STATEMENT OF ROD HOWARD CHIEF OPERATING OFFICER ENDEAVOUR ENERGY

I, Rod Howard, Chief Operating Officer at Endeavour Energy, of 51 Huntingwood Drive, Huntingwood of the State of New South Wales, swear:

Position

1. I am the Chief Operating Officer at Endeavour Energy. I have been in this role from 1 July 2012. I report to Vince Graham, the Chief Executive Officer of Endeavour Energy. Endeavour Energy, Ausgrid and Essential Energy have common governance arrangements including a common Chief Executive Officer. Networks NSW is used to describe the operating model where Endeavour Energy, Ausgrid and Essential Energy work cooperatively to achieve efficiency benefits and other reform initiatives under these common governance arrangements.

2. As the Chief Operating Officer I am responsible for the day-to-day operations of Endeavour Energy. The fundamental objective of this role is to provide value to customers in a manner that does not compromise safety, network reliability or sustainability. The position description for my role is attached as Appendix 1.

Educational background and professional experience in the energy sector

3. I hold a bachelor of engineering degree and a master of engineering science degree from the University of New South Wales in Sydney. I also hold a bachelor of business degree from Charles Sturt University in Bathurst and a master of business administration from the Australian Graduate School of Management which is part of the University of New South Wales in Sydney.

4. I have held various roles at Endeavour Energy, including various executive positions in business development, operational management and corporate activities. Later roles include the General Manager Corporate Development / Company Secretary, General Manager Full Retail Contestability, General Manager Capital Solutions, General Manager Network Development and Control, Deputy Chief Executive Officer Network (known as Group General Manager Network for a period) and currently Chief Operating Officer.

5. My CV is attached as Appendix 2.

Endeavour Energy

6. Endeavour Energy is a New South Wales state owned energy corporation serving some of the largest and fastest growing regional economies in the state. Endeavour Energy manages electricity distribution network for 933,500 customers, or 2.2 million people, in households and businesses across a network area spanning 24,500 square kilometres in Sydney's Greater West, the Blue Mountains, Southern Highlands, Illawarra and South Coast of NSW. These customers are served via a network with a regulated asset base

valued at $5.6 billion utilising a combination of 2,434 staff, 96 temporary agency resources and a multitude of external contract providers.

7. The legislation framing Endeavour Energy's regulatory determination includes:

- *Work, Health and Safety Act 2011* (NSW);
- National Electricity Law (**NEL**) and National Electricity Rules (**NER**), which provide for safe, reliable and efficient distribution services in the interest of consumers;
- *Fair Work Act 2009* (Cth), which binds Endeavour Energy as party to enterprise agreements; and
- a number of NSW electricity regulations, including Electricity Supply (Safety and Network Management) Regulation 2014, which impose standards for reliability, vegetation management and bushfire risk management.

Background

8. This statement is made in support of Endeavour Energy's revised regulatory proposal to the Australian Energy Regulator (**AER**). The AER has proposed, in its draft determination dated 27 November 2014, inter alia, real reductions in allowable capital expenditure (**capex**) of 39% and operational expenditure (**opex**) of 23% over the amounts proposed by Endeavour Energy in its initial regulatory proposal.

9. In my opinion, based on current information, the reductions proposed by the AER would likely lead to substantial underinvestment by Endeavour Energy in both capex and opex, and would compromise the safety, the reliability and the ongoing sustainability of its network.

10. My opinion is based in part on my experience at Endeavour Energy (then known as Integral Energy) of similar regulatory reductions by the Independent Pricing & Regulatory Tribunal (**IPART**) in the 1990s. IPART recommended reductions in capex and opex by distribution network service providers (**DNSP**s), including Endeavour Energy. In Endeavour Energy's case, these reductions were in the order of 15% for opex and 16% for capex for the period 1999-2004. The recommendations from IPART and its consultant Worleys are attached as Appendix 3 and 4.

11. This led to underspending for a period with a number of capital and maintenance programs cut or deferred. This in turn increased safety risks and decreased the reliability of the network. From Endeavour Energy's perspective, there were, by way of example:

(a) increased number of unassisted pole failures[1] (ie failures due to gravity and not induced by external factors eg bad weather or collision);

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[1] The definition of unassisted pole failure, as agreed by the Technical Secretary of the Energy Networks Association Power Poles and Crossarm Forum (and others, including Endeavour Energy) is:

"Any functional failure of the pole itself or where only conductors or stays are supporting the pole will be classified as an unassisted failure unless it can be shown that the pole was:

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(b) deterioration in reliability performance from about 80 minutes SAIDI ('SAIDI' refers to normalised unplanned System Average Interruption Duration Index) in 1999-00 to about 120 minutes in 2003-04; and

(c) a number of depots shut / consolidated, as a result of which some of Endeavour Energy's staff had to work from temporary facilities such as converted shipping containers, creating work health and safety concerns. This also impacted Endeavour Energy's response time to public and customer emergency situations.

12. The decrease in maintenance activities also led to serious concerns regarding safety, both to the public and to employees of Endeavour Energy. In the early to the mid-2000s only about 70% to 85% of required preventive maintenance on network assets was being completed. In recent years preventive maintenance compliance on network assets has grown to be in excess of 95%. Specifically, electricity network equipment was not maintained to manufacturers' recommended or industry accepted standards resulting in increased risk exposure to asset failures such as the unassisted pole failures mentioned in paragraph 11. Examples include the maintenance of power transformers / circuit breakers and the checking of protection systems where compliance levels in 2005-06 were only at 77% and 53% respectively. A further example is the Appin bushfire which is believed to have emanated from our network due to conductor clash when a low voltage spreader was not fitted. A copy of the Coroner's findings released in March 2003 is attached as Appendix 5. Similar regulatory constraints in the Queensland electricity supply industry (*Electricity Distribution and Service Delivery for the 21st Century, Detailed Report of the Independent Panel, July* 2004) as well as the issues mentioned in paragraph 11 and this paragraph led to the creation of the reliability and performance licence conditions for the NSW electricity industry. Specifically, the Design, Reliability and Performance Licence Conditions were imposed on Distribution Network Service Providers by the Minister for Energy on 1 August 2005 (and replaced with updated and revised conditions with effect from 1 December 2007). The Design, Reliability and Performance Licence Conditions is attached as Appendix 6 and 7.

13. To comply with these conditions, Endeavour Energy increased its capex and opex over the following periods. Both IPART in its determination for 2004-09 and the AER in its determination for 2009-14 recognised that increases in capex were needed to replace ageing assets and to improve network security and reliability (as well as to accommodate the growth in maximum demand for energy). It took four to five years to recover the overall reliability and performance of the network. The reliability graph based on normalised unplanned SAIDI is set out in Figure 1 below.

• Subject to sufficient force to exceed the design strength requirements set out by the relevant Utility's standards at the time of construction;

• Burned by a fire ignited by any source;

• Compromised by vandalism;

• Struck by lightning; or

• Otherwise subjected to a failure mechanism demonstrated by evidence to be outside the control of the Utility."

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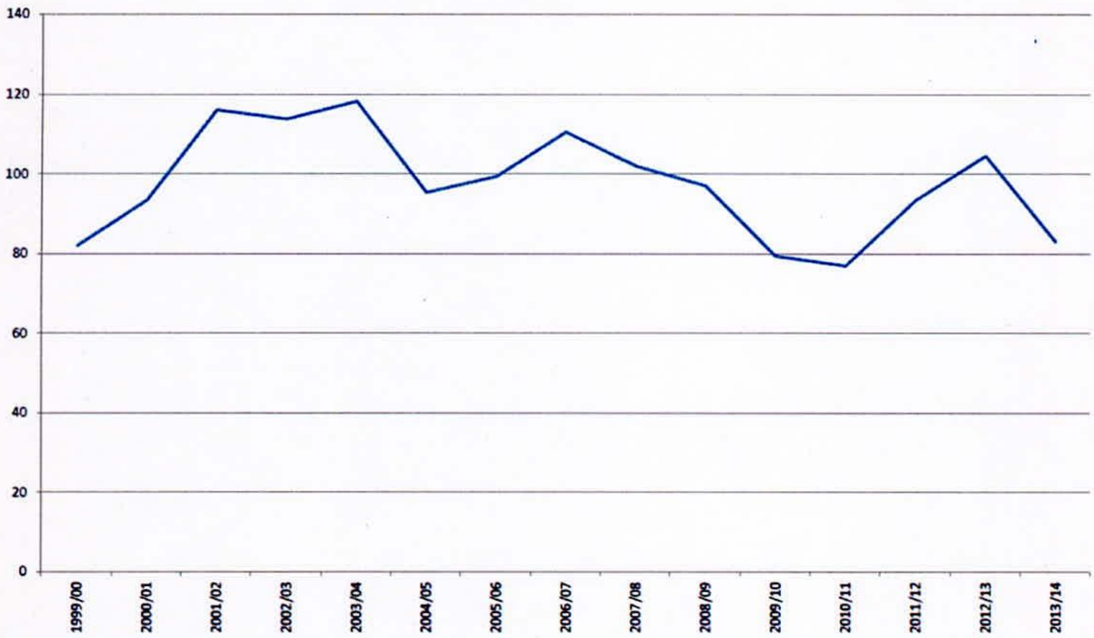
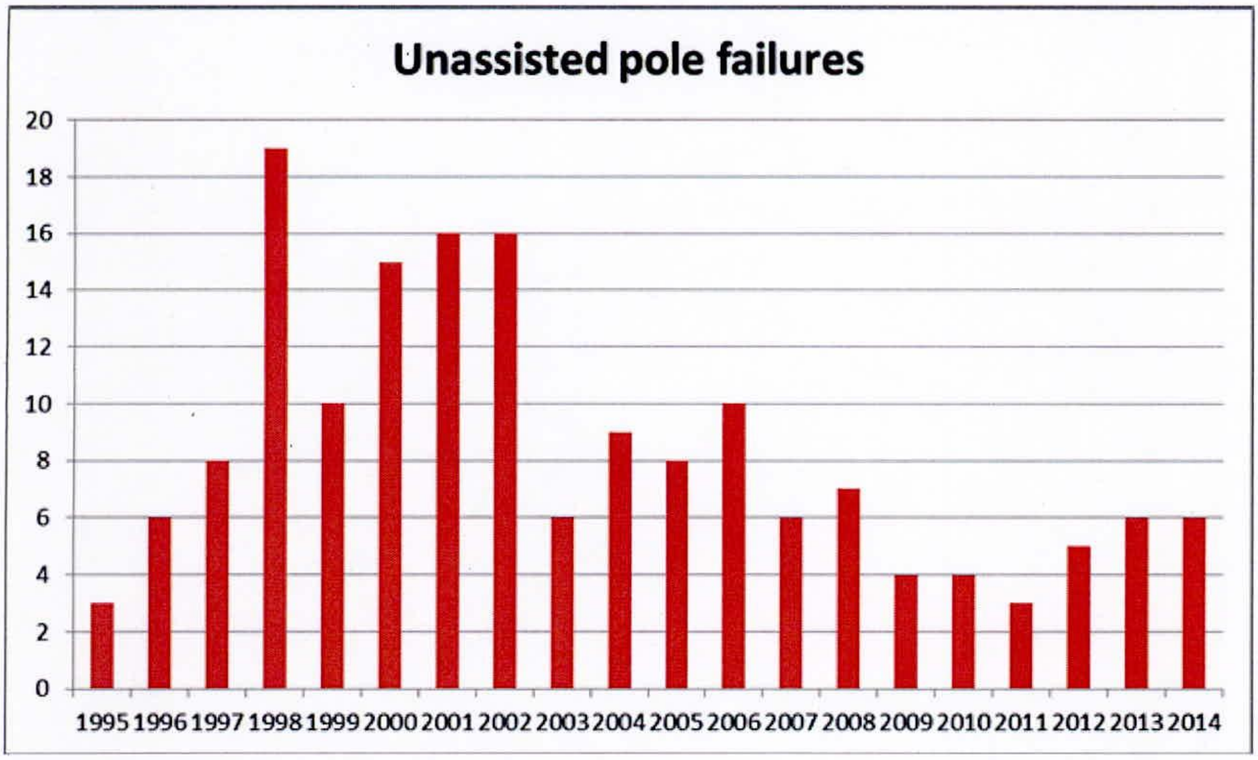
14. It should be noted that the relative adverse trend in 2011-12 and 2012-13 in Figure 1 was due to an abnormal high number of weather related high SAIDI days which is not a reflection of underlying reliability performance. Fluctuations in 2004-5 and 2006-07 were abnormal weather.

Figure 1 Network reliability - normalised Unplanned SAIDI (minutes) AER Beta Methodology



15. Figure 2 below demonstrates a similar trend regarding the number of unassisted pole failures per year. It should be noted that performance improved rapidly between 2002 and 2003 as a direct result of a concerted effort by Endeavour Energy at that time to clear the backlog of poles requiring replacement.

Figure 2 Unassisted Pole Failures in Endeavour Energy network



16. As a result of the investment made from 2009-14 in response to the reliability and performance conditions, I consider that Endeavour Energy's network is currently in a reasonable state. This can be measured by two parameters:

- Endeavour Energy is in a reasonably good position to service the ongoing urban growth and load expansion within the geographic area that we supply with electricity. Significant capacity shortfalls of the past to meet both organic demand and new 'greenfield' growth has now been overcome with ongoing 'greenfield' growth being the remaining challenge; and

- The weighted average of remaining life of the network assets operated by Endeavour Energy is approximately 50%, albeit still declining. A 50% weighted average of remaining life is considered to be a long term sustainable level provided it remains in a tolerance band of 45%-55%, meaning that asset replacements are occurring at a rate that is commensurate with the rate of asset ageing.

This has been achieved as a result of increased expenditure over the last two regulatory periods in response to Endeavour Energy's previous declining reliability outcomes over that period as well as increased network security conditions in Endeavour Energy's licence.

17. I am, however, concerned that if reductions in capex and opex of the order indicated in the AER's draft determination occur, Endeavour Energy's network would again deteriorate, leading to adverse reliability and safety outcomes and a further need for substantial remedial reinvestment in the future, as occurred from 2004 to 2009 and 2009 to 2014. This would increase the risk of non-compliance with NSW Electricity Regulations.

18. I consider that the investment in capex and opex in the past has generally been in a cycle of increased investment / improved reliability and safety, followed by less investment / decreased reliability and safety, and the cycle re-starts. I consider that Endeavour Energy was in the decreased investment / decreased reliability and safety phase in the 1999-2004 IPART review period and in the increased investment / improved reliability and safety phase for the last two regulatory periods, i.e. 2004-09 and 2009-14. With the proposed significant decrease in revenue in AER's draft determination, I consider that Energy Endeavour will again be in a decreased investment / decreased reliability and safety phase. The deterioration of network will have to be again compensated by significant increase in expenditure for the following regulatory period.

19. In addition, I am of the view that this cycle of investment is not efficient as the decision to invest more or less is largely in response to consequences of previous decisions rather than taking a holistic view of a longer term and the general safety and reliability of the network. An investment program with a more steady investment profile would be more beneficial towards that end for both customers and industry stakeholders.

20. Endeavour Energy also sets its capex and opex taking into consideration network need which is informed by the previous investment cycle as above and the trade-offs between capex and opex. If less opex is spent, network equipment deteriorates such that more capex will be required to compensate for reduction in opex. Similarly, less capex may contribute to (amongst other consequences) a decrease in reliability of the network for which more opex will be required.

Endeavour Energy's Assets

21. Endeavour Energy's assets fall into two categories: network assets and non-network assets.

Network assets

22. Network assets are assets that form part of the electricity distribution network. The main types of network assets are:

(a) Poles;

(b) Columns;

(c) Cables (both overhead, also referred to as "conductors", and underground);

(d) Substations, which principally comprise transformers and switchgear;

(e) Protection equipment;

(f) Control equipment;

(g) Meters; and

(h) Land network buildings.

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Poles

23. Endeavour Energy has approximately 300,100 poles. These poles are inspected every 4.5 years, which is generally in line with industry standard. This inspection work is fully outsourced to contractors by an open market tender process.

24. The majority of the poles (279,600 out of 300,100) are comprised of timber. The life of a timber pole is between 40 to 60 years. Timber poles start out their life as solid structures but over time, factors such as fungus, insects and moisture cause the inside of the pole to deteriorate, forming a 'pipe' of empty space. The wood surrounding the pipe is referred to as the 'wall' of the pole. The inspection of timber poles usually involves drilling a hole into the pole to measure the thickness of the wall and then the diameter of the pipe inside the pole. If the pipe becomes too wide (i.e. the pole wall becomes too thin), the pole becomes less stable and may fail. The consequential risk of unexpected failure of timber poles includes both a risk to public safety as well as impact on network supply reliability. By taking this measurement, the remaining life of the pole can be estimated and one of the following four possible actions can be taken based on the estimated remaining life of the pole:

- to re-inspect the pole in the next inspection cycle;
- to reinforce the pole with a steel stake driven into the ground at the base of the pole and attached to the pole by way of bolts. This technique is commonly called 'pole nailing' and is used to support a weakened pole. Pole nailing is only applicable for poles that are condemned at the base. Poles that are condemned at the pole top or mid pole (rare) are not suited for nailing. For the period 2012-13, approximately 70% of poles were condemned at the base and 30% at the head. Generally in order for nailing to be suitable, following pole base condemnation, sufficient healthy timber must be present at the nail brace points and the external surfaces of the pole unencumbered where the nail is to be applied to provide adequate restraint for the resultant pole load forces. Additionally the area below the pole ground-line must also be relatively unencumbered or capable of easy unencumbering to facilitate the nail penetrating this area in a safe manner. Generally in excess of 50% of pole base condemnations are suitable for pole nailing. Pole nailing can extend the life of a pole by about 15 years.
- to replace the pole within the next six months (where it appears that the pole is likely to fail prior to the next inspection cycle); or
- in cases where it appears the pole may be about to fail, to replace the pole within the following 48 hours.

25. There are also a small number of concrete poles (19,100 out of 300,100). Concrete poles require less maintenance but are more expensive to install. Concrete poles are generally deployed in certain areas, eg high bushfire risk areas subject to certain constraints. There is, however, an offsetting safety disadvantage of concrete poles which are conductive primarily due to their integrated steel reinforcement. The safety issue may arise if the insulator at the top of the pole fails thereby causing potential voltages on the pole or in the immediate ground area around the base of the pole. For this reason the application of the overall lower lifetime cost concrete pole in urban areas needs to be considered

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carefully. The failure consequences of concrete poles are not dissimilar to those of timber poles.

26. There are also a small number of steel poles (1,420 out of 300,100). These poles are also inspected on a 4.5 year cycle. The main risk exposure for this type of pole is corrosion occurring at the air/ground interface of the pole, ie rust. Failure to inspect these poles to the normal cycle of 4.5 years results in an increased risk of the poles failing prior to potential failure being identified. The failure consequences of steel poles are not dissimilar to those of timber poles.

Columns

27. There are approximately 99,600 steel columns within Endeavour Energy's coverage area, which are primarily used for the provision of public lighting services.

28. Column life is generally 20 to 40 years, which varies greatly subject to location (ie its relative proximity to coastal areas where salt and humidity act as catalysts to the rust deterioration process) and installed condition (eg whether the column is directly buried in the ground at its base or bolted onto a concrete plinth). Corrosion (ie rust) is the main issue that affects a column's life. The failure consequence of columns is not dissimilar to those of timber poles. In 2014 a rusted column located in coastal Corrimal NSW failed, falling onto a parked vehicle with a mother and child inside the vehicle.

29. Columns are inspected every 4 years by Endeavour Energy staff, though an alternative delivery method to improve delivery efficiency using a blend of internal and contracted resources is under consideration. They are then treated to inhibit the rust progression or replaced depending on the inspection finding and severity of the corrosion.

30. In addition to columns, poles are also used for the provision of public lighting. There are approximately 98,100 lights mounted on poles and 800 on other structures bringing the overall number of public lighting installations to 198,500. The lighting attachments on poles are inspected as part of the public lighting maintenance process. The condition of the attachment following inspection will determine whether it needs to be replaced. The resourcing of this inspection activity is set out in paragraph 36.

31. Bulbs are replaced when they fail (generally failure is reported to Endeavour Energy by members of the public), or as part of the bulk replacement program typically every three years.

32. The bulk replacement program is conducted to comply with the light quality requirement in the Public Lighting Code 2006 (NSW) and the Australian Public Lighting Standard, A/NZS 1158, and is required as the quality of light produced by a bulb decreases over time, although the bulbs may have not completely failed.

33. The Public Lighting Code 2006 (NSW) calls up AS/NZS 1158 and it is not currently compulsory. However, I understand that the Public Lighting Code 2006 (NSW) or at least

AS/NZS 1158 will become effective when the Electricity Supply (Safety and Network Management) Regulation 2014 takes full effect in March 2015. This regulation requires us to comply with AS5577 which in turn requires Endeavour Energy to nominate those Industry Codes and Standards that we are required to meet. The Public Lighting Code 2006 (NSW) is the industry code for public lighting in NSW and therefore this Code will be nominated in accord with AS5577.

34. Endeavour Energy does not believe a nil nomination of a Standard we will adopt would be acceptable under the regulation. The regulation also mandates that any variation from the nominated standard must achieve as good or a better outcome than the adoption of the Standard.

35. Local councils fund public lighting and the feedback from councils in Endeavour Energy's public engagement process throughout 2014 was that they were generally satisfied with the quality of service and pricing models. The councils require any lights not working to be repaired in a timely manner due to increased public risks when they are not working.

36. Endeavour Energy has market tested the provision of public lighting services (ie bulk replacement and minor fault/repair services) twice and on both occasions found that continued resourcing of this service by internal staff represented the better valued outcome in terms of safety, performance and cost. As a result this service has continued to be resourced internally by Endeavour Energy staff.

Cables

37. There are two types of electricity cables: underground or overhead (overhead cables are also referred to as 'conductors'). There are also secondary service cables utilised within the network of both overhead and underground construction.

38. Approximately one third of Endeavour Energy's network is underground. Underground networks require less maintenance, however faults are much harder to locate and / or repair. This means that an underground network has better reliability but higher maintenance cost, whenever maintenance work is required.

39. Historically, cables are generally of overhead construction. Since the 1980s, about 90% of new network construction in the urban parts of Endeavour Energy's area has been underground while about 95% of the new network in rural areas remains overhead.

40. In terms of expansion of capacity of an overhead network, Endeavour Energy considers the cost and benefits of different options on a case by case basis, which include expanding existing overhead network or building new underground network.

41. Endeavour Energy does not maintain any general inspection or maintenance programs for cables with the exception of critical sub-transmission cables (ie 33kV, 66kV or 132kV). Depending on the location of these cables, they may be inspected relatively frequently. By way of example, the underground 132kV cable network that supplies the Parramatta

CBD is surveyed almost daily, because our experience is that if not inspected, there is a significant chance that persons undertaking construction work may excavate into the areas where these cables are located, with attendant risks to public safety and disruption to the network.

42. Distribution cables (ie 22kV and lower voltages) are generally replaced either when they fail or are likely to fail. A class of cables may be proactively replaced if that class of cable has a history of repeated failures. Two examples are as follows:

(a) A type of underground cable that is being replaced is Consac cables, which started to exhibit a number of safety issues several years ago, including causing electric shocks within customer premises. The program for replacing this cable has been operating for five to six years on a risk priority basis. With approximately 520 kilometres of this type of cable remaining and being replaced at about 14 kilometres per year, this will take substantial funds and a significant time to complete; and

(b) There is a program to replace overhead steel cables in rural areas as they have a history of corrosion and subsequent failure, creating safety risks resulting from energised conductors falling to the ground and possible commencement of fires in bushfire prone areas. There is approximately one thousand kilometres of this type of steel conductor, which is being replaced at a rate of 50 to 60 kilometres every year on a risk priority basis.

Substations

43. Substations are where voltage of the electricity is transformed to a higher voltage to prepare for long distance of transmission, or transformed to a lower voltage for distribution.

44. In NSW, for Endeavour Energy in particular, the network configuration is unique (compared to Victoria) in that there is an extra layer of transmission.

(a) In NSW, generator alternators produce electricity in the 20kV range. It is usually transformed up to 330kV or 500kV at the power station for transmission into the NSW grid at the transformed higher voltage. The electricity is then transmitted across NSW by TransGrid at 330kV or 500kV. Some smaller generation can however, connected directly at 33kV or 132kV to distribution network service providers such as Endeavour Energy for local distribution. TransGrid then transforms down the electricity from 500 kV or 330 kV to 132 kV when supplying the electricity to Endeavour Energy (or Ausgrid or Essential Energy or major bulk customers). Endeavour Energy then distributes the electricity to sub-transmission substations which transforms the electricity down to 66kV or 33kV. The electricity then goes to zone substations which then transforms the electricity down to either 22kV or 11kV. 22kV or 11kV electricity is transformed at distribution transformers to 415V or 240v to supply consumers;

(b) In comparison, generally in Victoria, electricity is transmitted at either 500kV or 220kV and is transformed to 66kV for supply to distributors who then transform this voltage to 22kV or 11kV or 6.6kV which is generally in common with NSW and then to voltages of 415V or 240V. Hence the distributors in Victoria are not required to incur the costs associated with the 132kV to 66kV or 132kV to 33kV sub-transmission network.

45. Each layer introduces more capex and opex.

46. Endeavour Energy has in recent years stopped building new 33kV sub-transmission networks and instead now generally transforms electricity from either 132kV to 11kV or 132kV to 22kV directly.

47. However, prematurely replacing existing 66kV or 33kV sub-transmission networks with 132kV sub-transmission networks is not cost efficient and Endeavour Energy intends to continue operating and maintaining existing 66kV or 33kV sub-transmission networks until they are replaced for other reasons.

48. The principal assets making up a substation are the transformer (which transforms the voltage from one level to another), switchgear (which is used to switch on or off the different circuits running into and out of the substation), the land upon which the assets may reside and any building structures housing the assets.

49. There are three types of substations in Endeavour Energy's network: sub-transmission substations (which transform electricity from 132kV to 66kV or 33kV), zone substations (which transform electricity from 132kV or 66kV or 33 kV to 22kV or 11kV) and distribution substations (which transform electricity from either 22kV or 11kV to the voltage used by the customer, either 415V or 240V). Sub-transmission and zone substations are significantly more costly and complex assets to build and maintain than distribution substations (and each services many more customers than a distribution substation). In Endeavour Energy's network there are approximately:

(a) 22 sub-transmission substations;

(b) 170 zone substations; and

(c) 31,000 distribution substations.

50. The life of a distribution substation is usually approximately 50 years. The cost of a distribution transformer ranges from $1,700 for a 25kVA unit to $30,000 for a 1,500kVA unit. They are usually run to failure. When they fail, they are replaced, as refurbishing and re-deploying the transformer is less likely to be economic.

51. Both the transformers and the switchgear in a distribution substation are inspected every 4.5 years for pole mounted substations and 3 years for ground and pad mount substations. For pole mounted substations, these inspections are performed as part of the outsourced pole inspection process. For ground and pad mount substations, these inspections are undertaken by Endeavour Energy staff. High load substations are inspected annually by Endeavour Energy staff. Inspections undertaken by Endeavour Energy employees is on the basis of the need for specialist knowledge, equipment and experience.

52. Zone substations, given their greater complexity and cost (between $20 million to $40 million) and the greater consequences if they fail, are usually inspected every three or six months.

53. The major component in zone substations and sub-transmission substations is the transformer, which typically costs approximately $3 million per zone substation and approximately $8 million per sub-transmission substation. A zone or sub-transmission transformer is usually repaired when faults occur and is only replaced if it fails completely or is revealed to have fundamental issues identified by oil testing. Switch gears in zone substations and sub-transmission substations are also much more sophisticated (compared to those in distribution substation) as they are subject to extremely high power interruption requirements.

54. Each zone substation typically supports between 6,000 and 20,000 customers.

55. Sub-transmission substations are the largest and most complex substation assets managed by Endeavour Energy. Each sub-transmission substation costs between approximately $40 million and $70 million and supports between 10,000 and 100,000 customers.

56. Endeavour Energy is reluctant to outsource the inspection and maintenance of zone substations and sub-transmission substations to external service providers primarily due to safety concerns and the critical nature of the supply arrangements. I note that in 2010 there was a TransGrid fatality at their Sydney East substation when a contractor was killed due to unfamiliarity with the technical operation and safety requirements at their site.

Protection equipment

57. Protection equipment refers to circuit breaking and other technology designed to protect the Endeavour Energy network from excess power loads (caused by either fault conditions or higher than expected normal load cycles). This equipment includes both older technology devices and more modern electronic devices.

58. Older technology protection equipment typically lasts 40 to 50 years. Examples are mechanical devices (eg fuses on the top of poles) through which current flows which physically break the circuit in the event of excess current. These are still used as they provide a cost benefit and meet the required protection response time of the network. These are being supplemented with remotely controlled electronically operated devices to reduce the impact of faults on the number of affected customers and to improve fault response time as they are now directly controlled by the network operators. Another example is electromechanical relays that operate circuit breakers within a substation.

59. All zone and sub-transmission network protection equipment devices deployed in the last several years are electronic. The life of electronic protection equipment, due to its greater

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complexity and sophistication, is only approximately 10 or 15 years. This equipment is inspected as part of the zone and sub-transmission substation inspection programs and generally maintained on a 3 yearly cycle.

Control equipment

60. Control equipment refers to equipment used to control the Endeavour Energy network. The control equipment used by Endeavour Energy comprises what is called the Supervisory Control and Data Acquisition (**SCADA**) system.

61. In the SCADA system, computer terminals in substations and on the distribution network collect information regarding the network and which is sent to the Control Rooms at Huntingwood and Wollongong. Endeavour Energy staff within the Control Rooms can obtain real time monitoring data of the network, in particular sub-transmission and zone substations, and remotely switch them on or off.

62. The control equipment is subject to rigid inspection programs (typically every three to six months) and maintenance programs. This work is performed by Endeavour Energy employees, because of the strategic nature of the major substations where this equipment is fitted.

Meters

63. Endeavour Energy's network includes old electromechanical meters which last approximately 40 years and modern electronic meters which typically last 15 to 20 years.

64. Meters have to comply with the testing regime as approved by the Australia Energy Market Operator (AEMO).

65. Inspection of meters usually occurs in response to a customer's request. Endeavour Energy also conducts sampling of meter types to comply with the testing regime set out in the *National Measurement Act 1960* (Cth).

66. Meters are replaced:

(a) when they fail; or

(b) as a class, when that class of meters no longer meet the requirements of the testing regime.

Land and network buildings

67. All land and network buildings must be managed to comply with relevant legislation, codes of practice and standards including:

(a) *Work Health and Safety Act 2011* (NSW), *Work Health and Safety Regulation 2011* (NSW) and various Codes of Practice; and

(b) *Environmental Planning and Assessment Act 1979* (NSW), *Contaminated Land Management Act 1997* (NSW), *Environmental Protection and Biodiversity Conservation Act 1999* (NSW), *Environmental Hazardous Chemicals Act 1985* (NSW), and *Protection of the Environment Operations Act 1997* (NSW).

68. Each of the 22 sub-transmission substations, 170 zone substations and other owned and leased property fall under this asset category. Compliance to the relevant standards is managed by Endeavour Energy project and asset managers. The physical delivery of both inspection and corrective services where needed is delivered by a blend of internal resources and contractors.

Non-network assets

69. The main types of non-network assets are:

- Property for offices or depots, mostly owned: All land and non-network buildings must be managed to comply with relevant standards including for example Environmental Protection Acts, hazardous chemical requirements, etc.;

- Fleet: Endeavour Energy currently has a fleet of 1,029 vehicles, of which 624 are light vehicles (eg passenger cars, utilities and vans) and the rest are either heavy trucks or specialist plant. The number of vehicles in the fleet has reduced by about 100 in the last several years. Endeavour Energy owns all its heavy vehicles (eg Elevated Work Platforms (EWPs) and lifter/borer trucks). In terms of light vehicles Endeavour Energy has leased all new units acquired over the last several years. The lease is obtained via tender process, every five or six years. The current lease term is typically five years. Endeavour Energy expects to own no light vehicles by December 2015 and instead lease all of its light vehicle needs.

  The heavy vehicles are mostly used by field based staff for building and maintaining the network. They include specialised units, including

  - Service line trucks with specialised tools on them;

  - EWPs – elevated work platforms, on which staff can do elevated work;

  - Lifter/Borer trucks which are crucial to replacing or installing new power poles.

  A break-down of Endeavour Energy's fleet is set out in Table 1 below.

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Table 1 A break-down of Endeavour Energy's fleet

Trucks	288
EWPs	99
Lifter/Borers	18
Light commercial vehicles	453
Passenger vehicles	169
Total	**1029**

- Computer hardware and software: Computer hardware at Endeavour Energy comprises the assets installed at our four data centres and end user computing devices (mainly PCs and laptops). The four data centres are at Huntingwood (main corporate data centre where the main production server infrastructure is installed); Huntingwood (SCADA data centre); Glendenning (backup corporate data centre) and Springhill (backup SCADA data centre). The hardware is made up of servers, storage systems and networking equipment.

  Software is made up of all corporate application software and desktop software used for undertaking computer based tasks. It is comprised of both commercial software packages and in house developed modules that either customise commercial software or provide standalone functionality. This software includes direct network management software (ie SCADA, outage management, GIS, asset management) and corporate applications (ie finance, human resources, payroll, inventory management).

Opex

70. The three main components of Endeavour Energy's standard control opex are labour cost associated with operating and maintaining the network business including associated direct and indirect overheads and excluding vegetation management (approximately $161m per annum); the costs of the vegetation management program itself (approximately $87m per annum); and other non-labour costs primarily related to expenditure associated with materials, information and communications technology and other contractors (approximately $42m per annum).

<u>How Endeavour Energy Determined its Opex Requirements in its Initial Regulatory Proposal and Revised Regulatory Proposal</u>

71. Endeavour Energy, in its Initial Regulatory Proposal dated 30 May 2014 (**IRP**), determined an opex requirement based upon the opex needed to maintain the safety and reliability of its network assets and the operation of the network. This was done in the following manner:

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(a) Applied a base step trend 'revealed cost' approach method to the majority of Endeavour Energy's network maintenance activities, other operating costs and direct and indirect overhead operating expenditure. This method was deemed *appropriate* for forecasting recurrent expenditure because the base year amount encapsulates the actual annual cost that was currently required to provide standard control services;

(b) Determined 2012/13 was the base year used in the IRP forecast as this was the latest actual operating expenditure data available at the time of preparing the forecast that had been reviewed by an external auditor as part of the annual regulatory reporting to the AER;

(c) Included known change factors such as increased vegetation costs, the impact of capital prioritisation and higher output growth. The assumptions included:

- Vegetation: Increased contract conformance costs consistent with our ongoing focus on the achievement of required program compliance in addition to additional cost movements in market delivered contracts secured by Endeavour Energy;

- Capital prioritisation: Our IRP reflected a substantial decrease in our capex compared to the 2009-14 period based on an assessment of risk, several efficiency initiatives and a return to a more sustainable level of network investment. The overall investment portfolio was optimised using an investment prioritisation model creating a step-up in our opex compared to our base year reflecting redundancy costs and undertaking additional maintenance; and

- Output growth: Relates to a larger number of network assets to be maintained and operated due to growth in our customer numbers, network demand and our capex and opex programs during the 2009-14 period.

(d) Incorporated further saving efficiencies from both our internal efficiency programs and the ongoing Networks NSW reform program that were in addition to those included in our base year; and

(e) Reflected labour cost escalation from external expert advisers Competition Economists Group (CEG).

72. Following the AER's Draft Determination dated 27 November 2014, Endeavour Energy revised the opex requirements for its Revised Regulatory Proposal (**RRP**) in the following manner:

(a) Incorporated an additional audited annual regulatory reporting year (2013-14);

(b) Reflected updated workforce levels based on current levels and included progressive improvements in labour productivity;

(c) Increased vegetation costs further to reflect the introduction of LIDAR technology and consistent vegetation cutting standards in NSW;

(d) Updated the redundancy costs associated with the progressive reduction in our workforce, which are required to be paid as a regulatory obligation imposed by an enterprise agreement certified by the Fair Work Commission in accordance with the Fair Work Act;

(e) Proportionally reduced our non-labour operating costs for efficiency and labour productivity improvement opportunities; and

(f) Reflected updated labour cost escalation in line with the AER's draft determination.

73. I set out below an explanation of the different components of Endeavour Energy's opex.

Labour

Labour Allocation within Endeavour Energy

74. A current and projected breakdown of full time equivalent employees (**FTE**) in Endeavour Energy is set out in the Table 2 below. Labour FTEs associated with capital expenditure activities are also included for completeness. Labour FTEs associated with corporate overheads have been allocated to the direct operating and capital activity in accordance with the AER approved Corporate Allocation Method (CAM). Labour allocation for vegetation management, which is essentially an outsourced activity, reflects a combination of staff to manage and audit the external contracts plus the allocation of FTEs associated with corporate overheads, ie direct and indirect overheads.

Table 2 Breakdown of Opex and Capex FTEs

OPEX FTEs	Ref	2014/15	2015/16	2016/17	2017/18	2018/19
Other Network Operating Costs		135.2	146.9	140.8	134.3	128.2
Inspection		133.3	129.1	127.6	125.0	123.1
Maintenance & Repair		360.2	367.2	355.1	340.8	328.0
Vegetation Management		263.7	327.8	327.2	323.4	321.5
Emergency Response		231.3	242.4	234.2	224.7	216.2
Other NM operating costs		141.9	112.0	98.0	94.5	91.0
Customer Service		32.8	35.2	33.9	32.4	31.0
Other operating costs		90.4	105.6	102.8	99.3	96.2
Total Standard Control	a	1,389.0	1,466.4	1,419.6	1,374.5	1,335.1
Total Alternative Control	b	332.7	348.7	344.2	337.8	332.3
Total Unregulated	c	145.0	134.3	129.1	123.1	117.9
TOTAL Opex FTEs	d = a + b + c	1,866.6	1,949.4	1,892.9	1,835.4	1,785.3
CAPEX (system & non system) FTEs	Ref	2014/15	2015/16	2016/17	2017/18	2018/19
Total Standard Control	e	626.9	469.0	448.4	435.6	410.1
Total Alternative Control	f	19.8	17.9	20.9	17.9	20.8
Total Unregulated	g	-	-	-	-	-
TOTAL Capex FTEs	h = e + f + g	646.7	486.9	469.4	453.6	430.9
GRAND TOTAL FTEs	I = d + h	2,513.3	2,436.3	2,362.3	2,288.9	2,216.2

75. Endeavour Energy's internal field based staff resources are allocated to four broad categories. These four categories are:

- Depot based field staff;

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- System control group;
- Network connections group;
- Operational performance.

They typically perform the following tasks:

- Physical maintenance and construction;
- Fault restoration;
- Switching;
- Certifying / inspecting new development; and
- Control room.

76. Depot based field staff conduct physical maintenance and construction on the network. They are allocated across three regions, the northern region, the central region and the southern region. Based on their training their activity is generally targeted at one of two specific parts of the network:

- Sub-transmission - working on the sub-transmission network that distributes electricity at 33kV, 66kV or 132kV; and
- Distribution - working on the distribution network involving voltages at 22kV and below.

77. The skill sets involved are generally specialised while some staff can work in multiple areas.

(a) Sub-transmission related skill sets include:

- Overhead cable systems;
- Underground cable systems;
- Substations technologists;
- Protection technologists;
- High voltage testers; and
- Live line workers.

(b) Distribution related skill sets include:

- Overhead cable systems;
- Underground cable systems;
- Electrical fitter / mechanics;
- Live line workers;

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- Distribution power line workers (**DPW**), who are multi-skilled staff capable to perform any task on the distribution network. This is a skill set that Endeavour Energy pioneered and seeks to further develop.

Field staff also include a number of staff who are in unskilled trade positions, termed electricity workers, working in both sub-transmission and distribution. These roles perform tasks including truck driving, plant operating or general assistance.

78. The system control group includes:

(a) System controllers, which are located in either of the two control rooms. System controllers monitor the status of the network via the use of various monitoring computer systems, eg SCADA. Their role includes keeping abreast of external conditions that may impact the network, eg hot weather, fires or storms. They also co-ordinate Endeavour Energy's response to those events.

System controllers are senior and experienced staff working on regular shifts covering 24 hours every day - 365 days a year.

(b) District operators are responsible for operating the network switch gears. District operators are specialised staff who have undertaken two to three years of training. These roles provide coverage 24 hours a day – 365 days a year as switch gear operation is constantly required due to fault, emergency and maintenance work. Endeavour Energy currently has 33 district operators;

(c) Rapid response staff respond to emergencies. The rapid response team consists of eight staff and are on duty on a rotational basis. The rapid response staff are generally multi-skilled and can perform restoration work efficiently. They also carry out planned maintenance work when not responding to emergencies, including for example pole cap replacement / de-sap poles, cross arm repairs and replacement, spreader installs for bushfire management and pin insulator replacement. An overview of and analysis of the benefits provided by the rapid response team is set out in REX Rapid Response presentation slides, attached as Appendix 8;

(d) Emergency services officers are similar in role to rapid response staff but usually respond to single customer outages.

79. The network connections group is responsible for new network connections. A significant majority of work associated with the connection of new customers is undertaken by accredited service providers who work on behalf of (and are paid by) customers. Endeavour Energy currently has approximately 80 staff in the network connections group who work in conjunction with external accredited service providers, comprising:

(a) Design certifiers and design engineers, who review documents submitted in relation to network designs;

(b) Installation inspectors who perform on-site inspection of jobs performed by external providers contracted to the customer;

(c) Contract inspectors who perform on-site inspection of jobs carried out by accredited service providers on behalf of customers.

The number of new connections has been increasing and accordingly the network connections group needs to respond to meet this demand. By way of example, over the last 12 months there has been approximately 380 applications received for new subdivisions and major loads. This compares to 250 applications for the preceding 12 months. This represents a 50% increase in work load. For reference, Endeavour Energy's internal memorandum regarding Network Connections Staff Increase is attached as Appendix 9.

80. The operational performance group's role is to review performance of Endeavour Energy's internal field based resources and analyse how performance can be improved. This group also conducts internal benchmarking of the teams and participates in the benchmarking of internal crew performance with contractor performance to better understand the performance and efficiency levels of Endeavour Energy's field based staff. It consists of eight staff.

Enterprise agreement

81. The current enterprise agreement has passed its nominal expiry date of 24 December 2014, but continues to be in force until a new agreement is agreed. A copy of the current enterprise agreement is attached as Appendix 10.

82. A new enterprise agreement is being negotiated in accordance with good faith bargaining as required under the Fair Work Act. Endeavour Energy made a conditional offer to the Unions on 12 November 2014. The main components of the conditional offer were:

(a) the duration will be two or three years;

(b) a continuation of no forced redundancy for the life of the Agreement;

(c) wage/salary increase of between zero and 2.5% per annum for various competitiveness initiatives;

(d) an additional wage/salary increase of 0.5% per annum for a package of equity initiatives; and

(e) modernisation of certain clauses in the Agreement.

83. The Enterprise Agreement lacks flexibility for Endeavour Energy to manage its resources in response to changing business conditions. Endeavour Energy is restricted from forcing staff into redundancy to meet changes in staffing requirements. Endeavour Energy is attempting to increase flexibility over time (including in the amendments proposed by

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Endeavour Energy in the current negotiations), but this is dependent on agreement with the Unions.

84. The Unions rejected the conditional offer made by Endeavour Energy on 9 December 2014. The Unions have provided Endeavour Energy with a marked-up copy of the draft new enterprise agreement attached as Appendix 11. Endeavour Energy is currently in the process of reviewing the marked-up copy and considering its response to the Unions.

Vegetation management

85. Vegetation management refers to the cutting away of vegetation which encroaches on overhead distribution lines, to reduce the risk of interference with the network and associated safety risks, particularly bushfire risk.

86. All of Endeavour Energy's vegetation management is outsourced to external service providers via an open tender process, except for a small area in Wollongong. The vegetation management for that area was also market tested but Endeavour Energy determined that internal resources offered greater value with respect to safety, cost, and quality. Notwithstanding this, this area is currently being market tested again.

87. The vegetation management contracts are performance based outcome type contracts generally on three year term basis, with an option for multiple one year extensions at the end of the three year period (subject to compliance with contract terms including performance standards). The contracts may run up to seven years.

88. The contracts require the contractor to comply with the relevant vegetation management standard.

89. The vegetation management standard is an internal standard adopted by Endeavour Energy, based upon the ISSC 3 Guidelines for Managing Vegetation Near Power Lines for New South Wales (with a number of small variations for practical reasons). Endeavour Energy's internal standard regarding vegetation management (MMI 0013) is attached as Appendix 12. The ISSC 3 Guidelines are attached as Appendix 13.

90. The ISSC 3 Guideline is currently not compulsory. However, as a requirement of the Electricity Supply (Safety and Network Management) Regulation 2014, it will become a binding obligation on Endeavour Energy and its contractors. This regulation requires us to comply with AS5577 which in turn requires Endeavour Energy to nominate those Industry Codes and Standards that we are required to meet. The ISSC3 Guideline is the NSW Government's Industry based standard for vegetation management in NSW and therefore ISSC3 will be nominated in accord with AS5577.

Steps to increase efficiency / save costs

91. Endeavour Energy has taken extensive measures to seek to increase efficiency and reduce costs.

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92. In July 2009, Endeavour Energy formalised its commitment to customers and communities, and its commitment to continuous improvement through the establishment of a Customer Value Improvement Program (CVIP).

93. Since that time, hundreds of initiatives to increase efficiency and reduce costs have been implemented, ranging in value from a few thousand dollars to several million dollars. As at end December 2014, these initiatives have reduced expenditure by over $250 million across both capex and opex activities, and are forecast to deliver more than $265 million in additional capex/opex benefits over the next 18 months.

94. Currently, work is underway in the development of the next phase of the CVIP. Opportunities identified through branch-level analysis of functions and processes in 2014 have been consolidated into a suite of 26 programs under five pillars:

- Capital Efficiency – its objective is to continue to manage the capital program so that spend is necessary, to the right standard, and executed with the right delivery model;
- Opex Efficiency – its objective is to continue to safely drive ongoing improvements in the productivity of internal labour and other opex through further system and work practice reform;
- Blended Delivery – its objective is to increase blended delivery to achieve safe and effective outcomes for our customers and communities;
- Procurement, Logistics, Property & Fleet – its objective is to achieve efficiency improvements in procurement, property, fleet and logistics; and
- Competitive EBAs – its objective is to safely improve the competitiveness of our enterprise agreements to deliver sustainable employment.

Executive sponsors for each pillar are progressing discussions with relevant stakeholders to investigate potential opportunities for future sustainability savings.

95. One of the measures that has been effectively employed in the past and which is key to future improvement initiatives is to outsource work to external service providers where they can meet safety, cost and reliability requirements.

96. Endeavour Energy has established and complied with policies and procedures for procuring from and calling for tenders by external service providers. The main policies are:

(a) Board policy – Supply Management – 12.0.1 Purchasing, attached as Appendix 14;

(b) Company Policy – Supply Management – 12.1 Purchasing, attached as Appendix 15;

(c) Company Policy – Supply Management – 12.4 Probity in Procurement, attached as Appendix 16;

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(d) Company Procedure – Procurement & Logistics – GSU 0001 Purchasing, attached as Appendix 17;

(e) Company Procedure – Procurement & Logistics – GSU 0002 Tendering, attached as Appendix 18;

(f) Company Procedure – Supply Management – GSU 0016 Contract Management, attached as Appendix 19.

The market testing and sourcing of external services providers are in compliance with the above policies and procedures. External service providers that do not meet the required contractual obligations in terms of safety, service and compliance performance are subject to remedial action in accordance with the contract right up to and including the termination of the contract.

97. Endeavour Energy has conducted extensive market testing activities to seek to achieve the best outcome in terms of safety, reliability and cost.

98. In-house activities that have been market tested in recent years and resulted in the activity being sourced from the market include:

(a) Overhead Line Inspection/Ground Line Inspection, fully outsourced since 2008;

(b) Meter Reading Services, outsourced since 2009;

(c) Vegetation Management (Northern & Central Region crews), fully outsourced since 2011;

(d) Mailroom, Front Desk, Facilities Support, outsourced since 2013;

(e) Security Services, outsourced since 2012;

(f) Logistics - delivery services, outsourced since 2013;

(g) Annual Pre-summer Bushfire Inspection process, outsourced since 2013; and

(h) Meter/Relay replacement, outsourced since 2014.

99. Endeavour Energy has market tested other activities but determined that we would continue sourcing those activities internally, based on safety, reliability and cost considerations. These activities include:

(a) Vegetation Management (Southern Region crews), market tested in 2011 in relation to Wollongong (all other areas in region outsourced);

(b) Streetlight bulk replacement, market tested in 2010 and 2013;

(c) Substation Civil Maintenance, market tested in 2013 ;

(d) Logistics – Pole Delivery, market tested in 2013; and

(e) Fleet Management & Maintenance Services, market tested in 2014.

100. Endeavour Energy is currently market testing or planning to market test the following initiatives:

(a) Field Officers (Off-schedule meter reads), tenders closed with decision by March 2015;

(b) GIS Data Capture, currently in the market;

(c) Vegetation Management Southern Region, currently in the market;

(d) Column & Pillar Inspection, currently identified for market test;

(e) Fabrication Workshop, currently identified for market test;

(f) Non-fleet equipment maintenance, currently identified for market test; and

(g) Records Management, currently identified for market test.

101. Endeavour Energy has contracts with external providers for ad hoc externally engaged services, including traffic management and excavation / backhoe (including hole digging by hand).

102. Endeavour Energy also has in place a blended delivery of capital programs (ie mixed internal / external delivery). These programs include:

(a) Electrical and civil design (projects & programs);

(b) Civil and excavation construction works – totally outsourced;

(c) Electrical fit-out of major substations;

(d) Sub-transmission feeder construction;

(e) Distribution feeder works; and

(f) Customer service main replacements.

103. The ratio of externally sourced direct expenditure activities for the regulated opex categories of standard control services and alternate control services is set out in the following Table 3. This figure does not include any external sourcing for activities associated with network overheads or corporate overheads.

Table 3 Opex blended delivery ratios

Standard Control	2014/15
Total Standard Control Opex	293.13
Network & Corporate Overheads	151.08
Total Standard Control Opex Excluding Overheads	**142.05**
Vegetation Contractors (direct)	38.34
OLI/GLI Contractors (direct)	11.75
Meter Reading Contractors (direct)	-
Total Contractors	**50.09**
Blended Delivery Ratio	**35%**

Alternate Control	2014/15
Total Alternate Control Opex	73.30
Network & Corporate Overheads	40.09
Total Opex Alternate Control Excluding Overheads	**33.21**
Vegetation Contractors (direct)	-
OLI/GLI Contractors (direct)	-
Meter Reading Contractors (direct)	2.96
- Routine meter reading services	*2.96*
- Off cycle meter reading services	-
Total Contractors	**2.96**
Blended Delivery Ratio	**9%**

104. In relation to Endeavour Energy's internal field based activities, we for the last several years have undertaken standard job analysis to seek to improve the performance and efficiency of a number of standard jobs. These standard jobs comprise about 61.2% of Endeavour Energy's maintenance activities. By way of example, Endeavour Energy has improved (and in some cases significantly improved) the efficiency of the nine focus maintenance tasks, which represent 89% of all standard maintenance jobs. A summary of performance improvement of these standard jobs is in Table 4 as below.

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Table 4 Summary of performance improvement of standard jobs

STANDARD JOB	Annual Hours (3-yr ave)		BASELINE		LAST 3 MONTHS' AVERAGE			
			Average hours	Average cost	Number of jobs	Average hours	Average cost	% change
SI201	10,590	3.60%	15.8	$1,492	210	13.7	$1,351	**13.2%**
ABSMNT	13,288	4.50%	9.6	$1,266	272	7.8	$1,195	**18.8%**
1POLE	82,038	27.90%	49.8	$7,123	372	41.2	$7,138	**17.2%**
1TXREP	6,574	2.20%	21.9	$8,780	39	18.8	$8,240	**14.1%**
1LVARM	8,814	3.00%	9.4	$969	321	8.4	$1,050	**11.0%**
1HVARM	6,328	2.20%	10.8	$1,209	156	10.0	$1,347	**7.6%**
3RET11	12,520	4.30%	19.9	$2,993	121	15.4	$2,529	**22.6%**
1COLUM	9,939	3.40%	14.5	$2,028	186	16.4	$2,700	**-13.1%**
1ABSSW	9,800	3.30%	43.7	$7,997	11	37.8	$5,840	**13.6%**
1PLCAP	2,033	0.70%						
1SECDR	6,242	2.10%						
1SERCO	3,788	1.30%						
S1200A	3,210	1.10%						
HVNCTM	2,306	0.80%						
PCALDF	2,152	0.70%						
TOTAL	**179,622**	**61.20%**						**14.4%**

9 jobs in focus 159,891 89% % of jobs on our list

105. I describe below two routine maintenance tasks, two condition based maintenance tasks and two refurbishment tasks represented as standard job names in Table 4 above.

(a) Task SI201 is the maintenance of MD4 switchgear. This task is a routine maintenance task. It is performed between 700-800 times each year and involves typically two staff of which one is electrical trade qualified. A summary of the activities involved in this maintenance task is listed as follows in Table 5 below. In the period June to August 2014, Endeavour Energy achieved efficiency improvements in relation to routine maintenance of MD4 switchgear of 23.4% in terms of the average time to perform this task, as compared to the average time for the period July 2010 to March 2012.

Table 5 Cast resin HV switchgear routine maintenance

Routine maintenance
1.0 Inspection, PD and thermovision
Test resin enclosed switchgear, switchcaps and cable termination stem discharge using UltraTEV Plus+ PD device and prioritise as shown in Table 1 in section 5.7.1
Check compound level in wetbox. Defects must be prioritised as shown in Table 3 in section 5.9.1.3
Examine that labelling is present and legible.
Test switch caps for overheating using thermography as shown in section 5.8.1.
2.0 Major maintenance
Examine arcing contacts and arc chamber for signs of burning / discolouration.
Examine resin surface for contamination.
Examine fuse interlock for cracks in plastic material.
Examine fixed permanent magnet for security.
Examine switchgear frame for signs of corrosion.
Examine hold down bolts of steelwork for security and signs of corrosion.
Examine side and top dust cover(s) for damage/distortion.
Examine cable termination stem for signs of tracking and verdigris.
Examine wooden cable cleats for security.
Examine switch cap (newer style) for signs of cracks/damage.
Examine switch cap for signs of cracks/damage.
Examine fuse holder cap for signs of cracks/damage.
Check cam and leaf spring integrity by performing three (3) test operations of the switch cap.
3.0 Pre and post operation checks
Install switch dust covers where switch caps are removed.
Examine contacts in switch cap for security.
Clean operating handle.

(b) Task ABSMNT is the routine maintenance of an air break switch. This task is performed approximately 1,000 to 1,300 times each year and typically involves a crew of three live line workers with one EWP. Appendix 20 provides a summary of the activities involved in this maintenance task. In the period June to August 2014, Endeavour Energy achieved efficiency improvements in relation to routine maintenance of an air break switch of 21.9% in terms of the average time to perform this task, as compared to the average time for the period July 2010 to March 2012.

(c) Task 1LVARM is a low voltage crossarm replacement. It is a condition based maintenance task performed approximately 1,000-1,100 times each year primarily driven by the defecting of the crossarm following the inspection process. It typically involves two to three electrical trade qualified staff with one EWP. In the period June to August 2014, Endeavour Energy achieved efficiency improvements in relation to low voltage crossarm replacement of 8.3% in terms of the average time to perform this task, as compared to the average time for the period July 2010 to March 2012.

(d) Task 1HVARM is a high voltage crossarm replacement. It is a condition based maintenance task performed approximately 500-600 times each year primarily driven by the defecting of the crossarm following the inspection process. It typically involves three electrical trade qualified staff with one EWP. In the period

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June to August 2014, Endeavour Energy achieved efficiency improvements in relation to high voltage crossarm replacement of 17.1% in terms of the average time to perform this task, as compared to the average time for the period July 2010 to March 2012.

(e) Task 1POLE is a pole replacement. Pole replacement is a refurbishment task performed approximately 1,400-1,500 times each year primarily driven by the condemnation of the pole following the inspection process. It typically involves six to seven staff which comprises of four to five electrical trade qualified staff with an EWP and a line truck and two plant operators with one lifter borer. In the period June to August 2014, Endeavour Energy achieved efficiency improvements in relation to pole replacement of 17.0% in terms of the average time to perform this task, as compared to the average time for the period July 2010 to March 2012.

(f) Task 1TXREP is a distribution transformer replacement. Distribution transformer replacement is a refurbishment task performed approximately 100-150 times each year primarily driven by load increases. It typically involves four staff which include three electrical trade qualified staff with an EWP and one plant operator with a flatbed truck for transformer delivery. In the period June to August 2014, Endeavour Energy achieved efficiency improvements in relation to transformer replacement of 21.2% in terms of the average time to perform this task, as compared to the average time for the period July 2010 to March 2012.

Requirements of operation in NSW and Nationally

106. The electricity legislative and licence conditions obligations are set out in:

- Electricity Supply Act 1995;
- Electricity (Consumer Safety) Regulation 2006;
- Electricity Supply (Corrosion Protection) Regulation 2014;
- Electricity Supply (General) Regulation 2014;
- Electricity Supply (Safety and Network Management) Regulation 2014;
- Market Operations Rule (NSW Electricity Business to Business Procedures) No 1 Of 2013
- Ministerially imposed licence conditions for Distribution Network Service Providers:
  - Conditions 1 to 13; and
  - Conditions 14 – 19.

107. The national electricity legislative and licence condition obligations are set out in National Electricity Law and National Electricity Rules (NER), which provide for safe, reliable and efficient distribution services in the interests of consumers.

108. Endeavour Energy must comply with these legislative and licence conditions when developing, maintaining and operating the assets that make up Endeavour Energy's network as described above. A failure to do so and a failure to be provided with sufficient capex and opex in order to do this will jeopardise the safety and reliability of the network.

