PREFACE

The Electricity Corporation (trading as "Western Power" and hereinafter referred to as the "Corporation") was established on 1 January 1995 by the *Electricity Corporation Act 1994 (WA)* (the "Act").

The Act requires that the Corporation provide open access to capacity in its electricity transmission and distribution networks. For the electricity transmission networks, open access to capacity has been provided since 1 January 1997.

This paper outlines the methodology that has been adopted to formulate the prices for the network services provided under open access to the transmission networks, and nominates the prices that shall apply from 1 July 1999 to 30 June 2000. It also documents how prices will be redetermined in subsequent years.

It is expected that open access will facilitate competition in the energy industry which will in turn provide incentives to improve efficiency. It will provide opportunities for independent generators to contract with independent loads by utilising spare and new transmission network capacity and the various ancillary services provided by the Corporation. This will not preclude independent generators from contracting to supply energy to the Corporation.

At this stage it is not planned to introduce a market pool as used in the National Electricity Market in Eastern Australia. Trading in Western Australia is via contractual arrangement between users of the networks who approach the Corporation for network access.

Generators and associated loads will be required to balance energy taken from the network with energy injected. In addition, generators will be required to supply additional energy to the system to cover network losses. Unless otherwise arranged, there should be zero net interchange of energy with the Corporation. Balancing errors will be settled in accordance with the energy prices published in this paper. However users may contract to purchase standby power from the Corporation or other generator users.

This paper has been prepared in accordance with the guiding principles of the Act and *Electricity Transmission Regulations 1996 ("Regulations")*, and shall therefore be interpreted within the context of that Act and those regulations.

The subject matter of this document has been presented in considerable detail to provide users with a degree of certainty on prices and their movement with time. It provides existing and potential users with the information necessary to calculate the access charges likely to apply under reasonable circumstances, and also to be able to establish how the access prices are determined.

This document is divided into two major areas: sections 1 to 4; and the appendices.

Sections 1 to 4 provide the general terms and conditions pertaining to the determination, formulation and application of the prices and charges for access services.

The formulation of energy balancing, standby generation capacity and excess network usage charges is covered by the Regulations. This information is therefore not repeated, and the Regulations should be referred to for details. However, to assist users, sample calculations based on the formulas in the Regulations are provided in Appendix L.

The appendices provide price schedules and supporting information necessary to assist users in understanding the practical application of the pricing principles:

Appendix A gives definitions of the terms used in this document.

Appendix B identifies the principal elements of the transmission network, and details their subdivision into the various network asset categories which form the basis for charges.

Appendix C provides the structure of the charges and the principles for their application.

Appendices D to G give the schedules of prices, their method of determination, triennial review and annual adjustment.

Appendices H and I provide the loss factors and their adjustment methodology. The loss factors provided in this document are those in the Regulations.

Appendix J gives the categories of standby generation services available, and provides the charge calculations applicable to the use of these services.

Appendices K and L provide example calculations of network, ancillary services, energy balancing, excess standby generation capacity, and excess network usage charges.

Appendix M provides components of transmission network charges and a summary of charges to loads and generators.

CONTENTS

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1. General

1.1 Purpose

This paper sets out:

(a) the manner in which prices for ***access services*** are determined; and

(b) the manner in which those prices are used to calculate charges for ***access services***.

1.2 Background

1.2.1 ***Western Power*** was established on 1 January 1995 by the ***EC Act***. ***Western Power*** was formed to take over the electricity business of the State Energy Commission of Western Australia.

1.2.2 The ***EC Act*** requires ***Western Power*** to make available access to ***electricity transmission capacity***. ***Western Power*** makes this access available by providing ***access services***.

1.2.3 The procedures to be followed by ***Western Power*** in processing applications for the provision by ***Western Power*** of ***access services*** and certain of the terms and conditions on which ***access services*** are provided by ***Western Power*** to a ***user*** are specified in the ***Transmission Regulations***. Other terms and conditions are to be found in the ***access agreements*** between ***Western Power*** and the ***user***.

1.2.4 Under clause 6(2) of Schedule 5 to the ***EC Act***, ***Western Power*** must adopt pricing methods which have as their objective the recovery within a reasonable time from ***users*** of:

(a) the costs of maintaining and providing ***electricity transmission capacity***;

(b) the capital investment in the ***electricity transmission network***; and

(c) a reasonable rate of return on that capital investment.

1.2.5 Under clause 6(3) of Schedule 5 to the ***EC Act***, ***Western Power*** must:

(a) prepare and make publicly available a schedule of indicative prices for access to ***electricity transmission capacity*** which provides sufficient detail to allow existing or prospective ***users*** to calculate the electricity transmission prices likely to apply in any reasonable circumstances; and

(b) make publicly available such details of its pricing methods as are sufficient to indicate to existing or prospective ***users*** how prices for that access are established.

1.2.6 This document has been prepared, in part, to satisfy ***Western Power's*** obligations under clause 6(3) of Schedule 5 to the ***EC Act***.

1.2.7 As well, ***access agreements*** entered into by ***Western Power*** will provide that the prices and charges for the ***access services*** provided under the ***access agreement*** are to be determined in accordance with this document.

1.3 Timing

The price schedule set out in Appendix D applies until 30 June 2000 and will be replaced prior to that time with a new appendix calculated by adjusting it according to the methodology set out in Appendix F. Otherwise, this document applies for the period commencing at the start of 1 July 1999 and will continue to apply until it is amended or replaced by ***Western Power***.

1.4 Interpretation

1.4.1 In this document, unless the contrary intention appears:

(a) a word or phrase set out in **Appendix A** has the meaning set out opposite that word or phrase; and

(b) a word or phrase defined in the ***EC Act*** or the ***Transmission Regulations*** has the meaning given in that Act or those regulations (as the case requires), unless redefined in **Appendix A**.

1.4.2 This document must be interpreted in accordance with the rules of interpretation set out in regulation 4 of the ***Transmission Regulations***, unless the contrary intention appears.

1.5 Preparation

This document has been prepared by ***Western Power*** in consultation with the Office of Energy.

1.6 Right of Access

This document and the prices contained herein do not confer a right on any ***user*** or prospective ***user*** to access to ***electricity transmission capacity***. The rights and obligations of a ***user*** or prospective ***user*** in relation to access to ***electricity transmission capacity*** are set out in the ***EC Act***, ***Transmission Regulations*** and the Technical Code made under regulation 26 of the ***Transmission Regulations***.

1.7 Capital Contributions

In addition to the prices contained herein, ***Western Power*** may require a ***user*** or prospective ***user*** to make a capital contribution for ***access services*** in accordance with regulation 12 of the ***Transmission Regulations***.

1.8 Past Capital Contributions

Where a ***user*** has previously made an explicit, quantifiable capital contribution towards the cost of establishing clearly defined, dedicated network assets, a discount may apply to the network charge.

2. Structure of Charges

2.1 The charges which a ***user*** shall pay ***Western Power*** for the provision of ***access services*** in respect of each of its ***connections*** are as follows:

(a) a connection charge for the provision of ***connection services***;

(b) a use of system charge for the provision of ***use of system services***;

(c) a common service charge for the provision of ***common services***;

(d) the following ancillary services charges for the provision of ***ancillary services***:

(1) a spinning reserve charge;

(2) a post-trip management charge;

(3) a control system service charge (included in the connection charge);

(4) an energy balancing charge;

(e) a capital contribution in relation to any ***augmentation*** or an ***exempt connection***;

(f) excess standby generation capacity and excess network usage charges; and

(g) metering service charge for any connection requiring tariff metering installation.

2.2 If the ***connection*** at which ***connection services*** are provided is an ***existing connection***, then the connection charge for the provision of those ***connection services*** is determined in accordance with this document.

2.3 If the ***connection*** at which ***connection services*** are provided is not an ***existing connection***, then the connection charge for the provision of those ***connection services*** is determined in accordance with the relevant ***access agreement***.

2.4 The following charges are determined in accordance with this document:

(a) the use of system charge for the provision of ***use of system services***;

(b) the common service charge for the provision of ***common services***;

(c) the ancillary services charge for the provision of ***ancillary services***;

(d) the connection charge for the provision of ***connection services.***

2.5 A capital contribution is determined in accordance with clause 12 of the ***Transmission Regulations*** and the relevant ***access agreement***;

2.6 Energy balancing, excess standby generation capacity and excess network usage charges are determined in accordance with part 4 of the ***Transmission Regulations***; and

2.7 Metering service charge is determined in accordance with the Electricity Distribution Access Pricing and Charges paper.

3 Price Schedules

3.1 The price schedule (called the "***Price Schedule***") for a ***financial year*** is a schedule setting out the following matters in respect of that ***financial year***:

(a) the connection price (expressed in $) in respect of each ***existing connection***;

(b) the use of system price (expressed in $/kW) in respect of each ***existing connection***;

(c) the common service price (expressed in $/kW);

(d) the spinning reserve price (expressed in $/hour) (which may be different for ***generating units*** of different sizes);

(e) the following post-trip management prices:

(1) the generation startup price (expressed in $/MW);

(2) the out of merit generation price (expressed in $/MWh); and

(3) the load shedding price (expressed in $/MWh);

(f) the control system service price (expressed in $/RTU) (which is included in the connection charge);

(g) the following energy balancing prices:

(1) the energy balancing service price (expressed in $/Connection/Month/Access Agreement);

(2) the half hourly out of balance prices (sell) (expressed in ¢/kWh) for half hours falling in the following time zones:

(ii) peak summer;

(iii) peak winter;

(iv) peak autumn/spring;

(v) shoulder weekdays;

(vi) shoulder weekends; and

(vii) off peak;

(3) the half hourly out of balance prices (buy) (expressed in ¢/kWh) for half hours falling in the following time zones:

(i) peak summer;

(ii) peak winter;

(iii) peak autumn/spring;

(iv) shoulder weekdays;

(v) shoulder weekends; and

(vi) off peak;

(4) the out of balance price (sell) (expressed in ¢/kWh);

(5) the out of balance price (buy) (expressed in ¢/kWh); and

(6) the excess standby generation capacity price (expressed in $/kW); and

(h) the excess network usage factor (expressed as a rate).

3.2 The prices to be used in calculating the charges referred to in clauses 2.1(a) (in respect of ***existing connections***), (b), (c), (d) and (f) in respect of a ***financial year*** are those set out in the ***Price Schedule*** for that ***financial year***.

3.3 The ***Price Schedule*** for the ***financial year*** ending on 30 June 2000 is set out in **Appendix D**.

3.4 The prices set out in the ***Price Schedule*** in **Appendix D** have been determined by applying the methodology set out in **Appendix E** consistently with clause 6(2) of Schedule 5 to the ***Act***.

3.5 ***Western Power*** intends to make the ***Price Schedule*** for a subsequent ***financial year*** publicly available on or before 30 June immediately preceding the start of that subsequent ***financial year***.

3.6 A price set out in the ***Price Schedule*** for a ***financial year*** after the financial year ending 30 June 2000 will be determined by applying the methodology for adjusting that price set out in **Appendix E** or **F** or, if no methodology for adjusting that price is set out in **Appendix F**, will be consistent with the ***Act***.

3.7 ***Western Power*** may amend the ***Price Schedule*** for a ***financial year*** at any time prior to the end of that ***financial year*** in order to correct any errors.

3.8 If, during a ***financial year***, an ***exempt connection*** which is not contemplated by the ***Price Schedule*** for the ***financial year*** is commissioned, then the use of system price in respect of the ***exempt connection*** for the ***financial year*** is the same as the use of system price in respect of the ***connection*** located electrically closest to the ***exempt connection***.

4 Charges

4.1 Connection Charge *for Existing Connection (Entry & Exit Points)*

4.1.1 Subject to clause 4.1.2, the connection charge payable by a ***user*** for the ***connection services*** provided in respect of each of the ***user's connections*** that is an ***existing connection*** during a month is determined by applying the following formula:

$$CC = \frac{ACP}{12}$$

where:

CC (in $) is the monthly connection charge payable by a user for the connection services provided to that user by the existing connection; and

ACP (in $) is the connection price for the ***connection*** set out in the ***Price Schedule*** for the ***financial year*** in which the month falls.

4.1.2 If an ***existing connection*** is used to provide ***connection services*** to more than one ***user*** during a month, then the connection charge payable by each of those ***users*** in respect of that ***existing connection*** during the month is determined by applying the following formula:

$$CC = \frac{ACP \times LD}{12 \times TLD}$$

where:

CC (in $) is the monthly connection charge payable by a user for the connection services provided to that user by the existing connection;

ACP (in $) is the connection price for the ***connection*** set out in the ***Price Schedule*** for the ***financial year*** in which the month falls;

LD (in kW) is the higher of the user's contract maximum demand and declared sent-out capacity;

TLD (in kW) is the sum of all the LD's of the users supplied by the existing connection.

4.1.3 A connection charge is a fixed charge and is payable by a ***user*** irrespective of the extent to which the relevant ***connection*** is used.

4.2 Use of System Charges: Entry Points

4.2.1 The use of system charges payable by a ***user*** for the ***use of system services*** provided in respect of each of the ***user's connections*** which is an ***entry point*** during a month is determined by applying the following formula:

$$USC = \frac{USP \times DC}{12}$$

where:

USC (in $) is the use of system charge for the month in respect of the ***connection***;

USP (in $/kW) is the use of system price for the ***connection*** set out in the ***Price Schedule*** for the ***financial year*** in which the month falls; and

DC (in kW) is the aggregate ***declared sent-out capacity*** of the ***generating units*** connected at that ***connection***.

4.2.2 The use of system charge for an ***entry point*** is a fixed charge and is payable by a ***user*** irrespective of the ***user's*** use of the ***electricity transmission network***.

4.3 Use of System Charges: Exit Points

4.3.1 The use of system charge payable by a ***user*** for the ***use of system services*** provided in respect of each of the ***user's connections*** that is an ***exit point*** during a month is determined by applying the following formula:

$$USC = \frac{USP \times CMD}{12}$$

where:

USC (in $) is the use of system charge for the month in respect of the ***connection***;

USP (in $/kW) is the use of system price for the ***connection*** set out in the ***Price Schedule*** for the ***financial year*** in which the month falls.

CMD (in kW) is:

(a) subject to paragraph (b), the contract maximum demand in respect of the connection; and

(b) if the connection is a standby connection for the whole of the month and the month falls entirely within a standby term in respect of the standby connection, then the normal CMD in respect of the connection.

4.3.2 The use of system charge for an ***exit point*** is a fixed charge and is payable by a ***user*** irrespective of the ***user's*** use of the ***electricity transmission network.***

4.4 Common Service Charges: Exit Points

4.4.1 For the purposes of this clause, an applicable ***connection*** is a ***connection*** which is either:

(a) an ***exit point***; or

(b) an ***entry point*** to which ***Western Power*** may be required by the ***user*** to deliver ***standby power***.

4.4.2 The common service charge payable by a user for the ***common services*** provided in respect of an applicable ***connection*** during a month is determined by applying the following formula:

$$CSC = \frac{CMD \times CSP}{12}$$

where:

CSC (in $) is the common service charge for the month in respect of the ***connection***;

CMD (in kW) is:

(a) subject to paragraph (b), the contract maximum demand in respect of the connection; and

(b) if the connection is a standby connection for the whole of the month and the month falls entirely within a standby term in respect of the standby connection, then the normal CMD in respect of the connection.

CSP (in $/kW) is the common service price set out in the ***Price Schedule*** for the ***financial year*** in which the month falls.

4.4.3 The common service charge for an ***exit point*** is a fixed charge and is payable by a ***user*** irrespective of the ***user's*** use of the ***electricity transmission network***.

4.5 Network Standby Access

4.5.1 An ***access agreement*** may provide that the ***user*** is required to pay a combined use of system charge and common service charge for standby access in respect of a ***connection*** specified in the ***access agreement*** in accordance with this clause 4.5, but only if the requirements set out in clauses 4.5.2 and 4.5.3 are satisfied.

4.5.2 The combined use of system charge and common service charge only applies for standby access in respect of a ***connection*** if either of the following requirements are satisfied:

(a) there is a feeder at the ***connection*** dedicated to standby access (in which case, for the purposes of calculating the load factor of ***standby power***, all energy use recorded on meters installed on the feeder is regarded as having been taken for standby purposes); or

(b) there is no feeder at the ***connection*** dedicated to standby access, but an ***embedded generator*** with an aggregate generation capacity of more than 10 MW is connected to the ***electricity transmission network*** at the ***connection*** (in which case, for the purpose of calculating the load factor of the ***standby power***, the difference between the half hourly energy use recorded and the half hourly energy expected to be used based on the ***normal CMD*** in respect of the ***connection*** is regarded as having been taken for standby purposes).

4.5.3 The combined use of system charge and common service charge applies for standby access in respect of a ***connection*** if all of the following requirements apply to the satisfaction of ***Western Power*** in respect of the ***connection***:

(a) the period for which standby access is provided under the ***access agreement*** in respect of the ***connection*** (in this clause called the "**standby period**") is not less than 3 consecutive months;

(b) if the standby period is less than 12 months and extends more than 2 years from the date of the ***access application*** which resulted in the ***access agreement*** in respect of the ***connection***, then the ***access agreement*** provides that the ***user*** must elect for one of the applicable options referred to in clause 4.5.4 to occur in the event that:

(1) another person makes an ***access application***;

(2) there is not sufficient ***spare capacity*** to provide the ***access services*** requested in the ***access application***;

(3) there would have been sufficient ***spare capacity*** to provide the ***access services*** requested in the ***access application*** if ***Western Power*** did not have to provide the standby access in respect of the ***connection***; and

(4) ***Western Power*** requires the ***user*** to make an election.

(c) if the standby period is not at least 12 consecutive months, then the ***access agreement*** in respect of the ***connection*** provides that the ***user*** will pay an administration charge to ***Western Power*** calculated in accordance with the ***access agreement***; and

(d) the ***access agreement*** in respect of the ***connection*** gives ***Western Power*** the right to disconnect, interrupt or curtail the provision of ***standby power*** to the ***user*** before other ***users*** during shortages of ***electricity transmission capacity*** and provides for the ***user*** to pay for the cost of installing or modifying equipment to enable ***Western Power*** to do this.

4.5.4 The options for the purposes of clause 4.5.3(b) are as follows:

(a) that the ***connection*** ceases to be a ***standby connection*** for the purpose of calculating use of system charges under clause 4.3 and common service charges under clause 4.4 for the remainder of the term of the ***access agreement***;

(b) where the ***access agreement*** relates solely to standby access, that the ***access agreement*** terminates; or

(c) where the ***access agreement*** relates to standby access and the provision of other ***access services***, that standby access ceases to be provided under the ***access agreement***.

