Distribution meters and services	4.4	8.6	9.4
Distribution IT&T	18.7	16.1	14.2
Distribution SCADA & communications	2.1	1.7	1.8
Distribution Other, non-network	12.3	14.1	8.3
Distribution Land & Easements	0.0	0.0	0.0
TOTAL	**253.4**	**311.9**	**323.5**

4 Distribution operating and maintenance expenditure

4.1 Introduction

This section describes and substantiates the operating expenditure forecasts for the distribution network. The distribution operating expenditure requirements of the distribution network should achieve the following outcomes:

- satisfying future demand for Western Power's services, including new customer connections;
- aligning asset management strategies with industry best practice;
- ensuring that benchmark service standards for the distribution network are achieved;
- ensuring that Western Power complies with health, safety and environmental obligations;
- facilitating the minimisation of total life-cycle costs by optimising operations and maintenance (O&M) and capital expenditures; and
- delivering achievable and sustainable efficiency gains, in terms of improved performance, increased output and lower cost.

The remainder of this section is structured as follows:

- section 4.2 summarises the drivers for increased operating expenditure in the forthcoming access arrangement period; and
- section 4.3 presents Western Power's distribution network operating expenditure proposals.

4.2 Drivers for increased distribution operating expenditure

In relation to distribution operating expenditure, Western Power has identified ten principal drivers for increases in the forthcoming access arrangement period:

1. **Impacts of previous budget constraints** – leading to an unsustainable level of maintenance backlog.
2. **Compliance with health, safety and environmental obligations** – particularly relating to the need for additional network inspections and associated follow-up maintenance work to meet prescribed maintenance standards.
3. **Reliability** – additional expenditure to meet Western Power's service standard benchmarks in relation to SAIDI. Network maintenance programs have been developed to facilitate the achievement of the significant reductions in interruptions required to meet the proposed reliability targets.
4. **Whole of life efficiencies** - improved preventative maintenance programs have been introduced to achieve an optimal balance between maintenance and capital expenditure. These programs are expected to allow Western Power to extend the operational lives of some assets whilst minimising service interruptions and corrective maintenance costs, thus leading to a reduction in overall lifecycle costs.

5. **Increasing Asset Base** - additional operating expenditure will arise as a result of the growth in distribution network assets under the company's capital expenditure program.
6. **Increasing Resource Costs** - increases in average unit costs for maintenance are expected, due to competition for resources and contractors.
7. **Metering services** – metering inspections will increase in line with the projected increase in customer connections. In addition, installation and data management costs are expected to increase, as increasing numbers of customers request interval meters.
8. **Call centre costs** – historically, Western Power Corporation's retail business provided a fault call handling service during business hours but did not charge the network business for this service. However, a formal contract for provision of this service has now been established with Synergy.
9. **Market reform** – increases in operating expenditure are expected as a result of the new regulatory and market environment.
10. **Insurance** - additional insurance costs are expected as a result of a tightening of the market.

A number of these cost drivers have already been noted in respect of network capital expenditure and in relation to transmission operating expenditure. In the remainder of this section, therefore, Western Power focuses on how the above cost drivers will be reflected in additional distribution-specific maintenance activities in the forthcoming access arrangement period.

Western Power is proposing overall increases in maintenance expenditures compared to historical levels. These increases are required in order to address a number of the cost drivers identified above. The operational factors that have led to increased expenditure include:

- increased costs associated with maintaining an aging asset base;
- an increased focus on improving staff and public safety following the identification of a number of key risk areas;
- addressing identified maintenance backlogs which have emerged following periods of budget constraints;
- the implementation of new asset management maintenance initiatives identified through the ongoing reviews of the network, such as bushfire and vegetation management initiatives, aerial inspections, and washing and silicon coating of insulators; and
- increasing average unit costs for many of the maintenance programs as a result of resource constraints for contract services and skilled labour.

A key characteristic of past maintenance expenditure has been the suboptimal mix of preventative and corrective programs, as a result of budget constraints. In response, Western Power has now formulated programs for increased asset inspections, which are targeted to provide more timely information for undertaking rehabilitation works prior to asset failure. This information will be critical to enabling the continual adjustments to maintenance and capital expenditure programs, in order to minimise total asset management costs whilst improving the overall reliability of the distribution network.

Western Power's proposed increase in inspections is targeted to ensure compliance with the Industry (Network Quality and Reliability of Supply) Code 2005, and to reduce the costs of corrective maintenance. In particular, Western Power's analysis suggests that increased expenditure in relation to vegetation management and pole inspections could reduce unplanned outages, and therefore have positive impacts on both reliability and corrective maintenance costs, whilst also reducing the risks of bush fires and public safety incidents. Specific examples of the increased activities targeted by Western Power are detailed in Table 26 below.

Table 26: Key increased distribution maintenance activities

Pole Base Inspection and Treatment	Preventive routine inspection of poles from the ground, and sound wood testing of poles have been increased to comply with regulatory requirements and to reduce corrective maintenance costs. The company's adherence to a four yearly cycle is anticipated to reduce pole failures. The program also involves the chemical treatment for wood rot and termite infestation.
Vegetation Inspection	Routine 'vegetation spotting' patrols have been increased to identify vegetation encroachment into clearance zones, with specific emphasis on extreme and high fire risk areas. Medium and low fire risk areas are also included on a reduced inspection frequency.
Insulator Silicone Coating	Pole top fires have been identified by Western Power as a considerable factor influencing both the level and cost of supply restoration. The application of silicon grease to insulators has been introduced in order to reduce the incidence of pole top fires. This program covers most critical feeder sections close to the coast or in significant pollution zones. Pole top fires also represent a considerable safety and bushfire risk.
Line Patrols / Pole Top Inspection	This activity includes the inspection of overhead lines and pole top hardware from helicopter, light aircraft and EPVs. The inspections cover: • conductors and earth-wires; • cross-arms and insulators; • cable terminations; • capacitor banks; • surge arrestors; and • transformers. Pole top inspection programs cover approximately 200 feeders annually, representing one quarter of the feeders (or a four-year cycle). This activity provides an effective means of detecting sagging or deteriorating conductors, long bays or poor condition pole tops in order for preventative action to be taken before conductors clash or fall.
Ground Mounted Switchgear and Substation Inspections	This activity includes the inspection of substations and HV/LV ground mounted switchgear housed in indoor substations, compounds and kiosks. It also covers the four yearly routine maintenance of Ring Main Units (RMU) and is intended to identify equipment that is in poor condition.

As noted in relation to transmission operating expenditure, past budgetary constraints in preventative maintenance programs have resulted in some additional corrective expenditure. As a result of the proposed increases in preventative maintenance and inspections, Western Power expects corrective maintenance requirements to fall relative to current levels. The majority of these savings are expected to occur in years 2 and 3 of the access arrangement period as a result of the targeting of preventative maintenance programs to higher impact areas. From that time on the anticipated levels of expenditure should remain consistent with asset quantities and unit costs.

In addition, it was also noted in relation to transmission operating expenditure that the company is planning to commit additional resources to further development of a network management strategy. This expenditure will also encompass distribution maintenance activities, and is expected to deliver benefits by facilitating improvements in the cost-effectiveness of maintenance expenditure, and in network performance.

4.3 Western Power's forecast distribution operating expenditure

In relation to distribution (as well as transmission) operating expenditure, Western Power has sought to minimise the required increase in expenditure, recognising the cost drivers in the forthcoming regulatory period, the resource constraints and the broad goal of containing price increases. Western Power has also had regard to the importance of delivering efficiency improvements over the forthcoming access arrangement period and beyond. For further details of Western Power's operating expenditure plans, please refer to Appendix 6 of this document.

Table 27 below provides an overview of Western Power's historic and forecast distribution operating and maintenance expenditure by expenditure type.

Table 27 – Forecast Distribution Operating and Maintenance Expenditure by expenditure type ($ million real as at 30 June 06)

	Actual	*Actual*	*Actual*	*Forecast*	*Forecast*	*Forecast*	*Forecast*
	Historical			**Interim**	**First access arrangement period**		
	2002/03	**2003/04**	**2004/05**	**2005/06**	**2006/07**	**2007/08**	**2008/09**
Maintenance Strategy	3.2	3.8	3.9	5.3	6.1	6.7	6.6
Preventative Condition	9.3	9.4	16.8	18.7	22.3	22.1	21.0
Preventative Routine	9.6	9.8	27.4	28.1	29.5	29.7	29.7
Corrective Deferred	14.3	14.0	16.3	18.4	12.1	11.0	10.5
Corrective Emergency	33.1	28.5	30.8	34.9	26.6	24.5	23.5
Maintenance (Total)	**69.5**	**65.5**	**95.2**	**105.3**	**96.6**	**94.1**	**91.4**
Reliability	0.0	0.0	0.0	2.1	3.0	2.9	2.9
SCADA & Communications	0.0	0.0	0.5	0.8	0.9	0.9	0.8
Misc Network Services	0.0	0.0	2.2	2.0	1.9	1.9	1.9
Network Operations	4.3	5.4	7.7	8.5	8.6	8.8	9.0
IT&T	9.5	8.5	8.5	10.7	12.9	14.1	17.4
Metering	9.5	9.6	9.6	15.9	14.0	13.7	14.7
Call Centre	4.8	5.0	5.1	5.7	6.4	6.5	6.7
Network Support	24.0	27.6	27.3	45.4	44.6	47.5	49.4
Reliability Penalty Payment					1.4	1.3	1.3
DISTRIBUTION TOTAL ($M)	**121.5**	**121.7**	**156.0**	**196.4**	**190.3**	**191.7**	**195.4**

5 Asset valuation and depreciation

5.1 Introduction

The calculation of Western Power's target revenue in the forthcoming access arrangement period requires an assessment of the value of the capital base[41] and depreciation.

As noted in Section 6 of Part B of this document, the Authority's Draft Decision examined Western Power's proposed approach to valuing its capital base as at 30 June 2006, as described in Western Power's access arrangement information document submitted on 24 August 2005. The Authority considered submissions from interested parties, including the Office of Energy, in addition to a report from its consultants Wilson Cook.

The Authority's Draft Decision[42] examined Western Power's proposed approach to valuing its capital base as at 30 June 2006, as described in Western Power's access arrangement information document submitted on 24 August 2005. The Authority considered submissions from interested parties, including the Office of Energy, in addition to a report from its consultants Wilson Cook. Required Amendments 37 and 38 of the Authority's Draft Decision established a valuation for Western Power's capital base as at 30 June 2006.

Western Power accepts the Authority's valuation of its capital base as being in accordance with the Code, and therefore the company has adopted this valuation for the purposes of this access arrangement, updated for asset acquisitions associated with the restructuring of the former Western Power Corporation in April 2006, and the actual capital expenditure and depreciation to 30 June 2006, as noted in paragraph 308 of the Final Decision.

The Authority states in paragraph 312 of its Final Decision that it is satisfied that the revised proposed access arrangement incorporates or otherwise addresses the reasons for Draft Decision Amendments 37 and 38, and that the value proposed by Western Power for the capital base at 30 June 2006 (as set out in Table 27 of the Final Decision) meets the requirements of the Access Code.

The remainder of this section is structured as follows:

- section 5.2 describes valuation of the distribution capital base as at 30 June 2006 in light of the Code provisions and the Authority's Draft and Final Decisions;

- section 5.3 summarises Western Power's approach to depreciation for the distribution capital base in the light of the Authority's Draft and Final Decisions; and

- section 5.4 provides details of the calculations of the distribution capital base value from 1 July 2006, and for each subsequent year of the first access arrangement period.

41 The capital base is defined in the Code as the value of the network assets that are used to provide covered services on the covered network determined under sections 6.44 to 6.63. The capital base value is an input into the calculation of Western Power's target revenue.

42 ERA, Draft Decision, 21 March 2006, Required Amendments 37 and 38, page 119.

5.2 The valuation of the distribution capital base as at 30 June 2006

In accordance with Required Amendments 37 and 38 of the Authority's Draft Decision, Western Power proposes that the initial distribution capital base will be the optimized deprival value (ODV) of assets as at 30 June 2004 (determined in accordance with the independent valuation commissioned by the WA Government's Electricity Reform Implementation Unit (ERIU)) adjusted for inflation, depreciation, asset acquisitions and capital expenditure updated for the actual capital expenditure and depreciation to 30 June 2006. The initial capital base is net of accumulated capital contributions received by Western Power to 30 June 2006. For information purposes, the ERIU valuation is attached to this document at Appendix 10.

As noted in section 5.1 above, the Authority states in paragraph 312 of its Final Decision that it is satisfied that the revised proposed access arrangement incorporates or otherwise addresses the reasons for Draft Decision Amendments 37 and 38, and that the value proposed by Western Power for the capital base at 30 June 2006 (as set out in Table 27 of the Final Decision) meets the requirements of the Access Code.

Table 28 below sets out details of the ERIU valuation.

Table 28 – Net ODV valuation of distribution assets as at 30 June 2004 ($ million real as at 30 June 2006)

Asset Group	Remaining Life as at 30 June 2004 (years)	Value
Distribution lines - wood poles	14.6	446.6
Distribution lines - steel poles	N/A	0.0
Distribution underground cables	34.4	415.6
Distribution transformers	17.1	187.4
Distribution switchgear	12.5	87.8
Street lighting	3.1	13.5
Distribution meters and services	10.4	179.3
Distribution IT&T	12.5	0.8
Distribution SCADA & communications	12.5	10.0
Distribution Other, non-network	12.5	42.4
Distribution Land & Easements	N/A	18.0
TOTAL		**1,401.5**

Details of the calculation of the distribution capital base value as at 30 June 2006 are set out in table 29 below.

Table 29: Derivation of Distribution Initial Capital Base (net)
($ million real as at 30 June 2006)

Financial year ending:	30 June 2004	30 June 2005	30 June 2006
Opening capital base value		1,401.5	1,470.0
less Depreciation		86.5	91.0
plus Capital Expenditure (net)		158.2	209.1
less Redundant Assets		3.2	1.8
plus Corporate Assets allocated to Western Power		0.0	8.1
Closing capital base value	**1,401.5**	**1,470.0**	**1,594.5**

At the time of separation of Western Power Corporation into separate businesses, the transfer order gifted the following corporate assets to Western Power. These assets have been included within the initial capital base of both transmission and distribution with the value split 50%-50%. Table 30 below details the assets and their value at 30 June 2006.

Table 30 – Corporate Assets Transferred to Western Power
($ million real as at 30 June 2006)

Asset	Asset Value
Head Office Land	4.0
Head Office Building	9.3
Jandakot Land	2.7

For the avoidance of doubt, it is noted that the capital base valuation reflects actual capital expenditure for the year ending 30 June 2006..

5.3 Western Power's approach to depreciation – distribution assets

Under the approach to calculating target revenue set out in Subchapter 6.2 of the Code[43], depreciation (as defined sections 6.43 and 6.70 of the Code) represents a return of accumulated capital to investors. In this sense, it is necessary to distinguish between the depreciation charge that is applied in the calculation of target revenue pursuant to Subchapter 6.2 of the Code, and the depreciation charge that may appear in the company's statutory financial accounts, or in its tax return.

In accordance with the Draft Decision's Required Amendment 46, Western Power adopted the economic lives shown in table 31 below for depreciation purposes. It is noted that in its Final Decision[44], the Authority concludes that the economic lives in Table 31 below satisfy the Authority's Required Amendment 46.

[43] "Calculation of Service Provider's Costs".

[44] ERA, Final Decision on the Proposed Access Arrangement for the South West Interconnected Network, March 2007, paragraph 420.

Table 31 – Distribution asset groupings and economic lives for depreciation purposes

Asset group	Economic Life (years) for depreciation purposes
Distribution lines - wood poles	41 years
Distribution lines - steel poles	50 years
Distribution underground cables	60 years
Distribution transformers	35 years
Distribution switchgear	35 years
Street lighting	20 years
Distribution meters and services	25 years
Distribution IT&T	10.16 years
Distribution SCADA & communications	10.16 years
Distribution Other, non-network	10.16 years

Furthermore, in response to the Draft Decision's Required Amendment 47, Western Power confirms that it is adopting a straight-line approach to depreciation and is proposing accelerated depreciation in relation to existing distribution assets that will be decommissioned as a result of the retrospective undergrounding project undertaken by Western Power on behalf of the Western Australian government. It is noted that in its Final Decision[45], the Authority concludes that Western Power has satisfied the Authority's Required Amendment 47.

Table 32 below provides of accelerated depreciation by asset category.

Table 32: Distribution redundant capital by asset class ($ million real as at 30 June 2006)

Financial year ending:	30 June 2007	30 June 2008	30 June 2009
Distribution lines - wood poles	2.9	2.8	2.7
Distribution lines - steel poles	0.0	0.0	0.0
Distribution underground cables	0.0	0.0	0.0
Distribution transformers	0.8	0.7	0.7
Distribution switchgear	0.2	0.2	0.2
Street lighting	0.0	0.0	0.0
Distribution meters and services	0.0	0.0	0.0
Distribution IT&T	0.0	0.0	0.0
Distribution SCADA & communications	0.0	0.0	0.0
Distribution Other, non-network	0.0	0.0	0.0
Distribution Land & Easements	0.0	0.0	0.0
TOTAL	**3.8**	**3.7**	**3.6**

45 Ibid, paragraph 421.

5.4 Proposed distribution capital base and depreciation values

As noted in section 5.2 above, in accordance with Required Amendments 37 and 38 of the Authority's Draft and Final Decisions, Western Power has adopted a distribution capital base of $1,528.6 as at 30 June 2006, updated for the latest capital expenditure and depreciation forecasts.

Table 33 below provides details of the composition of the distribution capital base as at 30 June 2006, by asset group.

Table 33 – Distribution Initial Capital Base (net) as at 30 June 2006
($ million real as at 30 June 2006)

Asset Group	Remaining Life as at 30 June 2006 (years)	Value
Distribution lines - wood poles	14.5	472.6
Distribution lines - steel poles	N/A	0.0
Distribution underground cables	36.9	535.2
Distribution transformers	16.9	203.8
Distribution switchgear	13.5	108.6
Street lighting	1.2	5.3
Distribution meters and services	9.2	168.2
Distribution IT&T	9.8	15.4
Distribution SCADA & communications	10.2	12.8
Distribution Other, non-network	11.3	51.2
Distribution Land & Easements	N/A	21.4
TOTAL		**1,594.5**

Table 34 below provides an overview of the forecast distribution capital base values for each year of the forthcoming access arrangement period.

Table 34 – Forecast distribution asset values
($ million real as at 30 June 2006)

Financial year ending:	30 June 2006	30 June 2007	30 June 2008	30 June 2009
Opening capital base value		1,594.5	1,746.9	1,953.2
less Depreciation		-97.2	-101.9	-110.5
plus Capital Expenditure		253.4	311.9	323.5
less Redundant Assets		-3.8	-3.7	-3.6
Closing capital base value	1,594.5	1,746.9	1,953.2	2,162.6

6 The cost of capital

6.1 Introduction

As noted in section 7, Part B of this document, the weighted average cost of capital (WACC) is a critical determinant of the level of Western Power's capital-related costs. These capital-related costs, in turn, comprise a substantial proportion of the company's total costs, and hence its target revenue.

6.2 Summary of Western Power's views

Western Power's view is that the estimated WACC should be the same for Western Power's transmission and distribution networks that comprise the SWIN. Therefore, the analysis and findings presented in section 7, Part B of this document are equally applicable to this section. For ease of reference, Western Power's principal conclusions from section 7, Part B of this document are summarised below.

In its Final Decision, the Authority further considers the determination of the reasonable range for the WACC, taking into account the parameter values in its Draft Decision and recent observations from capital markets on risk free rates. The Authority's estimate of the reasonable range for the WACC is set out in table 56 of the Final Decision (reproduced below).

Table 56 Authority's Final Decision assessment of reasonable WACC range

Estimated WACC (per cent)	Nominal	Real
Post-Tax	6.19 – 7.11	3.00 – 3.89
Pre-tax	8.84 – 10.16	5.57 – 6.85

Western Power's proposed pre-tax real WACC of 6.76% as set out in its revised proposed access arrangement is within the reasonable range the Authority estimates in its Final Decision. Therefore, the Authority's Final Decision accepts Western Power's proposed WACC of 6.76%, concluding (in paragraph 453) that:

> "The WACC incorporated by Western Power in the revised proposed access arrangement (6.76 per cent pre-tax real) lies within the reasonable range determined by the Authority for the purposes of this Final Decision. Accordingly, the Authority accepts that this value meets the requirements of the Access Code."

Western Power fully accepts the Authority's findings in the Final Decision. In accordance with the Final Decision, Western Power will apply a pre-tax real WACC of 6.76% in its access arrangement.

On the basis of the Final Decision, Western Power has adopted a pre-tax WACC of 6.76% in its access arrangement.

7 Total Revenue Requirement

7.1 Introduction

Section 6.2(a) of the Code states that:

> "Without limiting the forms of *price control* that may be adopted, *price control* may set *target revenue* by reference to the *service provider's approved total costs*."