Potential consequences of revenues cuts

109. In my opinion, based on current information, the reductions proposed by the AER would likely lead to substantial under investment by Endeavour Energy in both capital and operating expenditure, and would compromise the safety, the reliability and the ongoing sustainability of its network

110. A prioritisation tool known as Capital Allocation Selection Hierarchy (CASH) is used to assist in selecting the projects for inclusion into the capital expenditure planning process each year which best meet Endeavour Energy's business objectives. The network risk topics considered in the most recent CASH ranking are:

- Network asset condition
- Public safety, environmental or regulatory impact
- Network initiated fire risk
- Network reliability impact
- Community impact (Reputation)
- Work health safety – employee risk
- Network capacity implications

Each of the risk categories are weighted equally in assessment. In order to facilitate an effective prioritisation, each program is broken down into pre-prioritised subcomponents of short term need (immediate requirement), medium term need (short-term requirement, but risk-manageable prior to replacement), and long term need (expected future or strategic renewal requirement).

111. In general, if the capex program was reduced in order to achieve the AER draft expenditure levels all Endeavour Energy's programs of work would be reduced on a risk assessed basis. Some equipment which would have been replaced in a timely fashion prior to failure will not be replaced, which will add to the safety and reliability risk of the business. For example, 11kV distribution switches which are not replaced will fail in service adding to customer interruptions and restoration times. Some of these switches may be deemed unsafe to operate and require staff to switch at more remote locations extending the level of outage to cover more customers than otherwise necessary.

112. In relation to opex, as set out at paragraph 71 and following above, Endeavour Energy has determined the amount of opex it requires for its IRP and RRP based upon the opex required to maintain the safety and reliability of its network assets and the operation of the network. Endeavour Energy as part of this process has identified and incorporated planned efficiency savings into the RRP. The AER's Draft Determination on opex is far below the opex required to maintain safety and reliability. If the Draft Determination was to be adopted, Endeavour Energy would not be able to carry out a material part of the

opex it had planned over the regulatory period. A failure to perform that opex will mean that network assets will not be maintained in a timely fashion or inspected in a manner which enables preventative maintenance to occur. This is likely to result in increased assets failures. For example, a reduction in the inspection and rectification of found defects with respect to poles and columns will, based on past experience, lead to an increase in asset failures that will impact safety outcomes, lead to poorer reliability and a more inefficient outcome due to its reactive unplanned nature.

113. In general terms any deferral or reduction of required network expenditure will increase staff, contractor and public safety risk, environmental risk, bushfire risk, have network reliability implications and have capacity impacts. Another outcome is the return to a 'boom-bust' cycle of investment, as deterioration in asset quality is likely to necessitate increased spending in the future to return the safety and reliability of the network to acceptable levels.

114. Furthermore, the proposed significant reduction in opex / capex by the AER coupled with the need to increase the level of external sourcing of services by the organisation may not be able to be absorbed by staff attrition, including voluntary redundancy. This will adversely impact the financial position of the organisation.

Summary Statement

115. In summary:

- Based on my training, history and experience as an executive of Endeavour Energy the implications of the AER draft determination, if implemented from both a quantum and step change perspective, are significant.
- This outcome will appreciably increase both the safety and operational risk profile of the business that will lead to adverse safety outcomes for our staff and contractors and the community we serve; result in a deterioration of network reliability and security; and impact the viability and sustainability of the business.
- The provision of insufficient capex and opex will also threaten our ability to comply with all required legislative and licence conditions.

116. The AER's draft determination if implemented will mirror the regulatory events of the late 1990s which in due course also led to adverse outcomes for customers, shareholders and regulators alike and led to the need to over compensate in subsequent determinations. A long term sustainable outcome is what is required.

Sworn at 51 Huntingwood Drive, Huntingwood New South Wales, this 19 January 2015

Rod Howard

Before me:

Signature of witness:

VITO TETTO

Name of witness:

SOLICITOR (NSW) # 9888

Qualification of witness: Australian Legal Practitioner

Table of Appendices

Appendices	Document
1.	Position description of Rod Howard
2.	Curriculum vitae of Rod Howard
3.	Recommendations of IPART for regulatory period 1999 - 2004
4.	Recommendations of IPART consultant Worleys for regulatory period 1999 - 2004
5.	Coroner's findings released in March 2003 in relation to the Appin bushfire
6.	Design, reliability and performance licence conditions imposed on NSW DNSPs by the Minister for Energy on 1 August 2005
7.	Revised and updated design, reliability and performance licence conditions imposed on NSW DNSPs by the Minister for Energy with effect from 1 December 2007
8.	REX Rapid Response presentation slides
9.	Endeavour Energy internal memorandum regarding Network Connections Staff Increase
10.	Endeavour Energy current enterprise agreement
11.	Union marked-up copy of draft enterprise agreement
12.	Endeavour Energy internal standard regarding vegetation management (MMI 0013)
13.	ISSC 3 Guidelines for Managing Vegetation Near Power Lines for New South Wales
14.	Endeavour Energy board policy regarding supply management (12.0.1 Purchasing)
15.	Endeavour Energy company policy regarding supply management (12.1 Purchasing)
16.	Endeavour Energy company policy regarding supply management (12.4 Probity in Procurement)
17.	Endeavour Energy company procedure regarding procurement and logistics (GSU 0001 Purchasing)

Appendices	Document
18.	Endeavour Energy company procedure regarding procurement and logistics (GSU 0002 Tendering)
19.	Endeavour Energy company procedure regarding supply management (GSU 0016 Contract Management)
20.	Summary of activities involved in the maintenance of an air break switch

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Position Description

Position Title:	Chief Operating Officer, Endeavour Energy		
Position Number:	200000	**Division:**	Endeavour Energy
Reports to:	Chief Executive Officer, Networks NSW		
Date Created:	June 2012	**Date Updated:**	
Job Analyst Name:	Andrew Pitman		
CEO Signature:	(signed)		

ORGANISATIONAL CONTEXT

Networks NSW is the group of companies comprising Ausgrid, Endeavour Energy and Essential Energy. Although they remain separate legal entities with separate network operations, these companies are managed together under common governance arrangements effective from 1 July 2012, to implement the Government's reform of the NSW electricity distribution industry.

As one of the three separate Network businesses, Endeavour Energy is responsible for the safe and efficient management and operation of the electricity distribution network consistent with the strategy, policies and standards as determined by the common group management structure.

While considerable changes are likely to occur in the operating environment of the business, Networks NSW and each network business will remain focused on:

- Achieving the objectives set out in the State Owned Corporations Act 1989, including
  - Operating at least as efficiently as any comparable privately owned business;
  - Maximising the value of the business to the State;
  - Operating a safe, reliable and sustainable network; and
  - Balancing commercial, social, environmental and customer expectations;
- Implementing initiatives identified under the Network Reform Program; and
- Fully harnessing the skills and capabilities of our people through a clear focus on leadership and cultural transformation, underpinned by our corporate values.

POSITION PURPOSE

The Chief Operating Officer is accountable to the CEO for the safe, reliable and sustainable development, construction, maintenance and operation of all electrical infrastructure in Endeavour Energy. The Chief Operating Officer also has responsibility for the delivery of safety, human resources, environment, communications and finance support and management of information and operations technology that enables the achievement of Endeavour Energy's objectives.

The Chief Operating Officer leads a whole of company commitment in which the safety of employees, contractors and the communities in which we work is seen as the number one priority and where continuous improvement in safety performance is owned by all employees.

The Chief Operating Officer is responsible to manage Endeavour Energy's performance of its contractual obligations with [insert Retailer] under the terms of the Transitional Services Agreement.

KEY ACCOUNTABILITIES

The Chief Operating Officer is accountable for the positions and key functions described below:

Chief Engineer

- Provide long term stewardship of the network including policies, standards, growth, renewal and maintenance planning, and reliability and compliance management. This includes development of a detailed asset management program within a framework determined by Group General Manager Network Strategy and development of plans to optimally sustain network condition, safety, asset utilisation, supply security and network performance.
- Direct and manage strategic projects including network technology.
- Manage the implementation of the network strategy & compliance framework as determined by Group General Manager Network Strategy.

Network Development

- Overall program management and delivery of the network capital and maintenance programs. This includes the establishment of a Program Management Office to provide end to end project management of all projects (including contractor management and the external works program).
- Deliver efficient and effective asset management services including vegetation management, asset inspection and streetlight management.

Network Operations

- Overall management of the network to deliver a safe, reliable and sustainable outcome
- Manage field operations resources to maintain the electricity distribution network to meet license requirements and customer expectations. This includes works scheduling, program delivery, supply interruptions, emergency response, line safety management and implementation of the metering strategy.
- Maintain oversight of the network and work being conducted on the network. This includes management of the systems control function.

People and Network Services

Support the network business through the delivery of key support activities as follows:

- Manage the provision of core people services to support improved delivery of business outcomes. This includes employee relations and business partnering, change management support employee advice, recruitment, payroll and training. This also includes implementation of Group people strategies and policies.
- Support the operations of the network business through the delivery of key support activities including customer and market services, procurement, transport, property and logistics consistent with strategic direction from the Group.
- Deliver local internal and external communications and stakeholder management. This includes employee communications, regional media management and community relations activity.
- Deliver retail support services to Origin in accordance to service levels established in the Transitional Services Agreement.

Finance and Compliance

- Financial management of the business including risk, compliance and regulation. This includes providing financial management support for the business, financial reporting and analysis, business development and commercial support, general ledger, accounts payable, budgeting and forecasting processes and provision of decision support analysis and advice.
- Manage governance requirements including risk and insurance, compliance, audit, fraud control and records, and provide Board and Executive support as required.

Health, Safety and Environment

- Manage the health, safety and environment strategy, program development, audit and compliance. This includes the development and management of health, safety and environment management systems within the network business in line with Group strategy and policies.
- Implement public safety strategies and investigation of accidents and incidents and capture to learnings in order to improve safety and environmental management systems and performance.

Information Communication and Technology

- Manage the provision, delivery and operations of all network and business Information, Communication and Technology (ICT) requirements in line with Group strategy. This includes leading Endeavour Energy’s IT/OT approach and delivery to optimise capital investment and opex spend, maximise value from IT/OT investments and drive efficiencies in the business which are aligned to Group strategy and initiatives.
- Maintains and operates network security and SCADA systems.

POSITION DIMENSIONS

Staff
Number of direct reports: 7
Number of staff reporting indirectly: approx 6000/4600/2950 FTE

Budget (annual) direct responsibility
CAPEX $1.7b/947m/673m
OPEX $797/472/394m

(Based on 2012/13 budget targets)

Value of electricity assets: $12.7/6.1/5 billion

CHALLENGES

- Ensuring a whole of organisation focus and commitment to safety as the “number on” priority and continuous improvement in safety performance
- Leading a large organisational change and reform agenda delivering significant cash savings in line with performance and savings objectives determined by Network’s NSW
- Meeting the customer service and network performance targets for Endeavour Energy
- Development of a culture that is safety focused, customer centred and efficiency drive
- Manage Endeavour Energy’s unions based on respect and consultation to deliver value to Endeavour Energy customers
- Developing a Strategic Asset Management Plan (SAMP) consistent with group policies and standards, including growth, renewal, compliance and maintenance plans and ensuring their implementation
- Lifting the performance of Endeavour Energy through optimised use of resources, rationalisation of operations
- Implementing Group strategies, policies and frameworks, and working to matrixed reporting relationships

KEY RELATIONSHIPS

- Chief Executive Officer, Chief Operating Officers, Group Executives and Board - advising and reporting on Endeavour Energy plans and performance.
- Managers and key staff - promoting organisational and business change, setting performance targets, leading cultural change and dealing with performance shortfalls.
- Major contractors and business customers - resolving major contractual performance problems.

WORK HEALTH AND SAFETY

Demonstrate personal leadership in the implementation of Endeavour Energy's Safety Management System and facilitate its effectiveness by ensuring adequate resources are available, that all employees are aware of their Work Health and Safety obligations and that one's personal behaviour models the organisation's commitment to Work Health and Safety.

ETHICS, EEO, ENVIRONMENT AND QUALITY

All employees within Endeavour Energy are required to have an awareness of, and a commitment to:

- The Endeavour Energy values and code of ethics
- Equal Employment Opportunity
- Environmental Management Protection

This is in addition to the specific job details described in this document, and in conjunction with the appropriate Endeavour Energy policies and procedures as amended from time to time.

KNOWLEDGE, SKILLS AND EXPERIENCE

Desirable Qualifications

- Tertiary qualifications in engineering or relevant degree discipline.
- Management qualification from a recognised institution.

Experience

- A senior executive with demonstrated experience in managing large scale infrastructure operations with significant weighting of experience in the electricity distribution industry.
- Strong resource, budget and people management and leadership with demonstrated experience in driving substantial reform and change agendas.
- Industrial Relations experience at a senior operating level in a highly industrialised environment.

LEADERSHIP COMPETENCIES

COMPETENCY	EXECUTIVE BEHAVIOURS
Strategic thinking Sees the bigger picture. Applies experience and knowledge to bring fresh insights and new ideas to the business.	▪ Conceptualises and delivers something new or significant for the business ▪ Breaks the mould, realises opportunities that others cannot see ▪ Can create innovative, breakthrough strategies and plans.
Initiative Anticipates and takes action to create opportunities, overcome challenges and avoid future problems.	▪ Anticipates and takes action to create an opportunity or avoid a future problem, looking ahead within a three to five year time frame ▪ Creates a framework which enables others to consider and/or anticipate the potential for future problems ▪ Proactively seeks out strategic opportunities to grow the business ▪ Re-shapes the organisation to take advantage of long term growth opportunities ▪ Thinks of and takes action which will benefit the whole organisation.
Developing others Recognises others' potential and their development needs. Supports their capability and long term.	▪ Provides (or assigns others to provide) in depth coaching or mentoring and ongoing developmental support ▪ Carefully selects development assignments in order to build long term capability.
Leading people Energises and aligns employees around a shared vision. Creates a climate in which our employees want to do their best.	▪ Provides a clear vision of future success which is compelling and engaging ▪ Believes in the vision and inspires confidence in the vision ▪ Generates excitement, enthusiasm and commitment to the vision ▪ Talks about possibilities; is optimistic about the future.
Communicating and influencing Gains the support of key stakeholders in courses of action that benefit the business.	▪ Thinks through how they will influence over time and develops deliberate influencing strategies ▪ Builds support for ideas through informal stakeholders ▪ Uses an in depth understanding of the interactions within a group to move towards a specific outcome.
Mobilising change Displays openness to change, inspires others to change and acts to make change happen.	▪ Creates a sense of urgency for change ▪ Challenges the status quo when appropriate by comparing it to an ideal or vision of change ▪ Anticipates and take actions to address the emotional impact of change ▪ Recognises and reinforces the behaviours of those who embrace the change ▪ Encourages others to recognise that change is the norm.
Customer focus Creates customer value by understanding and acting in the best interests of the customer.	▪ Looks for long term benefits that create value for the customer ▪ Becomes involved in the customer's decision making process as appropriate ▪ Builds an independent opinion on customers' needs and problems; recommends approaches which are ▪ new and different from those requested by the customer ▪ Anticipates the customer's future needs.
Drive for results Takes personal accountability for delivering results. Displays an inner drive to improve performance and achieve a standard of excellence.	▪ Takes calculated risks to achieve long term improvement ▪ Conducts detailed cost-benefit analyses, being mindful of the corporate values ▪ Persistently drives through obstacles ▪ Puts commercial results ahead of personal credibility; is courageous in decision making.
Holding to account Takes personal accountability for delivering results. Displays an inner drive to improve performance and achieve a standard of excellence.	▪ Rigorously manages performance against demanding targets ▪ Consistently challenges individuals openly and constructively about performance problems; takes action ▪ if performance does not improve ▪ Creates a 'performance culture' where effective performance and continuous improvement are valued.

CURRICULUM VITAE

PERSONAL DETAILS

Name:	Rod Howard
Current Position:	Chief Operating Officer Endeavour Energy – commencing 1 July 2012
Education:	Master of Business Administration (Executive) Australian Graduate School of Management Sydney – 2002
	Company Directors Course Diploma Australian Institute of Company Directors Sydney – 1999
	Change Management Certificate Australian Graduate School of Management Sydney – 1998
	Bachelor of Business Charles Sturt University Bathurst – 1988
	Master of Engineering Science University of New South Wales Sydney – 1981
	Bachelor of Engineering (Honours) University of New South Wales Sydney – 1978
Directorships:	Director – Since October 2012 Energy Networks Association
	Chairman – resigned 30 June 2012 Energy & Water Ombudsman NSW (Director since 2001, Deputy Chairman since 2005 and Chairman since 2011)
Memberships:	Australian Institute of Company Directors Fellow of Institution of Engineers, Australia
Honours:	Awarded a Public Service Medal 2009 Australia Day Honours List

CAREER HIGHLIGHTS

- As the Chief Operating Officer of Endeavour Energy I am responsible for the day-to-day operations of an electricity distribution utility that provides service to 2.2 million people in households and businesses and 933,500 customers via a network with a regulated asset base valued at $5.6 billion utilising 2,530 staff. In this and previous roles led the implementation of various reform initiatives to achieve customer value outcomes.

- Acted as Endeavour Energy's (and Integral Energy's) Chief Executive Officer on many occasions over the past 9 years including one period of seven weeks.

- With the support of the Board and management achieved the best network reliability outcomes in NSW for our customers for the period 2008 to 2011 and the third best amongst Australian utilities.

- Successfully delivered significant increases in the network capital program for Endeavour Energy. In the period between 2002 and 2012 the program has increased from $111 million to $552 million in order to response to the strategic growth and demand for electricity. This achievement was in a global environment of increasing demand for materials and skills.

- Successfully led and delivered Integral Energy's preparation for mass market retail energy competition between 2000 and 2002. This project, which involved 55 individual projects that impacted on all facets of Integral Energy's operations, was in response to a key policy initiative of both the NSW and Federal Governments.

- Seconded to lead on a part time basis the recovery from Integral Energy's "billing crisis" between 2000 and 2002. The involved the fundamental reconstruction of the customer billing process including the establishment of structure responsibility, staffing, performance management, customer management and shareholder liaison.

- Completed a new two year change management program developed by the Centre for Corporate Change at the Australian Graduate School of Management. I was fortunate to be included in the first intake for this very contemporary and innovative program. Completion of this program in 1998 provided me with advanced standing for completing the MBA program.

EXPERIENCE SUMMARY – Endeavour Energy

July 2012 to Current
Chief Operating Officer (initially in an interim position between July 2012 and August 2012)

Responsible for the day-to-day operations of an electricity distribution utility that provides service to 2.2 million people in households and businesses and 933,500 customers via a network with a regulated asset base valued at $5.6 billion utilising 2,530 staff. The fundamental objective of this role is to provide value to customers in a manner that does not compromise safety, network reliability or sustainability.

June 2009 to June 2012
Deputy Chief Executive Officer Network (known as Group General Manager Network up until May 2011)

Responsible for the overall management of the electrical network, including the delivery of the associated investment program, to ensure its capacity, sustained integrity and long term value in delivering a safe and reliable electricity supply to our customers.

January 2007 to June 2009
General Manager Network Development and Control

Responsible for the planning, operating and monitoring of the then Integral Energy network, including the delivery of a record capital program, to ensure its capacity, sustained integrity and long term value. The fundamental requirement of the role was to manage the network in order to deliver a reliable and safe supply to our customers.

July 2002 to December 2006
General Manager Capital Solutions

In recognition of the strategic imperative to increase the level of capital investment in the network this role was created to provide necessary focus and execution. Annual capital programs increased from $111 million to $249 million in an environment of increasing demands for materials, skills and electricity supply.

March 2000 to July 2002
General Manager Full Retail Contestability

Led this key strategic project associated with full retail contestability in NSW. This role, which involved 55 individual projects and impacted on all facets of operations, was in response to a key policy initiative of both the NSW and Federal Governments.

January 1999 to March 2000
General Manager Corporate Development/Company Secretary

Responsible for providing the CEO, under a framework of autonomous business units, with strategy and policy development advice for business development, organisation change, regulatory and risk, corporate affairs and marketing, quality and audit and legal. I was also appointed as the Company Secretary to the Board during this period.

January 1993 to January 1999
Various Executive Positions

During this period I was afforded the opportunity of gaining a broad level of knowledge and experience at executive level with various roles in business development, operational management and corporate activities.

REGULATION OF NEW SOUTH WALES ELECTRICITY DISTRIBUTION NETWORKS

Determination and Rules Under the National Electricity Code

December 1999

INDEPENDENT PRICING AND REGULATORY TRIBUNAL
OF NEW SOUTH WALES

REGULATION OF NEW SOUTH WALES ELECTRICITY DISTRIBUTION NETWORKS

Determination and Rules Under the National Electricity Code

December 1999

The Tribunal members for this review are:

Dr Thomas G Parry, Chairman
Mr James Cox, Full time member

This publication comprises two documents:

The Tribunal's determination on
Regulation of New South Wales Electricity Distribution Networks
under the National Electricity Code

Rules made by the Tribunal under clause 9.10.1(f) of the National Electricity Code

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Determination
Under the National Electricity Code

December 1999

INDEPENDENT PRICING AND REGULATORY TRIBUNAL
OF NEW SOUTH WALES

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FOREWORD

The Tribunal has issued this determination under the National Electricity Code (the Code). The Code became effective in December 1998, facilitating the introduction of the national electricity market. The Tribunal is the first regulator to issue a determination for distribution network service providers (DNSPs) under the Code. This has not been an easy task. The Code is riddled with inconsistencies and deficiencies that made our task far more difficult than it should have been.

In this determination the Tribunal establishes the annual revenue requirements for the six electricity DNSPs in New South Wales for the period from 1 February 2000 until 30 June 2004.

The Tribunal's determination will result in real price reductions for distribution service charges of 16 per cent on average over the next five years. Reflecting the benefits of greater volumes and rapid growth, customers of Integral Energy and EnergyAustralia, on average, will benefit from real reductions of around 27 per cent and 16 per cent, respectively. Because of the higher cost environment within which rural DNSPs operate, their customers will not enjoy the same level of price reductions as the metropolitan DNSPs. Average price movements will be limited to inflation or reducing in real terms.

The six distribution network service providers are public utilities owned and operated on behalf of the residents of NSW by the State Government. In protecting the value of the DNSPs, the Tribunal has had regard to the interest of the owners for the benefit of the taxpayers and residents of the State.

NSW taxpayers will benefit from the profits and tax equivalent payments made by the DNSPs. At the same time, the Tribunal has considered electricity customers, whose interests are best served by long-term, sustainable and efficient cost-reflective network prices.

In its deliberations, the Tribunal has attempted to seek an appropriate balance of the interests of both the owners and the users of electricity services in NSW. The outcomes determined in this report are very much underpinned by robust growth projections (particularly in the metropolitan areas) and a declining rate of return, offset by an increase in the value of the businesses' regulatory asset base.

The Tribunal has established four sets of rules under clause 6.10.1(f) of the Code that DNSPs must comply with. The rules relate to:

- unders and overs accounts
- pricing notification and information disclosure
- charges for miscellaneous services
- charges for monopoly services to support contestable works.

I would like to thank the organisations and individuals that contributed to this review process.

Thomas G Parry
Chairman
December 1999

EXECUTIVE SUMMARY

Background and legislative basis for determination (chapters 1 & 3)

The Independent Pricing and Regulatory Tribunal (the Tribunal) issues this determination under the National Electricity Code (the Code). The Code became effective in December 1998, facilitating the introduction of the national electricity market.

The Tribunal is the first regulator to issue a determination for distribution network service providers under the Code. This has not been an easy task. The Code is riddled with inconsistencies and deficiencies. The Tribunal is concerned that the Code may inhibit the development of better regulatory outcomes.

The Tribunal was granted a derogation from part E of chapter 6 of the Code. Part E of chapter 6 relates to pricing principles, but the Tribunal felt that the guidelines had undesirable outcomes.

This Tribunal had regard to analysis presented in its June 1999 report addressing the reference issued by the Premier under section 12A of the *Independent Pricing and Regulatory Tribunal Act 1992* (IPART Act).

In making this determination, the Tribunal has considered numerous objectives and principles outlined in various clauses under the Code.

The outcomes of this determination are underpinned by:

- robust growth projections (particularly for metropolitan areas)
- a declining rate of return
- increasing regulatory asset values.

Pricing outcomes (chapter 9)

The Tribunal establishes the base revenue requirements for each of the six electricity distribution network service providers (DNSPs) in New South Wales for the period from 1 February 2000 until 30 June 2004. Distribution services constitute around 40 per cent of a typical electricity account.

Table 1 Base revenue requirements ($m)

	1999/2000	2000/2001	2001/2002	2002/2003	2003/2004
EnergyAustralia[1]					
Building Block	674	692	710	730	752
Smoothed	691	706	721	736	752
Integral Energy					
Building Block	388	398	407	415	419
Smoothed	395	401	407	413	419
NorthPower					
Building Block	186	194	200	208	215
Smoothed	170	180	191	203	215
Great Southern Energy					
Building Block	117	122	126	129	132
Smoothed	113	117	122	127	132
Advance Energy					
Building Block	87	90	92	95	97
Smoothed	74	78	82	87	92
Australian Inland Energy					
Building Block	14	14	15	15	16
Smoothed	11	12	12	13	13
Industry Total					
Building Block	1466	1510	1550	1592	1631
Smoothed	1454	1494	1535	1579	1623

Table 2 Cumulative real reductions in network prices, 1999/00 to 2003/04

DNSP	Real reductions, 1999/2000 to 2003/04 (%)
EnergyAustralia[1]	16
Integral Energy	27
NorthPower	0
Great Southern Energy	6
Advance Energy	0
Australian Inland Energy	0
DNSP total	**16**

1 Includes costs and revenues for transmission services as determined by the ACCC.

Asset values (chapter 6)

The six DNSPs are public utilities owned and operated by the NSW Government on behalf of the residents of NSW. In balancing the interests of stakeholders, the Tribunal has had regard to:

- the value of the business for the benefit of the tax payers and residents of the state
- pricing outcomes for electricity users.

The regulatory asset base includes the initial capital bases and working capital. The regulatory asset bases at 30 June 1998 are as follows:[2]

Table 3 Initial capital bases as at 30 June 1998

DNSP	Initial capital base ($m) [3]
EnergyAustralia[1]	3,767
Integral Energy	1,732
NorthPower	858
Great Southern Energy	515
Advance Energy	303
Australian Inland Energy	50
DNSP total	**7,225**

1: EnergyAustralia's initial capital base includes its transmission assets.

The Tribunal wishes to emphasise that in its deliberations on the initial capital base it considered, among other issues, the government ownership of the DNSPs. This accords with the requirement of the Code that provides for the regulator to have regard to the pre-existing asset valuation policies for government-owned DNSPs. This decision does not bind the Tribunal's future regulatory decisions on initial capital bases for the electricity industry or any other industry.

Rate of return (chapter 5)

The cost of capital is an important ingredient in determining revenue streams. It is applied to the entire capital base of each utility and to new investment throughout the regulatory period.

For the purposes of calculating base revenues for the NSW DNSPs over the regulatory period, the Tribunal has determined that a real, **pre-tax rate for return of 7.5 per cent** is appropriate. This is consistent with a nominal post tax return on equity of approximately **11 to 12 per cent.**

2 Financial modelling is based on 1998/99 figures.

3 Includes streetlighting assets.

In its June 1999 s12A report the Tribunal states that the rate of return for Advance Energy and Australian Inland Energy should have a 25 basis point premium over the rate of return for the other DNSPs. Having reconsidered the associated risks. The Tribunal can no longer justify the premium, especially in the context of the straight revenue cap, now to be applied.

The Tribunal has applied a pre-tax nominal rate of return of 7.6 per cent to working capital.

Regulatory framework issues (chapter 3)

Form of regulation

The Tribunal has adopted a straight revenue cap, supported by a glide path, which allows the DNSPs to share the benefits of out-performance with customers over time.

Limits on price movements

The Tribunal has protected customers from large increases in the network component of their electricity accounts. Average prices across the network must not increase by more than CPI. To allow price restructuring, a residential customer's network bill cannot increase by the greater of CPI plus 2 per cent or $30 if that customer consumes the same amount of energy in the same pattern as in the corresponding period the previous year.

Standards of service

The Tribunal has not included a service reliability incentive mechanism in this determination due to a lack of adequate data. However, the Tribunal intends to work with stakeholders to develop its treatment of standards of service.

Capital contributions

The customer capital contributions issue is contentious. The Tribunal has been working with stakeholders to develop a workable solution. Unfortunately, the issue has not been resolved in this determination's timeframe and the Tribunal has made no decision on capital contributions in this determination. When this issue is resolved the Tribunal will issue a decision on capital contributions.

Rules under clause 6.10.1(f) of the Code

As part of a separate document, the Tribunal has established four sets of rules under clause 6.10.1(f) of the Code. The rules relate to:

- unders and overs accounts
- pricing notification and information disclosure
- charges relating to miscellaneous services
- charges relating to monopoly services.

DNSPs must comply with these rules.

SUMMARY OF DETERMINATION

What follows is a summary of the Tribunal's determination. It should be used and relied on only in conjunction with the full determination that follows.

Definition of prescribed services

It is the Tribunal's determination that, for the purpose of clause 6.10.4, 'prescribed distribution services' are those services performed by each DNSP that are associated with or ancillary to access to that DNSP's network for the supply of electricity within that DNSP's service area.

Length of regulatory period

The Tribunal has determined a revenue path for the NSW DNSPs effective from 1 February 2000 until 30 June 2004.

For the 1999/2000 financial year the revenue will comprise the (rolled forward) 1997 determination pro-rated for the period from 1 July 1999 to 31 January 2000, and this determination, pro-rated for the period from 1 February 2000 until 30 June 2000. Pro-rating will be on the basis of calendar days covered by each determination.

If a new determination is not issued to take effect from 1 July 2004, all charges for prescribed services must continue unchanged from the level at 30 June 2004 until a new determination takes effect.

Approach to setting revenue

The Tribunal has adopted a building block approach to determining base revenue requirements, supplemented by analysis of pricing outcomes and a range of financial indicators. The building block approach sets the base revenue requirement as the sum of estimated efficient operating costs, depreciation (return of capital) and a risk adjusted return on capital.

In this determination the Tribunal has adopted a fixed revenue cap and allows a glide-path[4] of base revenue gains and losses using 1998/99 as a base year. The base revenue set in this determination covers the efficient costs of providing prescribed distribution services.

The annual aggregate revenue requirement (AARR) that the DNSPs can collect will include the glide-pathed base revenue as established by the building blocks, together with:

- transmission charges and payments for network services made to other DNSPs. These payments may be subject to a prudency test if payments are not between unrelated parties at published regulated charges
- avoided transmission use of system (TUOS) payments to embedded generators, up to an amount determined by the Tribunal through an examination of avoided network costs
- payments for demand management and other network support services, up to an amount determined by the Tribunal through an examination of avoided network costs.

4 A glide path allows a company to retain some of the benefits of its additional efficiency gains over the subsequent regulatory period(s).

- contestability costs as determined by the Tribunal
- an amount to rectify unders and overs account balances
- the net impact of the GST.

The AARR is not subject to glide pathing. Rather, the base revenues are glide-pathed.

EnergyAustralia's base revenue includes incomes received under the ACCC determination for transmission services.

Contestability costs

Once the framework for contestability is known and the Tribunal can estimate the costs with reasonable certainty, it will publish a decision on the reasonable costs of contestability and add these costs to the AARR set in this determination. The Tribunal will index contestability costs by CPI-X in subsequent years.

Indexation of revenues and GST pass through

To derive the base revenue throughout the regulatory control period the Tribunal will apply the percentage change CPI figure (defined below) to the regulated revenues.

The Tribunal will incorporate the effect of the GST through a one-off indexation of revenues by the Goods and Services Tax (GST) as defined in *A New Tax System (Goods and Services Tax) Act 1999*. This indexation will exclude the economy-wide impact of the GST but include an estimate of the specific impact of the GST on each DNSP.

This can be expressed as:

$$\text{Base revenue}^{00/01} = \text{base year}^{5}\ \text{base revenue}^{99/00} * (1+CPI - X) + \text{net GST}^{\text{util.}}$$
$$\text{Base revenue}^{01/02} = \text{base revenue}^{00/01} * (1+CPI^{-GST} - X)$$
$$\text{Base revenue}^{02/03} = \text{base revenue}^{01/02} * (1+CPI - X)$$
$$\text{Base revenue}^{03/04} = \text{base revenue}^{02/03} * (1+CPI - X)$$

where

CPI^{-GST}	=	CPI minus the estimated impact of GST package on the CPI
$netGST^{util}$	=	net $ change in tax position by the utility under the GST package
CPI	=	year-on-year percentage change in the consumer price index, weighted average of eight capital cities, published by the Australian Bureau of Statistics relating to the December quarter (retrospectively).

The revenue rolled forward is the revenue resulting from the building blocks (and published in this determination), not the actual revenue collected in the previous year.

The Tribunal will require an audit of the changes in costs under the GST package, at the expense of the DNSPs. In consultation with the industry, the Tribunal will establish procedures for this audit. Each DNSP will be required to obtain the Tribunal's agreement on the consultant to be appointed.

5 The base year base revenue is the 1999/2000 base revenue as determined by the building blocks in this determination. It is not the pro-rated revenue cap for 1999/2000.

Unders and overs account balances

The DNSPs are required to comply with 'Unders and overs accounts, Rule 99/1', which sets out provisions and requirements for unders and overs accounts. The Tribunal issued this Rule under clause 6.10.1(f) of the Code.

Limits on price movements

Average prices across the network[6] must not increase by more than CPI. To allow restructuring, increases in the standard periodic bills[7] of any residential customers (including rural residential customers) for the same pattern and volume of electricity consumption must not exceed the bill for the corresponding period of the preceding year by more than the greater of CPI plus 2 per cent or $30. Network prices for the same pattern and volume of electricity consumption for residential customers (including rural residential customers), must not exceed the CPI plus 2 per cent, exclusive of the impact of the GST plus net GST impact (expressed as a percentage of the pre-GST total costs) on each DNSP in 2000/01. To illustrate the CPI limitation:

$$\text{residential network tariffs}^{99/00} \leq \text{residential network tariffs}^{98/99} * (1+\text{CPI})*1.02$$
$$\text{residential network tariffs}^{00/01} \leq \text{residential network tariffs}^{99/00} * (1+\text{CPI})*1.02 + \text{net GST}^{\text{util.}}$$
$$\text{residential network tariffs}^{01/02} \leq \text{residential network tariffs}^{00/01} * (1+\text{CPI}^{-\text{GST}})*1.02$$
$$\text{residential network tariffs}^{02/03} \leq \text{residential network tariffs}^{01/02} * (1+\text{CPI})*1.02$$
$$\text{residential network tariffs}^{03/04} \leq \text{residential network tariffs}^{02/03} * (1+\text{CPI})*1.02$$

where

CPI	=	year-on-year percentage change in the consumer price index, weighted average of eight capital cities, published by the Australian Bureau of Statistics relating to the December quarter
$\text{CPI}^{-\text{GST}}$	=	CPI minus estimated impact of GST package on the CPI (in percentage terms)
$\text{netGST}^{\text{util}}$	=	net change in tax paid by the utility under the GST package, expressed as a percentage of total pre-GST costs
residential network tariffs	=	DNSP-specific average residential network tariffs as at 30 June of the relevant year.

These price limits are to apply to all DNSPs, except where the DNSP can demonstrate to the Tribunal that changes to transmission prices resulting from the expiration of the derogation on transmission prices prevent DNSPs from recovering transmission charges from their customers.

Compliance with rules

Each DNSP must comply with this determination and any rules issued by the Tribunal under clause 6.10.1(f) of the Code.

6 Based on the AARR.

7 A standard periodic bill excludes fees for miscellaneous or monopoly services and charges for higher services standards available at the discretion of the user.

Pricing guidelines and disclosure requirements

The DNSPs are required to comply with clause 9.16.3(c) of the Code and the 'Pricing guidelines and information disclosure, Rule 99/2', which sets out pricing guidelines and disclosure requirements. The Tribunal issued this Rule under clause 6.10.1(f) of the Code.

Unless a DNSP has published a current pricing information package that meets the 'Pricing notification and information disclosure Rule 99/2', the DNSP may not increase its charge for any prescribed service. Under these circumstances, if actual revenue from the existing charges is projected to exceed the AARR, the DNSP must lower all its charges for prescribed services by a uniform percentage to reduce its revenues to the regulated levels.

Rate of return

The Tribunal has determined that an appropriate rate of return (real, pre tax) for the electricity distribution networks lies within the range, 5 to 8.5 per cent.

For the purpose of calculating regulated revenues for NSW DNSPs over the regulatory control period, the Tribunal has decided that a real, pre-tax rate of return of 7.5 per cent is appropriate. This is consistent with a nominal post tax return on equity of approximately 11-12 per cent.

The Tribunal has applied a pre-tax nominal return of 7.65 per cent to working capital.

Capital base

Regulatory asset base

The initial capital bases at 30 June 1998 are as follows:[8]

Table 4 Initial capital base as at 30 June 1998

DNSP	Initial capital base ($m) [9]
EnergyAustralia[1]	3,767
Integral Energy	1,732
NorthPower	858
Great Southern Energy	515
Advance Energy	303
Australian Inland Energy	50
DNSP total	**7,225**

1: EnergyAustralia's initial capital base includes its transmission assets.

8 The financial modelling is based on 1998/99 figures.

9 Includes streetlighting assets.

Rolling forward the capital base

The initial capital base as at 30 June 1999 is determined as follows:

- initial capital base as at 30 June 1998 indexed by the CPI[10]
- plus capital expenditure for 1998/99 indexed by half the CPI percentage change
- less depreciation (as calculated in Attachment 3)
- less asset disposals.

Capital expenditure

The Tribunal has incorporated capital expenditure projections illustrated in Table 5 into the building block analysis.

Table 5 Capital expenditure projections ($1999)[11]

	1999/00 ($m)	2000/01 ($m)	2001/02 ($m)	2002/03 ($m)	2003/04 ($m)
EnergyAustralia	143.4	147.5	149.5	168.0	178.0
Integral Energy	102.0	78.7	62.9	64.0	60.5
NorthPower	68.0	65.2	68.9	61.6	58.3
Great Southern Energy	38.6	42.6	36.1	36.0	32.5
Advance Energy	27.4	26.3	26.4	28.7	26.0
Australian Inland Energy	3.1	3.1	3.1	3.1	3.1
Total	**382.5**	**363.4**	**346.9**	**361.4**	**358.4**

Source: Worley capital expenditure review report. Excludes retail and retail IT related capital expenditure, recoverable works and capital contribution works. Revised capital expenditure estimates were submitted by Great Southern Energy and Australian Inland Energy. These revisions were reviewed by Worley.

Operating and maintenance expenditure

The Tribunal has determined the following efficiency gains in operating and maintenance expenditure for the NSW DNSPs over the regulatory period (using 1997/98 as the base year, rolled forward):[12]

10 See chapter 3 for an explanation of the treatment of the GST.

11 It should be noted that the DNSPs' capital expenditure forecasts include street lighting capital expenditure. This is consistent with the Tribunal's decision to include the street lighting business in the DNSPs' revenue cap.

12 The operating and maintenance projections are based on 1997/98 figures, plus streetlighting operating expenses. These figures were rolled forward to 1998/99 by inflation minus the annual efficiency target plus half the growth estimate. The cumulative real reductions will apply to this amended 1998/99 operating and maintenance figure.

Table 6 Cumulative real reductions in operating and maintenance figures

	Cumulative real reduction over 5 years before allowance for growth (%)
EnergyAustralia	10
Integral Energy	15
NorthPower	15
Great Southern Energy	15
Advance Energy	15
Australian Inland Energy	5

These efficiency targets are based on 1997/98 operating and maintenance expenditures.[13]

The Tribunal allows for operating and maintenance expenditure (after applying inflation and the cumulative real reduction outlined in Table 6 to grow by one half of the percentage growth in MWh sales. The resulting operating and maintenance expenditures (excluding TUOS), incorporated in the building blocks, are outlined in Table 7.

Table 7 Operating and maintenance building block components, 1999-2000 to 2003-2004 ($'000)

	1999-2000	2000-2001	2001-2002	2002-2003	2003-2004
EnergyAustralia	205,562	209,673	213,866	218,144	222,507
Integral Energy	157,174	159,924	162,723	165,570	168,468
NorthPower	70,687	71,747	72,824	73,916	75,025
Great Southern Energy	47,648	48,125	48,606	49,092	49,583
Advance Energy	43,826	44,374	44,929	45,491	46,059
Australian Inland Energy	6,861	7,033	7,208	7,389	7,573

Depreciation

The Tribunal has determined to:

- allow depreciation on the initial capital base established for regulatory purposes
- adopt the asset lives established in the GHD/Worley/Arthur Andersen asset valuation
- adopt depreciation schedules based on straight line depreciation methodology
- provide scope for alternative depreciation profiles in the future where these can assist in managing market risks and managing variations in the prices of new investment

[13] The operating and maintenance projections are based on 1997/98 figures, plus streetlighting operating expenses. These figures were rolled forward to 1998/99 by inflation minus the annual efficiency target plus half the growth estimate. The cumulative real reductions will apply to this amended 1998/99 operating and maintenance figure.

- establish net present value neutrality as an essential condition for alternative depreciation profiles.

The depreciation amounts included in the AARR are as set out in the table below:

Table 8 Return of capital building block components, 1999-2000 to 2003-2004[14] ($'000)

DNSP	1999-2000	2000-2001	2001-2002	2002-2003	2003-2004
EnergyAustralia	174,399	182,496	190,906	199,810	209,332
Integral Energy	94,779	98,476	103,099	106,695	106,892
NorthPower	44,991	47,869	49,480	52,459	55,379
Great Southern Energy	29,199	31,064	32,177	33,486	33,631
Advance Energy	18,890	20,051	19,630	20,396	20,586
Australian Inland Energy	2,606	2,752	2,906	3,068	3,237

14 Nominal dollars. Includes depreciation on Streetlighting assets.

Total revenue requirements

The following table illustrates the base revenue requirements for the NSW DNSPs for the period from 1 February 2000 to 30 June 2004:

Table 9 Base revenue requirements ($ million)

	1999/2000	2000/2001	2001/2002	2002/2003	2003/2004
EnergyAustralia[15]					
Building Block	674	692	710	730	752
Smoothed	691	706	721	736	752
Integral Energy					
Building Block	388	398	407	415	419
Smoothed	395	401	407	413	419
NorthPower					
Building Block	186	194	200	208	215
Smoothed	170	180	191	203	215
Great Southern Energy					
Building Block	117	122	126	129	132
Smoothed	113	117	122	127	132
Advance Energy					
Building Block	87	90	92	95	97
Smoothed	74	78	82	87	92
Australian Inland Energy					
Building Block	14	14	15	15	16
Smoothed	11	12	12	13	13
Industry Total					
Building Block	1466	1510	1550	1592	1631
Smoothed	1454	1494	1535	1579	1623

Charges for miscellaneous and monopoly services

Charges for miscellaneous services

The Tribunal has determined an exhaustive list of miscellaneous charges. This establishes the maximum amount that may be charged for the provision of the relevant miscellaneous service. No new charges may be levied by a DNSP during the regulatory control period. The list of approved maximum charges for miscellaneous services is shown in Table 10.

15 Includes costs and revenues for transmission services as determined by the ACCC.

Table 10 Maximum charges for miscellaneous services

Miscellaneous Service		Maximum allowable charges	
		Normal business hours maximum allowable ($)	Outside normal business hours maximum allowable ($)
Provision of time-of-use or half hourly metering data: per half hour		25.00	N/A*
Special meter reading		30.00	75.00
Meter test		50.00	125.00
Conveyancing inquiry:	desk inquiry	25.00	N/A*
	field visit	50.00	N/A*
	total	75.00	N/A*
Account establishment		35.00	87.50
Off-peak conversion		40.00	100.00
Disconnection visit:			
	if no disconnection (acceptable payment received)	30.00	N/A*
	disconnection (acceptable payment not received)	60.00	N/A*
	pole top/pillar box disconnection	100.00	N/A*
	Maximum total (pole top/pillar box & meter disconnection)	160.00	N/A*
Rectification of illegal connection		150.00	475.00

*N/A = Not applicable.

These charges must be levied in accordance with 'Charges for miscellaneous services, Rule 99/3'. The DNSPs must also ensure that they conduct an adequate customer information program as required by the Rule.

Revenue from charges levied for the provision of miscellaneous services is included in the base revenue of each DNSP.

Charges for monopoly services

The Tribunal has determined an exhaustive list of charges for monopoly services associated with contestable work.[16] This establishes the prescribed amount or where specified the maximum amount to be charged for the provision of the relevant monopoly service. No

16 'Contestable work' is work relating to the distribution network system that can be performed by an accredited service provider. A ring-fenced arm of the DNSPs business may compete for this work. The DNSP needs to inspect the work for security and safety reasons regardless of whether the ring-fenced arm or an external accredited service provider performs the work.

new charges may be levied by a DNSP during the regulatory control period. The list of prescribed charges for miscellaneous services is shown in Table 11.

Table 11 Charges for monopoly services associated with contestable work

	Underground urban residential subdivision (vacant lots)	**Rural Overhead Subdivisions and Rural Extensions**	**Underground Commercial and Industrial or Rural Subdivisions (vacant lots - no development)**	**Commercial and Industrial Developments**	**Asset Relocation Or Street Lighting**
Design Information (Minimum 1 Hr)	Up to 5 lots 2 Hrs @ R2 6 to 10 lots 3 Hrs @ R2 11 - 40 lots 5 Hrs @ R2 Over 40 lots 6 Hrs @ R2	R2 per hour	R2 per hour	R2 per hour	R2 or R3 per hour (See Note 5)
Design Certification (Minimum 1 Hr)	Up to 5 lots 1 Hr @ R2 6 to 10 lots 2 Hrs @ R2 11 - 40 lots 3 Hrs @ R2 Over 40 lots 4 Hrs @ R2	1 - 5 poles 1 Hr @ R2 6 -10 poles 2 Hrs @ R2 11 or more poles 3 Hrs @ R2	Up to 10 lots 2 Hrs @ R2 11 - 40 lots 3 Hrs @ R2 Over 40 lots 6 Hrs @ R2	R3 per hour	R2 or R3 per hour (See Note 5)
Design Rechecking (Minimum 1 Hr)	R2 per hour	R2 per hour	R2 per hour	R3 per hour	R2 or R3 per hour (See Note 5)
Inspection Fee (Minimum 2 Hrs @ R2)	Grade: A per lot / B per lot / C per lot First 10 lots: 0.5xR2 / 1.2xR2 / 2.5xR2 Next 40 lots: 0.3xR2 / 0.7xR2 / 1.5xR2 Remainder: 0.1xR2 / 0.4xR2 / 0.7xR2	Grade: A per pole / B per pole / C per pole 1-5 poles: 0.6xR2 / 1.2xR2 / 2.2xR2 6-10 poles: 0.5xR2 / 1.0xR2 / 2.0xR2 11+ poles: 0.4xR2 / 0.7xR2 / 1.5xR2 (see Note 4)	Grade: A per lot / B per lot / C per lot First 10 lots: 0.5xR2 / 1.2xR2 / 2.5xR2 Next 40 lots: 0.5xR2 / 1.2xR2 / 2.5xR2 Remainder: 0.5xR2 / 1.2xR2 / 2.5xR2	R2 or R3 per hour (see Note 1)	R2 or R3 per hour (see Note 1)
Access Permit	Residential Subdivisions: $18.00 per lot combined fee	$800 max. per access permit	$800 max. per access permit	$800 max. per access permit	$800 max. per access permit
Substation Commissioning		$600 per substation (See Note 2)	$600 per substation (see Note 2)	$600 per substation (see Note 2)	$600 per substation (see Note 2)
Administration	Up to 5 lots 3 hours @ R1 6 - 10 lots 4 hours @ R1 11 - 40 lots 5 hours @ R1 Over 40 lots 6 hours @ R1	Up to 5 poles: 3 Hrs @ R1 6-10 poles: 4 Hrs @ R1 11 or more poles 6 Hrs @ R1	R1 per hour (max 6 hours)	R1 per hour (max 6 hours)	R1 per hour
Notice of Arrangement	3 hours @ R1				
Re-Inspection	R2 per hour (max 1 hour per level 2 reinspection)				
Access	R1 per hour (see narrative)				
Authorisation	2 hours @ R2				
Inspection of Service Work (Level 2 work)	All Service connections: A Grade : $14 per NOSW B Grade: $22 per NOSW C Grade: $65 per NOSW (NOSW = Notification of Service Work)				

Notes:

1. Level of inspection determined prior to commencement of job & based on grade of accredited service provider.
2. $600 for a simple substation (single transformer/RMI unit) other at hourly rate including setting/re-setting protection equipment.
3. Where individual service connections are required for multiple dwelling subdivisions the per lot fee should be applied per service connection.
4. Inspections are based on 3 visits. Substation poles are not included. The inspection for substation poles is A Grade – 3.5Hrs @ R2; B Grade – 7Hrs @ R2; C Grade 9 Hrs @ R2.
5. Hourly rate to be determined based on complexity of the job.

Table 12 Hourly labour rates applicable to monopoly services

Labour class	Hourly rate
Admin R1	$44
Design R2a	$54
Inspector R2b	$54
Engineer R3	$65

These charges must be levied in accordance with 'Charges for monopoly services, Rule 99/4'.

Revenue from charges levied for the provision of monopoly services is to be included in the base revenue of each DNSP.

Embedded generation and avoided TUOS

With respect to Integral Energy's submission to the Tribunal regarding avoided TUOS payments, the Tribunal has decided that:

- as a matter of principle, it is appropriate for avoided TUOS payments paid to an embedded generator to be recovered in network revenues, to the extent that these payments reflect the actual TUOS charges avoided by the DNSP as a consequence of the embedded generator
- on a forward looking basis, it is appropriate that Integral's payments to Smithfield and Tower/Appin for the purposes of 'avoided TUOS' to be recovered in Integral's revenue requirement, to the extent that these payments reflect the actual TUOS charges that Integral avoids as a consequence of the embedded generators; and consequently
- for the period from 1 February 2000 to 30 June 2004, Integral's payments to Smithfield and Tower/Appin for avoided TUOS are to be passed through to customers to the extent that the payments reflect the actual avoided TUOS charges. The pass through amount in each year will be subject to the approval of the Tribunal.

GLOSSARY OF ACRONYMS AND TERMS

AARR	Aggregate annual revenue requirement determined under the National Electricity Code.
ACCC	Australian Competition and Consumer Commission
ACTEW	ACT Electricity and Water
AGL	The Australian Gas Light Company
AGSM	Australian Graduate School of Management
AIE	Australian Inland Energy
ASX	Australian Stock Exchange
Base revenue	The sum of operating costs and return of and return on capital.
CAIDI	Customer average interruption duration index
CAIFI	Customer average interruption frequency index
Capex	Capital expenditure
CAPM	Capital asset pricing model
CEGB	Central Electricity Generating Board (UK)
CIPSE	Community Information Project on Sustainable Energy
Code	National Electricity Code
COAG	Council of Australian Governments
CPI	Consumer price index, as defined in the Code glossary.
CPI-X	CPI minus a distributor indexation factor
CRNP	Cost reflective network pricing: a cost allocation method which reflects the value of assets used to provide transmission or distribution services to network users.
CSO	Community service obligation: a government subsidy for activities undertaken by a government enterprise which would not be undertaken as a commercial activity or would require higher prices to be commercial
CWWG	Contestable Works Working Group
DEA	Data envelopment analysis
Deprival value	A value ascribed to assets which is the lower of economic value or optimised depreciated replacement value.
Derogation	Modification, variation or exemption to one or more provisions of the Code.
DGM	Dividend growth model
DLF	Distribution loss factor, as calculated according to the Code in clause 3.6.3.
DNSP	Distribution network service provider: a person who engages in the activity of owning, controlling, or operating a distribution system.

DORC/ODRC	Depreciated optimised replacement cost (see definition under ODRC)
DSM	Demand side management
DUOS	Distribution use of system: a service provided to a Distribution Network User for use of the distribution network for the conveyance of electricity that can be reasonably allocated on a locational and/or voltage basis.
EAPA	Energy Accounts Payments Assistance (Scheme)
EBIT	Earning before interest and tax
EGWG	Embedded Generation Working Group
EICG	Electricity Industry Consultation Group
EION	Energy Industry Ombudsman, NSW
EPD	Energy Project Division, Victoria
ESI	Electricity Supply Industry
ETR	Effective tax rate
EUG	Energy Users Group
FDC	Fully distributed costs
γ	Franking credit gamma
Gas Code	National Third Party Access Code for Natural Gas Pipeline Systems
GSN	Great Southern Energy Gas Networks Pty Ltd
GWh	Gigawatt hour (one GWh=1000 megawatt hours or one million kilowatt hours)
IPART	The New South Wales Independent Pricing and Regulatory Tribunal established under the *Independent Pricing and Regulatory Tribunal Act 1992 (NSW).*
kWh	Kilowatt hour (the standard unit of energy which represents the consumption of electrical energy at the rate of one kilowatt over a period of one hour)
LCAB	Licence Compliance Advisory Board
MAR	Maximum allowable revenue, not to be confused with maximum allowed revenue as defined in the Code.
MCWG	Miscellaneous Charges Working Group
MMC	Monopolies and Mergers Commission (UK)
MoEU	Ministry of Energy and Utilities
MRP	Market risk premium for equity
MWh	Megawatt hour (one MWh=1000 kilowatt hours)
NCOSS	NSW Council of Social Services

NECA	National Electricity Code Administrator Limited A.C.N. 073 942 775, the company responsible for administering the Code.
NEMMCO	National Electricity Market Management Company Limited, the company which operates and administers the market in accordance with the Code.
NPV	Net present value
NSP	Network service provider: a person who engages in the activity of owning, controlling, or operating a transmission or distribution system and who is registered in that capacity with NEMMCO.
ODRC	Optimised depreciated replacement cost: the ODRC calculation is based on the gross replacement cost of modern equivalent network assets, adjusted for overdesign, overcapacity and redundant assets, less an appropriate allowance for depreciation. It measures the minimum cost of replicating the system in the most efficient way possible, given its service requirements and the age of the existing assets.
ODV	Optimised deprival value
OFFER	Office of the Electricity Regulator (UK)
OFGAS	Office of the Gas Regulator (UK)
OFWAT	Office of Water Regulator (UK)
Opex	Operating expenditure
ORC	Optimised replacement cost
ORG	Office of the Regulator General, Victoria
P/E	Price/earnings ratio
PIAC	Public Interest Advocacy Centre
QCA	Queensland Competition Authority
RAB	Regulatory asset base
Ring fencing	The clear separation of subsidiaries or divisions of a company that may have competitive advantages in dealing with each other.
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SEDA	Sustainable Energy Development Authority
SLUOS	Streetlighting use of system
TUOS	Transmission use of system
v	Volt (the unit of electric potential or electromotive force)
w	Watt (a measure of the power present when a current of one ampere flows under a pressure of one volt)

WACC	Weighted average cost of capital: a "forward looking" weighted average cost of debt and equity for a commercial business entity. The network owner's WACC will represent the shadow price or social opportunity cost of capital as measured by the rate of return required by investors in a privately-owned company with a risk profile similar to that of the network company.

1 INTRODUCTION

This determination is made under the National Electricity Code ('the Code'). In 1998 the Premier gave the Tribunal a reference under section 12A of the *Independent Pricing and Regulatory Tribunal Act 1992* ('the IPART Act') to investigate the pricing for electricity networks in NSW. The Tribunal's report, *Pricing for Electricity Networks and Retail Supply* ('the section 12A report'), provides useful information which the Tribunal has referred to in this determination.

1.1 The review process

On 21 August 1999 the Tribunal advertised in *The Sydney Morning Herald* seeking submissions to its determination under the Code. The Tribunal received 53 submissions from various stakeholders.

The Tribunal held public hearings on 14 and 15 October 1999 in IPART's meeting rooms on Level 2, 44 Market Street, Sydney. Twelve organisations presented information to the Tribunal.

Copies of all public submissions and a transcript of the hearings are available for inspection at the Tribunal's offices or on the Tribunal's website.

In 1998 the Tribunal established an electricity industry consultation group (EICG), comprising representatives of the DNSPs, the retailers, large customers and consumer and community groups. The EICG continued to meet throughout the preparation of this determination and provided valuable input to the determination. Additionally, working groups were established to consider the following specific issues:

- contestable works and monopoly fees
- miscellaneous charges
- capital contributions
- service standards
- embedded generation
- the form of regulation
- pricing principles.

The Tribunal members who conducted this inquiry are:

Dr Thomas Parry, Chairman
Mr James Cox, Full-time Member.

1.2 The National Electricity Code

The Code provides a framework for the national wholesale electricity market. The Tribunal is the Jurisdictional Regulator for distribution service pricing in New South Wales.[17]

1.2.1 Requirements of the Code

Chapters 5 and 6 of the Code establish an access regime within the national electricity market for distribution and transmission networks. Chapter 5 details access arrangements, network planning and technical requirements. Chapter 6 sets out the principles for distribution and transmission service pricing.

The Code requires that the distribution service pricing regime to be administered under part D of chapter 6 achieve the following outcomes:

- provide an equitable allocation of efficiency gains (clause 6.10.2(b)(1))
- provide a fair and reasonable return on efficient investment, given efficient operating and maintenance practices (clause 6.10.2(b)(2))
- prevent the extraction of monopoly rents (clause 6.10.2(c))
- foster efficient operating and maintenance practices (clause 6.10.2(e))
- foster efficient use of existing infrastructure (clause 6.10.2(f))
- permit the balancing of interests of owners, users and the public (clause 6.10.2(k)).

In making a determination under the Code, the Tribunal is required to comply with clause 6.10.7, by publishing full and reasonable details of the basis and rationale of the decision including:

- reasonable details of the qualitative and quantitative methodologies applied
- full reasons for material judgements and quantitative decisions made, options considered, and discretions exercised which have a material bearing on the outcome of the decision.

Clause 9.16.3(c) of the Code gives the Tribunal the discretion not to apply part E of chapter 6 of the Code. Part E deals with price structures. The Tribunal believes that the guidelines set out in part E are inappropriate and would deliver incorrect pricing signals. It has, therefore, exercised its discretion not to apply part E. However, the Tribunal has exercised its powers under clause 6.10.1(f) of the Code to develop ‘Pricing notification and information disclosure Rule 99/2’.

[17] Clause 9.16.3(b) of the Code provides that “IPART is and will always be taken to have been the Jurisdictional Regulator for the purposes of clause 6.10.1(b) of the Code and will continue to be the Jurisdictional Regulator until the Minister appoints another body.”