4.5.5 Subject to clause 4.5.6, the combined use of system charge and common service charge payable by a ***user*** for the standby access provided in respect of each of the ***user's standby connections*** during a month (in this clause called the "**relevant month**") is determined as follows:

(a) unless paragraph (b) or paragraph (c) applies to the relevant month, by applying the following formula:

$$UCC = (USP + 0.25 * CSP) * \frac{SCMD}{12};$$

(b) if ***Western Power*** estimates that the load factor of ***standby power*** taken and to be taken by the ***user*** at the ***connection*** during the ***standby term*** within which the relevant month falls is, or is likely to be, greater than 0.15, then by applying the following formula:

$$UCC = (USP + CSP) * \frac{SCMD}{12} + (0.75 * CSP * SCMD * \frac{N}{12})$$

(c) if paragraph (b) applies to a preceding month which falls in the same ***standby term*** as the relevant month, then by applying the following formula:

$$UCC = (USP + CSP) * \frac{SCMD}{12}$$

where:

UCC (in $) is the combined use of system charge and common service charge payable by the ***user*** for the relevant month for standby access in respect of the ***connection***;

USP (in $/kW) is the use of system price for the ***connection*** set out in the ***Price Schedule*** for the ***financial year*** in which the relevant month falls;

CSP (in $/kW) is the common service price for the ***connection*** set out in the ***Price Schedule*** for the ***financial year*** in which the relevant month falls;

SCMD (in kW) is the ***standby CMD*** in respect of the ***connection***; and

N (a number) is the number of preceding months falling within the ***standby term*** to which paragraph (a) applies.

4.5.6 Clause 4.5.5 does not apply in the case of a ***standby connection*** in respect of a month if the ***connection*** has not been a ***standby connection*** for the whole of the month or the month does not fall entirely within a ***standby term*** in respect of the ***standby connection***.

4.5.7 In making its estimate under clause 4.5.5(b), ***Western Power*** must take into account the actual load factor of ***standby power*** taken by the ***user*** at the ***connection*** during the relevant month and each of the preceding months which fall within the same ***standby term***.

4.5.8 The combined use of system charge and common service charge for a ***user*** for a ***connection*** under this clause 4.5 is a fixed charge and is payable by the ***user*** irrespective of the ***user's*** use of the ***electricity transmission network***.

4.5.9 ***Western Power*** is taken to be providing standby access in respect of a ***connection*** if some or all of the ***use of system services*** and ***common services*** provided by ***Western Power*** in respect of the ***connections*** are utilised in whole or in part to enable the transfer of ***standby power*** to the ***connection***.

4.6 Use of System and Common Service Charges: *Embedded Generators*

4.6.1 Notwithstanding clauses 4.2, 4.3, 4.4 and 4.5, if a ***connection*** is both an ***entry point*** and an ***exit point*** (for example because an ***embedded generating unit*** is connected to the ***electricity transmission network*** at that ***connection***), then the use of system charge and common service charge payable by the relevant ***user*** for the shared network services provided in respect of that ***connection*** during a month is the higher of:

(a) the use of system charge calculated under clause 4.2 in respect of that ***connection*** for that ***user*** for that month; and

(b) the total of the use of system charge and the common service charge calculated under clauses 4.3, 4.4 and 4.5 in respect of that ***connection*** for that ***user*** for that month.

4.6.2 The use of system charge and the common service charge for an ***embedded generator*** is a fixed charge and is payable by the ***user*** irrespective of the ***user's*** use of the electricity transmission network.

4.7 Ancillary Services Charges

4.7.1 The spinning reserve charge payable by a ***user*** for ***spinning reserve*** in respect of each of the ***user's connections*** that is an ***entry point*** for a month is determined by applying the following formula:

$$SRC = \sum_{i=1}^{i=n} \left(T_i \ x \ SRP_i \right)$$

where:

SRC (in $) is the spinning reserve charge for the month in respect of the ***connection***;

T_i (in hours) is the length of time that the ***generating unit***$_i$ is synchronised to the ***electricity transmission network*** during the month;

SRP_i (in $/hour) is the spinning reserve price set out in the ***Price Schedule*** for the ***financial year*** in which the month falls applicable to ***generating units*** with a maximum net MW output equal to the maximum net MW output of the ***generating unit*** $_i$***;***

the variable "$_i$" represents a ***generating unit*** (including an ***embedded generating unit***) connected at the ***connection***; and

the variable "$_n$" represents the number of ***generating units*** (including ***embedded generating units***) connected at the ***connection***.

4.7.2 The post-trip management charge payable by a ***user*** for ***post trip management services*** in respect of each of the ***user's connections*** which is an ***entry point*** for a month is the sum of the amounts, where an amount (in $) is determined each time a ***generating unit*** connected at that ***connection trips*** during the month as follows:

(a) if:

(1) GRR>5MW/min and 30MW ≤ TNGR ≤ 160MW; or

(2) 5MW/min<GRR<100MW/min and TNGR>160MW,

then the amount is determined by applying the following formula:

Amount = GSC + OMGC; and

(b) if GRR>100MW/min and TNGR>160MW, then the amount is determined by applying the following formula:

Amount = GSC + OMGC + LSC

where:

GRR (in MW/min) is the rate at which the MW transfer at the ***connection*** changed during the ***trip***;

TNGR(in MW) is the total change in MW transfer at the ***connection*** during the ***trip***;

GSC (in $) is the generation startup charge in respect of the ***trip*** and is determined by applying the following formula:

$$GSC = GSP \times (TNGR - 30)$$

where:

GSP (in $/MW) is the generator startup price set out in the ***Price Schedule*** for the ***financial year*** in which the ***trip*** occurs;

OMGC (in $) is the generation out of merit charge in respect of the trip and is determined by applying the following formula:

$$OMGC = OMGP \times \left(TNER - \frac{30 \times TD_1}{60}\right)$$

where:

OMGP (in $/MWh) is the generation out of merit price set out in the ***Price Schedule*** for the ***financial year*** in which the ***trip*** occurs;

TNER (in MWh) is the total variation in the energy transferred at the ***connection*** during the ***trip***;

TD_1 (in minutes) is the lesser of:

(1) the time duration of the ***trip***; and

(2) 60 minutes.

LSC (in $) is the load shedding charge in respect of the ***trip*** and is determined by applying the following formula:

$$LSC = LSP \times \left(TNER - \frac{160 \times TD_2}{60}\right)$$

where:

LSP (in $/MWh) is the load shedding price set out in the ***Price Schedule*** for the ***financial year*** in which the ***trip*** occurs; and

TD2 (in minutes) is the lesser of:

(1) the time duration of the ***trip***; and

(2) 5 minutes.

4.7.3 The control system service charge payable by a ***user*** for ***control system services*** in respect of each of the ***user's connections*** for a month is determined by applying the following formula:

$$CSSC = NRTU \times \frac{CSSP}{12}$$

where:

CSSC (in $) is the control system service charge for the ***connection*** for the month. CSSC is included in the connection charge;

NRTU (a number) is:

(a) the number of ***RTUs*** located at the ***connection*** or the plant and equipment connected at the ***connection*** at the end of the month; or

(b) if there are no ***RTUs*** located at the ***connection*** or the plant and equipment connected at the ***connection***, then 1/3;

CSSP (in $) is the control system service price set out in the ***Price Schedule*** for the ***financial year*** in which the month falls.

4.7.4 The control system service charge is a fixed charge and is payable by a ***user*** irrespective of the ***user's*** use of the ***electricity transmission network***.

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APPENDIX A

DEFINITIONS

Appendix A Definitions

access agreement has the meaning given in the ***Transmission Regulations***

access services means:

(a) ***use of system services;***

(b) ***common services;***

(c) ***connection services; and***

(d) ***ancillary services;***

ancillary services means the following services:

(a) ***voltage control;***

(b) ***control system services;***

(c) ***spinning reserve;***

(d) ***post-trip management; and***

(e) ***energy balancing;***

augment, in relation to the ***electricity transmission network***, means to enhance or expand the ***electricity transmission network***;

common services means a ***network service*** that ensures the integrity of the ***electricity transmission network*** and benefits all ***users*** and that cannot practically be allocated to ***users*** on a locational basis;

connection means the electrical equipment that allows the transfer of electricity between the ***electricity transmission network*** and an electrical system that is not part of that network and includes any transformers or switchgear at the point of interconnection (including those that operate at a nominal voltage of less than 66kV and a nominal frequency of 50Hz) that are necessary for that transfer but does not include the lines and switchgear at the ***connection*** that form part of the ***electricity transmission network***;

connection services, in respect of a ***connection***, means the establishment and maintenance of that ***connection***;

contract maximum demand in respect of a ***connection*** means the contract maximum demand (expressed in kW) specified in the ***access agreement*** in respect of the ***connection*** (if any);

control system services means the 24-hour control of the power system through monitoring, switching and dispatch which is provided through control centres and ***SCADA*** and communication equipment;

declared sent-out capacity in respect of a ***generating unit*** which is not an embedded generating unit is the capacity of the generating unit to generate and transfer electricity to the ***electricity transmission network***, taking into account any electricity used at the ***connection.*** The ***declared sent-out capacity*** of an ***embedded generating unit*** is the capacity of the ***generating unit*** to generate and transfer electricity

to the ***electricity transmission network***, taking into account any electricity used at the ***connection*** or supplied to persons otherwise than through the ***electricity transmission network***;

electricity distribution network means all parts of the system operated by ***Western Power*** for transportation of electricity at nominal voltages of less than 66kV and a nominal frequency of 50Hz;

EC Act means the Electricity Corporation Act 1994 (WA);

electricity transmission capacity means the capacity of the ***electricity transmission network*** to transport electricity, consistent with the need to maintain the continuity and integrity of the network;

electricity transmission network means all parts of the system operated by ***Western Power*** for transportation of electricity at nominal voltages of 66kV or higher and a nominal frequency of 50Hz other than:

any part of the system that forms part of an ***exempt connection;*** and

any part of the system that is not owned or leased by ***Western Power***

embedded generator means a ***generating unit*** which supplies on-site loads or loads at the same ***connection*** or which is connected to an ***electricity distribution network***;

entry point means a ***connection*** at which electricity is more likely to be transferred to the ***electricity transmission network*** than to be transferred from the ***electricity transmission network***;

exempt connection means a ***connection*** which is not an ***existing connection***;

existing connection means a ***connection*** which existed as at 1 January 1997;

exit point means a ***connection*** at which electricity is more likely to be transferred from the ***electricity transmission network*** than to be transferred to the ***electricity transmission network***;

financial year means the period commencing at the start of 1 July in one calendar year and terminating at the end of 30 June in the following calendar year, except for the ***financial year*** ending at the end of 30 June 1997, which commences at the start of 1 January 1997.

generating unit means an electricity generator and related equipment essential to the electricity generator's operation, which together function as a single entity;

load means a ***connection*** at which electrical power is delivered to a person or the amount of electrical power delivered at a defined instant at a ***connection;***

network services in respect of the ***electricity transmission network*** means the use of the ***electricity transmission network*** to transport electricity, including:

(a) ***network transmission services***, including:-

(i) the ***electricity transmission network's*** ability to transfer electricity;

(ii) configuration switching capability at nodes;

(iii) network security and stabilisation capability services; and

(iv) voltage and reactive control capability at nodes;

(b) network operation systems, including:-

(i) remote operation services;

(ii) voice and data communication services;

(iii) network performance monitoring services;

(iv) real time operational information and control capability;

(v) operational information (including plant characteristics);

(vi) generation scheduling; and

(vii) maintenance services;

(c) the maintenance of the security of the ***electricity transmission network***, including frequency control;

Normal CMD in respect of a standby connection means the contract maximum demand for the connection minus the standby CMD for the connection.

Price Schedule has the meaning given in clause 3.1;

post-trip management means the maintenance of system security in the aftermath of trips;

RTU means a remote terminal unit installed within a substation to enable monitoring and control of a facility from a control centre;

SCADA means Supervisory Control and Data Acquisition;

spinning reserve means the ability to immediately and automatically adjust generation or reduce demand in response to a variation in frequency;

standby connection means a ***standby connection*** in respect of which all of the following requirements are satisfied:

(a) the ***access agreement*** in respect of the ***connection*** contemplates that the ***user*** will be required to pay a combined use of system charge and common service charge for standby access in respect of the ***connection***;

(b) the ***connection*** satisfies either of the requirements set out in clause 4.5.2; and

(c) all of the requirements set out in clause 4.5.3 apply in respect of the ***connection*** to the satisfaction of ***Western Power***.

standby contract maximum demand in respect of a standby ***connection*** means that portion (expressed in kW) of the contract maximum demand for the connection which is intended to be utilised for standby access, as is specified in the access agreement in respect of the connection;

standby power has the meaning given in clause 1 of Schedule 5 to the ***EC Act***.

standby terms in respect of a ***standby connection*** are determined as follows:

(a) if a period (in this definition called a "**standby period**") for which standby access is provided continuously under the ***access agreement*** in respect of the ***standby connection*** is less than 12 months and falls entirely within the one ***financial year***, then the standby period is a ***standby term***; and

(b) if a standby period is less than 12 months and falls in part in one ***financial year*** and in part in another ***financial year***, then each of those parts of the standby period is a ***standby term***; and

(c) if a standby period is more than 12 months, then:

(1) each ***financial year*** which falls entirely in the standby period is a ***standby term***;

(2) if the standby period commences during a ***financial year***, then the period commencing at the start of the standby period and ending at the start of the next ***financial year*** is a ***standby term***; and

(3) if the standby period terminates during a ***financial year***, then the period commencing at the start of the ***financial year*** and ending at the end of the standby period is a ***standby term***.

Transmission Regulations means the Electricity Transmission Regulations 1996 made under the ***EC Act***;

a ***trip*** in respect of an ***entry point*** occurs when the total output of the ***generating units*** connected at that ***entry point*** decreases and:

(a) the rate of the decrease exceeds 5MW/min; and

(b) the total amount of the decrease exceeds 30MW.

For the purposes of determining the time duration of a ***trip*** in respect of an ***entry point***:

(a) a ***trip*** commences when the total output of the ***generating units*** connected at that ***entry point*** decreases at a rate greater than 5MW/min; and

(b) a ***trip*** terminates when the total output of the ***generating units*** connected at that ***entry point*** equals the total output of those ***generating units*** immediately prior to the commencement of the ***trip***;

use of system services means a ***network service*** provided to a ***user*** for use of the ***electricity transmission network*** for the transportation of electricity that can be reasonably allocated to a ***user*** on a locational basis;

user means a person who has an arrangement with ***Western Power*** for access to ***electricity transmission capacity*** and includes ***Western Power*** to the extent that it has access to ***electricity transmission capacity***;

voltage control means keeping network voltages within operational limits in normal operation and in the aftermath of trips by automatic regulation of generation MVAr output or by transmission voltage control equipment such as capacitor banks and automatic tap-changers; and

Western Power means the Electricity Corporation established under section 4 of the ***EC Act***.

APPENDIX B

ELECTRICITY TRANSMISSION NETWORK ASSETS

ELECTRICITY TRANSMISSION NETWORK ASSETS

The Corporation has two separate transmission networks: the South West Network and the North West Network. Refer to the Western Power publication "Transmission Networks" for geographic depictions of the transmission networks.

The principal elements of the transmission networks include transmission substations and zone substations, interconnected by transmission and subtransmission lines. The transmission networks enable the transportation of electricity from power stations to zone substations and high voltage customer loads. The zone substations provide the interface between the transmission networks and distribution networks.

For the purpose of transmission open access, the transmission networks assets comprise Connection assets, Shared Network assets and Ancillary Services assets. These are described as follows:

- **Connection Assets**: those assets at the point of physical interconnection with the transmission networks which are dedicated to a User - that is, at substations including transformers and switchgear, but excluding the incoming line switchgear. Connection assets for generators are referred to as **entry** assets and for loads they are called **exit** assets.

- **Shared Network Assets:** all other transmission assets in the networks not dedicated to any particular customer, but shared to some extent by network Users.

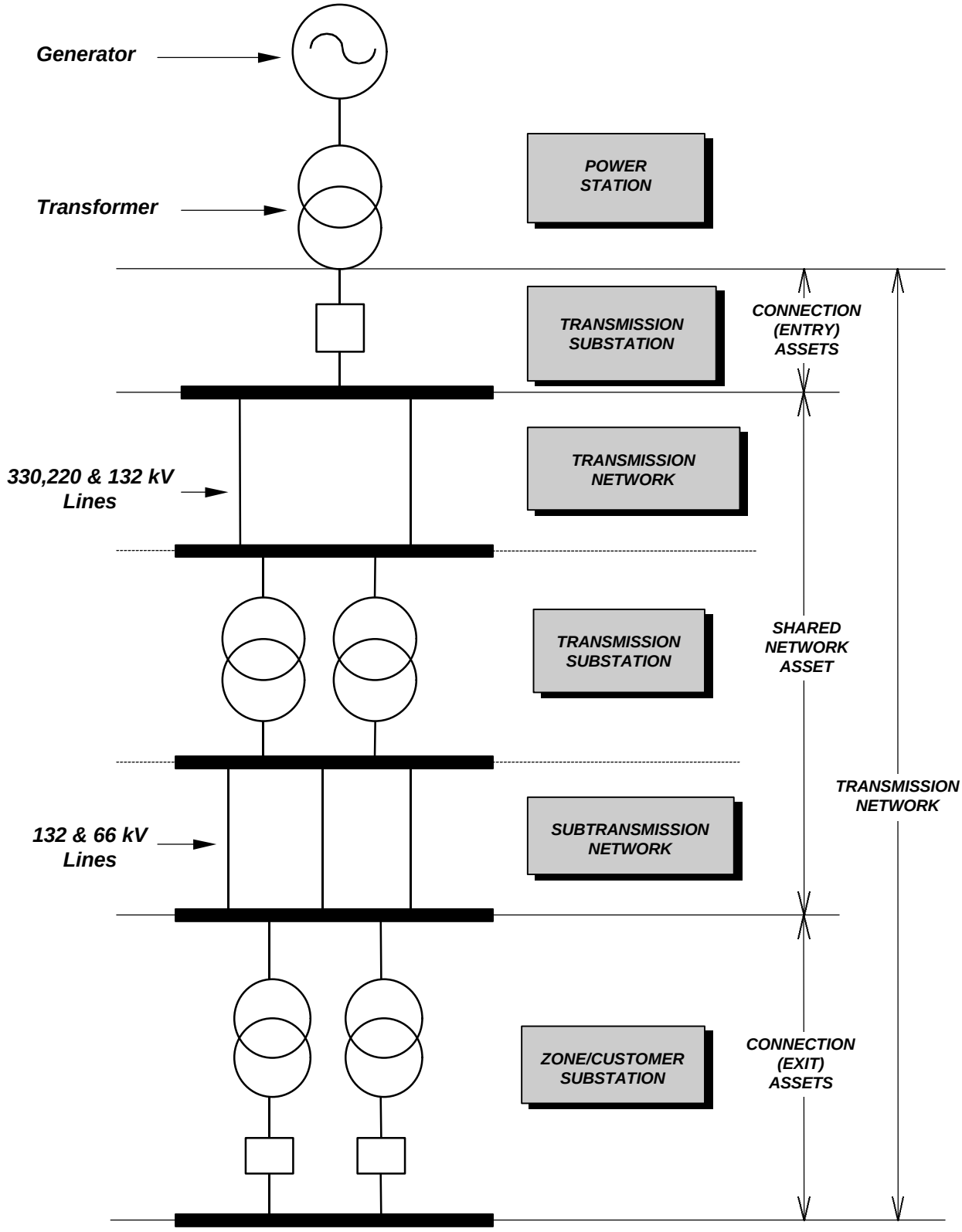
- **Ancillary Services Assets:** network assets performing an Ancillary Services function comprise:

  - Those providing a Control System Service, for example, system control centres, supervisory control and communications facilities.