Furthermore, in respect of the first access arrangement period, section 6.3 of the Code requires that the first access arrangement must contain the form of control described in section 6.2(a).

The earlier sections of this Part C provide a detailed explanation of Western Power's cost forecasts for the distribution network. Together, these cost forecasts comprise the approved total costs for the distribution network, for the purpose of determining target revenue. This approach to determining the annual revenue requirement of a regulated company is often referred to as the "building block" approach.

The purpose of this section of the document is to explain how each cost element discussed in the earlier sections of this Part C are combined to determine the target revenue in each year of the first access arrangement period. A similar calculation is explained in section 8, Part B of this document in relation to the transmission network.

The remainder of this section is structured as follows:

- section 7.2 provides an overview of the building block method for determining the target revenue for the distribution network; and

- section 7.3 provides details of the composition of the target revenue, including figures showing the trend of distribution revenue and average prices from 2002 to the end of the first access arrangement period.

7.2 Overview of "Building Block" Revenue Determination Method

The revenue requirements (target revenue) are calculated as the sum of a series of "building blocks" which are described briefly in Table 35, below. As already noted, the earlier sections of this document provide detailed analysis of each building block element.

Table 35 – Summary of the building block components of target revenue

Target revenue component	Brief description	Cross-references for further details
Operations and maintenance costs	This is Western Power's annual cost of operating the distribution network, and maintaining the assets used in the delivery of *covered services*.	Section 4, Part C
Return of capital	This is the annual depreciation charge on the distribution assets used in the delivery of *covered services*.	Section 5, Part C
Return on capital	This is the product of the required rate of return (the *weighted average cost of capital*, or WACC) and the *capital base*. (The *capital base* for a *covered network* means the value of the network assets that are used to provide *covered services* on the *covered network* determined under sections 6.44 to 6.63 of the Code.) The *capital base* value over the *access arrangement period* is, in turn, a function of the depreciated value of assets at the start of the period, the level of annual depreciation recovered during the period, and the level of efficient new capital expenditure (*new facilities investment*) that is assumed to be required over the course of the *access arrangement period*.	Sections 5 and 6, Part C
Taxation	The pre-tax approach to WACC provides an allowance for company tax in the WACC.	Section 6, Part C

Target revenue is calculated using a model developed by the Authority which adopts an end of year timing assumption for modelling revenues and expenses[46] in real terms. That model calculates target revenue for each year of the access arrangement period in accordance with the following formula:

$TR_t = r.RAB_{t,open} + Dep_t + O\&M_t$

where

TR_t = target revenue in year t.

r = WACC (in real pre-tax terms).

$RAB_{t,open}$ = opening value of the regulatory asset base (which takes into account forecast new facilities investment over the access arrangement period).

Dep_t = depreciation in year t (which takes into account forecast new facilities investment over the access arrangement period).

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

A copy of the revenue model outputs is provided in Appendix 11.

46 The calculations assume that all forecast capital expenditure occurs at the end of each relevant year. The effect of this assumption is to align the timing of forecast capital expenditure with that of all other costs and revenues, which are assumed to occur at the end of each relevant year.

7.3 Forecast target revenue for the distribution network

Table 36 below shows the composition of distribution network revenue for the forthcoming access arrangement period.

Table 36 – Composition of distribution network revenue ($ million real as at 30 June 2006)

Financial year ending:	30 June 2007	30 June 2008	30 June 2009	Present Value
Operating Costs	190.3	191.7	195.4	507.0
plus Depreciation	97.2	101.9	110.5	271.3
plus Redundant Assets	3.8	3.7	3.6	9.8
plus Return on Assets	107.8	118.1	132.0	313.1
plus Return on Working Capital	1.5	1.3	1.3	3.6
Target Revenue	**400.6**	**416.6**	**442.9**	**1,104.7**
plus Tariff Equalisation Contribution	67.8	67.9	66.5	177.7
less Non-Reference Services Revenue	-14.7	-14.7	-14.7	-38.8
less Capital Contributions	-91.6	-106.8	-122.3	-280.0
Net Reference Services Revenue	**362.0**	**363.0**	**372.4**	**963.7**
Smoothed Reference Services Revenue	**313.8**	**384.1**	**404.9**	**963.7**

Table 37 below shows the distribution capital base depreciation by asset class.

Table 37 – Distribution Capital Base depreciation by asset class ($ million real as at 30 June 2006)

Financial year ending:	30 June 2007	30 June 2008	30 June 2009
Distribution lines - wood poles	32.6	32.4	32.2
Distribution lines - steel poles	0.0	0.0	0.0
Distribution underground cables	14.5	14.5	14.5
Distribution transformers	12.1	12.0	12.0
Distribution switchgear	8.0	8.0	8.0
Street lighting	4.4	0.9	0.0
Distribution meters and services	18.3	18.3	18.3
Distribution IT&T	1.6	1.6	1.6
Distribution SCADA & communications	1.3	1.3	1.3
Distribution Other, non-network	4.5	4.5	4.5
Distribution Land & Easements	0.0	0.0	0.0
TOTAL	**97.2**	**93.4**	**92.3**

Table 38 below sets out distribution capital expenditure depreciation by asset class.

Table 38 – Distribution capital expenditure depreciation by asset class ($ million real as at 30 June 2006)

Financial year ending:	**30 June 2007**	**30 June 2008**	**30 June 2009**
Distribution lines - wood poles	0.0	1.3	3.1
Distribution lines - steel poles	0.0	0.0	0.0
Distribution underground cables	0.0	1.7	3.7
Distribution transformers	0.0	0.8	1.8
Distribution switchgear	0.0	0.6	1.6
Street lighting	0.0	0.6	1.2
Distribution meters and services	0.0	0.2	0.5
Distribution IT&T	0.0	1.8	3.4
Distribution SCADA & communications	0.0	0.2	0.4
Distribution Other, non-network	0.0	1.2	2.6
Distribution Land & Easements	0.0	0.0	0.0
TOTAL	**0.0**	**8.4**	**18.2**

Table 39 below sets out distribution redundant capital by asset class.

Table 39 – Distribution redundant capital by asset class ($ million real as at 30 June 2006)

Financial year ending:	**30 June 2007**	**30 June 2008**	**30 June 2009**
Distribution lines - wood poles	2.9	2.8	2.7
Distribution lines - steel poles	0.0	0.0	0.0
Distribution underground cables	0.0	0.0	0.0
Distribution transformers	0.8	0.7	0.7
Distribution switchgear	0.2	0.2	0.2
Street lighting	0.0	0.0	0.0
Distribution meters and services	0.0	0.0	0.0
Distribution IT&T	0.0	0.0	0.0
Distribution SCADA & communications	0.0	0.0	0.0
Distribution Other, non-network	0.0	0.0	0.0
Distribution Land & Easements	0.0	0.0	0.0
TOTAL	**3.8**	**3.7**	**3.6**

Table 40 below shows forecast distribution capital contributions for the first access arrangement period.

Table 40 – Forecast Distribution Capital Contributions (includes both cash and vested assets) by expenditure type ($ million real as at 30 June 06)

	2006/07	2007/08	2008/09
DEMAND RELATED			
Customer Driven	63.7	76.3	88.3
Customer Driven – Vested Assets	15.5	18.9	22.1
OTHER			
State Undergrounding Power Program (SUPP)	12.5	11.6	11.9
Rural Power Improvement Program (RPIP)	0.0	0.0	0.0
Distribution Total ($M)	**91.6**	**106.8**	**122.3**

Figures 11 and 12 show the trend in distribution tariff revenues and average distribution tariff prices in real dollars for the year ending 30 June 2002 to the end of the first access arrangement period.

Figure 11: Trend in Distribution Tariff Revenue in Real Dollars at 30 June 2006

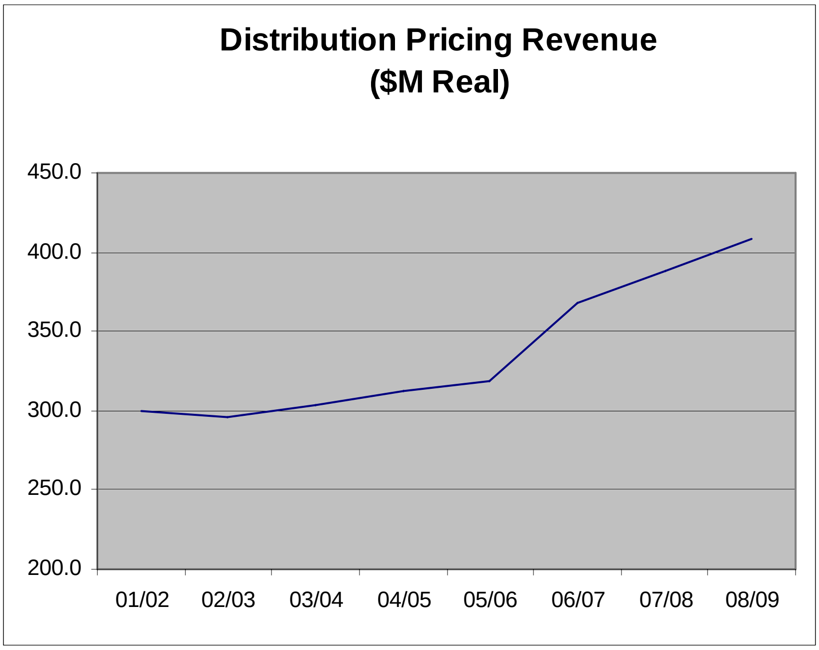
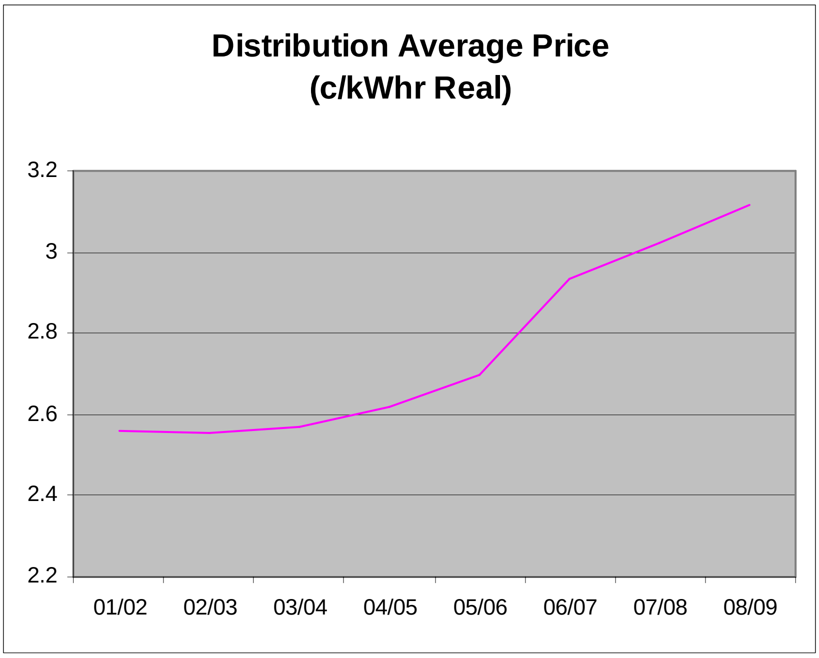


Figure 12: Trend in Distribution Average Price in Real Dollars at 30 June 2006



PART D: REGULATORY FRAMEWORK

1 Introduction to Part D

This Part D provides information that describes and explains the overall regulatory framework applying to Western Power's transmission and distribution networks.

Part D is structured as follows:

- section 2 examines the Code provisions relating to the definition of reference services, and develops an appropriate definition of reference and non-reference services, based on Western Power's application of the relevant Code provisions;
- section 3 examines the Code provisions relating to the definition of service standard benchmarks, and develops an appropriate practical definition of service standard benchmarks, based on Western Power's application of the relevant Code provisions;
- section 4 provides information setting out the basis of the design of the price controls that are to apply to the transmission and distribution network businesses;
- section 5 outlines the pricing methods that Western Power proposes to apply;
- section 6 sets out the basis of the proposed applications and queuing policy;
- section 7 describes the basis of the proposed capital contributions policy;
- section 8 provides explanatory information relating to the proposed standard access contract;
- section 9 provides explanatory information relating to Western Power's transfer and relocation policy;
- section 10 examines the provisions of the Code that relate to trigger events. The rationale for the trigger events that Western Power proposes to include in its access arrangement is also set out; and
- section 11 provides information on the supplementary matters set out in the Code.

2 Definition of Reference Services

2.1 Introduction

Western Power is focused on the efficient delivery of services at standards that meet or exceed its customers' expectations. The introduction of the Code, and Western Power's compliance with its provisions, should not divert the company's attention from service delivery. Importantly, however, the Code requires the company to express, or in some cases re-define, its price-service offering in a manner consistent with the provisions and terminology in the Code.

The purpose of this section of the document is:

- to outline the terminology and provisions in the Code relating to service definitions; and
- to explain how Western Power has interpreted and applied these Code provisions in relation to the services that it provides to its customers.

2.2 Code provisions

This document and the accompanying access arrangement only relate to services that are covered by the Code. The Code defines a covered service in the following terms:

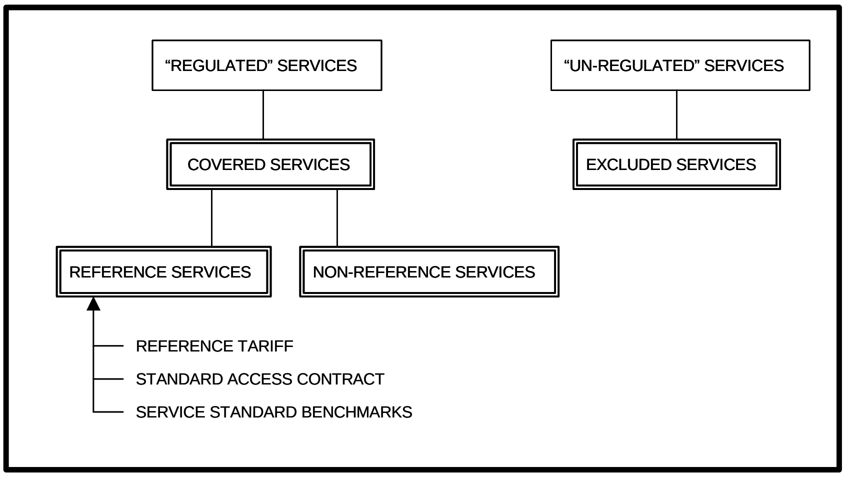
> "*covered service* means a *service* in relation to the *transportation* of electricity provided by means of a *covered network*, including:
>
> (a) a *connection service*; or
>
> (b) an *entry service* or *exit service*; or
>
> (c) a network use of system service; or
>
> (d) a *common service*; or
>
> (e) a *service* ancillary to a *service* listed in paragraphs (a) to (d) above, but does not include an *excluded service*."

The Code provides for three further categories of services that are relevant to the access arrangement:

- reference services;
- non-reference services; and
- excluded services.

Figure 13 below depicts these service categories and their relationships:

Figure 13: Categories of services under the Code



The Code defines each of these services as follows:

> "*reference service* means a *covered service* designated as a reference service in an *access arrangement* under section 5.1(a) for which there is a *reference tariff*, a *standard access contract* and *service standard benchmarks.*"
>
> "*non-reference service* means a *covered service* that is not a *reference service*."
>
> "*excluded service* means a *service* in relation to the *transportation* of electricity provided by means of a *covered network*, including:
>
> (a) a *connection service*; or
>
> (b) an *entry service* or *exit service*; or
>
> (c) a network use of system service; or
>
> (d) a *common service*, or
>
> (e) a *service* ancillary to the *services* listed in paragraphs (a) to (d) above,
>
> which meets the following criteria:
>
> (i) the supply of the *service* is subject to effective competition; and
>
> (ii) the cost of the *service* is able to be excluded from consideration for *price control* purposes without departing from the *Code objective*."

The critical issue in distinguishing an excluded service from other covered services is that the Code sets out two criteria (items (i) and (ii) above) for determining whether a service should be classified as an excluded service. In addition, sections 6.33 to 6.37 of the Code set out a process under which the Authority may make a determination of excluded services for a covered network. Under that process, a service provider may at any time request the Authority to determine that one or more services are to be treated as excluded services.

Importantly, the Code also provides guidance on how reference and non-reference services should be distinguished. In particular, the Code contains the following provisions in relation to the definition of reference services:

(a) An access arrangement must specify one or more reference services (section 5.1(a)).

(b) An access arrangement must include a standard access contract for each reference service (section 5.1(b)),

(c) An access arrangement must include service standard benchmarks for each reference service (section 5.1(c))

(d) Reference services are those services that are likely to be sought by a significant number of users and applicants or a substantial proportion of the market for services in the covered network (section 5.2 (b)).

(e) Reference services should be specified in a manner that enables a user to acquire by way of one or more reference services only those elements of a covered service that the user wishes to acquire (section 5.2 (c)).

(f) Reference services should be defined in a way that enables users to acquire entry (or exit) services without having to acquire corresponding exit (or entry) services (section 5.2 (d)).

(g) Service standard benchmarks must be reasonable (section 5.6 (a)).

(h) Service standard benchmarks must be sufficiently detailed and complete to enable a user to determine the value represented by the reference service at the reference tariff (section 5.6 (b)).

The remainder of this section applies these definitional requirements to Western Power's services, and explains Western Power's approach in developing its proposed reference services and non-reference services, which are presented in section 3 and Appendix 7 of the access arrangement.

2.3 Developing Code compliant reference and non-reference services

Western Power interprets the above Code provisions as collectively establishing a checklist of requirements that must be met in order for a service to be categorised as a reference service. In essence, if it is not possible or practical for a service to satisfy these requirements, then the service should be categorised as a non-reference service. It is also noted, for completeness, that there are a number of pricing provisions in the Code that relate specifically to reference services (in particular "pricing methods" in chapter 7).

In developing Western Power's definition of reference services, the company believes that the following Code provisions are particularly relevant:

1. Reference services are those services that are likely to be sought by a significant number of users and applicants or a substantial proportion of the market for services in the covered network (section 5.2 (b)).

2. Reference services should be specified in a manner that enables a user to acquire by way of one or more reference services only those elements of a covered service that the user wishes to acquire (section 5.2 (c)).

3. Reference services should be defined in a way that enables users to acquire entry (or exit) services without having to acquire corresponding exit (or entry) services (section 5.2 (d)).

In developing its definition of reference and non-reference services, Western Power also had regard to the following Code definition:

> " 'reference service' means a *covered service* designated as a reference service in an *access arrangement* under section 5.1(a) for which there is a *reference tariff*, a *standard access contract* and *service standard benchmarks*."

The Code defines standard access contract as:

> "the terms and conditions for a *reference service* in an *access arrangement* under section 5.1(b)."

Western Power notes that the model standard access contract in Appendix 3 of the Code indicates that the contract is between the service provider and a user who is party to an access contract with a service provider. It follows that reference services are services provided by Western Power to users of the network, rather than end-consumers.

Western Power also interprets the Code provisions as requiring that a particular service should be categorised as a non-reference service when:

- the service is not directly related to access provision; and therefore
- it is not possible or practical to set service standard benchmarks in relation to these services or to provide them in accordance with a standard access contract.

Western Power's reference and non-reference services have been carefully developed in the light of the above interpretation of the Code. Summary details are provided in section 2.4 below.

2.4 Western Power's reference and non-reference services

After careful consideration of the Code requirements, Western Power offers 11 *reference services* at *network exit points*:

1. Anytime Energy (Residential) Exit Service	A1
2. Anytime Energy (Business) Exit Service	A2
3. Time of Use Energy (Small) Exit Service	A3
4. Time of Use Energy (Large) Exit Service	A4
5. High Voltage Metered Demand Exit Service	A5
6. Low Voltage Metered Demand Exit Service	A6
7. High Voltage Contract Maximum Demand Exit Service	A7
8. Low Voltage Contract Maximum Demand Exit Service	A8
9. Streetlighting Exit Service	A9
10. Un-Metered Supplies Exit Service	A10

11. Transmission Exit Service A11

Western Power offers two entry services as *reference service*:

1. Distribution Entry Service B1

2. Transmission Entry Service B2

For further detail on each of these reference services, please refer to Appendix 7 of the access arrangement, which provides for each reference service:

- a detailed description;
- user eligibility criteria;
- the applicable reference tariff;
- the applicable standard access contract; and
- the applicable service standard benchmark.

As noted in section 2.3 above, Western Power interprets the Code as establishing characteristics that a service must satisfy in order to be classified as a reference service. Services that cannot be classified as either a reference service or an excluded service must (logically) fall within the definition of a non-reference service. Table 41 below provides a list of Western Power's non-reference service, showing why each service cannot be classified as either a reference service or an excluded service.