2 THE NSW ELECTRICITY INDUSTRY

2.1 Reforms to the industry

Over the past five years the NSW electricity industry has undergone major structural change. This has involved:

- amalgamating the previous 25 distributors into two large metropolitan and four rural distribution network service providers and retail supply businesses
- separating the transmission and generation functions, and establishing TransGrid
- splitting the generation sector into three companies: Pacific Power, Delta Electricity and Macquarie Generation.[18]

In addition to these structural changes, competition in the generation sector has been introduced. This competition arises from the electricity industries of New South Wales, Victoria, Australian Capital Territory and South Australia operating in a competitive wholesale market, which is underpinned by harmonisation of the NSW and Victorian markets.

The NSW Government is introducing competition in the retail market. Large customers are now able to choose their electricity retailer, and competition has been introduced progressively to smaller customers. The NSW Government has convened the Market Implementation Group (MIG) to oversee and direct electricity reform in NSW. MIG's responsibilities include guiding the transition to full retail competition.

This determination relates to distribution services. Distribution services primarily involve electricity wires. Because there is no competition on the wires business, it will continue to be regulated. The Tribunal is concurrently issuing a determination under the IPART Act that relates to franchise retail service providers.

2.2 Characteristics of DNSPs

Each distribution network service provider (DNSP) has individual customer and load characteristics, as illustrated in Table 2.1.

[18] Generation and transmission assets are also provided by the Snowy Mountains Hydro Electric Authority.

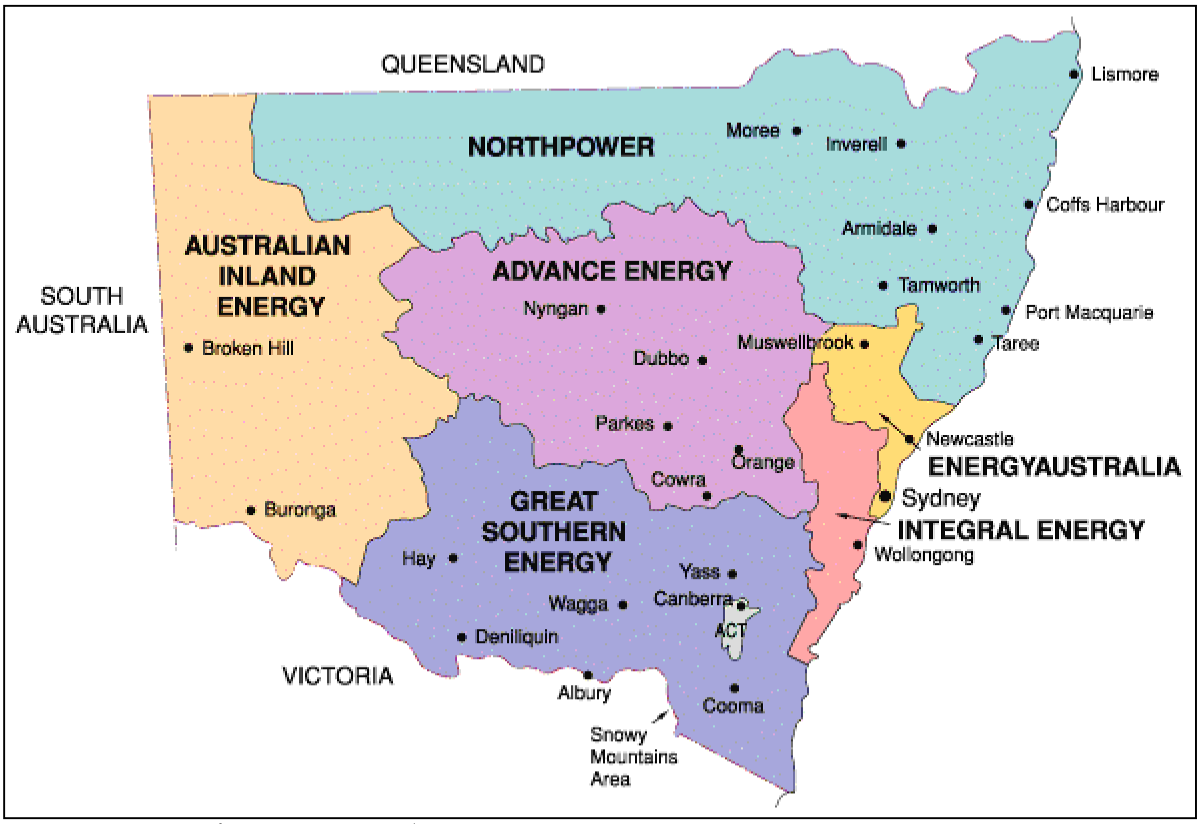
Table 2.1 NSW DNSP customer and load profiles, 1998/99

Distributor	Number of network customers	Total network load (MWh)	Network service area (sq. km)
EnergyAustralia	1,386,640	22,978,445	22,000
Integral Energy	751,028	14,002,026	24,500
NorthPower	362,522	3,878,134	230,000
Great Southern Energy	227,795	3,047,739	176,000
Advance Energy	119,982	2,636,787	167,000
Australian Inland Energy	21,410	417,786	155,000

Source: 1998-99 regulatory accounts for customer numbers and load, area from the Boundary Review Committee's final report.

Figure 2.1 illustrates the service territories for the New South Wales distribution network service providers.

Figure 2.1 Distribution network service provider boundaries



Source: Ministry for Energy & Utilities.

2.2.1 An average electricity bill

An electricity bill comprises distribution and transmission costs and energy costs plus a retail margin.

The Australian Competition and Consumer Commission (ACCC) regulates the transmission component. The energy costs comprise a mixture of contracts and pool prices.

Table 2.2 provides a summary of average network and franchise retail prices for each distributor.

Table 2.2 Average electricity prices, 1998/99

Distributor	Average retail price c/kWh	Average network price (DUOS + TUOS) c/kWh[19]
EnergyAustralia		3.56
Residential	9.8	
Business	10.3	
Integral Energy		3.33
Residential	9.4	
Business	9.8	
NorthPower		4.90
Residential	10.4	
Business	11.4	
Great South Energy		4.33
Residential	9.6	
Business	8.4	
Advance Energy		3.21
Residential	10.6	
Business	10.4	
Australian Inland Energy		3.36
Residential	9.5	
Business	6.4	

Source: 1998/99 regulatory accounts.

19 Actual average network price.

3 REGULATORY FRAMEWORK

3.1 Regulation of distribution services

3.1.1 Determination of 'prescribed distribution services'

It is the Tribunal's determination that, for the purpose of clause 6.10.4, 'prescribed distribution services' are those services performed by each DNSP that are associated with or ancillary to access to that DNSP's network for the supply of electricity within that DNSP's service area.

Code requirements

Clause 6.10.4 of the Code requires the Tribunal, as the jurisdictional regulator, to determine which services are 'prescribed distribution services' and therefore subject to economic regulation under the Code. Services which are not 'prescribed distribution services' are deemed to be 'excluded distribution services'. 'Excluded distribution services' may attract a light-handed regulatory approach.

In deciding which distribution services are prescribed distribution services, the Tribunal is required to have regard to:

- the principles contained in clause 6.10.3
- the extent of effective competition in the provision of that service and whether sufficient competition exists to warrant light-handed regulation
- the effectiveness of the form of economic regulation specified under clause 6.10.5.

3.1.2 Retailer of last resort

'Retailer of last resort' provisions are not part of this determination for two reasons: firstly, retailer of last resort provisions are licence requirements, which the Ministry of Energy and Utilities administers. Secondly, the Tribunal has issued this determination under the Code, which provides powers to regulate prescribed distribution services. Provisions for retailer of last resort do not fall into the prescribed distribution services category.

3.1.3 Determination on regulatory control period

For NSW DNSPs the annual aggregate revenue requirement (AARR) determined by the Tribunal will apply for the regulatory control period from 1 February 2000 until 30 June 2004.

If a new determination is not issued to take effect from 1 July 2004, all charges for prescribed distribution services are to continue unchanged from the level at 30 June 2004 until a new determination takes effect.

For the 1999/2000 financial year the AARR will comprise the (rolled forward) 1997 determination revenue pro-rated for the period from 1 July 1999 to 31 January 2000, and this determination, pro-rated for the period from 1 February 2000 until 30 June 2000. Pro-rating will be on the basis of calendar days covered by each determination.

3.1.4 Code requirements

This four year and five month regulatory control period complies with clause 6.10.5(c) of the Code, which requires that the regulatory control period for distribution be no less than three years.

3.2 Building block approach to pricing and financial analysis

3.2.1 Determination on approach to setting base revenue

The Tribunal has adopted a building block approach to determining base revenue requirements, supplemented by analysis of pricing outcomes and a range of financial indicators. The building block approach sets the base revenue requirement as the sum of estimated efficient operating costs, depreciation (return of capital) and a risk adjusted return on capital.

3.2.2 Code requirements

The Tribunal must determine the AARR in accordance with part D of chapter 6 of the Code. Part D does not expressly refer to the AARR. However, it does require the Tribunal to:

- adopt a form of economic regulation that is of the prospective CPI minus X form or other incentive-based variant of the CPI minus X form, consistent with the objectives and principles outlined in clauses 6.10.2 and 6.10.3
- specify a form of economic regulation to be applied to the DNSP in the form of a revenue cap, a weighted average price cap or a combination
- take into account each DNSP's revenue requirement during the regulatory control period having regard to the factors in clause 6.10.5(d)
- have regard to objectives in clause 6.10.2 and the principles in clause 6.10.3 of the Code.

3.2.3 Tribunal assessment

The Tribunal considers the building block approach, supplemented by pricing and financial analysis, to be a reasonable method of meeting the Code requirements. The analysis of pricing outcomes and financial indicators tests the reasonableness of the outcomes of the building block approach.

3.3 Form of economic regulation

3.3.1 Determination on revenue cap

In this determination the Tribunal has adopted a fixed revenue cap under clause 6.10.5(b) of the Code as the form of economic regulation to be applied to the DNSPs in NSW.

3.3.2 Code requirements

Section 6.10.5 (b) of the Code allows the Tribunal to regulate under a revenue cap, a weighted average price cap or a combined revenue/price cap. Under section 6.10.3(d) of the Code, the Tribunal is required to give two years' notice to DNSPs before amending the form of economic regulation set out in section 6.10.5 of the Code. There has been no prior determination under the Code and, therefore, no existing form of economic regulation under the Code.

3.3.3 Public consultation

The Tribunal's s12A report

The Tribunal held a public forum in February 1999 to discuss the industry's cost drivers. In the s12A report the Tribunal presented stakeholders comments, the DNSPs' reported cost drivers, and the following proposed maximum allowable revenue (MAR) formula:

$$MAR = [[a + bN + cM + dL] * (1 + (CPI-X))] + Y + GST$$

where

N	=	customer numbers
M	=	MWh sales
L	=	circuit kilometres (rural distributors only)
Y	=	Y2K costs, NEMMCO fees and costs of moving to full contestability ($)
GST	=	the net impact of the GST on the business[20]
a	=	residual fixed term capturing other costs ($'000)
b	=	dollars per customer
c	=	dollars per MWh
d	=	dollars per circuit kilometre
CPI	=	the ABS December year-on-year percentage change for all-groups all capitals

Public consultation for this determiantion

As part of the review process for this determination, the Tribunal consulted further with stakeholders and refined the MAR equation.

EnergyAustralia provided the Tribunal with modelling that estimated EnergyAustralia's marginal cost drivers. The Tribunal conducted further modelling based on EnergyAustralia's cost drivers and distributed the following revised MAR formula to stakeholders:

$$MAR = [(a + b(N^t - N^0) + c(M^t - M^0)) * (1 + CPI - X)] + Y + GST$$

where

N^t	=	Customer numbers in year t
N^0	=	Customer numbers in year 0 (1998-1999)
M^t	=	MWh sold in year t
M^0	=	MWh sold in year 0 (1998-1999)
CPI	=	the ABS December year-on-year percentage change for all-groups all capitals

20 The Tribunal will engage an auditor (at the DNSPs' expense) to verify the DNSPs' calculation of the net impact of the GST.

Y = Y2K costs, NEMMCO fees and costs of moving to full contestability ($)
GST = net impact of the GST and other concurrent tax changes on the business

a = revenue for year 0 of the review period (1998-1999)
b = customer billing, call centres and the low voltage network
c = dollars per MWh

Table 3.1 shows the coefficients distributed with the revised revenue formula for comment. Each set of coefficients produces a different 'X' factor for each DNSP (see section 3.4).

Table 3.1 Revenue formula coefficients distributed for comment

DNSP	Customer number (b) coefficient ($ per customer)	Energy (c) coefficient ($ per MWh)
EnergyAustralia & Integral Energy	120	6.25
	145	5.50
	180	5.00
	200	5.00
Great Southern Energy, NorthPower,	120	6.25
Advance Energy & Australian Inland Energy	200	5.50
	300	5.25
	400	5.25

The Tribunal held a forum in October 1999 to discuss the revised MAR formula and other regulatory options.

There was strong support for a revenue cap at the public forum, in submissions and at the public hearings. Strongly advocating a revenue cap, NorthPower states in its submission:

> The real revenues projected by the Tribunal under a smoothed transition to full cost recovery for NorthPower should be adopted as the actual allowable revenue caps and indexed by CPI over the regulatory period. There is no need for the development of a MAR equation.[21]

At the forum, Australian Inland Energy and Great Southern Energy indicated strong support for a revenue cap. Other DNSPs generally supported a revenue cap. SEDA added its support for a revenue cap.

Subsequent to the public forum, EnergyAustralia altered its position on the form of regulation, stating:[22]

> EnergyAustralia has critically assessed the current form of price control for the NSW electricity distribution and franchise retail businesses and proposed in the paper that the Tribunal adopt a "tariff basket" approach to price regulation. …

21 NorthPower submission, p 2, 10 September 1999.
22 EnergyAustralia submission, p 1, 25 November 1999.

> EnergyAustralia is committed to pursuing a price cap approach as the form of economic regulation. I understand from your officers that the Tribunal may have difficulties in implementing such a change in methodology in its entirety in the upcoming December 1999 determination. I do not believe, however, that this should prevent the form of economic regulation being addressed for another five years.

Demand management issues raised in public consultation

Demand management shifts or reduces demand for energy wherever it is more economic to do so than to provide supply capacity. Allowing demand management options to compete against supply side (or 'build' options) reduces the environmental impacts of energy supply.

Section 6.10.3(e)(2) of the Code requires the jurisdictional regulator to:

> … create an environment in which generation, energy storage, demand side options and network augmentation options are given due and reasonable consideration.

A number of stakeholders raised issues relating to the level of the 'c' factor in the proposed revenue formula. They expressed concern that even at $9.50/MWh (the level set in the 1997 determination), the MAR formula introduces an artificial bias against demand management. For instance, in its submission, SEDA states:

> The 'c' factor in the current revenue cap formula is $9.50/MWh. This 'c' factor effectively penalises the network business $9.50 of every MWh of energy a customer conserves.
>
> … SEDA strongly supports the removal of the volume related 'c' factor from the revenue cap. [23]

Some stakeholders argue that the 'c' factor should be very close to zero, reflecting their estimates of the marginal cost of transporting an additional kWh over the network. [24] Further, SEDA argues that if the Tribunal was to adopt a revenue formula with a 'c' factor, the Tribunal would need to include a 'f' factor to represent foregone revenue (from demand management initiatives). Under this scenario, SEDA also called for an 'e' factor representing embedded generation.

As previously mentioned, at the public forum on the MAR formula SEDA expressed support for a revenue cap.

Incentive mechanisms in the revenue formula

The Tribunal has considered using the MAR formula to provide DNSPs with incentives for certain activities. In its 1996 determination the Tribunal included a factor in the MAR formula to provide an incentive to invest in loss reduction projects. However, stakeholders argued that this loss factor mechanism was not effective. Nevertheless, industry participants support including a similar coefficient for service standard incentives (see section 3.9 for a discussion of service standards). [25]

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23 SEDA submission, p 2, 11 October 1999.

24 The Tribunal recognises that the marginal cost of transporting an addition kWh vastly increases as capacity becomes constrained.

25 The Tribunal has indicated that capital expenditure related to service reliability will be included in the regulated asset base at the next review, subject to a prudency test (see Chapter 3).

The Tribunal questions whether adding a coefficient to the revenue stream is the most appropriate method of providing incentives. Setting a coefficient for an incentive mechanism is highly subjective and may lead to inappropriate signals. Therefore, the Tribunal wishes to explore other incentive mechanisms.

The Tribunal supports and the Code requires incentive-based regulation. The Tribunal will continue to work with industry to develop appropriate and effective incentive mechanisms.

3.3.4 Tribunal's assessment of revenue cap

The Tribunal, therefore, specifies a revenue cap as the form of economic regulation under clause 6.10.5(b) of the Code. In adopting a revenue cap, the Tribunal has departed from the approach it recommended in the s12A report. After publishing that report, the Tribunal further analysed the form of regulation and considered the views put forward in public consultation. The Tribunal has decided to adopt a revenue cap in this determination because:

- there is industry and stakeholder support for a revenue cap
- revenue caps do not create a bias against demand management
- revenue caps are simpler to understand and administer than a revenue formula
- revenue caps provide flexibility in offering services and pricing options
- revenue caps provide equally strong incentives for DNSPs to pursue efficiency gains
- revenue caps are cost reflective.

3.4 Revenues, glide paths and X factors

3.4.1 Determination on revenues, glide paths and X factors

The base revenue requirements[26] determined allows a glide-path[27] of gains and losses using 1998/99 as a base year. The base revenue set in this determination covers the efficient costs of providing prescribed distribution services.

The AARR that the DNSPs can collect will be the glide-pathed base revenue, as established by the building blocks, together with:

- ***transmission charges and payments for network services made to other DNSPs. These payments may be subject to a prudency test if payments are between related parties at levels different to the published regulated charges***
- ***avoided transmission use of system (TUOS) payments to embedded generators, up to an amount determined by the Tribunal through and examination of avoided network costs***
- ***payments for demand management and other network support services, up to an amount determined by the Tribunal through an examination of avoided network costs.***
- ***contestability costs as determined by the Tribunal (added to the base revenues)***
- ***Y2K costs as approved by the Tribunal (added to the base revenues)***

26 Base revenue is the revenue determined by the building block analysis and includes operating costs, a return on capital and a return of capital.

27 A glide path allows a company to retain some of the benefits of its additional efficiency gains over the subsequent regulatory period(s).

- ***an amount to rectify unders and overs account balances***
- ***the net impact of the GST.***

The AARR is not subject to glide pathing. Rather, the base revenues are glide-pathed.

EnergyAustralia's base revenue includes incomes received under the ACCC determination for transmission services.

3.4.2 Tribunal's assessment of glide paths, revenue streams and X factors

By allowing a company to retain some of the benefits of its additional efficiency gains over the subsequent regulatory period(s), a glide path provides an incentive to pursue additional efficiency gains. A glide path also allows for a smoother transition to new price levels.

As outlined above, the base revenue for each DNSP is based on a building block analysis supported by pricing and financial analysis, and is subject to glide pathing. The resulting base revenues are set out in chapter 9. The AARR that the DNSPs can collect will be the base revenue as established by the building blocks, together with:

- transmission charges and payments for network services made to other DNSPs. This is consistent with 6.10.5.(7) (ii) of the Code. These payments may be subject to a prudency test if payments are not between unrelated parties at published regulated charges
- avoided transmission use of system (TUOS) payments to embedded generators, up to an amount determined by the Tribunal through and examination of avoided network costs
- payments for demand management and other network support services, up to an amount determined by the Tribunal through an examination of avoided network costs.
- contestability costs as determined by the Tribunal
- Y2K costs as approved by the Tribunal
- an amount to rectify unders and overs account balances
- the net impact of the GST.

The 'CPI-X' component does not represent the impact of inflation and efficiency gains. The CPI-X factor is used to achieve the desired revenue path, resulting in end-year revenues consistent with the building block/pricing and financial analysis/glide path outcomes. The building block components are indexed and the efficiency gains are built into the operating and maintenance expenditure – see chapter 8.

The X factors determined for each DNSP are set out in Table 3.2. The X factor is applied in indexing revenues for each year after the base revenue year. It is not an efficiency factor.

Table 3.2 X factors used to index revenues (%)

EnergyAustralia	0.86
Integral Energy	1.47
NorthPower	-3.16
Great Southern Energy	-0.89
Advance Energy	-2.57
Australian Inland Energy	1.03

3.5 Contestability costs, Y2K costs and NEMMCO fees

In its s12A report, the Tribunal indicated that it would allow a pass through of costs associated with Y2K and contestability, and National Electricity Market Management Company (NEMMCO) fees. The Tribunal has further considered this matter and this section outlines the treatment of these costs.

3.5.1 Determination on contestability costs

Once the framework for contestability is known and the Tribunal can estimate the costs with reasonable certainty, it will publish its decision on the reasonable costs of contestability and add these costs to the base revenue requirements set in this determination. The Tribunal will index contestability costs by CPI-X in subsequent years.

3.5.2 Tribunal's assessment of contestability costs

Since 1996 the NSW retail electricity market has been opened progressively to competition. Introducing contestability requires consideration of a range of issues, including metering technology, data collection and aggregation systems, a wholesale settlements system, and industry codes, standards and regulation.

The Tribunal commissioned SRC International to explore a range of issues surrounding the introduction of competition into the electricity market for residential and other low-use electricity consumers.

The costs of implementing retail contestability will depend upon the model adopted. Further, the proportion of those costs that DNSPs will need to pass-through will depend upon the allocation of those costs (eg whether customers, retailers or DNSPs are responsible for owning and/or maintaining meters).

The principal costs that will arise when implementing retail contestability will include:

- costs relating to metering or profiling arrangements
- data collection
- data aggregation and wholesale settlement
- billing and processing
- customer register and customer churn processes and systems and processes.

SRCI estimated that the total cost of implementing retail contestability in NSW will be $35m with ongoing annual costs of $27m. These estimates assume second-tier metering[28] with manual meter reading. The actual costs could vary significantly depending upon the model eventually chosen. It is likely that some of these costs will be borne by the DNSPs although both the overall level of costs and the allocation of those costs are currently unknown.

The Market Implementation Group (MIG) has been established to, among other issues, resolve retail contestability issues in New South Wales. Until the MIG determines the framework for introducing full contestability, the Tribunal will not know the level of associated costs. This puts the Tribunal in a very difficult position in relation to its regulatory treatment of contestability costs.

In its s12A report, the Tribunal indicates that it will allow DNSPs to pass through the cost of moving to full contestability. Having further considered this issue, the Tribunal is concerned that such an approach may pre-empt government policy. Furthermore, the Tribunal believes the costs associated with moving to full contestability should be treated in a similar manner to any other capital and/or operating costs. As these costs are unknown, it is not possible to include them in the current analysis.

Once the framework for contestability is known and the Tribunal can estimate the costs with reasonable certainty, it will publish its decision on the reasonable costs of contestability and add these costs to the AARR set in this determination. The Tribunal will index contestability costs by CPI-X in subsequent years.

3.5.3 Tribunal's assessment of Y2K costs

In the s12A report the Tribunal indicated it would pass through certain costs in the MAR formula, including Y2K costs. Having further considered this issue, the Tribunal believes that Y2K costs should be treated in the same manner as other operating expenditure.

The DNSPs have reported Y2K expenditures set out in Table 3.3. These figures have not been tested for prudency.

Table 3.3 Reported Y2K expenditure

DNSP	1997/98	1998/99
EnergyAustralia	none reported	$8,900,000
Integral Energy	none reported	none reported
NorthPower	none reported	$1,113,000
Great Southern Energy	none reported	$99,000
Advance Energy	$194,000	$190,000
Australian Inland Energy	none reported	$40,000

Source: 1997/98 and 1998/99 regulatory accounts.

[28] 'Second tier' customers are customers that change from their incumbent retailer. These customers would require a half hour meter.

The DNSPs should finalise their Y2K expenditure in 1999/2000. Before adding Y2K costs to the AARR set in this determination, the Tribunal will have these costs verified and tested for prudency by a consultant, at the expense of the DNSPs.

3.5.4 Tribunal's assessment of NEMMCO fees

Currently the DNSPs do not pay any fees to NEMMCO and the Tribunal is not aware of any new NEMMCO fees that will be imposed on DNSPs. Therefore, there is no need to provide for NEMMCO fees in this determination. If NEMMCO fees are imposed on DNSPs, the Tribunal will consider the issue in the next determination.

3.6 Indexation of revenues and GST pass through

3.6.1 Determination on indexation of revenues and GST pass through

To derive the base revenue for each year throughout the regulatory control period, the Tribunal will apply the percentage change CPI figure (defined below) to the base revenue of the previous year.

The Tribunal will incorporate the effect of the GST through a one-off indexation of base revenues by the Goods and Services Tax (GST) as defined in A New Tax System (Goods and Services Tax) Act 1999. This indexation will be exclusive of the economy-wide impact of the GST but including an estimate of the specific impact of the GST on the DNSP.

This can be expressed as:

$$\textit{Base revenue}^{00/01} = \textit{base year}^{[29]}\ \textit{base revenue}^{99/00} * (1+CPI - X) + \textit{net GST}^{\,util}$$
$$\textit{Base revenue}^{01/02} = \textit{base revenue}^{00/01} * (1+CPI^{-GST} - X)$$
$$\textit{Base revenue}^{02/03} = \textit{base revenue}^{01/02} * (1+CPI - X)$$
$$\textit{Base revenue}^{03/04} = \textit{base revenue}^{02/03} * (1+CPI - X)$$

where

CPI^{-GST} = CPI minus the estimated impact of GST package on the CPI

$netGST^{\,util}$ = net $ change in tax position of the utility under the GST package

CPI = year-on-year percentage change in the consumer price index, weighted average of eight capital cities, published by the Australian Bureau of Statistics relating to the December quarter.[30]

The base revenue rolled forward is the base revenue resulting from the building blocks (and published in this determination), not the actual revenue collected by the DNSPs in the previous year.

The Tribunal will require an audit of the changes in costs under the GST package, at the expense of the DNSPs. In consultation with the industry, the Tribunal will establish procedures for this audit. Each DNSP will be required to obtain the Tribunal's agreement on the consultant to be appointed.

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29 The base year base revenue is the 1999/2000 base revenue as determined by the building blocks in this determination. It is not the pro-rated revenue cap for 1999/2000.

30 The CPI is a retrospective CPI.

3.6.2 Tribunal's assessment of GST issues

A New Tax System is due to commence on 1 July 2000 and will:

- introduce a 10 per cent GST
- remove the wholesale sales tax and make changes to the excise on petrol and diesel and some other indirect taxes.

In addition to the GST, changes to the taxation system include reducing the rate of corporate income tax and abolishing accelerated depreciation. For a discussion of the impact of these changes on the rate of return, see chapter 5.

The package of taxation changes will affect the prices of all goods and services, including lowering those where the wholesale sales tax is higher than the GST. This will affect the economy-wide CPI calculated by the Australian Bureau of Statistics (ABS). The impact on individual businesses will reflect their operating and capital costs and revenue structure.

The Tribunal uses the CPI figure to:

- index revenues during the regulatory period
- index the regulated capital base until the start of the next regulatory period
- set limits on price movements (see section 3.8).

The Tribunal is aware that there is likely to be substantial changes in the DNSPs' costs and that these changes will differ substantially from the economy-wide impact reflected in the CPI.

The Tribunal's treatment of GST impacts involves no 'windfall' loss or gain for the utility owner. The impact on the consumer will equal the net impact of the GST package[31] on the industry. To implement this method, the Tribunal requires the DNSPs to provide more information.

3.7 Unders and overs account balances

An unders and overs account will apply to each DNSP in NSW. Any variation between the aggregate annual revenue requirement (AARR), as determined by the Tribunal, and actual revenue collected is to be monitored in the unders and overs accounts. The unders and overs account is cumulative from year to year.

For any year that a variance occurs between the AARR and the actual revenue collected in that year, an interest charge or an interest credit will apply, as appropriate. The interest adjustment will be applied on the cumulative balance at year-end. The total cumulative balance in the unders and overs account includes any prior year interest adjustments.

Interest will be pegged at the 3-year Commonwealth Bond rate as at the first Monday following the financial year-end. The Australian Financial Review will be the reference source for this rate.

31 The net impact may include incremental compliance costs.

DNSPs must provide annual returns to the Tribunal by 30 October each year. The annual returns must disclose account balances as a contingent item. These returns must demonstrate that the unders and overs account balances result from actual demand deviating from forecast demand. The Tribunal will allow the following tolerance margins for deviations from the related AARR and will require the following action on an annual basis[32] as a result of these deviations:

Table 3.4 Tolerance margins and actions that the Tribunal will require for unders and overs account balances

Tolerance	DNSP action required
less than +/- 2 per cent	Must notify the Tribunal within 30 days of year end with action plan[33] to resolve balance within the term of the price path.
between +/-2 per cent and +/- 5 per cent	Must notify the Tribunal within 30 days of year end with action plan[34] for rectifying the balance at the first subsequent changes to network tariffs.
over recovery of more than 5 per cent	Must provide a rebate to retailers on the first bill of the subsequent year to reduce the unders and overs account balance to zero.[35]
(under) recovery of more than 5 per cent	Unders and overs account balance will be reduced to under recovery of 5 per cent.[36]

Approved unders and overs account balances as at 31 January 2000 (accrued under determinations made by the Tribunal under the IPART Act) will carry forward into a determination made under the National Electricity Code effective from 1 February 2000. Each DNSP will be required to submit its unders and overs account balance for approval by the Tribunal as soon as practicable after 31 January 2000.

These requirements comply with 'Unders and overs accounts, Rule 99/1', which sets out provisions and requirements for unders and overs accounts. The Tribunal issued this Rule under clause 6.10.1(f) of the Code.

Any rectification of unders and overs account balances must comply with the limits on price movements imposed by the Tribunal.

32 The Tribunal will require the specified actions to commence on 1 July 2001.

33 An action plan must include the calculation of network prices (for each tariff class) based on maximum allowable revenues, demand forecasts and unders and overs balance rectification.

34 An action plan must include the calculation of network prices (for each tariff class) based on maximum allowable revenues, demand forecasts and unders and overs balance rectification.

35 The Tribunal intends to exercise its powers under state legislation to require retailers to pass on rebates to end-use customers.
The Tribunal recognises that issues may arise when customers disconnect from the system in the time between the period of over-collection and the payment of the rebate. The refund should be made to customers connected to the distribution network system on 30 June on the year that over recovery breaches the 5 per cent tolerance.

36 If, for example, at 30 June 2002 a DNSP has an under recovery of 8 per cent, the Tribunal will reduce the account balance to 5 per cent under recovered for the 2001/2002 financial year. The DNSP will lose the 3 per cent difference.

3.7.1 Tribunal's assessment of unders and overs account balances

In its 1996 determination, the Tribunal introduced unders and overs accounts. The purpose of an unders and overs account is to cater for variance between the allowable regulated revenue for a year and the actual revenue earned in that year.

The Tribunal's 1997 determination set out the following tolerance margins for deviations from the regulated revenue cap and required the following action on an annual basis as a result of deviations:

Table 3.5 Tolerance margins and actions required in 1997 determination for unders and overs account balances

Tolerance	Action
less than +/- 2 per cent	As part of on-going compliance, must notify IPART within 30 days of year end.
between +/-2 per cent and +/- 5 per cent	Notify IPART within 30 days of year end with action plan to resolve balance within the term of the price path.
greater than +/- 5 per cent	Notify IPART within 30 days of year end. Following consultation, immediate action by the distributor required.

As illustrated in Table 3.5, EnergyAustralia has substantially over recovered its allowed revenues. This has resulted from a $50 million over recovery in 1997/98 and a $25 million over recovery in 1998/99. Clearly, this level of over recovery breaches the tolerance levels set out in the 1997 determination. Advance Energy has under collected by 6 per cent.

The actions undertaken to rectify these balances have not been effective in dealing with under and/or over recovery.

Table 3.6 Network over/(under) recovery, 30 June 1999

	DNSP's reported over/(under) recovery	Adjustment	Balance to be carried forward	Balance carried forward as % of 1998/99 revenue
EnergyAustralia	96,503		96,503	12
Integral Energy	10,782		10,782	2
NorthPower	(8,765)	13,187[37]	4,422	2
Great Southern Energy	952[38]		952	1
Advance Energy	(8,280)	3,142[39]	(5,138)	-6
Australian Inland Energy	691	(934)[40]	(243)	-2

Note: NorthPower's balance will be reduced by a maximum of $1,509,256, representing payment to Advance Energy for electricity transportation from Wellington to Nyngan from 1996 to January 2000.

These balances were accrued under determinations made by the Tribunal under the IPART Act. The Tribunal intends to carry forward approved balances as at 31 January 2000 into the Code-based determination effective from 1 February 2000. Each DNSP will be required to submit its unders and overs account balance for approval by the Tribunal as soon as practicable after 31 January 2000.

As stated above, the intended purpose of the unders and overs account is to cater for differences between forecast demand and actual demand. The under/over account balances of some DNSPs do not result purely from differences between forecast and actual demand.

The Tribunal considered the issue of unders and overs accounts for this determination. It has concluded that there are compelling reasons for continuing unders and overs accounts.

To ensure that DNSPs are using the unders and overs accounts as the Tribunal intends, the Tribunal requires each DNSP to demonstrate each year that its unders and overs account balances result from actual demand deviating from forecast demand. The Tribunal recognises that there could be difficulties in forecasting network demand charges where there are large price increases on time of use tariffs (for example, when the system is constrained). However, the Tribunal expects that each DNSP will demonstrate to the Tribunal that the variations result from that class of customers.

In 'Unders and overs accounts, Rule 99/1' the Tribunal set tolerance margins (outlined in Table 3.6) to allow for deviations from the AARR. The Tribunal requires the respective action (from 1 July 2001) on an annual basis as a result of these deviations.

37 Transitional funding from Treasury.

38 Already includes transitional funding from Treasury.

39 Transitional funding from Treasury.

40 Includes $498,000 transitional funding from Treasury and a $1,432,000 payment to Powercor for transmission services.

Table 3.7 Tolerance margins and actions that the Tribunal will require for unders and overs account balances

Tolerance	DNSP action required
less than +/- 2 per cent	Must notify the Tribunal within 30 days of year end with action plan[41] to resolve balance within the term of the price path.
between +/-2 per cent and +/- 5 per cent	Must notify the Tribunal within 30 days of year end with action plan[42] for rectifying the balance at the first subsequent changes to network tariffs.
over recovery of more than 5 per cent	Must provide a rebate to retailers on the first bill of the subsequent year to reduce the unders and overs account balance to zero. [43]
(under) recovery of more than 5 per cent	Unders and overs account balance will be reduced to under recovery of 5 per cent. [44]

Any rectification of the unders and overs account balances must comply with the limitations on price movements imposed by the Tribunal.

3.8 Limits on price movements

3.8.1 Determination on limits on price movements

Average prices across the network must not increase by more than CPI. Increases in the standard periodic bills[45] of any residential customers (including rural residential customers) for the same pattern and volume of electricity consumption must not exceed the bill for the corresponding period of the preceding year by more than the greater of CPI plus 2 per cent or $30. Network prices for the same pattern and volume of electricity consumption for residential customers (including rural residential customers), must not exceed the CPI plus 2 per cent, exclusive of the impact of the GST plus net GST impact (expressed as a percentage of the pre-GST total costs) on each DNSP in 2000/01. To illustrate the CPI limitation:

41 An action plan must include the calculation of network prices (for each tariff class) based on maximum allowable revenues, demand forecasts and unders and overs balance rectification.

42 An action plan must include the calculation of network prices (for each tariff class) based on maximum allowable revenues, demand forecasts and unders and overs balance rectification.

43 The Tribunal intends to exercise its powers under state legislation to require retailers to pass on rebates to end-use customers.
The Tribunal recognises that issues may arise when customers disconnect from the system in the time between the period of over-collection and the payment of the rebate. The refund should be made to customers connected to the distribution network system on 30 June on the year that over recovery breaches the 5 per cent tolerance.

44 If, for example, at 30 June 2002 a DNSP has an under recovery of 8 per cent, the Tribunal will reduce the account balance to 5 per cent under recovered for the 2001/2002 financial year. The DNSP will lose the 3 per cent difference.

45 A standard periodic bill excludes fees for miscellaneous or monopoly services and charges for higher services standards available at the discretion of the user.

residential network tariffs$^{99/00}$ $\leq$ *residential network tariffs*$^{98/99}$ * $(1+CPI)*1.02$
residential network tariffs$^{00/01}$ $\leq$ *residential network tariffs*$^{99/00}$ * $(1+CPI)*1.02 + net\ GST^{util.}$
residential network tariffs$^{01/02}$ $\leq$ *residential network tariffs*$^{00/01}$ * $(1+CPI^{-GST})*1.02$
residential network tariffs$^{02/03}$ $\leq$ *residential network tariffs*$^{01/02}$ * $(1+CPI)*1.02$
residential network tariffs$^{03/04}$ $\leq$ *residential network tariffs*$^{02/03}$ * $(1+CPI)*1.02$

where

CPI	=	***year-on-year percentage change in the consumer price index, weighted average of eight capital cities, published by the Australian Bureau of Statistics relating to the December quarter (retrospectively)***
CPI^{-GST}	=	***CPI minus estimated impact of GST package on the CPI (in percentage terms)***
$netGST^{util}$	=	***net change in tax position of the utility under the GST package, expressed as a percentage of total pre-GST costs***
residential network tariffs	=	***DNSP-specific average residential network tariffs as at 30 June of the relevant year.***

These limits on price movements apply to each DNSPs' total AARR.

These price limits are to apply to all DNSPs, except where the DNSP can demonstrate to the Tribunal that changes to transmission prices resulting from the expiration of the derogation on transmission prices prevent DNSPs from recovering transmission charges from their customers.

3.8.2 Tribunal's assessment of limits on price movements

As it indicated in its s12A report, the Tribunal is adopting controls on price movements for both network prices (in this determination) and retail prices for residential customers (in its separate retail determination). The purpose of the limits on price movements is to avoid price shocks to residential customers.

The GST and associated changes in prices will impact on the application of the limits on price movements. The Tribunal has accounted for this in specifying the limits.

3.9 Service standards

3.9.1 Determination on service standards incentive mechanism

The Tribunal has not included a service reliability incentive mechanism in this determination. DNSPs must comply with the service standards and reporting requirements under the Code and any applicable law.

3.9.2 Public consultation

In its s12A report the Tribunal considers ways of introducing an incentive mechanism for improved service reliability. In public consultation following the s12A report, stakeholders repeatedly brought service standards to the Tribunal's attention.

In its submission, Advance Energy states its support for including a service reliability incentive in the regulatory framework:

> Advance Energy would welcome the inclusion of service standards in the regulation of network prices. ... Advance Energy believes that a regulatory focus encompassing the standards of service expected by customers is also required. A regulatory framework that concentrates on both efficiency and standards of service is more consistent with market-based outcomes. …[46]

The Tribunal's main concern with including a service reliability incentive in the regulatory framework is the lack of adequate, consistent and comparable data. Advance Energy notes the scarcity of data problem in its submission:

> Advance Energy shares the view of the Tribunal that the inclusion of service standards should be based on verifiable and meaningful data. It is however important for the Tribunal to allow sufficient time in order to develop the reporting systems required to compile the data and indicators which would form part of the service standards regulatory regime. As indicated above, this process is occurring through the Licence Compliance reporting regime. [47]

In the s12A report, the Tribunal states that unless reporting on the technical regulation of distribution service standards yields verifiable and meaningful data, it may adopt an asymmetric service standards incentive mechanism. This would impose penalties for failing to deliver specified service standards, without providing rewards for out-performing the specified standards. Asymmetric treatment of service standards concerned several stakeholders, including NSW Treasury:

> NSW Treasury is concerned that an 'asymmetric form of standards regulation' which includes financial penalties for failing to meet standards without matching rewards for exceeding standards would create an asymmetric risk profile for the distributors. IPART may wish to consider awarding a 'premium' above regulated revenue to distributors that consistently outperform agreed standards. [48]

3.9.3 Tribunal's assessment of service standards issues

The Tribunal has decided not to introduce the asymmetric incentive mechanism it proposed in the s12A report.

The Tribunal is aware that the industry supports an incentive mechanism for service reliability. It also recognises the potential merits of incorporating this sort of incentive mechanism into the economic regulatory framework. However, the framework for measuring service standards and targets is not developed to a level that the Tribunal believes adequate to enable it to incorporate an incentive mechanism based on those measures.

At this stage, the Tribunal is reluctant to include a service reliability incentive mechanism that is based on measured data. However, the Tribunal does not wish to hinder efficient provision of enhanced service standards. The Tribunal reaffirms that efficient, prudent costs

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46 Advance Energy submission, 30 September 1999, p 8.

47 Advance Energy submission, 30 September 1999, p 11.

48 NSW Treasury submission, November 1999.

associated with service reliability improvements will be considered in the operating and/or capital expenditure components of the AARR.

The Tribunal will continue to work with stakeholders to consider the treatment of improved service reliability within the regulatory framework.

3.10 Compliance with Rules

Each DNSP must comply with this determination and any rules issued by the Tribunal under clause 6.10.1(f) of the Code.

4 PRICING PRINCIPLES AND DISCLOSURE REQUIREMENTS

The Tribunal believes that clear requirements for disclosing the basis of pricing and for notifying price changes will improve the regulatory arrangements for DNSPs and electricity users. This section sets out the Tribunal's determination on these matters.

4.1 Determination on disclosure of information on pricing structures and future directions

Each DNSP will be required to comply with the provisions outlined in 'Pricing notification and information disclosure Rule 99/2', issued by the Tribunal under clause 6.10.1(f) of the Code.

Unless a DNSP has published a current pricing information package that meets the 'Pricing notification and information disclosure Rule 99/2', the DNSP may not increase its charge for any prescribed service. Under these circumstances, if actual revenue from the existing charges is projected to exceed the AARR, the DNSP must lower all its charges for prescribed services by a uniform percentage to reduce its revenues to the regulated levels.

4.2 Pricing guidelines

As indicated in chapter 1, the Tribunal has exercised its discretion in clause 9.16.3(c) of the Code, not to apply part E of chapter 6 of the Code. Pending the development of guidelines, clause 9.16.3 requires that prices are to be determined 'in accordance with the methodology applied by that Distribution Network Service Provider to derive prices for similar services under the [pre-existing] IPART Determinations … or such other methodology approved in writing by IPART'.

This provides an opportunity for the Tribunal to develop pricing principles and guidelines in consultation with other stakeholders and regulators, and for those measures to be recognised under parts D & E of the Code.

Further, DNSPs must comply with 'Pricing notification and information disclosure Rule 99/2' issued by the Tribunal under clause 6.10.1(f) of the Code.

4.3 Code requirements

Part E of chapter 6 of the Code sets out a method for calculating charges for prescribed distribution services. It details the steps involved, prescribes aspects of the classification of services and allocation of costs to services, and requires the jurisdictional regulator to agree to various aspects of the allocation procedures.

However, clause 6.11(e) provides that:

> The *Jurisdictional Regulator* may, in consultation with *Code Participants*, develop alternative pricing methodologies to the approach set out in Part E. Any new pricing methodology so developed must conform to any jurisdictional rules, principles, or guidelines for the regulation of *distribution* pricing formulated under clause 6.10.1(f).

Clause 6.10.1(f) requires that such guidelines be consistent with the objectives for pricing and any national guidelines:

> Subject to any provision relating to cross-border networks in Chapter 9, each *jurisdictional regulator* may formulate guidelines and rules to apply to *distribution service* pricing within that *Jurisdictional Regulator's* jurisdiction and any guidelines so formulated must:
>
> (1) not be inconsistent with the objectives and principles for *distribution service* pricing set out in clauses 6.10.2 and 6.10.3;
> (2) not be inconsistent with any national guidelines for *distribution service* pricing formulated by the *Jurisdictional Regulators* under clause 6.10.1(c)
> (3) not purport to regulate matters to which any national guidelines formulated by the *Jurisdictional Regulators* under clause 6.10.1(c) apply.

The Code provides for the development of over-arching national guidelines through clause 6.10.1(c):

> With the consent of each *participating jurisdiction*, the *Jurisdictional Regulators* may together formulate and agree national guidelines to apply to national *distribution service* pricing.

4.4 Section 12A report

4.4.1 Application of the Code

The Tribunal has harboured concerns about the practicality of Part E of the Code for some time. In its s12A report the Tribunal states:

> … chapter 6 of the Code is poorly drafted, has many ambiguities, and does not provide an ideal regulatory framework. Considerable work is required by all state-based regulators, in consultation with the ACCC and other stakeholders, before a determination can be made under the Code.
>
> Yet a determination is required to be released by December 1999. A way forward is for the Tribunal to issue a determination covering distribution under the IPART Act but at the same time endeavouring to comply with Parts D and E of chapter 6 of the Code. It may be necessary for a transitional regulation to be passed deeming the IPART Act determination to have been made under the Code. (Volume 1, Chapter 3 of the s12A report)

The Tribunal maintains its concerns.

4.4.2 Pricing guidelines

In its s12A report the Tribunal states its intention to:

> … work with the DNSPs and other stakeholders to establish agreed guidelines for pricing which can supplement the provisions in chapter 6 of the Code and reduce or streamline the requirements for approval of individual elements in the cost allocation and pricing process. The Tribunal wishes to work with ORG and other jurisdictional regulators to develop such guidelines.

In volume 2, chapter 2 of the s12A report, the Tribunal discusses the objectives for pricing at some length. In summary prices should:

- reflect economic costs by:
  - reflecting the level of available capacity
  - signalling future investment costs
  - discouraging uneconomic bypass
  - allowing negotiation to better reflect the economic costs of specific services
- provide a commercially sustainable revenue stream while recovering the gap between marginal and average costs in the least distorting manner possible
- reduce regulatory burdens by being:
  - simple
  - transparent
  - stable
  - predictable.

Except where there is network congestion, the marginal costs of transmission and distribution are likely to be less than average costs. This creates a tension between economically efficient prices and prices necessary for commercial sustainability. The gap between marginal and average costs should be recovered in the least distortionary manner possible. A practical approach to minimising distortions would recover the gap between marginal and average costs in a manner which:

- does not vary between locations
- contains a fixed component
- to the extent a variable component is necessary, includes both energy and demand components.

4.4.3 Disclosure of pricing methodology

In the s12A report the Tribunal proposes that, as far as possible, the DNSPs should bear responsibility for determining the structure of their network prices. However, the Tribunal considers that the freedom for a monopoly to determine its price structure should be accompanied by the responsibility to disclose medium term pricing strategies and information concerning the basis for determining prices. Such an obligation already exists, but it has not been included in a determination and the requirements have not been identified. In order to clarify the requirements and strengthen compliance the Tribunal plans to:

- work with the DNSPs and other stakeholders to refine existing rules or establish new rules or guidelines for information to be disclosed in pricing information booklets
- require DNSPs to publish such booklets
- require that if a DNSP has not published a complying booklet, that all DNSP's network charges should be decreased or increased by a uniform percentage consistent with the DNSP's overall CPI-X cap (see the discussion in volume 2, chapter 2 of the s12A report).

4.5 Development of workable regulatory arrangements

In a review commissioned by the Tribunal, DGJ Projects found that:

> The many ambiguities and conflicts that exist within Part E are likely to seriously compromise its effectiveness as a workable regulatory instrument and the ability of NECA's proposed code changes to achieve their intended purpose.[49]

This advice is consistent with the views expressed in the Tribunal's 12A report. Hence, the Tribunal proposes to work with stakeholders and other regulators to develop guidelines under the Code. These guidelines could provide a basis for redrafting part E of chapter 6.

4.5.1 Findings of the Pricing Principles Working Group

In order to achieve these goals, the Tribunal established the Pricing Principles Working Group (PPWG) to consider and report on:

a) the translation of the pricing principles in the 12A report into practical guidelines on cost allocation and compliance procedures

b) the requirement to publish information on pricing strategies

c) the requirement to notify the Tribunal and customers of network price changes.

The PPWG comprises representatives of the DNSPs, independent retailers, end-use customers, embedded generators and regulators other than the Tribunal. To date the PPWG has focused on items (b) and (c) above. The Tribunal considered the views expressed in its deliberations on these matters. Minutes of the meetings of the PPWG are available on the Tribunal's website (www.ipart.nsw.gov.au).

Requirement to publish a pricing information package

The PPWG reviewed the information disclosed in the current pricing booklets, the information disclosed under gas access arrangements, and the disclosure regime in New Zealand. The PPWG emphasised the importance of disclosing the basis of current prices and the directions for future price changes. The proposals discussed by the PPWG are based upon NZ disclosure requirements. In discussing these proposals, the PPWG noted that considerable information on the DNSPs' operations is, or will be, disclosed through the Tribunal's regulatory processes, the asset management plans and the reports of the Licence Compliance Advisory Board. Hence, the pricing information package could refer to information contained in other reports.

Having considered the proposals discussed by the PPWG, the Tribunal has concluded that they provide a sound basis for providing clear guidance to the DNSPs for the preparation of the required pricing information package. These proposals are reflected in 'Pricing notification and information disclosure Rule 99/2'.

Requirement to notify price changes

The PPWG considered the period established for notification of price changes and the timing of price changes.

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[49] DGJ Projects, *Review of Changes to Chapter 6, Part E of the National Electricity Code*, October 1999, pp 1-2.

The PPWG proposes that there should normally be only one change in network prices during a year and that this change should occur on 1 July.

The PPWG is also of the view that DNSPs should provide network users with a minimum of 30 days' notice prior to any changes taking effect. The Tribunal has endorsed this view and incorporated it in 'Pricing notification and information disclosure Rule 99/2'.

Whilst the Tribunal considers DNSPs should continue to be responsible for setting prices, it needs to be:

- adequately informed in advance of changes and potential impacts
- assured that the proposals comply with the Tribunal's determinations
- have an opportunity to raise any concerns it may have about the proposals.

In order to meet these needs, the 'Pricing notification and information disclosure Rule 99/2' requires DNSPs to notify the Tribunal of proposed price changes 30 days in advance of the changes taking effect. This notification must be supported by the information package required in 'Pricing notification and information disclosure Rule 99/2'.

5 RATE OF RETURN

The rate of return is applied to the regulatory asset base to yield a return on assets. The return on capital and return of capital (or depreciation) components constitute over 70 per cent of the base revenue requirement.

Much controversy has surrounded the determination of an appropriate asset base and rate of return for the DNSPs. As it has often signalled, the Tribunal is concerned that an approach, which places undue emphasis on the asset value and rate of return, may not produce appropriate outcomes and may counter the goals of incentive regulation.

5.1 Determination on rate of return

The Tribunal has determined that an appropriate weighted average cost of capital (WACC) (real, pre tax) for the electricity distribution networks lies within the range, 5.0 to 8.5 per cent.

For the purpose of calculating the AARR for NSW DNSPs over the regulatory control period, the Tribunal has decided that a real, pre-tax rate of return of 7.5 per cent is appropriate. This is consistent with a nominal post tax return on equity of approximately 11-12 per cent.

The Tribunal has applied a pre-tax nominal rate of return of 7.6 per cent to working capital.

5.2 Code requirements

The rate of return adopted for the purpose of calculating recommended revenue paths should take account of the outcomes in clause 6.10.2, the principles in clause 6.10.3, and the matters in clause 6.10.5 of the Code.

In particular, the Code requires that the distribution service pricing regulatory regime seek to achieve several outcomes:

Clause 6.10.2(b) states:

> … an incentive-based regulatory regime which: …
>
> (2) provides for, on a prospective basis, a sustainable commercial revenue stream which includes a fair and reasonable rate of return to Distribution Network Owners on efficient investment …; [emphasis added].

Clause 6.10.5 (5) states:

> The distribution network owner's weighted average cost of capital applicable to the relevant network service, having regard to the risk adjusted cash flow rate of return required by investors in commercial enterprises facing similar business risks to those faced by the distribution network owner in the provision of that network service.

The definition of 'weighted average cost of capital' in chapter 10 of the Code, refers to "an amount determined in a manner consistent with schedule 6.1". Schedule 6.1 defines weighted average cost of capital (WACC) as:

> The weighted average cost of capital is a 'forward looking' weighted average cost of debt and equity for a commercial business entity. Accordingly, the network owner's weighted average cost of capital will represent the shadow price or social opportunity cost of capital as measured by the rate of return required by investors in a privately owned company with a risk profile similar to that of the network company.

The Code provides guidance for the use of the capital asset pricing model (CAPM) and WACC. However, in assessing and applying the model's parameters, issues arise which reveal considerable differences of opinion. The Tribunal notes that CAPM is only one approach to setting a rate of return.

5.3 Public consultation

The Tribunal's s12A review provided useful information to be considered by the Tribunal in making this determination.

The WACC parameters and matters that received primary attention in submissions in response to the Tribunal's analysis for the section 12A review include:

- the risk free rate and the inflation rate
- the market risk premium
- the asset beta
- debt gearing
- the treatment of tax and WACC conversion formulae.

In its submission in response to the Tribunal's section 12A review, NSW Treasury concludes:

> Given recent regulatory determinations on cost of capital and uncertainty relating to the real pre-tax transformation and future tax reform, NSW Treasury proposes that a real pre-tax WACC of 8.0% for NSW distributors be adopted ... [50]

Some DNSPs have suggested that for this determination, a rate of return less than they had initially proposed is appropriate.[51] For example, Great Southern Energy[52] and EnergyAustralia[53] contend that a real pre-tax WACC of 8 per cent is appropriate for their network businesses.

On the basis of advice from KPMG Corporate Finance, Advance Energy notes the appropriate real pre tax WACC for its distribution business is 8.7 per cent in view of its size and inherent business risks borne by its network business. [54]

50 NSW Treasury, Pricing for Electricity Networks and Retail Supply – NSW Treasury Response, November 1999, p 29.

51 In an initial joint proposal to the Tribunal the DNSPs suggest that a 9.5 per cent real pre tax WACC is appropriate for the NSW electricity network businesses.

52 Great Southern Energy Networks, submission to IPART, September 1999, p 9.

53 EnergyAustralia, submission to IPART, September 1999, p 9.

54 Advance Energy, submission to IPART, September 1999.

NorthPower notes:

> It is NorthPower's position that for this review, the asset value and associated valuation methodology is a more critical issue to be resolved that the precise level of cost of capital for NorthPower. As such, we would not propose a rate of return higher than that, which allows for full ODRC and CPI average price increases. [55]

5.4 Tribunal's analysis and assessment

Cost of capital is a significant element in determining revenues and prices. Economic regulation aims to reflect efficient costs and provide a commercially sustainable revenue stream for the DNSPs. An appropriate rate of return on investment, ie, one that enables owners of regulated businesses to finance their regulated undertakings and obtain reasonable returns in accordance with the risks involved, is an essential component of the rate of return.

If the rate of return is set too low, prices will be distorted and the regulated businesses could become capital constrained or face financial distress. They would then have to reduce their maintenance and capital expenditure to below optimum levels. This would degrade the level of service, resulting in increased costs to consumers.

On the other hand, if the rate of return is set too high, this will be reflected in higher prices. This would provide inappropriate incentives to investors, which may lead to over investment in electricity network assets. This could also result in distorted pricing signals to consumers, and is likely to lead to inefficient outcomes. High prices could distort the apparent economics of network bypass options, demand side management, or the use of alternative energy sources.

In making its assessment on the rate of return, the Tribunal considered:

- submissions made in response to the Tribunal's report for the section 12A review
- the latest market conditions, including advice from Dr Garry Twite and Baring Brothers Burrows
- the principles and requirements of the Code
- the risks faced by the DNSPs, and the risks inherent in the regulatory system
- the impact on end-users and investors/utilities.

In its recent decision on gas arrangements,[56] the Tribunal determined that net working capital should be treated differently in calculating return on capital assets. A nominal return will be allowed on a forecast working capital level. This contrasts with the real return on capital assets (ie system and non-system assets), which will be indexed by CPI over time. The Tribunal notes that in the above and other access decisions, the issue of working capital is insignificant as the return on working capital represents a very small percentage of the total revenue requirement.

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55 NorthPower, response to the Pricing Tribunal's Report to the Premier of NSW, October 1999, p 14.

56 For example, IPART, Final Decision on Access Arrangement for Great Southern Energy Networks Pty Ltd, March 1999 and Draft Decision on Access Arrangement for Albury Gas Company Limited, July 1999.

Key issues considered by the Tribunal in making its determination are summarised below.

5.4.1 Approaches to rate of return

There are many approaches that can be taken to estimate an appropriate rate of return. These are set out in more detail in the Tribunal's section 12A report.

Schedule 6.1 of the Code promotes the use of the capital asset pricing model (CAPM) and the weighted average cost of capital (WACC). However, CAPM is just one way of estimating the cost of equity. Other methods that can be used include price/earnings (P/E) ratio, dividend growth model, and arbitrage pricing theory. These alternative models are generally hampered by implementation problems. Given the lack of data, they are impractical at this stage. Thus, at present, CAPM is the most widely accepted procedure for estimating the cost of capital. CAPM has been applied by regulatory agencies to estimate the cost of capital for regulated industries in the USA, UK and Australia. The industry and market participants support the use of CAPM.

As set out in the section 12A report, recent research and studies have revealed problems inherent in applying CAPM, particularly in respect of individual component parameters.[57] One of the most topical issues in relation to the application of CAPM is the treatment of tax.

CAPM expresses the rate of return as post tax nominal WACC. Traditionally, Australian regulators have used a pre-tax WACC formulation - primarily to avoid the complexity of undertaking tax forecasts. However, the debate surrounding the Victorian gas access arrangements last year revealed that none of the formulae available to convert the post-tax WACC to an equivalent pre-tax WACC is sufficiently complex to account for all the relevant factors. The debate revealed that calculations to estimate the effective tax rate were still required under the pre-tax WACC approach.

For this determination, the Tribunal has decided to continue to adopt a pre-tax WACC formulation. However, in doing so, the Tribunal has derived a WACC range using alternative transformation methods, including 'market practice', the approaches suggested by Professor Davis,[58] and a study by Macquarie Risk Advisory Services.[59] The Tribunal notes that is consistent with the approach used in other regulatory contexts, eg Envestra used an average of the two approaches in the access arrangement submitted for the South Australian distribution system.