  - Those providing a Voltage Control Service in the networks, for example, a proportion of the costs of capacitor and reactor banks in substations.

The following diagram shows in simplified form the principal elements of the transmission networks and the categorisation of the assets as described above.

TRANSMISSION NETWORK
Asset Description



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APPENDIX C

SUMMARY OF CHARGES

SUMMARY OF CHARGES

Transmission Network charges consist of three components:

- Connection;
- Use of System (UOS); and
- Common Service (CS).

In addition to the above Network charges, Ancillary Services charges may also be levied separately depending on usage. To simplify the structure of charges, all Ancillary Services charges to loads have been added to the Common Service and Connection charges. Ancillary Services charges to generators will be levied separately except for the Control System Services charge which will be included in the Connection charge.

The charges for the connection points listed in Table D1 of the Price Schedule (Appendix D) are applicable to either:

- a connection at the transmission voltage level (66kV or higher) where transformers are not installed; or

- a connection at the distribution voltage level (less than 66kV) where transformers are installed.

The structure of Transmission Network and Ancillary Services charges is summarised in the following tables:

TRANSMISSION NETWORK CHARGES

Charge	To Whom	How
Connection (Exit)	• Transmission - connected loads	• Fixed annual charge based on specific connection assets (ie at each exit point) • Where use is shared, the total charge is allocated to each user in accordance with clause 4.1.2.
Connection (Entry)	• Generation directly connected to the transmission system	• Fixed annual charge based on specific connection assets (ie at each entry point) • Where use is shared, the total charge is allocated to each user in accordance with clause 4.1.2.
Use of System (Loads)	• Transmission - connected loads	• Fixed annual charge based on contract maximum demand • Prices are location specific (ie each exit point
Use of System (Generators)	• Generators directly connected to the transmission system • Some generators indirectly connected to the transmission system eg. Cogenerators, distribution-embedded generators. (See section 4.6)	• Fixed annual charge based on declared sent-out capacity • Prices are location specific (ie each entry point)
Common Service (Loads)	• Transmission - connected loads	• Fixed annual charge based on contract maximum demand • Common price at every exit point

ANCILLARY SERVICES CHARGES FOR THE SOUTH WEST NETWORK

Service Category	Service Providers	Service Users	Charging Structure
Spinning Reserve	Specific Generators Specific Interruptible Loads	Generators and Loads	Generators pay based on unit size and unit running hours. Loads pay a small proportion (for frequency control), through the transmission Common Service charge.
Voltage Control	Generators and Transmission	Loads	Included in transmission Connection and Common Service Charges.
Control System Services	Transmission	Generators and Loads	Generators and any loads with Remote Terminal Units (RTU) pay a fixed annual charge per RTU. RTU charges allocated to Entry and Exit Points charged through transmission Connection charges.
Post-trip Management	Generators and Transmission	Specific Generators (when they trip)	Generators pay on each unit trip, based on unit size, rate of MW change, decrease in energy output and length of trip.
Energy Balancing	Generators	Independent Generators	Reconciled through energy balancing, but additional charges levied for trading outside the permitted tolerance.

ANCILLARY SERVICES CHARGES FOR THE NORTH WEST NETWORK

Service Category	Service Providers	Service Users	Charging Structure
Voltage Control	Generators and Transmission	Loads	Included in transmission Connection and Common Service Charges.
Control System Services	Transmission	Generators and Loads	Generators and any loads with Remote Terminal Units (RTU) pay a fixed annual charge per RTU. RTU charges allocated to Entry and Exit Points charged through transmission Connection charges.
Energy Balancing	Generators	Independent Generators	Reconciled through energy balancing, but additional charges levied for trading outside the permitted tolerance.

APPENDIX D

PRICE SCHEDULE

CONTENTS

D1 Connection Charges For South West Transmission Network Existing Exit Points in 1999/00

TABLE D1

SUBSTATION - EXIT POINT		
ABBREVIATION	**NAME**	**CONNECTION CHARGE $K**
A 132	Arkana	628.37
ABD 132	ALCOA Boddington	*
AFM 132	Australian Fused Material	*
AKW 132	ALCOA Kwinana	*
ALB 132	Albany	506.23
APJ 132	ALCOA Pinjarra	*
APM 66	Aust Paper Mills	398.86
BCH 132	Beechboro	441.22
BHK 66	Broken Hill Kwinana	*
BEL 132	Belmont	482.59
BKF 132	Black Flag	282.63
BLD132B2	Boulder	846.00
BNP 132	Beenup	*
BNY132	Bounty	*
BP 66	British Petroleum	382.12
BSI 132	Barrack Silicon Smelter (Simcoa)	*
BSN 66	Busselton	341.73
BTN 132	Bridgetown	274.75
BUH 132	Bunbury Harbour	468.80
BUR 66	Burswood Island Casino	*
BYF 132	Byford	430.39
C 66	Cottesloe	452.06
CAP 66	Capel	364.39
CAR 66	Carrabin	*
CBK 132	Claisebrook (Summer St)	*
CBP 132	CSBP	*
CC 132	Cockburn Cement	487.52
CK 66	Cook Street	395.91
CL 66	Clarence Street	

SUBSTATION - EXIT POINT		
ABBREVIATION	**NAME**	**CONNECTION CHARGE $K**
		372.27
CLP 66	Coolup	293.47
CO 66	Collie	446.15
COL 66	Collier Street	367.34
CPN 132	Chapman	235.35
CUN 66	Cunderdin	276.72
CVE 132	Canning Vale	639.21
D 132	Darlington	359.46
E 66	Edmund Street	353.55
ENB 132	Eneabba	486.53
EWR 132	Edgewater	*
F 66BUS1	Forrest Ave	335.82
FFD 132	Forrestfield	*
G 132	Gosnells	621.48
GGV 132	Golden Grove	*
GTN 132	Geraldton	193.98
H 132	Hadfields	487.52
HAY 132	Hay Street	987.90
HE 66	Herdsman Parade	331.88
HIS 132	Hismelt	*
JT66BUS1	Joel Terrace	367.34
K 132	Kalamunda	436.30
KAT 66	Katanning	436.30
KDN 220	Kondinin	371.28
KEL 66	Kellerberrin	287.56
KMC 132	Kerr McGee Cataby	*
KMK 132	Kerr McGee Kwinana	*
KMM 132	Kerr McGee Muchea	*
KOJ132B2	Kojonup	273.77
LMC 132	Muchea Local	357.03
LMR 132	Marriott Road Local	

SUBSTATION - EXIT POINT		
ABBREVIATION	**NAME**	**CONNECTION CHARGE $K**
		256.04
MA 132	Manning Street	437.28
MC 66	Medical Centre	315.14
MED 132	Medina	425.46
MER 66	Merredin	326.96
MH 132	Mandurah	842.12
MIL 132	Milligan Street	1,163.24
MJ 132	Midland Junction	635.27
MJP 132	Manjimup	442.21
MO 132	Morley	561.39
MOR 132	Moora	434.33
MR 66	Margaret River	284.60
MUL 132	Mullaloo	601.78
MW 66	Mundaring Weir	300.36
MY 66	Myaree	418.57
N 66	Nedlands	429.40
NB 132	North Beach	622.46
NF 66	North Fremantle	370.30
NGN 66	Narrogin	430.39
NOR 66	Northam	291.50
NP 66	North Perth	387.04
OC 66	O'Connor	500.32
OP 132	Osborne Park	491.46
PCY 132	Piccadilly	500.32
PIC 66	Picton	340.75
PNJ 132	Pinjarra	*
QNP 66	Quinninup	304.30
RBD 132	Reynolds Boddington	301.87

SUBSTATION - EXIT POINT		
ABBREVIATION	**NAME**	**CONNECTION CHARGE $K**
RO 132	Rockingham	454.32
RTN 132	Riverton	453.04
RV 66	Rivervale	376.21
SF 66	South Fremantle	99.42
SP 66	Shenton Park	453.04
SV 66	Sawyers Valley	311.20
SX 66	Southern Cross	438.27
TLN 66	Tomlinson Street	*
TS 132	Three Springs	460.92
TT 66	Tate Street	481.61
U 66	University	313.17
VP 66	Victoria Park	363.40
W 66BUS1	Wellington Street	368.33
WAG 66	Wagin	420.54
WCL 132	Western Colleries	*
WD 66	Wembley Downs	329.91
WE 132	Welshpool	465.85
WEB 66	WEB Grating	*
WGP 132	Wagerup	445.16
WKT132B1	West Kalgoorlie	247.17
WM 132	Western Mining	*
WOR 132	Worsley	*
WSD 66	Westralian Sands	*
WUN 66	Wundowie	333.85
Y 132	Yokine	478.65
YER 66	Yerbillon	210.44
YLN 220	Yilgarn	710.13
YNP 66	Yornup	393.94
YP 132	Yanchep	352.57

Note:

[1] * denotes the price is to be determined subject to the provisions of existing contractual arrangements.

[2] if more than one user is connected to the same connection, the above connection charges will be allocated to each user in accordance with clause 4.1.2.

D2 Connection Charges For South West Transmission Network Existing Entry Points in 1999/00

TABLE D2

GENERATOR – ENTRY POINT		
ABBREVIATION	**NAME**	**CONNECTION CHARGE $K**
BU	Bunbury	547.3
GTN	Geraldton	90.3
KW	Kwinana	885.9
MGA	Mungara	287.4
MU	Muja	1,712.3
PJR	Pinjar	965.9
WKT	West Kalgoorlie	222.6

Note: if more than one user is connected to the same connection, the above connection charges will be allocated to each user in accordance with clause 4.1.2.

D3 Connection Charges for North West Transmission Network Existing Exit Points in 1999/00

TABLE D3

SUBSTATION - EXIT POINT		
ABBREVIATION	**NAME**	**CONNECTION CHARGE $K**
AST	Anderson Street	420
BUL	Bulgarra	424
CLB 33	Cape Lambert	346
DMP	Dampier (WPC)	84
FIN-66	Finucane Island (BHP)	*
GW	Goldsworthy	*
MDR	Murdock Drive	375
MNM-66	Mt Newman (BHP)	*
PCK	Pegs Creek	419
WFD	Wedgefield	331

Note:

[1] * denotes the price is to be determined subject to the provisions of existing contractual arrangements.

[2] if more than one user is connected to the same connection, the above connection charges will be allocated to each user in accordance with clause 4.1.2.

D4 Connection Charges for North West Transmission Network Existing Entry Points in 1999/00

TABLE D4

GENERATOR – ENTRY POINT		
ABBREVIATION	**NAME**	**CONNECTION CHARGE $K**
BPS	BHP Power Station	*
LPS	Cape Lambert Power Stn	*
DPS	Dampier Power Station	*

Note:

[1] * denotes the price is to be determined subject to the provisions of existing contractual arrangements.

[2] if more than one user is connected to the same connection, the above connection charges will be allocated to each user in accordance with clause 4.1.2.

D5 Use of System and Common Services Prices For South West Transmission Network Exit Points In 1999/00

TABLE D5

SUBSTATION - EXIT POINT		PRICE ($/kW)		
ABBREVIATION	NAME	Use of System (UOS)	Common Service (CS)	TOTAL
A 132	Arkana	14.83	14.34	29.17
ABD 132	ALCOA Boddington	6.20	14.34	20.54
AFM 132	Australian Fused Material	8.97	14.34	23.32
AKW 132	ALCOA Kwinana	8.28	14.34	22.62
ALB 132	Albany	50.39	14.34	64.73
APJ 132	ALCOA Pinjarra	3.92	14.34	18.26
APM 66	Aust Paper Mills	16.24	14.34	30.58
BCH 132	Beechboro	13.49	14.34	27.83
BHK 66	Broken Hill Kwinana	27.00	14.34	41.34
BEL 132	Belmont	11.74	14.34	26.08
BKF 132	Black Flag	45.93	14.34	60.28
BLD132B2	Boulder	39.33	14.34	53.67
BNP 132	Beenup	196.58	14.34	210.92
BNY132	Bounty	62.22	14.34	76.56
BP 66	British Petroleum	23.20	14.34	37.54
BSI 132	Barrack Silicon Smelter	10.02	14.34	24.36
BSN 66	Busselton	26.97	14.34	41.31
BTN 132	Bridgetown	23.45	14.34	37.80
BUH 132	Bunbury Harbour	8.91	14.34	23.25
BUR 66	Burswood Island Casino	28.60	14.34	42.94
BYF 132	Byford	11.66	14.34	26.00
C 66	Cottesloe	15.93	14.34	30.27
CAP 66	Capel	21.43	14.34	35.78
CAR 66	Carrabin	158.03	14.34	172.37
CBK 132	Claisebrook (Summer St)	26.83	14.34	41.17
CBP 132	CSBP	10.68	14.34	25.02
CC 132	Cockburn Cement	7.27	14.34	21.61
CK 66	Cook Street	16.71	14.34	31.06
CL 66	Clarence Street	19.40	14.34	33.74
CLP 66	Coolup	43.32	14.34	57.66
CO 66	Collie	30.33	14.34	44.68
COL 66	Collier Street	21.19	14.34	35.53
CPN 132	Chapman	14.64	14.34	28.99
CUN 66	Cunderdin	43.28	14.34	57.62
CVE 132	Canning Vale	10.85	14.34	25.19
D 132	Darlington	7.65	14.34	21.99
E 66	Edmund Street	14.84	14.34	29.18
ENB 132	Eneabba	36.17	14.34	50.52
EWR 132	Edgewater	20.49	14.34	34.83
F 66BUS1	Forrest Ave	21.68	14.34	36.02
FFD 132	Forrestfield	18.77	14.34	33.12
G 132	Gosnells	12.03	14.34	26.37

SUBSTATION - EXIT POINT		PRICE ($/kW)		
ABBREVIATION	NAME	Use of System (UOS)	Common Service (CS)	TOTAL
GGV 132	Golden Grove	79.15	14.34	93.49
GTN 132	Geraldton	48.90	14.34	63.24
H 132	Hadfields	16.29	14.34	30.63
HAY 132	Hay Street	15.73	14.34	30.07
HE 66	Herdsman Parade	20.25	14.34	34.59
HIS 132	Hismelt	3.29	14.34	17.63
JT66BUS1	Joel Terrace	19.04	14.34	33.38
K 132	Kalamunda	12.62	14.34	26.96
KAT 66	Katanning	29.56	14.34	43.90
KDN 220	Kondinin	10.50	14.34	24.85
KEL 66	Kellerberrin	99.09	14.34	113.44
KMC 132	Kerr McGee Cataby	6.18	14.34	20.52
KMK 132	Kerr McGee Kwinana	13.96	14.34	28.30
KMM 132	Kerr McGee Muchea	17.80	14.34	32.14
KOJ132B2	Kojonup	36.93	14.34	51.27
LMC 132	Muchea Local	4.23	14.34	18.57
LMR 132	Marriott Road Local	10.38	14.34	24.72
MA 132	Manning Street	13.64	14.34	27.98
MC 66	Medical Centre	20.65	14.34	34.99
MED 132	Medina	10.31	14.34	24.65
MER 66	Merredin	115.70	14.34	130.04
MH 132	Mandurah	9.62	14.34	23.96
MIL 132	Milligan Street	22.68	14.34	37.02
MJ 132	Midland Junction	18.23	14.34	32.57
MJP 132	Manjimup	46.65	14.34	61.00
MO 132	Morley	17.51	14.34	31.85
MOR 132	Moora	34.49	14.34	48.83
MR 66	Margaret River	25.83	14.34	40.17
MUL 132	Mullaloo	13.44	14.34	27.78
MW 66	Mundaring Weir	20.82	14.34	35.16
MY 66	Myaree	18.68	14.34	33.02
N 66	Nedlands	18.43	14.34	32.77
NB 132	North Beach	13.61	14.34	27.95
NF 66	North Fremantle	17.91	14.34	32.25
NGN 66	Narrogin	6.74	14.34	21.08
NOR 66	Northam	46.16	14.34	60.50
NP 66	North Perth	19.89	14.34	34.23
OC 66	O'Connor	13.51	14.34	27.85
OP 132	Osborne Park	18.12	14.34	32.46
PCY 132	Piccadilly	29.20	14.34	43.55
PIC 66	Picton	11.70	14.34	26.05
PNJ 132	Pinjarra	3.94	14.34	18.28
QNP 66	Quinninup	39.42	14.34	53.77
RBD 132	Reynolds Boddington	12.83	14.34	27.17
RO 132	Rockingham	12.74	14.34	27.08
RTN 132	Riverton	9.91	14.34	24.25
RV 66	Rivervale	25.27	14.34	39.61