Table 41 - Non-reference Services

Non Reference Service	Reference Service Criteria			Excluded Service Criteria	
	Reference Tariff	Standard Access Contract	Service Standard Benchmark	Effective Competition	Costs of Service can be excluded
Relocation of Transmission assets at the request of a user	No	No	No	No	No
Relocation of Distribution assets at the request of a user	No	No	No	No	No
Electricity Network Planning Studies	No	No	No	No	No
Re-inspection of a Customer's facilities and equipment by a Western Power Inspector	No	No	No	No	No
Rental of properties (including commercial & residential) that are in the capital base	No	No	No	Yes	No
Profit on sale of assets (eg scrap value)	No	No	No	No	No
Establishment & Removal of a Temporary Builders Supply	No	No	No	No	No
Planning for and providing an escort for movement of high loads	No	No	No	No	No
Temporary removal of overhead service lead for work at a customer's premises	No	No	No	No	No
Insulate and make safe aerial conductors	No	No	No	No	No
Disconnection/Reconnection of overhead service leads or underground consumer mains at a customer's request	No	No	No	No	No
User Network Switching Services at Request of a user (on WPC's asset)	No	No	No	No	No
Jointly Owned Asset works	No	No	No	No	No
Provide expertise to enable work to be undertaken in the vicinity of power lines	No	No	No	No	No
Sale of network schematics	No	No	No	No	No
Services fees for Access Applications & Access Contracts	No	No	No	No	No
Costs recovered from asset damage to due to a car accident, graffiti or vandalism	No	No	No	No	No
Extended metering services provided under the Metering Code Service Level Agreement	No	No	No	No	No
Access Billing Services Fees	No	No	No	No	No
Transition Access Services	No	No	Yes	No	No
Standby Access Services	No	No	Yes	No	No
Capital Works Application Fees	No	No	No	No	No

Table 42 below sets out the forecast of annual revenue form the provision of non reference services for each year of the forthcoming access arrangement period. These revenue forecasts have been taken into account in the calculation of Western Power's target revenue for the forthcoming access arrangement period.

Table 42 –Forecast of annual non-reference services revenue for the first access arrangement period ($ million real per annum as at 30 June 2006)

	Distribution	Transmission
Extended Metering Services	4.7	0.0
Transition Access Services	3.4	9.7
Standby Access Services	0.1	1.8
Other Non Reference Services	6.5	6.9
Total Non Reference Services Revenue	**14.7**	**18.4**

2.5 Identification of Excluded Services

As at the time of lodging this document:

- the Authority had not made a determination of excluded services for a covered network under powers conferred on the Authority by sections 6.33 to 6.37 inclusive; and

- Western Power does not intend to seek a determination of excluded services pursuant to section 6.35 of the Code.

Accordingly, there are presently no excluded services identified in Western Power's access arrangement. Notwithstanding this, it is noted that Western Power may, under section 6.35, at any time request the Authority to determine under section 6.33 that one or more services provided by means of the SWIN are excluded services.

3 Service standard benchmarks

3.1 Introduction

This section provides details of Western Power's service standard benchmarks in respect of each reference service. As noted in section 2.3 of this Part D, the Code sets out a number of requirements regarding the definition of reference services, and the standard terms and conditions that should apply to their provision. In particular, the Code (in section 5.1(c)) requires that an access arrangement must include (amongst other things) service standard benchmarks for each reference service.

This section addresses the requirements of section 5.1(c) of the Code, and is structured as follows:

- section 3.2 examines the Code provisions relating to service standard benchmarks;
- section 3.3 explains Western Power's approach to setting service standard benchmarks in light of the applicable Code provisions;
- section 3.4 describes Western Power's service standard benchmarks against each transmission reference service;
- section 3.5 describes Western Power's service standard benchmarks against each reference service provided to users connected to the distribution network;
- section 3.6 briefly describes Western Power's other commitments and obligations regarding service delivery that do not form part of the service standard benchmarks; and
- section 3.7 sets out concluding comments.

3.2 Code provisions relating to service standard benchmarks

The Code defines service standard benchmarks as:

> "the benchmarks for *service standards* for a *reference service* in an *access arrangement* under section 5.1(c)."

In turn, the Code defines service standards as:

> "either or both of the technical standard, and reliability, of delivered electricity."

It is noted that neither "technical standard" nor "reliability" are defined terms in the Code.

Section 5.6 of the Code provides the following guidance in setting service standard benchmarks:

> "A *service standard benchmark* for a *reference service* must be:
>
> (a) reasonable; and
>
> (b) sufficiently detailed and complete to enable a *user* or *applicant* to determine the value represented by the *reference service* at the *reference tariff*."

Section 6.9 defines a *service standards adjustment mechanism* as:

> "a mechanism in an *access arrangement* detailing how the *service provider's* performance during the *access arrangement period* against the *service standard benchmarks* is to be treated by the *Authority* at the next *access arrangement review*."

Section 11.1 of the Code also refers to service standard benchmarks, as follows*:*

> "A service provider must provide reference services at a service standard at least equivalent to the *service standard benchmarks* set out in the access arrangement and must provide non-reference services to a service standard at least equivalent to the service standard in the access contract."

In terms of reporting against the service standard benchmarks, section 11.2 of the Code states:

> "The *Authority* must monitor and, at least once each year, *publish* a *service provider's* actual *service standard* performance against the *service standard benchmarks*."

In summary, therefore, the Code requires Western Power to propose service standard benchmarks that:

1. are reasonable, and sufficiently detailed and complete to enable a user or applicant to determine the value represented by the reference service at the reference tariff (section 5.6 of the Code); and

2. can be applied in the service standards adjustment mechanism (section 6.9); and

3. set the level of service that Western Power should provide to users of reference services (section 11.1).

Against this backdrop, Western Power's approach to setting service standard benchmarks is discussed in detail in section 3.3, below.

3.3 Western Power's approach to setting service standard benchmarks

3.3.1 Defining the standard of service to be delivered

As noted in Part A of this document:

- there is a need for service performance to be improved markedly from recent historic levels; and accordingly

- Western Power's capital and operating expenditure plans (which involve increases in expenditure compared to recent actual levels of spending) are aimed at enabling the company to deliver substantial improvements in service performance.

Over the first access arrangement period and beyond, the prices paid by Western Power's customers will reflect the costs associated with achieving the planned improvements in service. Western Power therefore recognises that the service standard benchmarks should reflect the substantial improvements in average performance that the company plans to achieve over the first access arrangement period.

Whilst Western Power will plan its investment and expenditure programs, and use its best endeavours to meet these challenging service standard benchmarks, the company cannot guarantee that the service standard benchmarks will always be met. Instead, Western Power believes that the objectives of the Code are best satisfied by establishing service standard benchmarks that are commensurate with the standard of service that the company is targeting to deliver, given its expenditure plans.

It should also be noted that:

- Western Power's service performance will be subject to a monitoring and reporting regime (to be administered by the Authority pursuant to section 11.2 of the Code).

- Western Power's performance against the service standard benchmarks will be subject to monitoring in accordance with the service standards adjustment mechanism, further details of which are provided in section 4.8 below.

- Aspects of Western Power's service performance will also be monitored pursuant to Western Power's operating licence.[47]

These monitoring and reporting regimes will provide a discipline on the company to meet or exceed the service improvements to which it has committed, and will provide suitable assurances to interested parties with regard to service delivery.

3.3.2 Service standard benchmarks to provide information to users or applicants

The Code requires that the service standard benchmarks provide sufficient detail to enable a user or applicant to determine the value represented by the reference service at the reference tariff. This section sets out Western Power's interpretation of this Code requirement, and explains how Western Power intends to address it.

In considering the Code's requirements on the provision of information to users regarding the value of reference services, it is worth noting that the user referred to in the Code will typically be a retailer or a generator. The commercial value that a retailer or generator places on the standard to which a reference service is provided will depend in part on the commercial arrangements between each user and their customers. As competition in the retail and generation sectors develop, users may ascribe increasingly diverse values to the provision of reference services. In this regard, it is impractical to devise service standard benchmarks to enable a user to precisely "determine the value represented by the reference service at the reference tariff".

In the light of the above discussion, Western Power interprets section 5.6(b) of the Code as requiring Western Power to provide the user with meaningful information regarding:

- the standard of service that a user can reasonably expect to obtain in exchange for purchasing a particular reference service;

- the aggregate compensation (if any) that will be paid to users of reference services (as a whole) via the service standards adjustment mechanism[48] if the applicable benchmark service standard is not satisfied; and

[47] See section 3.9 of Western Power's Response to the Required Amendments for further details.

- the aggregate reward (if any) accruing to Western Power via the service standards adjustment mechanism in respect of the reference services if actual network-wide service performance exceeds the applicable benchmark service standard.

In summary, Western Power believes that the requirements of section 5.6(b) of the Code can be met by the proposed service standard benchmarks that are presented in sections 3.4 and 3.5 below, in relation to transmission and distribution respectively.

3.4 Service standard benchmarks for transmission reference services

3.4.1 Arrangements in the National Electricity Market

In the course of developing service standard benchmarks for its transmission reference services, Western Power has examined the approaches applicable to electricity transmission companies in other Australian jurisdictions. The ACCC has been responsible for regulating Transmission Network Service Providers (TNSPs) in the eastern states of Australia since the mid late 1990s, so its experience in this area is instructive.

A review of the information published by the ACCC on transmission performance standards suggests that the ACCC has found very little commonality in performance data and standards among transmission companies in Australia and internationally. Moreover, the ACCC has acknowledged that the application of performance benchmarks requires consideration of the unique and complex operating environments of the individual companies. Consequently, the ACCC has chosen to use the actual performance levels achieved by each TNSP in recent years as a guide when setting future performance targets for each TNSP.

Standardised performance indicators for TNSPs have only recently been introduced by the ACCC. The general categories of indicators applied are:

- circuit availability;
- loss of supply event frequency;
- average outage duration; and
- transmission constraints.

The ACCC has also recognised that there is a requirement for some flexibility in the definitions of the indicators that would broadly measure the same parameters. In this regard, a key consideration is to ensure that the performance of each individual TNSP is measured consistently over time, having regard to each TNSP's particular measurement systems and performance data. This consistency, in turn, preserves the incentive for TNSPs to seek continuous performance improvement over time. The standard definitions may therefore be modified to align with the information that a particular TNSP has been collecting in the past.

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[48] Details of the proposed service standards adjustment mechanism (SSAM) are set out in section 4.8 below. It is noted that in this access arrangement, the SSAM does not provide for financial bonus or penalties. Nevertheless, in Western Power's view the interpretation of section 5.6(b) of the Code described here remains reasonable.

3.4.2 Proposed performance measures

As has been common practice elsewhere in Australia, Western Power has previously developed various performance indicators for internal use. However, the service standard indicators currently used by Western Power are not consistent with those which have recently been introduced by the ACCC.

Western Power recognises the benefits of applying service standard performance indicators which are consistent with those used elsewhere in Australia. However, in selecting the performance measures to apply to Western Power for the first access arrangement period, a critical consideration is whether it is possible to establish a reasonable record of historical performance against a particular proposed performance measure. As already noted, this is an important consideration because there is a need to establish future performance targets that are consistent with recent actual levels of performance, as well as planned future expenditure.

Circuit Availability is the most commonly used indicator for transmission service standards in Australia. As noted below, there are a number of good reasons for Western Power to adopt this performance measure for the first access arrangement period:

- Circuit Availability is the most general of the standard indicators;
- Circuit Availability can be calculated to include all outages (that is, both planned and unplanned outages);
- Circuit Availability can be calculated to include all transmission assets (that is, both shared network and connection assets);
- Circuit Availability is used by many other TNSPs in Australia and is also used as the sole service standard indicator by some. This measure therefore enables comparison of performance between TNSPs (to the extent that the scope of reported events and exclusions are similar); and
- Historical Circuit Availability can be readily calculated for Western Power's transmission network from existing data in order to establish realistic and meaningful future performance targets.

Circuit Availability is calculated from the sum of all outage durations in hours divided by the total number of circuits times the number of hours in a year. This index provides an indication of the overall level of reliability of the network; it essentially measures (as a proportion of total time) the extent to which supply is available via each major component in the network.

Western Power proposes to adopt Circuit Availability as one of the performance measures to be applied in the definition of the company's transmission service standard benchmarks.

While availability provides a useful measure of overall reliability, the interconnected nature of the network means that the measure provides little true indication of the impact of faults on customers. This is because only about 2 to 3% of all transmission faults involve loss of supply to end customers.

Two of the three performance indicators favoured by the ACCC (namely loss of supply event frequency and average outage duration) are intended to provide measures of transmission network performance from the perspective of end customers. The indicator applied by Western Power to measure performance from the end customer's perspective is System Minutes Interrupted. This measure is calculated as MWh of electricity not supplied times 60, divided by the system peak demand in MW.

This measure is preferred by Western Power because:

- it provides a meaningful indication of the overall impact of transmission faults on customers;
- the index is normalised by the system peak demand, making it more useful in comparing the performance of systems of different sizes; and
- importantly, reliable historical records exist.

For System Minutes Interrupted, Western Power proposes separate benchmarks for radial and meshed networks. It should be noted, however, that radial network elements are relatively few in number and their performance is dramatically affected by even a single significant event, making the setting of a meaningful target level (and bandwidth for the service standards adjustment mechanism[49]) somewhat challenging.

The final indicator applied by the ACCC (relating to transmission constraints) is not particularly meaningful in Western Power's case, given the nature and configuration of the transmission network and the location of major generating plant.

In summary, Western Power proposes to use System Minutes Interrupted (for meshed and radial circuits) and Circuit Availability as the measures of the service standard benchmarks for transmission reference services under the access arrangement.

[49] Details of the service standards adjustment mechanism are set out in section 4.8 of this Part D.

3.4.3 Definition of transmission performance indicators

The performance indicators to be applied in the definition of the service standard benchmark applying to transmission reference services shall be Circuit Availability, and System Minutes Interrupted as defined below:

Performance Indicator:	Circuit Availability
Unit of measure:	Percentage of total possible hours available.
Source of data:	SCADA and System Operation Databases
Definition/Formula:	$\frac{\text{No of Hours per Annum Circuits are Available}}{\text{Total Possible No. of Circuit Hours}} x100$ Definition: The actual circuit hours available for transmission circuits divided by the total possible defined circuit hours available.
Exclusions:	• Non-transmission primary equipment (primary equipment operating at voltages less than 66 kV, including zone substation power transformers) • Tee configuration line circuits • Unregulated transmission assets. • Outages shown to be caused by a fault or other event on a ‘3rd party system’ e.g. intertrip signal, generator outage, customer installation. • Force majeure events. • Duration of planned outages for major construction work is to be capped at 14 days in calculating transmission line availability.
Inclusions:	• ‘Circuits’ includes primary transmission equipment such as overhead lines, underground cables and bulk transmission power transformers. • Circuit ‘unavailability’ to include outages from all causes including planned, forced and emergency events, including extreme events, but not including the events defined as exclusions.

Performance Indicator:	System Minutes Interrupted (for both Meshed and Radial Transmission Network)
Unit of measure:	Minutes
Source of data:	SCADA and System Operation Databases
Definition/Formula:	$\sum \frac{\text{MW Minutes of Unserved Energy}}{\text{System Peak MW}}$ (for both Meshed and Radial Transmission Network separately) Definition: System Minutes Interrupted (Meshed)- The summation of MW Minutes of unserved energy at substations which are connected to the meshed transmission network divided by the system peak MW. System Minutes Interrupted (Radial)- The summation of MW Minutes of unserved energy at substations which are connected to the radial transmission network divided by the system peak MW.
Exclusions:	• Unregulated transmission assets. • Outages shown to be caused by a fault or other event on a '3rd party system' e.g. intertrip signal, generator outage, customer installation. • Force majeure events.
Inclusions:	• All unserved energy due to outages on any primary transmission equipment including all overhead lines, underground cables, power transformers, static var compensators, capacitor banks, etc. including primary zone substation equipment. • All unserved energy due to outages for forced and emergency events, including extreme events, but not including the events defined as exclusions.

3.4.4 Service standard benchmarks – transmission reference services

The service standard benchmarks applying to transmission reference services for the first access arrangement period are:

- consistent with the expectation that recently achieved standards of service will be maintained or improved; and
- consistent with the level of maintenance and capital expenditure that the company plans to undertake over the course of the first access arrangement period.

Service standard benchmarks should be developed with reference to many years of data on past performance, however the availability of suitable data for this purpose is limited. Data showing historical performance for the proposed indicators of Circuit Availability and System Minutes Interrupted have been derived by Western Power from existing databases. Table 43 below shows Western Power's transmission performance in terms of the Circuit Availability measured from July 2002 to Mar 2006.

Table 43: Circuit Availability: historical performance

	2002/03	2003/04	2004/05	2005/06 (9 months)
Circuit Availability (% of total possible hours available)	98.82	99.06	98.96	98.22

In relation to circuit availability, it should be noted that Western Power has recently commenced a program of major construction work to extend and expand the system to meet projected load growth. Western Power is managing circuit availability to facilitate this construction in a responsible and prudent manner, balancing the requirements of avoiding costs of restoring circuits unnecessarily and ensuring system security is not compromised.

The most recent data for circuit availability reflects the impacts of recent major construction work, and this work is expected to continue throughout the access arrangement period. In addition, the data and definitions for circuit availability set out above assume that an exclusion is applied to cap planned outages for major construction work at 14 days. In this context, it is noted that the AER has approved similar exclusions for other TNSPs. The AER's predecessor (the ACCC) determined that outages relating to major line works should be treated as excluded events under the revenue cap decision and guidelines, and Western Power proposes to adopt this approach also. With respect to tee configuration line circuits (which are very few in number), Western Power does not currently have systems for efficient reporting of performance, and historical data is not available. Therefore, these circuits have been excluded from the calculation of the benchmarks.

Table 44 below shows Western Power's transmission performance in terms of the System Minutes Interrupted, measured from July 2000 to June 2005 (on a financial year basis).

Table 44: System Minutes Interrupted: historical performance

	2000/01	2001/02	2002/03	2003/04	2004/05	Average
Meshed network	6.5	7.8	10.8	7.9	5.8	7.8
Radial network	3.4	4.4	8.3	1.7	1.5	3.9

The inherent uncertainty associated with extrapolating the relatively limited time series of historical data which is available suggests that a conservative approach should be adopted in setting service standard benchmarks for the first access arrangement period. Accordingly, in relation to system minutes interrupted Western Power proposes to adopt the average actual performance over the previous 5 years.

In relation to circuit availability, Western Power recognises that its significant program of transmission capital expenditure will have a detrimental effect on circuit availability in the immediate future. On this basis, Western Power proposes that the benchmark for circuit availability is to be set on the basis of 9 months of actual performance in financial year 2005/06 being the most recent and typical of the expected service over the access arrangement period.

Each of the service standard performance indicators as the service standard benchmarks for each year of the first access arrangement period, as shown in Table 45 below.

Table 45: Service standard benchmarks for transmission reference services

	First access arrangement period		
	Year ending June 2007	**Year ending June 2008**	**Year ending June 2009**
Circuit Availability (% of total time)	98.2	98.2	98.2
System Minutes Interrupted (meshed network)	7.8	7.8	7.8
System Minutes Interrupted (radial network)	3.9	3.9	3.9

These targets do not reflect the possible impacts of any changes to the network operating environment which may be required as a result of the introduction of the Wholesale Electricity Market. Accordingly, Western Power proposes that the impact of any such changes should be taken into account in measuring Western Power's performance.

3.5 Service standard benchmarks: Reference services for users connected to the distribution network

3.5.1 Considerations relevant to defining service standards

Service standard benchmarks for users connected to the distribution network must be defined in a manner that is meaningful to users of the service, and which facilitates ready measurement of Western Power's service delivery performance, having regard to the available data and established data gathering processes and systems.

Western Power has modified its initial proposal in relation to service standard benchmarks to address the Authority's Required Amendments 11 to 15 (inclusive) in the Draft Decision and Required Amendment 2 in the Final Decision. In particular, in response to Western Power's revised proposed access arrangement, the Authority's Final Decision includes a single Required Amendment in relation to service standard benchmarks (Required Amendment 2), which states that:

> "The revised proposed access arrangement should be amended to distinguish between rural-short and rural-long feeders in specification of service standard benchmarks for SAIDI and SAIFI for distribution network."

Western Power's access arrangement now addresses Required Amendment 2, and the details of Western Power's proposed performance indicators and benchmarks are set out below.

3.5.2 Proposed performance measures

Western Power proposes to report its distribution network performance generally in accordance with the definitions set out in the National Regulatory Reporting for Electricity Distribution and Retailing Businesses Guidelines (the "guidelines"). Western Power proposes to report performance for the following feeder classifications:

- CBD;
- Urban;
- Rural Short; and
- Rural Long.