The conventional market practice conversion sequence involves adjusting first for tax and then for inflation. This is consistent with the approach outlined in schedule 6.1 of the Code.[60] However, the Tribunal is of the view that schedule 6.1 provides a guide, but does not prescribe a mandatory approach for use in regulating electricity networks.

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57 The practical difficulties were discussed at the Public Forum on WACC in relation to gas access undertakings which was jointly held by ACCC and ORG on 3 July 1998.

58 *Access Arrangements and Discount Rates: Real Pre Tax and Nominal Post Tax Relationship*, K Davis, 19 May 1998.

59 Macquarie Risk Advisory Services Limited, *Weighted Average Cost of Capital for Victorian Gas Distribution Access Arrangements, July 1998*, p 30. The study models the 50 year financial position, suggesting that under the 'market practice' transformation methods actual returns are higher than expected returns.

60 The conversion method reflects the fact that taxable income is calculated on nominal, rather than real profits. The DNSPs contend that this approach is the most appropriate.

The Tribunal wishes to foreshadow its intention to consider the merits of moving to a post tax rate of return, and thus treating tax as an explicit component of the cost of service in subsequent determinations. For this reason the Tribunal will be seeking more detailed information relating to tax from the NSW DNSPs in the lead up to the next determination.

Attachment 3 of the Tribunal's section 12A report provides a summary of the Tribunal's analysis and consideration of the application of CAPM and WACC. The Tribunal considers that its analysis in the section 12A report is appropriate for regulation under the Code and has, therefore, adopted it in this determination.

5.4.2 Tribunal's assessment of WACC parameters

Risk free rate and inflation

In accordance with the CAPM principles, the risk free rate of return should be assessed on a forward-looking basis. In theory, an 'on-the-day' rate should be used in the CAPM model. However, the use of a relatively short averaging period is considered to be reasonable by the market and academics. Thus, the Tribunal considers that it is most appropriate to derive the risk free rate from a 20 day average of the bond yield. For the reasons given in the s12A report, the Tribunal is of the view that it is most appropriate to use the 10 year Australian Commonwealth bond rate (as opposed to the 5 year rate) to derive the risk free rate.

The 10 year Commonwealth bond rate has moved up by approximately 40 basis points since the release of the section 12A report. The 20 day average of the nominal rates (20 days to 16 December 1999) is 6.62 per cent. This compares with an average (2010) indexed bond rate of 3.52 per cent over the same period. This implies an inflation expectation of 3.0 per cent.

Table 5.1 Risk free rates (%)

	10 year bond	2010 indexed bond	implied inflation
s12A review - 20 day average to 9 June 1999	6.02	3.65	2.30
20 day average to 16 December 1999	6.62	3.52	3.00

Despite the recent increase in the nominal bond yield, the observed real bond yield has been relatively stable over the past 12 months. In effect, the upward movement in the nominal rate is predominantly due to an increase in inflation expectation. For this reason, the increase in the nominal rate has had virtually no impact on the average cost of capital in real terms.

On the basis of this information, for the purpose of this determination the Tribunal has chosen to adopt a nominal risk free rate of 6.6 per cent, and an inflation rate of 3 per cent.

Market risk premium

The market risk premium (MRP) is the margin above the risk-free rate that investors can expect to earn from a well-diversified portfolio of equities. In the section 12A report, the Tribunal recommends a market risk premium range of 5 to 6 per cent for establishing the

WACC for the DNSPs. This figure was based on recent studies that suggest market risk premiums are trending downwards.[61]

NSW Treasury in its submission to the Tribunal has argued that a range of 6 to 7 per cent for the MRP is more acceptable, with the use of a 6 per cent margin for establishing the WACC. Advance Energy, on the advice of KPMG Corporate Finance, states that 5 to 7 per cent is a more appropriate range for its distribution business, given the historical wide fluctuations in risk premium from one period to the next.

The Tribunal has examined a number of more recent studies in considering the appropriate level for the market risk premium for this determination.

A study undertaken by the Centre for Research in Finance at the Australian Graduate School of Management (AGSM) shows a wide range of risk premium.

Table 5.2 Average equity risk premium

Method	Period	Risk premium (%)
Including October 1987		
Arithmetic average	1964-95	6.2
Geometric average	1964-95	4.1
Excluding October 1987[62]		
Arithmetic average	1964-95	8.1
Geometric average	1964-95	6.6

Source: Discussion paper by Dr Gary Twite, prepared for IPART, based on data from the Centre for Research in Finance for 1974-1998.

As shown above, there are significant fluctuations in the measure of market premium. Measures of risk premium are also influenced by the measurement period.

Ibbotson Associates have measured the MRP for various countries, including the USA. The longer term equity risk premium (from 1970-1998) is estimated to be 6.4 per cent.[63] Ibbotson

61 Kortian, T (1998), *Australian Sharemarket Valuation and the Equity Premium*, Department of Finance, University of Sydney. As well as the decline in inflation and the increasing importance of institutional investors which have exerted downward pressure on the Australian equity premium, Kortian (1998) argues that demographic changes due to an increased number of younger savers in Australia's population are important in underpinning the decline of the Australian equity premium.

In addition, in his advice to the ACCC and ORG, Professor Kevin Davis estimates a range of 4.5 to 7.0 per cent for the market risk premium.

The Tribunal also notes that OFWAT considers a more appropriate range for the equity risk premium is 2.75 - 3.75 per cent. In arriving at this range, OFWAT has considered the results of the survey of institutional investors carried out by Credit Lyonnaise Securities Europe (CLSE), recent research published by equity analysts, academic studies, and a Price Waterhouse survey.

62 Exclusion of the October 1987: reduction in share prices increases the market risk premium. However, exclusion of such one off adjustments is controversial and may well bias the estimates upwards.

63 IbbotsonAssociates, *International Equity Risk Premia Report*, 1999.

Associates estimated the market risk premium for Australia to be 3.4 per cent for the period 1970-1998.[64]

Cornell Hirshleifer and James (1997) and Goyal & Welch (1999) have estimated the market risk premium in the US to be 5.6 per cent and 5 per cent respectively.[65]

CSFB Equity Research values AGL at a risk premium of 5.5 per cent.[66]

In its most recent draft decision on the Central West Transmission Pipeline, ACCC adopted a value of 5.5 per cent. This is consistent with Arthur Andersen's comment for AGLGN. In its earlier draft regulatory principles for electricity, ACCC comments that it is probable that a 5.0 per cent market risk premium is more appropriate than the 6.0 per cent allowed in the Victorian decisions.[67]

Recent regulatory decisions and academic advice establish the following risk premium range:

Table 5.3 Market risk premium

Regulatory decision	Date of release	Market risk premium (%)
Officer (according to ORG) [68]	March 1998	6.0
Davis[69]	March 1998	4.5 - 7.0[70]
ACCC (Gas final decision) [71]	October 1998	6.0
ORG Victoria[72]	October 1998	6.0
ACCC Electricity Transmission (draft)	May 1999	6.0
ACCC Central West (draft)	September 1999	5.5
Davis advice to SAIPAR[73]	October 1999	6.0
IPART AGLGN (draft)	October 1999	5.0-6.0

64 IbbotsonAssociates, *International Equity Risk Premia Report*, 1999.
65 Advice from Dr Garry Twite AGSM UNSW.
66 Credit Suisse First Boston, The Australian Gas Light Company, May 1999.
67 ACCC, *Draft Statement of Principles for the Regulation of Transmission Revenue*, 27 May 1999, p 79.
68 See Office of the Regulator-General, *Weighted Average Cost of Capital for Revenue Determination: Gas Distribution*, 27 March 1998, p ii.
69 Kevin Davis, *The Weighted Average Cost of Capital for the Gas Industry*, Report Prepared for the Australian Competition and Consumer Commission and Office of the Regulator General, March 18 1998, p 13-4.
70 With a preference towards the lower end of this range.
71 Australian Competition and Consumer Commission, *Victorian Gas Transmission Access Arrangements Final Decision*, 6 October 1998, p 53.
72 Office of the Regulator-General, *Weighted Average Cost of Capital for Revenue Determination: Gas Distribution*, 27 March 1998, p ii.
73 Davis, K, The Weighted Average Cost of Capital for Access Arrangements for Envestra, Draft, prepared for the South Australian Independent Pricing and Access Regulator (SAIPAR), October 1999.

In the light of the above information and given the continued low inflation environment, [74] the Tribunal considers that the market risk premium of 5 to 6 per cent recommended in the section 12A report should be used in establishing the WACC range for the purpose of this determination.

Asset beta

The Tribunal recommends an asset beta of 0.35 to 0.50 for the WACC for the NSW DNSPs. NSW Treasury notes in its submission to the Tribunal that this asset beta range is low relative to "both relevant industry benchmarks and the recent Victorian gas decisions". [75] The Treasury provides a selection of asset betas to support its case.

In their draft decision for the Victorian gas network, the ACCC and ORG used a range of 0.35 to 0.40. They then adjusted the asset beta upward to 0.55 to allow for company-specific risks in the final decision. This practice is inconsistent with CAPM, [76] as recently noted by Professor Kevin Davis in his report to the South Australian Independent Pricing and Access Regulator (SAIPAR) regarding its decision on Envestra's proposed access arrangement. Thus the asset beta assumption for the decision is artificially high, and is not an appropriate benchmark.

Recent regulatory decisions in relation to electricity utilities have applied asset betas as low as 0.3 and as high as 0.5 (see table below). The Tribunal's proposed asset beta assumption appears to be consistent with recent regulatory decisions.

Table 5.4 Asset betas used in regulatory decisions

Regulator	Decision	Asset beta
ACCC	Victoria Gas (draft)	0.35
ACCC	Victoria Gas (final)	0.55
ORG	Victoria Gas (draft)	0.40
ORG	Victoria Gas (final)	0.55
IPARC	ACTEW electricity (draft)	0.35 - 0.45
ACCC	TransGrid (draft)	0.45
ACCC	Central West Pipeline (draft)	0.60
IPART	Wagga Wagga gas network (final)	0.4 – 0.5
IPARC	ACTEW electricity (final)	0.3 – 0.5
IPART	Albury gas network (draft)	0.4 – 0.5
IPART	AGLGN (draft decision)	0.4 - 0.5
OTTER	Tasmania electricity (final)	0.42 [77]

74 Recent surveys of indicators of prices have shown that inflationary pressures remain subdued. Separating out the impact of the GST, it is expected only modest upward pressure on the underlying CPI will occur during the next year or so.

75 NSW Treasury, NSW Treasury Response, November 1999, p 24.

76 The purpose of an asset or equity beta is to capture the systematic risk of a company, which may not align with the company's total risk.

77 This asset beta is implied by OTTER's equity beta assumption of 0.95 and its debt gearing assumption of 50-70 per cent, assuming a debt beta of 0.06, and using the Monkhouse delivering formula.

According to a World Bank policy research working paper, firms regulated under the rate of return regulation have lower asset beta than a comparable firm operating under a price cap mechanism. Thus, electricity utilities tend to have relatively lower asset betas than their counterparts in the gas monopoly.

Table 5.5 Asset betas of utilities

Type of regulatory regime	Gas	Electricity	All
High power incentives, eg price cap regime	0.84	0.57	0.71
Intermediate	0.57	0.41	0.60
Lower powered incentives, eg rate of return regime	0.20	0.35	0.32

Source: Regulatory Structure and Risk of Infrastructure Firms: An International Comparison, Alexander, Mayer and Weeds, World Bank Policy Research Working Paper 1998.

The building block approach applied by the Tribunal in this determination in determining the base revenue requirements for NSW DNSPs is similar to the rate of return regulatory regime. Arguably, the asset beta applicable to an electricity network business should not be as high as that borne by the utilities operating under a 'high powered' incentive regime, particularly when the regulatory approach is moving toward a fixed revenue cap. This suggests that the asset beta assumption for the NSW DNSPs should be lower than the asset beta assumptions used for the gas regulatory decisions noted above.[78]

This analysis is supported by the National Economic Research Associates (NERA) in its recent critique of the WACC parameters proposed by the ACCC for TransGrid:

> … we would expect the fact that TransGrid is to be regulated by means of a revenue cap (as opposed to the `revenue yield' form of price control applied to the Victorian gas businesses) to cause its beta to lie towards the bottom of the range for network service providers. All else equal, a revenue cap is more likely to shield a regulated business from swings in the economic cycle than other forms of price control which allow revenue to move in relation to energy transported.[79]

Furthermore, arguments that the distribution businesses face significant demand risk are not relevant for the asset beta estimate. Volatility of demand is a firm specific risk and as such, is diversifiable by investors. To the extent that this risk can be recovered, it should be reflected in the cashflow estimation rather than in the required rate of return.

In addition, various 'industry benchmarks' can be used to support the Tribunal's asset beta assumption, such as those for Australian industry groups:

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78 The Tribunal recognises that care should be taken when reviewing overseas companies to derive beta assumptions, particularly in respect of the adjustments for gearing and the implicit assumption that the risk of the market portfolio is the same in each country.

79 NERA, A *Critique of the WACC Parameters Proposed for TransGrid*, May 1999, p 13.

Table 5.6 Asset beta assumptions for selected Australian industry groups

ASX industry group	Geared beta	Asset beta[80]
Telecommunications	0.70	0.41
Infrastructure & utilities	0.61	0.46

Source: Risk Management Service, Centre for Research in Finance, AGSM.

In light of above, the Tribunal does not see merit in revising its asset beta assumption of 0.35 to 0.50 (with a midpoint of 0.425) as recommended in the section 12A review. The Tribunal has therefore used this assumption to establish the WACC for the DNSPs.

Gearing

In the section 12A review the Tribunal concludes that a gearing of 60 per cent is appropriate for establishing the WACC for the DNSPs.

Drawing on advice from KPMG, Advance Energy in its submission to the final review argues for a lower gearing because of the small size of Advance relative to other DNSPs, and its concentrated industrial customer base. These customers' businesses (principally mining and agriculture) are by nature more subject to variable business cycles. It is argued that a gearing assumption of 40 to 45 per cent is more appropriate for Advance Energy.

However, Advance's arguments are not in accordance with the CAPM theory. Volatility of demand and hence earnings is categorised as firm specific risk and as such, is diversifiable by investors. To the extent that this risk can be insured against, it should be reflected in the cashflow estimation rather than in the required rate of return. For example, the expected cashflow of Advance could be adjusted to incorporate an allowance for a fair cost of insurance against such risks or a faster rate of depreciation.

The size of a firm does not impact directly on its capital structure. Gearing depends more on the capacity of a firm to repay debt and interest. This capacity depends on the sustainability of cashflows from its operations.

Advance Energy argues that generally, smaller firms have higher expected returns because they have higher risk, in keeping with the 'small company' theory. Whilst the small company theory is well documented and researched in the field of finance, the debate continues. A recent UK study[81] documents the long term performance of smaller companies, as compared to large capitalisation equities in the UK. The study reveals that the historical size premium of small cap companies (for 1955 to 1988) went into reverse during the last decade (1989 to 1997). The study concludes that the 'size effect' causes small cap stocks to perform differently from large caps, but does not necessarily manifest itself through a 'size premium'.

The gearing of 60 per cent was determined on the basis of an efficient, typical network business rather than the specific circumstances of a particular business. There appears to be

80 Delivered by the Monkhouse formula used by ACCC.

81 *Murphy's Law and Market Anomalies*, Elroy Dimson and Paul Marsh, Professors of Finance at London Business School, August 1998.

no theoretically good reason for adjusting the gearing of Advance Energy on the basis of its size and variability of demand.

NSW Treasury proposes a gearing of 50 per cent, arguing that a high gearing level is unsustainable given the possibility that accelerated depreciation will be abolished following a recent recommendation by the Ralph Business Tax Review. This would have the effect of increasing the tax charge and reducing the after tax cashflow of the DNSPs.

However, the Ralph Business Tax Review also proposes reducing the capital gains and company tax from 36 to 34 per cent and then 30 per cent in two steps. This would reduce the tax paid by businesses and increase the after tax cashflows. The impact of the tax review on the distributors cannot be known until a thorough assessment of the total tax package is undertaken.

It should be noted that ACCC in its draft decision on TransGrid uses 60 per cent gearing to establish the WACC. In his report to SAIPAR regarding a suitable WACC for access arrangements for Envestra, Kevin Davis concurs that 60 per cent is a reasonable gearing assumption for a typical utility.

The latest financial position of the listed utilities shows the following debt to debt and equity ratio:

Table 5.7 Gearing of Australian listed utilities

$ million	Debt	Market capitalisation	Debt/(Debt+Market capitalisation %))
United Energy	1,228	832	59
Envestra	1,228	899	69
AGL group	1,316	3,614	27

Having regard to the above evidence and information, a gearing assumption of 60 per cent is considered appropriate for the electricity network businesses, given the stability and sustainability of their operating cashflows.

Cost of equity

On the basis of the parameters noted above, ie:

- a nominal risk free rate of 6.6 per cent
- a risk premium on equity in the range 5.0-6.0 per cent
- a range for the asset beta of 0.35-0.50
- an equity beta of 0.78-1.14 derived assuming 60 per cent debt gearing and a debt beta of 0.06, [82]

the Tribunal has derived a nominal post tax return on equity of 10.5 to 13.5 per cent.

[82] The equity beta is converted from the asset beta using the Monkhouse formula: Be=Ba+(Ba-Bd(1-rd)/(1+rd)T)D/E.

Cost of debt

In the section 12A report, the Tribunal concluded that the cost of debt appropriate for the electricity utilities is 1.0 per cent above the 10 year Commonwealth bond rate.

The cost of debt varies, depending on the gearing of the business and the terms of the debts. The cost of debt is established by the WACC calculation by adding a margin to the risk free rate.

Debt margins used in regulatory decisions and advised by academics are as follows:

Table 5.8 Debt margin

	Debt margin (%)
ACCC Victoria gas (draft)	0.80
ACCC Victoria gas (final)	1.00
ACCC TransGrid (draft)	0.80 – 1.20[83]
IPART section 12A report	1.00
ACCC Central West Pipeline (draft)	0.80 – 1.20[84]
Davis (advice on Envestra gas access)	1.2[85]
IPART- AGLGN (draft decision)	0.90 – 1.10[86]

Since the release of the Victorian gas final decision the uncertainty in global financial markets has reduced. [87]

In the financial year to 30 June 1998, the NSW distributors reported the following interest rate risk exposure:

83 but use 1.00 for calculation.
84 but use 1.00 for calculation.
85 based on a BBB rating.
86 As proposed by Arthur Andersen.
87 As proposed by Arthur Andersen.

Table 5.9 Effective interest rates of NSW distributors ($'000, except where otherwise indicated)

	Floating interest rate	Maturing 1 year or less	Maturing 1 to 5 years	Maturing more than 5 years	Total borrowings	Weighted average EIR[88] (%)
EnergyAustralia	296	3	620	386	1,305	6.66
Integral	-	11	214	595	820	5.67
NorthPower	60	2	40	36	139	7.58
Great Southern Energy	1	0	91	0	91	6.85
Advance Energy	-	6	6	28	40	7.82
Australian Inland Energy	-	-	-	-	-	-
Total	357	22	970	1,045	2,395	6.40
Portfolio weighting	15%	1%	41%	44%		

The weighted average effective interest rate borne by the distributors varies from 5.7 per cent to 7.8 per cent based on a portfolio of short and long term borrowings. The overall weighted average for the industry is 6.4 per cent with 44 per cent of the loans maturing after more than five years.

As at 30 June 1998, the 10 year bond rate was 5.58 per cent. This indicates that the distributors' aggregate borrowings were exposed to a margin of 0.82 per cent over the 10 year Commonwealth bond rate at 30 June 1998.

In the light of the distributors' weighted average effective interest rate, recent regulatory decisions, and other information detailed above, the Tribunal is of the view that it is more appropriate to use a debt margin range of 0.80 to 1.00 per cent to establish the WACC for the network businesses. However, it is worth noting that adopting this range for the debt premium, relative to using a point estimate of 1 per cent, only results in a marginal change in the WACC range. All else equal, it reduces the mid-point of the range by 0.06 per cent.

Tax assumptions

As set out in section 5.4.1, CAPM provides a basis for calculating the post tax cost of equity, ie an after tax return to equity investors. The required post tax rate of return is then translated to a pre tax return by reference to a tax rate. At issue is whether the effective tax rate or statutory tax rate should be assumed for this purpose. In line with the initial proposals by the DNSPs and the government shareholder, the Tribunal assumes a statutory tax rate of 36 per cent in the section 12A review.

Government owned enterprises (and therefore the NSW DNSPs) do not pay income tax to the Australian Taxation Office. Instead it is calculated under the NSW tax equivalent

88 Effective interest rate.

regime.[89] Until recently, the NSW Treasury adopted a financial distribution policy based on pre tax profits. However, its current policy has been negotiated and set on a post tax basis. NSW Government trading enterprises (GTEs) are required to adopt tax effect accounting and tax planning. It appears GTEs are in the early years of the tax equivalent regime. If fully applied, the depreciation deduction for tax purposes is likely to be greater than accounting depreciation. As a result, the effective tax rate is likely to be less than 36 per cent. In a recent discussion paper, the Tribunal's notes its analysis suggests that the effective rate for the six NSW distribution network businesses in the next ten years is likely to average 27 per cent.[90]

The Tribunal believes the utilities should manage their own tax affairs. Applying the effective tax rate would pass some of the tax benefits on to end-users.

The benefits of accelerated depreciation and the tax shield provided by debt defer tax liabilities. As a result, the effective tax rate will vary over time. Initially, it will be below the statutory rate. In later years it will be above the statutory rate. Given current depreciation and inflation rates, the long term average rate is likely to be below the statutory rate.[91]

The difference between the statutory and effective tax rates raises risks if the statutory rate is used in establishing the regulated revenue path.[92] For instance, the varying effective rates of return may encourage gold-plating in the early years and under-investment later.

At this stage further work is required to estimate the effective tax rate and consider how this can be incorporated into the regulatory regime.

As a consequence of the Ralph Business Tax Review, there is likely to be a change in the corporate statutory tax rate from 36 to 34 per cent and then 30 per cent in two steps. These changes will affect the value of imputation credits and will abolish accelerated depreciation for tax purposes. All else being equal, adopting a tax rate assumption of 34 or 30 per cent will have little impact on the WACC.[93] However, changes that affect the value of imputation credits are likely to have a more substantial impact on the WACC. The exact magnitude is difficult to quantify at this stage. Further, the changes in the effective tax rate as a result of the changes in the tax depreciation rules are not relevant while the Tribunal continues to use the statutory tax rate. For these reasons, the Tribunal has calculated the WACC at both the existing and proposed statutory tax rates, and had regard to the impact on a range for WACC.

The Tribunal recognises that a key question that remains is the difference in net present value terms between actual tax paid over the life of an asset, and tax allowed using the statutory rate. As signalled in section 5.4.1, the treatment of taxation will be examined further in future reviews and determinations.

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89 Effective interest rate.

90 IPART, *The Rate of Return for Electricity Distribution Networks*, A Discussion Paper, November 1998, p 9.

91 See ORG, *Cost of Capital Financing*, May 1999, p 43.

92 Ibid, p 46.

93 Changing the tax assumption from 36 per cent to 34 or 30 per cent reduces the WACC (real, pre tax) by between 0.1 and 0.3 per cent.

5.4.3 A feasible range for the rate of return

Given the inherent conversion problems and the arbitrariness of the combined effects of different inputs to CAPM, the Tribunal has adopted a feasible range for the cost of capital.

As detailed above, the Tribunal has revised a number of parameters used in the section 12A report. These revisions have been made in light of prevailing market conditions and methodologies currently followed by market practitioners and other regulators. The changes involve:

- an increase in the nominal risk free rate by 0.6 per cent
- an increase in the inflation assumption from 2.29 per cent to 3.00 per cent
- a decrease in the real risk free rate by 0.13 per cent
- a change in the debt premium from 1 per cent to consideration of a range of 0.8 to 1 per cent
- a range for the tax rate assumption of 30 to 36 per cent, instead of 36 per cent.

Using these parameters, the application of the CAPM/WACC model results in a rate of return in the range of either:

- 10.5 - 13.5 per cent nominal post tax return on equity
- 5.0 - 8.5 per cent pre tax real rate of return on capital. [94]

Table 5.10 presents the results of the parameters adopted by the Tribunal for the purposes of this determination:

Table 5.10 WACC parameters adopted by IPART

	Section 12A review	This determination
Risk free rate	6.02%	6.62%
CPI	2.29%	3.00%
Real risk free rate	3.65%	3.52%
Market risk premium	5.0 - 6.0%	5.0 – 6.0%
Debt margin	1.0%	0.8 - 1.0%
Debt to total assets	60%	60%
Gamma	0.5 - 0.3	0.5 - 0.3
Tax rate	36%	30 – 36%
Asset beta	0.35 - 0.50	0.35 - 0.50
Debt beta	0.06	0.06
Equity beta	0.77 - 1.14	0.78 - 1.14
Cost of equity (nominal post tax)	9.9 - 12.9%	10.5 – 13.5%
Cost of debt (nominal pre tax)	7.0%	7.4 – 7.6%
WACC (nominal post tax)	5.8 - 7.1%	6.6 – 7.5%
WACC (real pre tax)	5.3 - 8.6%	5.0 – 8.5%

94 The lower and upper range are the real pre tax WACC derived using the two alternative conversion methods from nominal post tax WACC to real pre tax WACC.

5.4.4 Other evidence and considerations

As set out in the Tribunal's section 12A report there are a number of other considerations relevant to the decision of an appropriate rate of return. In the report the Tribunal notes that market expectations and the decisions of overseas regulators[95] are both relevant to the Tribunal's decisions. Since the release of the Tribunal's section 12A report, a number of UK regulators have released their decisions.

OFWAT recently made a decision in which a range of 4.25-5.25 per cent was adopted for the post-tax real cost of capital for "an efficiently financed water company". [96] This range was derived using:

- a risk free rate of 2.5 – 3 per cent
- a debt premium of 1.5 to 2 per cent
- an equity risk premium of 3 to 4 per cent
- an equity beta of 0.7 to 0.8
- gearing of 'around' 50 per cent.

OFGEM recently decided that a real pre-tax WACC range of 6 to 6.9 percent was applicable, and that a rate of 6.5 per cent should be adopted for the purpose of calculating the price controls of the UK electricity distribution business. [97] OFGEM bases this decision on:

- a risk free rate of 2.5 per cent
- a debt premium of 1.4 per cent
- a cost of debt of 4.3 per cent
- an equity risk premium of 3.5 per cent
- an equity beta of 1.0
- gearing of 50 per cent
- a post tax cost of equity of 6 per cent
- a 'taxation adjustment' of 1.429.

5.4.5 Conclusions

As established above, the use of CAPM/WACC means the rate of return for the electricity distribution networks should be within the range 5.0 - 8.5 per cent (real, pre tax). Within this range, a single rate of return must be used to calculate the regulated revenue for each DNSP.

The Tribunal is required to arrive at a rate of return having regard to all the objectives and requirements of the Code. Important considerations include the impact on end-users and investors/utilities. If returns are set too high, they will impact adversely on the competitiveness of end-users and may encourage inefficient bypass. If returns are set too low, there will be an equally undesirable outcome - investors/utilities may be reluctant to

95 While these estimates are of interest, the Tribunal recognises that care should be taken when comparing rates.

96 OFWAT, Final Determination Future Water and Sewerage Charges 2000-2005.

97 OFGEM, Distribution Price Control Review, Final Proposals, December 1999.

invest in the industry, resulting in a degradation of service standards. A return on new investment should be sufficient to satisfy capital providers, lenders and investors operating in the market. However, given the differences of opinion about how WACC should be calculated under a CAPM framework, the regulator's judgement is critical in arriving at an appropriate point estimate for the rate of return.

In the section 12A report, the Tribunal proposed that a rate of return towards the higher end of the range under the CAPM framework, is appropriate for the DNSPs. This was proposed by the Tribunal once it had considered the risks facing the DNSPs, evidence on market expectations of the rate of return, risks inherent in the regulatory system, and other economic considerations. The Tribunal proposed that a real pre tax rate of return of 7.5 per cent should apply to EnergyAustralia, Integral Energy, NorthPower and Great Southern Energy, and that a real pre tax rate of return of 7.75 per cent should apply to Advance Energy and Australian Inland Energy. This conclusion was in line with a nominal post tax return on equity of approximately 11-12 per cent.

A higher rate of return for Advance Energy and Australian Inland Energy was proposed by the Tribunal in the section 12A report to account for the DNSPs' higher proportion of industrial customers, and thus exposure to revenue risk due to the potential closure of any of these large businesses. [98]

On balance, the Tribunal considers that a rate of return within the range 7-8 per cent (real pre tax) is appropriate for the DNSPs. Changes in market conditions since the section 12A report, has had little impact on the range under the CAPM framework. Indeed, the midpoint of the return range derived under CAPM has only fallen marginally by 0.2 per cent.

However the Tribunal no longer considers it appropriate for Advance Energy and Australian Inland Energy to earn a higher rate of return. In contrast to the MAR formula used in the section 12A report, the Tribunal has adopted a pure revenue cap approach for this determination. Under a revenue cap, the DNSPs are sheltered from the revenue risks arising from a high industrial customer base, and therefore should not be compensated for these risks.

Having considered the matters described above, the Tribunal determines that a real pre tax rate of return of 7.5 per cent should apply to all DNSPs, EnergyAustralia, Integral Energy, NorthPower, Great Southern Energy, Advance Energy and Australian Inland Energy. This conclusion is consistent with a nominal post tax return on equity of approximately 11-12 per cent.

This determination should not be seen as binding the Tribunal's future regulatory decisions on rates of return for this or other industries.

98 It should be noted that the Tribunal recognises, as detailed in the section 12A report, that business risk of this type is diversifiable and therefore not captured by CAPM. Under the CAPM model, these risks should be included in the cash flow rather than the WACC. However, a similar effect can be achieved by adopting the common practice of including a loading on the rate of return.

6 CAPITAL BASE

6.1 Initial capital base

Together with operating and maintenance expenditure, return on capital and return of capital constitute the building blocks used to determine base revenue requirements. Return on and return of capital constitute over 70 per cent of the base revenue requirement.

As is noted in Chapter 5, the Tribunal is concerned that an approach that places too much emphasis on the asset value and rate of return may not produce appropriate outcomes and may counter the goals of incentive regulation.

6.1.1 Determination on regulatory capital base

The DNSPs' initial capital base for each DNSP as at 30 June 1998 is as follows:

Table 6.1 Initial capital base at 30 June 1998

DNSP	Initial capital base ($m)[99]
EnergyAustralia[1]	3,767
Integral Energy	1,732
NorthPower	858
Great Southern Energy	515
Advance Energy	303
Australian Inland Energy	50
DNSP total	**7,225**

1: EnergyAustralia's initial capital base includes its transmission assets.

See Attachment 2 for information on working capital.

6.1.2 Code requirements

Clause 6.10.3 of the Code sets out the requirements for valuing the initial capital base. In particular, clause 6.10.3(e)(5)(iii) states that:

> … valuation of assets brought into service after 1 July 1999 ("new assets"), any subsequent revaluation of any new assets and any subsequent revaluation of assets existing and generally in service on 1 July 1999 is to be undertaken on a basis to be determined by the Jurisdictional Regulator. In determining the basis of asset valuation to be used, the Jurisdictional Regulator must have regard to:
>
> A the agreement of the Council of Australian Governments of 19 August 1994, that deprival value should be the preferred approach to valuing network assets;
>
> B any subsequent relevant decisions of the Council of Australian Governments; and
>
> C such other matters reasonably required to ensure consistency with the objectives specified in clause 6.10.2

99 Includes streetlighting assets.

6.1.3 Public consultation

Throughout the s12A review and subsequent public consultation, much attention has focused on the initial capital base. As mentioned above, the Tribunal is concerned that stakeholders place too much emphasis on issues surrounding the asset base. Doing this deflects attention from the regulatory framework and its ability to provide incentives for efficient performance.

Nevertheless, the Tribunal notes the healthy debate surrounding the proposed asset values set out in the s12A report. Those asset values are close to the depreciated optimised replacement cost (DORC) valuations. Stakeholders were clearly divided into two positions: those supporting a DORC valuation and those opposing a DORC valuation.

The DNSPs and Treasury support the use of DORC. For example, in its submission, EnergyAustralia states:

> EnergyAustralia supports the Tribunal's use of ODRC as a means to provide an appropriate base for regulated assets.
>
> EnergyAustralia requests the Tribunal establish guidelines on ODRC valuation and optimisation in consultation with network service providers.

Advance Energy also supports the use of DORC, stating:

> Advance Energy strongly supports the first main principle in this report which is the ODRC approach for valuation of assets as it provides for transparent and repeatable network asset valuations. It is also economically efficient by replicating asset valuations under market conditions, meets the objectives of the National Electricity Code (the Code), has no revenue circularity problems, is independently verifiable and is consistent with the building block approach.

The NSW Treasury position is summarised as:

> NSW Treasury endorses the asset values for DNSPs proposed by IPART for the following reasons:
>
> - The values are based on independently determined professional valuations
> - The valuations were confirmed by an independent IPART review
> - The values were determined following the ODRC approach
> - The values are consistent with an appropriate balancing of the interests of owner and customer.

On the other hand, the Business Council of Australia object to the use of DORC, stating:

> The late intervention of the government, by requiring the Tribunal to adopt the inflated DORC asset valuation is regrettable, as it will mean electricity prices to consumers and downstream industries that are higher than otherwise might be the case.
>
> We consider that the justification for intervention (viz "reasonable recognition of pre-existing policies of the government") cannot be supported if the Tribunal is seeking "to balance the interests of the owners and users of NSW electricity services."

Likewise, in its submission, the Energy Markets Reform Forum states its opposition to DORC:

> We are strongly opposed to the intervention by the NSW Government, which has resulted in IPART adopting the inflated DORC asset valuation. This action raises the asset value of the Distribution Businesses by some $2.2 billion, and will in effect over-recover some $160 million to $170 million in revenue per year from electricity users in this State. This will deliver an economically sub-optimal outcome for the NSW economy and the people in this State.

6.1.4 Tribunal's assessment

The Tribunal has considered the principles and matters set out in the Code including clauses 6.10.2 and 6.10.3.

Clause 6.10.2(e) of the Code requires the Tribunal to give reasonable recognition to the pre-existing policies regarding asset values, revenue paths and prices where the assets are government-owned. The s12A report notes that the Premier wrote to the Chairman of IPART in June 1999, confirming the Government's pre-existing policies, which include:

- independently determined ODRC valuations of the physical assets of the NSW distributors (incorporating revisions to Treasury guidelines as recommended by the independent consultants); and
- replacement cost valuations of easements prepared by independent consultants.

Having considered all information presented to the Tribunal, it has balanced the interests of stakeholders and determined that the position on the initial capital base in Table 6.1 is appropriate in this determination. The initial capital base illustrated in Table 6.1 is consistent with the proposed valuations in the s12A report. These values are expected to deliver revenue streams and network prices sufficient to finance network functions, maintain service standards and earn reasonable returns.

The Tribunal's determination does not bind future regulatory decisions on initial capital bases for the electricity industry or any other industry.

6.1.5 Easements

The Tribunal included in the initial capital base at historical costs easements in existence at 1 July 1999, as specified in table 6.2.

Table 6.2 Easement values as at 30 June 1998, ($'000)

DNSP	Value of easements
EnergyAustralia	9,797
Integral Energy	2,916
NorthPower	205
Great Southern Energy	987
Advance Energy	nil
Australian Inland Energy	nil

Source: GHD/Worley/Arthur Andersen asset valuation report.

To include a market value for existing easements in the initial asset base would be of no economic benefit. If new easements need to be acquired, the expenditure will be considered on the same basis as the other elements of capital expenditure (see section 6.3).

The Tribunal recognises that easements are required by the DNSP to provide prescribed distribution services. Electricity easements generally apply in perpetuity. Gradual growth in load, and the difficulty and expense of negotiating a new easement means that they are rarely replaced. Indeed, a network is far more likely to seek to alter the terms of an existing easement to allow a different sized wire to be erected than to extinguish an easement and negotiate a new one. The restrictive nature of easements (ie being an easement for electricity distribution lines only) may mean that they have no value to any other entity.

6.1.6 Working capital

The Tribunal considers that any business must maintain an investment in working capital to allow it to manage the lag between payments to suppliers and receipts from customers. Also, many businesses maintain an investment in spares inventory. The Tribunal considers that an investment in working capital is a necessary part of conducting a network business, and should earn a return in a manner similar to investment in physical assets.

In its recent decisions on access arrangements[100], the Tribunal determined that net working capital should be treated differently in calculating return on capital assets. A nominal return of 7.6 per cent (the pre-tax nominal cost of debt per Table 5.11) will be allowed on a forecast working capital level. This contrasts with the real return on capital assets (ie system and non-system assets), to which the Tribunal has applied CPI indexation over time. The Tribunal notes that in many cases, the issue of working capital is insignificant as the return on working capital represents a very small percentage of the total revenue requirement. In some cases (eg Albury Gas Company), net working capital is assumed to be zero.

In this determination, the Tribunal assessed the reasonableness of working capital based on a balance sheet approach. This analysis was distorted by a number of one-off adjustments and prepayments, and also by inconsistent reporting by the DNSPs from year to year. This led to significant variability in the relative amounts of working capital among the DNSPs.

In order to determine a reasonable level of working capital for each of the DNSPs, the Tribunal adopted a simplified payment cycle approach. Generally, this approach allows for the amount of working capital to be estimated based on the amount of time payments and receipts are outstanding. For the purposes of this determination, the Tribunal has assessed the level of working capital assuming that payments from customers are outstanding for 45 days from the date of service delivery, and that suppliers (for both operating and capital expenditures) are paid 30 days after service delivery. The Tribunal also added an allowance for inventory.

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100 See for example, IPART, *Final Decision on Access Arrangement for Great Southern Energy Networks Pty Ltd*, March 1999, *Draft Decision on Access Arrangement for Albury Gas Company Limited*, July 1999, and *Draft Decision*, *Access Arrangement for AGL Gas Networks Limited Natural Gas System in NSW*, October 1999.

This can be expressed as follows:

	Total network revenue (DUoS + TUoS)	* 45/365
less	Operating costs (including TUoS costs)	* 30/365
less	Capital expenditure	* 30/365
plus	Inventory ($).	
Equals	Working capital	

The return on working capital is included in the building block analyses shown in Attachment 2.

6.2 Rolling forward the capital base

6.2.1 Determination on rolling forward the capital base

The initial capital base at 30 June 1999 is determined as follows:

- ***initial capital base as at 30 June 1998 (listed in Table 6.1) indexed by the CPI***
- ***capital expenditure for 1998/99 indexed by half the CPI percentage[101]***
- ***depreciation as calculated in Attachment 3 deducted***
- ***asset disposals deducted.***

6.2.2 Future treatment of the initial capital base

In respect of regulatory assets in existence at 1 July 1999, the Tribunal is of the view that:

- stranded or redundant assets should be dealt with via the calculation of optimised deprival value (ODV) for each DNSP at 30 June 2003
- in calculating ODV the economic value of the assets should be compared to the then current estimate of DORC, on an asset class by asset class basis.

For assets brought into existence after 1 July 1999:

- subject to a prudency test, the asset base should be rolled forward based on forecast capital expenditure until 30 June 2003. After 30 June 2003 this capital expenditure will be tested for prudency and the regulatory capital base will be adjusted to take account of actual capital expenditure. The service provider will retain the return on the difference between projected and actual expenditure during the period
- prudent investment in demand management should be recovered and rolled forward on the same basis as prudent investment in capital expenditure or operations and maintenance expenditure.

For the purposes of determining the AARR until 30 June 2004:

- the initial capital base at the start of each year is indexed by the CPI
- projected capital expenditure (excluding capital contributions) is added and indexed by half the CPI percentage for the year in which the expenditure has been incurred[102]

101 Capital expenditure occurs throughout the year. Half the percentage change in CPI is used because, on average, the capital expenditure would be incurred half way through the year.

- depreciation and asset disposal are subtracted.

6.2.3 Code requirements

The Code does not explicitly specify an asset roll forward methodology. However, the principles in clauses 6.10.2 and 6.10.3 of the Code apply. As noted above, clause 6.10.3(e)(5)(iii) of the Code provides guidance on any valuations of new or revaluations of existing assets. The Code requires the Tribunal and the jurisdictional regulator to have regard to the Council of Australian Governments agreement of 19 August 1994, that deprival value is the preferred approach to valuing network assets.

Clause 6.10.2(b)(2) requires that the jurisdictional regulator seek to achieve a sustainable commercial revenue stream which provides distribution network owners with a fair and reasonable rate of return on efficient investment:

> 6.10.2 Objectives of the distribution service pricing regulatory regime to be administered by the Jurisdictional Regulators
>
> The distribution service pricing regulatory regime to be administered under Part D of the Code must seek to achieve the following outcomes: …
>
> (b) an incentive-based regulatory regime which: …
>
> (2) provides for, on a prospective basis, a sustainable commercial revenue stream which includes a fair and reasonable rate of return to Distribution Network Owners on efficient investment, given efficient operating and maintenance practices of the Distribution Network Owners;

It is reasonable to regard 'efficient investment' as including efficient capital investment between regulatory reviews. This reading suggests that DNSPs should receive a return of capital and a return on capital on efficient capital investment at the time that the investment is made. Efficient capital investment should be rolled into the regulatory asset base when it is commissioned, rather than requiring DNSPs to wait until the following regulatory review before a return on the new capital expenditure is granted.

Clause 6.10.2 appears to recognise that a balance is required between investment in the industry, and the efficient use of existing infrastructure:

> (d) an environment which fosters an efficient level of investment within the distribution sector, and upstream and downstream of the distribution sector;
>
> …
>
> (f) an environment which fosters efficient use of existing infrastructure;

6.2.4 Public consultation

Several DNSPs have expressed concern about the Tribunal's proposal to calculate an ODV for each DNSP as part of the next regulatory review. For example, EnergyAustralia states:

> EnergyAustralia does not support the Tribunal's proposal to adopt the Optimised Deprival Value by asset class at the next regulatory review. There are a number of flaws with this method if applied to the electricity industry. EnergyAustralia supports all asset

102 Capital expenditure occurs throughout the year. Half the percentage change in CPI is used because, on average, the capital expenditure would be incurred half way through the year.

> values to be valued consistently by ODRC and trusts that the Tribunal will adequately consult with the industry before the next review about this issue.

NorthPower expresses similar reservations:

> NorthPower is concerned by IPART's reference to conducting an ODV of this nature for pre 1 July 1999 assets as it reintroduces the inherent circularity problems of prices linked to asset values linked to prices.

SEDA is concerned that the proposed process for rolling in new assets may encourage DNSPs to focus on supply side options only. In order to align DNSPs' incentives with broader economic efficiency objectives, SEDA recommends:

> … that IPART state explicitly that prudent investment in DM [demand management] may be recovered and rolled forward on the same basis as prudent investment in capital expenditure or operations and maintenance expenditure

6.2.5 Tribunal's assessment

The Tribunal acknowledges that an ODV valuation depends on cost allocation methodology and costs and revenue assumptions. As stated in section 6.1, the Tribunal has determined a write up in asset values to DORC from their 1996 value rolled forward, while at the same time delivering network price reductions. This has been facilitated by the reduction in the cost of capital since the 1996 review.

The Code does not 'lock in' asset values. Rather, the Code allows regulators scope to revalue existing assets and new assets (clause 6.10.3(5)). The Tribunal proposes to split the asset base into sunk and new assets. Consistent with the intention in clause 6.10.3(e)(5) of the Code, the Tribunal requires DNSPs to keep two separate pools of assets:

- assets in existence and in service at 1 July 1999
- assets brought into existence after 1 July 1999.

In its next determination, the Tribunal may consider calculating an ODV value for each DNSP for pre-1999 assets.

Capital related costs are the major portion of costs in infrastructure industries. Any improvements in the efficiency of capital expenditure may provide cost savings in the long term. The Tribunal is mindful that it must provide the appropriate signals to regulated entities to encourage efficient investment. Such incentives are in the long term interests of customers.

Before rolling into the initial capital asset base actual capital expenditure for the period 1 July 1999 to 30 June 2003, the Tribunal will have a prudency review conducted. Prudent investment in demand management may be recovered and rolled forward on the same basis as prudent investment in capital expenditure or operations and maintenance expenditure.

6.3 Capital expenditure

In determining the AARR, the Tribunal must ensure that each DNSP has sufficient capacity (either debt or equity) to fund prudent and efficient investments in its network, having regard to future demand and service standards. In making this assessment, the Tribunal is mindful of the relationship between capital expenditure, operating expenditure, demand management and distributed generation.

6.3.1 Determination on capital expenditure

The Tribunal has incorporated the capital expenditure projections illustrated in Table 6.3 into the building block analysis.

Table 6.3 Capital expenditure projections ($1999)

	1999/00 ($m)	2000/01 ($m)	2001/02 ($m)	2002/03 ($m)	2003/04 ($m)
EnergyAustralia	143.4	147.5	149.5	168.0	178.0
Integral Energy	102.0	78.7	62.9	64.0	60.5
NorthPower	68.0	65.2	68.9	61.6	58.3
Great Southern Energy	38.6	42.6	36.1	36.0	32.5
Advance Energy	27.4	26.3	26.4	28.7	26.0
Australian Inland Energy	3.1	3.1	3.1	3.1	3.1
Total	**382.5**	**363.4**	**346.9**	**361.4**	**358.4**

Source: Worley capital expenditure review report, adjusted for inflation of 3 per cent. Excludes retail and retail IT related capital expenditure, recoverable works and capital contribution works. Revised capital expenditure estimates have been submitted by Great Southern Energy and Australian Inland Energy. These revisions have been reviewed by Worley.

The Tribunal wishes to stress that these capital expenditure forecasts are derived for the purpose of determining the base revenue requirements. This procedure is by no means a direction to the DNSPs on the amount of capital expenditure they should incur in any given year.

6.3.2 Code requirements

The Code does not contain any provisions relating specifically to capital expenditure. However, the principles in clause 6.10.2 and 6.10.3 of the Code make references to 'new assets', suggesting that it contemplates expenditure on new assets.

6.3.3 Public consultation

As noted in the s12A report, the Tribunal engaged Worley International to review the capital expenditure forecasts of the DNSPs. In the public consultation that followed that review, the DNSPs reiterated their support for the Worley process. For instance, EnergyAustralia states:

> EnergyAustralia supports the capital expenditure review process outlined by the Tribunal and undertaken by Worley's.

6.3.4 Revised forecasts for Great Southern Energy

In their report to the Tribunal as part of the section 12A review, Worley stated that Great Southern Energy did not have adequate information for a full assessment of its capital expenditure. In early 1999 Great Southern Energy engaged Worley to re-run the capital expenditure review of the network based on additional information that had become available. The revised capital expenditure forecasts (see Table 6.4) were included in the section 12A report and subject to public consultation. The Tribunal considers it relevant and appropriate that these forecasts be included in its building block analysis in this determination.

Table 6.4 Capital expenditure forecasts for Great Southern Energy

	1999/00	2000/01	2001/02	2002/03	2003/04
Original IPART/Worley capital expenditure review ($mill)	22.3	22.3	22.3	22.3	22.3
GSE/Worley revised capital expenditure review ($mill)	38.0	41.9	35.5	35.4	32.0
Change in capital expenditure projections ($ mill)	15.7	19.6	13.2	13.1	9.7
Change in capital expenditure projections (%)	71	88	59	59	43

6.3.5 Revised forecasts for Australian Inland Energy

Capital expenditure projected for Australian Inland Energy in the 12A report was based on the initial Worley review. Projected expenditure declined rapidly during the forecast period (see Table 6.5). In part, this reflected the constraints of the available data. However, Worley notes:

- Australian Inland Energy's capital expenditure is driven primarily by new connections or augmentation funded by capital contributions
- age profiles show that the network is relatively new
- the network is characterised by low load growth and low load density
- although there are no set targets, reliability is the main driver of network design.

Table 6.5 Capital expenditure forecasts for Australian Inland Energy

	1999/00	2000/01	2001/02	2002/03	2003/04
Original IPART/Worley capital expenditure review ($m)	2.8	2.4	0.4	0.4	0.4
Revised AIE/Worley capital expenditure review ($m)	5.6	4.4	3.3	5.5	2.9
Difference between capital expenditure projections ($ m)	2.8	2.0	2.9	5.1	2.5
Difference between capital expenditure projections (%)	100	83	725	1275	625

AIE subsequently commissioned Worley to undertake a further review of the capital expenditure requirements. Projected capital expenditure over the next five years more than trebles from $6.4m to $21.7m. The increase reflects:

- increased growth related expenditure
- increased expenditure to meet higher, but undefined, reliability standards
- increased capital expenditure on non-network assets.

The magnitude of the increase over a very short period raises questions about the robustness of current and previous estimates.

Expenditure relating to the planned substation at Balranald has is not included in these projections as Government is funding the project.

Unlike the projections in the 12A review, these revised projections have not been subject to disclosure and stakeholder review. In view of this, the Tribunal does not consider it appropriate to incorporate the revised projections in calculating revenues for the period of this determination. However, the Tribunal accepts that the previous projections were too low in the later years. Consequently, the Tribunal has decided to incorporate annual capital expenditure of $3.1m annually (ie the same level of expenditure as for 1997/98). Total capital expenditure included for revenue setting purposes over the five years is $15.5m.

The Tribunal wishes to stress that AIE is not obliged to spend this amount nor constrained from spending more. If AIE is confident that the captial expenditure is economic, it should be confident that it will be rolled into the asset base at the next review.

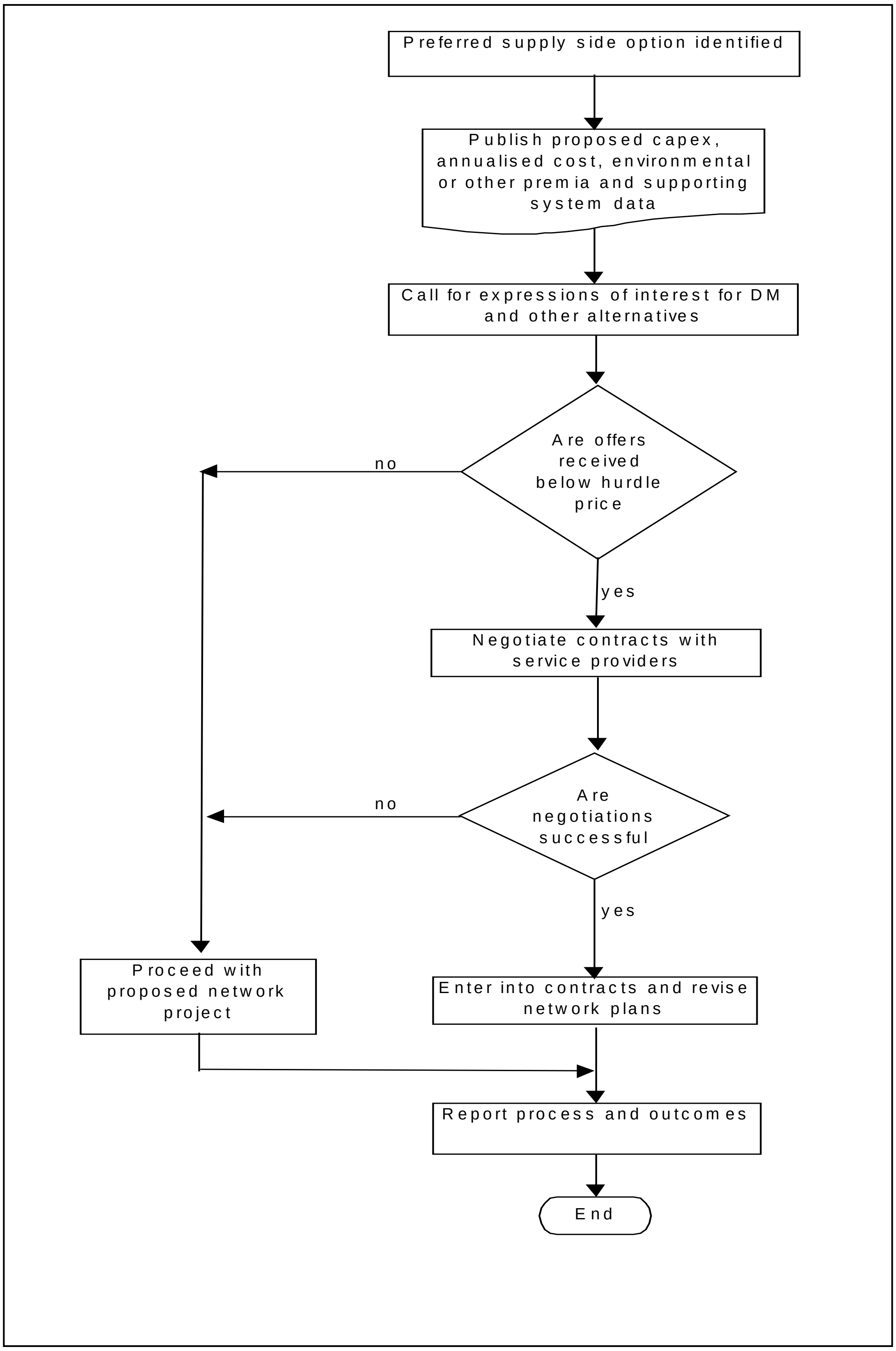
6.4 Demand management and other strategies

The Code requires that the regulatory regime must have regard to the need to ‘create an environment in which generation, energy storage, demand side options and network augmentation options are given due and reasonable consideration’.

An essential feature of the Tribunal’s assessment of the prudence of a DNSP’s capital expenditure is clear evidence that the DNSP has investigated demand management and distributed resource options as a crucial part of its network planning function. See volume 2, chapter 7 of the s12A report for a discussion on demand management strategies.

The Tribunal supports the framework illustrated in Figure 6.1 as a method for DNSPs to investigate demand management strategies and other alternatives. This framework involves public disclosure of planning criteria and capital expenditure proposals together with a call for expressions of interest in alternatives. Implementation of this approach may allow competition to disclose the best alternative and reduce the risk that the investment may be disallowed under the prudency review at the next determination.

Figure 6.1 Demand Management Investigation Flowchart



7 DEPRECIATION

Depreciation policy or 'return of capital' is crucial to the determination of the DNSPs' financial and operational capacity. In providing for the return of capital previously invested, depreciation accounts for about 30 per cent of total network costs and revenues.

7.1 Determination on depreciation

The Tribunal has determined to:

- ***allow depreciation on the initial capital base established for regulatory purposes***
- ***adopt the asset lives established in the GHD/Worley/Arthur Andersen asset valuation***
- ***adopt depreciation schedules based on straight line depreciation methodology***
- ***provide scope for alternative depreciation profiles in the future where these can assist in managing market risks and managing variations in the prices of new investment***
- ***establish net present value neutrality as an essential condition for alternative depreciation profiles.***

The depreciation amounts included in the AARR are as set out in the table below:

Table 7.1 Return of capital building block components, 1999-2000 to 2003-2004[103] ($'000)

DNSP	1999-2000	2000-2001	2001-2002	2002-2003	2003-2004
EnergyAustralia	174,399	182,496	190,906	199,810	209,332
Integral Energy	93,467	98,476	103,099	106,695	106,892
NorthPower	44,991	47,869	49,480	52,459	55,379
Great Southern Energy	29,199	31,064	32,177	33,486	33,631
Advance Energy	18,890	20,051	19,630	20,396	20,586
Australian Inland Energy	2,606	2,752	2,906	3,068	3,237

7.2 Code requirements

The Code provides no specific guidance on depreciation. However, the principles in clauses 6.10.2 and 6.10.3 are relevant. Depreciation is also a crucial component in determining the AARR specified under clause 6.10.5.

7.3 Public consultation

There has been little debate on depreciation following the release of the Tribunal's section 12A report. Overall, there has been general agreement that a straight line approach is appropriate. For example, Advance Energy notes that:

103 Nominal dollars. Includes depreciation on streetlighting assets.

> For the sake of simplicity and transparency a straight-line approach is supported.[104]

However, there are two areas in which interested parties have raised concerns. Namely, the need to consider alternate depreciation methods in specific situations, and the Tribunal's choice of asset life assumptions.

With respect to alternative methods, several points have been raised. Whilst EnergyAustralia supports a straight line depreciation approach "at the present time", in its submission to the Tribunal, EnergyAustralia notes:

> EnergyAustralia supports further investigation into an annuity approach and economic forms of depreciation.[105]

In relation to asset lives, NSW Treasury states:[106]

> NSW Treasury supports the Tribunal's recommendations on depreciation with the exception that asset lives should be consistent with that used in the ODRC valuation undertaken by the GHD, Worley and Arthur Andersen consortium.

This is consistent with the comments made by the DNSPs. For example, Advance Energy argues:[107]

> To ensure consistency between the ODRC valuation and the depreciation allowance reflected in the calculation of the revenue requirement, the asset lives established in the GHD asset valuation review should be adopted.

Furthermore Great Southern Energy Networks has raised a concern in relation to the aggregated nature of the asset lives:[108]

> Great Southern Energy is concerned at the significant gap between the capex allowance ($37.75m) and depreciation estimate of IPART ($23.942m). Whilst in the short term this gap can be covered with debt finance, this gap needs to be eliminated in the longer term. Great Southern Energy has used a more sophisticated individual asset useful life approach to estimating depreciation which flags the need for an allowance exceeding that provided by IPART.

These issues are addressed below.

7.4 Tribunal's assessment

Depreciation provides for the return of capital previously invested. As a major non-cash item, depreciation can also provide an important source of funding for new investment. For this reason, the DNSPs require certainty that depreciation will provide for the return of past investment, except where the value of an investment has been unexpectedly stranded through optimisation.

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104 Advance Energy, Submission to IPART, 30 September 1999, p 21.

105 *Submission to the Independent Pricing and Regulatory Tribunal of NSW concerning Pricing for Electricity Networks and Retail supply*, EnergyAustralia September 1999, p 27.

106 NSW Treasury, *Pricing for Networks and Retail Supply – NSW Treasury Response*, November 1999, p 17.

107 Advance Energy, Submission to IPART, 30 September 1999, p 22.

108 Great Southern Energy Networks, Submission to IPART, 30 September 1999, p 5.

Customers require assurance that the depreciation over the life of the asset will not recover more than the cost of past investments. These concerns may arise where there are changes in the calculation of asset lives.

The profile of depreciation will affect the profile of prices over time, and the allocation of stranding risks between customers and the DNSPs. However, it should not affect the expected net present value of future streams of revenues.