SUBSTATION - EXIT POINT		PRICE ($/kW)		
ABBREVIATION	**NAME**	**Use of System (UOS)**	**Common Service (CS)**	**TOTAL**
SF 66	South Fremantle	8.22	14.34	22.56
SP 66	Shenton Park	17.54	14.34	31.88
SV 66	Sawyers Valley	25.76	14.34	40.11
SX 66	Southern Cross	32.17	14.34	46.51
TLN 66	Tomlinson Street	36.53	14.34	50.87
TS 132	Three Springs	24.21	14.34	38.56
TT 66	Tate Street	19.44	14.34	33.79
U 66	University	20.60	14.34	34.94
VP 66	Victoria Park	19.78	14.34	34.12
W 66BUS1	Wellington Street	27.13	14.34	41.48
WAG 66	Wagin	87.58	14.34	101.92
WCL 132	Western Colleries	5.65	14.34	19.99
WD 66	Wembley Downs	12.61	14.34	26.95
WE 132	Welshpool	11.79	14.34	26.14
WEB 66	WEB Grating	20.37	14.34	34.72
WGP 132	Wagerup	5.26	14.34	19.60
WKT132B1	West Kalgoorlie	11.93	14.34	26.28
WM 132	Western Mining	6.57	14.34	20.91
WOR 132	Worsley	6.76	14.34	21.10
WSD 66	Westralian Sands	21.39	14.34	35.73
WUN 66	Wundowie	24.33	14.34	38.67
Y 132	Yokine	15.64	14.34	29.98
YER 66	Yerbillon	219.48	14.34	233.82
YLN 220	Yilgarn	24.65	14.34	38.99
YNP 66	Yornup	28.27	14.34	42.61
YP 132	Yanchep	9.02	14.34	23.36

D6 Use of System Prices for South West Transmission Network Entry Points in 1999/00

TABLE D6

GENERATOR - ENTRY POINT		USE OF SYSTEM PRICE
ABBREVIATION	NAME	($/kW)
BU	Bunbury	9.21
GTN	Geraldton	7.35
KW	Kwinana	6.10
MGA	Mungara	7.35
MU	Muja	9.20
PJR	Pinjar	5.50
WKT	West Kalgoorlie	2.14

D7 Use of System and Common Services Prices for North West Transmission Network Exit Points in 1999/00

TABLE D7

SUBSTATION - EXIT POINT		PRICE ($/kW)		
ABBREVIATION	NAME	USE OF SYSTEM (UOS)	COMMON SERVICES (CS)	TOTAL
AST	Anderson Street	30.59	30.22	60.81
BUL	Bulgarra	25.03	30.22	55.25
CLB 33	Cape Lambert	11.09	30.22	41.31
DMP	Dampier (WPC)	44.66	30.22	74.88
GW	Goldsworthy	100.81	30.22	131.04
MDR	Murdock Drive	16.94	30.22	47.16
MNM-66	Mt Newman (BHP)	26.44	30.22	56.66
PCK	Pegs Creek	22.69	30.22	52.91
WFD	Wedgefield	25.83	30.22	56.05

D8 Ancillary Services Prices in 1999/00

D8.1. Spinning Reserve Prices

TABLE D8

GENERATOR UNIT MAXIMUM NET OUTPUT (MW)	PRICE ($/h)
0-9	NIL
10-45	4.80
46-65	10.88
66-125	60.21
126-200	113.94
201-300	243.54

Note: the spinning reserve charge is not applicable to generators in the North West transmission network.

D8.2. Post Trip Management Prices

TABLE D9

CHARGE COMPONENT	PRICE
Generator start-up	$10.00/MW
Out-of-merit generation	$30.00/MWh
Load shedding	$10,000.00/MWh

Note: the post-trip management charge is not applicable to generators in the North West transmission network.

D8.3. Control System Service Price

The control system service price is $75,780 per Remote Terminal Unit (RTU) per year for the South West and $56,994/RTU/year for the North West transmission network.

Note that the Control System Service charge is included in the connection charge for existing connections.

D8.4. Energy Balancing Prices

D8.4.1 Energy Balancing Service Price

The Energy Balancing Service price is $1,000.00 per month per connection per access agreement.

D8.4.2 Out of Balance Energy Prices

TABLE D10

WESTERN POWER TRANSACTION	PRICE (c/kWh)
Buy	2.000
Sell	9.400

D8.4.3 Half Hourly Out of Balance Prices (Sell - Supplied by Western Power)

TABLE D11

TIME ZONE	PRICE (c/kWh)
Peak Summer	9.400
Peak Winter	8.100
Peak Autumn/Spring	7.700
Shoulder Weekdays	5.700
Shoulder Weekends	4.900
Off Peak	3.500

D8.4.4 Time Zones

TABLE D12

SEASON	MONTH	PEAK	SHOULDER	OFF PEAK
Summer	January February March	11:00am - 5:00pm	6:00am - 11:00am 5:00pm - 11:00pm	11:00pm - 6:00am
Autumn	April May	7:30am - 10:30am 5:00pm - 8:00pm	6:00am - 7:30am 10:30am - 5:00pm 8:00pm - 11:00pm	11:00pm - 6:00am
Winter	June July August September	7:30am - 10:30am 5:00pm - 8:00pm	6:00am - 7:30am 10:30am - 5:00pm 8:00pm - 11:00pm	11:00pm - 6:00am
Spring	October November December	11:00am - 5:00pm	6:00am - 11:00am 5:00pm - 11:00pm	11:00pm - 6:00am
Weekend **(Sat & Sun)**	All Year		8:00am - 10:00pm	12:00am - 8:00am 10.00pm – 12.00am

D8.4.5 Half Hourly Out of Balance Price (Buy - Purchased by Western Power)

TABLE D13

TIME ZONE	PRICE (c/kWh)
Peak Summer, Winter, Autumn and Spring	4.000
Shoulder Weekdays and Weekends	3.000
Off Peak Weekdays and Weekends	2.000

D8.4.6 Excess Standby Generation Capacity Price

The Excess Standby Generation Capacity price is $20.00/kW/excess demand period.

D9 Excess Network Usage Factor

The excess network usage factor is 0.125 (=1.5/12)

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APPENDIX E

PRICE DETERMINATION & TRIENNIAL REVIEW OF TRANSMISSION SOURCED ACCESS PRICES

CONTENTS

INTRODUCTION

This schedule describes the steps involved in the initial methodology used to calculate the transmission sourced access prices and in the triennial review of these prices.

STEP 1 ASSET VALUATION

A valuation of transmission assets is undertaken using the Optimised Deprival Value methodology. An outline of the valuation approach is as follows:

Step 1.1: Data Collection

The specific information required is:

- a listing of the system fixed assets that make up the network and connections, and their specifications;
- data on the utilisation of the system fixed assets, such as rated capacities, demand and *load* flows;
- an understanding of the design and planning criteria and specifications, both at the macro *system* level and in relation to the specification of the component assets;
- a listing of the non-system fixed assets (SCADA, communications related SCADA, control centre, minor assets, etc…);
- equipment replacement cost data; and
- construction and installation cost data.

Step 1.2: Optimisation of the Existing Network

Optimisation of the existing *network* design is carried out in accordance with the optimised deprival value methodology set out below:

The optimised deprival value (ODV) of an asset is the depreciated value of the lower of the optimised replacement cost of the asset and the economic replacement value of the asset, where:

(a) the optimised replacement cost of the asset is the cost of meeting the current (and projected future) supply needs with the most technically efficient design and configuration of the asset based on the existing system configuration; and

(b) the economic replacement value of an asset is the minimum cost of replacing the asset with a more economic alternative which still achieves the same result.

To determine the ODV of an asset, the following steps are carried out:

(1) the modern equivalent asset for the asset is established. The modern equivalent asset of an asset (called the "existing asset") is the asset which would be selected to replace the existing asset if the existing asset was replaced today with an asset which would have the same service capability;

(2) any overbuild or sub-optimal configuration of the existing system is identified, taking into account load forecast, system security, reliability and the overall system integrity;

(3) the replacement cost of the optimal asset is determined, based on the modern equivalent asset;

(4) subsystems where the economic replacement value of assets might be less than the optimised replacement cost are identified and the economic replacement value of those subsystems is established; and

(5) the optimised replacement cost of the asset and the economic replacement value of the asset are compared to determine the ODV of the asset.

Step 1.3: Valuation

This involves:

System fixed assets

1. calculating the overall replacement cost of the assets forming the optimised *network* using present-day labour charges and modern efficient practices, both in respect of technology and work practices;

2. where the economic value of assets (ie cost of replacing each asset with a more economic alternative) might be less than the optimised replacement cost, the economic value of those assets is established;

3. the lower of the optimised replacement cost and economic value of each asset is taken to form the gross ODV of the assets;

4. depreciating the gross ODV of the assets based on the proportion of their economic life remaining, to determine the net ODV of the assets;

Non-system fixed assets

5. calculating the gross book value of the non-system fixed assets; and

6. calculating the net book value of the non-system fixed assets.

Items 3 and 5 are added to give the gross ODV of the transmission assets (system and non-system fixed assets).

Items 4 and 6 are added to give the net ODV of the transmission assets (system and non-system fixed assets).

STEP 2 DETERMINE ANNUAL OPERATING & MAINTENANCE COSTS

The components of operating and maintenance costs are:

1. operating and maintenance costs expected to be incurred in the financial year in connection with the operation, planning and maintenance of the transmission network; and

2. forecast allocated Corporate overheads.

The operating and maintenance costs must be reasonable.

STEP 3 DETERMINE AGGREGATE ANNUAL REVENUE REQUIREMENT

The aggregate annual revenue requirement is calculated using the following formula:

$AARR = WACC_r * (ODV-CCON) + DEP + OM +((DEP - TD) / (1- t)) * t +ADJ +C$

where:

AARR = aggregate annual revenue requirement.

$WACC_r$ = real pre-tax weighted average cost of capital (see below).

ODV = net optimised deprival value of transmission assets (system and non-system fixed assets).

CCON = total capital contribution made since 1 January 1997 towards new prescribed assets to the extent that each contribution increased the optimised deprival value minus the amortisation.

DEP = depreciation charge for the financial year on gross optimised deprival value of transmission assets (system and non-system fixed assets).

OM = forecast operating and maintenance costs .

TD = tax depreciation charge for the financial year relating to the transmission assets (system and non-system fixed assets).

t = marginal tax rate.

ADJ = adjustment for under or over-recovery in the previous financial year (where under-recovery of revenue is a positive number and over-recovery is a negative number).

C = cost of force majeure and significant events in the previous financial year.

The $WACC_r$ is calculated using the following formula:

$$WACC_n = R_e * E/(D+E) / (1-t * (1-G)) + R_d * D/(D+E)$$

$$WACC_r = \{(1 + WACC_n) / (1+ CPI)\} - 1$$

where:

$WACC_r$ = real pre-tax weighted average cost of capital.

$WACC_n$ = nominal pre-tax weighted average cost of capital.

R_e = post-tax cost of equity (see below).

R_d = pre-tax cost of debt.

E = market value of equity.

t = marginal tax rate.

G = imputation factor.

D = market value of debt.

CPI = expected inflation for Perth determined by taking the average of the forecasts produced by BankWest and Westpac/Challenge banks operating in Australia under licenses issued by the Reserve Bank of Australia. The expected inflation must be for the same period for which the revenue requirement calculation is being performed.

R_e, post-tax cost of equity, and R_d, pre-tax cost of debt, are calculated using the following formula:

$$R_e = R_f + (B_e * MRP)$$

$$R_d = R_f + D_p$$

where:

R_f = risk-free rate.

B_e = equity beta, a measure of the assets' riskiness relative to the market.

MRP = market risk premium.

D_p = debt premium.

STEP 4 ALLOCATE AGGREGATE ANNUAL REVENUE REQUIREMENT TO COST POOLS

The next step in the process is to allocate the total revenue requirement of the transmission business to cost pools. For this purpose a revenue rate (RR) is determined as follows:

$$RR = AARR / \sum GODV$$

where:

AARR = aggregate annual revenue requirement.

$\sum$GODV = gross optimised deprival value (GODV) of all transmission assets (system and non-system fixed assets).

Allocation of revenue is in proportion to the GODV of the assets in each cost pool. That is, the annual revenue allocated to each cost pool is equal to:

$$RR * GODV (Cost Pool)$$

The cost pools are:

- Connection Services Cost Pool which is further allocated to the following pools:
  - exit points; and
  - entry points.
- Shared Network Services Cost Pool which is further allocated to the following pools:
  - use-of-system to loads;
  - use-of-system to generators; and

- common service to loads.

- Transmission-sourced Ancillary Services Cost Pool which is further allocated to the following pools:

  - voltage control; and
  - control system service.

Connection Services Cost Pool

The gross asset values at each Entry and Exit Point include substation assets minus two-thirds of the value of voltage control equipment at those points (since the function of voltage control equipment is partly location specific and partly system related).

Use of System to Loads Cost Pool

Use of system for loads represents 50% of the Shared Network Services cost pool.

Use of System to Generators Cost Pool

Use of system for generators represents 20% of the Shared Network Services cost pool.

Common Service to Loads Cost Pool

The Common Service price is set to recover the remainder of the shared network cost pool - that is, after allowing for UOS charges to loads and to generators. The common service cost pool is also adjusted for any over or under recovery in the previous financial year (ADJ in Step 3).

Voltage Control Cost Pool

The voltage control cost pool consists of two-thirds of the value of voltage control equipment at Entry and Exit points (since the function of voltage control equipment is partly location specific and partly system related) and the value of all of the voltage control equipment at transmission terminals. The remaining one-third of the value of the voltage control equipment at Entry and Exit points is included in the connection services cost pool (see above).

Control System Service Cost Pool

A separate cost pool is allocated for Control System Service. It consists of the total cost of all SCADA and SCADA related communications equipment, and costs associated with the control centre.

STEP 5 DETERMINE PRICES

Prices are then calculated as follows:

Connection Service Prices

Prescribed Connection Service prices are expressed as $/year for a particular Exit or Entry Point and are independent of usage. Where there is more than one user, this charge is allocated to each user in accordance to clause 4.1.2.

The Connection Service Price is adjusted to include the Control System Service price for that connection point.

Use of System Prices for Loads

Use of System prices for loads are calculated by allocating the Use of System to Loads cost pool to each Exit Point using the Cost Reflective Network Pricing method described below. These allocated costs are then converted into prices by dividing by the contract maximum demand agreed between Western Power and the user.

The Cost Reflective Network Pricing cost allocation method allocates the revenue requirement (calculated in Step 3) to all network elements, based on their gross (ie undepreciated) ODV, then determines the use made of each network element by each connection point during the survey period.

The Cost Reflective Network Pricing cost allocation process requires detailed network analysis and involves the following steps:

(i) determining the annual revenue requirement (ARR) for individual transmission shared network assets (see below);

(ii) determining the network load and generation pattern;

(iii) performing a load-flow to calculate the mega-volt-ampere (MVA) loading on network elements;

(iv) determining the allocation of generation to loads;

(v) determining the utilisation of each asset on the network by each connection point;

(vi) allocating the revenue requirement of individual network elements to each user based on the assessed usage share; and

(vii) determining the total cost allocated to each connection point by adding the share of the costs of each individual network element attributed to each point in the network.

The annual revenue requirement for each element, Item (i), is calculated using the following formula:

$$ARR_i = RR * GODV_i$$

where:

ARR_i = annual revenue requirement for an individual element.

RR = revenue rate.

$GODV_i$ = gross optimised deprival value for an individual element.

Use of System Prices for Generators

Use of system prices for generators are calculated by allocating the Use of System to Generators cost pool to each Entry Point using the Cost Reflective Network Pricing method described above.

The Entry Point prices are calculated by taking the allocated costs described above and dividing them by the declared sent-out capacity of each power station.

Common Service Price to Loads

The Common Service price is calculated by taking the Common Service cost pool and dividing it by the agreed aggregate (over all Exit Points) contract maximum demands. To this is added the voltage control price (see below) and the spinning reserve price. The spinning reserve price is calculated as follows:

$$SRPL = 0.5 * SR_1 / ACMD$$

where:

SRPL = spinning reserve price to loads.

SR_1 = total forecast stage 1 spinning reserve cost for the financial year.

ACMD = agreed aggregate (over all Exit Points) contract maximum demand. ACMD is the sum of the total contract maximum demand of all loads minus three quarters of the total contract maximum demand of standby loads.

Voltage Control Price

The Voltage Control price is calculated by taking the Voltage Control cost pool and dividing it by the agreed aggregate (over all Exit Points) contract maximum demand. This price is added to the Common Services price to simplify the charging structure.

Control System Service Price

The Control System Services price is calculated by taking the Control System Services cost pool and dividing it by the number of equivalent remote terminal units (RTUs) in the network. Users will be charged on the basis of the number of RTU's installed at their connection. The charge is included in the Connection charge.

Charges for Use of System for Embedded Generators

Where an embedded generator is connected to an exit point the Use of System charge for that exit point is calculated by taking the greater of the Use of System charge for generator use and Use of System plus Common Service charge for load use.

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APPENDIX F

ANNUAL ADJUSTMENT TO TRANSMISSION SOURCED ACCESS CHARGES AND PRICES

CONTENTS

ANNUAL ADJUSTMENTS TO TRANSMISSION SOURCED ACCESS CHARGES AND PRICES
(Connection Charges
Use Of System Prices
Common Service Prices
Control System Services Charge)

INTRODUCTION

For the years between the 'triennial review years', when a comprehensive review is proposed, an interim adjustment to charges is required. This attachment details the annual adjustment methodology for these 'adjustment years'.

The factors in determining these adjustments are:

Prospective

- Forecast CPI for next year.
- Forecast contract maximum demand for next year.
- Appropriate WACC for next year.
- Tax imposts.
- Book value of non-system and minor assets.

Retrospective

- Difference between forecast and actual CPI for current year.
- Extraordinary operating and maintenance costs due to force majeure events during current year.
- Assets commissioned or decommissioned during the current year.
- Depreciation of existing assets.
- Any taxes or tax rates imposed or changed during the year.
- Capital contributions on existing assets since 1 January 1997.

The first step in determining charges for the coming year is to determine the prescribed revenue or AARR (by simplified means) incorporating all the adjustment factors mentioned above.

AARR = WACC*(ODV-CCON) + DEP + OM + C + DC + ADJ

where:
- AARR = aggregate annual revenue requirement.
- WACC = real pre-tax weighted average cost of capital.
- ODV = optimised deprival value of assets.
- CCON = the value of capital contributions made towards new system assets after 1 January 1997 to the extent that each contribution increased the optimised deprival value.
- DEP = total depreciation.