It should be noted that all feeder classification definitions are now identical to those adopted by the Steering Committee on National Regulatory Reporting Requirements (SCNRRR). Western Power's previous feeder classifications were based on geographical areas, whereas the SCNRRR definitions relate to load density and high voltage carrier length. As a result, Western Power has made consequential changes to the Urban performance benchmarks in the access arrangement. There is no change to the proposed CBD service standard benchmarks.

Collectively, the revised service standard benchmarks are statistically equivalent to those previously submitted to the Authority, and equate to the same overall service standard benchmark for the SWIN. This is illustrated in the following table which provides a breakdown of the redistribution of the customer minutes interrupted as a result of the change in feeder classifications, calculated for the 12 months to January 2007.

CUSTOMER MINUTES INTERRUPTED	Previous	New
CBD	154,465	154,465
Urban	169,266,872	111,091,048
Rural	55,423,039	-
Rural Short	-	45,684,696
Rural Long	-	67,914,168
SWIN (Total)	**224,844,376**	**224,844,376**

For the purpose of Western Power's access arrangement, performance will be monitored against the following indicators:

- SAIDI; and
- SAIFI.

Reports relating to performance against these performance indicators will be provided to the Authority in accordance with the service standard adjustment mechanism set out in section 5 of the access arrangement.

Western Power will provide the information requested by the Authority in relation to Western Power's 40 Worst Performing Feeder Program, in accordance with Required Amendment 15 of the Draft Decision. Western Power notes that the provision of this information does not formally form part of the access arrangement, and is best managed through a licence condition.

The performance indicators that will apply for the purpose of the access arrangement are defined in section 3.5.3 below. Western Power's service standard benchmarks for reference services for users connected to the distribution network are set out in section 3.5.4 below.

3.5.3 Definition of SAIDI and SAIFI performance indicators

The SAIDI performance indicator is defined as follows:

Performance Indicator:	System Average Interruption Duration Index (SAIDI)
Unit of measure:	System minutes per annum
Definition:	Over a 12 month period, the sum of the duration of each sustained (greater than 1 minute) customer interruption (in minutes) attributable solely to distribution (after exclusions) divided by the average of the total number of connected *consumers* at the beginning and end of the period.
Exclusions:	• Major event days in accordance IEEE1366-2003 definitions as adopted by Steering Committee on National Regulatory Reporting Requirements (SCNRRR). • Outages shown to be caused by a fault or other event on the transmission system or a third party system (for instance, without limitation outages caused by an intertrip signal, generator unavailability or a customer installation). • *Force majeure* events.

The SAIFI performance indicator is defined as follows:

Performance Indicator:	System Average Interruption Frequency Index (SAIFI)
Unit of measure:	Supply interruptions per annum
Definition:	Over a 12 month period, the total number of sustained (greater than 1 minute) customer interruptions (number) attributable solely to distribution (after exclusions) divided by the average of the total number of connected *consumers* at the beginning and end of the period.
Exclusions:	• Major event days in accordance with IEEE1366-2003 definitions as adopted by Steering Committee on National Regulatory Reporting Requirements (SCNRRR). • Outages shown to be caused by a fault or other event on the transmission system or a third party system (for instance, without limitation outages caused by an intertrip signal, generator unavailability or a customer installation).- • *Force majeure* events.

3.5.4 Service standard benchmarks: reference services for users connected to the distribution network

As stated elsewhere in this document, Western Power's overall service performance objective is to achieve a 25% improvement in reliability from the June 2004 SAIDI by

June 2009 (i.e. the end of the first access arrangement period). Western Power has applied the 25 percent improvement target to each of the three feeder classifications, to develop the proposed SAIDI service standard benchmarks shown in Table 46, and the SAIFI service standard benchmarks shown in Table 47 below:

Table 46: SAIDI service standard benchmarks (expressed as system minutes per annum)

SAIDI	SWIN total	CBD	Urban	Rural Short	Rural Long
June 2007	277	21.4	222	425	741
June 2008	259	20.0	208	398	693
June 2009	224	17.3	179	343	598

Table 47: SAIFI service standard benchmarks (expressed as supply interruptions per annum)

SAIFI	SWIN total	CBD	Urban	Rural Short	Rural Long
June 2007	3.44	0.32	3.12	4.89	5.58
June 2008	3.22	0.30	2.91	4.58	5.22
June 2009	2.78	0.26	2.51	3.95	4.50

In respect of *reference service* A9 ("Streetlighting Exit Service"), where Western Power is responsible for the repair of faulty streetlights, the following service standard benchmark will apply in relation to repair times for reported faults.

Table 48: Repair times for Streetlighting

	First access arrangement period		
	Year ending June 2007	**Year ending June 2008**	**Year ending June 2009**
Perth Metropolitan area	5 days	5 days	5 days
Major regional towns	5 days	5 days	5 days
Remote and rural towns	9 days	9 days	9 days

3.6 Western Power's other commitments and obligations regarding service delivery

The foregoing discussion has focused on the setting of service standard benchmarks in relation to reference services. This focus is appropriate given the requirements of the Code provisions that relate to service standard benchmarks. However, it is also important to note that Western Power has other commitments and obligations regarding service delivery in addition to those defined by the service standard benchmarks.

For completeness, it is important to note the following service delivery obligations and commitments, which are highly relevant to users of the network and end-consumers of electricity:

- Quality of supply obligations in the Technical Rules: These obligations have been an important driver of Western Power's expenditure plans as discussed in Parts B and C of this document.

- Western Power's Networks Customer Charter: The Charter applies to residential and small business customers using less than 50 MWh of electricity per year. This group of customers comprises some 98% of all customers. The Charter sets out comprehensive information about Western Power's network services and associated standards of service for these customers, along with these customers' rights and obligations in their relationship with Western Power.

- Western Power's Customer Reliability Payment Scheme. This scheme was announced by Government in March 2005, and applies to all households and small businesses using less than 50 MWh per year. A rebate of $80 is paid to any eligible customer who experiences a supply interruption in excess of 12 hours duration.

It should also be noted that in addition to the obligations described above, Western Power also has a wide range of environmental and health and safety obligations that must be met. It is important for interested parties to note, therefore, that:

- the service standard benchmark is only one of a number of measures of Western Power's service delivery commitments and obligations; and

- the costs associated with meeting all of the company's service delivery commitments must be fully reflected in Western Power's expenditure plans.

3.7 Concluding comments

It is considered that the proposed suite of service standard benchmarks for reference services satisfies the Code requirements of being reasonable and understandable by customers. The proposed service standard benchmarks are also commensurate with the company's proposed expenditure programs and the significant service improvements that these expenditure programs are expected to deliver. The company's proposal to use the service standard benchmarks in a service standards adjustment mechanism will, along with other measures proposed in the access arrangement, provide a clear discipline on the company to deliver its planned service performance improvements.

4 Design of price controls

4.1 Introduction

This section sets out detailed information to substantiate and explain the basis of the arrangements proposed by Western Power in relation to the target revenue and price control requirements set out in section 6 of the Code. Accordingly, this section provides information on:

- the proposed form of price control;
- mechanisms for adjustment of target revenue for unforeseen events in accordance with sections 6.6 to 6.8 of the Code;
- mechanisms for adjustment of target revenue for technical rule changes in accordance with sections 6.9 to 6.12 of the Code;
- the operation of the investment adjustment mechanism (provided for in sections 6.13 to 6.18 of the Code) and a capital contributions adjustment mechanism;
- the gain sharing mechanism (provided for in sections 6.19 to 6.28 of the Code); and
- the service standards adjustment mechanism (provided for in sections 6.30 to 6.32 of the Code).

Appendix 8 of Western Power's access arrangement provides further explanation of the proposed revenue cap arrangements, the correction factor, the capital contributions adjustment mechanism and the investment adjustment mechanism as set out in the access arrangement. It is intended that the explanatory notes provided in Appendix 8 of the access arrangement will assist in the interpretation of the price control arrangements set out in section 5 of the access arrangement should the need for such assistance arise.

4.2 Form of price control

4.2.1 Code provisions

Section 6.2 of the Code states:

> "Without limiting the forms of *price control* that may be adopted, *price control* may set *target revenue*:
>
> (a) by reference to the *service provider's approved total costs*; or
>
> {Note: This includes "revenue cap" *price controls* based on controlling total revenue, average revenue or revenue yield and "price cap" *price controls* based on cost of service.}
>
> (b) by setting *tariffs* with reference to:
>
> (i) *tariffs* in previous *access arrangement periods*; and
>
> (ii) changes to costs and productivity growth in the electricity industry;
>
> {Note: This includes "price cap" *price controls* based on controlling the weighted average of *tariffs* or individual *tariffs*.}
>
> or
>
> (c) using a combination of the methods described in sections 6.2(a) and 6.2(b)."

Notwithstanding the provisions cited above, section 6.3 states:

> "The *first access arrangement* must contain the form of *price control* described in section 6.2(a)."

4.2.2 *Alternative price control forms*

There are three basic forms of price control which could be adopted, and which would be likely to meet the requirements of the Code. These are:

1. a "tariff basket" (or weighted price cap);
2. a pure revenue cap; and
3. a revenue yield control.[50]

Variations and hybrids of these basic forms of control have been adopted in a number of Australian jurisdictions. For instance:

- Western Power's transmission and distribution network businesses are presently subject to an average revenue yield form of control;
- electricity and gas distributors in Victoria are presently subject to a "tariff basket" form of control;
- the draft decision on electricity distribution price controls for 2005 to 2010 published recently by the Essential Services Commission of South Australia proposes the application of an average revenue yield form of control;
- electricity transmission companies that are regulated by the ACCC under the National Electricity Code are subject to a revenue cap form of control.

4.2.3 *Assessment of alternatives*

Over recent years, there has been a good deal written about the merits of different forms of price controls.[51] Each alternative form has its relative merits and weaknesses, and there is no "first best" or "correct" form of control. (For this reason, section 6.2(a) of the Code provides for a range of different forms of control to be incorporated into Western Power's access arrangement.)

One of the most important factors that has been raised by regulators in considering the merits of different price control forms is the extent to which businesses face risks that are difficult to manage due to demand forecast errors. In this context, it is noteworthy that the Victorian ESC has been at the forefront of advocating the use of a tariff basket form of control in the distribution sector, for reasons that relate to, among other things:

- minimising the impact of demand forecast errors on company revenues and profits; and

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[50] A "rate of return" form of control, in which regulated companies are essentially permitted to recover all "prudently incurred" costs, plus a regulated rate of return, is widely regarded as providing insufficient incentives for efficient investment in and operation of regulated infrastructure. On this basis, the "rate of return" form of control is unlikely to be deemed to meet the Code objective, and therefore Western Power has not included this form of control for consideration in this discussion.

[51] A number of consultation papers, and draft and final decisions published by the Victorian Essential Services Commission (and its predecessor, the Office of the Regulator-General), the Queensland Competition Authority and the Independent Pricing and Regulatory Tribunal of NSW have addressed this issue in detail.

- minimising the incentives and opportunities for regulated companies to engage in "gaming" activities that aim to increase company profits.

The ESC's predecessor (the Office of the Regulator-General) advanced strong conceptual arguments to justify the application of the tariff basket price control form to Victorian electricity distributors at the last price determination (in 2001).[52] However, in the course of the five-yearly electricity distribution price review which was recently concluded in Victoria, the ESC observed that:

> "Tariff revenue for the 2001-03 period exceeded the benchmark level by 7.3 per cent, due to a combination of distributed energy being higher than forecast and the restructuring of tariffs in a manner that caused revenue to be higher than forecast for any given volume growth, for example, by increasing the variable component of charges by a greater amount than the fixed component. The Commission's preliminary analysis suggests the latter had the more important effect."[53]

Reading between the lines, it would not be unreasonable to infer that the ESC's observation reflects some frustration that in practice, the results delivered under the tariff basket control form have not met the regulator's expectations. Not surprisingly, these observations suggest that approaches (such as the tariff basket form) which appear to have strong merit "on paper" will not necessarily perform in accordance with expectations *in practice*. On this basis, Western Power considers there are good grounds to be sceptical about the benefits *in practice* that the tariff basket price control form is likely to have over the revenue yield control which is presently applied to the company.

The other broad alternative form of price control is a revenue cap. Under a pure revenue cap, a regulated company is permitted to earn a specified level of income, regardless of the volumes of energy transmitted over its infrastructure. In its examination of different forms of price controls, the Office of the Regulator-General stated:

> "Under a pure revenue cap, the licensee retains an incentive to minimise the cost of providing distribution services, since allowed revenue will remain unaffected, resulting in improved profitability.
>
> Completely severing the link between allowed revenue and volume may however lead to a deterioration in the licensees' willingness to expand distribution services to both new and existing consumers. Distribution licensees may be reluctant to attract new consumers within a specific price control period, since to do so would imply an increase in costs without a corresponding increase in allowed revenue. Some formulations of a pure revenue control try and compensate for this incentive effect by linking the allowed revenue to the number of customers. However, licensees still retain an incentive to minimise the volume distributed to each customer, providing that the marginal cost of additional load distribution is non-zero.
>
> Whilst such an incentive is broadly compatible with demand management objectives and may move towards meeting greenhouse gas emissions targets, the incentives to reduce load under a pure revenue cap may be artificially strong. Licensees may reduce demand beyond the point where this is efficient. There may also be an

[52] See, for instance, the Office of the Regulator-General, *Consultation Paper no. 3 - 2001 Electricity Distribution Price Review: The form of price control.*

[53] Essential Service Commission, Position Paper: Electricity Distribution Price Review, 2006-10, March 2005, page 11.

> incentive to be less vigilant about network reliability standards, such as minutes of lost supply."[54]

Western Power notes the potential shortcomings associated with adopting a revenue cap control. However, it is noted that the Code provides for the application of an Investment Adjustment Mechanism. This mechanism can be designed so as to mitigate risks under a revenue cap that are associated with material variations between forecast and actual capital expenditure requirements within an access arrangement period. Therefore, the Investment Adjustment Mechanism can mitigate or remove the possibility of a material divergence between costs and revenues due to capital expenditure forecasting error.

In relation to a revenue yield form of control, Western Power notes that the principal advantage of this form of control is that

- all stakeholders are already familiar with the operation of the control;
- all the key systems and processes required to implement and administer the control are already ostensibly in place and are operational; and
- the costs and risks of migrating to a new (and untested) set of price control arrangements are avoided.

Western Power also acknowledges that the principal weakness of the revenue yield control is that demand forecasting error could create windfall gains or losses for the regulated entity.

4.2.4 Selection of proposed price control form

In its August 2005 access arrangement submission, Western Power proposed that a revenue yield form of control should apply to the transmission and distribution businesses. The Authority's Draft Decision argued that Western Power should adopt a revenue cap in accordance with Required Amendment 20.

In responding to the Authority's required amendments in the Draft Decision[55], Western Power noted that it did not accept some of the Authority's reasoning for its decision. However, Western Power accepted the Authority's Draft Decision that a revenue cap should be adopted. In paragraph 489 of the Authority's Final Decision, the Authority concludes that it is satisfied that Western Power has determined the value of target revenue consistent with the requirements of Draft Decision Amendment 20.

In accordance with the Draft and Final Decisions, Western Power's access arrangement adopts a revenue cap for the transmission and distribution businesses.

4.3 Adjusting target revenue for unforeseen events

4.3.1 Code provisions

Sections 6.6 to 6.8 inclusive set out provisions which, under certain circumstances, enable Western Power to include in its target revenue for the next access

54 Office of the Regulator-General, *Consultation Paper no. 3 - 2001 Electricity Distribution Price Review: The form of price control*, page 18.

55 Western Power, Response to the Required Amendments, May 2006.

arrangement period unforeseen costs which were incurred during the previous access arrangement period as a result of a force majeure event.

Under section 6.7 of the Code, there is no guarantee that the company will be able to recover all (or even any) of the costs actually incurred as a result of a force majeure event. In any event, section 6.8 limits the amount that can be recovered to an amount not exceeding the costs which would have been incurred by a service provider efficiently minimising costs.

4.3.2 Western Power's proposed approach

Where it is possible to do so, Western Power will continue to purchase insurance of a standard of a reasonable and prudent person (as to the insurers and the type and level of insurance) in relation to force majeure events.

Where commercial insurance is either unavailable or prohibitively expensive, Western Power has the option of either:

- self-insuring against the force majeure risk, and having a "self insurance" premium included in the forecast non capital costs component of its target revenue for the duration of the access arrangement period; or

- relying on the provisions for recovery of unforeseen costs – after a force majeure event has occurred – in accordance with the provisions set out in sections 6.6 to 6.8 inclusive.

Broadly speaking, there is a limited data set available on which to assess the actuarial fair value of certain force majeure events. As a consequence, Western Power would face a potentially very high risk if it self insured against such events.

As a matter of principle therefore, Western Power prefers to rely on the provisions set out in sections 6.6 to 6.8 inclusive to recover any unforeseen costs it incurs as a result of force majeure events.[56]

Western Power considers that the provisions set out in sections 6.7 and 6.8 of the Code are intended to provide the company with strong incentives to efficiently manage the company's exposure to force majeure risk. Hence, the reliance of the company on cost pass-through provisions will not dilute the incentives faced by the company to actively manage all of its risk exposures.

For further details of Western Power's proposed approach please refer to Section 5 of the access arrangement and Appendix 8 of the access arrangement, which includes the methodology for making an adjustment to revenue to account for the impact of unforeseen events.

[56] Where the company does seek a self-insurance provision in its target revenue, the relevant self-insured risk will be clearly identified in parts B and C (as applicable) of this access arrangement information, to ensure that the company cannot be compensated twice for such costs.

4.4 Adjusting target revenue for technical rule changes

4.4.1 Code provisions

Sections 6.9 to 6.12 inclusive set out provisions which enable Western Power to include in its target revenue for the next access arrangement period unforeseen costs (or savings) which occurred during the previous access arrangement period as a result of a change in costs arising from a change in the technical rules.

Under sections 6.11 and 6.12 of the Code, the amount by which the target revenue for the next access arrangement period is to be adjusted for unforeseen cost changes is to be consistent with the levels of costs that would have been incurred by a service provider efficiently minimising costs.

For further details of Western Power's proposed approach please refer to Section 5 of the access arrangement.

4.4.2 Western Power's proposed approach

Western Power's proposed capital and operating expenditure for the forthcoming access arrangement period reflects the costs associated with meeting the requirements for asset and system performance under the technical rules that are expected to be in effect at the time of the Authority's approval of the access arrangement.

If the technical rules are amended over the course of the first access arrangement period, then Western Power will, as part of its proposed *access arrangement* for the next *access arrangement period,* provide a report to the Authority setting out:

(a) a description of the nature and timing of the impact of the technical rule change on Western Power's operating and capital costs for the *first access arrangement period*; and

(b) a fair and reasonable estimate of the additional costs (or cost savings) accruing to Western Power as a result of that technical rule change.

The Authority will then determine an adjustment to Western Power's target revenue for the second access arrangement period, to compensate for any change in costs during the first access arrangement period, in accordance with the provisions contained in sections 6.9 to 6.12 of the Code.

For further details of Western Power's proposed approach please refer to Section 5 of the access arrangement and Appendix 8 of the access arrangement, which describes the methodology for making an adjustment to revenue to account for the impact of technical rule changes.

4.5 Investment adjustment mechanism and capital contributions adjustment mechanism

4.5.1 Code provisions and other relevant considerations

Section 6.13 defines investment adjustment mechanism as:

"a mechanism in an access arrangement detailing how any investment difference for the access arrangement period is to be treated by the *Authority* at the next access arrangement review."

Section 6.14 states:

"In sections 6.13 and 6.16, "investment difference" for an access arrangement period is to be determined at the end of the access arrangement period by comparing:

(a) the nature (including amount and timing) of actual new facilities investment which occurred during the access arrangement period;

with

(b) the nature (including amount and timing) of forecast new facilities investment which at the start of the access arrangement period was forecast to occur during the access arrangement period."

Section 6.15 specifies that:

"If an access arrangement uses the form of price control described in section 6.2(a), then the access arrangement must contain an investment adjustment mechanism."

However, section 6.16 states:

"Without limiting the types of investment adjustment mechanism which may be contained in an access arrangement, an investment adjustment mechanism may provide that:

(a) adjustments are to be made to the target revenue for the next access arrangement in respect of the full extent of any investment difference; or

(b) no adjustment is to be made to the target revenue for the next access arrangement in respect of any investment difference."

Section 6.17 states:

"An investment adjustment mechanism must be:

(a) sufficiently detailed and complete to enable the *Authority* to apply the *investment adjustment mechanism* at the next *access arrangement review*;

and

(b) without limiting this Code, consistent with the *gain sharing mechanism* (if any) in the *access arrangement*;

(c) consistent with the *Code objective*."

Section 6.18 of the Code states:

"An *investment adjustment mechanism* in an *access arrangement* applies at the next *access arrangement review*."

Required Amendment 45 of the Authority's Draft Decision required Western Power to include in its proposed access arrangement a "capital contributions adjustment mechanism" to account for any differences between forecast and actual capital contributions over the initial access arrangement period, so that the company and users are effectively held economically neutral to any such differences.