7.4.1 Methodology

The Tribunal has adopted straight line depreciation in this determination. It has done so in view of the submissions it has received and the reasons expressed in its section 12A report[109] which it considers relevant to this determination. However, the Tribunal acknowledges, as it did in the section 12A report, that no single depreciation profile is consistently the most appropriate. This is particularly the case in the context of technological change and its differential impact on assets.

Mindful of these limitations, the Tribunal believes the regulatory regime should provide flexibility for alternative depreciation schedules where these better reflect economic risks and market values. On this basis, and consistent with the comments raised in submissions, the Tribunal will continue to investigate alternative approaches, and may consider adjusting depreciation profiles in its next determination.

7.4.2 Asset lives

In the section 12A report, the Tribunal applied a weighted average remaining asset life for each DNSP to the (depreciated) initial capital base rolled forward over time. This included system and non-system assets. Weighted average lives were calculated on the basis of the asset lives used in the GHD/Arthur Andersen/Worley International consortium asset valuation studies, weighted by the replacement cost of assets.[110]

The Tribunal adopted these asset lives to ensure consistency between the determination of the regulatory asset base, ie, the ODRC valuation, and the determination of regulatory depreciation. Furthermore, these asset lives had been reaffirmed by the PB Power review. [111] PB Power had reported that the asset lives used by the consortium were reasonable and even conservative in some cases. [112]

> Provided that adequate controls are instituted to ensure that the condition of equipment and quality of maintenance are regularly monitored, we believe that in general a substantial proportion of equipment will survive longer than the asset lives adopted by the Consortium.[113]

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109 See Chapter 8 of the Tribunal's section 12A report, p91-103.

110 The section 12A report states that the asset lives contained in Worley's capital expenditure review had been adopted by the Tribunal. However, the report should have noted that the asset lives used were those by the GHD/Arthur Andersen/Worley International consortium.

111 NSW Treasury engaged a consortium comprised of Arthur Andersen, GHD and Worley International to carry out a DORC valuation of the network assets of the DNSPs. The Tribunal engaged PB Power to review the valuations conducted by the consortium.

112 PB Power, *NSW Distribution Companies Asset Valuation Review*, April 1999, p 5.

113 PB Power, *NSW Distribution Companies Asset Valuation Review*, April 1999, p 20.

Since the release of the section 12A report, the Tribunal has obtained further information from the GHD/Arthur Andersen/Worley International consortium and has refined the asset lives adopted for each DNSP in order to more accurately reflect where each DNSP is in its asset life cycle.

For this determination, the Tribunal has calculated depreciation rates for system assets on the basis of the effective lives of asset classes assumed in the GHD/Arthur Andersen/Worley International studies, and applied these to the optimised replacement cost of those assets. Non-system assets have been depreciated on the basis of information contained in each DNSP's regulatory accounts at a weighted-average rate based on each DNSPs' non-system assets.[114]

Capital contributions are excluded from the asset base for the purposes of return of capital and return on capital calculations.[115] Depreciation of capital additions and disposals to the asset base has been calculated on the basis of the depreciation rate for system assets. Implicit in this treatment is the assumption that capital expenditure, capital contributions and asset disposals comprise existing[116] system assets. Further information on the asset composition of capital works, capital contributions and asset disposals will be obtained by the Tribunal for use in subsequent determinations.

This approach addresses the concerns raised by interested parties.

114 as at 30 June 1998.

115 The value of capital contributions identified by GHD/Worley/Arthur Andersen has been assumed in this analysis. For a discussion of why capital contributions have been excluded for the purposes of calculating return of and return on capital, see chapter 11 of volume 2 of the Tribunal's section 12A report.

116 ie, as at 30 June 1998.

8 EFFICIENCY TARGETS FOR OPERATING AND MAINTENANCE EXPENDITURE

Operating and maintenance expenditure constitutes part of the building block used to set base revenues. Together with return on capital and return of capital, operating and maintenance expenditure constitutes the total base revenue.

8.1 Determination on operating and maintenance expenditure

The Tribunal has determined the following efficiency gains in operating and maintenance expenditure for the NSW DNSPs over the regulatory control period (using 1997/98 as the base year and rolled forward): [117]

Table 8.1 Cumulative real reductions in operating and maintenance figures

	Cumulative real reduction over 5 years before allowance for growth (%)
EnergyAustralia	10
Integral Energy	15
NorthPower	15
Great Southern Energy	15
Advance Energy	15
Australian Inland Energy	5

These efficiency targets are based on 1997/98 operating and maintenance expenditures.

After applying inflation and the cumulative real reduction outlined in Table 8.1, the Tribunal will allow operating and maintenance expenditure to grow by half the percentage growth in MWh sales. The resulting operating and maintenance expenditures (excluding TUOS), incorporated in the building blocks, are outlined in Table 8.2.

Table 8.2 Operating and maintenance building block components, 1999-2000 to 2003-2004[118] ($'000)

	1999-2000	2000-2001	2001-2002	2002-2003	2003-2004
EnergyAustralia	205,562	209,673	213,866	218,144	222,507
Integral Energy	157,174	159,924	162,723	165,570	168,468
NorthPower	70,687	71,747	72,824	73,916	75,025
Great Southern Energy	47,648	48,125	48,606	49,092	49,583
Advance Energy	43,826	44,374	44,929	45,491	46,059
Australian Inland Energy	6,861	7,033	7,208	7,389	7,573

117 The operating and maintenance projections are based on 1997/98 figures, plus streetlighting operating expenses. These figures were rolled forward to 1998/99 by inflation minus the annual efficiency target plus half the growth estimate. The cumulative real reductions will apply to this amended 1998/99 operating and maintenance figure.

118 Nominal dollars. Includes streetlighting operating expenses.

8.2 Code requirements

The objectives of the Code include adopting an incentive-based regulatory regime which:

- provides an equitable allocation of efficiency gains (clause 6.10.2(b)(1))
- provides a sustainable commercial revenue stream which includes a fair and reasonable return on efficient investment given efficient operating and maintenance practices (clause 6.10.2(b)(2))
- fosters efficient operating and maintenance practices (clause 6.10.2(e))
- fosters efficient use of existing infrastructure (clause 6.10.2(f)).

The Code requires the regulatory regime for DNSP's to be administered according to a number of *principles*, including providing distribution network owners with:

- incentives and reasonable opportunities to increase efficiency (clause 6.10.3 (e) (1))
- a fair and reasonable risk-adjusted cashflow rate of return on efficient investment, given efficient operating and maintenance practices on the part of distribution network owners (clause 6.10.3(e)(5)).

The Tribunal must take into account each DNSP's requirements during the regulatory control period, having regard to a number of factors, including:

> Clause 6.10.5(d)(4) – Distribution network service pricing – potential for efficiency gains
> … the Jurisdictional Regulator's reasonable judgment of the potential for efficiency gains to be realised by the Network Owner in expected operating, maintenance and capital costs, taking into account the expected demand growth and service standards …

8.3 Public consultation

This section briefly summarises the issues raised in submissions or at public hearings.

8.3.1 The level of efficiency gains

Several DNSPs raise concerns about the level of efficiency gains the Tribunal has recommended in its section 12A review. For example, the then Chief Executive Officer of Integral Energy, commented:

> … if we invested more in the past in underground networks we would end up with a much better revenue capital and we would have in fact lower operating costs. So we were certainly annoyed, miffed, disappointed, when EnergyAustralia was given a 10 per cent operating cost reduction, but we were in fact given 15 per cent.
>
> We would assert, again, that with a more modest operating cost reduction, and we argued for a 9 per cent operating cost reduction from 1998-99, we will still continue to have a significant reduction in the real network prices paid by our customers as long as the Tribunal continues to use the current revenue formula and the basis by which it is so developed. [119]

[119] Transcript of public hearings, 14 October 1999.

In its submission, NSW Treasury states:

> NSW Treasury does not object to IPART's [efficiency target] proposals.[120]

The Tribunal has maintained its position on efficiency targets, given the lack of substantial evidence to justify the DNSPs claims that the efficiency targets are too high.

8.3.2 The trade off between capital expenditure, operating expenditure and service reliability

The review process for this determination has largely examined operating and capital expenditure separately. However, the London Economics data envelopment analysis (DEA) study (which assessed the overall efficiency of the DNSPs), jointly assessed operating and capital costs.

The DNSPs called for capital and operating expenditures to be considered together. Indicative of other DNSPs' comments, EnergyAustralia states:

> During the course of the present review, the Tribunal separately assessed capital and operating expenditure. Consequently, there has been insufficient recognition of the continual tradeoff that is made between capital expenditure, operating expenditure and service levels.[121]

The Tribunal recognises there is a trade off between capital expenditure and operating expenditure. This can impact on service reliability. The Tribunal also recognises the trade off between demand management/energy efficiency and capital expenditure. In its next review, the Tribunal will consider the merits of jointly assessing operating and capital expenditure and demand management.

Comments relating to service reliability and capital expenditure are discussed in chapters 3 and 6, respectively, of this determination.

8.3.3 Productivity indicators

In the section 12A review, stakeholders vigorously debated the productivity measures the Tribunal considered. Whilst some stakeholders support the London Economics and/or UMS studies, others argue that the methodologies adopted are flawed or irrelevant. In public consultation following the section 12A report, stakeholders have continued to raise concerns relating to these studies.

After further consideration and review of the submissions made to it, the Tribunal is satisfied of its view in relation to the London Economics or UMS studies. As stated in the section 12A report, the Tribunal is mindful of the limitations of each of those benchmarking studies when assessing the scope for productivity gains. Further, the Tribunal also considered a range of indicators, without relying on any one study.

Although the DNSPs consider that there are flaws in the current benchmarking studies, some have indicated a preference for an unlinked form of benchmarking. An unlinked approach would involve the Tribunal setting efficiency targets based on the DNSP' relative

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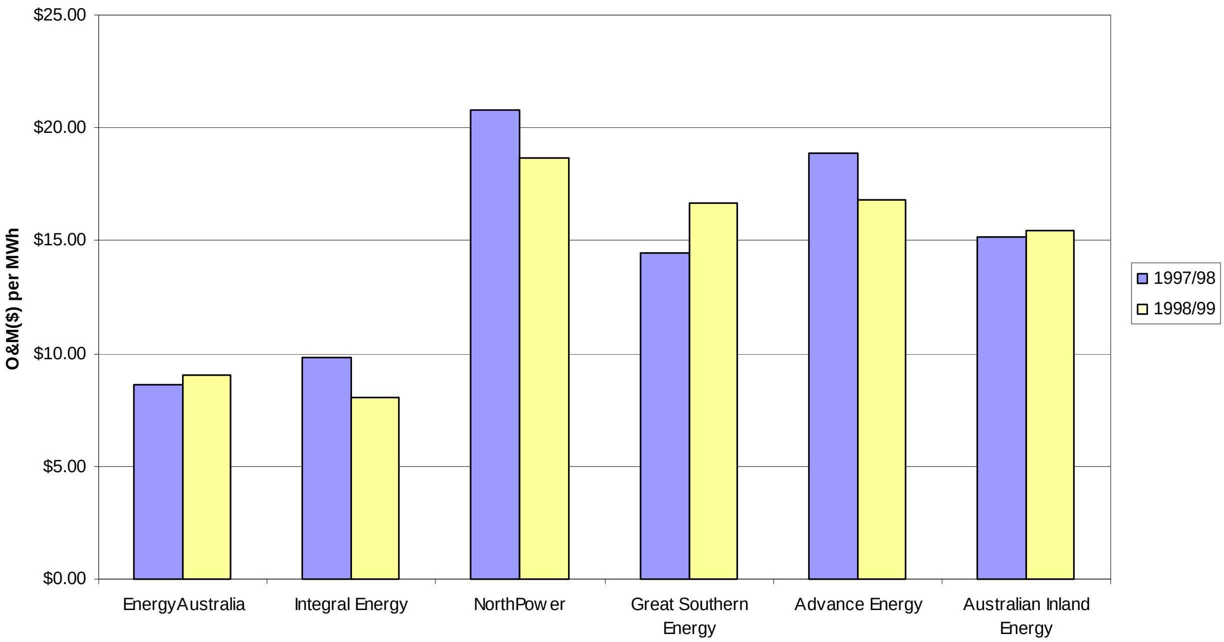
120 NSW Treasury submission, November 1999, p 30.

121 Submission from EnergyAustralia, 30 September 1999, p 40.

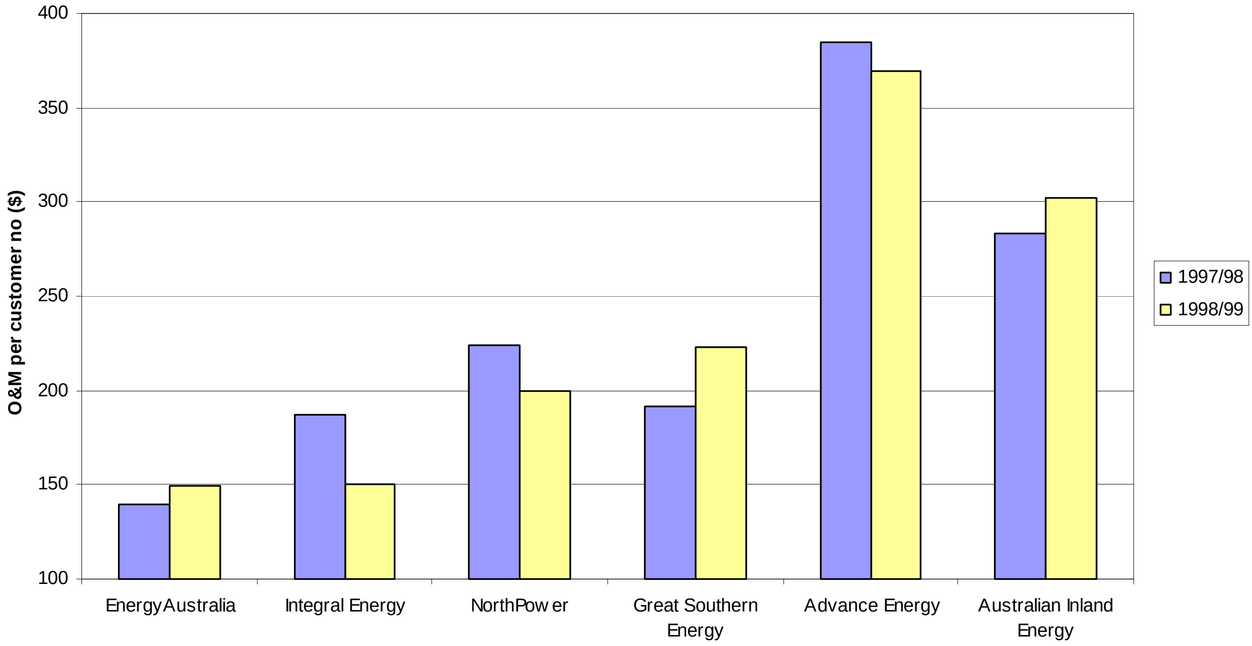
performances, without examining the underlying cost structures. The Tribunal recognises that before it can consider adopting such a regulatory framework, it must have a robust benchmarking framework. The Tribunal is willing to work with stakeholders, including other regulators, to develop appropriate performance measures.

Figure 8.1 Operating and maintenance expenditure per MWh distributed,



1997/98 – 1998/99

Figure 8.2 Operating and maintenance expenditure per customer, 1997/98 – 1998/99



Advance Energy raised concerns regarding the partial productivity indicators the s12A report. These partial productivity indicators are based on franchise customer load. As Advance Energy has a relatively high proportion of contestable customer load, it is disadvantaged relative to the other DNSPs. The Tribunal again considered and re-analysed the partial indicators, based on total load, and incorporated information from the 1998/99 Regulatory Accounts (see figure 8.1 and figure 8.2). The Tribunal acknowledges the improved relative performance of Advance Energy, but maintains that a 15 per cent reduction over five years is appropriate.

These partial productivity measures are based on data from the DNSPs' regulatory accounts.[122] This data includes any Y2K and contestability operating costs already incurred by the DNSPs.

According to the regulatory accounts, some DNSPs substantially increased their operating and maintenance expenditure in 1998/99, while others substantially decreased their expenditure. In the timeframe available, the Tribunal has not been able to fully analyse these movements. They may partly result from changes to the cost allocation policies of the DNSPs.

8.4 Tribunal's assessment

In making its determination relating to efficient operating and maintenance costs, the Tribunal has had regard to the analysis presented in the s12A report, ensuing public consultation (including public hearings and submissions), and further analysis of partial productivity indicators.

Throughout the public consultation process, there has been a lack of substantial evidence to justify the DNSPs' claims that the efficiency targets set out in the s12A report are too high. The Tribunal has again considered those efficiency targets to be appropriate. It has, therefore, applied them in this determination.

The Tribunal has determined the following efficiency gains in operating and maintenance expenditure for the NSW DNSPs over the regulatory period (using 1997/98 as the base year, rolled forward)[123]

122 Excluding avoided TUOS reported in Integral Energy's 1997/98 regulatory accounts.

123 The operating and maintenance projections are based on 1997/98 figures, plus streetlighting operating expenses. These figures were rolled forward to 1998/99 by inflation minus the annual efficiency target plus half the growth estimate. The cumulative real reductions will apply to this amended 1998/99 operating and maintenance figure.

Table 8.3 Cumulative real reductions in operating and maintenance figures

	Cumulative real reduction over 5 years before allowance for growth (%)
EnergyAustralia	10
Integral Energy	15
NorthPower	15
Great Southern Energy	15
Advance Energy	15
Australian Inland Energy	5

These efficiency targets are based on 1997/98 operating and maintenance expenditures because the benchmarking studies and partial productivity indicators were based on those figures. Therefore, the efficiency targets established in the section 12A report were determined on 1997/98 figures.

After applying the cumulative real reduction outlined in Table 8.1, operating and maintenance expenditure will grow by half the percentage growth in MWh sales.

9 TOTAL REVENUE REQUIREMENTS

The previous chapters have examined each of the cost-based 'building blocks' for the DNSPs. This chapter outlines the construction of the annual revenue requirements for the DNSPs from these building blocks.

Two key 'building blocks' are the return of and return on capital. Each of these is crucially dependent on the initial capital base, yet as indicated there is no one method of asset valuation which is always appropriate. The regulator faces a range of possible asset valuations with different strength and weaknesses. In light of this the Tribunal has tempered the use of the strict 'building block' approach through a consideration of a range of indicators. The indicators used, and the manner of their consideration, are outlined in this chapter.

9.1 Determination on total revenue requirements

The Tribunal has determined the following total revenue requirements for the NSW DNSPs for the period from 1 February 2000 to 30 June 2004:

Table 9.1 Total Revenue Requirements ($ million)

	1999/2000	2000/2001	2001/2002	2002/2003	2003/2004
EnergyAustralia[124]					
Building Block	674	692	710	730	752
Smoothed	691	706	721	736	752
Integral Energy					
Building Block	388	398	407	415	419
Smoothed	395	401	407	413	419
NorthPower					
Building Block	186	194	200	208	215
Smoothed	170	180	191	203	215
Great Southern Energy					
Building Block	117	122	126	129	132
Smoothed	113	117	122	127	132
Advance Energy					
Building Block	87	90	92	95	97
Smoothed	74	78	82	87	92
Australian Inland Energy					
Building Block	14	14	15	15	16
Smoothed	11	12	12	13	13
Industry Total					
Building Block	1,466	1,510	1,550	1,592	1,631
Smoothed	1,454	1,494	1,535	1,579	1,623

124 Includes costs and revenues for transmission services as determined by the ACCC.

The annual aggregate revenue requirement for the fiscal year 1999/2000 is to be determined by pro-rating and adding:

- the revenue cap as determined under IPART Act Determination 5.3 of 1997 (as continued to 31 January 2000 by regulation) for the period from 1 July 1999 to 31 January 2000
- the annual aggregate revenue requirement as determined in this Determination, pro-rated for the period from 1 February 2000 to 30 June 2000.

This can be illustrated as:

$$\boxed{\begin{array}{c}\text{1999/2000 Revenue Cap}\\ \text{per determination 5.3, 1997}\end{array} \times \frac{215}{366}} + \boxed{\begin{array}{c}\text{1999/2000 Revenue Cap}\\ \text{per this determination}\end{array} \times \frac{151}{366}}$$

9.2 Code requirements

The Tribunal must determine the AARR in accordance with part D of chapter 6 of the Code. Part D does not expressly refer to the AARR. However, it does require the Tribunal to:

- adopt a form of economic regulation that is of the prospective CPI minus X form or other incentive-based variant of the CPI minus X form, consistent with the objectives and principles outlined in clauses 6.10.2 and 6.10.3
- specify a form of economic regulation to be applied to the DNSP in the form of a revenue cap, a weighted average price cap or a combination
- take into account each DNSP's revenue requirement during the regulatory control period having regard to the factors in clause 6.10.5(d)
- have regard to objectives in clause 6.10.2 and the principles in clause 6.10.3 of the Code.

9.3 Public consultation

The DNSPs propose a price path based on accrual building block approach.

> Revenues for network monopolies should be based on a building block approach which provides for:
> - Efficient operating costs.
> - Depreciation expenses.
> - An adequate return for funds invested.

There were no submissions on the use of the 'building block' approach from other interested parties.

9.4 Summary of approach

9.4.1 The 'building block' approach

In general, the 'building block' approach builds up the base revenue from three major components:

- return on capital
- return of capital
- efficient operating costs.

Under this approach, the jurisdictional regulator would make a separate decision on each 'building block'. The Tribunal has long been concerned about such an approach, in that it can lead to a procedure-bound methodology in which key decisions on major components of the base revenue requirement are made in isolation of other key components. The Tribunal prefers an approach which has regard to the interaction of key components, and also the impact on the firm's prices and profitability. Hence, the building block analysis is supplemented by a consideration of the overall implication, and outcomes of the resulting price paths.

The components of return on capital, namely the initial capital base, the treatment of capital expenditure, depreciation and the rate of return, are discussed in chapters 6, 7 and 5 respectively.

9.4.2 Financial indicator analysis

The Code permits a regulator to assess financial performance in order to establish the initial capital base and determine an appropriate rate of return.

> 6.10.5 Form and mechanism of economic regulation
> In respect of distribution services subject to economic regulation pursuant to clause 6.10.4(a): …
>
> (d) In setting a separate regulatory cap to be applied to each Network Owner in accordance with clause 6.10.5(b), the Jurisdictional Regulator must take into account each Distribution Network Owner's revenue requirements during the regulatory control period, having regard for: …
>
> (11) any other relevant financial indicators.

The Tribunal favours an approach to initial asset valuation and the ongoing determination of revenue requirement that has regard to a broader range of financial indicators. The Tribunal rejects strict reliance on 'return on rate base' as the driving determinant of asset valuation and the revenue requirement of the network.

The Tribunal recognises the circularity inherent in determining revenues dependent on the value of an asset base whose value is in turn reliant on the revenue stream. There is a wide range of price and asset value combinations consistent with the efficient, commercial operation of the utilities and the ongoing provision of services. The difficulty facing the regulator is to determine an initial capital base and price path that provides an appropriate balance of stakeholder interests.

The use of indicators based on publicly available or easily accessible information reduces the problems of information asymmetry prevalent in regulatory regimes around the world. The Tribunal has taken the view that reliance on any single indicator may distort the regulatory framework by encouraging inappropriate behaviour. A broader focus reduces the incentive for an infrastructure owner to enter into gaming behaviour in order to influence one particular revenue driver.

The financial indicators applied in the Tribunal's determination have been chosen on the basis of relevance, availability of information, and common usage in the financial community. Attention was given to cash based measures (particularly where the objective is to determine the appropriate opening asset valuation) and, where possible, indicators in wide use in the financial markets.

In order to develop a robust conclusion, the regulator must be able to cross-check revenue scenarios against a range of financial indicators.

The Tribunal considers that a cross-check approach is appropriate both in determining the opening regulatory value of the existing assets, and as a means of assessing the reasonableness of the network operator's revenue requirement on an ongoing basis. The Tribunal does not consider that it will necessarily be appropriate to set the opening regulatory asset valuation and revenue requirement at a level that maintains the historical level of the performance indicators. This is particularly true where the level of those indicators reflects excess profits or cash flows within the network system. This consideration must be balanced with the regulator's responsibility not to jeopardise the financial integrity of the infrastructure owner.

9.4.3 Integration of analysis

The Tribunal's financial models are structured in a 'building block' design, with inputs on such factors as the value of the regulatory asset base, forecast capital expenditure, the rate of return, depreciation and operating costs. Given these inputs, the models produce a forecast revenue path and report the results against a range of financial indicators.

The DNSPs' performance against this range of indicators is then used to guide the Tribunal's assessment of the sustainable revenue stream. This involves an iterative process, testing the sensitivity of the financial indicators to different forecast revenue or price paths and initial capital bases. It should be noted that, in determining the reasonableness of that revenue stream, the Tribunal will be required to make assumptions about the future revenue path and load growth beyond the current review period. In proposing the base revenue the Tribunal must also consider the relevant Code requirements.

The selection of the appropriate price path takes into account a reasonable sharing of costs and efficiency gains between the network owner and customers.

This revenue path will then be translated into a maximum allowable revenue path, which will reflect the Tribunal's decision on glide paths. Subsequent to this report, the DNSPs will then allocate this revenue requirement to different services based on the cost drivers of the system and pricing principles developed by the Tribunal. The DNSP will then design tariffs to respond to the cost drivers for the service. A final check will then completed to ensure that the tariffs will generate the revenue requirement at the forecast customer and volume levels. These tariffs, and a guide to explain the procedures and allocations used in their development, will be published jointly by the DNSP and the jurisdictional regulator.

9.5 Tribunal's assessment

9.5.1 Network financial projections and modelling

In conducting its analysis, the Tribunal assessed the proposals of the DNSPs and other parties, and its own analysis, on such matters as the cost of capital, necessary capital expenditure levels, the scope for efficiency gains in operating costs, and the amount of load growth expected to be experienced by the network. These forecasts are summarised in Table 9.2.

Table 9.2 Summary of modelling inputs

Distributor	WACC (pre tax real)	Capital expenditure	Operating cost reduction 2000-2004	Load Growth
EnergyAustralia	7.5%	per Worley	10%	2.0%
Integral Energy	7.5%	per Worley	15%	3.5%
NorthPower	7.5%	per Worley	15%	3.0%
Great Southern Energy	7.5%	per Worley	15%	2.0%
Advance Energy	7.5%	per Worley	15%	2.5%
Australian Inland Energy	7.5%	trend line[125]	5%	1.0%

9.5.2 Revenue glide path

In order to reduce volatility in annual revenues, reduce the potential for price shocks to customers and provide stronger incentives for the future, the Tribunal has applied a mechanism to smooth the DNSPs' revenue paths. In the absence of smoothing, the Tribunal's proposals could result in a significant reduction in average prices for the metropolitan DNSPs in the first year followed by increases in subsequent years. This would result in greater volatility in earnings. The Tribunal has decided to smooth the revenue path over the entire period so that price changes can be phased in.

The revenue path modelled is 'smoothed' to reach the revenue target at the end point in a straight line from 1998/99.

The Tribunal's analysis indicates that under this scenario, DNSPs will benefit from a slight improvement in cashflow and financial performance, as compared with the 'unsmoothed' scenario.

9.5.3 Scenario testing

In its section 12A report to the Premier, the Tribunal tested the outcomes of a number of capital base and rate of return combinations, assessing the reasonableness of the range of financial indicators of each scenario. This scenario analysis was used to assist the Tribunal in reaching its decisions in this Determination. This process, and the results of the scenario analysis, is described in some detail in Volume 1, chapter 11 of the section 12A report.

9.5.4 Financial indicator analysis

The Tribunal recognises that comparisons of forecast financial results are difficult. This is not to suggest that such comparisons should not be performed. Rather, it means that the results of such comparisons must be interpreted with caution.

125 See section 6.3.5.

Choice of financial indicators

As discussed above, the Tribunal has used a series of financial indicators. The definition of the ratios used is shown in Attachment 6 of the s12A report to the Premier. The Tribunal has also used a set of indicators used by debt rating agency Standard & Poor's and NSW Treasury. These ratios derived under this Determination are presented in Table 9.4.

Rating agencies commonly assess an organisation's financial capacity and ability to service debt using ratios such as:

- funds flow interest cover - to assess a utility's ability to service debt
- net cashflow/capital expenditure - to assess internal financing capacity
- net debt/funds from operation - to assess ability to repay debt.

Although the ratios are useful, the Tribunal recognises that it would be dangerous to use them without some judgement of the appropriateness of financial outcomes.

S&P has recently published the financial ratio medians for energy utilities including overseas utilities. It appears that the median numbers for the cash flow ratios are broadly within the ranges for a utility with average and above average business risk profile. The Tribunal considers that the rating ratios in Table 9.4 remain a useful guide in its financial indicators analysis and that a business profile between excellent and above average is appropriate.

9.5.5 Summary

The Tribunal has considered a number of revenue path scenarios. It has assessed the results for each of the DNSPs and for industry as a whole. The end points for the range of asset values, being the rolled-forward 1996 value and the latest DORC estimates were modelled for each of the DNSPs. Much of the analysis involved running alternative values for each of the DNSPs within this range. Each of the scenarios was also examined in terms of the overall results for the DNSPs. This aggregate analysis is made more relevant by the fact that the DNSPs share a common owner - the NSW Government. Each scenario was also assessed in terms of complying with this reviews terms of reference.

9.6 Conclusions

Following consideration of the submissions from stakeholders and interested parties, the requirements of the terms of reference and the Premier's letter of 18 June 1999, the Tribunal concludes that an initial capital base in aggregate of $7.2bn as at 30 June 1998, revenue requirement in 1999/2000 of $1,453m, real reductions in distribution prices on average of 16.0 per cent per cent, in all circumstances balances the interest of owners and customers.

The Tribunal proposes the annual aggregate revenue requirements of the DNSPs as shown in Table 9.3:

Table 9.3 DNSPs nominal annual revenue requirements and projected distribution prices ($mill)

Industry Total	1999/00	2000/01	2001/02	2002/03	2003/04
Regulatory asset value[1]	7,433	7,651	7,850	8,050	8,258
Capital expenditure	394	386	379	407	416
Depreciation	365	383	398	416	429
Return on capital base (%)	7.3	7.3	7.3	7.3	7.4
Operating costs	532	541	550	560	569
Total revenue (unsmoothed)	1,453	1,497	1,540	1,584	1,626
Smoothed allowed revenue	1,453	1,493	1,535	1,578	1,622
Average distribution price (c/kWh)	3.02	3.02	3.03	3.04	3.05
Cumulative real reduction in distribution prices	-6.4%	-8.9%	-11.4%	-13.7%	-16.0%

1) Representing average of opening and closing regulatory asset base and comprising system and non-system assets.

The initial capital base at 30 June 1998 is made up of system assets of $6.7bn and non system assets of $0.5bn. This yields an aggregate initial capital base of $7.2bn for the NSW distribution networks as at 30 June 1998. The adoption of the $7.2bn asset valuation as the initial capital base is expected to deliver a revenue stream sufficient for DNSPs to finance their network functions, maintain an adequate service, and earn reasonable returns. Table 9.4 provides the forecast financial indicators.

Attachments 2.1 through 2.6 provide financial profiles of each DNSP. Included in these profiles are the building block components of the revenue requirements for each of the five years 1999/00 to 2003/4 and financial indicators. A brief summary for each DNSP is as follows.

9.6.1 Financial profiles

The financial indicators in attachments 2.1 through 2.6 are based on actual capital structure, ie relatively low gearing. The level of gearing is a matter for Government. However the Tribunal has also calculated the financial indicators based on a commercial gearing level. The results indicate that the DNSPs are forecast to have relatively strong financial outcomes.

Energy Australia

The revenue requirements proposed for EnergyAustralia cover both transmission (regulated by the ACCC) and distribution. When the transmission revenue requirements are finalised by the ACCC the revenue requirements for distribution will be the difference between the total proposed and the ACCC determined amount.

The five year financial projections to 2003/04 (covering both transmission and distribution) indicate that EnergyAustralia has a very strong profile, with funds flow interest cover of 8.1 times in fiscal year 1999/2000, and forecast to remain above that level in the following four years. The gearing level (total debt to total capital) is at 31 per cent in 1999/2000, declining to 23 per cent at the close of the regulatory period. Net debt payback is forecast to remain around 1.8 to 2.8 years over the next five years. The internal financing ratio at well over 100 per cent indicates that EnergyAustralia is capable of financing its capital expenditure without any apparent difficulty. Together, these indicate that the regulated revenue path provides sufficient cashflow for Energy Australia to fund its operations, repay debt and meet capital expenditure forecasts.

The operating margin (EBITD/revenue) remains at above 60 per cent with EBIT averaging 37 per cent over the period. Anticipated annual growth is 2 per cent. Operating cost per kWh is projected to reduce in real terms by 10 per cent over the 5 year period. This is before an allowance for growth.

The strong cashflow from operations enables the distributor to provide a constant tax and dividend stream to its owner, the Government, over the next five years. This is forecast to average $230m per annum over the next 5 years. The proposed revenue requirements result in average distribution price reductions of 16 per cent in real terms for EnergyAustralia's customers over the five year period.

Integral Energy

The proposed distribution network revenue for Integral Energy is around $407m for the next five years with operating margin (EBITD/revenue) projected to remain at 51 per cent. Integral Energy is provided with strong operating cashflow which will enable the DNSP to fund its capex, repay debt and interest and provide tax and dividend to its Government owner. As a result of its strong financial position, gearing is forecast to decrease from 38 per cent in 1999/00 to 27 per cent in 2003/04.

As indicated by its robust fund flow interest cover, net debt payback and internal financing ratio, Integral Energy is projected to have a strong financial profile over the next five years. This is achieved at the same time as average distribution real price reductions of 27 per cent are forecast.

NorthPower

The proposed network revenue for NorthPower is forecast to increase by approximately 16 per cent in real terms over the next 5 years. However, network prices on average are forecast to remain constant in real terms over the same period. Profitability is forecast to improve over this period with the operating margin increasing from 50 per cent to 56 per cent and EBIT from 28 per cent to 34 per cent. Tax and dividend payments to its owner, the Government is forecast to be between $50m to $74m. These represent 85 per cent of the profit before tax. Rate of return on assets (real pre tax) improves from 5.7 per cent in 1999/00 to 7.5 per cent in 2003/04.

NorthPower has forecast a relatively large capital expenditure program. The funding of this capital expenditure impacts measures such as fund flow interest cover, net debt payback and the internal financing ratio. By the end of the 5 years, NorthPower's lending ratios are forecast to be heading towards the AA credit rating. NorthPower's gearing remains at around 20 per cent over the period.

Great Southern Energy

Great Southern Energy's proposed revenue requirement is forecast to put them in a very strong financial position over the 5 years. This strong financial position facilitates forecast distribution network charges reducing over the period by 6 per cent in real terms. Fund flows from operations grow from $65m in 1999/00 to $80m in 2003/04. Fund flow interest cover stays well above the AAA benchmark and so is the net debt payback ratio. Although the debt level is anticipated to increase, the gearing remains between 17 per cent to 19 per cent over the period.

Its high operating margin, between 49 and 54 per cent provides GSE with strong cashflow. The profit margin over the period enables GSE to maintain a market return and the level of tax and dividend payments to its owner.

Advance Energy

The proposed network revenue for Advance Energy is forecast to increase by approximately 13 per cent in real terms over the next 5 years. However, network prices on average are forecast to remain constant in real terms over the same period with forecast load growth of 2.5 per cent and operating cost per kWh is projected to reduce in real terms by 19 per cent over the 5 year period.

Operating margin and profit margin compare favourably with industry average. The proposed revenues enables Advance Energy to service its debts, fund the projected capital expenditures and maintain a stable tax and dividend stream to its owner.

Advance Energy's financial profile compares favourably with other DNSPs as indicated by the credit rating ratios of fund flow interest cover, net debt payback and internal financing ratio. Although these ratios are anticipated to weaken over the period these still remain at above the A to AAA benchmark. Debt level is expected to increase toward the close of the period but remains low. Gearing increases from 19 per cent in 1999/00 to 23 per cent in 2003/04.

Australian Inland Energy

Underpinning Australian Inland Energy's forecast financial position over the next five years is stable cashflow from operations. Operating margin and profitability is projected to be relatively strong with EBITD remaining at around $7m from 1999/00 to 2003/04. Given the negligible debt level and modest capital expenditure program, the credit rating ratios remain robust at above AAA level. Annual tax and dividend payments to its shareholder stay at around $5m to $5.8m. Average distribution network prices are forecast to remain constant in real terms.

Table 9.4 Credit rating ratios

Rating	AAA	AA	A	BBB	BB
Funds flow interest cover (times)					
Utility business risk profile					
Excellent	4.00	3.25	2.75	1.50	<1.0
Above average	4.25	3.50	3.00	2.0	1.5
Average	5.00	4.00	3.25	2.5	2.0
Below average	X	4.25	3.50	3.0	2.5
Vulnerable	X	X	4.00	3.5	3.0
Net debt/Fund flow from operation (times)					
Utility business risk profile					
Excellent	4.0	6.0	9.0	12	20
Above average	3.5	5.0	7.0	9.0	>15
Average	3.0	4.0	5.5	7.0	>10
Below average	X	4.0	5.5	7.0	>9
Vulnerable	X	X	4.0	6.0	>8
Internal financing ratio (per cent)					
Utility business risk profile					
Excellent	100	70	60	40	>35
Above average	100	80	70	50	>45
Average	100	100	90	55	<55
Below average	X	100	100	75	<60
Vulnerable	X	X	100+	90	<70

Source: Capital Structure Policy for NSW Government Trading Enterprises, Appendix 1, August 1994.

10 CHARGES FOR MISCELLANEOUS AND MONOPOLY SERVICES

10.1 Determination

10.1.1 Determination on charges for miscellaneous services

The Tribunal has determined an exhaustive list of miscellaneous charges. This establishes the maximum amount that may be charged for the provision of the relevant miscellaneous service. No new charges may be levied by a DNSP during the regulatory control period. The list of approved maximum charges for miscellaneous services is shown in Table 10.1.

The circumstances under which these charges may be levied are listed in 'Charges for Miscellaneous Services Rule 99/3', issued by the Tribunal. The DNSPs must also ensure that they conduct an adequate customer information program as outlined in 'Charges for Miscellaneous Services Rule 99/3'.

Revenue from charges levied for the provision of miscellaneous services is included in the AARR of each DNSP.

10.1.2 Determination on charges for monopoly services

The Tribunal has determined an exhaustive list of charges for monopoly services associated with contestable work. This establishes the prescribed amount to be charged for the provision of the relevant monopoly service. No new charges may be levied by a DNSP during the regulatory control period. The list of prescribed charges for monopoly services is shown in Table 10.2.

The circumstances under which these charges are to be levied are listed in 'Charges for Monopoly Services Rule 99/4', issued by the Tribunal.

Revenue from charges levied for the provision of monopoly services is to be included in the AARR of each DNSP.

10.2 Public consultation

10.2.1 Charges for miscellaneous services

To assist this review, the Electricity Industry Consultation Group (EICG) established a Miscellaneous Charges Working Group (MCWG) to investigate, discuss, and make recommendations on aspects of miscellaneous charges which members believed to be pertinent to their respective constituents. The MCWG comprises representatives of: EnergyAustralia, Integral Energy, Advance Energy, the Energy Industry Ombudsman NSW, the NSW Department of Community Services, the NSW Council of Social Services (NCOSS), and the Public Interest Advocacy Centre (PIAC).

The MCWG reported to the EICG in May 1999. Following the Tribunal's s12A report, the MCWG was reconvened and issued its final report on 30 September 1999. The report was distributed to the EICG, made available to interested parties, and placed on the Tribunal's website.

Submissions from the DNSPs tend to concentrate on two proposals discussed in the section 12A Report: the exhaustive list of miscellaneous charges, and the inclusion of miscellaneous charge revenues in the DNSP revenue cap.[126] Some submissions recommended refinements to the regime proposed in the s12A report.[127]

10.2.2 Charges for monopoly services associated with contestable works

Established by the EICG, the Contestable Works and Monopoly Fees Working Group (CW&MFWG) comprises representatives of the DNSPs, Department of Energy, Energy Industry Ombudsman, NSW (EION), the National Electrical Contractors Association, UDIA, developers and design and construction service providers. Having reviewed all charges for monopoly services associated with contestable works, the CW&MFWG has produced a report with recommendations.

The CW&MFWG first reported to the EICG on 17 March 1999. An amended report was filed on 21 April 1999. Following the Tribunal's s12A report, the CW&MFWG was reconvened and an amended report was provided on 29 September 1999. That report was distributed to the EICG, made available to interested parties, and placed on the Tribunal's website. A significant proportion of the CW&MFWG's discussion is devoted to the critical, very contentious issue of ring fencing.[128]

Submissions from the DNSPs identify contestable works as difficult to manage. While supporting the work of the CW&MFWG, Advance Energy comments that there are few accredited service providers in the rural areas, and it is costly for the DNSP to appoint dedicated inspection staff.[129] EnergyAustralia supports the development of a simpler fee structure which ensures an adequate return to the DNSPs.[130]

10.3 Charges for miscellaneous services

In addition to their core charges, the DNSPs levy a suite of charges for services relating indirectly to the conveyance of electricity. In this sense, the provision of miscellaneous services is incidental to the provision of the core service of electricity distribution.

Charges for miscellaneous services are applied in various forms. The most frequently applied charges by DNSPs include personal disconnection visit charges and application fees. The Tribunal published a list of permissible miscellaneous charges in its Determination 5.3 of July 1997. However, a wide disparity remains in the type and application of these charges across the DNSPs. The Tribunal's concern about miscellaneous charges is highlighted by complaints made to EION. Although miscellaneous charges do not collectively account for a material proportion of total DNSP revenue, they can be individually significant, particularly for low income consumers.

126 See, for example, Great Southern Energy submission p28, Integral Energy submission p 27.
127 See Advance Energy submission, pp71-73, EnergyAustralia submission, pp 54-55.
128 Generally, independent contractors were concerned that the incumbent contracting departments were filling the inconsistent roles of approving contestable works and competing to perform the work themselves.
129 Advance Energy submission, p 74.
130 EnergyAustralia submission, p 62.

10.3.1 Exhaustive list of charges for miscellaneous services

To address the complaints in this area, the Tribunal has determined an exhaustive list of charges for miscellaneous services, as shown in Table 10.1. Each miscellaneous service is a prescribed distribution service. The DNSPs are not to levy any charges not shown on the list, and they are authorised to levy the approved charges only in the circumstances outlined in 'Charges for Miscellaneous Services Rule 99/3' issued by the Tribunal. It should be noted that these charges for miscellaneous services are maximum charges, exclusive of the GST and the DNSPs are at liberty to reduce or waive these charges as may be appropriate in the circumstances.

Submissions from the electricity DNSPs and retailers indicate a clear preference for flexibility in determining the suite of miscellaneous charges to be levied. The DNSPs and retailers argue that this flexibility is required to address the changes being introduced with full contestability. The Tribunal is sympathetic to the DNSPs' desire to maintain flexibility in the face of changes to the industry. However, the Tribunal does not consider it appropriate or desirable to amend the schedule of charges for miscellaneous services without a public consultation process. Nor in the Tribunal's view does the Code permit an amendment to the Tribunal's determination during the regulatory control period, except in very limited circumstances. For these reasons, it is not possible for the Tribunal to give the DNSPs the flexibility they desire.

10.3.2 Separation into charges for network and retail services

The MCWG was asked to separate the recommended list of charges for miscellaneous services into network and retail lists. Given the diverse internal structures of the DNSPs, the working group was unable to arrive at an agreed view. The Tribunal has had regard to the recommendations of the MCWG in approving the suite of charges for miscellaneous services in this Determination. The Tribunal considers some charges are more clearly retail charges than network charges. The suite of miscellaneous charges will not fit each DNSP's business objectives exactly. In reaching this distinction, the Tribunal has considered that the retailer will be the entity with the ongoing customer service relationship. Accordingly, those charges relating to physical network operation have been assigned to the DNSP.

The Tribunal considers the DNSP may not have a direct financial relationship with the end use customers. Therefore, approved charges for miscellaneous services levied by the DNSP must be levied on the retailer having the financial relationship with the particular end use customer. The retailer will make a decision as to whether to absorb the charge or pass it through to the end use customer.

Table 10.1 Maximum charges for miscellaneous services

Miscellaneous Service		Maximum allowable charges	
		Normal business hours maximum allowable ($)	Outside normal business hours maximum allowable ($)
Provision of time-of-use or half hourly metering data: per half hour		25.00	N/A*
Special meter reading		30.00	75.00
Meter test		50.00	125.00
Conveyancing inquiry:	desk inquiry	25.00	N/A*
	field visit	50.00	N/A*
	total	75.00	N/A*
Account establishment		35.00	87.50
Off-peak conversion		40.00	100.00
Disconnection visit:			
	if no disconnection (acceptable payment received)	30.00	N/A*
	disconnection (acceptable payment not received)	60.00	N/A*
	pole top/pillar box disconnection	100.00	N/A*
	Maximum total (pole top/pillar box & meter disconnection)	160.00	N/A*
Rectification of illegal connection		150.00	475.00

*N/A = Not applicable.

10.4 Charges for monopoly services associated with contestable works

The Electricity Supply (Customer Contracts) Regulations require the DNSPs to compete with private entities to provide many former monopoly services. In particular, the provision of customer connection services is an area where customer choice must evolve as a means of ensuring efficient costs and prices. However, although competition is developing in this area, DNSPs still retain ownership of networks and must maintain the reliability, safety standards and quality of supply of their networks.

In order to safeguard these standards, distributors have developed an accreditation process whereby persons or companies seeking to undertake connection work are graded as to their competency. Additionally, in line with the requirements of safety and reliability, distributors need to inspect the work of accredited persons, to examine and certify electrical designs submitted by external contractors, and to provide information in regard to electrical designs.[131]

Distributors view these as monopoly services, and for the purposes of this report, these services are accepted as monopoly services.

131 Electricity Association of NSW, Code of Practice – Contestable Works, section 2(d).

Charges for monopoly services associated with contestable works do not represent a significant proportion of a DNSP's AARR. Nevertheless, the Tribunal must ensure these charges for monopoly services relating to contestable works are competitively neutral and that the methodology by which they are applied does not restrict entry of non-DNSP contractors engaging in contestable works by increasing the cost of development.

Consistent with its decisions on miscellaneous charges and streetlighting, the Tribunal has determined that revenues from charges for monopoly services should be included in the AARR for each DNSP. The Tribunal considers that the charges for monopoly services should be set on the basis of incremental costs, given that the other 'overhead costs' will be recovered through charges for network services.

The key pricing recommendations of the CW&MFWG are to:

- provide revised hourly rates for some services (see Table 10.3)
- introduce a fee to authorise accredited service providers to work on or near a distributor's network
- rename and restructure the administrative overhead fee
- revise inspection rates
- change the narrative and level of the access permit fee.

The CW&MFWG made many valuable recommendations for the conduct of contestable works. The Tribunal considers these recommendations are best dealt with in an industry code of practice. The Tribunal encourages industry participants to convene a group to agree on such a code of practice.

Perceived failure to ring fence remains the most contentious issue facing the CW&MFWG. The Tribunal considers ring fencing to be a larger issue, of which the contestable works area is a subset. The Tribunal is working with industry participants and other regulators to develop ring fencing guidelines under the Code, and expects that these matters will be largely resolved through that process.

10.4.1 Exhaustive list of charges for monopoly services associated with contestable works

Similar to its experience with miscellaneous services, the Tribunal has experienced considerable complaint activity in this area. However, the complaints tend to focus on the consistent application of charges for monopoly services, rather than the level of charges. The contestable contractors argue that the inconsistent application of monopoly charges creates a perception of an uneven playing field, and concern that the fees may not be applied consistently to the incumbent DNSPs' contracting arms.

This is largely a ring fencing and competitive neutrality issue. The ring fencing aspects will be considered as part of the broader work on ring fencing guidelines to be established under the Code. Competitive neutrality complaints will need to be addressed by each jurisdiction's competitive neutrality body.

Although the Tribunal has approved an exhaustive list of *maximum* charges to be applied to miscellaneous services, the Tribunal considers that, for most monopoly services, any perceived scope for the DNSP to reduce charges to the incumbent contracting arm should be removed. Subject to one qualification, a DNSP must not charge more or less than the charges listed in Table 10.2. The qualification is that if a charge in Table 10.2 is listed as a maximum charge, a DNSP may charges less than the maximum. That is, the DNSP must not charge more or less than the prescribed charge. Each monopoly service is a prescribed distribution service. Charges for monopoly services are to be levied in accordance with the conditions set out in 'Charges for Monopoly Services Rule 99/4', issued by the Tribunal.

The Tribunal considers that it is important the DNSP be able to demonstrate clearly that charges for monopoly services have been levied consistently on the incumbent DNSP contracting arm and any independent contractors.

Amendments to the working group's recommendations

The CW&MFWG has recommended that the previous fee for travel time be removed, and that inspection fees include a component for average travel time. In making this recommendation, the working group notes that in Integral Energy's case, an inspector would rarely travel more than two hours to a site. This recommendation has the effect of charging for travel in the EnergyAustralia and Integral Energy service territories, where the travel time may not be incurred. The Tribunal is of the view that a reasonable amount of travel is consistent with the operation of a DNSP's business. However, the Tribunal is concerned that for the rural distributors, significant travel times can be necessary. The Tribunal prefers to determine a charge for travel time where incurred, rather than to increase fees across the board to include an average element for travel time. The Tribunal has therefore reduced those charges for monopoly services with an embedded travel time component as recommended in the working group report, and retained the specific charge for travel time.

Similarly, some recommended fees include an administration component. As stated above, the Tribunal believes that charges for monopoly services should be calculated on an incremental basis. The Tribunal is of the view that it is inappropriate to levy an 'administration fee' and to include administration charges within the various monopoly fees. The Tribunal has therefore reduced those charges containing an administrative component by the amount of the embedded administration.

Table 10.2 Charges for monopoly services associated with contestable work

Monopoly Service	Underground urban residential subdivision (vacant lots)	Rural Overhead Subdivisions and Rural Extensions	Underground Commercial and Industrial or Rural Subdivisions (vacant lots - no development)	Commercial and Industrial Developments	Asset Relocation Or Street Lighting
Design Information (Minimum 1 Hr)	Up to 5 lots 2 Hrs @ R2 6 to 10 lots 3 Hrs @ R2 11 - 40 lots 5 Hrs @ R2 Over 40 lots 6 Hrs @ R2	R2 per hour	R2 per hour	R2 per hour	R2 or R3 per hour (See Note 5)
Design Certification (Minimum 1 Hr)	Up to 5 lots 1 Hr @ R2 6 to 10 lots 2 Hrs @ R2 11 - 40 lots 3 Hrs @ R2 Over 40 lots 4 Hrs @ R2	1 - 5 poles 1 Hr @ R2 6 -10 poles 2 Hrs @ R2 11 or more poles 3 Hrs @ R2	Up to 10 lots 2 Hrs @ R2 11 - 40 lots 3 Hrs @ R2 Over 40 lots 6 Hrs @ R2	R3 per hour	R2 or R3 per hour (See Note 5)
Design Rechecking (Minimum 1 Hr)	R2 per hour	R2 per hour	R2 per hour	R3 per hour	R2 or R3 per hour (See Note 5)
Inspection Fee (Minimum 2 Hrs @ R2)	Grade: A per lot / B per lot / C per lot First 10 lots: 0.5xR2 / 1.2xR2 / 2.5xR2 Next 40 lots: 0.3xR2 / 0.7xR2 / 1.5xR2 Remainder: 0.1xR2 / 0.4xR2 / 0.7xR2	Grade: A per pole / B per pole / C per pole 1-5 poles: 0.6xR2 / 1.2xR2 / 2.2xR2 6-10 poles: 0.5xR2 / 1.0xR2 / 2.0xR2 11+ poles: 0.4xR2 / 0.7xR2 / 1.5xR2 (see Note 4)	Grade: A per lot / B per lot / C per lot First 10 lots: 0.5xR2 / 1.2xR2 / 2.5xR2 Next 40 lots: 0.5xR2 / 1.2xR2 / 2.5xR2 Remainder: 0.5xR2 / 1.2xR2 / 2.5xR2	R2 or R3 per hour (see Note 1)	R2 or R3 per hour (see Note 1)
Access Permit	Residential Subdivisions: $18.00 per lot combined fee	$800 max. per access permit	$800 max. per access permit	$800 max. per access permit	$800 max. per access permit
Substation Commissioning		$600 per substation (See Note 2)	$600 per substation (see Note 2)	$600 per substation (see Note 2)	$600 per substation (see Note 2)
Administration	Up to 5 lots 3 hours @ R1 6 - 10 lots 4 hours @ R1 11 - 40 lots 5 hours @ R1 Over 40 lots 6 hours @ R1	Up to 5 poles: 3 Hrs @ R1 6-10 poles: 4 Hrs @ R1 11 or more poles 6 Hrs @ R1	R1 per hour (max 6 hours)	R1 per hour (max 6 hours)	R1 per hour
Notice of Arrangement	3 hours @ R1				
Re-Inspection	R2 per hour (max 1 hour per level 2 reinspection)				
Access	R1 per hour (see narrative)				
Authorisation	2 hours @ R2				
Inspection of Service Work (Level 2 work)	All Service connections: A Grade : $14 per NOSW B Grade: $22 per NOSW C Grade: $65 per NOSW (NOSW = Notification of Service Work)				

Notes:

1. Level of inspection determined prior to commencement of job & based on grade of accredited service provider.
2. $600 for a simple substation (single transformer/RMI unit) other at hourly rate including setting/re-setting protection equipment.
3. Where individual service connections are required for multiple dwelling subdivisions the per lot fee should be applied per service connection.
4. Inspections are based on 3 visits. Substation poles are not included. The inspection for substation poles is A Grade – 3.5Hrs @ R2; B Grade – 7Hrs @ R2; C Grade 9 Hrs @ R2.
5. Hourly rate to be determined based on complexity of the job.

Table 10.3 Hourly labour rates applicable to monopoly services

Labour class	Hourly rate
Admin R1	$44
Design R2a	$54
Inspector R2b	$54
Engineer R3	$65

11 CAPITAL CONTRIBUTIONS

In December 1996, the Tribunal issued Determination 10, Pricing for Capital Contributions and Recoverable Works. This Determination, as amended and supplemented by the capital contribution guidelines in Determination No. 5.4 of 1997 sets out the current arrangements under which customers are required to contribute to the costs of connecting to the distribution system, and the basis for determining the amount of such costs.

Key elements of these arrangements are:

- DNSPs are responsible for funding all shared parts of the network upstream from the point of customer connection
- customers are responsible for the cost of all non-shared assets required for their connection to the distribution system downstream from the point of connection
- where economically and environmentally superior alternatives to system connection are available, and the customer (or group of customers) decides to connect, the customer is required to meet the full cost of connection, including the cost of any augmentation required upstream from the point of connection
- at their discretion, customers may either retain or hand over to the DNSP any assets they have fully funded.

In response to industry and customer concerns regarding the effect of Determination 10, the Electricity Industry Consultation Group (EICG) formed the Capital Contributions Working Group (CCWG). The CCWG comprises industry, customer, government, and community representatives.[132] The CCWG examined capital contributions issues and developed proposals for the Tribunal's consideration. The CCWG completed an initial report in April 1999. This was distributed to interested parties and placed on the Tribunal's web site. However, the CCWG had foreshadowed further examination of the implementation issues associated with its recommendations. The Tribunal discussed the issues and provided comments in its Section 12A report of July 1999.[133]

The CCWG identified the capital contributions area as very complex, with significant government policy implications. In particular, the capital contributions issue highlights the tensions felt by the DNSPs in meeting the sometimes conflicting 'successful business', 'social responsibility' and 'regional development' requirements of the State Owned Corporations Act.[134]

The CCWG was not able to produce a final report in time for an adequate public consultation process to be completed before the release of this determination. ***Accordingly, this determination reaches no conclusions on the treatment of capital contributions.*** Determination No. 10 of 1996, as amended by determination No. 5.4 of 1997, will remain in effect until 31 January 2000 under clause 9.16.3(a) of the Code. The Tribunal will endeavour to hold a public consultation process on the working group's report, and will publish a decision on capital contributions as soon as practicable.

132 A full list of working group participants is appended to the report.

133 *Pricing for Electricity Networks and Retail Supply*, Volume 2 Chapter 11.

134 See *State Owned Corporations Act 1989* - Sect 20E.

11.1 Determination on capital contributions

This determination makes no decision on capital contributions. The Tribunal will publish a decision on capital contributions as soon as practicable.

11.2 Code requirements

Capital contributions are considered under Part E of Chapter 6 of the Code. Consistent with the NSW derogation under clause 9.16.3(c) of the Code, the Tribunal has not applied the provision of part 6E in this determination. However, the Tribunal considers that it should have some regard to the Code provisions regarding capital contributions:

> **6.15.2 Capital contributions, pre-payments and financial guarantees**
>
> The principles to be applied to capital contributions, pre-payments and financial guarantees are:
>
> (a) the *Distribution Network Service Provider* is not entitled to receive any asset related cost component of *annual revenue requirement* for assets provided by *Network Users*;
>
> (b) the *Distribution Network Service Provider* may receive a capital contribution, pre-payment and/or financial guarantee up to the future *annual revenue requirement* for any new assets installed as part of a new *connection* or modification to an existing *connection*, including any *augmentation* to the *distribution network*;
>
> (c) where assets have been the subject of a contribution or prepayment, the *Distribution Network Service Provider* must amend the *aggregate annual revenue requirement*; and
>
> (d) the asset categories referred to in clause 6.13.3 must not incorporate the asset related cost components of the *annual revenue requirement* for any asset category covered by clause 6.15.2 and the *Network Users* who use any such asset together as a group are to pay less for the ongoing use of that asset category than they otherwise would have paid.

The Tribunal considers that consistency with the Code's requirements relating to capital contributions will not affect the Tribunal's decisions on total revenue requirements under this Determination. While there may be secondary implications for the DNSPs' forecast capital expenditure, the Tribunal does not expect these impacts to affect the total revenue requirements.