OM = operating and maintenance, administration and corporate overhead costs.
C = costs of force majeure events.
DC = depreciation correction.
ADJ = adjustment for discrepancy between sales and prescribed revenue for the prior financial year.

Once the AARR for the coming year has been determined the various charges can be adjusted to recover it.

DETERMINATION OF NEW AARR

1 RETURN ON ASSETS

The return on assets component of AARR is WACC *(ODV-CCON).

a ODV

In this analysis ODV_k is determined by the triennial review process and is the value of the assets at the *beginning* of the triennial year *(k)* used to determine the *AARR* for that year. The value of prescribed assets (those system assets that are included in the access regime) used to determine rates for the next 2 years *(k+1 and k+2)* will be adjusted for depreciation, CPI, new and decommissioned assets.

for the first year following *(k)* the triennial review year:

$$ODV_{k+1} = \left(ODV_k - NBV_k - DE_k\right)\left(1+acpi_k\right) + \left(NA_k - 0.5DNA_k - DA_k + 0.5DDA_k\right)\left(1+acpi_k\right)^{\frac{1}{2}} + 0.5\left(NA_{k+1} - DA_{k+1}\right)\left(1+ fcpi_{k+1}\right)^{-\frac{1}{2}} + NBV_{k+1}$$

for the second year:

$$ODV_{k+2} = \left(ODV_k - NBV_k - 2\times DE_k\right)\left(1+acpi_k\right)\left(1+acpi_{k+1}\right) + \left(NA_k - 1.5DNA_k - DA_k + 1.5DDA_k\right)\left(1+acpi_k\right)^{\frac{1}{2}}\left(1+acpi_{k+1}\right) + \left(NA_{k+1} - 0.5DNA_{k+1} - DA_{k+1} + 0.5DDA_{k+1}\right)\left(1+acpi_{k+1}\right)^{\frac{1}{2}} + 0.5\left(NA_{k+2} - DA_{k+2}\right)\left(1+ fcpi_{k+2}\right)^{-\frac{1}{2}} + NBV_{k+2}$$

where:
NA = the cost of new prescribed assets commissioned during *subscript* year (assumed to be added mid *subscript* year).
DA = the ODV of decommissioned prescribed assets (before end of economic life) and decommissioned during *subscript* year (assumed to be decommissioned mid *subscript* year).
DE$_k$ = depreciation of prescribed assets existing at commencement of the triennial review year (depreciation is assumed to occur at start of each year).

DNA = depreciation of new prescribed assets added during *subscript* year.
DDA = depreciation of decommissioned assets. Adjustment to depreciation for assets decommissioned during *subscript* year.
NBV = net book value of non-system assets.
acpi = actual March to March CPI for *subscript* year.
fcpi = forecast March to March CPI for *subscript* year. Expected inflation produced by BankWest and Westpac/Challenge banks.

b CCON

For the first year following (k) the triennial review year:

$$CCON_{k+1} = HCON_k + CON_k + 0.5CON_{k+1} - AM_k$$

for the second year:

$$CCON_{k+2} = HCON_k + CON_k + CON_{k+1} + 0.5CON_{k+2} - AM_{k+1}$$

where:

HCON = total capital contributions made between 1 January 1997 and year *k* towards new prescribed assets to the extent that each contribution increased the optimised deprival value.
CON = capital contributions made towards new prescribed assets during *subscript* year to the extent that the contribution increases the optimised deprival value.
AM = amortisation of all capital contributions made up to and including *subscript* year.

c WACC

The real pre-tax weighted average cost of capital (WACC) used in determining the return on asset component of charges reflects the underlying economic and taxation factors affecting Western Power's cost of capital. WACC will be adjusted annually to account for changes to the risk free rate (R_f) and debt premium (D_p).

$$WACC = \{(1 + WACC_n) / (1+fcpi)\} - 1$$

where:

$WACC_n$ = Nominal pre-tax weighted average cost of capital.

The real pre-tax WACC and fcpi in 1999/00 are 6.87% and 2.3%, respectively.

To determine $WACC_n$:

$$WACC_n = R_e \times \frac{E}{D+E} \times \frac{1}{1-t(1-G)} + R_d \times \frac{D}{D+E}$$

where:

R_e = post-tax cost of equity (see below).
R_d = pre-tax cost of debt.
E = market value of equity.
t = marginal tax rate.
G = imputation factor.
D = market value of debt.

and:

$R_e = R_f + (B_e * MRP)$
$R_d = R_f + D_p$

where:

R_f = risk-free rate.
B_e = equity beta, a measure of the asset's riskiness relative to the market.
MRP = market risk premium.
D_p = debt premium.

2 DEPRECIATION (DEP)

For the first year following triennial review depreciation will be:

$$DEP_{k+1} = \left(DE_k + DNA_k - DDA_k\right)\left(1 + acpi_k\right) + 0.5\left(DNA_{k+1} - DDA_{k+1}\right) + DNS_{k+1}$$

for the second year:

$$DEP_{k+2} = \left(DE_k + DNA_k - DDA_k\right)\left(1 + acpi_k\right)\left(1 + acpi_{k+1}\right) + \left(DNA_{k+1} - DDA_{k+1}\right)\left(1 + acpi_{k+1}\right) + 0.5\left(DNA_{k+2} - DDA_{k+2}\right) + DNS_{k+2}$$

where

DEP = total depreciation for *subscript* year.
DNS = depreciation of non-system assets for *subscript* year.

3 CORPORATE OVERHEADS, ADMINISTRATION, OPERATING AND MAINTENANCE (OM)

All these costs are referred to generically as Operating and Maintenance (OM) in this attachment and are lumped together and treated identically. For 'adjustment years' the charges to cover these costs will be based on the prescribed charges for the previous year, indexed by a percentage of CPI.

For the first year following triennial review:

$$OM_{k+1} = OM_k\left(1 + y_k * acpi_k\right)$$

where: OM = total OM costs.
y = efficiency factor, y is an agreed number between +1 and -1 reflecting anticipated increases in efficiency in operating and maintenance.

For the second year:

$$OM_{k+2} = OM_k\left(1 + y_k * acpi_k\right)\left(1 + y_{k+1} * acpi_{k+1}\right)$$

Note: Prescribed OM for year k is used and not actual to both reward Western Power if costs were kept below the prescribed charge and avoid perpetuating inefficiency if the opposite were true.

4 CORRECTION AMOUNT FOR UNFORSEEN EXPENDITURE COSTS (C)

This income is required for significant unforseen expenditure resulting from *force majeure* events and for significant expenditure as approved by the Minister occurring in the year prior to the triennial redetermination year.

The costs of force majeure and significant events will be recovered in the following year.

For the first year following triennial review:

$$C_{k+1} = \sum fmc_k (1 + Rd_k)^{\frac{m}{12}} \left(\frac{Rd_{k+1}}{1 - \frac{1}{\left(1 + \frac{Rd_{k+1}}{12}\right)^{12}}} \right)$$

For the second year:

$$C_{k+2} = \sum fmc_{k+1} (1 + Rd_{k+1})^{\frac{m}{12}} \left(\frac{Rd_{k+2}}{1 - \frac{1}{\left(1 + \frac{Rd_{k+2}}{12}\right)^{12}}} \right)$$

where:
Rd = pre-tax cost of debt.

fmc = cost of force majeure and significant events occurring subscript year.
m = remaining months to end of year.

5 ADJUSTMENT FOR DIFFERENCE BETWEEN SALES AND PREVIOUS AARR

Calculation of AARR for the year just completed may need to be adjusted for the value of fcpi used in the ODV calculation and the possible changes to planned NA and DA in the ODV and DEP calculations. The transmission prescribed income is the AARR determined using the actual CPI, actual NA and DA values. The actual CPI will be known because the March to March CPI is used.

$$ADJ_{k+1} = AARR_k^{\#} - S_k$$

where:

S = sales of transmission services,
$AARR^{\#}$ = AARR for past year after forecast CPI (fcpi) is replaced by actual CPI (acpi) and forecast NA and DA with actual.

Although the adjustment is shown in the AARR equation it is actually made to the common service price so as to distribute the affect equitably among all users. Refer to 'Adjustment to Charges to Recover AARR' section.

6 DEPRECIATION CORRECTION (DC)

Depreciation correction is the pretax adjustment to required revenue to compensate for extra tax paid by using tax depreciation instead of ODV depreciation.

$$DC = \frac{DEP - TD}{1 - t} \times t$$

where:

TD = tax depreciation
t = marginal tax rate

TAX

The impact of tax and any future tax changes will need to be assessed for the coming year. In addition any changes to taxation that occurred during the current year will be recovered.

ADJUSTMENT OF CHARGES AND PRICES TO RECOVER AARR

The AARR is recovered through connection charges, use of system charges and a common service charge. The connection charges are fixed annual charges while the use of system and the common service charges are based on usage. The new AARR is used to scale these charges and prices after removal of the adjustment component which is recovered in the common service charge. The following equations do not apply to new

connections or to those existing connections subject to asset changes subsequent to the triennial review. Connection charges and use of system prices will be separately determined for those cases.

For first year:

$$CC_{k+1} = CC_k \times \frac{AARR^*_{k+1}}{AARR^*_k}$$

where:

CC = connection charge

$$AARR^*_{k+1} = AARR_{k+1} - ADJ_{k+1}$$

$$USP^{site}{}_{k+1} = USP^{site}{}_k \times \frac{AARR^*_{k+1}}{AARR^*_k} \times \frac{cmd^{site}_k}{cmd^{site}_{k+1}}$$

where:

USP = use of system price

cmd = contracted maximum demand for substation

$$CSSC_{k+1} = CSSC_k \times \frac{AARR^*_{k+1}}{AARR^*_k}$$

where:

CSSC = control system services charge

$$CSP_{k+1} = \left(\left(CSP_k \times acmd_k - ADJ_k - SR_k \right) \times \frac{AARR^*_{k+1}}{AARR^*_k} + ADJ_{k+1} + SR_{k+1} \right) \div acmd_{k+1}$$

where:

CSP = common service price

ADJ = adjustment for difference between forecast and actual sales:

SR = spinning reserve costs allocated to loads

acmd = aggregate contracted maximum demand

For the second year:

$$CC_{k+2} = CC_k \times \frac{AARR^*_{k+2}}{AARR^*_k}$$

where:

$$AARR^*_{k+2} = AARR_{k+2} - ADJ_{k+2}$$

$$USP^{site}_{k+2} = USP^{site}{}_{k} \times \frac{AARR^{*}{}_{k+2}}{AARR^{*}{}_{k}} \times \frac{cmd^{site}_{k}}{cmd^{site}_{k+2}}$$

$$CSSC_{k+2} = CSSC_{k} \times \frac{AARR^{*}_{k+2}}{AARR^{*}_{k}}$$

$$CSP_{k+2} = \left(\left(CSP_{k} \times acmd_{k} - ADJ_{k} - SR_{k} \right) \times \frac{AARR^{*}{}_{k+2}}{AARR^{*}{}_{k}} + ADJ_{k+2} + SR_{k+2} \right) \div acmd_{k+2}$$

APPENDIX G

ANNUAL ADJUSTMENTS TO NON TRANSMISSION SOURCED ACCESS PRICES

CONTENTS

page

ANNUAL ADJUSTMENTS TO NON-TRANSMISSION SOURCED ACCESS PRICES

G1.0 SPINNING RESERVE

Spinning reserves are provided by those generators that have made a commitment to be constrained to a lower than optimal level of output in order to provide reserve generation to maintain frequency during load fluctuations, and to arrest and restore frequency in the aftermath of generator trips. Interruptible loads are also used to assist in arresting frequency decline in the aftermath of generator trips, and can therefore contribute to the system operator's spinning reserve requirements.

Spinning Reserve is therefore required for two major purposes:

- To control frequency variations caused by load and generation fluctuations; and
- To prevent supply interruption due to generating unit trips.

The costs of holding spinning reserve for each of these purposes are similar, however different levels of spinning reserve, Stage 1 and Stage 2, are required for each purpose.

- Stage 1 spinning reserve is the level of spinning reserve that is required to control frequency during load and generation fluctuations. Its cost is divided equally between loads and generators. Stage 1 spinning reserve is provided by generators only.

- Stage 2 spinning reserve is the level of spinning reserve that is required to prevent supply interruption due to generating unit trips. Its cost is therefore allocated to generators only. The majority of Stage 2 spinning reserve is currently provided by generators. However, a portion of Stage 2 spinning reserve can also be provided by interruptible load. Refer to section G2.

Western Power's current system operating policy is to hold a level of spinning reserve equal to 70% of the maximum net MW output of the largest generating unit. The largest generating unit on the system is currently the 300MW unit at Collie Power Station. However, to satisfy efficient generation dispatch this generator will be dispatched to 200MW for the majority of the time (estimated 4,869 hours), and to its maximum output of 300 MW output for the remainder of the time (estimated 3,891 hours). Accordingly, the level of spinning reserve will be maintained at 140MW for most of the time, and be increased to 210MW for the remainder of the time.

The level of spinning reserve necessary to satisfy the requirements of Stage 1 has been set at 65MW. Therefore, the additional level of spinning reserve necessary to satisfy Stage 2 will range from 75MW (for a total spinning reserve of 140MW) to 145MW (for a total spinning reserve of 210MW).

In summary:

- Stage 1 Spinning Reserve = 65MW
- Stage 2 Spinning Reserve = 75MW (140MW total) to 145MW (210MW total)

G1.1 CAPITAL COSTS OF SPINNING RESERVE

The capital cost of providing spinning reserve is based on the acceptable level of spinning reserve required under worst case loading conditions. The annualised capital cost of ensuring that this acceptable level of spinning reserve is maintained is $3,885,000. This amount is determined based on the cost of installing open cycle gas turbines.

G1.2 OPERATING COSTS OF PROVIDING SPINNING RESERVE

The following are the major operating costs associated with holding spinning reserve:

- **Energy cost of deloading generating units**

  When a generating unit deloads to provide spinning reserve it runs at a sub-optimal point on its operating curve, resulting in a reduction in conversion efficiency.

- **Energy cost of out of merit generation**

  Holding spinning reserve incurs additional energy costs because generating plant lower in merit order must be dispatched to cover spinning reserve capacity.

- **Generator unit start-up costs**

  Holding spinning reserves may result in additional generating unit starts across the network.

- **Interruptible load costs**

  A portion of Stage 2 spinning reserve can be substituted by interruptible load. The cost of providing interruptible load is currently estimated to be the operating cost of the equivalent amount of Stage 2 spinning reserve that it replaces. Refer to section G2.

A power system simulation software package is used to model the network's generation requirements and thereby provide an estimate of generation fuel costs. These simulations estimate the incremental cost of holding different levels of spinning reserve, thereby capturing the energy cost of out of merit generation, unit start costs and the deloading efficiency loss.

The annual operating cost of providing 140MW of spinning reserve, based on 98/99 costs and the current generating unit mix, is estimated from power system simulations

to be $6,580,000. The incremental operating cost of providing an additional 70MW (totalling 210MW) of spinning reserve for approximately 3,891 hours is $2,254,204.

G1.3 TOTAL SPINNING RESERVE COSTS

The incremental costs of providing spinning reserve for 1999/2000 are as follows:

C_{SR140} = C_{SRcap} + $C_{SR140\text{-}op}$
= $3,885,000 + $6,580,000
= $10,465,000

C_{SR210} = $2,254,204

C_{SRTOT} = C_{SR140} + C_{SR210}
= $12,719,204

where:

C_{SR140} is the total annual cost (in $) of providing the first 140MW of spinning reserve.

C_{SRcap} is the annual capital cost (in $) of maintaining the minimum level of spinning reserve.

$C_{SR140\text{-}op}$ is the annual operating cost (in $) of providing the first 140MW of spinning reserve.

C_{SR210} is the operating cost (in $) of providing an additional 70MW to a total of 210MW of spinning reserve for approximately 44% of the year (3,891 hours).

G1.4 SPINNING RESERVE COSTS ALLOCATED TO LOADS AND GENERATORS

The total spinning reserve costs are allocated across the two spinning reserve stages as follows:

$C_{Stage\ 1}$ = C_{SR65}
= (65/140) x C_{SR140}
= $4,858,750

$C_{Stage\ 2}$ = C_{SR75} + C_{SR210}

= (75/140) x C_{SR140} + C_{SR210}

= $5,606,250 + $2,254,204

= $7,860,454

where:

$C_{Stage\ 1}$ is the total annual cost (in $) of providing Stage 1 spinning reserve.

CSR_{65} is the total annual cost (in $) of providing the first 65MW of spinning reserve.

$C_{Stage\ 2}$ is the total annual cost (in $) of providing Stage 2 spinning reserve.

CSR_{75} is the total annual cost (in $) of providing an additional 75MW of spinning reserve, up to 140MW.

The spinning reserve costs for each stage are allocated to loads and generators as follows:

$C_{SRL} = 0.5 \times C_{Stage\ 1}$
$= \$2,429,375$

$C_{SRG} = 0.5 \times C_{Stage\ 1} + C_{Stage\ 2}$
$= \$2,429,375 + 7,860,454$
$= \$10,289,829$

where:

C_{SRL} is the total annual cost (in $) to loads of providing spinning reserve.

C_{SRG} is the total annual cost (in $) to generators of providing spinning reserve.

G1.5 SPINNING RESERVE PRICES

LOADS

The spinning reserve price for loads (in $/MW) is the total annual cost to loads as a function of the total system contract maximum demand.

$SRP_{Load} = C_{SRL} / CMD_{Tot}$

where:

SRP_{Load} is the spinning reserve price (in $/MW) to loads.

CMD_{Tot} is the total system contract maximum demand (in MW)

Loads are therefore charged for spinning reserve based on their individual contract maximum demands. This charge is included in the network common services charge.

Generators

The spinning reserve prices for generators (in $/hour) are a function of the incremental costs to provide spinning reserve to each MW block of generation, and the total estimated running hours for generators in each of the blocks. The sizes of these blocks are based on typical groupings of generator unit maximum net MW outputs. Refer to Table G1 below for details.

Note that the total size of Block 2 is the sum of the two sub- blocks: Block 2_{210} and Block 2_{140}, ie 126MW – 200MW, equalling 75MW.

The resulting generator spinning reserve prices are provided in section D8.1, Table D8. Note that the smaller, 0 - 9 MW, generators in Block 1 are not charged for spinning reserve.