In its response to the Draft Decision, Western Power accepted the Required Amendment and proposed a capital contributions adjustment mechanism in its revised access arrangement. In paragraph 395 of the Final Decision, the Authority concludes that it is satisfied that Western Power's revised proposed access arrangement incorporates Draft Decision Amendment 45.

4.5.2 Western Power's proposed approach

In Western Power's view, effective price control arrangements should:

- provide incentives to Western Power to operate and invest efficiently; and
- provide reasonable certainty to Western Power of recovering all of the costs of uncertain (and often large-scale) customer-initiated transmission investment.

There is, however, a trade-off between providing incentives for efficiency on the one hand, and certainty of cost recovery on the other. In essence, the design of the investment adjustment mechanism should appropriately balance this trade-off.

In paragraph 328 of the Draft Decision, the Authority commented that:

> "In accordance with the objectives of section 6.4(a)(ii) of the Access Code, the Authority considers that an appropriate incentive is to not subject reliability driven capital expenditure to the investment adjustment mechanism in the event that Western Power meets or exceeds the required service standard benchmarks at less than the forecast reliability driven capital expenditure during the initial access arrangement period. This form of incentive mechanism for reliability driven capital expenditure is considered to be consistent with the price control objectives of section 6.4(a)(ii) of the Access Code given the importance of improving service standards in the SWIN over the initial access arrangement period."

In responding to the Draft Decision, Western Power sought to address the Authority's key concerns in relation to the investment adjustment mechanism, but did not fully implement the Authority's preferred approach. Western Power proposed an investment adjustment mechanism and a capital contributions adjustment mechanism for the first access arrangement period that would:

- adjust Western Power's target revenue in the next access arrangement period in a manner that leaves Western Power economically neutral as a result of any differences between actual and forecast transmission and distribution capital expenditure and capital contributions in each year of the first access arrangement period, with the exception that:
- the investment adjustment mechanism will not have regard to any differences between actual and forecast capital expenditure with respect to the refurbishment or renewal of the distribution or transmission network in the first access arrangement period.

Western Power also proposed in sections 5.30, 5.33 and 5.41 and 5.44 of the revised proposed access arrangement, to exclude certain revenues from the revenue cap, including:

- revenues from capital contributions made in respect of works that have been provided on a competitive basis or where the terms and conditions have been negotiated in accordance with section 2.5 of the Access Code; and

- revenue received by Western Power for excluded services or in respect of services that are not provided by Western Power in accordance with the access arrangement.

In paragraph 708 of the Final Decision, the Authority concludes that it is satisfied that the scope of capital works indicated in the revised proposed access arrangement to be included in the investment adjustment mechanism is consistent with the requirements of the Access Code. The Authority also states that it is satisfied that application of the investment adjustment mechanism to investment associated with the rural power improvement program and state underground power project is consistent with the requirements of the Access Code as the extent of investment under both of these programs is determined by government decisions that are outside of the control of Western Power.

However, the Authority's Final Decision identifies three areas in which the Authority is not satisfied with Western Power's proposed approach:

- In paragraph 528 of the Final Decision, the Authority considers that the provisions of sections 5.30, 5.33 and 5.41 and 5.44 of the revised proposed access arrangement are inconsistent with the requirements of the Access Code except to the extent that they relate to excluded services. The Authority also notes that Western Power indicates in its revised proposed access arrangement that, for the purposes of the access arrangement, there are no excluded services.

- In paragraph 719 of the Final Decision, the Authority makes further comments (which correspond to those in paragraph 528) regarding the operation of the investment adjustment mechanism.

- In paragraph 709 of the Final Decision, the Authority explains that it is not satisfied that application of the investment adjustment mechanism to new facilities investment in information technology assets is consistent with the requirements of the Access Code and the Code objective. The Authority considers that investment in information technology assets should be able to be planned by Western Power with reasonable certainty and that the Code objective is better met by determining target revenue in accordance with a forecast of new facilities investment in this category and not applying the investment adjustment mechanism to this investment.

In relation to the above comments, the Authority's Final Decision includes Required Amendments 4, 11 and 10 (ordered in this way to correspond to the above points), as follows:

- Required Amendment 4:

  The revised proposed access arrangement should be amended to remove provisions under sections 5.30, 5.33 and 5.41 and 5.44 for exclusion of revenues from consideration under the revenue cap, other than revenues earned from services that are excluded services or that are otherwise not covered services. Corresponding amendments should be made to remove explanatory notes on this element of the proposed price control from Appendix 8 of the revised proposed access arrangement.

- Required Amendment 11:

  The revised proposed access arrangement should be amended to remove the provision under clause 5.52 for exclusion of new facilities investment from consideration under the investment adjustment mechanism, other than where the relevant new facilities investment occurs for the provision of excluded services or other services that are not covered services.

- Required Amendment 10:

  The revised proposed access arrangement or access arrangement information should be amended so that the investment adjustment mechanism is applied to new facilities investment undertaken for augmentation of the distribution system under the regional power improvement program and state underground power program. The investment adjustment mechanism should not be applied to investment in information technology assets.

In accordance with the Final Decision, Western Power has amended its access arrangement to implement the Authority's Required Amendments 4, 10 and 11.

In addition, Western Power has made further amendments to sections 5.32 and 5.43, and Appendix 8 of its access arrangement to address issues raised by the Authority in a notice published on 17 January 2007, inviting interested parties to make submissions on, among other things, Western Power's proposed treatment of capital contributions.

Following the publication of that notice and during informal discussions between Western Power and the Authority, the Authority suggested that Western Power may wish to consider amending its proposed access arrangement to enable the adjustment of revenues for any differences between forecast and actual capital contributions to be applied over a number of future access arrangement periods, rather than concentrating any required revenue adjustment in the next access arrangement period. Accordingly, Western Power has made minor amendments to sections 5.32 and 5.43, and Appendix 8 of its access arrangement to give effect to the Authority's suggestion.

Further details of the operation of the investment adjustment mechanism and the capital contributions adjustment mechanism are provided in section 5 and Appendix 8 of the access arrangement. For the purposes of this access arrangement information, however, Western Power believes that the information presented above is sufficient to explain that Western Power has adopted an approach that is consistent with the Code and the Authority's Draft and Final Decisions.

4.6 Gain sharing mechanism

4.6.1 Code provisions

A gain sharing mechanism is defined in sections 6.19 and 6.21 as a mechanism in an access arrangement which is applied at the next access arrangement review to determine an amount to be included in the target revenue for one or more of the following access arrangement periods, and which has the objectives of:

- giving the service provider an incentive to reduce costs or otherwise improve productivity in a way that is neutral in its effect on the timing of such initiatives; and
- achieving an equitable allocation over time between users and the service provider of innovation and efficiency gains achieved by the service provider.

Section 6.20 states:

> "An *access arrangement* must contain a *gain sharing mechanism* unless the *Authority* determines that a *gain sharing mechanism* is not necessary to achieve the objective in section 6.4(a)(ii)."

4.6.2 Western Power's proposed approach

In recent years, there has been considerable debate and discussion throughout Australia regarding the design and application of incentive mechanisms in infrastructure regulation. Many Australian regulators now apply some form of mechanism that seeks to achieve the objectives set out in section 6.21 of the Code.

Western Power acknowledges and recognises the important role that such incentive mechanisms have to play in fostering efficient behaviour within established regulatory regimes. However, the design and implementation of such mechanisms is not a straightforward matter[57] and, arguably, developing and implementing a gain sharing mechanism at this time could inappropriately divert management resources away from service delivery imperatives.

It is also worth noting that this document explains in detail that Western Power must substantially increase network investment and operating expenditure to deliver the level of service that customers rightly expect. The document also highlights the challenges that Western Power must address in order to ramp-up expenditure over the forthcoming access arrangement period. In short, Western Power expects to face a number of resource-constraints in meeting its service objectives.

Against this background, Western Power's view is that a gain-sharing mechanism is not appropriate at this time. In particular, whilst Western Power intends to achieve efficiency improvements over the forthcoming period, it may be counter-productive for the access arrangement to over-emphasise the importance of under-spending against benchmark levels. It seems more appropriate to introduce a gain-sharing mechanism once expenditure levels reach a 'steady-state'.

In any event, it is worth noting that Western Power will face significant pressure to improve performance over the forthcoming period. This document explains some of the measures that have already been put in place to drive better service delivery at lower cost. The company fully expects its shareholder, customers and management team to continue to drive performance improvement initiatives during the first access arrangement period. These pressures on performance will remain in play, even in the absence of a formal gain-sharing mechanism.

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[57] As illustrated by the Discussion Paper published by the Authority in March 2004, titled *Incentive mechanisms for Code regulated gas pipeline systems.*

It is also noted that the disaggregation of Western Power into four independent business units is likely to create cost uncertainty and change-management challenges in the forthcoming access arrangement period. These issues add further weight to Western Power's view that a strong focus on reducing operating and capital expenditure below the benchmark level may not be appropriate at this time.

In view of all of these considerations, Western Power proposes not to include a gain sharing mechanism in its access arrangement for the first access arrangement period, on the basis of its reasonable expectation that pursuant to the provisions set out in section 6.20 of the Code, the Authority will determine that a gain sharing mechanism is not necessary at this time to achieve the objective in section 6.4(a)(ii).

It is suggested that the conduct of the next access arrangement review will present a timely opportunity to review in greater detail the need for, and design alternatives of a gain sharing mechanism that could be applied from that time.

An important aspect of the design of a gain sharing mechanism is the establishment of efficiency and innovation benchmarks. The Code requirements relating to these benchmarks, and Western Power's proposed approach are discussed in detail in the next section.

4.7 Efficiency and innovation benchmarks

4.7.1 Code provisions

Code provisions governing the establishment of efficiency and innovation benchmarks are closely related to those that govern the design of a gain sharing mechanism. The applicable provisions are set out in sections 5.25 and 5.26 as follows:

> 5.25 An access arrangement which contains a gain sharing mechanism must, and an access arrangement which does not contain a gain sharing mechanism may, contain efficiency and innovation benchmarks.
>
> 5.26 Efficiency and innovation benchmarks must:
>
> (a) if the access arrangement contains a gain sharing mechanism, be sufficiently detailed and complete to permit the *Authority* to make a determination under section 6.25 in the next access arrangement review, and
>
> (b) provide an objective standard for assessing the service provider's efficiency and innovation during the access arrangement period, and
>
> (c) be reasonable.

4.7.2 Western Power's proposed approach

As noted in section 4.6 above, Western Power does not propose to include a gain sharing mechanism in its access arrangement for the first access arrangement period. In accordance with this proposal, the company also proposes to not include efficiency and innovation benchmarks in this access arrangement.

As already noted however, the company does consider it would be appropriate to conduct a thorough assessment of the need for, and the design options for a gain sharing mechanism at the next access arrangement review. To ensure that the company is well positioned to participate constructively in such a review, Western Power undertakes to establish, during the course of the first access arrangement period, data collection and performance monitoring processes to facilitate the development of appropriate efficiency and innovation benchmarks that would apply from the commencement of the second access arrangement period. The company anticipates that these benchmarks will be included in the access arrangement to apply during the second access arrangement period, and would be adopted for the purpose of any gain sharing mechanism which may apply during that access arrangement period.

4.8 Service standards adjustment mechanism

4.8.1 Code provisions

The applicable Code provisions are as follows:

> 6.29 A **"service standards adjustment mechanism"** is a mechanism in an *access arrangement* detailing how the *service provider's* performance during the *access arrangement period* against the *service standard benchmarks* is to be treated by the *Authority* at the next *access arrangement review*.
>
> 6.30 An *access arrangement* must contain a *service standards adjustment mechanism*.
>
> 6.31 A *service standards adjustment mechanism* must be:
>
> (a) sufficiently detailed and complete to enable the *Authority* to apply the *service standards adjustment mechanism* at the next *access arrangement review*; and
>
> (b) consistent with the *Code objective*.
>
> 6.32 A *service standards adjustment mechanism* in an *access arrangement* applies at the next *access arrangement review*.

4.8.2 Principles guiding the design of the mechanism

In principle, Western Power's view is that the service standard adjustment mechanism (SSAM) should be designed:

- to encourage Western Power to achieve, or exceed, the service standard benchmarks for reference services; and

- to ensure that the incentives for Western Power to improve service performance (where that is economically efficient) are not outweighed by the incentives to reduce expenditure inherent in the regulatory regime.

Ideally, Western Power believes that the following matters should be considered in developing the operational features of SSAM:

1. The incentive mechanism should be as simple as possible to understand for both Western Power and customers, without unduly distorting the incentives.

2. Western Power should be fairly rewarded for its efforts in delivering service improvements, and ideally should not be affected financially for impacts on performance that are beyond its reasonable control. In particular, Western Power should be economically neutral under the SSAM if its actual performance over the access arrangement period is broadly consistent with the service standard benchmarks.

3. The incentives should be specified clearly and in advance, to maximise their effectiveness.

4. The incentives should be based on reliable and verifiable performance measures.

5. The incentive arrangements should encourage improvements for urban and rural customers, noting that these groups of customers presently receive (and expect) different levels of service.

6. The incentives should encompass both penalties for sub-standard performance and rewards for superior performance.

7. The amount of revenue that Western Power stands to gain or lose under the incentives should be limited, but large enough to provide meaningful commercial incentives at the margin. It is desirable, but not essential, that the amount of the incentives should be greater than the cost to Western Power of achieving an increment of reliability, but less than the value that customers place on that increment of reliability.

8. The incentive arrangements should be appropriately balanced across the distribution and transmission systems.

9. Future service standard benchmarks should be set to ensure that Western Power retains a fair share of the benefit that customers are estimated to derive from service improvements.

These principles are generally consistent with those applied by the ACCC in the development of its Service Standards Guidelines (which form part of its Statement of Regulatory Principles). The principles are also broadly consistent with those that form the basis of the service incentive mechanism ("S factor") applied by the Essential Services Commission to Victorian electricity distributors.

It is noted that these principles can only provide a broad guide to the design of the SSAM.

4.8.3 Developing the service standard adjustment mechanism

Western Power's August 2005 access arrangement submission developed a SSAM that applied financial incentives to service performance up to a maximum of +/- 1% of Western Power's target revenue. Broadly speaking, the SSAM originally proposed by Western Power would have operated as follows:

(a) Western Power's actual performance would be measured in accordance with the appropriate service definitions; and

(b) The reward or penalty applicable under the SSAM would be calculated by multiplying the difference between the actual performance and the service standard benchmark, only where actual performance fell outside a pre-defined "deadband" which Western Power believed represented 'normal performance'.

In its Draft Decision, the Authority commented in paragraph 379 that the 'deadband' definitions proposed by Western Power were too narrow:

> "The Authority is not yet convinced that there is a demonstrable historical basis to ascertain that the proposed targets are not readily attainable with negligible downside risk. Accordingly, the proposed 10 per cent "deadband" outside of which the financial incentive/penalty is to apply is considered too narrow for the first access arrangement period given the information asymmetry that exists."

The Authority's analysis of Western Power's proposed SSAM concluded with Required Amendments 35 and 36, which required Western Power to remove the incentive payments from the SSAM. Western Power accepted Required Amendments 35 and 36 and therefore no longer proposes financial incentives in relation to service performance. In accepting these Required Amendments, Western Power noted that it is difficult to benchmark service performance precisely in this first access arrangement period, especially given Western Power's program of increased capital and operating expenditure.

Western Power also notes, however, that the Code requires an access arrangement to include a SSAM that is:

- sufficiently detailed and complete to enable the Authority to apply the service standards adjustment mechanism at the next access arrangement review; and
- consistent with the Code objective.

It follows, therefore, that Western Power should adopt a SSAM that meets these Code requirements; addresses the Authority's comments in relation to the calibration of the deadband; and adopts Draft Decision Required Amendments 35 and 36. Given these considerations, Western Power's amended SSAM will operate as follows:

- Western Power's actual performance will be measured in accordance with the appropriate service definitions;
- a 'deadband', based on recent historical performance, will be set, recognising that 'normal' performance can vary from year-to-year without implying that the Authority should take corrective action or that financial penalties or bonuses should apply;
- Where Western Power's actual performance falls outside the low or high limits of the normal performance range for any performance measure, Western Power is required to make a submission to the Authority within 40 business days of the end of the relevant financial year as follows:

    (a) where performance is superior, Western Power will explain the actions taken by Western Power's management, staff and contractors and any other factors that have led to the service improvement; or

    (b) where performance is inferior, Western Power will explain the reasons for the poor performance and the corrective action taken or to be taken by Western Power to ensure that future performance is improved; and

    (c) in either case, Western Power will indicate whether performance is expected to fall outside the normal performance range in future financial years.

- At the next access arrangement review, the Authority will consider the submissions made by Western Power in setting new benchmarks and approving related capital and operating expenditure for the next access arrangement period.

- For the avoidance of doubt, no financial penalties or bonuses will apply in the first or subsequent access arrangement period as a result of this service standard adjustment mechanism.

Details of the SSAM for the distribution-connected users and the transmission network are described in the following two sections. For a formal description of the SSAM, please refer to section 5 of the access arrangement.

4.8.4 Service standards adjustment mechanism

Tables 49 and 50 below list the upper and lower limits that define ‘normal performance’ in relation to transmission and distribution service performance. The upper and lower limits reflect Western Power’s assessment of the likely normal variation in performance as explained in section 4.8.3 above. The following percentage bandwidths have been applied to the service standard benchmarks in order to establish the upper and lower limits:

- availability +/- 5%
- system minutes +/- 10%
- SAIDI +/- 10%
- SAIFI +/- 10%

Table 49: Transmission service standard – normal performance

		Low Limit	**High Limit**
Circuit Availability (%)	2006/07	97.7%	98.7
	2007/08	97.7%	98.7
	2008/09	97.7%	98.7
System Minutes Interrupted (meshed network)	2006/07	7.0	8.6
	2007/08	7.0	8.6
	2008/09	7.0	8.6
System Minutes Interrupted (radial network)	2006/07	3.5	4.3
	2007/08	3.5	4.3
	2008/09	3.5	4.3

Tables 50 and 51 below establish the normal performance range for distribution performance.

Table 50: Distribution service standard as measured by SAIDI – normal performance

		Low Limit	High Limit
SAIDI - SWIN (Minutes)	2006/07	249	305
	2007/08	233	285
	2008/09	202	246
SAIDI - CBD (Minutes)	2006/07	19	24
	2007/08	18	22
	2008/09	16	19
SAIDI - Urban (Minutes)	2006/07	200	244
	2007/08	188	228
	2008/09	162	196
SAIDI - Rural Short (Minutes)	2006/07	383	467
	2007/08	359	437
	2008/09	309	377
SAIDI - Rural Long (Minutes)	2006/07	667	815
	2007/08	624	762
	2008/09	539	657

Table 51: Distribution service standard as measured by SAIFI – normal performance

		Low Limit	High Limit
SAIFI - SWIN (Average interruptions per annum)	2006/07	3.10	3.78
	2007/08	2.90	3.54
	2008/09	2.50	3.06
SAIFI - CBD (Average interruptions per annum)	2006/07	0.29	0.35
	2007/08	0.27	0.33
	2008/09	0.23	0.29
SAIFI - Urban (Average interruptions per annum)	2006/07	2.81	3.43
	2007/08	2.62	3.20
	2008/09	2.26	2.76
SAIFI - Rural Short (Average interruptions per annum)	2006/07	4.40	5.37
	2007/08	4.13	5.03
	2008/09	3.56	4.34
SAIFI - Rural Long (Average interruptions per annum)	2006/07	5.03	6.13
	2007/08	4.70	5.74
	2008/09	4.05	4.95

5 Pricing methods

5.1 Introduction and background

In accordance with the requirements of section 4.3 (b) of the Code this section of the access arrangement information sets out information detailing and supporting the pricing methods in the access arrangement.

Network access prices applying to the SWIS have been in place since 1996. Initially these prices applied only to contestable consumers. However, in July 2001 network prices were established for all contestable and franchise consumers. At that time, access price structures were revised in order to:

- improve the efficiency of the tariff structure and to cater, in particular, for smaller non-contestable consumers; and to

- ensure compatibility between the transmission and distribution tariff structures, so that for distribution–connected consumers the tariffs could be added together at a component level to form a bundled network tariff[58].

Consumers that were contestable prior to July 2001 were given the option at the time of remaining on the previous tariffs or migrating to the new tariffs. This policy was facilitated by the retention of a set of transition tariffs. These transition tariffs have been indexed by CPI plus two percent each year and, over time, consumers on the transition tariffs have migrated to the standard tariffs as these become more cost-effective. Presently, there remain approximately 30 consumers on transition tariffs and this number is expected to drop considerably over the next few years.

Western Power intends to retain the transition tariffs during the forthcoming access arrangement. It should be noted that these transition tariffs are not generally available to users and therefore are not *reference services*. In continuing to provide transition tariffs, Western Power notes the requirements of section 4.34 of the Code which refers to prior contractual rights. Western Power will separately notify the affected customers of the proposed changes to the transition tariffs, and provide a copy of this notification to the Authority for its information.