11.3 Public Consultation

In submissions made to the Tribunal, and discussions held by the CCWG, several issues are raised by industry and customers. These issues may be grouped into two broad categories:

- those associated with the clarity, workability and coverage of determination No. 10 of 1996 and determination 5.4 of 1997 and its guidelines. Some DNSPs have reported difficulty in applying the specified approach due to ambiguities in the terms used, and the inadequacy of the guidance provided to deal with common circumstances. This has been a cause of frustration and confusion for DNSPs and customers alike.

- those associated with the identification and treatment of uneconomic connections. From the DNSPs' perspective, there is concern that the current approach will stimulate requests for connections which will require substantial and continued funding support from other customers. From the customers' perspective, there is concern that any increased application of a user pays approach to connection will disregard the broader social and regional considerations involved. Both groups are concerned at the prospect that DNSPs may, de facto, be required to arbitrate between economic and social objectives.

In the relatively short time available to it, the CCWG has made valuable progress in identifying the key concerns of the interested parties. The CCWG has endeavoured to relate these concerns to the principal underlying economic and social issues. Arising in the provision and funding of infrastructure, these may combine individual, shared, private and external benefits. From this analysis, initial proposals for an alternative approach have been developed. However, the CCWG has indicated that considerable further work on implementation is required before substantial changes to the current arrangements can be recommended.

11.4 Tribunal's consideration

One of the CCWG's major tasks has been to define what constitutes an 'uneconomic' (as opposed to economic) connection. Where connections are uneconomic, the working group has proposed approaches may be used to assess the appropriate level of customer contribution and recover any shortfall that may be assessed as reasonable.

The issue of uneconomic connections raises many of the conceptual difficulties of establishing a uniform capital contributions policy. For example:

- the revenues contributed by a new customer will normally be based on average uniform tariffs and may make varying contributions to fixed costs
- whether an extension is economic depends on the comparison of revenues to marginal costs, not average costs[135]
- the level of asset utilisation is unknown at the time of connection
- the potential for additional customers to connect to the new extension assets under consideration is often uncertain at the time of construction.

A key recommendation of the CCWG's April 1999 report is:

> Distributors should undertake an 'economic' assessment of proposed new connections. To the extent that Network revenues from new connections will provide more than their associated costs of supply, distributors should contribute to the costs of connections. A practical method of implementing this recommendation may be for specific distributor contribution levels to be determined for defined customer classes.[136]

The CCWG has made the following draft final recommendations:[137]

> 1. Many issues associated with the recommendations of this report require further consideration. The EICG should establish a working group to develop an implementation plan for submission to the Independent Pricing and Regulatory Tribunal of NSW and the NSW Government.
> 2. Distributors should undertake an "economic" assessment of proposed new connections. To the extent that Network revenues from new connections will

135 However, marginal costs are more difficult to measure and are likely to be substantially different from average costs.
136 Report of the Capital Contributions Working Group, April 1999, p 2.
137 Draft final report of the Capital Contributions Working Group, December 1999, p 3.

provide more than their associated costs of supply, distributors should contribute to the costs of connections. A practical method of implementing this recommendation may be for specific distributor contribution levels to be determined for defined customer classes. [Implementation issues will need to be addressed as per recommendation 1.]

3. After allowing for distributors' contributions to new connections, customers would be responsible for all additional connection costs relating to dedicated connection assets and shared line extensions.
4. System augmentation costs on existing lines would be the responsibility of distributors unless a customer requires a load of more than 100 amps single phase. The customer shall be responsible for augmentation costs in those instances.
5. A scheme to reimburse previous customers where new customers are connecting to assets that were previously funded by customer contributions should be reintroduced. New customers would be responsible for their proportion of line extensions constructed within the previous six years.
6. An agency should be appointed to assess the merits for funding assistance to customers subject to capital contributions. This agency would consider the social, environmental and extrinsic commercial impacts of new connections to establish whether funding assistance is appropriate. Funding options that the agency may consider could include:
   - increasing tariffs and revenues in that distributor's geographic area
   - increasing tariffs and distribution revenues across all customers in NSW
   - an industry fund which could include retailers
   - explicit taxpayer funding through NSW consolidated revenue.
7. Distribution system assets on public property (or subject to easements) should generally be owned by the franchise area distributor. Customers should own and have responsibility for consumer mains. No recommendation is offered in this report relating to responsibility for other assets on customer premises (excluding consumer mains).
8. Connection assets funded by distributors should derive appropriate returns and associated operating cost recovery through regulated revenues. Contributions received from customers should not provide returns to distributors, however, associated operating and maintenance costs incurred by distributors should be recovered through regulated revenues.

The Tribunal will consider these recommendations as part of its intended public consultation process on capital contribution issues.

The CCWG estimates the indicative DNSP contribution levels as follows:

Table 13 Distributor contributions (indicative)

	Below 100 amps single phase	Above 100 amps single phase
Residential (including Off peak) ($/Customer)	$1,500	$150 / MWh
Rural/farm (excluding irrigation) ($/Customer)	200	$20 / MWh
Business low voltage ($/MWh)	250	320
Business high voltage ($/MWh)	*	*
Business subtransmission ($/MWh)	*	*

Source: Draft final report of the Capital Contributions Working Group, December 1999, p 15.
Notes:
Threshold as specified under Recommendation 4.
Low voltage = (240 and 415 Volt), high voltage = (> 415 volt & < 33 kV), Subtransmission = (33 kV – 132 kV)
Subtransmission rates are normally calculated on an individual customer basis rather than using standard rates.
* = Highly variable – Not possible to give an indicative figure

The Tribunal has not endorsed the CCWG's recommendations. Following a public consultation process, the Tribunal will publish a decision on capital contributions.

12 EMBEDDED GENERATION

This chapter sets out the Tribunal's intentions with respect to embedded generation issues, and also addresses the Tribunal's assessment of a specific matter relating to avoided transmission use of system (TUOS) payments made by a DNSP to an embedded generator.

12.1 Determination on embedded generation and avoided TUOS

The Tribunal will continue to work with the embedded generation working group and other regulators to develop a framework within which parties can negotiate agreements for embedded generation. It is envisaged that the framework will include:

- ***procedural guidelines***
- ***agreed methodologies***
- ***dispute resolution processes and***
- ***standardised contract documentation.***

With respect to Integral Energy's submission to the Tribunal regarding avoided TUOS payments made to embedded generators, the Tribunal determines that:

- ***on a forward looking basis, it is appropriate that Integral's payments to Smithfield and Tower/Appin for the purposes of 'avoided TUOS' to be recovered in Integral's AARR, to the extent that these payments reflect the actual TUOS charges that Integral avoids as a consequence of the embedded generators; and consequently***
- ***for the period from 1 February 2000 to 30 June 2004, Integral's payments to Smithfield and Tower/Appin for avoided TUOS are to be passed through to customers to the extent that the payments reflect the actual avoided TUOS charges. The pass through amount in each year will be calculated by Integral, and submitted to the Tribunal for approval. The payments will not form part of the Integral's AARR unless the pass through amount has been approved by the Tribunal.***

With respect to avoided TUOS payments made by a DNSP to embedded generators more generally, the Tribunal determines that:

- ***as a matter of principle, it is appropriate for avoided TUOS payments paid to an embedded generator to be recovered in the AARR, to the extent that these payments reflect the actual TUOS charges avoided by the DNSP as a consequence of the embedded generator; and***
- ***if a DNSP begins to make payments to an embedded generator for the purposes of avoided TUOS within this regulatory control period, then these payments are to be passed through to customers to the extent that the payments reflect the actual avoided TUOS charges. The pass through amount in each year will be calculated by the DNSP, and submitted to the Tribunal for approval. The payments will not form part of the DNSP's AARR unless the pass through amount has been approved by the Tribunal.***

12.2 Code requirements

The Code establishes arrangements and procedures for generators to access the transmission and distribution networks, the basis for determining access charges, and procedures governing network planning and augmentation. Of special relevance to embedded generation are references to:

- the need to pass through avoided transmission use of system (TUOS) charges
- payments that may be made to or received from embedded generators for distribution network services
- the inclusion of embedded generation as a possible option for addressing projected network limitations.

12.2.1 Avoided TUOS payments

The Code is explicit with regard to the pass through of avoided TUOS to embedded generators. Clause 5.5 (which deals with connection agreements) permits transmission costs avoided by a DNSP to be passed through to the embedded generator, funded out of the DNSP's AARR:

> (f) The Network Service Provider and the Generator shall negotiate in good faith to reach agreement as appropriate on the: …
>
> (3) amount to be passed through to the Generator (where the Generator is an Embedded Generator) for avoided transmission use of system charges that would otherwise be payable by the Network Service Provider as a result of the Generator not being connected to its distribution network; …
>
> (h) Any payments to Embedded Generators under clause 5.5(f)(3) are to be included as part of the AARR of the Network Service Provider and are to be recovered in the same manner as payments to Embedded Generators under clause 6.13.3(d).

This reflects the position of the ACCC in its final decision on the Code access arrangements. The ACCC regarded the pass through of TUOS (based on the Tribunal's 'with and without' basis) as a means of restoring competitive neutrality with generators that were not paying TUOS.

> .... as generators will be dispatched into the wholesale market largely on the basis of generation and connection asset costs, the incidence of network charges appears to disadvantage embedded generation which competes on a delivered cost basis. [p 62]

12.2.2 Network support payments

Chapter 6 of the Code recognises that the DNSPs may pay embedded generators for the contribution they make to network support.

Clause 6.10.5 requires that payments to embedded generators be included in the DNSP's revenue cap:

> (d) In setting a separate regulatory cap to be applied to each Network Owner …, the Jurisdictional Regulator must take into account each Distribution

> Network Owner's revenue requirements during the regulatory control period, having regard for: …
>
> (7) the right of the Distribution Network Owner… to recover reasonable costs arising from: …
>
> (iii) payments made to Embedded Generators for demand side management programs and local energy storage facilities which provide distribution service… where the Jurisdictional Regulator determines that this is appropriate;

For instance, Chapter 6, Part E of the Code also deals with payments to embedded generators. Clause 6.13.3 requires that payments received from or made to embedded generators to be included in the AARR for the appropriate DNSP asset category:

> (c) Payments to and from Embedded Generators are to be determined up to an amount of the long run marginal cost of augmenting the distribution network….
>
> (d) Any payments made under clause 6.13.3(c):
>
> (1) to Embedded Generators must be added to: and
>
> (2) from Embedded Generators must be deducted from,
>
> the AARR for the relevant asset category…

Clause 6.14.1, recognises that in converting DNSP costs into prices:

> (e) There may be situations where the DNSP is prepared to pay for equivalent network service by Embedded Generators…. prices for such equivalent network services are to be agreed between the relevant DNSP and Jurisdictional Regulator.

This point is discussed further in part 4.5 of schedule 6.6:

> Embedded generators can in some circumstances provide significant benefits in certain parts of a distribution network….Distribution service charges are negotiable between the Network Owner and the Generator. The charges (or payment) need to reflect the benefit available to the Network Owner from the embedded generation. This will depend on — the degree to which any benefits to the network that might accrue from the generation are shared between the NSP, the Generator and other Network Users. … The long run marginal cost (benefit) of the shared network reinforcement represents the upper limit of payment to the Generator.

Part 5 of this schedule also provides discretion for the regulator to treat services provided to embedded generators for reserve (or standby) capacity, other distribution services and access as, effectively, competitive services that can be excluded from the revenue or price cap.

However chapter 6, Part E does not apply expressly to this determination as the Tribunal has exercised its discretion not to apply Part E (see chapter 10 of this report). Nevertheless the principles in Part E provides useful guidance to the Tribunal's approach to embedded generation under Part D.

12.2.3 Network planning

By offering ways of addressing future network limitations, particularly within regions, embedded generation offers benefits. The Code assigns responsibility for network planning within regions to the relevant NSP. Clause 5.6.2 requires NSPs to select options which maintain the operating standards of their networks while maximising the net benefit to customers. NSPs are required to consult with participants and interested parties to identify these options:

> (f) … the Network Service Provider must consult with affected Code Participants and interested parties on the possible options, including but not limited to demand side and generation options, to address the projected limitations of the relevant transmission system or distribution system.
>
> (g) Network Service Providers must carry out cost effectiveness analysis of possible options to identify the option that maximises the net benefit to customers …

Part 4.5 of schedule 6.6 briefly discusses the competitive process that NSPs may use to ensure that the most cost effective option is identified correctly:

> As a general principle, commercial arrangements shall be made with Generators and this may include a competitive tendering process to ensure equal opportunity for other Generators. For example, a statement of opportunity for the area concerned could be issued with an invitation to bid for generation capacity in the area. This would facilitate free market forces providing the optimum outcome for the network business and existing network customers.

12.2.4 Other matters

In addition, and as set out in the Tribunal's section 12A report, other matters may impact on the issue of embedded generation. The NECA review, which is directed at improving the network pricing sections of the Code, addresses a number of issues of direct relevance to embedded generation. These include TUOS pass through, standby charges and network bypass, as well as more fundamental principles of network access, and pricing affecting the development of the electricity market. If changes are made to the Code as a consequence of the review they may affect the requirements guiding the Tribunal.

12.3 General Principles

Embedded generation may take the form of a local generator or a combined generator and load, and can offer a number of advantages. Namely, it can:

- increase the level of competition in the wholesale electricity market. Because it can displace the use of parts of the networks, it can also introduce competitive pressures on network pricing.
- depending on its location and energy source, it may also offer environmental advantages.
- where networks are congested, embedded generation may reduce costs by avoiding or deferring capital expenditure on the network.

The commercial viability of embedded generation is influenced by the availability and conditions of network connections, the use for exporting and importing energy, and the recognition and sharing of relevant network cost savings. On this basis, network pricing and its regulation can significantly affect incentives to establish embedded generation (ie local generation and cogeneration).

Recognising this, the Code establishes arrangements and procedures for generators to access the transmission and distribution networks, the basis for determining access charges, and procedures governing network planning and augmentation (as set out above). Nevertheless, proponents of embedded generation have raised concerns regarding difficulties encountered in negotiating network access, use and benefit sharing with DNSPs.

The Tribunal wishes to ensure that price regulation encourages efficient decision making concerning the establishment of embedded generation rather than other forms of generation, load management, and network investment. The Tribunal's preferred approach to network access is to encourage negotiation among the involved parties within a framework of established pricing principles. However the Tribunal recognises that to facilitate this negotiation, clear signals with respect to future regulatory treatment are required, and on this basis supports the development of a framework within which the parties can negotiate agreements.

In developing this regulatory framework, the Tribunal recognises that consultation is essential for the development of a workable approach that addresses the concerns of affected parties. Consequently, the Tribunal envisages that the Tribunal's Electricity Industry Consultation Group, and in particular the Embedded Generation Working Group will continue to make a valuable contribution to the development and documentation of the framework. The Tribunal also recognises that it is essential that the framework developed is consistent among jurisdictions, and other regulatory requirements such as the NSW demand management code of practice.

12.4 Integral Energy and Avoided TUOS

Integral Energy has two agreements with embedded generators. The Smithfield Power Purchase Agreement was made in June 1995, and the Appin Tower Colliery Power Purchase Agreement was made in May 1995.

Integral has submitted to the Tribunal that both agreements allow for a pass through of avoided TUOS charges to the embedded generator. On this basis Integral argues that: [138]

- in principle, the avoided TUOS payments should be recovered in Integral's AARR
- a pro-rata of TUOS charges paid by Integral on the basis of the embedded generators' relative peak and shoulder energy output provides an appropriate basis for calculating 'avoided TUOS'
- the 'avoided TUOS' is about $9 million per annum
- Integral's network revenue for 1997/98, 1998/99 and 1999/00 should be increased by $9 million.

These issues were not addressed in the Tribunal's section 12A report.

[138] This is based on information provided to the Tribunal by Integral Energy in its confidential submission dated 30 April 1999, and subsequent confidential submission dated 27 August 1999.

12.4.1 Tribunal's analysis and assessment

Should payments to embedded generators be recovered in network revenue?

As set out in the Tribunal's guidelines on embedded generation, sound economic and equity arguments support the case for a DNSP to pass on the benefits of avoided TUOS charges to an embedded generator, and for the DNSP to recover these payments from customers, albeit for a short period. In line with these arguments, and as set out in section 12.2 of this report, section 5.5 of the Code deals explicitly with the pass through of avoided TUOS charges to embedded generators.

The Tribunal is of the view that the reference to "any payment" in section 5.5 means all amounts "passed through to the Generator (where the Generator is an Embedded Generator) for avoided transmission use of system charges that would otherwise have been payable by the Network Service Provider as a result of the Generator not being connected to its distribution network". Hence, to be included in the DNSP's AARR under the Code, the payments recovered in network revenues must truly answer this description.[139]

On this basis amounts to be passed through from Integral to the embedded generators, Smithfield and Appin during this regulatory control period which are amounts truly representing avoided TUOS charges must (by virtue of clause 5.5 (h)):

- be *included* as part of the AARR; and
- are to be *recovered* in the same manner as payments to embedded generators under clause 6.13.3(d).

This is consistent with the economic and equity arguments for a DNSP to pass on the benefits of avoided TUOS charges to an embedded generator and for the DNSP to recover these payments.[140]

Should retrospective payments to embedded generators be recovered?

Integral has also sought to recover payments on a retrospective basis, ie, in 1997/98 and 1998/99. However the principles relating to the recovery of payments described above apply only after the Code commenced, ie, after December 1998, not retrospectively. No determinations of the Tribunal under the IPART Act expressly permit the recovery of Integral's payments to an embedded generator for avoided TUOS. Accordingly there is no support for Integral's request for the inclusion of payments on a retrospective basis.

However, the Tribunal must determine the avoided TUOS charges, that would otherwise have been payable by Integral, as a result of the embedded generators for this regulatory control period, ie, from 1 February 2000. This is discussed below.

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139 This does not in any way affect the obligation on the DNSP to make or receive payments made under agreements between a DNSP and an embedded generator. The obligation to make payments and the right to receive payments for avoided TUOS are governed by the terms of the relevant agreement. However, the payments made under the agreements may not necessarily equate to the payments that may be properly included for the purpose of the AARR under the Code, as indicated.

140 If the Tribunal were to allow a DNSP to recover an amount that is greater than the actual avoided TUOS charges, then this would merely serve to 'over signal' the benefits of embedded generation. This would promote inefficient investment in embedded generation, and raise network charges to non-embedded generation customers to inefficient levels.

What TUOS charges will a DNSP avoid as a consequence of an embedded generator?

Local or embedded generation essentially serves as a substitute for an electricity transmission network. Therefore, the connection of an embedded generator, which reduces the load on the network, may result in a reduction in transmission costs incurred by the TNSP. A reduction in costs should be reflected in TUOS charges.[141]

The amount of the avoided TUOS charge can be determined by what is generally known as the "with and without" test. That is, the avoided TUOS charge will be the difference between the TUOS charge payable with the embedded generator and the TUOS charge payable without the embedded generator. The "with or without" concept sounds simple, however in practice it is quite difficult to apply.

Current TUOS charges are calculated on the basis of the Tribunal's March 1996 determination. From March 1996 to 30 June 1997, the determination sets out energy, demand and fixed TUOS charges payable by each DNSP.[142] From 1 July 1997 to 30 June 1999, the determination sets out that these energy, demand and fixed TUOS charges are to be rolled forward annually by CPI-3%.[143]

Clause 9.16.2 of the Code establishes that TUOS charges, from 1 July 1999 to 30 June 2002, will be calculated on the basis of the Tribunal's March 1996 determination. This means that charges over this period will be calculated by adjusting the energy, demand and fixed TUOS charges in place at 30 June 1999 to reflect the difference between TransGrid's 1998/99 allowable revenue and the ACCC's determination on transmission revenues. TransGrid is also required to collect EnergyAustralia's transmission revenue, payable by the NSW DNSPs.[144]

Hence, if an embedded generator connects to a distribution network over this period, it will reduce the load (energy and maximum demand) on the transmission network, and hence the amount of TUOS payable by the DNSP. The DNSP's TUOS payments will reduce by:

- energy TUOS charge * the energy generated by the embedded generator; and
- demand TUOS charge * the reduction in the DNSP's overall maximum demand attributable to the embedded generator (if any).[145]

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141 The remainder of the discussion assumes that TUOS charges are set to reflect transmission costs.

142 See Tribunal's Determination 2.1 March 1996 p 13.

143 In 1997/98 a one-off adjustment for actual 1996/97 loads was to be made.

144 It is to be collected from the DNSPs on the basis of their relative peak and shoulder energy load.

145 This holds as long as there are no adjustments for under/over recoveries of transmission revenues. If there are adjustments for under/over recoveries of transmission revenues, the DNSP will avoid TUOS charges in the year that the embedded generator connects to the system by the amount detailed above. In the next year the amount of avoided TUOS will be recovered by the TNSP from all of its customers – and thus the DNSP will only avoid a proportion of:

- energy TUOS charge * the energy generated by the embedded generator; and
- demand TUOS charge * the reduction in the DNSP's overall max demand attributable to the embedded generator.

Nevertheless, the DNSP serving the region where the embedded generator is located will still avoid some TUOS charges. Although, some may argue that there is no 'avoided TUOS' at all, as other transmission customers pay for the TUOS charges the DNSP avoids.

This outcome, that is that the TNSP recovers its revenue cap irrespective of changes in load, signals that all transmission costs are fixed. As such, it signals that no transmission costs can be avoided as a consequence of a change in load, including due to the connection of an embedded generator. This is not

While transmission revenues post 30 June 2002 will be revealed shortly in the ACCC's forthcoming decision on NSW transmission revenues, the specific TUOS charges payable by the DNSPs is uncertain at this stage. Indeed the methodology for their calculation will remain uncertain until the outcome of the NECA review is finalised. As such, avoided TUOS post 30 June 2002 can not be calculated at this time. In principle however, if the load in the DNSP's area falls due to an embedded generator, all else equal, the amount of transmission revenue allocated to the DNSP post 30 June 2002 will be smaller relative to the March 1996 determination.

What TUOS charges will Integral Energy avoid as a consequence of Smithfield and Tower Appin?

Integral has submitted to the Tribunal that a proportion of the TUOS fixed, demand and energy charge is currently being passed to the embedded generators, and that this is reflective of 'avoided TUOS'. However, applying the relevant principles as discussed above, the Integral estimates are likely to be considerably more than the actual avoided TUOS charges.

The principles discussed above suggest that for the period to 30 June 2002:

1. There will be no reduction in the fixed TUOS charge payable by Integral as a consequence of the embedded generation.
2. There will be a reduction in the TUOS demand charges payable by Integral as a consequence of the embedded generators – by the amount that the embedded generators reduce maximum chargeable demand.
3. There will be a reduction in the TUOS energy charges payable as a consequence of the embedded generators – by the amount that the embedded generators reduce total peak and shoulder load.

The amount of TUOS charges avoided from 1 July 2002 is uncertain at this time, for the reasons indicated above. The Tribunal however acknowledges that it is appropriate for Integral to continue to recover payments to embedded generators for the entire regulatory control period.

Specific TUOS charges over the entire regulatory control period are unknown at this time. For this reason the Tribunal is of the view that payments to embedded generators should be treated as a pass-through, subject to the approval by the Tribunal. In addition, pass through arrangements means that the DNSPs have an incentive to ensure that payments to embedded generators for the purposes of avoided TUOS do not exceed actual 'avoided TUOS'.

In principle:

- in the period from 1 February 2000 to 2001/02, payments should be calculated as the:
  - energy TUOS charge * the peak and shoulder energy generated by the embedded generators in the relevant year; and
  - demand TUOS charge * the reduction in Integral's overall maximum demand attributable to the embedded generators in the relevant year.

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consistent with the actual structure of transmission costs. As such, a pure revenue cap approach is problematic.

- in the period 2002/03 through to 2003/04, payments should be calculated as the reduction in allocated transmission revenue to Integral as a consequence of the embedded generator.

The exact amount will be calculated by Integral in each year once TUOS charges are known, and submitted to the Tribunal for approval (prior to a price change).

ATTACHMENT 1 NSW TRANSITIONAL PROVISIONS

9.16 Transitional Arrangements for Chapter 6 - Network Pricing

9.16.3 Distribution Network Service Pricing - IPART Determinations to prevail to the exclusion of Parts D and E in Chapter 6

(a) Until the end of 31 January 2000, *Distribution network service* pricing for *distribution networks* situated in New South Wales will be regulated by *IPART* under the *IPART Act* and the following determinations made by *IPAR*T, to the exclusion of Parts D and E of Chapter 6 of the *Cod*e:

   (1) Determination No. 2.2 of 1996 published in Gazette No. 43 of 4 April 1996 at pages 1616-1623, as modified by the Determination referred to in paragraph (3);

   (2) Determination No. 10 of 1996 published in Gazette No. 1 of 3 January 1997 at pages 29-34 as modified by the Determination referred to in paragraph (4);

   (3) Determination No. 5.3 of 1997 published in Gazette No. 93 of 22 August 1997 at pages 6609-6621;

   (4) Determination No. 5.4 of 1997 published in Gazette No. 93 of 22 August 19997 at pages 6622-6628;

   (5) Determination No. 6 of 1998 published in Gazette No. 171 of 11 December 1998 at pages 9681-9662

(b) *IPART* is and will always be taken to have been the *Jurisdictional Regulator* for the purposes of clause 6.10.1(b) of the *Code* and will continue to be the *Jurisdictional Regulator* until the *Minister* appoints another body.

(c) Notwithstanding clauses 6.11 to 6.16 of this *Cod*e, the prices for *prescribed distribution services* provided by means of *distribution networks* and associated *connection assets* located in New South Wales applying to individual *connection points* located in New South Wales in the period commencing on 1 February 2000 until the end of 30 June 2000 and in the years commencing on 1 July 2000 and 1 July 2001 will, unless no later than 3 months prior to the start of the relevant year the *Jurisdictional Regulator* determines that such prices should be determined on the basis of Part E of Chapter 6 of the *Cod*e, be determined on the following basis:

   (1) subject to clause 9.16.3(c)(2), the prices for *prescribed distribution services* provided by a *Distribution Network Service Provider* will be the prices determined in accordance with the methodology applied by that *Distribution Network Service Provider* to derive prices for similar services under the IPART Determinations set out in clause 9.16.3(a) or such other methodology approved in writing by IPART (an "alternate methodology") provided that, references in any such determination to a "network revenue cap" in respect of a *Distribution Network Service Provider* will be deemed to be a reference to the *aggregate annual revenue requirement* determined for that *Distribution Network Service Provider* in respect of the year commencing on 1 July 1999 or the years commencing on 1 July 2000 or 1 July 2001 (as the case may be) in accordance with clause 6.12 of the *Cod*e; and

   (2) the price to apply at any *connection point* on any *distribution network* which became a *connection point* after 30 June 1999 will be:

      (i) if IPART has not approved an alternate methodology, the price reasonably determined by the *Distribution Network Service Provider* for the *distribution network* on which the *connection point* is located which would have applied at that *connection point* in the year commencing on 1 July 1999 or the year commencing on 1 July 2000 and 1 July 2001 (as the case may be) if that *connection point* had been a *connection point* on or before 30 June 1999; and

(ii) if IPART has approved an alternate methodology, the price reasonably determined in accordance with the alternate methodology.

(d) For the purposes of clauses 6.10 to 6.18 and clause 6.20 of the Code, any amounts paid to a *Distribution Network Service Provider* to reflect the increase in price provided for by section 43B of the *ES Act* are deemed to not be paid in respect of the provision of *distribution services* by that *Distribution Network Service Provide*r.

(e) This clause 9.16.3 is a specific derogation for the purposes of clause 6.10.1(f) of the *Cod*e.

(f) Clause 9.16.3(a) will cease to apply on and from 1 February 2000 and clauses 9.16.3(c), (d) and (f) will cease to apply on and from 1 July 2002.

ATTACHMENT 2 FINANCIAL INFORMATION

A2.1 EnergyAustralia profile

A2.1.1 Background

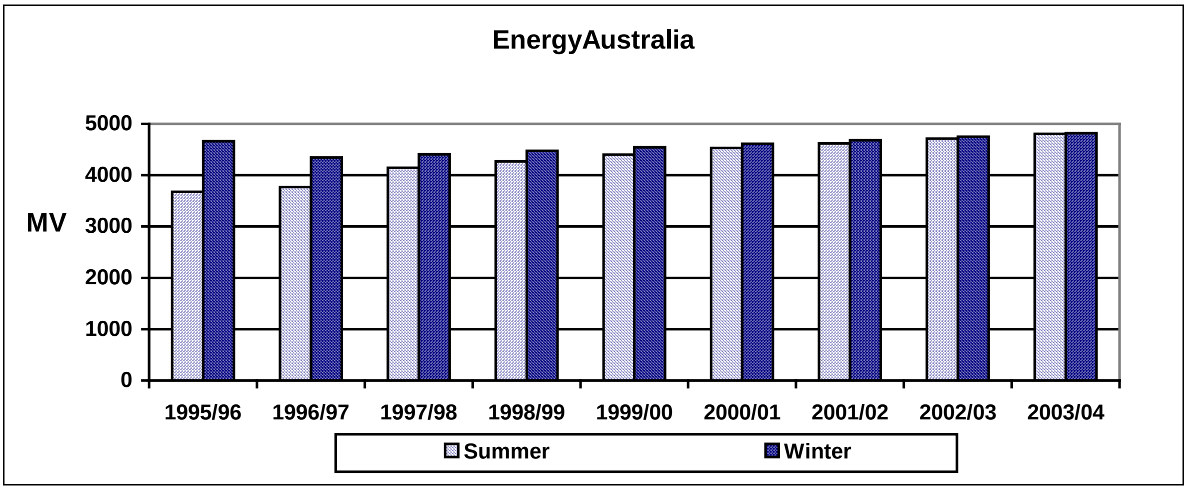
Head Office	570 George Street, Sydney NSW 2000
Major Towns/Cities[1]	Cessnock, Gosford, Maitland, Muswellbrook, Newcastle, Singleton, Sydney
Network Service Area (sq. km)[1]	22,275
Employee Numbers[2]	3,017

Sources: [1] Distribution Boundary Review Committee (1998); [2] 1997/98 Regulatory Accounts.

A2.1.2 Network Demand Profile

EnergyAustralia	1995/96	1996/97	1997/98
Total GWh delivered	21,035	21,212	22,067
Peak Demand (MW)	4,563	4,660	4,481
Total Customers	1,330,099	1,347,295	1,370,000
Residential	1,191,955	1,208,037	1,225,000
Non-Residential	138,144	139,258	145,000
Total Route km	28,670	28,818	29,956

A2.1.3 Maximum Demands



Source: Worley (1998).

A2.1.4 EnergyAustralia Distribution Revenue Path Forecasts 1999/2000 – 2003/04

EnergyAustralia Core Assumptions	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Regulatory Asset Base[1] ($000)	3,837,028	3,913,611	3,992,069	4,080,544	4,183,937
Operating Costs ($000)	205,562	209,673	213,866	218,144	222,507
Capital Expenditure per Worley review ($000)	147,745	156,492	163,408	189,135	206,358
Depreciation ($000)	174,399	182,496	190,906	199,810	209,332
Network Sales (GWh)	23,438	23,907	24,385	24,873	25,370
Sales Growth (%)	2.00%	2.00%	2.00%	2.00%	2.00%

1 Includes transmission assets

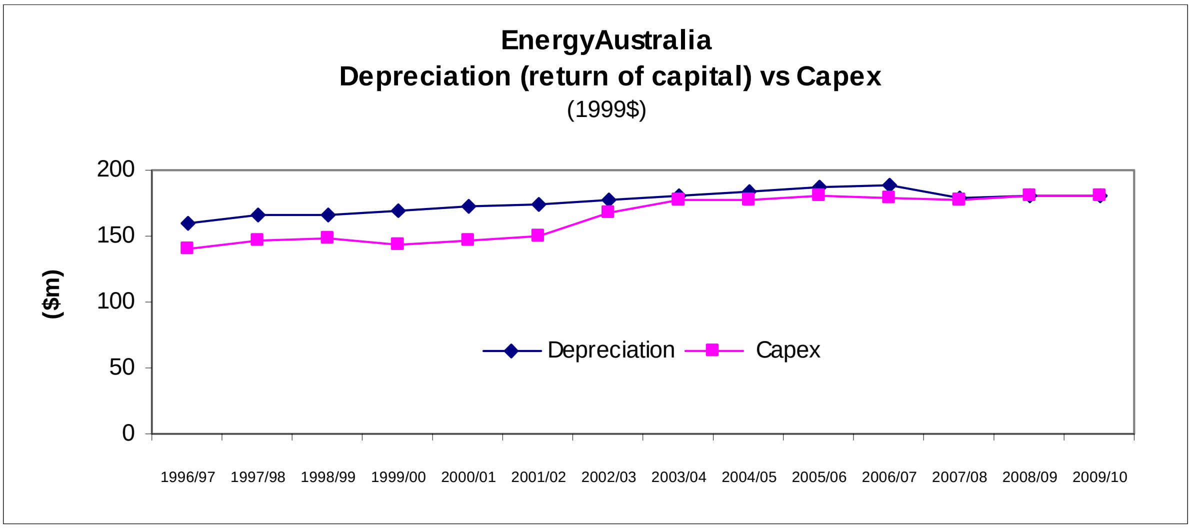
EnergyAustralia Output Summary ($'000)	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Building Block Revenue Requirement					
Operating Costs	205,562	209,673	213,866	218,144	222,507
Return of Capital (depreciation)	174,399	182,496	190,906	199,810	209,332
Return on Capital	287,777	293,521	299,405	306,041	313,795
Return on Working Capital	6,165	6,214	6,276	6,222	6,224
Total Base Revenue (duos)	673,903	691,903	710,454	730,217	751,858
Smoothed Base Revenue	690,892	705,653	720,731	736,130	751,858
Regulated Return on Assets	7.9%	7.9%	7.8%	7.6%	7.5%
Network Price (nominal c/kWh)	2.95	2.95	2.96	2.96	2.96
Network Price (real c/kWh)	2.86	2.78	2.70	2.63	2.56
Cumulative Real Network Price Change	-6.3%	-8.9%	-11.5%	-13.9%	-16.3%

Note: Amounts in nominal dollars. Columns may not add due to rounding.

EnergyAustralia Regulated Fixed Assets($'000)	1999/00	2000/01	2001/02	2002/03	2003/04
Opening Balance	3,799,463	3,874,593	3,952,628	4,031,509	4,129,580
Add: Revaluation of Assets	113,984	116,238	118,579	120,945	123,887
Add: Capital Expenditure	147,745	156,492	163,408	189,135	206,358
Less: Depreciation	174,399	182,496	190,906	199,810	209,332
Less: Disposals	12,199	12,199	12,199	12,199	12,199
Closing Balance	3,874,593	3,952,628	4,031,509	4,129,580	4,238,293
Average Regulated Fixed Assets	3,837,028	3,913,611	3,992,069	4,080,544	4,183,937

Note: Amounts in nominal dollars. Columns may not add due to rounding.

A2.1.5 Return of Capital (depreciation) Versus Capex Profile



Source: Worley (1998).

EnergyAustralia Financial Performance Ratios	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Operating costs as % of base revenue	36%	35%	35%	35%	35%
EBIT margin on sales (EBIT/revenue)	38%	38%	37%	37%	36%
EBITDA margin on sales (EBITDA/revenue)	60%	60%	61%	61%	61%
NPAT/Shareholders Funds	6%	6%	5%	5%	5%
EBIT/(Total Assets - cash & investments)	7%	7%	7%	7%	7%
EBIT/(Borrowings + Equity)	8%	7%	7%	7%	7%
EBITDA/(Equity - revaluation)					
Effective tax rate	36%	36%	36%	36%	36%
Dividend cover	77%	77%	77%	77%	77%

EnergyAustralia Ratio Analysis	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Ability to service debt					
(a) Funds flow interest cover (using net interest)	9.93	10.61	11.57	12.78	13.92
NSW Treasury rating (1994)	AAA	AAA	AAA	AAA	AAA
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(b) Funds flow interest cover (using interest expense)	8.06	8.52	9.15	9.92	10.62
NSW Treasury rating (1994)	AAA	AAA	AAA	AAA	AAA
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(a) Pre tax interest cover (EBIT/net interest)	4.61	4.87	5.23	5.68	6.09
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(b) Pre tax interest cover (EBIT + interest earnings) / interest expense)	3.86	4.03	4.26	4.55	4.79
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
EBITDA / net interest	7.25	7.78	8.50	9.38	10.23

Ability to repay debt					
Funds flow net debt payback (Net debt/Funds from operations)	2.78	2.49	2.21	1.99	1.81
NSW Treasury rating (1994)	AA	AA	AA	AA	AA
Funds from operations/Total debt	0.27	0.29	0.32	0.35	0.38
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Total Debt/Total capital	31%	28%	26%	24%	23%
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Funds from operations/Net debt	0.36	0.40	0.45	0.50	0.55
Cash flow before capex/Total debt	16%	18%	21%	23%	25%
EBIT/(total debt + total equity)	10%	11%	11%	12%	12%
Total Debt / Total assets	27%	25%	23%	22%	20%
Reliance on debt					
Internal financing ratio (Net cash flow/net Capex)	1.35	1.40	1.42	1.28	1.22
NSW Treasury rating (1994)	AAA	AAA	AAA	AAA	AAA
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Net cash flow/Capex	1.18	1.26	1.29	1.18	1.13
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Cash flow before Capex and cap cons/net Capex	1.33	1.40	1.42	1.28	1.22
Cash flow before Capex/Capex	1.29	1.36	1.38	1.26	1.21
Funds flow adequacy					
Funds from operations/(dividends + capex) excl cap cons	1.18	1.22	1.23	1.16	1.13
Funds from operations/(dividends + capex) including cap cons	1.36	1.36	1.36	1.28	1.24

The credit rating ratios as shown above are based on actual capital structure, which is relatively conservatively geared. The level of gearing is a matter for the Government. The Tribunal has also tested the financial strength of DNSPs using a hypothetical gearing commensurate with the private utilities. EnergyAustralia is forecast to have a strong financial outcome.

Income & Expenditure Statement ($'000)

EnergyAustralia	1999/00	2000/01	2001/02	2002/03	2003/04
Income					
Regulated Revenue Cap	690,892	705,653	720,731	736,130	751,858
Transmission Revenue	114,151	114,670	115,192	115,716	116,242
Other Income	-	-	-	-	-
Total Income	805,043	820,324	835,922	851,845	868,100
Operating Expenditure					
Operating Costs	205,562	209,673	213,866	218,144	222,507
Transmission Charges	114,151	114,670	115,192	115,716	116,242
Total Operating Expenditure	319,713	324,343	329,058	333,859	338,748
EBITDA	485,330	495,981	506,864	517,986	529,351
Depreciation	176,549	185,555	194,636	204,133	214,238
EBIT	308,781	310,426	312,228	313,853	315,113
Interest and financing charges	66,960	63,761	59,658	55,211	51,749
Profit Before Tax and Abnormal Items	241,821	246,664	252,570	258,642	263,364
Plus: Capital Contributions	21,341	17,226	16,232	16,622	17,021
Profit Before Tax	263,162	263,890	268,802	275,264	280,385
Tax expense	94,738	95,000	96,769	99,095	100,939
Net Profit After Tax	168,424	168,890	172,033	176,169	179,446
Dividends declared	128,949	129,306	131,713	134,879	137,389

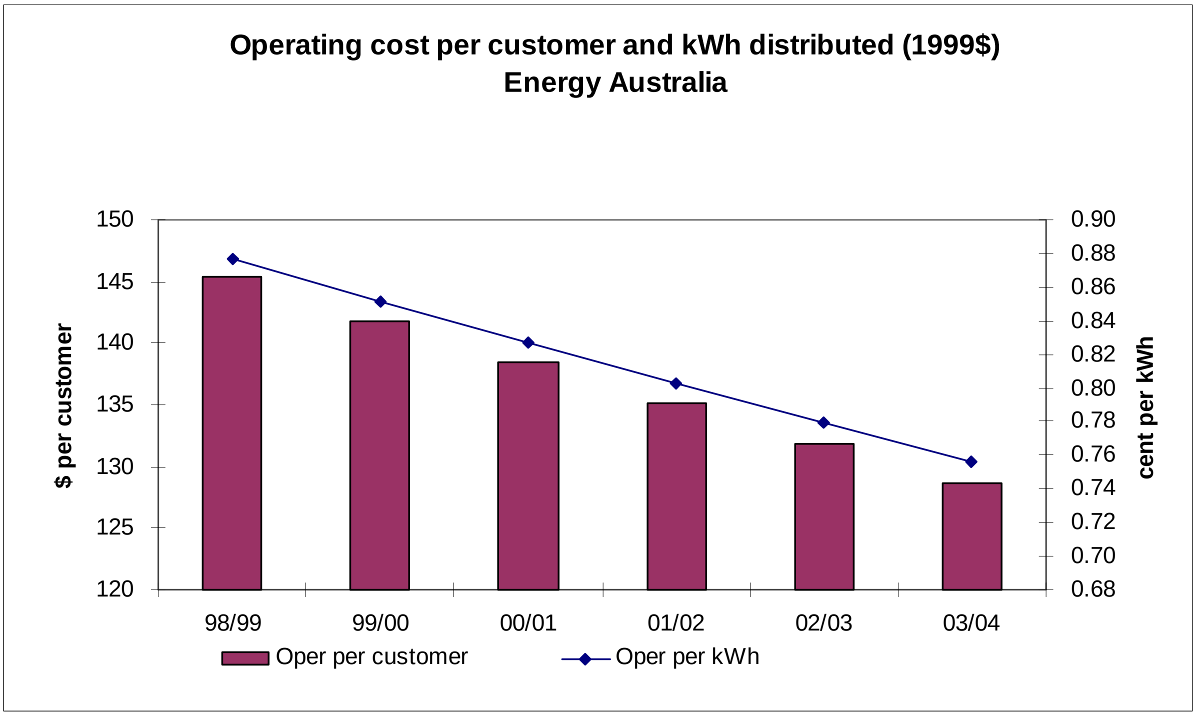
Note: Amounts in nominal dollars. Columns may not add due to rounding.

Balance Sheet ($000)

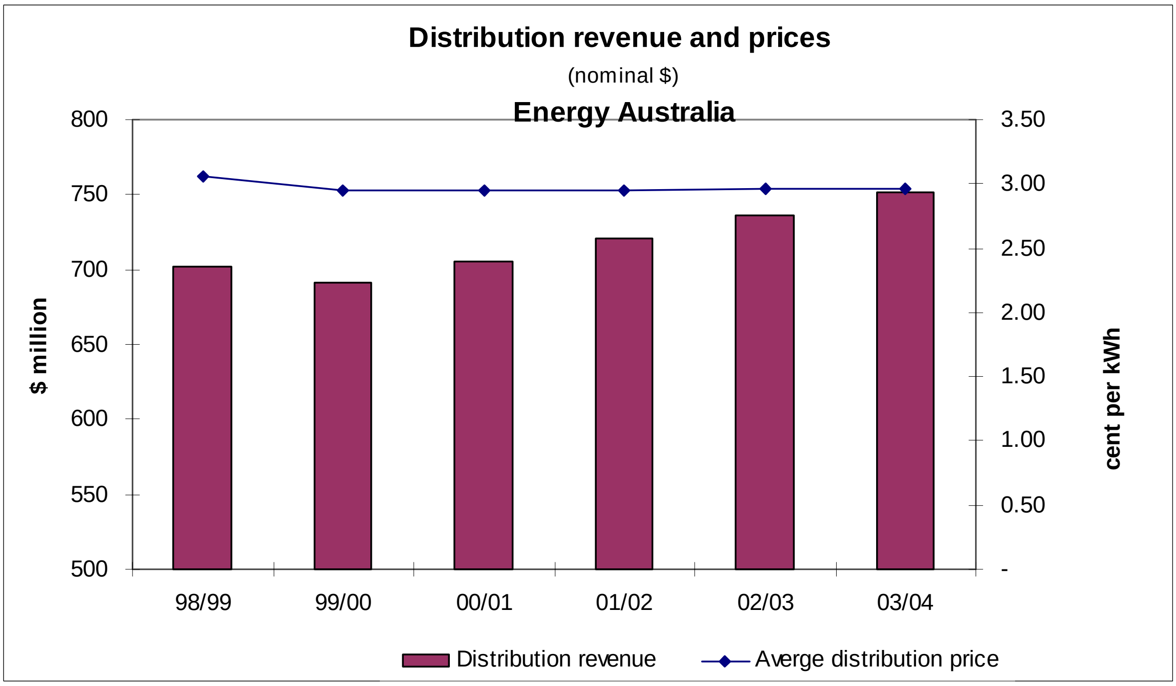
EnergyAustralia	1999/00	2000/01	2001/02	2002/03	2003/04
Cash	-	-	-	-	-
Receivables	89,775	91,694	93,653	95,654	97,697
Inventories	19,900	19,900	19,900	19,900	19,900
Investments	322,400	322,400	322,400	322,400	322,400
Prepayments	14,354	14,354	14,354	14,354	14,354
Accrued Revenue	91,700	91,700	91,700	91,700	91,700
FITB	54,300	54,300	54,300	54,300	54,300
Property, Plant and Equipment	3,939,137	4,031,338	4,122,722	4,233,091	4,353,920
Other assets	57,846	57,846	57,846	57,846	57,846
Total assets	4,589,413	4,683,532	4,776,874	4,889,245	5,012,117
Bank overdraft	-	-	-	-	-
Creditors	82,037	83,225	84,435	85,667	86,922
Accruals	-	-	-	-	-
Borrowings	1,253,743	1,190,609	1,122,197	1,068,936	1,022,893
Customer deposits	400	400	400	400	400
Provision for Income Tax	23,685	23,750	24,192	24,774	25,235
PDIT	120,600	120,600	120,600	120,600	120,600
Provision for dividend	64,475	64,653	65,857	67,440	68,694
Other provisions (employee etc)	138,600	138,600	138,600	138,600	138,600
Other liabilities (provisions per 98 reg accounts)	66,100	66,100	66,100	66,100	66,100
Total liabilities	1,749,640	1,687,938	1,622,381	1,572,516	1,529,443
Share Capital	1,480,000	1,480,000	1,480,000	1,480,000	1,480,000
Asset Revaluation Reserve	1,243,839	1,360,077	1,478,656	1,599,601	1,723,489
Other reserves	-	-	-	-	-
Accumulated Profits/Losses	76,459	115,934	155,517	195,838	237,127
This year's profits retained	39,474	39,583	40,320	41,290	42,058
Shareholders' funds	2,839,773	2,995,594	3,154,494	3,316,728	3,482,674
Total Liabilities and Shareholder's funds	4,589,413	4,683,532	4,776,874	4,889,245	5,012,117

Note: Amounts in nominal dollars. Columns may not add due to rounding.

A2.1.6 Projected operating costs efficiency



A2.1.7 Regulated distribution revenue and price movements



A2.2 Integral Energy profile

A2.2.1 Background

Head Office	51 Huntingwood Drive, Huntingwood NSW 2148
Major Towns/Cities[1]	Lithgow, Katoomba, Nowra, Wollongong
Network Service Area (sq. km)[1]	24,602
Employee Numbers[2]	2,039

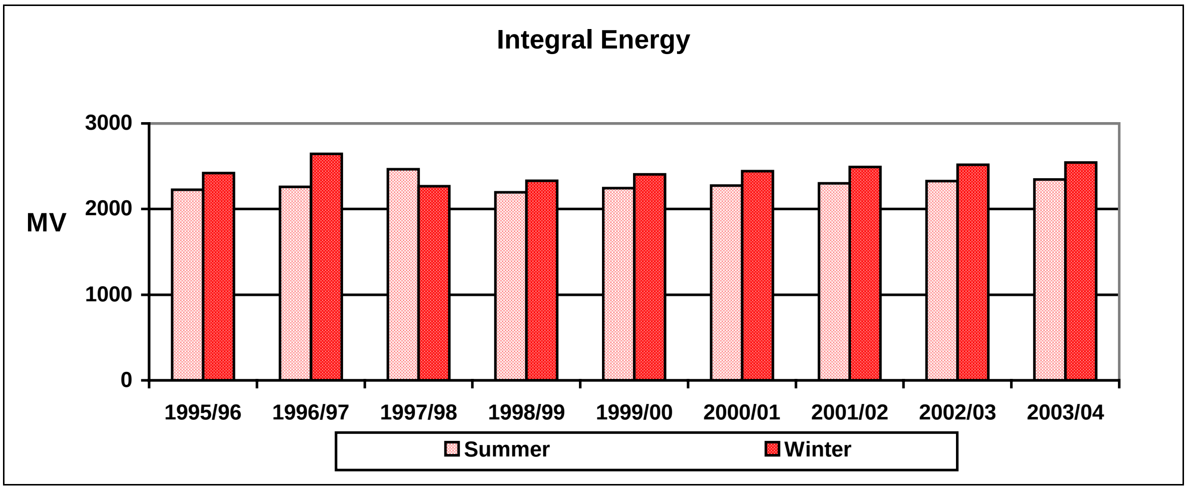
Sources: [1] Distribution Boundary Review Committee (1998); [2] 1997/98 Regulatory Accounts.

A2.2.2 Network Demand Profile

Integral Energy	1995/96	1996/97	1997/98
Total GWh delivered	12,092	12,669	14,005
Peak Demand (MW)	2,421	2,643	2,642
Total Customers	691,359	735,364	739,322
Residential	628,459	658,642	661,472
Non-Residential	62,900	76,722	77,850
Total Route km	25,836	25,680	27,134

Source: London Economics (1999), Final Annex 2.

A2.2.3 Maximum Demands



Source: Worley (1998).

A2.2.4 Integral Energy Distribution Revenue Path Forecasts 1999/2000 – 2003/04

Integral Energy Core Assumptions	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Regulatory Asset Base ($000)	1,773,722	1,821,198	1,847,099	1,863,971	1,880,133
Operating Costs ($000)	157,174	159,924	162,723	165,570	168,468
Capital Expenditure per Worley review ($000)	105,128	83,477	68,762	72,084	70,122
Depreciation ($000)	93,467	98,476	103,099	106,695	106,892
Network Sales (GWh)	14,492	14,999	15,524	16,068	16,630
Sales Growth (%)	3.5%	3.5%	3.5%	3.5%	3.5%

Integral Energy Output Summary ($'000)	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Building Block Revenue Requirement					
Operating Costs	157,174	159,924	162,723	165,570	168,468
Return of Capital (depreciation)	93,467	98,476	103,099	106,695	106,892
Return on Capital	133,029	136,590	138,532	139,798	141,010
Return on Working Capital	2,710	2,884	3,016	3,034	3,087
Total Base Revenue (duos)	386,380	397,874	407,370	415,098	419,457
Smoothed Base Revenue	394,719	400,763	406,900	413,131	419,457
Regulated Return on Assets	7.90%	7.66%	7.47%	7.39%	7.50%
Network Price (nominal c/kWh)	2.72	2.67	2.62	2.57	2.52
Network Price (real c/kWh)	2.64	2.52	2.40	2.28	2.18
Cumulative Real Network Price Change	-11.3%	-15.5%	-19.5%	-23.3%	-27.0%

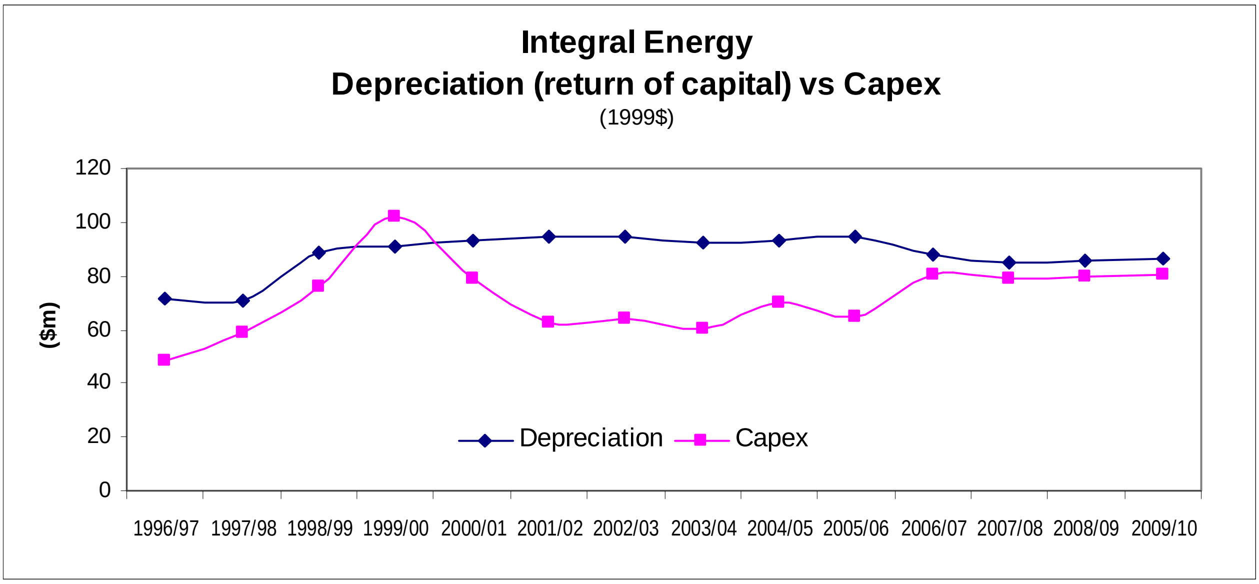
Note: Amounts in nominal dollars. Columns may not add due to rounding.

Integral Energy Regulated Fixed Assets($'000)	1999/00	2000/01	2001/02	2002/03	2003/04
Opening Balance	1,743,768	1,803,676	1,838,720	1,855,478	1,872,464
Add: Revaluation of Assets	52,313	54,110	55,162	55,664	56,174
Add: Capital Expenditure	105,128	83,477	68,762	72,084	70,122
Less: Depreciation	93,467	98,476	103,099	106,695	106,892
Less: Disposals	4,066	4,066	4,066	4,066	4,066
Closing Balance	1,803,676	1,838,720	1,855,478	1,872,464	1,887,801
Average Regulated Fixed Assets	1,773,722	1,821,198	1,847,099	1,863,971	1,880,133

Note: Amounts in nominal dollars. Columns may not add due to rounding.

A2.2.5 Return of Capital (depreciation) Versus Capex Profile

Source: Worley (1998).



Integral Energy Financial Performance Ratios	1999/00	2000/01	2001/02	2002/03	2003/04
Operating costs as % of base revenue	0.49	0.49	0.49	0.49	0.49
EBIT margin on sales (EBIT/revenue)	0.31	0.30	0.29	0.29	0.29
EBITDA margin on sales (EBITDA/revenue)	0.51	0.51	0.51	0.51	0.51
NPAT/Shareholders Funds	0.05	0.05	0.04	0.04	0.04
EBIT/(Total Assets - cash & investments)	0.07	0.07	0.07	0.07	0.07
EBIT/(Borrowings + Equity)	0.07	0.07	0.07	0.07	0.07
EBITDA/(Equity - revaluation)	0.34	0.34	0.34	0.33	0.33
Effective tax rate	0.36	0.36	0.36	0.36	0.36
Dividend cover	0.77	0.77	0.77	0.77	0.77

Integral Energy Ratio Analysis	1999/00	2000/01	2001/02	2002/03	2003/04
Ability to service debt					
(a) Funds flow interest cover (using net interest)	6.60	6.73	7.15	7.91	8.89
NSW Treasury rating (1994)	AAA	AAA	AAA	AAA	AAA
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(b) Funds flow interest cover (using interest expense)	6.17	6.29	6.66	7.31	8.15
NSW Treasury rating (1994)	AAA	AAA	AAA	AAA	AAA
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(a) Pre tax interest cover (EBIT/net interest)	3.11	3.10	3.22	3.49	3.92
S&P - US Utilities (1995)	A	A	A	A	AA
(b) Pre tax interest cover (EBIT + interest earnings) / interest expense)	2.95	2.94	3.04	3.28	3.65
S&P - US Utilities (1995)	A	A	A	A	AA
EBITDA / net interest	5.17	5.28	5.62	6.19	6.89
Ability to repay debt					

Funds flow net debt payback (Net debt/Funds from operations)	4.34	4.00	3.57	3.14	2.73
NSW Treasury rating (1994)	AA	AA	AA	AA	AA
Funds from operations/Total debt	0.21	0.23	0.25	0.28	0.32
S&P - US Utilities (1995)	A	A	A	AA	AA
Total Debt/Total capital	38%	35%	32%	30%	27%
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Funds from operations/Net debt	0.23	0.25	0.28	0.32	0.37
Cash flow before capex/Total debt	15%	16%	18%	20%	23%
EBIT/(total debt + total equity)	9%	9%	10%	10%	12%
Total Debt / Total assets	36%	34%	31%	28%	25%
Reliance on debt					
Internal financing ratio (Net cash flow/net Capex)	1.06	1.40	1.77	1.76	1.83
NSW Treasury rating (1994)	AAA	AAA	AAA	AAA	AAA
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Net cash flow/Capex	1.04	1.38	1.74	1.72	1.80
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Cash flow before Capex and cap cons/net Capex	1.06	1.40	1.77	1.76	1.84
Cash flow before Capex/Capex	1.05	1.39	1.76	1.75	1.83
Funds flow adequacy					
Funds from operations/ (dividends + capex) excl cap cons	1.04	1.25	1.46	1.45	1.48
Funds from operations/ (dividends + capex) including cap cons	1.06	1.27	1.48	1.48	1.51

The credit rating ratios as shown above are based on actual capital structure, which is relatively conservatively geared. The level of gearing is a matter for the Government. The Tribunal has also tested the financial strength of DNSPs using a hypothetical gearing commensurate with the private utilities. Integral Energy is forecast to have a strong financial outcome.