The incremental cost for each of the generator blocks are calculated in Table G1 below:

TABLE G1

Block Number	Block Size (MW)	Block Range (MW)	Incremental Cost Calculation ($)	Incremental Cost ($)
1	100	201 - 300	(10/70) x CSR_{210}	IC_1
2_{210}	60	141 - 200	(60/70) x CSR_{210}	IC_{2210}
2_{140}	15	126 - 140	(15/140) x CSR_{140}	IC_{2140}
3	60	66 - 125	(60/140) x CSR_{140}	IC_3
4	20	46 - 65	0.5 x (20/140) x CSR_{140}	IC_4
5	45	0 - 45	0.5 x (45/140) x CSR_{140}	IC_5

where:

$C_{SRG} = IC_1 + IC_{2210} + IC_{2140} + IC_3 + IC_4 + IC_5$, and

IC_j is the incremental cost (in $) of providing spinning reserve to generating units in block j, for j = 1,3,4 & 5.

IC_{2140} is the incremental cost (in $) of providing 140MW of spinning reserve to generating units in Block 2.

IC_{2210} is the incremental cost (in $) of providing 210MW of spinning reserve to generating units in Block 2.

Note that Blocks 3 to 5 are covered by the incremental costs of providing up to 140MW of spinning reserve, and Block 1 is covered by the incremental cost of providing 210MW of spinning reserve. However, generators in Block 2 are partially covered by the incremental costs of providing 140MW and partially covered by the

incremental cost of providing 210MW of spinning reserve. Hence the need to divide Block 2 into two sub-blocks to equitably recover the costs associated with both levels of spinning reserve coverage.

The principle used to determine generator spinning reserve prices ensures that generator users are only charged for the level of spinning reserve that they create a need for. The larger the generating unit the greater the spinning reserve price.
Therefore, calculated first is the individual price element for each of the blocks as a function of the incremental block costs and generator running times, as follows:

$SRP_{Block\ 1} = IC_1 / RT_1$

$SRP_{Block\ 2_{210}} = IC_{2_{210}} / (RT_1 + RT_{2_{210}})$

$SRP_{Block\ 2_{140}} = IC_{2_{140}} / (RT_1 + RT_{2_{140}} + RT_{2_{210}})$

$SRP_{Block\ 3} = IC_3 / (RT_1 + RT_{2_{140}} + RT_{2_{210}} + RT_3)$

$SRP_{Block\ 4} = IC_4 / (RT_1 + RT_{2_{140}} + RT_{2_{210}} + RT_3 + RT_4)$

$SRP_{Block\ 5} = IC_5 / (RT_1 + RT_{2_{140}} + RT_{2_{210}} + RT_3 + RT_4 + RT_5)$

where:

$SRP_{Block\ j}$ is the spinning reserve price element (in $/hour) applicable to block j, for j = 1,3,4 & 5; and 2_{210} & 2_{140}

RT_j is the total annual running time (in hours) for all generator units in block j, for j = 1,3,4 & 5

$RT_{2_{140}}$ is the running time (in hours) during which those generators in block 2 are covered by 140MW of spinning reserve.

$RT_{2_{210}}$ is the running time (in hours) during which those generators in block 2 are covered by 210MW of spinning reserve.

Based on the principle of charging generators for all those levels of spinning reserve that they create a need for, the smallest generators in block 5 will only be charged at the rate calculated for their particular block. However the rate or price for a larger generator, up to those included in block 1, will be determined by adding the rate for its particular block to the progressive sum of the rates for all subordinate blocks.

The total spinning reserve prices for each of the generator blocks are, therefore, calculated as follows:

$SRP_{Gen1} = SRP_{Block\ 1} + SRP_{Block\ 2_{210}} + SRP_{Block\ 2_{140}} + SRP_{Block\ 3} + SRP_{Block\ 4} + SRP_{Block\ 5}$

$SRP_{Gen2_{210}} = SRP_{Block\ 2_{210}} + SRP_{Block\ 2_{140}} + SRP_{Block\ 3} + SRP_{Block\ 4} + SRP_{Block\ 5}$

$SRP_{Gen2_{140}} = SRP_{Block\ 2_{140}} + SRP_{Block\ 3} + SRP_{Block\ 4} + SRP_{Block\ 5}$

SRP_{Gen3} = $SRP_{Block\ 3}$ + $SRP_{Block\ 4}$ + $SRP_{Block\ 5}$

SRP_{Gen4} = $SRP_{Block\ 4}$ + $SRP_{Block\ 5}$

SRP_{Gen5} = $SRP_{Block\ 5}$

The price for generators in Block 2 is simplified by averaging its two (140/210) component prices as follows:

SRP_{Gen2} = $[(SRP_{Gen2140} \times RT_{2140}) + (SRP_{Gen2210} \times RT_{2210})] / [RT_{2140} + RT_{2210}]$

where:

SRP_{Genj} is the total spinning reserve price (in \$/hour) for a generating unit in block j, for j = 1, 3, 4 and 5. Refer to Table D8 for actual prices.

$SRP_{Gen2210}$ is the component spinning reserve price (in \$/hour) associated with providing those generators in block 2 with 210MW of spinning reserve.

$SRP_{Gen2140}$ is the component spinning reserve price (in \$/hour) associated with providing those generators in block 2 with 140MW of spinning reserve.

G2.0 INTERRUPTIBLE LOAD

Interruptible load is used as a substitute for Stage 2 spinning reserve. It can be provided by both Western Power and Independent Users of the Transmission Network.

If a proposal to provide interruptible load satisfies a number of technical and commercial criteria, the supplier will be paid the Interruptible Load Price (ILP), calculated below, for providing this service.

The purchase price for interruptible load (in \$/MW) is the operating cost per MW of Stage 2 spinning reserve. This price is calculated as follows:

$C_{Stage\ 2\text{-}op}$ = (75/140) x $CSR_{140\text{-}op}$ + CSR_{210}
= \$3,525,000 + \$2,254,204
= \$5,779,204

$SR_{Stage\ 2}$ = $[(75 \times RT_{140}) + (145 \times RT_{210})] / [RT_{140} + RT_{210}]$
= [(75 x 4869) + (145 x 3891)] / [4869 + 3891]
= 106.092MW

ILP = $C_{Stage\ 2\text{-}op}$ / $SR_{Stage\ 2}$
= \$54,473 per MW

where:

$C_{Stage\ 2\text{-}op}$ is the annual operating cost (in $) of providing Stage 2 spinning reserve.

$CSR_{140\text{-}op}$ is the annual operating cost (in $) of providing the first 140MW of spinning reserve.

CSR_{210} is the operating cost (in $) of providing an additional 70MW to a total of 210MW of spinning reserve for approximately 44% of the year (3,891 hours).

$SR_{Stage\ 2}$ is the average level of Stage 2 spinning reserve (in MW) provided for the year.

RT_{140} is the estimated time (in hours) that the system operator will dispatch 140MW of spinning reserve.

RT_{210} is the estimated time (in hours) that the system operator will dispatch 210MW spinning reserve.

ILP is the annual interruptible load purchase price (in $/MW) paid for supply of the interruptible load service.

G2.1 PROPOSALS FOR THE SUPPLY OF INTERRUPTIBLE LOAD

Western Power's Manager Transmission Customer Services will perform the brokering function of procuring interruptible load from Western Power and Independent Suppliers, and on-selling it as an integral component of the spinning reserve service to all generator users.

Conditions apply to the supply of interruptible load. Prospective suppliers of this service must first contact the Manager Transmission Customer Services with details of any interrupible load proposal to determine its suitability.

G3.0 POST TRIP MANAGEMENT

Post trip management prices are intended to reflect the costs of rescheduling generation in the aftermath of a sudden loss of generation capacity to preserve the integrity of the power system. The more unreliable a generator, the greater will be the annual charges for this service.

Generator Startup Price ($/MW)

This price reflects the estimated fuel and maintenance costs incurred through starting standing reserve gas turbine units.

Out of Merit Generation Price

The Out of Merit Generation price reflects the excess cost of running standing reserves out of merit to replace tripped generation. The price is the difference between the estimated average generation marginal price and the estimated standing reserve rate. It is assumed the system can be returned to merit dispatch within one hour.

Load Shedding Price ($/MWh)

The Load Shedding Price reflects the notional value of loss of supply to the customer. It is taken to have an average value of $10,000/MWh. The charge is applied for only five minutes, as beyond this time standing reserves should be able to take up load. It is applied only to that portion of a trip greater than the assumed level of spinning reserve.

G4.0 ENERGY BALANCING

The energy sell prices are based on the estimated marginal electricity production costs at different periods, and include a capacity component.

The energy buy prices are based on the avoided costs of production at different times of the year. These do not include a capacity component because it is not possible to rely on this capacity for generation planning purposes.

The energy balancing prices are provided in Appendix D:

- the energy out of balance price (buy) will be the off peak rate for energy purchases by Western Power;
- the energy out of balance price (sell) will be the peak summer supply rate of Western Power; and
- the half hourly out of balance prices (buy and sell) will be published Western Power sale and purchase rates for energy at corresponding time zones.

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APPENDIX H

LOSS FACTOR SCHEDULE

CONTENTS

H1. LOSS FACTORS - SOUTH WEST TRANSMISSION NETWORK CONNECTION POINTS

TABLE H1		
CONNECTION POINT		LOSS FACTOR
ABBREVIATION	NAME	MU 330 REF BUS
A 132	Arkana	1.04728
ABD 132	ALCOA Boddington	1.02622
AKW 132	ALCOA Kwinana	1.03787
ALB 132	Albany	1.06467
APJ 132	ALCOA Pinjarra	1.04271
APM 66	Aust Paper Mills	1.05004
BCH 132	Beechboro	1.04569
BEL 132	Belmont	1.05182
BKF 132	Black Flag	1.20056
BLD132B2	Boulder	1.19794
BNP 132	Beenup	1.02404
BNY132	Bounty	1.10072
BP 66	British Petroleum	1.04051
BPR 132	B.P. Refinery	1.03924
BSI 132	Barrack Silicon Smelter	1.02002
BSN 66	Busselton	1.07134
BPS 132	Bunbury Power Station	1.01477
BTN 132	Bridgetown	1.00859
BUH 132	Bunbury Harbour	1.01981
BUR 66	Burswood Island Casino	1.06045
BYF 132	Byford	1.04831
C 66	Cottesloe	1.05630
CAP 66	Capel	1.05101
CBK 132	Claisebrook	1.05168
CBP 132	CSBP	1.03926
CC 132	Cockburn Cement	1.04066
CK 66	Cook Street	1.05930
CL 66	Clarence Street	1.06379
CLP 66	Coolup	1.04610
CO 66	Collie	1.00910
COL 66	Collier Street	1.06359
CPN 132	Chapman	1.07407
CUN 66	Cunderdin	1.10577
CVE 132	Canning Vale	1.05017
D 132	Darlington	1.06067
E 66	Edmund Street	1.04966
ENB 132	Eneabba	1.07392
EWR 132	Edgewater	1.04823
F 66BUS1	Forrest Ave	1.05728
G 132	Gosnells	1.05231
GGV 132	Golden Grove	1.08723

TABLE H1 (Continued)		
CONNECTION POINT		LOSS FACTOR
ABBREVIATION	NAME	MU 330 REF BUS
	Gera	1.08341
H 132	Hadfields	1.04711
HAY 132	Hay Street	1.05238
HE 66	Herdsman Parade	1.05993
HIS 132	Hismelt	1.03925
JT66BUS1	Joel Terrace	1.05368
K 132	Kalamunda	1.05819
KAT 66	Katanning	1.05292
KDN 220	Kondinin	1.06746
KEL 66	Kellerberrin	1.14189
KMC 132	Kerr McGee Cataby	1.05647
KMK 132	Kerr McGee Kwinana	1.03924
KMM 132	Kerr McGee Muchea	1.03623
KOJ132B2	Kojonup	1.02481
KPS 330 & 132	Kwinana Power Station	1.03407
LMC 132	Muchea Local	1.03623
LMR 132	Marriott Road Local	1.01998
MA 132	Manning Street	1.04890
MC 66	Medical Centre	1.05704
MED 132	Medina	1.03942
MER 66	Merredin	1.13215
MGA 132	Mungarra	1.04816
MH 132	Mandurah	1.04386
MIL 132	Milligan Street	1.04783
MJ 132	Midland Junction	1.06094
MJP 132	Manjimup	1.01490
MO 132	Morley	1.04736
MOR 132	Moora	1.06185
MPS 330, 220 & 132	Muja Power Station	1.00000
MR 66	Margaret River	1.08670
MUL 132	Mullaloo	1.04822
MW 66	Mundaring Weir	1.07258
MY 66	Myaree	1.05408
N 66	Nedlands	1.05680
NB 132	North Beach	1.04892
NF 66	North Fremantle	1.05420
NGN 66	Narrogin	1.03469
NOR 66	Northam	1.08230
NP 66	North Perth	1.05948
OC 66	O'Connor	1.05284
OP 132	Osborne Park	1.04853
PCY 132	Piccadilly	1.19458
PIC 66	Picton	1.02320

PJR 132	Pinjar	1.03062
QNP 66	Quinninup	1.01318
RBD 132	Reynolds Boddington	1.02623
RO 132	Rockingham	1.04100

TABLE H1 (Continued)		
CONNECTION POINT		LOSS FACTOR
ABBREVIATION	NAME	MU 330 REF BUS
RTN 132	Riverton	1.04587
RV 66	Rivervale	1.06061
SF 66	South Fremantle	1.04530
SP 66	Shenton Park	1.05726
SV 66	Sawyers Valley	1.07661
SX 66	Southern Cross	1.25348
TLN 66	Tomlinson Street	1.05948
TS 132	Three Springs	1.06752
TT 66	Tate Street	1.05838
U 66	University	1.05736
VP 66	Victoria Park	1.05924
W 66BUS1	Wellington Street	1.05520
WAG 66	Wagin	1.06188
WD 66	Wembley Downs	1.05774
WE 132	Welshpool	1.05394
WEB 66	WEB Grating	1.05924
WGP 132	Wagerup	1.02638
WKT 220 & 132	West Kalgoorlie	1.19000
WM 132	Western Mining	1.04002
WOR 132	Worsley	1.01169
WSD 66	Westralian Sands	1.04551
WUN 66	Wundowie	1.08284
Y 132	Yokine	1.04782
YER 66	Yerbillon	1.13349
YLN 220	Yilgarn	1.13889
YNP 66	Yornup	1.01278
YP 132	Yanchep	1.04426

Note: the entry and exit loss factors of each connection point are the same.

H2. LOSS FACTORS - NORTH WEST TRANSMISSION NETWORK CONNECTION POINTS

TABLE H2		
CONNECTION POINT		LOSS FACTOR
ABBREVIATION	NAME	CLB33KV REF BUS
AST	Anderson Street	1.03939
BUL	Bulgarra	1.01795
CLB-33	Cape Lambert Terminal 33kV	1.00000
DMP	Dampier (WPC)	1.01885
LPS-33	Cape Lambert Power Station	0.97354
MDR	Murdoch Drive	1.02738
MNM-66	Mt Newman (BHP)	1.04003
NGA-66	Nimingarra (BHP)	1.06559
PCK	Pegs Creek	1.01783
PSN-33	Point Samson	1.00037
WFD	Wedgefield	1.02533

Note: the entry and exit loss factors of each connection point are the same.

APPENDIX I

ANNUAL ADJUSTMENTS TO LOSS FACTORS

ANNUAL ADJUSTMENTS TO LOSS FACTORS

Loss Factors for Exit and Entry points represent the ratio of energy generated to energy taken for increments of load at each network Entry and Exit point with respect to a network reference node. They are calculated from network simulations using half-hourly load data. Loss factors apply for the full financial year and may be recalculated each year.

Loss factors can be understood in reference to the following equations:

For a lossless network with n nodes,

$$\sum_{i=1}^{i=n} P_i = 0$$

i.e. all energy injected equals energy taken.

For actual networks where a proportion of energy is consumed (lost) in lines and transformers, the energy balance equation is to be represented by:

$$\sum_{i=1}^{i=n} L_i * P_i = 0$$

where L_i is the loss factor for node i at which energy P_i is injected or taken.

In practice each loss factor L_i will be an average derived from simulation of multiple half hourly actual network load and generation conditions.

Loss factors are used to assist in the determination of:

- the additional energy required to be produced by generator users to cover network losses;
- the additional energy recovered to be purchased by load users to cover network losses; and
- charges for standby power and energy balancing.

APPENDIX J

STANDBY GENERATION CAPACITY AND SERVICES CHARGES

CONTENTS

STANDBY GENERATION CAPACITY AND SERVICE CHARGES
(This service is currently under review and subject to change)

J1 South West Network

Standby capacity is required by generator Users who require the delivery of energy during periods of maintenance of their own generators, or during unplanned outages.

J1.1 Types of Standby Services

Western Power may offer to supply standby power on the following bases:

- anytime supply;
- anytime non firm supply; and
- scheduled cover.

Anytime supply: Available without notice provided demand does not exceed a contractually agreed Standby Generation Reservation. Supply reliability will be equal to other customers supplied by the system at the time.

Anytime non firm supply: May be available without notice provided demand does not exceed a contractually agreed Standby Generation Reservation, but is subject to non supply in order to maintain acceptable reliability of supply to other customers.

Scheduled cover: Offered on the basis of firm supply provided the timing is agreed with System Operations on an annual basis three months prior to the start of a new financial year. This cover will generally not be offered during periods of forecast peak system demands.

J1.2 Components of Standby Charges

The charges for standby power will consist of one or more of the following three components:

- service charges;
- capacity charges; and
- energy charges.

Service charges will apply on an annual basis and will be charged according to Standby Demand Reservation for the year. All three standby supply arrangements will incur this charge.

Capacity charges will apply for “anytime supply” only.

The service and capacity charges are given in table J1.

Energy charges will be calculated as per the energy balancing charge. Refer to regulation 22 of the Regulations and Appendix L for details.

Where demand exceeds the agreed Standby Generation Reservation plus Generation Output, an **Excess Standby Generation Charge** (refer to regulation 23 of the Regulations for details) will apply in addition to energy charges for the energy usage.

TABLE J1

ANNUAL STANDBY CAPACITY AND SERVICE PRICES

	Price
Capacity	$14.40 /kW
Service	$10.00 /kW

The annual Standby Generation Charge, excluding energy charges, is calculated as follows:

SGC = (SGCP + SGSP) x SGR

where:

SGC (in $) is the Standby Generation Charge;

SGCP (in $/kW) is the Standby Generation Capacity Price;

SGSP (in $/kW) is the Standby Generation Service Price;

SGR (in kW) is the Standby Generation Reservation for the group of connections in respect of the standby generation capacity agreement for the period; and

$SGR = \sum (NSGR_i \times LFExit_i)$

where:

the variable "i" represents an exit point which is one of the group of connections.