Details of Western Power's reference tariffs are set out in the price list, which is provided as Appendix 5 to the access arrangement. The description of Western Power's pricing methods in this section sets out the kind of explanatory information that is contemplated by chapter 7 of the Code.

In order to avoid price shocks to particular tariff customers, annual changes to tariffs for the second and third pricing years of the access arrangement period will be subject to the following side constraints:

- For each year of this access arrangement period, Western Power will not increase or decrease any *reference tariff* by more than CPI+5% per annum.

- For *reference services* A1 to A10 and B1, Western Power may give effect to this side constraint by ensuring that no tariff component increases or decreases in any financial year by more than CPI+5% per annum.

[58] Prior to 2001 the transmission and distribution access price structures were entirely different and customers seeking access to the networks had separate transmission and distribution access contracts and paid separate charges.

The remainder of this section is structured as follows:

- section 5.2 examines the Code provisions that relate to pricing methods;
- section 5.3 sets out the pricing objectives adopted by Western Power, which underpin the company's detailed pricing methods;
- based on the applicable Code provisions and the pricing objectives adopted by Western Power, section 5.4 outlines the principles applied by the company to guide the development of its pricing methods and the design of network tariffs;
- section 5.5 sets out information demonstrating that Western Power's pricing methods comply with the relevant Code provisions;
- section 5.6 sets out Western Power's policy relating to prudent discounting; and
- section 5.7 sets out Western Power's policy relating to discounts for distributed generation.

5.2 Code provisions

Chapter 7 of the Code sets out the provisions governing the pricing methods to be applied by Western Power.

Under section 7.2, an access arrangement may contain any pricing methods provided they collectively meet the objectives set out in sections 7.3 and 7.4 and otherwise comply with Chapter 7. The relevant objectives are as follows:

> **"Objectives of pricing methods - Primary objectives**
>
> 7.3 Subject to sections 7.5 and 7.7, the *pricing methods* in an *access arrangement* must have the objectives that:
>
> (a) *reference tariffs* recover the forward-looking efficient costs of providing *reference services*; and
>
> (b) the *reference tariff* applying to a *user*:
>
> (i) at the lower bound, is equal to, or exceeds, the *incremental cost of service provision*; and
>
> (ii) at the upper bound, is equal to, or is less than, the *stand-alone cost of service provision*.
>
> **Objectives of pricing methods - Other objectives**
>
> 7.4 Subject to sections 7.5 and 7.7, the *pricing methods* in an *access arrangement* must have the objectives that:
>
> (a) the *charges* paid by different *users* of a *reference service* differ only to the extent necessary to reflect differences in the *average cost of service provision* to the *users*; and
>
> (b) the structure of reference tariffs so far as is consistent with the Code objective accommodates the reasonable requirements of users collectively; and

(c) the structure of reference tariffs enables a user to predict the likely annual changes in reference tariffs during the *access arrangement* period; and

(d) the structure of reference tariffs avoids price shocks (that is, sudden material tariff adjustments between succeeding years).

Objectives of pricing methods - Reconciling primary and other objectives

7.5 To the extent that the objectives in section 7.3 conflict with the objectives in section 7.4 in respect of *pricing methods* in a *proposed access arrangement*, the *Authority*, when determining whether the *pricing methods* are consistent with this Chapter 7, must reconcile the conflict, or determine which objective is to prevail, having regard to the *Code objective* but where necessary permitting the objectives in section 7.3 to prevail over the objectives in section 7.4."

Section 7.6 sets out the provisions governing tariff components as follows:

"Unless an *access arrangement* containing alternative *pricing methods* would better achieve the *Code objective*, for a *reference service*:

(a) the *incremental cost of service provision* should be recovered by *tariff* components that vary with usage or demand; and

(b) any amount in excess of the *incremental cost of service provision* should be recovered by *tariff* components that do not vary with usage or demand."

Section 7.7 requires uniform or "postage stamp" charges to be applied to users who transfer electricity out of an exit point in respect of which the contracted maximum demand under a contract for services is less than 1 MVA.

Under section 7.9, Western Power may propose in its access arrangement to discriminate between users in its pricing to the extent that it is necessary to do so to aid economic efficiency through the application of a policy regarding prudent discounts.

Section 7.10 requires Western Power to include in its access arrangement a policy governing the provision of discounts to distributed generation for recognition of network cost savings created specifically by the location of the generator in the network.

Section 7.11 requires that the access arrangement must contain a detailed mechanism for determining when a user will be entitled to receive a discount (in accordance with section 7.9 and 7.10) and for calculating the discount to which the user will be entitled.

Section 7.12 requires that the tariff equalisation contribution must: be included in the reference tariffs for distribution network users; be equitable in its effect as between those users; and otherwise be consistent with the Code objective.

5.3 Western Power's network pricing objectives

In accordance with section 7.3 (a) of the Code, reference tariffs are designed to recover forward-looking costs of providing reference services. It is recognised that the total forward-looking costs for the provision of covered services relate to the provision of reference and non-reference services.

Non-reference service revenue is recovered on a fee-for-service basis and reflects that component of the forecast costs related to the provision of non-reference services.

Reference tariffs are designed to recover the forward-looking costs for the provision of reference services. Capital contributions are charged in accordance with Western Power's capital contributions policy. In general terms, capital contributions seek to recover in net present value terms any shortfall between the expected revenue from reference tariffs and the costs of connection.

Western Power's reference tariffs are designed to meet the objectives of the pricing methods (as set out in Chapter 7 of the Code), the Code objective (section 2.1), and a number of other objectives adopted by the company. Specifically, under Western Power's pricing methods, the target revenue is recovered from users in a manner that is:

- economically efficient (in accordance with the requirements of sections 7.3(b) and 7.6 of the Code);
- simple and practical (thus facilitating the ability of users to predict likely annual changes in tariffs, as required by section 7.4 (c) of the Code); and
- equitable (in accordance with the requirements of section 7.7 of the Code).

In addition to these high-level objectives, the pricing methods proposed by Western Power have the following aims:

- to deliver the target revenue so as to facilitate the maintenance of a viable network business (in accordance with sections 6.4 and 7.3(a) of the Code) and to facilitate the delivery of efficient network services to all network users;
- to be as cost reflective as is practicable, by reflecting the user's utilisation of the network including use of dedicated assets, pursuant to sections 7.3(b) and 7.6 of the Code;
- to promote efficient use of the network through appropriate price signalling;
- to provide reasonable price stability and certainty, so as to enable network users to make informed investment decisions, as required by section 7.4 of the Code;
- to be as simple and straightforward as is reasonable taking into account other objectives; and
- to avoid cross subsidy between different customer groups, by pricing in an economically efficient manner (in accordance with the requirements of sections 7.3, 7.4 and 7.6 of the Code).

5.4 Network pricing principles

Given the applicable Code provisions, and the objectives outlined above, Western Power has adopted the following principles to guide the development of its pricing methods and the design of network tariffs:

1. Network tariffs are to be designed to recover the costs of providing reference services while meeting any applicable side constraints (the aim of which is to prevent price shock to users).

2. Network tariffs will be based on a well-defined and transparent methodology.

3. Network tariffs will be based on analysis of the cost of service provision that includes:

   a. definition of the classes of service provided;

   b. allocation of fixed and variable network costs to service classes; and

   c. setting of the fixed and variable components of prices at levels that will recover the fixed and variable costs.

4. Network tariffs will signal the economic cost of service provision in that they will:

   a. avoid cross subsidies between classes of service, and

   b. to the extent practicable, avoid cross subsidies within classes of service.

5. Subject to the provision that the reference service revenue is to be recovered, network tariffs will be responsive to customer requirements in order to:

   a. avoid economic bypass; and

   b. allow for negotiation and discounting of network prices in accordance with the applicable provisions of the Code.

6. Network tariffs will provide economic signals to encourage efficient use of the network.

7. Where applicable, any “postage stamp” component of network tariffs will be determined in accordance with the requirements of section 7.7 of the Code as far as is practicable.

5.5 Demonstration of compliance of pricing methods with Code provisions

5.5.1 Introduction

The purpose of this section is to demonstrate that the pricing methods applied by Western Power comply with the provisions set out in sections 7.3, 7.4, 7.6, and 7.7 of the Code.[59]

Section 7.1 of the Code defines "pricing methods" as the structure of reference tariffs included in the access arrangement. For convenience, Western Power's reference tariffs are listed below:

Reference tariffs for users connected to the distribution system	RT1	Anytime Energy (Residential) Exit tariff
	RT2	Anytime Energy (Business) Exit tariff
	RT3	Time of Use Energy (Small) Exit tariff
	RT4	Time of Use Energy (Large) Exit tariff
	RT5	High Voltage Metered Demand Exit tariff
	RT6	Low Voltage Metered Demand Exit tariff
	RT7	High Voltage Contract Maximum Demand Exit tariff
	RT8	Low Voltage Contract Maximum Demand Exit tariff
	RT9	Streetlighting Exit tariff
	RT10	Un-Metered Supplies Exit tariff
	RT11	Distribution Entry tariff
Reference tariffs for users connected to the transmission system	TRT1	Transmission Exit tariff
	TRT2	Transmission Entry tariff

Compliance with the Code's requirements regarding the pricing objectives and the structuring of tariffs is demonstrated below, by examining the reference tariffs collectively and, where appropriate, by examining each reference tariff individually.

5.5.2 Recovery of forward-looking efficient costs

The reference tariffs that apply to users connected to the distribution network (reference tariffs RT1 to RT11) are made up of a transmission network related tariff component and a distribution network related tariff component. The two components add together to make a bundled reference tariff. The transmission reference tariffs (TRT1 and TRT2) are made up of transmission network related tariff components only. That is to say, all reference tariffs contain a transmission network related tariff

59 These sections of the Code specify the requirements that must be met in terms of the pricing objectives, the structuring of reference tariffs and related issues. Western Power's compliance with the Code provisions relating to the requirement for the access arrangement to contain certain policies regarding discounts (namely, sections 7.9 to 7.11 of the Code) is demonstrated in Sections 5.6 and 5.7 below.

component, while reference tariffs RT1 to RT11 also contain a distribution network tariff component.

As noted in Parts B and C of this document, the target revenue is determined to recover the forward looking efficient costs of providing covered services that are made up of reference services and non-reference services. Costs relating to the provision of non-reference services are recovered from customers on a fee for service basis. The remainder of the target revenue is recovered through reference tariffs and through capital contributions in accordance with the capital contributions policy.

Reference tariffs are designed to recover the costs of providing reference services in each year, based on forecast energy volumes. However, the actual revenue collected by the company will be a function of actual, rather than forecast energy volumes. For these reasons, the maximum revenue that the company is to collect each year under the price control may differ from the target revenue.

Notwithstanding this however, the methods of determining the company's target revenue[60] and tariffs ensure that the revenue generated through the sale of covered services recovers an amount that meets the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved.

The following table provides detailed information regarding the allocation of the target revenue to each reference service, based on the cost of service for that reference service, and the forecast revenue to be recovered from each of the corresponding reference tariffs (for year 1 of the access arrangement period).

Reference Service	Reference Tariff	Target Revenue Allocated to each reference Tariff ($000 per annum)	Forecast Recovered Revenue for each Reference Tariff ($000 per annum)
A1	RT1	250,240	251,122
A2	RT2	84,433	86,939
A3	RT3	7,133	7,002
A4	RT4	74,163	72,641
A5	RT5	8,265	6,825
A6	RT6	23,708	27,839
A7	RT7	51,323	51,809
A8	RT8	7,080	7,298
A9	RT9	14,141	13,098
A10	RT10	1,460	1,507
B1	RT11	555	555
A11	TRT1		12,812
B2	TRT2		34,986

Target revenue for transmission reference tariffs TRT1 and TRT2 is not included in the table because the prices are derived using T-Price.

60 As explained in section 8 of Part B and section 7 of Part C of this document, Western Power's target revenue is determined in accordance with section 6.4(a)(i) of the Code.

On the basis of the foregoing information, Western Power considers that the requirements of section 7.3(a) of the Code are met.

5.5.3 Reference tariffs should be between incremental and stand-alone cost

In accordance with sections 7.3 (b)(i) and (ii) of the Code, reference tariffs are set to at least recover the incremental cost, but to be less than the stand-alone cost of service provision. Western Power understands that these Code provisions are intended to ensure that reference tariffs are set to be cost-reflective, and to avoid cross subsidies within reference tariffs, and between reference tariffs. The Price List Information (contained in Appendix 6 of the access arrangement) explains in detail how Western Power derives the cost of service for each reference service, and then translates those costs into appropriate reference tariffs that are set to recover that cost of service.

(a) The incremental and stand-alone cost of service for each of the reference services A5, A6, A7, A8, and B1 are determined by calculation at a customer level.

The following table gives the sum of the incremental costs, the sum of the stand-alone costs, and the sum of the forecast revenue recovered from the customers for each of these reference tariffs.

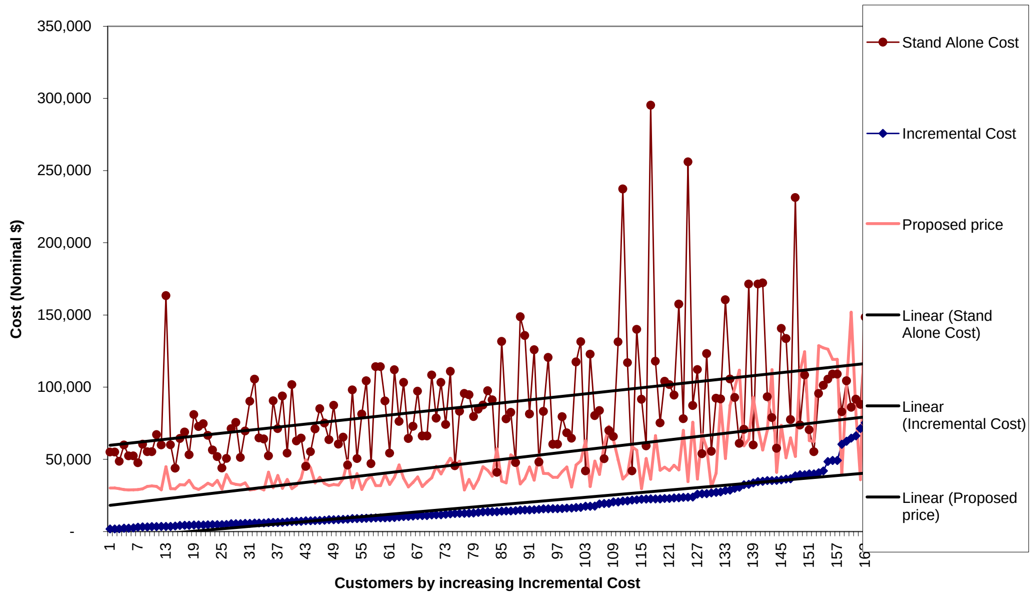
Reference Service	Reference Tariff	Incremental Cost Of Service ($000 per annum)	Stand-Alone Cost of Service Provision ($000 per annum)	Forecast Revenue Recovered from Reference Tariff ($000 per annum)
A5	RT5	4,965	57,967	6,825
A6	RT6	20,281	79,329	27,839
A7	RT7	41,537	58,652	51,809
A8	RT8	4,697	8,582	7,298
B1	RT11	555	58,652	555

For the distribution component of the reference tariff, calculation of the incremental cost is carried out by deriving annualised costs based on the location and contracted demand for each existing customer. The incremental cost is the minimum cost to service each customer assuming the feeder is in service and supplying all other customers on that feeder. The stand-alone cost is the cost to supply that customer assuming a dedicated supply is established that feeds only that customer. The discount rate used to derive annualised costs reflects Western Power's cost of capital.

By calculating the incremental and stand-alone costs for each customer, a price is set that will recover at least the incremental cost of supply, but which is less than the stand-alone cost. The same process is used in each of the pricing zones (urban, rural, mixed, mining and CBD) to derive the demand and demand/length prices. The prices in each zone are set to be equal at a demand of 1000 kVA to meet the requirements of section 7.7 of the Code.

As an example, this principle is illustrated in the following graph for the Urban area. The graphs for all of the pricing zones are contained in the Price List Information provided in Appendix 6 of the access arrangement.

Figure 14 - Demonstration that Urban Reference Tariff RT7 meets Code requirements



It is important to note that in the vast majority of cases the price will meet the requirements of section 7.3(b) of the Code. However no pricing structure can be guaranteed to meet the Code requirement in every individual case. For example, if the price is reduced so that the charge is below the stand-alone cost for every single customer, cases emerge where the price is then below the incremental cost for some other customers. The prices have been set to achieve a balance between all customers, while still meeting the requirements of section 7.3(b) of the Code.

The transmission component of the tariffs is derived by setting a price at each zone substation to reflect the cost of supply to those customers connected to that zone substation. This cost is based on the transmission nodal price, which is derived using the transmission network pricing software package (T-Price). This model establishes a price reflecting average costs at each network node (substation/connection point). T-Price is a transmission network pricing software package provided by Rolib Pty Ltd and is used by all Australian utilities and the National Electricity Market Management Company (NEMMCO). This model establishes a price reflecting average costs at each network node (substation / connection point). On the basis that T-price is used to derive prices and is the industry standard, it is considered that the prices are efficient and consistent with the objectives of the Code and in particular the objectives of chapter 7 of the Code.

The nodal prices at each zone substation are adjusted to be equal at a demand of 1000 kVA to meet the requirements of 7.7 of the Code.

(b) The incremental cost of service provision for reference services A1, A2, A3, A4, A9, and A10 is that part of the approved total costs that would be avoided by not servicing these groups of customers. This cost is equivalent to the variable cost of service allocated to each reference service in accordance with the Price List Information.

The standalone cost of providing services to a particular group of customers is the approved total costs that would be incurred if only those customers were served. This cost is equivalent to the total fixed cost of service provision and the variable cost of service provision for the particular group of customers.

The following table gives the sum of the incremental costs, the sum of the stand-alone costs, and the sum of the forecast revenue recovered from the customers for each of these reference tariffs.

Reference Service	Reference Tariff	Incremental Cost Of Service ($000 per annum)	Stand-Alone Cost of Service Provision ($000 per annum)	Forecast Revenue Recovered from Reference Tariff ($000 per annum)
A1	RT1	206,221	269,840	251,122
A2	RT2	78,822	136,771	86,939
A3	RT3	6,322	63,646	7,002
A4	RT4	72,266	129,734	72,641
A9	RT9	12,632	68,642	13,098
A10	RT10	800	67,975	1,507

(c) For the transmission reference tariffs TRT1 and TRT2, location specific nodal prices are derived using the T-Price computer model, which is described in sub-section (a) above. On the basis that T-price is used to derive prices and is the industry standard, it is considered that the prices are efficient and consistent with the objectives of the Code and in particular the objectives of chapter 7 of the Code.

(d) Section 7.7 of the Code requires the tariffs applying to a standard tariff exit point to be uniform across the SWIN. Notwithstanding the requirements of section 7.3(b) of the Code, reference tariffs RT1 to RT6, RT9 and RT10 are designed to meet the requirement set out in section 7.7 of the Code.

On the basis of the foregoing information, Western Power considers that the requirements of section 7.3(b) of the Code are satisfied.

5.5.4 Differences in charges paid by users to reflect differences in the average cost of service provision

The distribution components of reference tariffs RT1 to RT11, and the transmission components of RT1 to RT11, TRT1 and TRT2, are based on metered quantities including energy usage, energy demand, time of use of energy and demand, and location of connection. The application of each of the tariffs to each of these measured quantities result in different charges to different users.

Where the measured quantities are identical, the charge to the users will be the same for reference tariffs RT1 to RT4, and RT5 and RT6 for demands less than 1 MVA. For reference tariffs RT7, RT8 and RT11, as well as RT5 and RT6 where demand exceeds 1 MVA, the charges will vary according to location, to the extent that the users are supplied from different geographical sections of the network to which different locational price components apply, reflecting the different average cost of service in those different parts of the network.

For transmission, location specific nodal prices are derived using the T-Price computer model. This model establishes a price reflecting average costs at each network node (substation / connection point). It is noted that all Australian utilities use T-Price to calculate transmission network prices.

Reference tariffs RT5 to RT8, and RT11 employ the transmission nodal prices directly in deriving the price components. The transmission tariff components of reference tariffs RT1 to RT4, RT9 and RT10 are set to recover the average cost of service for standard exit points.

On the basis of the foregoing information, Western Power considers that the requirements of section 7.4(a) of the Code have been met.

5.5.5 Structure of reference tariffs to accommodate the reasonable requirements of users collectively

All reference tariffs have been developed through a consultative process that involved the Office of Energy and an industry consultative committee called the “Electricity Access Consultative Committee” (EACC). The EACC comprised representatives of generators, retailers and energy consumers.