Income & Expenditure Statement ($'000)

Integral Energy	1999/00	2000/01	2001/02	2002/03	2003/04
Income					
Regulated Revenue Cap	394,719	400,763	406,900	413,131	419,457
Transmission Revenue	71,279	72,672	74,092	75,541	77,017
Other Income	157	161	166	171	176
Total Income	466,154	473,596	481,158	488,842	496,650
Operating Expenditure					
Operating Costs	157,174	159,924	162,723	165,570	168,468
Transmission Charges	71,279	72,672	74,092	75,541	77,017
Total Operating Expenditure	228,452	232,596	236,815	241,111	245,485
EBITDA	237,702	241,000	244,343	247,731	251,165
Depreciation	94,779	99,787	104,410	108,006	108,202
EBIT	142,923	141,213	139,934	139,726	142,963
Interest and financing charges	45,979	45,603	43,457	39,999	36,439
Profit Before Tax and Abnormal Items	96,944	95,610	96,476	99,727	106,524
Plus: Capital Contributions	1,296	1,296	1,296	1,296	1,296
Profit Before Tax	98,240	96,906	97,772	101,023	107,820
Tax expense	35,366	34,886	35,198	36,368	38,815
Net Profit After Tax	62,874	62,020	62,574	64,655	69,005
Dividends declared	48,138	47,484	47,908	49,501	52,832

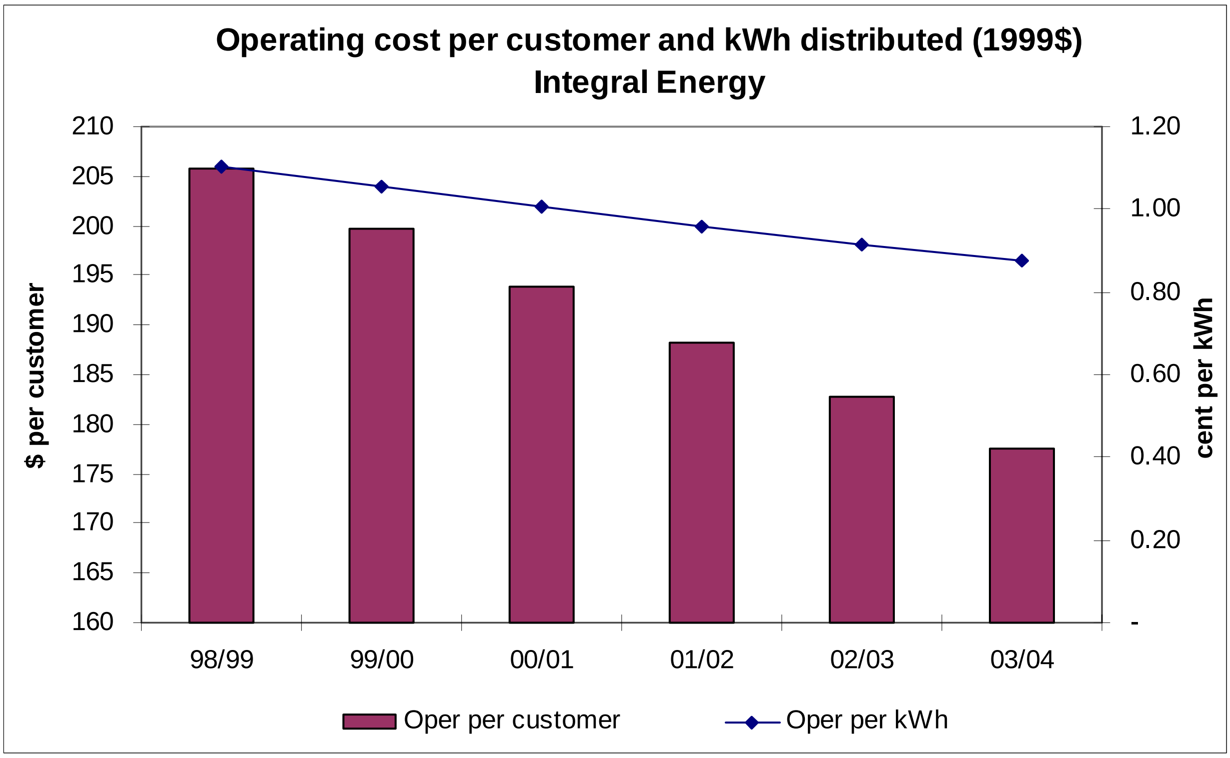
Note: Amounts in nominal dollars. Columns may not add due to rounding.

Balance Sheet ($000)

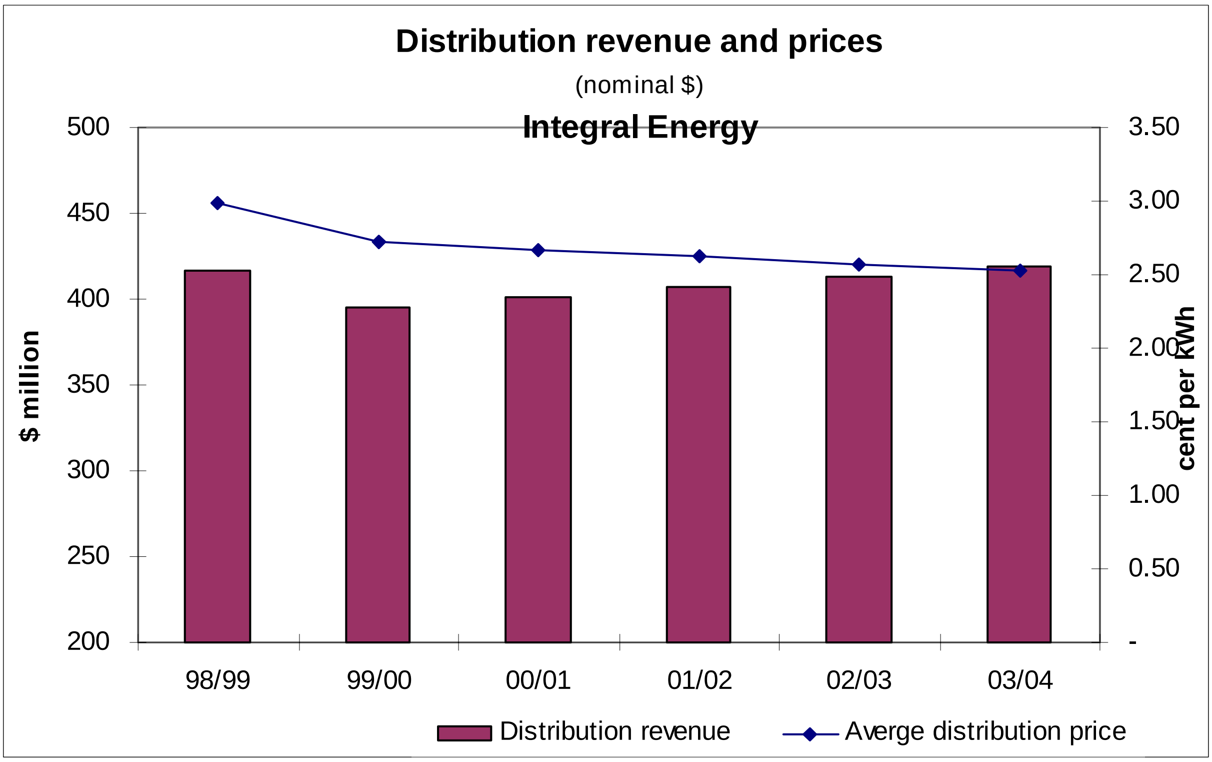
Integral Energy	1999/00	2000/01	2001/02	2002/03	2003/04
Cash	-	-	-	-	-
Receivables	51,313	52,099	52,897	53,707	54,529
Inventories	5,460	5,460	5,460	5,460	5,460
Investments	68,796	68,796	68,796	68,796	68,796
Prepayments	1,136	1,136	1,136	1,136	1,136
Accrued Revenue	26,000	26,000	26,000	26,000	26,000
FITB	-	-	-	-	-
Property, Plant and Equipment	1,833,960	1,868,989	1,885,733	1,902,705	1,918,029
Other assets	137,370	137,370	137,370	137,370	137,370
Total assets	2,124,035	2,159,850	2,177,392	2,195,174	2,211,320
Bank overdraft	-	-	-	-	-
Creditors	34,268	34,889	35,522	36,167	36,823
Accruals	-	-	-	-	-
Borrowings	759,790	726,784	673,576	618,807	559,672
Customer deposits	1,034	1,034	1,034	1,034	1,034
Provision for Income Tax	8,842	8,722	8,800	9,092	9,704
PDIT	-	-	-	-	-
Provision for dividend	24,069	23,742	23,954	24,751	26,416
Other provisions (employee etc)	19,629	19,629	19,629	19,629	19,629
Other liabilities (provisions per 98 reg accounts)	10,703	10,703	10,703	10,703	10,703
Total liabilities	858,335	825,503	773,218	720,182	663,981
Share Capital	1,086,748	1,086,748	1,086,748	1,086,748	1,086,748
Asset Revaluation Reserve	570,285	624,395	679,557	735,221	791,395
Other reserves	-	-	-	-	-
Accumulated Profits/Losses	-406,068	-391,332	-376,796	-362,130	-346,977
This year's profits retained	14,736	14,536	14,666	15,153	16,173
Shareholders' funds	1,265,700	1,334,347	1,404,174	1,474,992	1,547,339
Total Liabilities and Shareholder's funds	2,124,035	2,159,850	2,177,392	2,195,174	2,211,320

Note: Amounts in nominal dollars. Columns may not add due to rounding.

A2.2.6 Projected operating costs efficiency



A2.2.7 Regulated distribution revenue and price movements



A2.3 NorthPower profile

A2.3.1 Background

Head Office	NorthPower House, 9 Short Street, Port Macquarie NSW 2444
Major Towns/Cities[1]	Armidale, Bourke, Casino, Coffs Harbour, Glen Innes, Grafton, Gunnedah, Inverell, Kempsey, Lismore, Moree, Murwillumbah, Narrabri, Port Macquarie, Taree, Tenterfield
Network Service Area (sq. km)[1]	230,000
Employee Numbers[2]	1,127

Sources: [1] Distribution Boundary Review Committee (1998); [2] 1997/98 Regulatory Accounts.

A2.3.2 Network Demand Profile

NorthPower	1995/96	1996/97	1997/98
Total GWh delivered	3,285	3,552	3,720
Peak Demand (MW)	683	771	800
Total Customers	330,043	340,189	350,798
Residential	261,035	269,544	278,517
Non-Residential	69,008	70,645	72,281
Total Route km	66,830	67,281	67,841

Source: London Economics (1999), Final Annex 2.

A2.3.3 Maximum Demands

Not available from NorthPower

A2.3.4 NorthPower Distribution Revenue Path Forecasts 1999/2000 – 2003/04

NorthPower Core Assumptions	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Regulatory Asset Base ($000)	917,925	965,574	1,015,041	1,063,800	1,107,178
Operating Costs ($000)	70,687	71,747	72,824	73,916	75,025
Capital Expenditure per Worley review ($000)	70,051	69,132	75,317	69,338	67,529
Depreciation ($000)	44,991	47,869	49,480	52,459	55,379
Network Sales (GWh)	3,994	4,114	4,238	4,365	4,496
Sales Growth (%)	3%	3%	3%	3%	3%

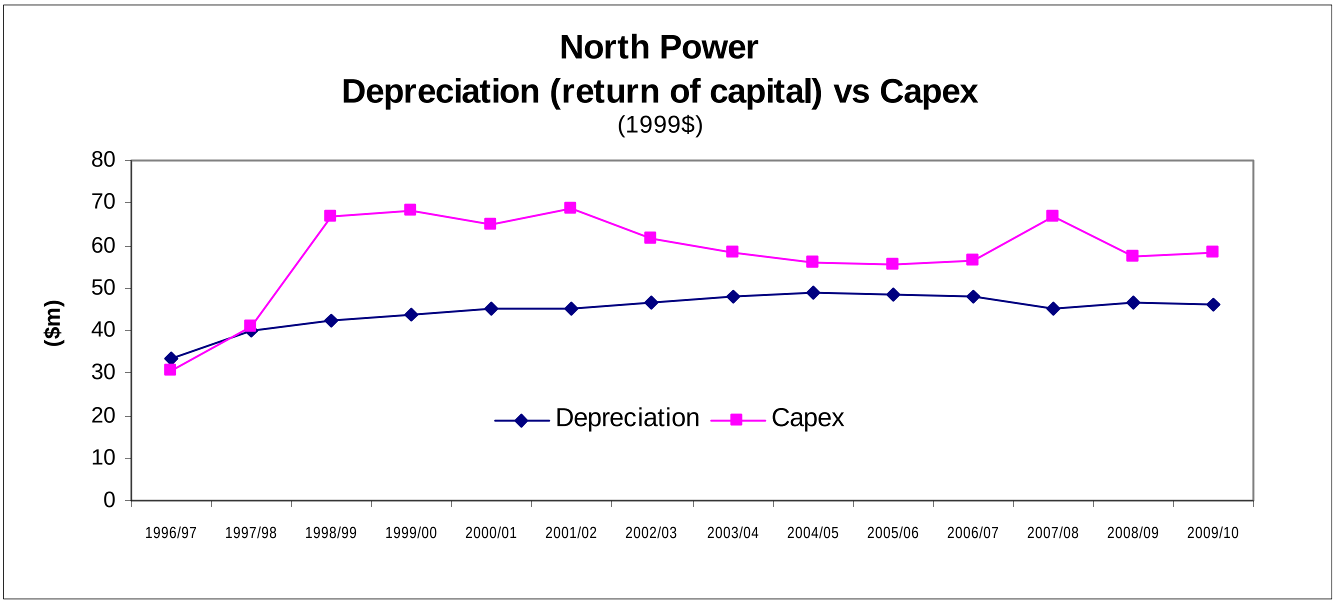
NorthPower Output Summary ($'000)	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Building Block Revenue Requirement					
Operating Costs	70,687	71,747	72,824	73,916	75,025
Return of Capital (depreciation)	44,991	47,869	49,480	52,459	55,379
Return on Capital	68,844	72,418	76,128	79,785	83,038
Return on Working Capital	1,536	1,632	1,688	1,828	1,947
Total Base Revenue (duos)	186,058	193,666	200,120	207,988	215,390
Smoothed Base Revenue	169,597	180,041	191,127	202,896	215,390
Regulated Return on Assets	5.71%	6.09%	6.61%	7.02%	7.50%
Network Price (nominal c/kWh)	4.26	4.38	4.52	4.65	4.79
Network Price (real c/kWh)	4.13	4.13	4.13	4.13	4.13
Cumulative Real Network Price Change		0%	0%	0%	0%

Note: Amounts in nominal dollars. Columns may not add due to rounding.

NorthPower Regulated Fixed Assets($'000)	1999/00	2000/01	2001/02	2002/03	2003/04
Opening Balance	893,517	942,332	988,815	1,041,266	1,086,334
Add: Revaluation of Assets	26,806	28,270	29,664	31,238	32,590
Add: Capital Expenditure	70,051	69,132	75,317	69,338	67,529
Less: Depreciation	44,991	47,869	49,480	52,459	55,379
Less: Disposals	3,050	3,050	3,050	3,050	3,050
Closing Balance	942,332	988,815	1,041,266	1,086,334	1,128,023
Average Regulated Fixed Assets	917,925	965,574	1,015,041	1,063,800	1,107,178

Note: Amounts in nominal dollars. Columns may not add due to rounding.

A2.3.5 Return of Capital (depreciation) Versus Capex Profile



Source: Worley (1998).

NorthPower Financial Performance Ratios	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Operating costs as % of base revenue	53%	50%	47%	45%	42%
EBIT margin on sales (EBIT/revenue)	28%	29%	31%	33%	34%
EBITDA margin on sales (EBITDA/revenue)	50%	51%	53%	55%	56%
NPAT/Shareholders Funds	5%	5%	5%	5%	6%
EBIT/(Total Assets - cash & investments)	6%	6%	6%	7%	7%
EBIT/(Borrowings + Equity)	6%	6%	6%	7%	7%
EBITDA/(Equity - revaluation)	21%	22%	24%	25%	27%
Effective tax rate	36%	36%	36%	36%	36%
Dividend cover	77%	77%	77%	77%	77%

NorthPower Ratio Analysis	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Ability to service debt					
(a) Funds flow interest cover (using net interest)	20.32	18.64	18.35	17.79	18.46
NSW Treasury rating (1994)	AAA	AAA	AAA	AAA	AAA
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(b) Funds flow interest cover (using interest expense)	13.31	12.93	13.13	13.14	13.79
NSW Treasury rating (1994)	AAA	AAA	AAA	AAA	AAA
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(a) Pre tax interest cover (EBIT/net interest)	8.30	7.72	7.82	7.69	8.07
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(b) Pre tax interest cover (EBIT + interest earnings) / interest expense)	5.65	5.55	5.77	5.83	6.18
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
EBITDA / net interest	14.82	13.57	13.28	12.86	13.29

Ability to repay debt					
Funds flow net debt payback (Net debt/Funds from operations)	1.52	1.57	1.66	1.62	1.52
NSW Treasury rating (1994)	AA	AA	AA	AA	AA
Funds from operations/Total debt	0.41	0.41	0.41	0.42	0.45
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Total Debt/Total capital	0.19	0.19	0.20	0.20	0.19
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Funds from operations/Net debt	0.66	0.64	0.60	0.62	0.66
Cash flow before capex/Total debt	26%	27%	26%	27%	28%
EBIT/(total debt + total equity)	13%	14%	14%	15%	16%
Total Debt / Total assets	18%	18%	19%	18%	18%
Reliance on debt					
Internal financing ratio (Net cash flow/net Capex)	0.70	0.78	0.76	0.88	0.96
NSW Treasury rating (1994)	A	A	A	AAA	AAA
S&P - US Utilities (1995)	A	A	A	A	AA
Net cash flow/Capex	0.64	0.71	0.69	0.78	0.85
S&P - US Utilities (1995)	BBB	A	BBB	A	A
Cash flow before Capex and cap cons/net Capex	0.70	0.79	0.77	0.88	0.97
Cash flow before Capex/Capex	0.73	0.81	0.79	0.90	0.97
Funds flow adequacy					
Funds from operations/ (dividends + capex) excl cap cons	0.79	0.85	0.83	0.92	0.98
Funds from operations/ (dividends + capex) including cap cons	0.93	1.00	0.98	1.08	1.15

The credit rating ratios as shown above are based on actual capital structure, which is relatively conservatively geared. The level of gearing is a matter for the Government. The Tribunal has also tested the financial strength of DNSPs using a hypothetical gearing commensurate with the private utilities. NorthPower is forecast to have a strong financial outcome.

Income & Expenditure Statement ($'000)

NorthPower	1999/00	2000/01	2001/02	2002/03	2003/04
Income					
Regulated Revenue Cap	170,022	180,376	191,361	203,015	215,379
Transmission Revenue	35,644	36,163	36,689	37,223	37,764
Other Income	4,981	5,131	5,285	5,443	5,607
Total Income	210,648	221,670	233,335	245,681	258,749
Operating Expenditure					
Operating Costs	70,687	71,747	72,824	73,916	75,025
Transmission Charges	35,644	36,163	36,689	37,223	37,764
Total Operating Expenditure	106,331	107,910	109,512	111,138	112,789
EBITDA	104,316	113,760	123,822	134,542	145,961
Depreciation	45,930	49,049	50,908	54,139	57,322
EBIT	58,386	64,711	72,914	80,403	88,639
Interest and financing charges	7,037	8,382	9,326	10,459	10,982
Profit Before Tax and Abnormal Items	51,350	56,329	63,588	69,944	77,657
Plus: Capital Contributions	7,038	7,491	7,853	8,335	8,833
Profit Before Tax	58,388	63,820	71,441	78,278	86,490
Tax expense	21,020	22,975	25,719	28,180	31,136
Net Profit After Tax	37,368	40,845	45,722	50,098	55,353
Dividends declared	28,610	31,272	35,006	38,356	42,380

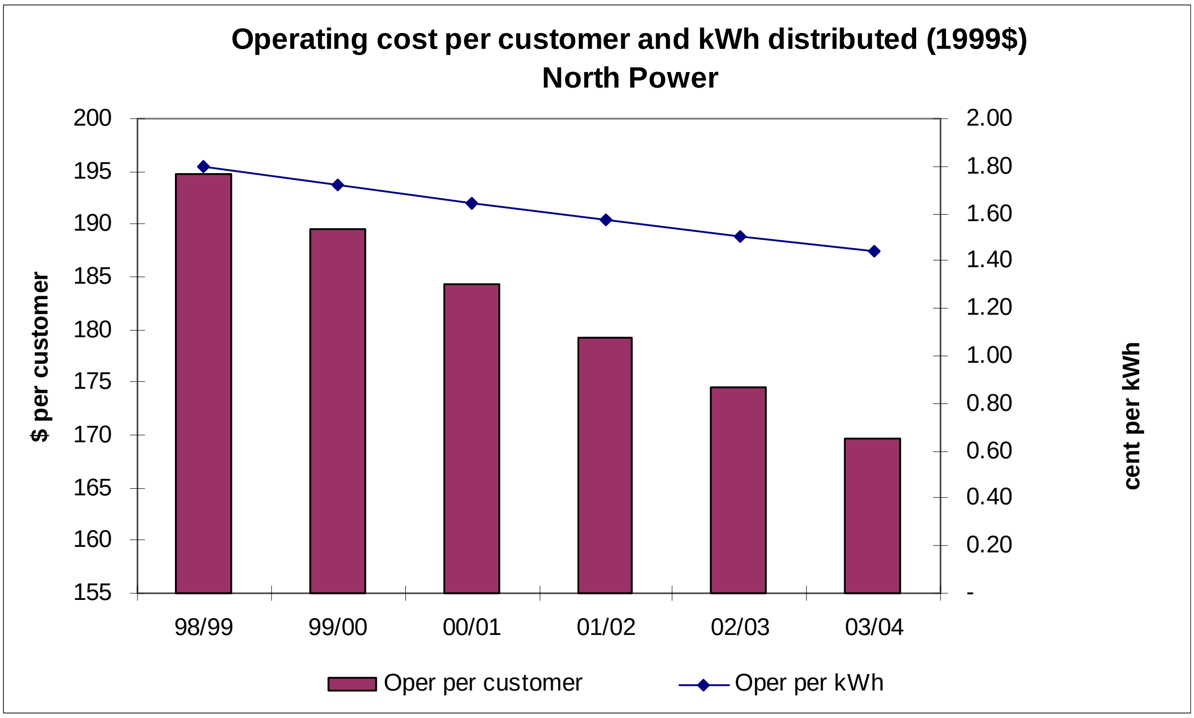
Note: Amounts in nominal dollars. Columns may not add due to rounding.

Balance Sheet ($000)

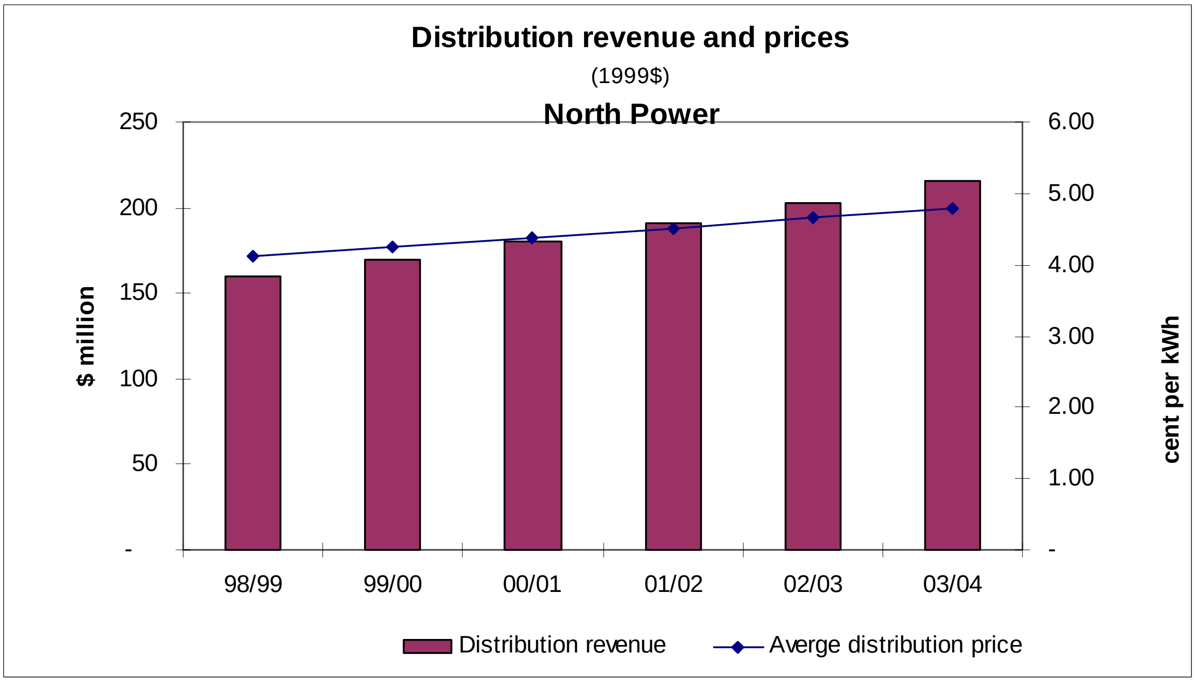
NorthPower	1999/00	2000/01	2001/02	2002/03	2003/04
Cash	-	-	-	-	-
Receivables	25,503	27,056	28,704	30,452	32,307
Inventories	9,304	9,304	9,304	9,304	9,304
Investments	72,934	72,934	72,934	72,934	72,934
Prepayments	115	115	115	115	115
Accrued Revenue	-	-	-	-	-
FITB	-	-	-	-	-
Property, Plant and Equipment	972,281	1,025,076	1,083,952	1,135,674	1,184,254
Other assets	61	61	61	61	61
Total assets	1,080,198	1,134,547	1,195,071	1,248,540	1,298,974
Bank overdraft	-	-	-	-	-
Creditors	10,633	10,791	10,951	11,114	11,279
Accruals	-	-	-	-	-
Borrowings	190,668	205,196	222,626	230,662	232,618
Customer deposits	1	1	1	1	1
Provision for Income Tax	5,255	5,744	6,430	7,045	7,784
PDIT	-	-	-	-	-
Provision for dividend	14,305	15,636	17,503	19,178	21,190
Other provisions (employee etc)	32,673	32,673	32,673	32,673	32,673
Other liabilities (provisions per 98 reg accounts)	-	-	-	-	-
Total liabilities	253,535	270,041	290,184	300,674	305,545
Share Capital	95,910	95,910	95,910	95,910	95,910
Asset Revaluation Reserve	322,879	351,149	380,813	412,051	444,641
Other reserves	-	-	-	-	-
Accumulated Profits/Losses	399,116	407,875	417,448	428,164	439,905
This year's profits retained	8,758	9,573	10,716	11,742	12,973
Shareholders' funds	826,663	864,506	904,887	947,867	993,430
Total Liabilities and Shareholder's funds	1,080,199	1,134,547	1,195,071	1,248,540	1,298,975

Note: Amounts in nominal dollars. Columns may not add due to rounding.

A2.3.6 Projected operating costs efficiency



A2.3.7 Regulated distribution revenue and price movements[146]



146 Nominal $.

A2.4 Great Southern Energy profile

A2.4.1 Background

Head Office	Level 1, CityLink Plaza, 30 Morisset Street, Queanbeyan NSW 2620
Major Towns/Cities[1]	Albury, Bega, Cooma, Cootamundra, Deniliquin, Eden, Griffith, Hay, Junee, Leeton, Queanbeyan, Temora, Wagga Wagga, Yass, Young
Network Service Area (sq. km)[1]	176,000
Employee Numbers[2]	901

Sources: [1] Distribution Boundary Review Committee (1998); [2] 1997/98 Regulatory Accounts.

A2.4.2 Network Demand Profile

Great Southern Energy	1995/96	1996/97	1997/98
Total GWh delivered	3,159	3,018	2,999
Peak Demand (MW)	576	576	576
Total Customers	219,512	223,303	225,841
Residential	185,693	188,378	191,248
Non-Residential	33,819	34,925	34,593
Total Route km	52,191	53,544	54,896

Source: London Economics (1999), Final Annex 2.

A2.4.3 Maximum Demands

Not supplied by Great Southern Energy

A2.4.4 Great Southern Energy Distribution Revenue Path Forecasts 1999/2000 – 2003/04

Great Southern Energy Core Assumptions	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Regulatory Asset Base ($000)	529,694	556,926	583,309	606,930	629,672
Operating Costs ($000)	47,648	48,125	48,606	49,092	49,583
Capital Expenditure per Worley review ($000)	39,790	45,189	39,436	40,504	37,712
Depreciation ($000)	29,199	31,064	32,177	33,486	33,631
Network Sales (GWh)	3,109	3,171	3,234	3,299	3,365
Sales Growth (%)	2%	2%	2%	2%	2%

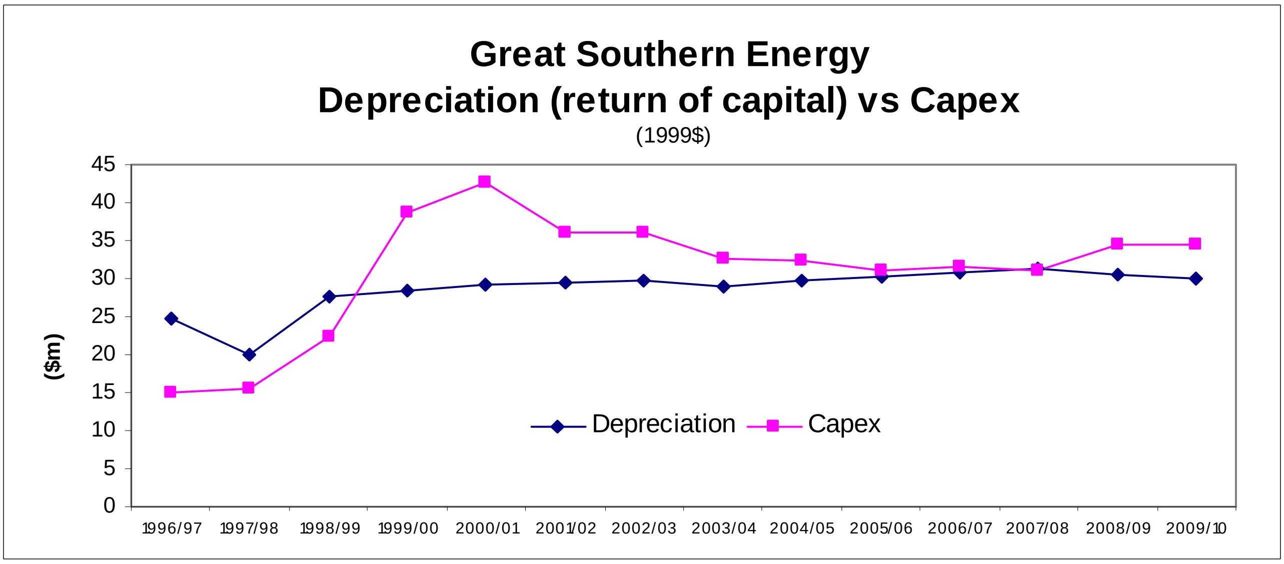
Great Southern Energy Output Summary ($'000)	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Building Block Revenue Requirement					
Operating Costs	47,648	48,125	48,606	49,092	49,583
Return of Capital (depreciation)	29,199	31,064	32,177	33,486	33,631
Return on Capital	39,727	41,769	43,748	45,520	47,225
Return on Working Capital	905	908	983	1,016	1,075
Total Base Revenue (duos)	117,479	121,867	125,514	129,113	131,514
Smoothed Base Revenue	112,884	117,278	121,843	126,587	131,514
Regulated Return on Assets	6.63%	6.68%	6.87%	7.08%	7.50%
Network Price (nominal c/kWh)	3.63	3.70	3.77	3.84	3.91
Network Price (real c/kWh)	3.53	3.49	3.45	3.41	3.37
Cumulative Real Network Price Change	-1.1%	-2.2%	-3.3%	-4.4%	-5.4%

Note: Amounts in nominal dollars. Columns may not add due to rounding.

Great Southern Energy Regulated Fixed Assets($'000)	1999/00	2000/01	2001/02	2002/03	2003/04
Opening Balance	517,150	542,239	571,614	595,004	618,857
Add: Revaluation of Assets	15,514	16,267	17,148	17,850	18,566
Add: Capital Expenditure	39,790	45,189	39,436	40,504	37,712
Less: Depreciation	29,199	31,064	32,177	33,486	33,631
Less: Disposals	1,017	1,017	1,017	1,017	1,017
Closing Balance	542,239	571,614	595,004	618,857	640,487
Average Regulated Fixed Assets	529,694	556,926	583,309	606,930	629,672

Note: Amounts in nominal dollars. Columns may not add due to rounding.

A2.4.5 Return of Capital (depreciation) Versus Capex Profile



Source: Worley (1998).

Great Southern Energy Financial Performance Ratios	1999/00	2000/01	2001/02	2002/03	2003/04
Operating costs as % of base revenue	53%	51%	50%	48%	46%
EBIT margin on sales (EBIT/revenue)	27%	28%	29%	29%	31%
EBITDA margin on sales (EBITDA/revenue)	49%	50%	51%	52%	54%
NPAT/Shareholders Funds	6%	5%	5%	5%	6%
EBIT/(Total Assets - cash & investments)	6%	6%	6%	6%	7%
EBIT/(Borrowings + Equity)	6%	6%	6%	6%	7%
EBITDA/(Equity - revaluation)	19%	20%	20%	21%	22%
Effective tax rate	36%	36%	36%	36%	36%
Dividend cover	77%	77%	77%	77%	77%

Great Southern Energy Ratio Analysis	1999/00	2000/01	2001/02	2002/03	2003/04
Ability to service debt					
(a) Funds flow interest cover (using net interest)	40.64	31.38	25.38	24.10	23.61
NSW Treasury rating (1994)	AAA	AAA	AAA	AAA	AAA
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(b) Funds flow interest cover (using interest expense)	16.65	15.30	14.07	13.98	14.15
NSW Treasury rating (1994)	AAA	AAA	AAA	AAA	AAA
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(a) Pre tax interest cover (EBIT/net interest)	16.13	12.38	10.16	9.74	9.79
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(b) Pre tax interest cover (EBIT + interest earnings) / interest expense)	6.97	6.35	5.91	5.91	6.11
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
EBITDA / net interest	28.73	22.32	18.17	17.31	16.87

Ability to repay debt					
Funds flow net debt payback (Net debt/Funds from operations)	0.80	1.04	1.12	1.16	1.14
NSW Treasury rating (1994)	AA	AA	AA	AA	AA
Funds from operations/Total debt	0.47	0.44	0.43	0.44	0.45
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Total Debt/Total capital	0.17	0.18	0.19	0.19	0.18
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Funds from operations/Net debt	1.24	0.97	0.90	0.86	0.88
Cash flow before capex/Total debt	25%	25%	25%	26%	27%
EBIT/(total debt + total equity)	14%	13%	13%	14%	15%
Total Debt / Total assets	16%	17%	17%	17%	17%
Reliance on debt					
Internal financing ratio (Net cash flow/net Capex)	0.67	0.67	0.82	0.85	0.94
NSW Treasury rating (1994)	BBB	BBB	AAA	AAA	AAA
S&P - US Utilities (1995)	BBB	BBB	A	A	AA
Net cash flow/Capex	0.55	0.56	0.67	0.70	0.76
S&P - US Utilities (1995)	BBB	BBB	BBB	BBB	A
Cash flow before Capex and cap cons/net Capex	0.67	0.67	0.82	0.85	0.95
Cash flow before Capex/Capex	0.73	0.72	0.85	0.88	0.96
Funds flow adequacy					
Funds from operations/ (dividends + capex) excl cap cons	0.79	0.78	0.88	0.90	0.97
Funds from operations/ (dividends + capex) including cap cons	1.09	1.05	1.19	1.20	1.29

The credit rating ratios as shown above are based on actual capital structure, which is relatively conservatively geared. The level of gearing is a matter for the Government. The Tribunal has also tested the financial strength of DNSPs using a hypothetical gearing commensurate with the private utilities. Great Southern Energy is forecast to have a strong financial outcome.

Income & Expenditure Statement ($'000)

Great Southern Energy	1999/00	2000/01	2001/02	2002/03	2003/04
Income					
Regulated Revenue Cap	112,884	117,278	121,843	126,587	131,514
Transmission Revenue	23,664	23,772	23,880	23,989	24,098
Other Income	2,552	2,628	2,707	2,789	2,872
Total Income	139,100	143,678	148,431	153,364	158,484
Operating Expenditure					
Operating Costs	47,648	48,125	48,606	49,092	49,583
Transmission Charges	23,664	23,772	23,880	23,989	24,098
Total Operating Expenditure	71,312	71,897	72,486	73,081	73,681
EBITDA	67,787	71,782	75,945	80,283	84,804
Depreciation	29,736	31,989	33,464	35,116	35,588
EBIT	38,051	39,793	42,481	45,167	49,215
Interest and financing charges	2,360	3,215	4,180	4,639	5,028
Profit Before Tax and Abnormal Items	35,691	36,577	38,300	40,528	44,187
Plus: Capital Contributions	8,930	8,778	8,749	8,724	8,898
Profit Before Tax	44,621	45,355	47,049	49,252	53,086
Tax expense	16,064	16,328	16,938	17,731	19,111
Net Profit After Tax	28,558	29,027	30,112	31,521	33,975
Dividends declared	21,865	22,224	23,054	24,134	26,012

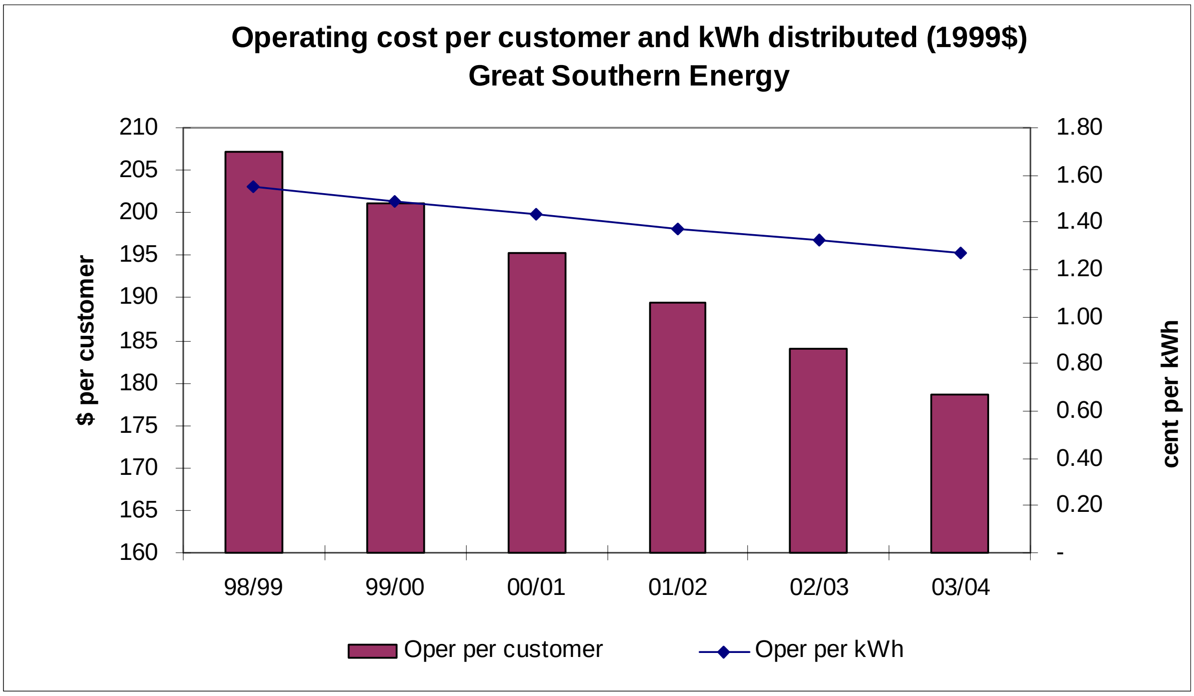
Note: Amounts in nominal dollars. Columns may not add due to rounding.

Balance Sheet ($000)

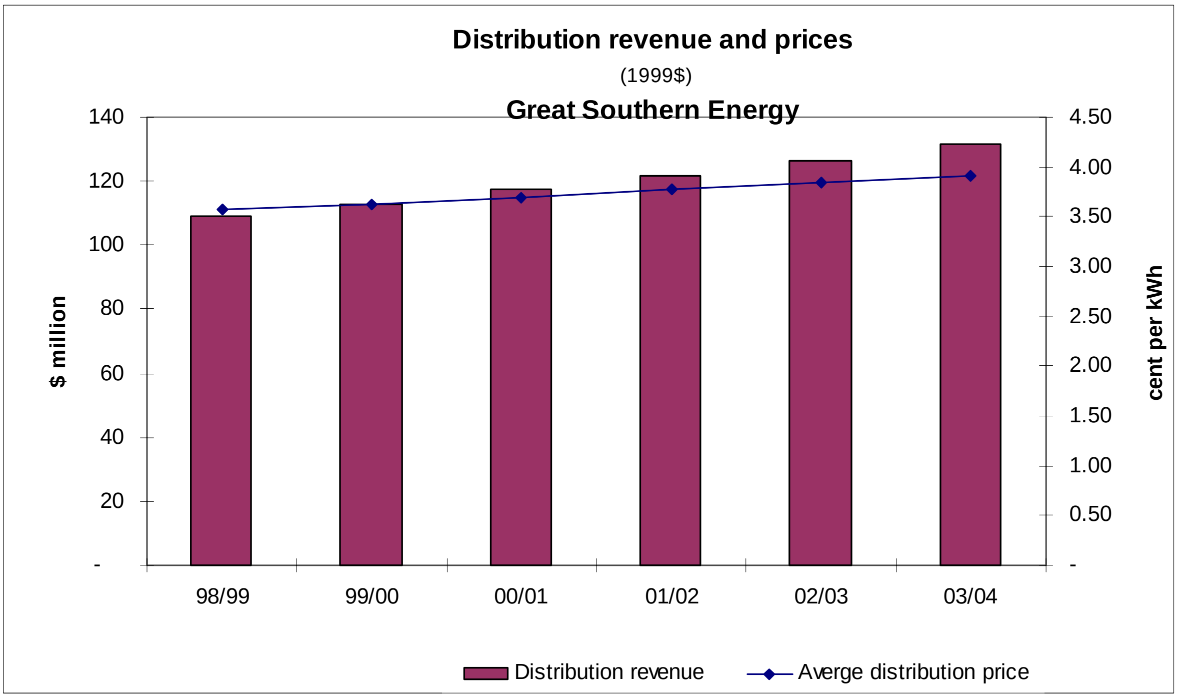
Great Southern Energy	1999/00	2000/01	2001/02	2002/03	2003/04
Cash	-	-	-	-	-
Receivables	27,057	28,110	29,204	30,341	31,522
Inventories	4,156	4,156	4,156	4,156	4,156
Investments	65,754	65,754	65,754	65,754	65,754
Prepayments	3,451	3,451	3,451	3,451	3,451
Accrued Revenue	-	-	-	-	-
FITB	-	-	-	-	-
Property, Plant and Equipment	562,304	599,533	630,386	661,332	689,903
Other assets	13,532	13,532	13,532	13,532	13,532
Total assets	676,254	714,536	746,483	778,566	808,318
Bank overdraft	-	-	-	-	-
Creditors	14,486	14,604	14,724	14,845	14,967
Accruals	-	-	-	-	-
Borrowings	105,106	119,953	127,007	132,993	134,811
Customer deposits	22	22	22	22	22
Provision for Income Tax	4,016	4,082	4,234	4,433	4,778
PDIT	-	-	-	-	-
Provision for dividend	10,932	11,112	11,527	12,067	13,006
Other provisions (employee etc)	30,458	30,458	30,458	30,458	30,458
Other liabilities (provisions per 98 reg accounts)	-	-	-	-	-
Total liabilities	165,020	180,232	187,972	194,817	198,041
Share Capital	253,154	253,154	253,154	253,154	253,154
Asset Revaluation Reserve	150,955	167,222	184,371	202,221	220,787
Other reserves	-	-	-	-	-
Accumulated Profits/Losses	100,432	107,125	113,928	120,986	128,374
This year's profits retained	6,693	6,803	7,057	7,388	7,963
Shareholders' funds	511,234	534,305	558,511	583,749	610,277
Total Liabilities and Shareholder's funds	676,254	714,536	746,483	778,566	808,318

Note: Amounts in nominal dollars. Columns may not add due to rounding.

A2.4.6 Projected operating costs efficiency



A2.4.7 Regulated distribution revenue and price movements[147]



147 Nominal $.

A2.5 Advance Energy profile

A2.5.1 Background

Head Office	Crn Littlebourne Street and Hampden Park Road KELSO NSW 2795
Major Towns/Cities[1]	Bathurst, Cobar, Coonamble, Dubbo, Forbes, Gilgandra, Mudgee, Nyngan, Parkes, Orange, Wellington
Network Service Area (sq. km)[1]	167,272
Employee Numbers[2]	547

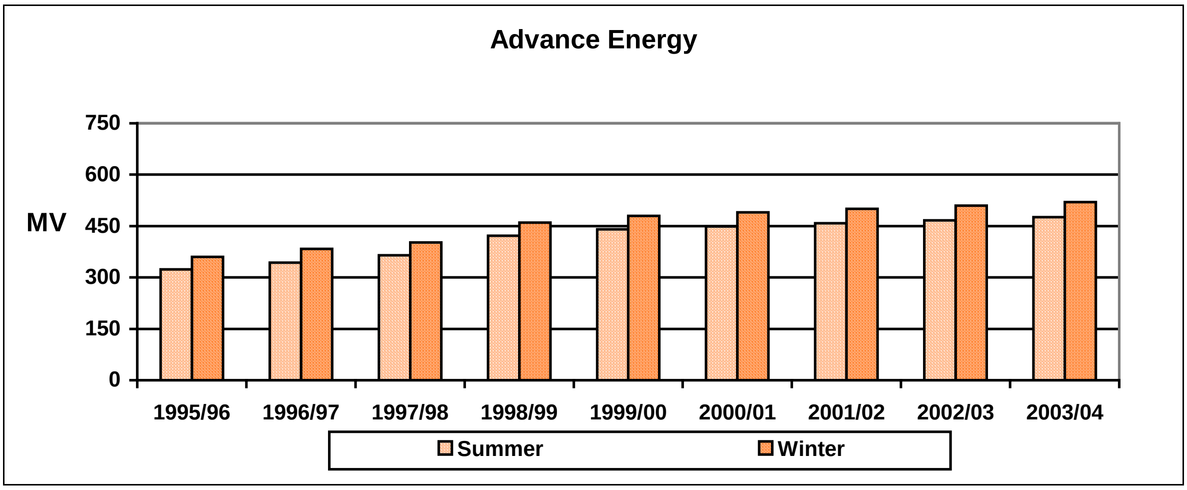
Sources: [1] Distribution Boundary Review Committee (1998); [2] 1997/98 Regulatory Accounts.

A2.5.2 Demand Growth Profile

Advance Energy	1995/96	1996/97	1997/98
Total GWh delivered	1,995	2,368	2,393
Peak Demand (MW)	360	383	402
Total Customers	116,156	116,537	117,613
Residential	100,307	97,970	98,653
Non-Residential	15,849	18,567	18,960
Total Route km	41,858	41,985	42,231

Source: London Economics (1999), Final Annex 2.

A2.5.3 Maximum Demands



Source: Worley (1998).

A2.5.4 Advance Energy Distribution Revenue Path Forecasts 1999/2000 – 2003/04

Advance Energy Core Assumptions	1999/00	2000/01	2001/02	2002/03	2003/04
Regulatory Asset Base ($000)	322,641	339,198	356,188	375,681	395,925
Operating Costs ($000)	43,826	44,374	44,929	45,491	46,059
Capital Expenditure per Worley review ($000)	28,272	27,933	28,882	32,266	30,170
Depreciation ($000)	18,890	20,051	19,630	20,396	20,586
Network Sales (GWh)	2,703	2,770	2,840	2,911	2,983
Sales Growth (%)	2.5%	2.5%	2.5%	2.5%	2.5%

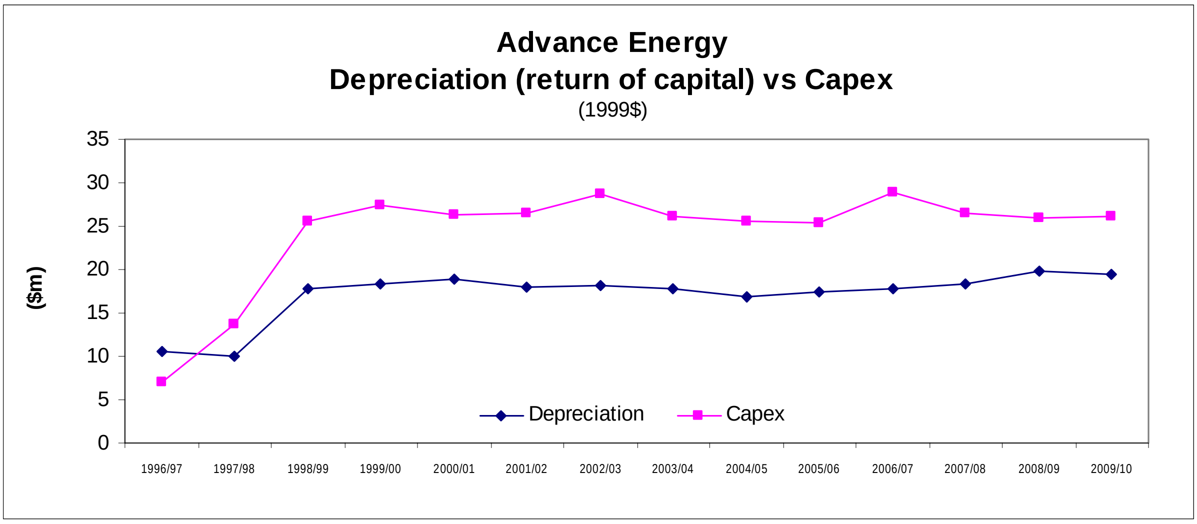
Advance Energy Output Summary ($'000)	1999/00	2000/01	2001/02	2002/03	2003/04
Building Block Revenue Requirement					
Operating Costs	43,826	44,374	44,929	45,491	46,059
Return of Capital (depreciation)	18,890	20,051	19,630	20,396	20,586
Return on Capital	24,198	25,440	26,714	28,176	29,694
Return on Working Capital	551	589	621	640	695
Total Base Revenue (duos)	87,465	90,454	91,893	94,702	97,035
Smoothed Base Revenue	73,924	78,045	82,396	86,989	91,839
Regulated Return on Assets	3.26%	3.76%	4.71%	5.28%	5.98%
Network Price (nominal c/kWh)	2.74	2.82	2.90	2.99	3.08
Network Price (real c/kWh)	2.66	2.66	2.66	2.66	2.66
Cumulative Real Network Price Change	0%	0%	0%	0%	0%

Note: Amounts in nominal dollars. Columns may not add due to rounding.

Advance Energy Regulated Fixed Assets($'000)	1999/00	2000/01	2001/02	2002/03	2003/04
Opening Balance	314,115	331,166	347,230	365,146	386,217
Add: Revaluation of Assets	9,423	9,935	10,417	10,954	11,587
Add: Capital Expenditure	28,272	27,933	28,882	32,266	30,170
Less: Depreciation	18,890	20,051	19,630	20,396	20,586
Less: Disposals	1,754	1,754	1,754	1,754	1,754
Closing Balance	331,166	347,230	365,146	386,217	405,634
Average Regulated Fixed Assets	322,641	339,198	356,188	375,681	395,925

Note: Amounts in nominal dollars. Columns may not add due to rounding.

A2.5.5 Return of Capital (depreciation) Versus Capex Profile



Source: Worley (1998).

Advance Energy Financial Performance Ratios	1999/00	2000/01	2001/02	2002/03	2003/04
Operating costs as % of base revenue	75%	71%	67%	64%	60%
EBIT margin on sales (EBIT/revenue)	17%	19%	22%	24%	26%
EBITDA margin on sales (EBITDA/revenue)	38%	40%	42%	44%	46%
NPAT/Shareholders Funds	5%	5%	5%	6%	6%
EBIT/(Total Assets - cash & investments)	4%	5%	5%	6%	6%
EBIT/(Borrowings + Equity)	5%	5%	6%	6%	7%
EBITDA/(Equity - revaluation)	14%	16%	17%	18%	20%
Effective tax rate	36%	36%	36%	36%	36%
Dividend cover	77%	77%	77%	77%	77%

Advance Energy Ratio Analysis	1999/00	2000/01	2001/02	2002/03	2003/04
Ability to service debt					
(a) Funds flow interest cover (using net interest)	18.86	16.16	15.27	14.50	13.62
NSW Treasury rating (1994)	AAA	AAA	AAA	AAA	AAA
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(b) Funds flow interest cover (using interest expense)	14.44	13.08	12.73	12.36	11.87
NSW Treasury rating (1994)	AAA	AAA	AAA	AAA	AAA
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(a) Pre tax interest cover (EBIT/net interest)	6.23	5.49	5.67	5.59	5.51
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(b) Pre tax interest cover (EBIT + interest earnings) / interest expense)	4.93	4.58	4.84	4.86	4.89
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
EBITDA / net interest	13.53	11.60	10.82	10.28	9.62

Ability to repay debt					
Funds flow net debt payback (Net debt/Funds from operations)	1.90	2.05	2.23	2.42	2.50
NSW Treasury rating (1994)	AA	AA	AA	AA	AA
Funds from operations/Total debt	0.40	0.38	0.36	0.35	0.34
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Total Debt/Total capital	19%	20%	21%	23%	23%
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Funds from operations/Net debt	0.52	0.49	0.45	0.41	0.40
Cash flow before capex/Total debt	25%	24%	23%	21%	20%
EBIT/(total debt + total equity)	10%	10%	11%	11%	12%
Total Debt / Total assets	17%	18%	19%	21%	21%
Reliance on debt					
Internal financing ratio (Net cash flow/net Capex)	0.58	0.66	0.66	0.62	0.69
NSW Treasury rating (1994)	BBB	BBB	BBB	BBB	BBB
S&P - US Utilities (1995)	BBB	BBB	BBB	BBB	BBB
Net cash flow/Capex	0.46	0.52	0.52	0.50	0.55
S&P - US Utilities (1995)	BBB	BBB	BBB	BBB	BBB
Cash flow before Capex and cap cons/net Capex	0.58	0.66	0.67	0.63	0.70
Cash flow before Capex/Capex	0.67	0.73	0.74	0.70	0.77
Funds flow adequacy					
Funds from operations/ (dividends + capex) excl cap cons	0.69	0.75	0.76	0.73	0.80
Funds from operations/ (dividends + capex) including cap cons	1.08	1.17	1.16	1.09	1.18

The credit rating ratios as shown above are based on actual capital structure, which is relatively conservatively geared. The level of gearing is a matter for the Government. The Tribunal has also tested the financial strength of DNSPs using a hypothetical gearing commensurate with the private utilities. Advance Energy is forecast to have a strong financial outcome.

Income & Expenditure Statement ($'000)

Advance Energy	1999/00	2000/01	2001/02	2002/03	2003/04
Income					
Regulated Revenue Cap	73,924	78,045	82,396	86,989	91,839
Transmission Revenue	15,135	15,274	15,414	15,555	15,698
Other Income	5,870	6,046	6,227	6,414	6,606
Total Income	94,929	99,365	104,037	108,958	114,143
Operating Expenditure					
Operating Costs	43,826	44,374	44,929	45,491	46,059
Transmission Charges	15,135	15,274	15,414	15,555	15,698
Total Operating Expenditure	58,962	59,648	60,343	61,046	61,757
EBITDA	35,967	39,716	43,694	47,913	52,386
Depreciation	19,414	20,899	20,795	21,876	22,375
EBIT	16,553	18,818	22,899	26,037	30,011
Interest and financing charges	2,659	3,425	4,039	4,661	5,444
Profit Before Tax and Abnormal Items	13,894	15,393	18,860	21,376	24,567
Plus: Capital Contributions	7,226	7,428	7,688	7,880	8,077
Profit Before Tax	21,120	22,821	26,548	29,256	32,644
Tax expense	7,603	8,215	9,557	10,532	11,752
Net Profit After Tax	13,517	14,605	16,991	18,724	20,892
Dividends declared	10,349	11,182	13,008	14,335	15,995

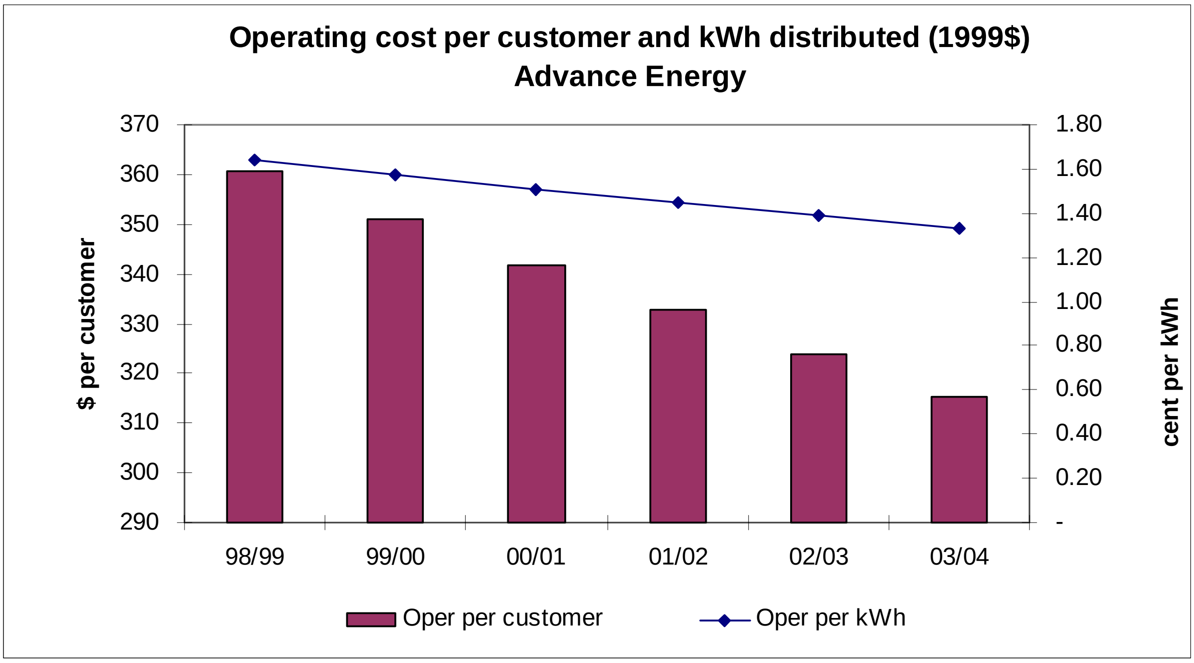
Note: Amounts in nominal dollars. Columns may not add due to rounding.