$NSGR_i$ (in kW) is the Nominal Standby Generation Reservation nominated for exit point i in respect of the standby generation capacity agreement for the period;

LFExit (a rate) is the loss factor for exit point i determined in accordance with the Transmission Regulations;

J2 North West Network

In general, standby requirements in the Pilbara are managed by the Corporation by pooling all available generating capacity connected to the network on the principle of mutual support. This arrangement is constrained by various automatic load shedding arrangements. Limited Corporation generation is available on cold standby but at a high marginal cost.

New standby arrangements will be negotiated individually with penalty rates for balancing energy depending on the User's requirements and the potential for mutual support.

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APPENDIX K

SAMPLE CALCULATION OF NETWORK AND ANCILLARY SERVICES CHARGES

CONTENTS

SAMPLE CALCULATION OF NETWORK AND ANCILLARY SERVICES CHARGES

K1 Example 1

In this example we will assume that an application for access to the transmission network has been made for a new load with a contract maximum demand (CMD) of say 20MW at 132kV from the Corporation's Black Flag substation. An application also includes access for a new generator with a declared sent out capacity of say 25 MW at or near Pinjar Power Station north of Perth, with the intention of forming an energy supply contract. The calculation of charges to each of these network users is outlined below.

K2 Charges for the Load Offtake

a) Connection Charge

This is a user specific charge and will be determined by the capacity and type of the substation which the User elects to build.

Assume for this exercise that no new connection asset is required at Black Flag to connect this new load and the TLD (refer to clause 4.1.2) of the existing users connected to Black Flag is 20MW. In accordance with clause 4.1.2, the new load user will pay a connection charge of $141,315p.a. (=$282,630p.a. x 20 / (20 + 20)) which is 50% of the total connection charge for Black Flag of $282,630p.a. from Table D1.

b) Use of System (UoS) Charge

From the Pricing Schedule (Table D5), the annual UOS price for Black Flag is $45.93/kW.

Therefore the UOS charge will be $45.93* 20,000=$918,600 p.a.

c) Common Service Charge

From the Pricing Schedule (Table D5) the common service price is $14.34/kW.

Therefore, the common service charge will be $14.34*20,000=$286,800p.a.

d) Standby Charges

This will depend on usage. The user may contract with the Corporation or another user for supply of standby power.

Summary of possible annual charges for load:

Annual Charge	$ 000's
Connection	141.32
UOS	918.6
Common Service	286.8
Total	**$1346.72**

K3 Charges for the Generator

a) Connection Charge

This is a user specific charge and will be determined by the capacity and type of the substation which the User elects to build.

Assume for this exercise that a new connection is required and the connection charge is the same as that for Geraldton GT in Table D2 because the installations are similar.

Therefore the connection charge will be $90,300 p.a.

b) Use of System Charge

From the Price Schedule (Table D6) the annual UOS price for Pinjar is $5.50/kW.

Therefore the UOS charge will be $5.50*25,000=$137,500 p.a.

c) Ancillary Services Charges

c.1) Spinning Reserve
The spinning reserve price for generators with the maximum net output of between 10MW and 45MW is $4.80/hr (Table D8). Assume that the generator will be in service for 6000 hours per year. Therefore the spinning reserve charge will be $4.80*6,000 = $28,800 p.a.

c.2) Post Trip Management
The post trip management charge will depend on the characteristics of each event.

c.3) Control System Services
The control system services charge is incorporated in the connection charge.

c.4) Energy Balancing

The energy balancing service fee applies to both entry and exit connections. From the Price Schedule (D8.4.1) the price is $1,000 per month per connection per access agreement. The annual charge for this example will therefore be $12,000 each to the generator and the load, giving a total of $24,000.

Energy balancing charges will depend on usage. Refer to Appendix L for an example calculation of balancing charges.

Summary of possible annual charges for generator

Annual Charge	**$ 000**
Connection	90.3
UOS	137.5
Ancillary Services	52.8
Total	**$280.6**

Explanatory Notes:

1. These charges are indicative only. Actual charges will be determined by user specific requirements.

2. It is expected that the users will make arrangements for the purchase of standby energy, either from the Corporation or a third party. There will be access charges for a third party generator supplying standby energy. The generator will be required to generate additional energy to cover incremental network losses.

3. The ancillary services charge excludes post trip management and energy balancing.

4. The charges are subject to change in accordance with the charges and prices published in the "Electricity Transmission Access Pricing and Charges" paper which is reviewed annually.

K4 Example 2 Network Charges for an Embedded Generator

Suppose there is an energy supply contract between a generator user at Manjimup and a load user at Black Flag. The generator user at Manjimup has an embedded generator which has a maximum net output of 30MW and an on-site load of 20MW. This generator user wants to export up to 10MW and secure a reserved standby supply of 15MW for Manjimup ("MJP").

Therefore, at Manjimup the generator user's declared sent out capacity is 10 MW and the standby contract maximum demand is 15MW.

At Black Flag the contract maximum demand is 10MW.

K4.1 Charges for the generator

a) Connection Charge

Assume for this exercise that no new connection asset is required at Manjimup to connect the new generator and the TLD (refer to clause 4.1.2) of the existing users at Manjimup is 30MW. In accordance to clause 4.1.2, the connection charge allocated to the generator user is $147,403p.a (=442,210*15/(30+15)) which is 1/3 of the total connection charge for Manjimup of $442,210 pa from Table D1.

b) Network Charge

The annual network charge for the generator user at Manjimup is calculated as follows:

b.1) Network charge calculation for export:

USC = 10MW * $9.20/kW= $92,000 p.a.
[The UOS price for MU of $9.20/kW : Appendix D, Table D6 – electrically closest to MJP]

b.2) Network charge calculation for import:

Assume that the required load factor for the use of standby energy is higher than 0.15 (i.e. no standby concession).

USC = 15MW * $46.65/kW = $ 699,750 p.a.
[The UOS price for MJP is $43.75/kW: Appendix D, Table D5]

CSC = 15MW * $14.34/kW = $215,100
[The common service price is $14.34/kW : Appendix D, Table D5]

Total= $914,850 p.a

b.3) Network charge to the generator User at Manjimup

The network charge payable will be the greater of b.1 and b.2 (refer to clause 4.6).

In this example the calculated network charge for import is greater than the calculated network charge for export.

Therefore, the network charge to the generator user at Manjimup is $914,850 p.a.

K4.2 Charges to the Load

The annual network charges for the load user at Black Flag are calculated in a similar manner to those in K2 as follows:

a) Connection Charge

Again, assume for this exercise that no new connection asset is required at Black Flag to connect this new load and the TLD of the existing users connected to Black Flag is 20MW. The connection charge will be: $282,630*10/(10+20) = $94,210p.a.

b) Use of System Charge

USC = $45.93 * 10,000 = $459,300p.a.
[The UoS price for Black Flag is $45.93/kW, Appendix D, Table D5]

c) Common Service Charge

CSC = $14.34 * 10,000 = $143,400 p.a.

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APPENDIX L

SAMPLE CALCULATION OF ENERGY AND DEMAND BALANCING AND EXCESS NETWORK USAGE CHARGES

CONTENTS

SAMPLE CALCULATION OF ENERGY AND DEMAND BALANCING AND EXCESS NETWORK USAGE CHARGES

For the purposes of this example the following access agreement parameters have been assumed:

Number of Entry Points	= 1
Number of Exit Points	= 1
Declared Sent Out Capacity (DSOC)	= 37000kW
Contract Maximum Demand (CMD)	= 35000kW
Standby Generation Reservation (SGR)	= 1500kW
Entry Point Loss Factor (LFEntry)	= 1.025
Exit Point Loss Factor (LFExit)	= 1.04

The formulas used in this example are based on Part 4 of the Electricity Transmission Regulations, 1996. Unless otherwise stated, the demand/energy data and prices used in these formulas can be found in Tables L1 and L2, and the Price Schedule (Appendix D) respectively.

L1 Energy Balancing - Half Hourly Out of Balance Charge

A half hourly out of balance charge is recorded when the absolute value of the difference between the energy entry amount and the energy exit amount exceeds the greater of 3% of the CMD divided by 2 and 500kWh, ie, the Permitted Tolerance.

Given this is the case, and:

- the energy entry amount is greater than the energy exit amount, then the charge is payable by WPC to the User; or if
- the energy entry amount is less than the energy exit amount, then the charge is payable by the User to WPC.

The charges will be calculated in accordance with the prices nominated in Tables D11 and D13 of the Price Schedule.

L1.1 Energy Readings

In this example the calculations are based on the half hour entry and exit energy readings taken at 1330 hours on 9/10/96 (Spring-Peak Time Zone). Refer to Table L1.

ETEntry	= 8002.50 kWh
ETExit	= 8659.00 kWh

L1.2 Energy Entry Amount (EEA)

EEA = ETEntry x LFEntry = 8002.50 x 1.025 = 8202.56 kWh

L1.3 Energy Exit Amount (EEXA)

EEXA = ETExit x LFExit = 8659.00 x 1.04 = 9005.36 kWh

L1.4 Energy Imbalance (EIMB)

EIMB = EEA - EEXA = 8202.56 - 9005.36 =-802.80 kWh

L1.5 Permitted Tolerance (TOL)

TOL = 3% x CMD/2 = 525 kWh

L1.6 Adjusted Net Amount - Half Hour Readings (ANA_{HH})

ANA_{HH} are the energy out of balance amounts recorded half hourly when there is a difference between the energy entry amount and the energy exit amount. These amounts are limited to a maximum equal to plus the permitted tolerance and a minimum equal to minus the permitted tolerance.

ANA_{HH}	= EIMB	for	$\lvert EIMB \rvert < TOL$
ANA_{HH}	= +TOL	for	$EIMB \geq +TOL$
ANA_{HH}	= -TOL	for	$EIMB \leq -TOL$

$\therefore ANA_{HH}$ = -TOL = -525 kWh

L1.7 Revised Net Amount (RNA)

RNA is the energy for this half hour that will not be included in the next monthly balance.

RNA = EIMB - ANA_{HH} = -802.80 - (-525) = -277.80 kWh

L1.8 Half Hourly Out of Balance Price (HOBP)

RNA is negative, therefore, the HOBP is the WPC selling price given in Table D11 of the Price Schedule.

$\therefore$ HOBP = 7.7 c/kWh for the Spring-Peak time zone.

L1.9 Half Hourly Out of Balance Charge (HOBC)

HOBC = RNA x HOBP x 1/100 = -277.80 x 7.7 x 1/100 = -$21.39

L1.10 Half Hourly Out of Balance Charge - Monthly Total ($\sum$HOBC)

$\sum$HOBC= $33,864.66. Refer Table L2

The resulting amount is positive and is therefore payable by WPC to the User.

L2 Energy Balancing - Monthly Out of Balance Charge

The monthly out of balance charge is the sum of the half hourly out of balance amounts (ANA) multiplied by the appropriate energy price (OBP) nominated in Table D10 of the Price Schedule. ANA is the monthly aggregate of the ANA_{HH} energy amounts.

If ANA is positive, the charge is payable by WPC to the User. If ANA is negative, the charge is payable by the User to WPC.

The following calculations are based on the monthly data given in Table L2.

L2.1 Sum of the Adjusted Net Amounts for the Month (ANA)

ANA = 37069.79 kWh

L2.2 Out of Balance Price (OBP)

ANA is positive, therefore, the OBF is the WPC buy price given in Table D10 of the Price Schedule.

$\therefore$ OBP = 2c/kWh

L2.3 Out of Balance Charge (OBC)

OBC = ANA x OBP x 1/100 = 37069.79 x 2 x 1/100 = $741.40

The result is positive and is therefore payable by WPC to the User.

L3 Demand Balancing - Excess Standby Generation Capacity Charge

An excess standby generation charge is payable by a User when it experiences an excess demand (ED), ie, when its demand exit rate is greater than the sum of its demand entry rate and standby generation reservation.

An excess demand period of 336 half hours (one week) in duration is initiated by the occurrence of an excess demand.

The charge payable will be calculated based on the maximum excess demand occurring during each excess demand period.

L3.1 Demand Readings

In this example the calculations are based on the readings for 1330 hours on 9/10/96. Refer to Table L1.

PTEntry = 16005.00 kW
PTExit = 17318.00 kW

L3.2 Demand Exit Rate (DERA)

DERA = PTExit x LFExit = 17318.00 x 1.04 = 18010.72 kW

L3.3 Demand Entry Rate (DER)

DER = PTEntry x LFEntry = 16005.00 x 1.025 = 16405.13 kW

L3.4 Excess Demand (ED)

ED = DERA - DER - SGR for DERA - DER - SGR > 0
ED = 0 for DERA - DER - SGR ≤ 0

∴ED = DERA - DER - SGR = 18010.72 - 16405.13 - 1500 = 105.60 kW

L3.5 Maximum Excess Demand (Ei)

In this part of the example the determination of maximum excess demand is based on the daily excess demand data given in Table L2.

L3.6 Maximum Excess Demand in First Excess Demand Period (E1)

The first excess demand period (EDP1) commenced at 1430 hours on 3/10/96 when an excess demand of 163.48 kW was recorded for that half hour.

Before the conclusion of EDP1 (336 half hours) a further excess demand of 105.60 kW was recorded at 1330 hours on 9/10/96.

No further excess demands were recorded for the remainder of EDP1 which concluded at 1400 on 10/10/96. Note that the excess demand on 9/10/96 does not affect the duration of EDP1.

∴ E1 = 163.48 kW

L3.7 Maximum Excess Demand in Second Excess Demand Period (E2)

A second excess demand period commenced at 1030 hours on 17/10/96 when an excess demand of 2987.62 kW was recorded for that half hour.

A further 12 excess demand readings were recorded in the following half hours till 1630 hours. However, the highest of these readings, occurring at 1100 hours, was 16206.11 kW.

No further excess demand readings were recorded for the remainder of EDP2.

$\therefore$ E2 = 16206.11kW

L3.8 Excess Standby Generation Capacity Charge (ESCC)

ESCC = $\sum$ Ei x ESGP where ESGP is nominated in D8.4.6 of the Price Schedule.

$\therefore$ ESCC= (E1 + E2) x ESGP = (163.48 + 16206.11) x \$20.00 = \$327,391.80

This charge is payable by the User to WPC.

L4 Excess Network Usage Charge

L4.1 Entry Point

An excess network usage charge is payable by a generator when its PTEntry is greater than its declared sent out capacity. The amount by which it is greater is called the excess amount.

An excess period of 336 half hours in duration is initiated by the occurrence of an excess amount.

The charge payable will be calculated based on the maximum excess amount occurring during each excess period (Ei).

L4.1.1 Maximum Excess Amount (Ei)

For the purposes of this example assume that within the month only one excess period was initiated and that the corresponding maximum excess amount is 1000 kW.

L4.1.2 Use of System Price (USP)

For the purposes of this example assume that the use of system price for this entry point, determined in accordance with the access agreement, is \$5.00/kW.

L4.1.3 Excess Network Usage Factor (EF)

The excess network usage factor, nominated in D9 of the PriceSchedule, is 1.5/12 = 0.125.

L4.1.4 Excess Network Usage Charge - Entry Point (ENUC)

$$ENUC = \sum Ei \times USP \times EF = 1000 \times \$5 \times 1.5/12 = \$625.00$$

L4.2 Exit Point

An excess network usage charge is payable by a load when its PTExit is greater than its contract maximum demand. The amount by which it is greater is called the excess rate.

An excess demand period of 336 half hours in duration is initiated by the occurrence of an excess rate.

The charge payable will be calculated based on the maximum excess rate occurring during each excess demand period (Ei).

L4.2.1 Maximum Excess Amount (Ei)

For the purposed of this example assume that within the month only one excess demand period was initiated and that the corresponding maximum excess rate is 500 kW.

L4.2.2 Use of System Price (USP)

For the purposes of this example assume that the use of system price for this exit point, determined in accordance with the access agreement, is $25.00/kW.

L4.2.3 Common Services Price (CSP)

The common services price, nominated in table D5 of the Price Schedule, is $14.39/kW.

L4.2.4 Excess Network Usage Factor (EF)

The excess network usage factor, nominated in D9 of the Price Schedule, is 1.5/12 =0.125.