Most tariffs have been in place since 2001 and are accepted by the electricity industry as being appropriate for the provision of network access. It is considered that the tariffs reflect the reasonable requirements of network users. On this basis, Western Power considers that the requirements of section 7.4(b) have been met.

5.5.6 Structure of tariffs should enable a user to predict the likely changes

All reference tariffs are specified clearly for the first year of the access arrangement period. For each subsequent year of the access arrangement period, network users will be able to predict annual price movements because:

- the forecast tariff revenue has been smoothed across the access arrangement period so that transmission and distribution reference tariff price movements will be smoothed across each year of the access arrangement period, and
- side constraints apply on all tariff component adjustments to limit annual price movements.[61]

On this basis, Western Power considers that the requirements of section 7.4(c) of the Code are met.

5.5.7 Avoidance of price shocks

Price shock during the access arrangement period is avoided by the following measures:

In accordance with section 7.4(d) of the Code, the structure of reference tariffs is designed to avoid price shocks, principally by the imposition of side constraints on

[61] Further details of the price control are set out in section 4 of this Part D.

annual price movements. In addition, as already noted in section 5.5.6, the forecast reference service revenue has been smoothed across the access arrangement period so that price movements will be smoothed across each year. The revenue smoothing process only affects the profile of price movements, and does not impact the total revenue in present value terms over the access arrangement period.

The average annual revenue is smoothed to increase at a rate of CPI+3% in the second and third years for both transmission and distribution. This rate of increase has been chosen as an optimal “best fit” in order to provide tariff increases in the second and third years comparable with the initial tariff movements in year 1 (compared with current published tariffs).

Moreover, to ensure that customers do not face significant increases in prices (and having regard to section 6.4(c) of the Code), Western Power is proposing to include the future costs and revenues arising from capital contributions in its revenue building block calculations. As noted in section 6.3 of Part B, the effect of this treatment is neutral in revenue terms over a number of access arrangement periods, but has the desirable effect of reducing Western Power’s tariff related revenue requirement in the forthcoming access arrangement period and thereby reducing potential price rises.

On this basis, Western Power considers that the requirements of section 7.4(d) of the Code are met.

5.5.8 Fixed and variable components of tariffs to reflect underlying cost structure

Reference tariffs have been designed to recover the cost of service provision in a cost reflective manner. Section 7.6 of the Code requires the incremental cost of service provision to be recovered by tariff components that vary with usage, and the costs in excess of the incremental costs to be recovered through tariff components that do not vary with usage.

This requirement has been achieved through the method described in the Price List Information (contained in Appendix 6 of the access arrangement), in which, subject to section 7.7 of the Code price components have been derived to recover the cost of service provision using a cost reflective approach consistent with the requirements of sections 7.3 and 7.4 of the Code.

On the basis described in the Price List Information, usage related charges reflect the incremental costs to Western Power of providing reference services, and tariff components that do not vary with usage reflect the costs in excess of the incremental costs of service provision.

For transmission reference tariffs, location specific nodal prices are derived reflecting average costs at each network node (substation/connection point). On the basis that T-price is used to derive prices and is the industry standard, it is considered that the prices are efficient and consistent with the objectives of the Code and in particular the objectives of chapter 7 of the Code.

On the basis of the foregoing information, Western Power considers that the requirements of section 7.6 of the Code are met.

5.5.9 Postage stamp charges in certain cases

Reference tariffs RT1 to RT6, RT9 and RT10 apply uniformly to all standard tariff users (those with a maximum demand less than 1 MVA) across the SWIN, irrespective of location. On this basis, Western Power considers that the requirements of section 7.7 of the Code are satisfied.

5.6 Policy relating to prudent discounting

5.6.1 Code provisions

Section 7.9 of the Code states:

> "A *service provider* may propose in its *access arrangement* to discriminate between *users* in its pricing of *services* to the extent that it is necessary to do so to aid economic efficiency, including:
>
> (a) by entering into an agreement with a *user* to apply a *discount* to the *equivalent tariff* to be paid by the user for a *covered service*; and
>
> (b) then, recovering the amount of the *discount* from other *users* of *reference services* through *reference tariffs*."

5.6.2 Western Power's policy

Reference tariffs are designed to reflect the costs of providing reference services. Reference services will normally represent the most cost-effective option for transporting electricity between generators and load users.

However, there may be cases where an existing or prospective network user has an option available that is more cost-effective (from the user's perspective) than the reference service. In such cases, economic efficiency is aided if the user is encouraged - by being offered a discount on the reference tariff - to continue to use the reference service, provided always that the discounted price covers the avoidable (or incremental) cost of continuing to provide the reference service. The offering of a discount in this way, and the funding of the discount by the remaining existing users, aids economic efficiency because it:

- discourages inefficient new network developments that replicate or bypass existing infrastructure;
- results in an increase in (or at least, the maintenance of) average network utilisation, compared to the level that would prevail if the relevant user chose not to use the reference service; and
- results in a reduction in the level of average network costs compared to the level that would prevail if the relevant user chose not to use the reference service (and therefore made no contribution to the cost of the network).

In view of these considerations, and in accordance with the provisions set out in the section 7.9 of the Code, Western Power's policy relating to prudent discounting is as follows:

- In exercising its discretion with regard to prudent discounting under section 7.9 of the Code, Western Power will have regard to the pricing objectives in sections 7.3 and 7.4 of the Code;

- Western Power may offer a prudent discount if the existing user or applicant seeking access to the SWIS is able to demonstrate that an alternative option will provide a comparable service at a lower price than that offered by Western Power's reference services and reference tariffs;

- The existing user or applicant must provide Western Power with sufficient details of the cost of the alternative option to enable Western Power to calculate the annualised cost of the alternative option; and

- Western Power's discounted price offer will be set to reflect the higher of:

    - the cost of the alternative option, or

    - the incremental cost of service provision.

5.7 Discounts for distributed generation

5.7.1 Code provisions

Section 7.10 of the Code states:

> "If a *user* seeks to *connect distributed generating plant* to a *covered network*, a *service provider* must reflect in the *user's tariff*, by way of a *discount*, a share of any reductions in either or both of the *service provider's capital-related costs* or *non-capital costs* which arise as a result of the *entry point* for *distributed generating plant* being located in a particular part of the *covered network* by:
>
> (a) entering into an agreement with a *user* to apply a *discount* to the *equivalent tariff* to be paid by the *user* for a *covered service*; and
>
> (b) then, recovering the amount of the *discount* from other *users* of *reference services* through *reference tariffs*."

5.7.2 Western Power's Policy

Western Power believes that it is appropriate to encourage distributed generation where this leads to a net saving in providing network services to customers. Savings in network costs will accrue if Western Power is able to avoid costs as a result of an embedded generator connecting to its network. The determination of any saving will be based on the total costs incurred with the generator connecting, compared to the total costs incurred if the generator does not connect.

In assessing the saving that arises from the embedded generator it is necessary to study the impact on Western Power's network operating and capital expenditure over an extended period of time. Ideally, the analysis might extend 20 years, examining the present value of the costs with and without the generator connecting. However, data limitations may suggest that a shorter period of analysis is more appropriate.

Western Power's policy is that the cost analysis will be conducted over a period of at least 10 years, depending on the availability and accuracy of data. A discount will only be payable if the calculated saving from the connecting generator is greater than zero. The discount will be paid in all circumstances, including where the discount exceeds the access charges.

6 Applications and queuing policy

6.1 Introduction

Section 5.1(g) of the Code states that an access arrangement must include an applications and queuing policy under sections 5.7 to 5.11.

Broadly speaking, the purpose of an applications and queuing policy is to manage applications for an access contract in an orderly and fair manner, especially where network capacity is scarce. Section 5.7 of the Code provides a more detailed summary of the scope of the applications and queuing policy. Section 5.7 states:

> "An *applications and queuing policy* must:
>
> (a) to the extent reasonably practicable, accommodate the interests of the *service provider* and of *users* and *applicants*; and
>
> (b) be sufficiently detailed to enable *users* and *applicants* to understand in advance how the *applications and queuing policy* will operate; and
>
> (c) set out a reasonable timeline for the commencement, progressing and finalisation of *access contract* negotiations between the *service provider* and an *applicant*, and oblige the *service provider* and *applicants* to use reasonable endeavours to adhere to the timeline; and
>
> (d) oblige the *service provider*, subject to any reasonable confidentiality requirements in respect of *competing applications*, to provide to an *applicant* all commercial and technical information reasonably requested by the *applicant* to enable the *applicant* to apply for, and engage in effective negotiation with the *service provider* regarding, the terms for an *access contract* for a *covered service* including:
>
> i. information in respect of the availability of *covered services* on the *covered network;* and
>
> ii. if an *augmentation* will be required to provide the *covered services* sought:
>
> A. operational and technical details of the *required augmentation*; and
>
> B. commercial information regarding the likely cost of the *required augmentation*; and
>
> (e) set out the procedure for determining the priority that an *applicant* has, as against another *applicant*, to obtain *access* to *covered services*, where the *applicants' access applications* are *competing applications*; and
>
> (f) to the extent that *contestable consumers* are *connected* at *exit points* on the *covered network*, contain provisions dealing with the transfer of capacity associated with a *contestable consumer* from the *user* currently supplying the *contestable consumer* ('outgoing user') to another *user* or an *applicant* ('incoming user') which, to the extent that it is applicable, are consistent with and facilitate the operation of any *customer transfer code*; and
>
> (g) establish arrangements to enable a *user* who is:
>
> i. a *supplier of last resort* as defined in section 67 of the Act to comply with its obligations under Part 5 of the Act; and

ii. a *default supplier* under regulations made in respect of section 59 of the Act to comply with its obligations under section 59 of the Act and the regulations; and

(h) facilitate the operation of Part 9 of the Act, any enactment under Part 9 of the Act and the market rules as defined in section 121(1) of the Act; and

(i) if applicable, contain provisions setting out how *access applications* (or other requests for *access* to the *covered network*) lodged before the start of the relevant *access arrangement period* are to be dealt with."

The remainder of this section of the document is structured as follows:

- section 6.2 cites the remaining Code provisions in relation to the applications and queuing policy, and concludes with a brief statement of Western Power's approach to establishing its policy; and

- section 6.3 notes that Western Power's amendments to the model applications and queuing policy comply with the Code, and are explained in more detail in Appendix 7 to this document.

6.2 Code provisions

In addition to section 5.7 of the Code, the following provisions are relevant to the establishment of the applications and queuing policy.

"5.8 The paragraphs of section 5.7 do not limit each other.

5.9 Under section 5.7(e), the *applications and queuing policy* may:

(a) provide that if there are *competing applications*, then priority between the *access applications* is to be determined by reference to the time at which the *access applications* were lodged with the *service provider*, but if so the *applications and queuing policy* must:

(i) provide for departures from that principle where necessary to achieve the *Code objective*; and

(ii) contain provisions entitling an *applicant*, subject to compliance with any reasonable conditions, to:

A. current information regarding its position in the queue; and

B. information in reasonable detail regarding the aggregated capacity requirements sought in *competing applications* ahead of its *access application* in the queue; and

C. information in reasonable detail regarding the likely time at which the *access application* will be satisfied; and

(b) oblige the *service provider*, if it is of the opinion that an *access application* relates to a particular project or development

(i) which is the subject of an invitation to tender; and

(ii) in respect of which other access applications have been lodged with the service provider, (project applications) to, treat the *project applications*, for the purposes of determining their priority, as if each of them had been lodged on the date that the *service provider* becomes aware that the invitation to tender was announced.

5.10 An *applications and queuing policy* may:

(a) be based in whole or in part upon the *model applications and queuing policy*, in which case, to the extent that it is based on the *model applications and queuing policy*, any matter which in the *model applications and queuing policy* is left to be completed in the *access arrangement*, must be completed in a manner consistent with:

(i) any instructions in relation to the matter contained in the *model applications and queuing policy*; and

(ii) sections 5.7 to 5.9;

(iii) the *Code objective*; and

(b) be formulated without any reference to the *model applications and queuing policy* and is not required to reproduce, in whole or in part, the *model applications and queuing policy*.

5.11 The *Authority*:

(a) must determine that an *applications and queuing policy* is consistent with sections 5.7 to 5.9 and the *Code objective* to the extent that it reproduces without material omission or variation the *model applications and queuing policy*; and

(b) otherwise must have regard to the *model applications and queuing policy* in determining whether the *applications and queuing policy* is consistent with sections 5.7 to 5.9 and the *Code objective*."

Western Power has made a number of relatively minor but important modifications to the *model applications and queuing policy*, which are detailed in section 6.3 below. In making these modifications, and in accordance with section 5.10(a) of the Code, Western Power has had regard to:

- any instructions in relation to the matter contained in the *model applications and queuing policy*;
- sections 5.7 to 5.9 of the Code; and
- the *Code objective*.

6.3 Western Power's modifications to the *model applications and queuing policy*

Appendix 7 to this document demonstrates that Western Power's application and queuing policy complies with the Code. In addition, Western Power's applications and queuing policy has taken into account the Authority's Draft and Final Decisions and its Required Amendments. In particular, the Authority's Final Decision contains Required Amendments 17 to 21, which relate to Western Power's proposed applications and queuing policy as described in Western Power's revised proposed access arrangement submitted to the Authority in May 2006. Western Power has accepted each of the Authority's Required Amendments 17 to 21.

For a detailed description of Western Power's response to the relevant Required Amendments, please refer to the separate document titled *Western Power's Response to the Required Amendments in the Authority's Final Decision*.

7 Capital contributions policy

7.1 Introduction

Section 5.1(h) of the Code states that an access arrangement must include a capital contributions policy under sections 5.12 to 5.17.

Broadly speaking, the capital contributions policy applies where it is necessary for Western Power to undertake an augmentation, or procure a non-network option (for example, by contracting with a generator for network support) in order to provide to an applicant a covered service which is sought in an access application. The capital contribution policy describes the circumstances in which a capital contribution will be payable by the applicant and the method for calculating the capital contribution.

The remainder of this section is structured as follows:

- section 7.2 cites the Code provisions in relation to the capital contributions policy, and concludes with a brief statement of Western Power's approach to establishing its policy; and
- section 7.3 explains that Western Power's amendments to the capital contributions policy comply with the Code, and are explained in more detail in Appendix 8 to this document.

7.2 Code provisions

This section provides details of the relevant Code provisions in relation to the capital contributions policy, and concludes with a summary of Western Power's approach to establishing its policy.

"5.12 The objectives for a *capital contributions policy* must be that:

(a) in respect of a *required augmentation*, it strikes a balance between the interests of:

i. the *contributing user*; and

ii. other *users*; and

iii. *consumers*;

and

(b) it does not constitute an inappropriate barrier to entry.

5.13 A *capital contributions policy* must facilitate the operation of this Code, including:

(a) section 2.9; and

(b) the *new facilities investment test*; and

(c) the *regulatory test*.

5.14 Subject to section 5.14A, a *capital contributions policy* must not require a *user* to make a *capital contribution* in respect of any part of *new facilities investment* which meets the *new facilities investment test*.

5.14A A *capital contributions policy* may provide for a *user* to make a *capital contribution* in respect of a *new facility* whether or not the *new facilities investment* meets the *new facilities investment test*, if an *approved extensions and expansions policy* provides for the *user* to pay in respect of the *new facility* an amount specified in, or determined under, the policy.

5.15 A *capital contributions policy* must set out:

(a) the circumstances in which a *contributing user* may be required to make a *capital contribution* in respect of a *required augmentation*; and

(b) the method for calculating any *capital contribution* a *contributing user* may be required to make towards the *required augmentation*; and

(c) for any *capital contribution*:

i. the terms on which a *contributing user* must make the *capital contribution*; or

ii. a description of how the terms on which a *contributing user* must make the *capital contribution* are to be determined.

5.16 A *capital contributions policy* may:

(a) be based in whole or in part upon the *model capital contributions policy*, in which case, to the extent that it is based on the *model capital contributions policy*, any matter which in the *model capital contributions policy* is left to be completed in the *access arrangement*, must be completed in a manner consistent with:

i. any instructions in relation to the matter contained in the *model capital contributions policy*; and

ii. sections 5.12 to 5.15; and

iii. the *Code objective*;

and

(b) be formulated without any reference to the *model capital contributions policy* and is not required to reproduce, in whole or in part, the *model capital contributions policy*.

5.17 The *Authority*:

(a) must determine that a *capital contributions policy* is consistent with sections 5.12 to 5.15 and the *Code objective* to the extent that it reproduces without material omission or variation the *model capital contributions policy*; and

(b) otherwise must have regard to the *model capital contributions policy* in determining whether the *capital contributions policy* is consistent with sections 5.12 to 5.15 and the *Code objective*."

The most significant change from the model capital contribution policy has been the incorporation of the provisions with respect to the new section 5.14A of the Code.

The Coordinator of Energy has now approved the extensions and expansions policy, and the amended capital contributions policy refers to the extensions and expansions policy but no longer deals with matters contained in that policy.

Excluding matters relating to the extensions and expansions policy, Western Power has made a number of relatively minor but important modifications to the model capital contributions policy, which are detailed in section 7.3 below. In making these modifications, and in accordance with section 5.16(a) of the Code, Western Power has had regard to:

- any instructions set out in the Code that relate to the matter contained in the model capital contributions policy;
- sections 5.12 to 5.15 of the Code; and
- the Code objective.

7.3 Western Power's modifications to the *model capital contributions policy*

Appendix 8 to this document demonstrates that Western Power's capital contributions policy complies with the Code. In addition, Western Power's capital contributions policy has taken into account the Authority's Draft and Final Decisions and its Required Amendments. In particular, the Authority's Final Decision contains Required Amendments 22 to 26, which relate to Western Power's proposed capital contributions policy as described in Western Power's revised proposed access arrangement submitted to the Authority in May 2006. Western Power has accepted each of the Authority's Required Amendments 22 to 26.

For a detailed description of Western Power's response to the relevant Required Amendments, please refer to the separate document titled *Western Power's Response to the Required Amendments in the Authority's Final Decision*.

8 Standard access contract

8.1 Introduction

Section 5.1(b) of the Code states that an access arrangement must include a standard access contract under sections 5.3 to 5.5.

Broadly speaking, the standard access contract sets out the terms and conditions on which Western Power offers to provide covered services to applicants and users. Western Power's standard access contract comprises four parts:

- Part A contains definitions and commencement provisions, and is included in all standard access contracts issued by Western Power.
- Part B contains provisions dealing with capacity services. It forms part of the capacity contract. A capacity contract is a type of access contract typically used by a user who does not operate a power station but buys electricity in bulk and sells it to consumers.
- Part C contains provisions dealing with technical compliance. It forms part of the technical compliance contract. A technical compliance contract is a type of

access contract typically used by a user that operates a power station and sells electricity in bulk to another user such as a retailer. A technical compliance contract deals with technical matters relating to the operation of the power station and its connection to the network.

- Part D contains general contractual provisions, and is included in all access contracts.

The remainder of this section is structured as follows:

- section 8.2 cites the Code provisions in relation to the *standard access contract*, and concludes with a brief statement of Western Power's approach to establishing its *standard access contract*; and

- section 8.3 explains that Western Power's amendments to the standard access contract set out in the Code, and are explained in more detail in Appendix 9 to this document.

8.2 Code provisions

This section cites the relevant Code provisions relating to the standard access contract, and concludes with a summary of Western Power's approach to establishing its standard access contract.

"5.3 A *standard access contract* must be:

(a) reasonable; and

(b) sufficiently detailed and complete to:

i. form the basis of a commercially workable *access contract*; and

ii. enable a *user* or *applicant* to determine the value represented by the *reference service* at the *reference tariff*.

5.4 A *standard access contract* may:

(a) be based in whole or in part upon the *model standard access contract*, in which case, to the extent that it is based on the *model standard access contract*, any matter which in the *model standard access contract* is left to be completed in the *access arrangement*, must be completed in a manner consistent with:

i. any instructions in relation to the matter contained in the *standard access contract*; and

ii. sections 5.3; and

iii. the *Code objective*;

and

(c) be formulated without any reference to the *model standard access contract* and is not required to reproduce, in whole or in part, the *model standard access contract*.

5.5 The *Authority*:

(c) must determine that a *standard access contract* is consistent with section 5.3 and the *Code objective* to the extent that it reproduces without material omission or variation the *model standard access contract*; and

(d) otherwise must have regard to the *model standard access contract* in determining whether the *standard access contract* is consistent with section 5.3 and the *Code objective*."

Western Power has made a number of important modifications to the model standard access contract, which are detailed in section 8.3 below. In making these modifications, and in accordance with section 5.4(a) of the Code, Western Power has had regard to:

- any instructions in the Code relating to the matter contained in the model standard access contract;
- section 5.3 of the Code; and
- the Code objective.