L4.2.5 Excess Network Usage Charge - Exit Point (ENUC)

$$ENUC = \sum Ei \times (USP + CSP) \times EF$$

$$= 500 \times (25 + 14.39) \times 1.5/12$$
$$= \$2,461.87$$

TABLE L1

ENERGY AND DEMAND BALANCING DATA - HALF HOURLY READINGS																9/10/96
	ENTRY			EXIT			ENERGY	ENERGY IMBALANCE CHARGES				DEMAND IMBALANCE			
	LFEntry = 1.025			LFExit = 1.04			IMBALANCE	TOLERANCE = 525				STANDBY GEN RES (SGR) = 1500			
TIME	PTEntry KW	ETEntry KWHR	EEA KWHR	PTExit KW	ETExit KWHR	EEXA KWHR	EIMB KWHR	ANA_{HH} KWHR	RNA KWHR	HOBP c/KWHR	HOBC $	DERA KW	DER KW	DIMB KW	ED KW
30	21056.00	10528.00	10791.20	21319.00	10659.50	11085.88	-294.68	-294.68	0.00	3.50	0.00	22171.76	21582.40	589.36	0.00
100	20808.00	10404.00	10664.10	20875.00	10437.50	10855.00	-190.90	-190.90	0.00	3.50	0.00	21710.00	21328.20	381.80	0.00
130	18789.00	9394.50	9629.36	18942.00	9471.00	9849.84	-220.48	-220.48	0.00	3.50	0.00	19699.68	19258.73	440.96	0.00
200	15011.00	7505.50	7693.14	15168.00	7584.00	7887.36	-194.22	-194.22	0.00	3.50	0.00	15774.72	15386.28	388.45	0.00
230	13962.00	6981.00	7155.53	12934.00	6467.00	6725.68	429.84	429.84	0.00	2.00	0.00	13451.36	14311.05	-859.69	0.00
300	16968.00	8484.00	8696.10	17507.00	8753.50	9103.64	-407.54	-407.54	0.00	3.50	0.00	18207.28	17392.20	815.08	0.00
330	18192.00	9096.00	9323.40	18679.00	9339.50	9713.08	-389.68	-389.68	0.00	3.50	0.00	19426.16	18646.80	779.36	0.00
400	19235.00	9617.50	9857.94	18998.00	9499.00	9878.96	-21.02	-21.02	0.00	3.50	0.00	19757.92	19715.88	42.05	0.00
430	20320.00	10160.00	10414.00	20167.00	10083.50	10486.84	-72.84	-72.84	0.00	3.50	0.00	20973.68	20828.00	145.68	0.00
500	18427.00	9213.50	9443.84	18424.00	9212.00	9580.48	-136.64	-136.64	0.00	3.50	0.00	19160.96	18887.68	273.29	0.00
530	20212.00	10106.00	10358.65	18699.00	9349.50	9723.48	635.17	525.00	110.17	2.00	2.20	19446.96	20717.30	-1270.34	0.00
600	20166.00	10083.00	10335.08	19842.00	9921.00	10317.84	17.23	17.23	0.00	2.00	0.00	20635.68	20670.15	-34.47	0.00
630	18950.00	9475.00	9711.88	18422.00	9211.00	9579.44	132.43	132.43	0.00	3.00	0.00	19158.88	19423.75	-264.87	0.00
700	15784.00	7892.00	8089.30	15371.00	7685.50	7992.92	96.38	96.38	0.00	3.00	0.00	15985.84	16178.60	-192.76	0.00
730	15102.00	7551.00	7739.78	15067.00	7533.50	7834.84	-95.07	-95.07	0.00	5.70	0.00	15669.68	15479.55	190.13	0.00
800	18864.00	9432.00	9667.80	18523.00	9261.50	9631.96	35.84	35.84	0.00	3.00	0.00	19263.92	19335.60	-71.68	0.00
830	20988.00	10494.00	10756.35	20841.00	10420.50	10837.32	-80.97	-80.97	0.00	5.70	0.00	21674.64	21512.70	161.94	0.00
900	21226.00	10613.00	10878.33	21454.00	10727.00	11156.08	-277.76	-277.76	0.00	5.70	0.00	22312.16	21756.65	555.51	0.00
930	19667.00	9833.50	10079.34	20231.00	10115.50	10520.12	-440.78	-440.78	0.00	5.70	0.00	21040.24	20158.68	881.57	0.00
1000	19166.00	9583.00	9822.58	20103.00	10051.50	10453.56	-630.99	-525.00	-105.99	5.70	-6.04	20907.12	19645.15	1261.97	0.00
1030	19022.00	9511.00	9748.78	19944.00	9972.00	10370.88	-622.11	-525.00	-97.11	5.70	-5.53	20741.76	19497.55	1244.21	0.00
1100	19654.00	9827.00	10072.68	20402.00	10201.00	10609.04	-536.37	-525.00	-11.37	5.70	-0.65	21218.08	20145.35	1072.73	0.00
1130	14410.00	7205.00	7385.13	15083.00	7541.50	7843.16	-458.04	-458.04	0.00	7.70	0.00	15686.32	14770.25	916.07	0.00
1200	12650.00	6325.00	6483.13	13531.00	6765.50	7036.12	-553.00	-525.00	-28.00	7.70	-2.16	14072.24	12966.25	1105.99	0.00

ENERGY AND DEMAND BALANCING DATA - HALF HOURLY READINGS															9/10/96
	ENTRY			EXIT			ENERGY	ENERGY IMBALANCE CHARGES				DEMAND IMBALANCE			
	LFEntry = 1.025			LFExit = 1.04			IMBALANCE	TOLERANCE = 525				STANDBY GEN RES (SGR) = 1500			
TIME	PTEntry	ETEntry	EEA	PTExit	ETExit	EEXA	EIMB	ANA_{HH}	RNA	HOBP	HOBC	DERA	DER	DIMB	ED
	KW	KWHR	KWHR	KW	KWHR	KWHR	KWHR	KWHR	KWHR	c/KWHR	$	KW	KW	KW	KW
1230	13641.00	6820.50	6991.01	14028.00	7014.00	7294.56	-303.55	-303.55	0.00	7.70	0.00	14589.12	13982.03	607.10	0.00
1300	17491.00	8745.50	8964.14	17421.00	8710.50	9058.92	-94.78	-94.78	0.00	7.70	0.00	18117.84	17928.28	189.57	0.00
1330	16005.00	8002.50	8202.56	17318.00	8659.00	9005.36	-802.80	-525.00	-277.80	7.70	-21.39	18010.72	16405.13	1605.60	105.60
1400	18654.00	9327.00	9560.18	19024.00	9512.00	9892.48	-332.31	-332.31	0.00	7.70	0.00	19784.96	19120.35	664.61	0.00
1430	18922.00	9461.00	9697.53	18683.00	9341.50	9715.16	-17.64	-17.64	0.00	7.70	0.00	19430.32	19395.05	35.27	0.00
1500	19199.00	9599.50	9839.49	19456.00	9728.00	10117.12	-277.63	-277.63	0.00	7.70	0.00	20234.24	19678.98	555.27	0.00
1530	18163.00	9081.50	9308.54	18844.00	9422.00	9798.88	-490.34	-490.34	0.00	7.70	0.00	19597.76	18617.08	980.69	0.00
1600	17086.00	8543.00	8756.58	16949.00	8474.50	8813.48	-56.91	-56.91	0.00	7.70	0.00	17626.96	17513.15	113.81	0.00
1630	20266.00	10133.00	10386.33	19484.00	9742.00	10131.68	254.64	254.64	0.00	4.00	0.00	20263.36	20772.65	-509.29	0.00
1700	21821.00	10910.50	11183.26	21613.00	10806.50	11238.76	-55.50	-55.50	0.00	7.70	0.00	22477.52	22366.53	111.00	0.00
1730	20869.00	10434.50	10695.36	20697.00	10348.50	10762.44	-67.08	-67.08	0.00	5.70	0.00	21524.88	21390.73	134.16	0.00
1800	19552.00	9776.00	10020.40	19374.00	9687.00	10074.48	-54.08	-54.08	0.00	5.70	0.00	20148.96	20040.80	108.16	0.00
1830	19245.00	9622.50	9863.06	19281.00	9640.50	10026.12	-163.06	-163.06	0.00	5.70	0.00	20052.24	19726.13	326.12	0.00
1900	22190.00	11095.00	11372.38	22009.00	11004.50	11444.68	-72.31	-72.31	0.00	5.70	0.00	22889.36	22744.75	144.61	0.00
1930	21801.00	10900.50	11173.01	21614.00	10807.00	11239.28	-66.27	-66.27	0.00	5.70	0.00	22478.56	22346.03	132.54	0.00
2000	21222.00	10611.00	10876.28	20968.00	10484.00	10903.36	-27.09	-27.09	0.00	5.70	0.00	21806.72	21752.55	54.17	0.00
2030	23208.00	11604.00	11894.10	22911.00	11455.50	11913.72	-19.62	-19.62	0.00	5.70	0.00	23827.44	23788.20	39.24	0.00
2100	21231.00	10615.50	10880.89	21119.00	10559.50	10981.88	-100.99	-100.99	0.00	5.70	0.00	21963.76	21761.78	201.99	0.00
2130	20915.00	10457.50	10718.94	20777.00	10388.50	10804.04	-85.10	-85.10	0.00	5.70	0.00	21608.08	21437.88	170.21	0.00
2200	19805.00	9902.50	10150.06	19614.00	9807.00	10199.28	-49.22	-49.22	0.00	5.70	0.00	20398.56	20300.13	98.44	0.00
2230	18857.00	9428.50	9664.21	18647.00	9323.50	9696.44	-32.23	-32.23	0.00	5.70	0.00	19392.88	19328.43	64.46	0.00
2300	18925.00	9462.50	9699.06	18681.00	9340.50	9714.12	-15.06	-15.06	0.00	5.70	0.00	19428.24	19398.13	30.12	0.00
2330	21607.00	10803.50	11073.59	21419.00	10709.50	11137.88	-64.29	-64.29	0.00	3.50	0.00	22275.76	22147.18	128.59	0.00
2400	16522.00	8261.00	8467.53	16462.00	8231.00	8560.24	-92.72	-92.72	0.00	3.50	0.00	17120.48	16935.05	185.43	0.00
TOTAL		452913.00	464235.83		453459.50	471597.88	-7362.06	-6951.98	-410.08		-33.57				

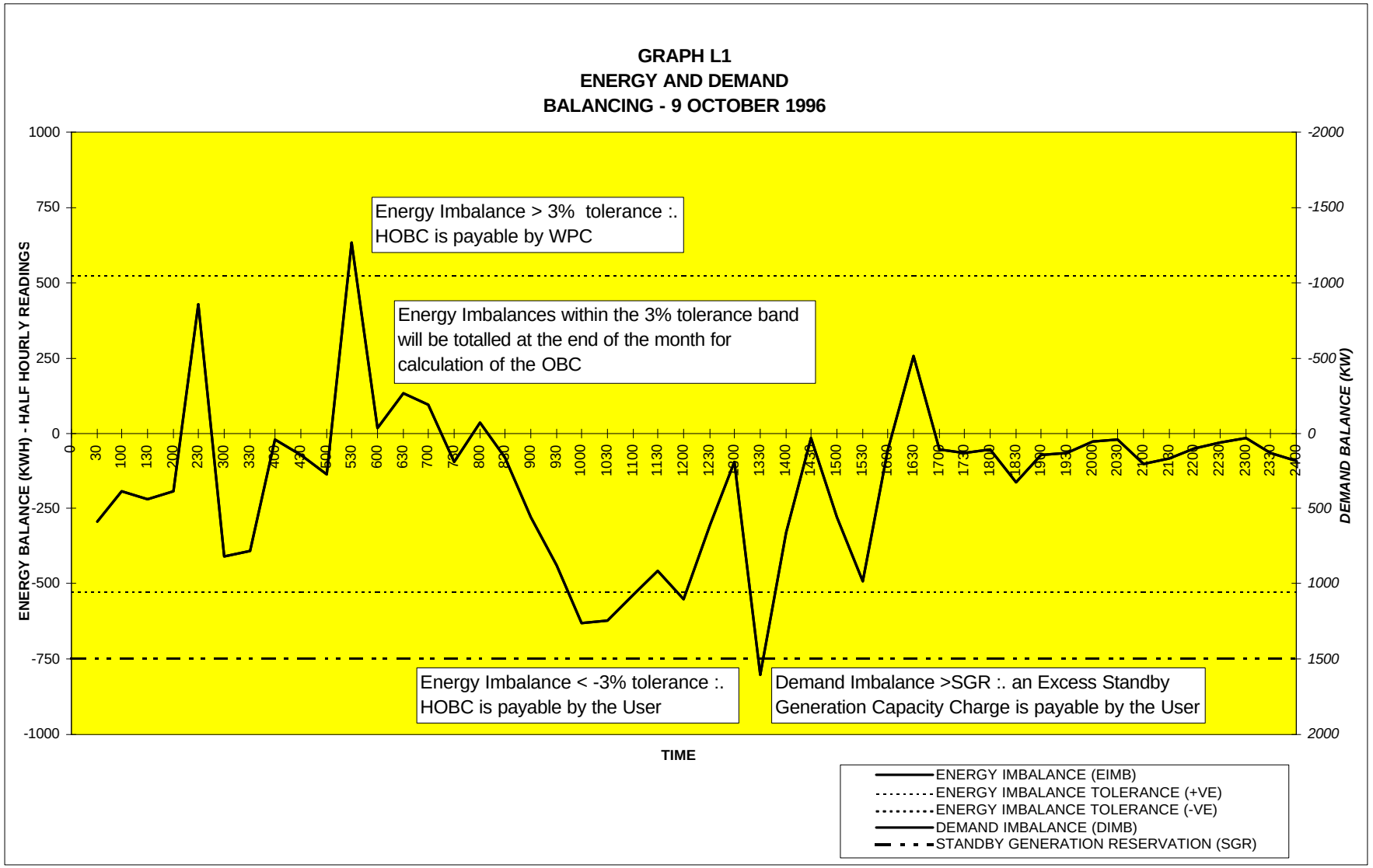
GRAPH L1
ENERGY AND DEMAND
BALANCING - 9 OCTOBER 1996
ENERGY BALANCE (KWH) - HALF HOURLY READINGS
DEMAND BALANCE (KW)
TIME
Energy Imbalance > 3% tolerance :.
HOBC is payable by WPC
Energy Imbalances within the 3% tolerance band
will be totalled at the end of the month for
calculation of the OBC
Energy Imbalance < -3% tolerance :.
HOBC is payable by the User
Demand Imbalance >SGR :. an Excess Standby
Generation Capacity Charge is payable by the User
ENERGY IMBALANCE (EIMB)
ENERGY IMBALANCE TOLERANCE (+VE)
ENERGY IMBALANCE TOLERANCE (-VE)
DEMAND IMBALANCE (DIMB)
STANDBY GENERATION RESERVATION (SGR)

TABLE L2

ENERGY AND DEMAND MONTHLY BALANCING CHARGES - OCTOBER 1996

DAY	ENTRY EEA KWHR	EXIT EEXA KWHR	ENERGY IMBALANCE ANA KWHR	RNA KWHR	HOBC $	DEMAND IMBALANCE ED (DAY MAX) KW	Ei (PERIOD MAX) KW
1	502161.43	526166.04	-12146.21	-11858.40	-959.67	0.00	0.00
2	516530.21	517443.18	-912.97	0.00	0.00	0.00	0.00
3	515424.29	518370.15	-2639.12	-306.74	-23.62	163.48	0.00
4	497436.08	498137.78	-701.70	0.00	0.00	0.00	0.00
5	465003.00	468968.95	-3932.85	-33.10	-1.62	0.00	0.00
6	404713.82	402995.41	1718.41	0.00	0.00	0.00	0.00
7	470344.61	454186.35	8448.19	7710.07	225.05	0.00	0.00
8	436839.46	444638.68	-7606.61	-192.62	-10.98	0.00	0.00
9	464235.83	471597.88	-6951.98	-410.08	-33.57	105.60	0.00
10	409862.03	412251.38	-2389.35	0.00	0.00	0.00	163.48
11	553546.82	553937.35	-390.53	0.00	0.00	0.00	0.00
12	575436.35	576821.08	-1384.73	0.00	0.00	0.00	0.00
13	527082.82	528298.53	-1215.71	0.00	0.00	0.00	0.00
14	522452.00	524978.04	-2526.04	0.00	0.00	0.00	0.00
15	476303.26	479927.50	-3624.24	0.00	0.00	0.00	0.00
16	484943.58	486742.45	-1798.87	0.00	0.00	0.00	0.00
17	555565.40	489072.92	286.45	66206.03	-935.36	16206.11	0.00
18	897555.30	549482.26	22344.85	325728.18	11115.18	0.00	0.00
19	574948.91	575810.71	-861.81	0.00	0.00	0.00	0.00
20	508414.86	509904.28	-1489.42	0.00	0.00	0.00	0.00
21	578008.95	578553.78	-544.83	0.00	0.00	0.00	0.00
22	500639.92	502282.35	-1642.43	0.00	0.00	0.00	0.00
23	530989.28	532453.39	-1464.11	0.00	0.00	0.00	0.00
24	778559.82	546701.54	16712.84	215145.44	7398.52	0.00	16206.11
25	909606.67	588199.19	25200.00	296207.48	9624.74	0.00	0.00
26	770325.14	495253.15	21449.83	253622.16	6774.86	0.00	0.00
27	487515.77	484562.14	-616.42	3570.04	107.10	0.00	0.00
28	476765.63	469374.65	473.31	6917.67	276.71	0.00	0.00
29	467592.80	470746.73	-3153.92	0.00	0.00	0.00	0.00
30	536792.59	534050.09	-323.89	3066.39	91.99	0.00	0.00
31	547907.43	543702.13	-1246.36	5451.66	215.32	0.00	0.00
TOTAL	16943504.05	15735610.06	37069.79	1170824.20	33864.66		16369.59
			OBP(c/kWh)				**ESGP($/KW)**
			2.00				20.00

CMD	**35000**
TOLERANCE (3% x CMD/2)	**525**
STANDBY GENERATION RESERVATION	**1500**

OBC =	**$**	**741.40**	**WPC PAY**
HOBC =	**$**	**33,864.66**	**WPC PAY**
ESCC =	**$**	**327,391.80**	**USER PAY**

$$OBC = OBP * \sum ANA$$

$$ESCC = ESGP * \sum Ei$$

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APPENDIX M

TRANSMISSION AGGREGATE REVENUE REQUIREMENT FOR 1999/00

CONTENTS

M1 Summary of Charges to Loads and Generators for the South West Transmission Network for 1999/00

TABLE M1

NETWORK CHARGES	TOTAL CHARGE $000's	AVERAGE $/kW
LOADS		
Connection charge	40,161	13.50
Use	57,339	19.28
Common Services	40,872	14.34
Total Charges to Loads	138,373	
GENERATORS		
Connection charge	4,579	1.43
Use of System charge	22,809	7.13
Total Charges to Generators	27,388	
Total Network Charges	165,761	See Note

Note: The Total Network Charges include an amount of $2.429M which is the spinning reserve cost allocated to loads.

M2 Components of the South West Transmission Network Charges for 1999/00

TABLE M2

COMPONENT	ANNUAL $ 000's	%
Return on Assets	61,955	37.9
Depreciation	46,958	28.8
O&M (sys & minor assets)	39,892	24.4
Tax Depreciation Adjustment	11,114	6.8
Under/over Recovery from Previous Financial Year	541	0.3
Cost of Force Majeure Events	2,872	1.8
Network Revenue Requirement	163,332	100

M3 Summary of Charges to Loads and Generators for the North West Transmission Network for 1999/00

TABLE M3

NETWORK CHARGES	TOTAL CHARGE $000's	AVERAGE $/kW
LOADS		
Connection charge	2,456	21.1
Use of System charges	3,173	27.2
Common Services	3,521	30.2
Total Charges to Loads	9,149	
GENERATORS		
Connection charge	133	
Total Charges to Generators	133	
Total Network Charges	9,282	

M4 Components of the North West Transmission Network Charges for 1999/00

TABLE M4

COMPONENT	ANNUAL $ 000's	%
Return on Assets	4,204	45.3
Depreciation	2,774	29.9
O&M (sys & minor assets)	2,320	25.0
Tax Depreciation Adjustment	-15	-0.2
Under/over Recovery from Previous Financial Year	0	0.0
Cost of Force Majeure Events	0	0.0
Network Revenue Requirement	9,282	100