It should also be noted that Western Power is obliged to include a transfer and relocation policy in its access arrangement in accordance with sections 5.18 to 5.24 of the Code. The model standard access contract includes some provisions in relation to bare transfers, which form an element of the transfer and relocation policy. Western Power has included some further modifications to the model standard access contract to address the Code provisions relating to the transfer and relocation policy. These additional modifications are also explained in section 8.3 below.

8.3 Western Power's modifications to the model standard access contract

Appendix 9 to this document demonstrates that Western Power's standard access contract (re-named as Western Power's "electricity transfer access contract") complies with the Code. In addition, Western Power's electricity transfer access contract has taken into account the Authority's Draft and Final Decisions and its Required Amendments. In particular, the Authority's Final Decision contains Required Amendments 13 to 16, which relate to Western Power's proposed electricity transfer access contract as described in Western Power's revised proposed access arrangement submitted to the Authority in May 2006. Western Power has accepted each of the Authority's Required Amendments 13 to 16.

For a detailed description of Western Power's response to the relevant Required Amendments, please refer to the separate document titled *Western Power's Response to the Required Amendments in the Authority's Final Decision*.

9 Transfer and relocation policy

9.1 Introduction

Section 5.1(i) of the Code states that an access arrangement must include a *transfer and relocation policy* under sections 5.18 to 5.24. There is no model policy in the Code.

Broadly speaking, the transfer and relocation policy sets out the circumstances under which a User may assign its access rights or relocate its contracted capacity, together with the conditions attached to any such arrangement. A copy of the transfer and relocation policy is included in Appendix 2 of the access arrangement.

The remainder of this section is structured as follows:

- section 9.2 cites the Code provisions in relation to the *transfer and relocation policy*;
- section 9.3 explains Western Power's *transfer and relocation policy* noting the policy's compliance with the relevant provisions in the Code; and
- section 9.4 provides some concluding comments.

9.2 Code Provisions

This section cites the relevant Code provisions relating to the transfer and relocation policy as follows:

"5.18 A *transfer and relocation policy*:

(a) must permit a *user* to make a *bare transfer* without the *service provider's* consent; and

(b) may require that a *transferee* under a *bare transfer* notify the *service provider* of the nature of the *transferred access rights* before using them, but must not otherwise require notification or disclosure in respect of a *bare transfer*.

5.19 For a *transfer* other than a *bare transfer*, a *transfer and relocation policy*:

(a) must oblige the *service provider* to permit a *user* to *transfer* its *access rights* and, subject to section 5.20, may make a *transfer* subject to the *service provider's* prior consent and such conditions as the *service provider* may impose; and

(b) subject to section 5.20, may specify circumstances in which consent will or will not be given, and conditions which will be imposed, under section 5.19(a).

5.20 Under a *transfer and relocation policy*, for a *transfer* other than a *bare transfer*, a *service provider*:

(a) may withhold its consent to a *transfer* only on reasonable commercial or technical grounds; and

(b) may impose conditions in respect of a *transfer* only to the extent that they are reasonable on commercial and technical grounds.

5.21 A *transfer and relocation policy*:

(a) must permit a *user* to relocate capacity at a *connection point* in its *access contract* to another *connection point* in its *access contract*, (a "**relocation"**) and, subject to section 5.22, may make a *relocation* subject to the *service provider's* prior consent and such conditions as the *service provider* may impose; and

(b) subject to section 5.22, may specify in advance circumstances in which consent will or will not be given, and conditions which will be imposed, under section 5.21(a).

5.22 Under a *transfer and relocation policy*, for a *relocation* a *service provider*:

(a) must withhold its consent where consenting to a *relocation* would impede the ability of the *service provider* to provide a *covered service* that is sought in an *access application*; and

(b) may withhold its consent to a *relocation* only on reasonable commercial or technical grounds; and

(c) may impose conditions in respect of a *relocation* only to the extent that they are reasonable on commercial and technical grounds.

5.23 An example of a thing that would be reasonable for the purposes of sections 5.20 and 5.22 is the *service provider* specifying that, as a condition of its agreement to a *transfer* or *relocation*, the *service provider* must receive at least the same amount of revenue as it would have received before the *transfer* or *relocation*, or more revenue if *tariffs* at the destination point are higher.

5.24 Section 5.23 does not limit the things that would be reasonable for the purposes of sections 5.20 and 5.22."

9.3 Western Power's transfer and relocation policy

Western Power's transfer and relocation policy (TRP) should be read in conjunction with Electricity Transfer Access Contract (ETAC) and the Applications and Queuing Policy (AQP), to which this policy strongly relates.

The model standard access contract (MAC) includes some clauses related to assignment and relocation. Western Power considered that there was significant overlap between the provisions in the MAC and the provisions that a TRP is required to contain under sections 5.18 to 5.24 of the Code. For this reason, Western Power has removed the provisions from the ETAC and incorporated them into the TRP only, to avoid any duplication or inconsistency arising between the ETAC and the TRP.

9.3.1 Bare transfer

Section 5.18 of the Code requires that the TRP permits a user to make a 'bare transfer' without Western Power's consent. MAC clause 15.8 (a) has been effectively replicated in the TRP. A provision preventing a bare transferee from making a further bare transfer has also been included to prevent a possibly unending chain of bare transfers.

9.3.2 Assignment other than a bare transfer

Sections 5.19 and 5.20 of the Code require that the TRP permits users to assign their access rights, other than as a bare transfer, subject to Western Power's reasonable conditions. Clause 5 of the TRP has effectively made it a pre-condition to Western Power's consent to any assignment that the assigned ETAC contains identical terms to the ETAC terms (excluding capacity) between the assignor and Western Power.

This provides clarity for an assignee in relation to its obligations under the ETAC and ensures Western Power's security requirements are maintained.

9.3.3 Relocation

Section 5.21 of the Code requires that the TRP permits users to perform a 'relocation' subject to Western Power's reasonably conditions. Section 5.22 requires a service provider to withhold its consent to a relocation where providing consent would impede the service provider's ability to provide a covered service sought in an access application.

Relocation has been removed from the ETAC and placed in Western Power's transfer and relocation policy, as envisaged by section 5.21 of the Code, and to avoid conflict between the contract and the policy (thus providing contractual certainty under the ETAC).

Western Power considers the only effective means of complying with section 5.22 is to require a user who wants to 'relocate' capacity to decrease capacity at the first connection point in accordance with its contract and increase it at another point in accordance with the contract, which means making an application under the AQP and entering the queue. Only by using the queuing provisions under the AQP can Western Power ensure that its ability to provide covered services to an applicant is not impeded.

This means that if an applicant is currently in the queue, and capacity becomes available because of the decrease by the relocating user at a connection point, then that applicant has first access to that capacity under the first-come, first-served principle. In general, the mechanisms in the CCP will ensure that costs are shared fairly. However, if there is insufficient network capacity to provide the requested services to both parties, the first-come, first-served principle will apply.

9.4 Concluding comments

The discussion presented in section 9.3 demonstrates that Western Power's transfer and relocation policy complies with the relevant Code provisions. A copy of Western Power's transfer and relocation policy is provided in Appendix 2 of the access arrangement.

10 Trigger events

10.1 Code provisions relating to *trigger events*

The following Code provisions are relevant to the definition of trigger events:

> **"trigger event"** is a set of one or more circumstances specified in an *access arrangement* under section 5.1(l)(ii), the occurrence of which requires a *service provider* to submit *proposed revisions* to the *Authority* under section 4.37.

4.37 If an *access arrangement*:

(a) specifies one or more *trigger events*; and

(b) the conditions of a *trigger event* are satisfied, then:

(c) as soon as practicable, the *service provider* must notify the *Authority* that the conditions of the *trigger event* are satisfied; and

(d) the *service provider* must submit *proposed revisions* to the *Authority* by the *designated date*; and

(e) the *Authority* must consider the *proposed revisions* in accordance with sections 4.46 to 4.52.

5.1(l) An *access arrangement* must include provisions dealing with:

(i) the submission of *proposed revisions* under sections 5.29 to 5.33; and

(ii) *trigger events* under sections 5.34 to 5.36.

5.34 If it is consistent with the *Code objective* an *access arrangement* may specify one or more *trigger events*.

5.35 To avoid doubt, under section 5.34, an *access arrangement* may specify a *trigger event* which was not proposed by the *service provider*.

5.36 Before determining whether a *trigger event* is consistent with the *Code objective* the *Authority* must consider:

(a) whether the advantages of including the *trigger event* outweigh the disadvantages of doing so, in particular the disadvantages associated with decreased regulatory certainty; and

(b) whether the *trigger event* should be balanced by one or more other *trigger events*.

{Example: The *service provider* may wish to include a *trigger event* allowing it to reopen the *access arrangement* if actual *covered service* consumption is more than x% below forecast. However, if the *Authority* were minded to allow such a *trigger event*, it may also require the inclusion of a complementary *trigger event* requiring the *service provider* to reopen the *access arrangement* if *covered service* consumption is more than y% above forecast.}

15.3 Without limiting sections 5.34 to 5.36, an *access arrangement* for a *covered network* which forms part of the *SWIS* may specify as *trigger events* one or more events or sets of circumstances in connection with the arrangements established under Part 9 of the Act [Note: Part 9 relates to the development of market rules for the wholesale supply of electricity].

15.4 Without limiting sections 5.34 to 5.36, an *access arrangement* for a *covered network* may specify as *trigger events* one or more events or sets of circumstances in connection with changes to the thresholds for contestability with respect to electricity supply.

10.2 Considerations guiding the definition of *trigger events*

In considering how Western Power might define trigger events, it is important to consider how the Code addresses other examples of risk and uncertainty. In particular, the Code also provides for the recovery of costs arising from:

- unforeseen events (section 6.6 of the Code);
- technical rule changes (section 6.9); and
- the investment adjustment mechanism – defined differences between forecast and actual capital expenditure (sections 6.13 to 6.18).

Each of these provisions addresses issues of risk, which might otherwise be covered by a trigger event. It is noteworthy that the above three mechanisms for addressing risk do not require a re-opening of the access arrangement. In other words, the likely consequences arising from unforeseen events; technical rule changes; or capital expenditure forecasting errors are not considered sufficiently material to warrant a formal revision to the access arrangement. These observations are important because they provide guidance in defining the scope of trigger events.

In light of the foregoing discussion, Western Power considers that:

- trigger events should cover circumstances that potentially require material changes to the access arrangement (and also warrant the detailed review and approval process that must be conducted by the Authority under section 4.52); and
- trigger events should not cover matters that are addressed by the mechanisms covering unforeseen events; technical rule changes; and investment adjustments.

In addition to the above, it is also noted that the Code makes specific references to the development of the market rules and contestability as being two possible areas where trigger events could be defined (sections 15.3 and 15.4 respectively).

10.3 Provisions enabling the Authority to re-open an access arrangement

In addition to the trigger event provisions, the Code also provides for the Authority to revise the access arrangement in the event that significant unforeseen developments have occurred. Specifically, section 4.38(b)(ii) states the Authority may by notice to a service provider vary the price control or pricing methods in an access arrangement before the next revisions commencement date, but only if the Authority determines that significant unforeseen developments have occurred that:

- are outside the control of the service provider; and

- are not something that the service provider, acting in accordance with good electricity industry practice, should have been able to prevent or overcome; and

- have an impact so substantial that the Authority considers that the advantages of making the variation before the end of the access arrangement period outweigh the disadvantages, having regard to the impact of the variation on regulatory certainty.

It is noted that apart from the guidance provided in section 4.38(b)(ii) “unforeseen developments” is not a defined term in the Code. In essence, its apparent effect is to give the Authority an opportunity to revise the access arrangement, whether or not the event is captured within the definition of a trigger event. On this interpretation, narrowing the scope of trigger events does not necessarily restrict the Authority’s ability to revise the access arrangement if a significant unforeseen development arises.

The notion of an access arrangement being re-opened as a result of the occurrence of a significant unforeseen development seems very consistent with the Code objective. However, it is not clear whether section 4.38(b)(ii) of the Code would provide a reasonable means to Western Power to seek a re-opening of the access arrangement if the company considered that a significant unforeseen development had occurred. Indeed, it is noteworthy that at least one other Australian regulator has stated that: “only TNSPs [the regulated companies] would be able to propose that the revenue cap be reopened” [62].

On the basis of the reasoning adopted in the ACCC’s December 2004 Decision on its Statement of Principles, and given the fact that section 4.38(b)(ii) has been included in the Code, it would seem reasonable for Western Power to seek to define a trigger event in a way that encompasses the “significant unforeseen developments” referred to in section 4.38(b)(ii). This would provide both Western Power and the Authority with an ability to initiate a re-opening of an access arrangement if a significant unforeseen development occurs.

10.4 Identification of proposed *trigger events*

As noted already, section 5.34 states that if it is consistent with the Code objective an access arrangement may specify one or more trigger events. The Code objective (set out in section 2.1) is to:

> promote the economically efficient:
>
> (a) investment in; and
>
> (b) operation of and use of,
>
> *networks* and *services* of *networks* in Western Australia in order to promote competition in markets upstream and downstream of the *network*s.

On this basis, Western Power proposes the inclusion of a trigger event (defined below) on the basis that:

[62] Decision 7.2 of the ACCC’s Statement of Principles for the Regulation of Electricity Transmission Revenues, 8 December 2004.

- The inclusion of the trigger event reduces the company's financial exposure to defined events that are beyond its control and which, if eventuated, would have a material impact on the financial performance of the company.

- The company could therefore reasonably claim that if the proposed trigger event provision were not allowed either:

    - network prices would need to reflect the higher risks borne by shareholders (which would be less conducive to efficient use of the network); or

    - investment in networks would be lower than would otherwise be the case.

- Either of the two outcomes listed immediately above would be inconsistent with the Code objective, and therefore the inclusion of the proposed trigger event in the company's access arrangement is warranted, and meets the requirements of section 5.34.

Based on the foregoing discussion, in its revised proposed access arrangement Western Power proposed to define a trigger event in section 8.1(a) as follows:

> Any significant unforeseen development which has a materially adverse impact on the service provider and which is:
>
> (i) outside the control of the service provider; and
>
> (ii) not something that the service provider, acting in accordance with good electricity industry practice, should have been able to prevent or overcome; and
>
> (iii) an event the impact of which is so substantial that the Authority considers that the advantages of making the variation before the end of the access arrangement period outweigh the disadvantages, having regard to the impact of the variation on regulatory certainty.

In paragraph 852 of the Final Decision, the Authority comments on section 8.1(a)(iii) as follows:

> "Section 8.1(a)(iii) of the revised proposed access arrangement contemplates a role of the Authority in determining whether the "impact" of an event is sufficiently "substantial" that the trigger event should operate. The Authority is generally of the view that an access arrangement should not create a role for the Authority that is not otherwise a statutory role or function. Section 4.37(c) of the Access Code provides that the service provider must notify the Authority that a trigger event has occurred, implying that the Service Provider determines whether a trigger event has occurred without seeking the Authority's view. Accordingly, the Authority does not have a role of the type contemplated by clause 8.1(a)(iii) of the revised proposed access arrangement."

In light of the above comments, the Authority's Final Decision includes Required Amendment 12, which states:

> "Clause 8.1(a)(iii) of the revised proposed access arrangement should be amended to remove the role of the Authority in determining whether a trigger event has occurred."

Western Power accepts the Authority's Final Decision Required Amendment 12, and has amended the proposed definition of trigger events in the access arrangement accordingly.

In addition to addressing the Final Decision Required Amendment 12, Western Power has also included a provision in the access arrangement relating to the designated date, as required by section 4.37(d) of the Code, which was overlooked in Western Power's previous submissions and in the Final Decision. This provision requires Western Power to submit its proposed revision to the access arrangement within 30 business days after a trigger event has occurred. The access arrangement also provides for Western Power to address issues of cost uncertainty in any proposed revision to the access arrangement submitted after the occurrence of a trigger event.

11 Supplementary matters

11.1 Introduction

The access arrangement is required to include provisions dealing with supplementary matters under section 5.27 and 5.28 of the Code. In general, supplementary matters will be dealt with in a manner consistent with the Wholesale Electricity Market Rules and the Metering Code.

This section examines the relevant provisions of the Code and related instruments, and explains Western Power's proposed treatment of each of the supplementary matters.

11.2 Code provisions

As already noted, sections 5.27 to 5.28 of the Code set out the provisions relating to supplementary matters as follows:

> 5.27 Each of the following matters is a "supplementary matter":
>
> (c) balancing; and
>
> (d) line losses; and
>
> (e) metering; and
>
> (f) ancillary services; and
>
> (g) stand-by; and
>
> (h) trading; and
>
> (i) settlement; and
>
> (j) any other matter in respect of which arrangements must exist between a *user* and a *service provider* to enable the efficient operation of the *covered network* and to facilitate *access* to *services*, in accordance with the *Code objective*.
>
> 5.28 An *access arrangement* must deal with a *supplementary matter* in a manner which:
>
> (a) to the extent that the *supplementary matter* is dealt with in:
>
> (i) an enactment under Part 9 of the Act; or
>
> (ii) the 'market rules' as defined in section 121(1) of the Act,
>
> applying to the *covered network* -- is consistent with and facilitates the treatment of the *supplementary matter* in the enactment or market rules; and
>
> (b) to the extent that the *supplementary matter* is dealt with:
>
> (i) in a *written law* other than as contemplated under section 5.28(a); and

(ii) in a manner which is not inconsistent with the requirement under section 5.28(a) to the extent that it applies to the *covered* network,

is consistent with and facilitates the treatment of the *supplementary matter* in the *written law*; and

(c) otherwise -- in accordance with the *technical rules* applying to the *covered network* and the *Code objective*.

11.3 Related instruments

11.3.1 Market Rules

The Wholesale Electricity Market Rules (5 October 2004) are made under Part 9 of the Electricity Industry Act 2004, and govern the market and the operation of the South West Interconnected System, including the wholesale sale and purchase of electricity, Reserve Capacity, and Ancillary Services.

The objectives of the market are:

(a) to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West Interconnected System;

(b) to encourage competition among generators and retailers in the South West Interconnected System, including by facilitating efficient entry of new competitors;

(c) to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions;

(d) to minimise the long-term cost of electricity supplied to customers from the South West interconnected system; and

(e) to encourage the taking of measures to manage the amount of electricity used and when it is used.

The Market Rules are available at:
http://www.eriu.energy.wa.gov.au/files/wholesale/gg177.pdf

11.3.2 Metering Code

The Electricity Industry Metering Code 2005 (Metering Code) is made under Division 7 of Part 2 of the Electricity Industry Act 2004, and is issued by the Authority. The Metering Code contains provisions governing the metering of the supply of electricity including:

- the provision, operation and maintenance of metering equipment; and
- ownership of and access to metering data.

11.4 Proposed treatment of supplementary matters

Having regard to the respective objectives and purposes of the Code, the Metering Code and the Market Rules, Western Power proposes to adopt the approaches detailed below in relation to supplementary matters.

11.4.1 Balancing

Balancing requirements under the access arrangement shall be in accordance with the Market Rules.

11.4.2 Line Losses

Requirements for the treatment of line losses under the access arrangement shall be in accordance with the Market Rules.

11.4.3 Metering

Metering requirements under the access arrangement shall be in accordance with the Metering Code.

11.4.4 Ancillary Services

Requirements for the treatment of ancillary services under the access arrangement shall be in accordance with the Market Rules.

11.4.5 Stand-by

The requirement for generation stand-by has been superseded by the Market Rules and is no longer applicable.

11.4.6 Trading

Trading requirements under the access arrangement shall be in accordance with the Market Rules.

11.4.7 Settlement

Settlement requirements under the access arrangement shall be in accordance with the Market Rules.

11.4.8 Any other matters

Western Power is not aware of any other matter in respect of which arrangements must exist between a user and a service provider to enable the efficient operation of the covered network and to facilitate access to services, in accordance with the Code objective.

Appendices

Appendix 1: *Benchmarking Western Power's Electricity Distribution Operations and Maintenance and Capital Expenditure*: Report Prepared for Western Power Corporation by Meyrick and Associates Pty Ltd, 3 February 2005

Appendix 2: *Western Power: Network cost analysis & efficiency indicators*: Report by Benchmark Economics, July 2005

Appendix 3: *Weighted Average Cost of Capital*: Report prepared by KPMG, May 2005

Appendix 4: *A Framework for Quantifying Estimation Error in Regulatory WACC*: Report for Western Power in relation to the Economic Regulation Authority's 2005 Network Access Review, prepared by Strategic Finance Group Consulting, May 2005

Appendix 5: *Weighted Average Cost of Capital*: Further Report prepared by KPMG, May 2006.

Appendix 6: Western Power’s capital and operating expenditure program for the South West Interconnected Networks

Appendix 7: Application and queuing policy - Demonstration of Code compliance

Appendix 8: Capital contributions policy - Demonstration of Code compliance

Appendix 9: Standard Electricity Transfer Access Contract - Demonstration of Code compliance

Appendix 10: Asset Valuation Report, prepared by ERIU

Appendix 11: Western Power Revised Access Arrangement Real Pre-tax Model