Balance Sheet ($000)

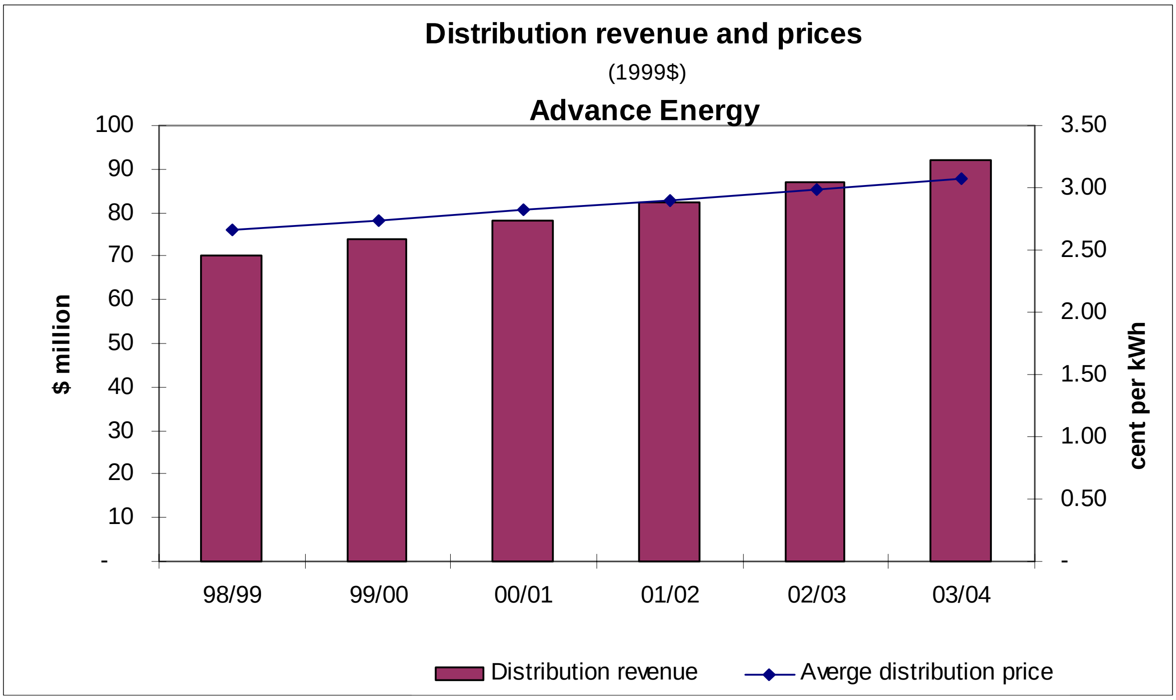
Advance Energy	1999/00	2000/01	2001/02	2002/03	2003/04
Cash	-	-	-	-	-
Receivables	15,814	16,696	17,627	18,609	19,647
Inventories	3,387	3,387	3,387	3,387	3,387
Investments	15,902	15,902	15,902	15,902	15,902
Prepayments	309	309	309	309	309
Accrued Revenue	8,432	8,432	8,432	8,432	8,432
FITB	-	-	-	-	-
Property, Plant and Equipment	348,710	371,354	395,792	423,263	448,967
Other assets	-	-	-	-	-
Total assets	392,554	416,080	441,449	469,902	496,644
Bank overdraft	-	-	-	-	-
Creditors	12,972	13,123	13,275	13,430	13,586
Accruals	-	-	-	-	-
Borrowings	66,147	75,594	85,163	97,211	106,179
Customer deposits	-	-	-	-	-
Provision for Income Tax	1,901	2,054	2,389	2,633	2,938
PDIT	-	-	-	-	-
Provision for dividend	5,174	5,591	6,504	7,168	7,998
Other provisions (employee etc)	18,996	18,996	18,996	18,996	18,996
Other liabilities (provisions per 98 reg accounts)	-	-	-	-	-
Total liabilities	105,190	115,357	126,328	139,438	149,697
Share Capital	-2,004	-2,004	-2,004	-2,004	-2,004
Asset Revaluation Reserve	35,961	45,896	56,313	67,267	78,854
Other reserves	-	-	-	-	-
Accumulated Profits/Losses	250,239	253,407	256,830	260,812	265,201
This year's profits retained	3,168	3,423	3,982	4,388	4,897
Shareholders' funds	287,364	300,722	315,121	330,464	346,947
Total Liabilities and Shareholder's funds	392,554	416,080	441,449	469,902	496,644

Note: Amounts in nominal dollars. Columns may not add due to rounding.

A2.5.6 Projected operating costs efficiency



A2.5.7 Regulated distribution revenue and price movements[148]



148 Nominal $.

A2.6 Australian Inland Energy profile

A2.6.1 Background

Head Office	160-162 Beryl Street, Broken Hill NSW 2880
Major Towns/Cities[1]	Broken Hill, Menindee, Mildura, Wilcannia, Tibooburra
Network Service Area (sq. km)[1]	155,100
Employee Numbers[2]	98

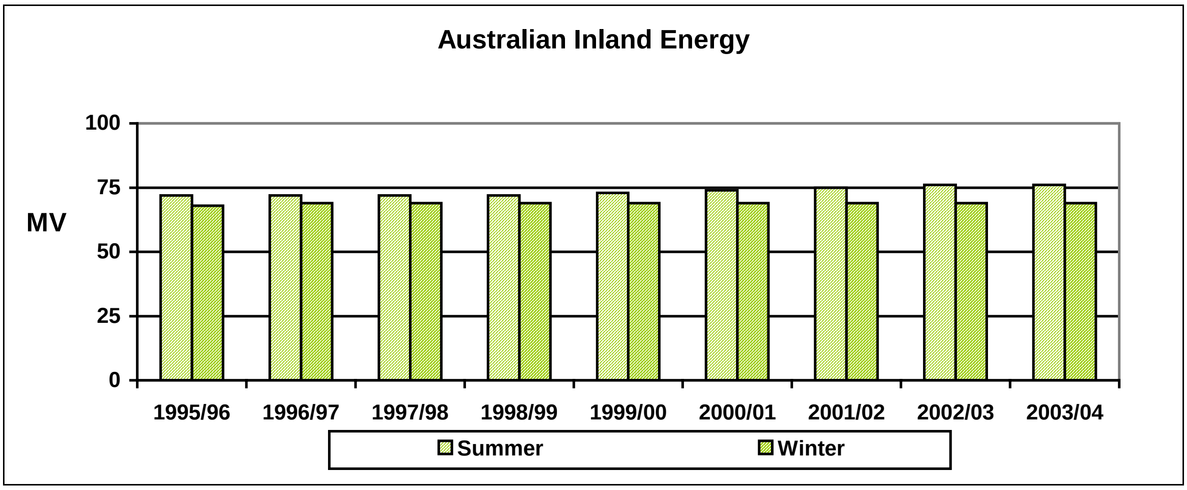
Sources: [1] Distribution Boundary Review Committee (1998); [2] 1997/98 Regulatory Accounts.

A2.6.2 Demand Growth Profile

Australian Inland Energy	1995/96	1996/97	1997/98
Total GWh delivered	361	383	393
Peak Demand (MW)	72	72	73
Total Customers	18,923	19,127	19,046
Residential	15,622	15,836	15,836
Non-Residential	3,301	3,291	3,210
Total Route km	8,993	9,048	9,096

Source: London Economics (1999), Final Annex 2.

A2.6.3 Maximum Demands



Source: Worley (1998).

A2.6.4 Australian Inland Energy Distribution Revenue Path Forecasts 1999/2000 – 2003/04

Australian Inland Energy Core Assumptions	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Regulatory Asset Base ($000)	52,351	54,537	56,738	58,949	61,165
Operating Costs ($000)	6,861	7,033	7,208	7,389	7,573
Capital Expenditure per Worley review ($000)	3,246	3,343	3,444	3,547	3,653
Depreciation ($000)	2,606	2,752	2,906	3,068	3,237
Network Sales (MWh)	421,964	426,183	430,445	434,750	439,097
Sales Growth (%)	1.0%	1.0%	1.0%	1.0%	1.0%

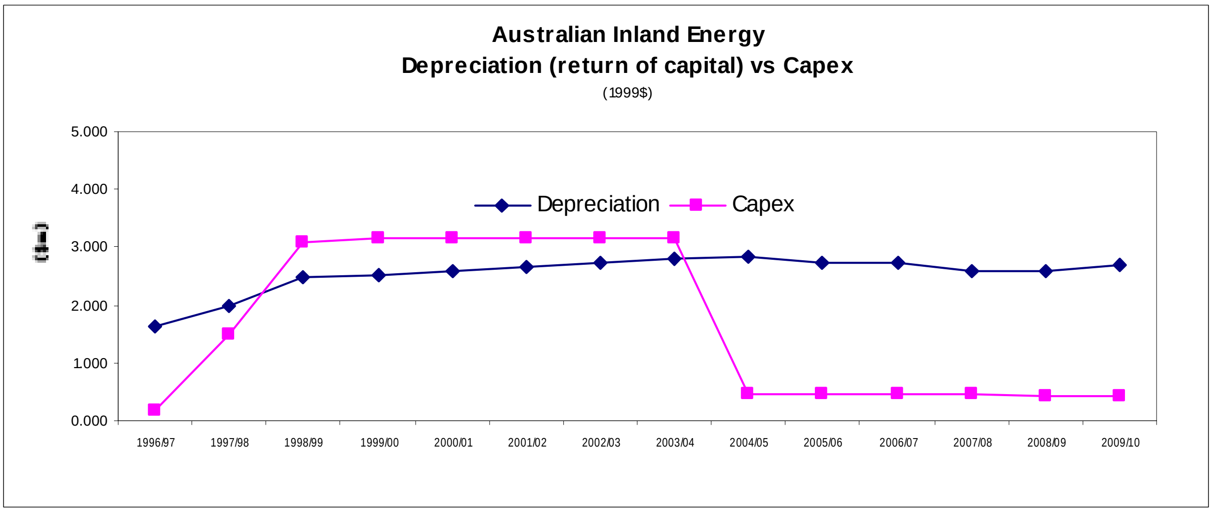
Australian Inland Energy Output Summary ($'000)	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Building Block Revenue Requirement					
Operating Costs	6,861	7,033	7,208	7,389	7,573
Return of Capital (depreciation)	2,606	2,752	2,906	3,068	3,237
Return on Capital	3,926	4,090	4,255	4,421	4,587
Return on Working Capital	182	185	188	190	193
Total Base Revenue (duos)	13,576	14,059	14,557	15,068	15,591
Smoothed Base Revenue	11,322	11,778	12,252	12,746	13,260
Regulated Return on Assets	3.19%	3.32%	3.44%	3.56%	3.69%
Network Price (nominal c/kWh)	2.68	2.76	2.85	2.93	3.02
Network Price (real c/kWh)	2.60	2.60	2.60	2.60	2.60
Cumulative Real Network Price Change	0.00%	0.00%	0.00%	0.00%	0.00%

Note: Amounts in nominal dollars. Columns may not add due to rounding.

Australian Inland Energy Regulated Fixed Assets($'000)	1999/00	2000/01	2001/02	2002/03	2003/04
Opening Balance	51,262	53,440	55,635	57,842	60,056
Add: Revaluation of Assets	1,538	1,603	1,669	1,735	1,802
Add: Capital Expenditure	3,246	3,343	3,444	3,547	3,653
Less: Depreciation	2,606	2,752	2,906	3,068	3,237
Less: Disposals	-	-	-	-	-
Closing Balance	53,440	55,635	57,842	60,056	62,274
Average Regulated Fixed Assets	52,351	54,537	56,738	58,949	61,165

Note: Amounts in nominal dollars. Columns may not add due to rounding.

A2.6.5 Return of Capital (depreciation) Versus Capex Profile



Source: Worley (1998).

Australian Inland Energy Financial Performance Ratios	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Operating costs as % of base revenue	86%	83%	81%	78%	76%
EBIT margin on sales (EBIT/revenue)	27%	26%	24%	23%	22%
EBITDA margin on sales (EBITDA/revenue)	45%	45%	44%	43%	43%
NPAT/Shareholders Funds	7%	6%	6%	5%	5%
EBIT/(Total Assets - cash & investments)	6%	6%	5%	5%	5%
EBIT/(Borrowings + Equity)	6%	5%	5%	5%	4%
EBITDA/(Equity - revaluation)	15%	15%	15%	15%	15%
Effective tax rate	36%	36%	36%	36%	36%
Dividend cover	77%	77%	77%	77%	77%

Australian Inland Energy Ratio Analysis	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Ability to service debt					
(a) Funds flow interest cover (using net interest)	-13.54	-16.75	-19.85	-24.12	-30.46
NSW Treasury rating (1994)	>AAA	>AAA	>AAA	>AAA	>AAA
S&P - US Utilities (1995)	>AA	>AA	>AA	>AA	>AA
(b) Funds flow interest cover (using interest expense)	120.29	46.55	33.02	25.93	21.61
NSW Treasury rating (1994)	AAA	AAA	AAA	AAA	AAA
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(a) Pre tax interest cover (EBIT/net interest)	-4.94	-5.94	-6.87	-8.13	-9.98
S&P - US Utilities (1995)	>AA	>AA	>AA	>AA	>AA
(b) Pre tax interest cover (EBIT + interest earnings) / interest expense)	49.73	18.82	13.08	10.06	8.20
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
EBITDA / net interest	-8.25	-10.35	-12.48	-15.42	-19.76

Ability to repay debt					
Funds flow net debt payback (Net debt/Funds from operations)	-2.54	-2.18	-1.85	-1.55	-1.27
NSW Treasury rating (1994)	>AAA	>AAA	>AAA	>AAA	>AAA
Funds from operations/Total debt	1.27	0.92	0.73	0.62	0.54
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Total Debt/Total capital	6%	7%	9%	10%	11%
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Funds from operations/Net debt	-0.39	-0.46	-0.54	-0.65	-0.79
Cash flow before capex/Total debt	22%	32%	28%	25%	23%
EBIT/(total debt + total equity)	22%	18%	16%	14%	12%
Total Debt / Total assets	5%	7%	8%	9%	10%
Reliance on debt					
Internal financing ratio (Net cash flow/net Capex)	0.33	0.53	0.57	0.60	0.63
NSW Treasury rating (1994)	<BB	BBB	BBB	BBB	BBB
S&P - US Utilities (1995)	BB	BBB	BBB	BBB	BBB
Net cash flow/Capex	0.20	0.33	0.36	0.38	0.40
S&P - US Utilities (1995)	<BB	BB	BB	BB	BB
Cash flow before Capex and cap cons/net Capex	0.26	0.53	0.56	0.60	0.63
Cash flow before Capex/Capex	0.54	0.70	0.73	0.74	0.76
Funds flow adequacy					
Funds from operations/ (dividends + capex) excl cap cons	0.69	0.76	0.78	0.79	0.80
Funds from operations/ (dividends + capex) including cap cons	1.35	1.53	1.55	1.57	1.61

The credit rating ratios as shown above are based on actual capital structure, which is relatively conservatively geared. The level of gearing is a matter for the Government. The Tribunal has also tested the financial strength of DNSPs using a hypothetical gearing commensurate with the private utilities. Australian Inland Energy is forecast to have a strong financial outcome.

Income & Expenditure Statement ($'000)

Australian Inland Energy	1999/00	2000/01	2001/02	2002/03	2003/04
Income					
Regulated Revenue Cap	11,322	11,778	12,252	12,746	13,260
Transmission Revenue	3,359	3,341	3,323	3,305	3,287
Other Income					
Total Income	14,681	15,119	15,575	16,051	16,546
Operating Expenditure					
Operating Costs	6,861	7,033	7,208	7,389	7,573
Transmission Charges	3,359	3,341	3,323	3,305	3,287
Total Operating Expenditure	10,220	10,374	10,531	10,693	10,860
CSOs and Grants	2,200	2,000	1,800	1,600	1,400
EBITDA	6,660	6,745	6,844	6,958	7,087
Depreciation	2,672	2,871	3,077	3,289	3,508
EBIT	3,988	3,874	3,767	3,668	3,579
Interest and financing charges	(807)	(652)	(549)	(451)	(359)
Profit Before Tax and Abnormal Items	4,795	4,526	4,316	4,119	3,938
Plus: Capital Contributions	2,000	2,000	2,010	2,020	2,060
Profit Before Tax	6,795	6,526	6,326	6,139	5,998
Tax expense	2,446	2,349	2,277	2,210	2,159
Net Profit After Tax	4,349	4,177	4,049	3,929	3,839
Dividends declared	3,330	3,198	3,100	3,008	2,939

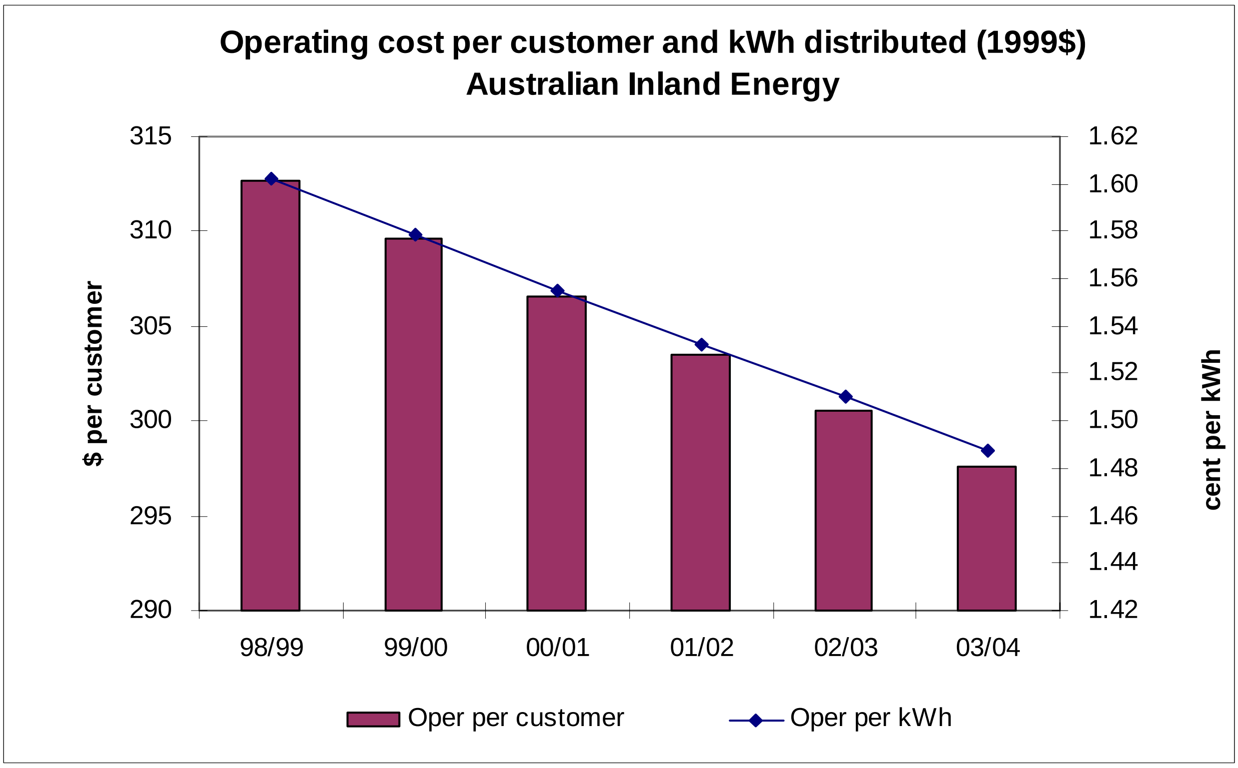
Note: Amounts in nominal dollars. Columns may not add due to rounding.

Balance Sheet ($000)

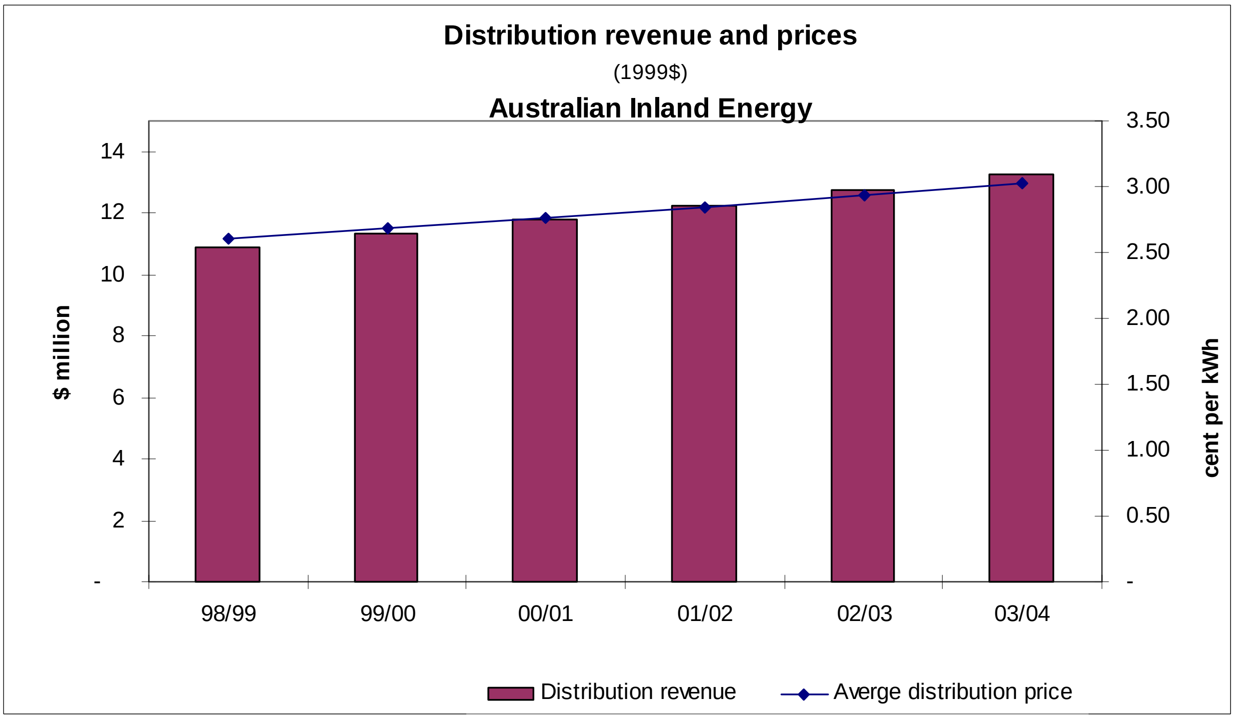
Australian Inland Energy	1999/00	2000/01	2001/02	2002/03	2003/04
Cash	-	-	-	-	-
Receivables	793	824	858	892	928
Inventories	1,680	1,680	1,680	1,680	1,680
Investments	16,467	16,467	16,467	16,467	16,467
Prepayments	291	291	291	291	291
Accrued Revenue	-	-	-	-	-
FITB	1,039	1,039	1,039	1,039	1,039
Property, Plant and Equipment	57,799	61,875	65,921	69,934	73,942
Other assets	1,103	1,103	1,103	1,103	1,103
Total assets	79,172	83,279	87,359	91,406	95,450
Bank overdraft	-	-	-	-	-
Creditors	1,902	1,930	1,960	1,990	2,021
Accruals	-	-	-	-	-
Borrowings	3,908	5,495	6,994	8,417	9,776
Customer deposits	327	327	327	327	327
Provision for Income Tax	612	587	569	553	540
PDIT	2,671	2,671	2,671	2,671	2,671
Provision for dividend	1,665	1,599	1,550	1,504	1,469
Other provisions (employee etc)	2,857	2,857	2,857	2,857	2,857
Other liabilities (provisions per 98 reg accounts)	-	-	-	-	-
Total liabilities	13,941	15,466	16,928	18,319	19,662
Share Capital	34,922	34,922	34,922	34,922	34,922
Asset Revaluation Reserve	20,710	22,313	23,982	25,718	27,519
Other reserves	-	-	-	-	-
Accumulated Profits/Losses	8,579	9,599	10,577	11,526	12,447
This year's profits retained	1,019	979	949	921	900
Shareholders' funds	65,231	67,813	70,431	73,087	75,788
Total Liabilities and Shareholder's funds	79,172	83,279	87,359	91,406	95,450

Note: Amounts in nominal dollars. Columns may not add due to rounding.

A2.6.6 Projected operating costs efficiency



A2.6.7 Regulated distribution revenue and price movements[149]



149 Nominal $.

ATTACHMENT 3 DEPRECIATION

As discussed in chapter 7, since the release of the section 12A report, the Tribunal has obtained further information from the GHD/Arthur Andersen/Worley International consortium and has refined the asset lives adopted for each DNSP in order to more accurately reflect where each DNSP is in its asset life cycle.

For this determination, the Tribunal has calculated depreciation rates for system assets on the basis of the effective lives of asset classes assumed in the GHD/Arthur Andersen/Worley International studies, and applied these to the optimised replacement cost of those assets. Non-system assets have been depreciated on the basis of information contained in each DNSP's regulatory accounts at a weighted-average rate based on each DNSPs' non-system assets.[150]

This attachment details the ORC values and asset lives supporting the depreciation of system assets. It also provides the total depreciation on system assets for the 1999/2000 year as a guide. To arrive at the total depreciation used in the financial modelling, as discussed in chapter 7 this total must be adjusted by adding the depreciation on non-system assets and on capital additions in the year, and deducting depreciation on capital contributions and assets disposed during the year.

150 as at 30 June 1998.

Depreciation	EnergyAustralia			Integral Energy		
Description of Asset	**ORC ($000)**	**Effective Life**	**1999/2000 Depreciation**	**ORC ($000)**	**Effective Life**	**1999/2000 Depreciation**
132 kV Tower Lines	$69,191	50.0	1,449	$27,137	50.0	2,186
132 kV Concrete and Steel Pole Lines	$65,010	45.0	1,513	$2,179	45.0	113
132 kV Other Lines	$0	0.0	-	$21,483	45.0	1,101
132 kV Underground Cable	$772,040	45.0	17,964	$22,150	45.0	1,364
66 kV Concrete Pole Lines	$29,915	45.0	696	$1,188	45.0	48
66 kV Other Lines		0.0	-	$20,129	45.0	811
33 kV Concrete and Steel Pole Lines	$100,252	45.0	2,333	$182,677	45.0	155
33 kV Other Lines	$288	35.0	9	$53,310	45.0	2,541
66 kV Underground Cable	$612	60.0	11	$3,569	60.0	78
33 kV Underground Cables (Gas Type)		0.0	-	$0	0.0	-
33 kV Underground Cables (Solid Type)	$248,654	60.0	4,339	$23,644	60.0	635
22 kV Distribution Overhead Lines	$1,301	45.0	30	$2,408	44.3	109
11 kV Distribution Overhead Lines	$228,065	43.7	5,461	$94,814	43.7	6,154
LV Distribution Overhead Lines (Including Services)	$566,955	38.4	15,455	$121,731	42.6	7,179
SWER Lines	$1,488	45.0	35	$779	45.0	45
22 kV Underground Cable		0.0	-	$4,970	60.0	98
11 kV Underground Cable	$1,277,823	70.0	19,114		60.0	4,251
LV Underground Cable	$460,503	59.0	8,173	$441,423	60.0	10,271
Sub -Transmission Substations (132/66/33 kV Includes Building Excludes Land)	$413,080	46.6	9,276	$35,818	40.0	4,234
Zone Substations (Includes Building, Excludes Land)	$881,467	47.1	19,603	$204,412	40.0	13,144
132/66/33/22/11 kV Transformers	$283,207	50.0	5,931	$85,493	50.0	3,840
Pole Substations (Excluding Transformers)	$61,805	40.5	1,596	$29,648	40.5	1,691
Pole Transformers	$75,822	35.0	2,268	$36,711	36.9	2,429
Group/Kiosk/Chamber/Ground Substations (Excluding Transformers)	$516,265	40.0	13,514	$104,472	40.0	4,374
Group/Kiosk/Chamber/Ground Transformers	$259,091	44.9	6,043	$66,632	45.0	2,245
HV Customers Subs/Tap changing/Misc Subs (incl TXs)	$25,512	39.9	669		0.0	-
Pilots	$11,019	60.0	192		0.0	-
Customer Metering and Load Control	$315,769	25.4	13,036	$123,537	25.0	11,180
Street Lighting Overhead (Including Mains)	$245,000	20.0	12,827	$13,026	20.0	1,868
Street Lighting Underground (Including Mains)		0.0	-	$47,357	20.0	6,793
SCADA and Central Control Facilities	$57,496	37.7	1,596	$17,152	9.4	3,935
Communication Bearer Systems (Excludes Mobile)		0.0	-	$3,339	7.0	874
Easements	$9,797	0.0	-	$2,916	0.0	-
Land	$292,617	0.0	-	$35,503	0.0	-
Emergency Spares (Major Plant, Excludes Inventory)	$9,797	0.0	-	$11,195	30.1	-
Work In Progress	$191,600	0.0	-	$39,983	0.0	-
Total	**$7,471,441**		**$163,133**	**$1,884,045**		**$93,746**

Depreciation	NorthPower			Great Southern Energy		
Description of Asset	**ORC ($000)**	**Effective Life**	**1999/2000 Depreciation**	**ORC ($000)**	**Effective Life**	**1999/2000 Depreciation**
132 kV Tower Lines	$3,020	50.0	63	$2,144	50.0	45
132 kV Concrete and Steel Pole Lines	$2,122	55.0	40		0.0	-
132 kV Other Lines		0.0	-	$48,655	53.5	952
132 kV Underground Cable		0.0	-		0.0	-
66 kV Concrete Pole Lines	$10,507	55.0	200		0.0	-
66 kV Other Lines	$125,351	51.4	2,555	$98,081	53.5	1,920
33 kV Concrete and Steel Pole Lines		0.0	-	$12,098	53.5	237
33 kV Other Lines	$83,533	52.0	1,682	$83,037	53.2	1,635
66 kV Underground Cable	$549	60.0	10	$100	60.0	2
33 kV Underground Cables (Gas Type)		0.0	-		0.0	-
33 kV Underground Cables (Solid Type)	$350	60.0	6	$5,428	60.0	95
22 kV Distribution Overhead Lines	$149,935	53.8	2,916		0.0	-
11 kV Distribution Overhead Lines	$322,690	47.4	7,135	$342,552	52.4	6,846
LV Distribution Overhead Lines (Including Services)	$305,661	46.2	6,929	$162,906	49.3	3,457
SWER Lines	$35,103	54.0	680	$31,692	53.4	621
22 kV Underground Cable	$1,854	60.0	32		0.0	-
11 kV Underground Cable	$41,200	60.0	719	$17,593	60.0	307
LV Underground Cable	$89,736	60.0	1,566	$35,403	60.0	618
Sub -Transmission Substations (132/66/33 kV Includes Building Excludes Land)	$4,860	40.0	127	$2,540	40.0	66
Zone Substations (Includes Building, Excludes Land)	$135,115	40.0	3,537	$108,058	40.0	2,829
132/66/33/22/11 kV Transformers	$78,196	50.1	1,633	$63,280	50.0	1,324
Pole Substations (Excluding Transformers)	$138,639	40.0	3,629	$109,778	40.0	2,874
Pole Transformers	$88,578	39.8	2,330	$81,985	43.5	1,973
Group/Kiosk/Chamber/Ground Substations (Excluding Transformers)	$31,043	40.0	813	$23,828	40.0	624
Group/Kiosk/Chamber/Ground Transformers	$13,061	45.0	304	$10,226	45.0	238
HV Customers Subs/Tap changing/Misc Subs (incl TXs)	$0	0.0	-		0.0	-
Pilots	$0	0.0	-		0.0	-
Customer Metering and Load Control	$89,544	25.0	3,750	$97,017	25.0	4,062
Street Lighting Overhead (Including Mains)	$20,619	20.0	1,080	$9,644	21.7	466
Street Lighting Underground (Including Mains)	$26,521	20.0	1,388	$27,639	20.4	1,420
SCADA and Central Control Facilities	$5,700	4.6	1,286	$580	4.4	138
Communication Bearer Systems (Excludes Mobile)	$5,319	12.1	461	$4,026	7.3	576
Easements	$205	0.0	-	$987	0.0	-
Land	$5,059	0.0	-	$1,247	0.0	-
Emergency Spares (Major Plant, Excludes Inventory)	$1,270	0.0	-	$835	0.0	-
Work In Progress	$20,230	0.0	-	$5,344	0.0	-
Total	$1,835,570		$44,872	$1,386,703		$33,325

Depreciation	Advance Energy			Australian Inland Energy		
Description of Asset	**ORC ($000)**	**Effective Life**	**1999/2000 Depreciation**	**ORC ($000)**	**Effective Life**	**1999/2000 Depreciation**
132 kV Tower Lines		0.0	-	$267	50.0	6
132 kV Concrete and Steel Pole Lines	$26,093	55.0	497		0.0	-
132 kV Other Lines	$21,725	55.0	414		0.0	-
132 kV Underground Cable	$1,580	60.0	28		0.0	-
66 kV Concrete Pole Lines		0.0	-	$8,497	55.0	162
66 kV Other Lines	$66,821	55.0	1,272	$4,761	54.9	91
33 kV Concrete and Steel Pole Lines	$2,016	55.0	38	$32,868	54.9	627
33 kV Other Lines	$6,690	55.0	127		0.0	-
66 kV Underground Cable		0.0	-		0.0	-
33 kV Underground Cables (Gas Type)		0.0	-		0.0	-
33 kV Underground Cables (Solid Type)		0.0	-		60.0	-
22 kV Distribution Overhead Lines	$135,647	52.9	2,683	$31,678	53.0	626
11 kV Distribution Overhead Lines	$143,986	52.7	2,863	$415	52.0	8
LV Distribution Overhead Lines (Including Services)	$119,720	51.4	2,438	$16,535	51.0	339
SWER Lines	$41,437	54.6	795	$22,481	54.8	430
22 kV Underground Cable	$417	60.0	7	$435	60.0	8
11 kV Underground Cable	$10,575	60.0	185		0.0	-
LV Underground Cable	$25,094	60.0	438		0.0	-
Sub -Transmission Substations (132/66/33 kV Includes Building Excludes Land)	$10,155	40.0	266		0.0	-
Zone Substations (Includes Building, Excludes Land)	$57,498	37.9	1,588	$3,991	40.0	104
132/66/33/22/11 kV Transformers	$35,270	49.4	747	$5,660	50.0	119
Pole Substations (Excluding Transformers)	$77,602	40.0	2,031	$9,484	40.0	248
Pole Transformers	$44,959	45.0	1,046	$10,418	45.0	242
Group/Kiosk/Chamber/Ground Substations (Excluding Transformers)	$14,913	40.0	390	$1,346	40.0	35
Group/Kiosk/Chamber/Ground Transformers	$8,276	45.0	193	$790	45.0	18
HV Customers Subs/Tap changing/Misc Subs (incl TXs)		0.0	-		0.0	-
Pilots		0.0	-		0.0	-
Customer Metering and Load Control	$31,692	25.0	1,327	$3,216	24.0	140
Street Lighting Overhead (Including Mains)	$8,132	28.0	304	$2,169	21.1	108
Street Lighting Underground (Including Mains)	$12,387	20.0	649		0.0	-
SCADA and Central Control Facilities	$4,779	4.1	1,208		0.0	-
Communication Bearer Systems (Excludes Mobile)	$2,659	7.0	398		0.0	-
Easements		0.0	-		0.0	-
Land	$1,339	0.0	-	$340	0.0	-
Emergency Spares (Major Plant, Excludes Inventory)	$1,500	0.0	-	$518	0.0	-
Work In Progress	$1,440	0.0	-		0.0	-
Total	$914,402		$21,932	$155,869		$3,311

ATTACHMENT 4 SUBMISSION LIST

Organisation	Name
	G. McDonell
Advance Energy	M. Coble
Australian Baldor Motors and Drivers	K. Limly
Australian Business	P. Orton
Australian Cogeneration Association	R. Brazzale
Australian Conservation Foundation	S. van Rood
Bathurst City Council	P. Perram
BB Water Saver Syste	B. Hibberd
BCA Energy Task Force	P. Weickhardt
Canterbury City Council	R. Davidson
Centron ToughGuard	J. Brady
Cessnock City Council	M. Alexander
Copmanhurst Shire Council	G. Cowan
Dynamic Synergies International Pty Ltd	D. Willis
Ecopower	B. Ellul
Energy Engineering of Australia Pty Ltd	J. Wyer
Energy Industry Ombudsman NSW	C. Petre
Energy Markets Reform Forum	W. Martin
EnergyAustralia	P. Broad
EnergyAustralia	M. Davies
Environmental Law & Policy Consultants	M. Mobbs
Gloucester Shire Council	N. McLeod
Great Southern Energy	L. Elder
Great Southern Energy	P. Hoogland
Harris Energy Solutions Pty Ltd	G. Harris
Ilum-a-Lite Pty Ltd	J. Rutherford
Institute for Sustainable Futures	G. Milne
Integral Energy Australia	J. Allen
Integral Energy Australia	J. Allen
Integral Energy Australia	R. Thorn
Lane Cove Council	R. Selleck
Manly Council	J. Thompson
National Farmers Federation	

NCON Corporation Pty Limited	D. Barnes
NorthPower	P. Topfer
NSW Treasury	B. Hartnell
Port Stephens Council	R. Bowen
Power Visions	I. Lawrence
Public Interest Advocacy Centre	T. Benson
PV Solar Energy Pty Ltd	P. Erling
Quantum energy syste Pty Ltd	S. Harmon
Riverina Wool Combing Pty Ltd	B. Hamilton
Riverina Wool Combing Pty Ltd	B. Hamilton
Robert Turner Consulting Pty Ltd	R. Turner
SEDA	B. Precious
Singleton Shire Council	B. Carter
Sustainable Technologies Australia Limited	S. Tulloch
Sutherland Shire Council	G. Smith
Sydney Airports Corporation	N. Westnedge
TD International Pty Ltd	L. Taylor
Total Environment Centre	S. Crawford
Track Electrics	W. Allwood
Wagga Wagga City Council	C. Earnshaw
Waverley Council	M. McMahon
Wingecarribee Shire Council	D. McGowan

Rules made by the Tribunal under clause 6.10.1(f) of the National Electricity Code

December 1999

INDEPENDENT PRICING AND REGULATORY TRIBUNAL
OF NEW SOUTH WALES

INDEPENDENT PRICING AND REGULATORY TRIBUNAL
OF NEW SOUTH WALES

Clause 6.10.1(f) National Electricity Code

Rule 99/1
Unders And Overs Accounts

Interpretation

This rule is made by the Independent Pricing and Regulatory Tribunal of NSW (the Tribunal) as the jurisdictional regulator under clause 6.10.1(f) of the National Electricity Code.

This rule is to be referred to as the 'Unders and overs accounts, Rule 99/1'.

This rule applies to DNSPs in New South Wales.

This rule commences on 30 December 1999 and will remain in force until revoked by the Tribunal. This rule may be amended or supplemented by the Tribunal from time to time.

Except where indicated, expressions used in this rule have the same meaning as in the National Electricity Code (approved for the purpose of National Electricity (NSW) Law) and any determination of the Tribunal under the National Electricity Code.

Rule provisions

The following provisions apply:

Unders and overs accounts to apply

Each DNSP must maintain an unders and overs account in a manner consistent with any relevant determination or direction by the Tribunal. Any variation between the aggregate annual revenue requirement (AARR), as determined by the Tribunal, and actual revenue collected is to be monitored in the unders and overs accounts. The unders and overs account is cumulative from year to year.

For any year that a variance occurs between the AARR and the actual revenue collected in that year, an interest charge or an interest credit will apply, as appropriate. The interest adjustment will be applied on the cumulative balance at year-end. The total cumulative balance in the unders and overs account includes any prior year interest adjustments.

Interest will be pegged at the 3-year Commonwealth Bond rate as at the first Monday following the financial year-end. The Australian Financial Review will be the reference source for this rate.

Annual returns and tolerances

DNSPs must provide annual returns to the Tribunal by 30 October each year. The annual returns must disclose account balances as a contingent item. These returns must demonstrate that the unders and overs account balances result from actual demand deviating from forecast demand. The Tribunal will allow the following tolerance margins for deviations from the related AARR and will require the following action on an annual basis[151] as a result of these deviations:

Table 1 Tolerance margins and actions that the Tribunal will require for unders and overs account balances

Tolerance	DNSP action required
less than +/- 2 per cent	Must notify the Tribunal within 30 days of year end with action plan[152] to resolve balance within the term of the price path.
between +/-2 per cent and +/- 5 per cent	Must notify the Tribunal within 30 days of year end with action plan[153] for rectifying the balance at the first subsequent changes to network tariffs.
over recovery of more than 5 per cent	Must provide a rebate to retailers on the first bill of the subsequent year to reduce the unders and overs account balance to zero.[154]
(under) recovery of more than 5 per cent	Unders and overs account balance will be reduced to under recovery of 5 per cent.[155]

Approved unders and overs account balances as at 31 January 2000 (accrued under determinations made by the Tribunal under the IPART Act) will carry forward into a determination made under the National Electricity Code effective from 1 February 2000. Each DNSP will be required to submit its unders and overs account balance for approval by the Tribunal as soon as practicable after 31 January 2000.

151 The Tribunal will require the specified actions to commence on 1 July 2001.

152 An action plan must include the calculation of network prices (for each tariff class) based on maximum allowable revenues, demand forecasts and unders and overs balance rectification.

153 An action plan must include the calculation of network prices (for each tariff class) based on maximum allowable revenues, demand forecasts and unders and overs balance rectification.

154 The Tribunal intends to exercise its powers under state legislation to require retailers to pass on rebates to end-use customers.
The Tribunal recognises that issues may arise when customers disconnect from the system in the time between the period of over-collection and the payment of the rebate. The refund should be made to customers connected to the distribution network system on 30 June on the year that over recovery breaches the 5 per cent tolerance.

155 If, for example, at 30 June 2002 a DNSP has an under recovery of 8 per cent, the Tribunal will reduce the account balance to 5 per cent under recovered for the 2001/2002 financial year. The DNSP will lose the 3 per cent difference.

Clause 6.10.1(f) National Electricity Code

Rule 99/2
Pricing notification and information disclosure

Interpretation

This rule is made by the Independent Pricing and Regulatory Tribunal of NSW (the Tribunal) as the jurisdictional regulator under clause 6.10.1(f) of the National Electricity Code.

This rule is to be referred to as the 'Pricing notification and information disclosure Rule 99/2'.

This rule applies to DNSPs in New South Wales.

This rule commences on 30 December 1999 and will remain in force until revoked by the Tribunal. This rule may be amended or supplemented by the Tribunal from time to time.

Except where indicated, expressions used in this rule have the same meaning as in the National Electricity Code (approved for the purpose of National Electricity (NSW) Law) and any determination of the Tribunal under the National Electricity Code.

Rule provisions

The following provisions apply:

Disclosure of information on pricing structures and future directions

By 30 November each year[156], DNSPs must publish a pricing information package that discloses:

a) the methodology used to derive prices for prescribed distribution services

b) medium term directions for prices for prescribed distribution services.

For the pricing information package due on 30 November 2000 and subsequent years, the information disclosed must include, but is not limited to:

a) a list of the cost components for providing prescribed distribution services. This must include the definition of the costs, the total of each cost for the network business, and the basis for allocating costs shared with other activities of the network owner and/or operator. The costs for the preceding year must reconcile with the regulatory accounts as specified by the Tribunal. Projected costs for the current year must be provided.

156 Except for 1999/2000, when the due date is 30 April 2000.

b) a statement of the basis for valuing assets and calculating depreciation. If the depreciated optimised replacement cost (DORC) approach is adopted, the extent of optimisation and relevant unit rates must be provided or referenced. Assumed asset lives and other assumptions in the calculation of depreciation must be described or referenced.

c) an explanation and quantification of the methodology used to calculate current prices from the costs identified under (a) & (b), including:
   - definition of the prescribed distribution services, customer classes and regions for pricing, and the components of charges such as the demand, energy and fixed components
   - allocation of costs to prescribed distribution services, customer classes, and/or regions used for pricing purposes
   - allocation of costs to, and calculation of, the various components of charges such as the demand, energy and fixed components.

d) identification of forecast demand and load factors used in calculating charges for prescribed distribution services

e) data on performance measured against a range of key indicators, including:
   - summary indicators of reliability and quality of service drawn from the reporting requirements determined by the Ministry of Energy and Utilities
   - other indicators as may be determined by the Tribunal

f) an outline of future pricing strategies, specifying proposed changes to the prescribed distribution services, charging options offered, structure of charges and/or allocation of costs, and quantifying potential impact on prices

g) a summary of the DNSP's asset management and development plans, identifying potential impacts on pricing

h) a summary of any other industry or company developments that may affect pricing.

Where it believes there is a net public benefit, the Tribunal may waive any of the above requirements on the request of a DNSP.

The pricing information package may be published electronically as well as in hard copy and may include supplements and appendices. Paper copies must be available on request. Some of the requirements may be met through reference to other documents, such as asset management reviews and asset valuation studies. However, the information package must contain sufficient information to enable the user to understand the information package without referring to these documents.

Notification of price changes

Except with the Tribunal's prior approval, charges for prescribed distribution services may be changed annually only on 1 July, or as near as practicable to that date, consistent with any applicable determination of the Tribunal.

Unless a DNSP has published a current pricing information package that meets the 'Pricing notification and information disclosure Rule 99/2', the DNSP may not increase its charge for any prescribed distribution service. Under these circumstances, if actual revenue from the existing charges is projected to exceed the AARR, the DNSP must lower all its charges for prescribed distribution services by a uniform percentage to reduce its revenues to the regulated levels.

DNSPs are to give network users and the Tribunal 30 days' notice of proposed changes to charges for prescribed distribution services. DNSPs should publish existing and proposed charges, and any changes in the associated terms and conditions.

Notification of price changes to the Tribunal must be accompanied by supporting material that:

a) indicates the percentage and absolute change in the charges or average bills for each customer class

b) demonstrates that revenues are projected to recover no more than the sum of the base revenue as established by the glide path, together with:

   - transmission charges and payments for network services made to other DNSPs. This is consistent with 6.10.5.(7) (ii) of the Code. These payments may be subject to a prudency test if payments are not between unrelated parties at published regulated charges
   - avoided transmission use of system (TUOS) payments to embedded generators, up to an amount determined by the Tribunal through and examination of avoided network costs
   - payments for demand management and other network support services, up to an amount determined by the Tribunal through an examination of avoided network costs.
   - contestability costs as determined by the Tribunal
   - Y2K costs as approved by the Tribunal
   - an amount to rectify unders and overs account balances
   - the net impact of the GST.

c) demonstrates compliance with side constraints on maximum increases in charges for prescribed distribution services

d) provides the cost of supply modelling that underpins the proposed charges

e) notification to the Tribunal should be accompanied by a statement signed by the Chairman and Chief Executive Officer, undertaking that the above requirements have been met.

INDEPENDENT PRICING AND REGULATORY TRIBUNAL
OF NEW SOUTH WALES

Clause 6.10.1(f) National Electricity Code

Rule 99/3
Charges for Miscellaneous services

Interpretation

This rule is made by the Independent Pricing and Regulatory Tribunal of NSW (the Tribunal) as the jurisdictional regulator under clause 6.10.1(f) of the National Electricity Code.

This rule is to be referred to as the 'Charges for miscellaneous network services Rule 99/3'.

This rule applies to DNSPs in New South Wales.

This rule commences on 30 December 1999 and will remain in force until revoked by the Tribunal. This rule may be amended or supplemented by the Tribunal from time to time.

Except where indicated, expressions used in this rule have the same meaning as in the National Electricity Code (approved for the purpose of National Electricity (NSW) Law) and any determination of the Tribunal under the National Electricity Code.

Rule provisions

The following provisions apply:

Levying charges for miscellaneous services

Outside normal business hours fees

For those charges which allow for an after hours fee to be charged, the 'outside normal business hours' fee may be charged only:

- where the customer has been informed of the additional cost before work commences
- the customer is advised of the times during which the work can be carried out at normal rates
- after receiving this information the customer requests that the work be carried out outside normal business hours.

Provision of time-of-use or half-hourly metering data

This charge applies to cover the cost of obtaining and providing historical metering data on a half hourly or time of use basis to non-contestable customers where such data is not available from the customer's normal meter readings. The charge is intended to cover the cost of installing and removing recording instruments to obtain the half-hourly or time of use metering data. The charge is $25.00 per half-hour (or part thereof) of staff time required to make the information available.

Special meter reading

This charge applies to cover the costs of a special meter reading either at the customer's explicit request or because the meter is inaccessible at the normal reading time and an estimated reading has been offered to the customer and the customer does not accept that offer and insists on an actual meter reading being carried out.

The charge is not to be applied for:

- a reading associated with a final account; or
- for a check of a disputed reading carried out at the customer's request if the original reading is subsequently found to be incorrect.

Meter test

This charge applies to cover the cost of testing a meter for accuracy when requested by the customer. The customer may be present at any field test conducted by the DNSP. The fee is to be charged to the customers next account if the meter is found to be reading correctly as defined in clause 21(3) of Schedule 2 of the Electricity Supply (General) Regulation 1996.

While a customer's meter is being tested at the request of the customer, the DNSP must give the customer an extension to the due date for payment of their electricity account. No late fees are to be levied while such an extension is in effect.

It should be noted that under the Code of Practice for Franchise Customer Metering a customer is entitled to request a test from another body having qualifications acceptable to the DNSP. This test is at the customer's expense. The DNSP is entitled to be present at this test.

The Code of Practice also requires the DNSP to establish a maintenance plan for maintenance testing of their franchise meters. Details of this plan must be communicated to customers on request.

Conveyancing inquiry

This charge applies for the supply of information regarding the availability of supply, presence of DNSP's equipment, power lines etc for property conveyancing. Freedom of information (FOI) inquiries are excluded.

Account establishment

This charge applies to cover the DNSP's costs of establishing a new customer in its records, recording the meter reading for the new customer. The fee applies to both new and existing premises and excludes all charges by way of capital contribution. This fee is not to be applied in the case of reconnecting power following an involuntary disconnection, but may be charged to effect reconnection following disconnection at the customer's request.

Off-peak conversion

Customers will be allowed to change their off-peak pricing option once in a 12 month period at no cost. Should the customer request a further change in off-peak pricing option within that 12 month period then this fee will apply.

This charge does not cover repairs to damaged metering or time control equipment.

Disconnection Visit

This charge applies to the cost of a visit by DNSP staff with the specific intent to disconnect a customer at the time of the visit.

The visit to the customer with the intent of disconnection can only occur once the provisions of the Electricity Supply (General) Regulation 1996 (Schedule 2, Part 4, Division 2, Clause 40) with respect to the disconnection of customers have been completed in full.

The Personal Visit fee may be levied only in circumstances where:

1. The customer has been warned of impending disconnection by issue of a late payment reminder notice. This notice must clearly provide information to customers regarding financial assistance available, particularly through the Energy Account Payment Assistance (EAPA) scheme. Subject to the rules applicable to Late Payment charges, the $5.00 Late Payment charge may be levied for this notice.
2. The DNSP has sent to the customer at least 2 written notices of the DNSP's intention to disconnect, the second notice to be sent no earlier than one week after the first notice.
3. The DNSP has made and documented reasonable attempts to deal with the customer in person or by telephone, whether before or after sending any disconnection notice, for the purpose of assisting the customer to do whatever is necessary to remove the grounds referred to in that notice.
4. Having completed this process, a DNSP's representative visits the customer personally with an intention to disconnect. The Tribunal considers it important that the customer be given the opportunity to make an acceptable payment on the account before a Personal Visit fee is levied. At the time of the personal visit, the customer may avoid disconnection by making an acceptable payment on the account (not necessarily the full outstanding balance).

If an acceptable payment is received, and the DNSP's representative does not proceed with disconnection, the DNSP may charge the $30 Personal Visit fee. DNSPs are encouraged to waive this fee where the customer can provide evidence that a payment has been made but not recorded, such as where a payment was made at a collection outlet such as a post office, or payment has been mailed.

In cases where the customer does not make an acceptable payment and disconnection proceeds, the DNSP may charge the $60 Personal Visit fee. This also covers the cost of a second visit to reconnect the customer. If the customer makes an acceptable payment on the overdue account, and pays the $60 disconnection visit charge, during normal business hours, then the customer is entitled to be reconnected that day at no extra cost; that is, no after hours fees can be charged for the reconnection.

Where disconnection is to be effected, and the customer denies access for disconnection, or there is evidence that the customer has reconnected supply illegally after an earlier disconnection, the customer may be disconnected at the pillar box or pole top and the $100 Pillar Box/Pole Top Disconnection fee may be levied. The maximum charge for a disconnection visit will be $160 (ie $60 for the visit plus $100 to make a disconnection at a pole top or pillar box should such a disconnection be necessary).

The customer would be reconnected after making an acceptable payment on the account (not necessarily the full outstanding balance) or acceptable payment arrangements. No fee is chargeable for reconnection.

It should be noted that the personal visit is considered to be the culmination of this process. Once a Personal Visit is effected, the entire process described above must be repeated before another charge for a personal visit can be made. The DNSP or retailer are encouraged to visit the customer to discuss payment arrangements, but they cannot impose the $30 fee before the entire process described above is repeated. Considering the complaint activity in this area, the Tribunal will seek evidence that this process has been followed in response to future complaints.

Rectification of illegal connection

This charge applies when a customer connects the electricity supply by interfering with property belonging to the electricity distributor in an unauthorised manner and without the distributor's permission.

Informing Customers

End use customers must be informed of the charges for miscellaneous services that may be levied by the DNSP and passed through the retailer. The Tribunal considers this information will help reduce the level of complaint activity in this area.

Information should be provided to customers:

- in advance of any fees being charged
- in plain language
- in a physical form on bills and notices so that it is accessible to customers
- in a way which makes clear when the fees are applied.

DNSPs should also clarify to end use customers:

- the internal and external dispute resolution mechanisms available if they query or dispute any of the charges
- the times during which 'normal business hours' fees apply and beyond which 'outside business hours' fees may apply
- the normal business hours of the network business.

This information should be provided by DNSPs and retailers to:

- new customers at the time of connection
- existing customers in advance of fees being charged for the first time
- all customers from time to time as part of general customer information.

Clause 6.10.1(f) National Electricity Code

Rule 99/4
Charges For Monopoly Services

Interpretation

This rule is made by the Independent Pricing and Regulatory Tribunal of NSW (the Tribunal) as the jurisdictional regulator under clause 6.10.1(f) of the National Electricity Code.

This rule is to be referred to as the 'Charges for monopoly services Rule 99/4'.

This rule applies to DNSPs in New South Wales.

This rule commences on 30 December 1999 and will remain in force until revoked by the Tribunal. This rule may be amended or supplemented by the Tribunal from time to time.

Except where indicated, expressions used in this rule have the same meaning as in the National Electricity Code (approved for the purpose of National Electricity (NSW) Law) and any determination of the Tribunal under the National Electricity Code.

Rule provisions

The following provisions apply:

Levying charges for monopoly services

Access

Providing access to switchrooms, substations etc for accredited meter and service providers. The fee for this service should be based on an hourly rate as the time taken to provide access will vary considerably from one location to the next, as will the time required to be on site (depending on whether it is inspection only or for the duration of the work).

DNSPs are encouraged to offer an alternative to paying this charge by arranging for the authorised person to have a key. If keys are provided, this fee would cease to apply.

Authorisation

When an employee or sub-contractor of an accredited service provider is required to work on or near a DNSP's network such persons must be individually authorised to do so every 12 months. An authorisation charge may be levied at rate 2 for a maximum of 2 hours.

Travel Time

$50 per hour for travel in excess of two hours (one way) for work associated with contestability, such as inspection of private contractor's work.

Administration

The administrative overhead charge is designed to cover the cost that a DNSP incurs because of the contestable development. It includes not only the work carried out by the contestable works administrator but such things as legal, accounting, records (both administration and technical) survey, corporate overheads etc.

INDEPENDENT PRICING AND REGULATORY TRIBUNAL
OF NEW SOUTH WALES

CAPITAL EXPENDITURE REVIEW
OF NSW DISTRIBUTORS AND TRANSGRID

IPART is currently conducting a review of the NSW electricity industry according to the terms of reference provided to IPART by the Premier under s12A of the IPART Act. The terms of reference require IPART to report on the appropriate pricing of government monopoly electricity services by energy distributors and TransGrid (network service providers or NSPs) for the period from 1 July 1999.

IPART engaged Worley International in association with PricewaterhouseCoopers (hereinafter referred to as Worley) to conduct a review of the NSPs' capital expenditure (capex) programmes. The capex review was to:

- assist IPART in its review of the NSW electricity industry
- better inform the Tribunal of the issues and reasonable capex costs involved in providing and maintaining electricity supply to customers
- help the Tribunal contribute to the discussion of these issues and the development of the approach for identifying and accommodating efficient and reasonable capex costs in the pricing of government monopoly electricity services to customers
- assist the Tribunal in assessing how these issues and costs relate to the capital or asset roll-forward base from the 1996 Determinations.

Worley completed the review of the NSW distributors and produced a final report in October, 1998. The review of TransGrid was completed in November, 1998 with a separate report. These final reports were provided to key stakeholders including members of the Electricity Industry Consultation Group formed by IPART as part of the public consultation process in the s12A review.

On 4 November, 1998, IPART hosted a seminar on the capex review at which key stakeholders were given an opportunity to comment on the distributors' and TransGrid's reports and any related issues. Stakeholders were also given the opportunity to provide comment on the reports in writing.

Worley's reports on the NSW distributors and TransGrid are attached and contain a number of useful insights. In particular, the Tribunal noted Worley's findings that:

- TransGrid's asset management strategies and expenditure projections for asset renewals were considered appropriate.

- The Sydney inner city network comprising both TransGrid's 330kV and energyAustralia's 132kV networks when considered together as a combined network supplying a major CBD and dense urban load only marginally meets N-1 security requirements. Adjustments to the capex programmes have been made by Worley in support of an advanced solution. TransGrid and energyAustralia have established a joint planning process to review the requirements of the Sydney inner city supply.
- The renewal of aged assets was an important driver of capex but was not well analysed or documented by the distributors generally.

The Australian Consumer and Competition Commission (ACCC), consistent with its responsibilities under the National Electricity Code, is concurrently conducting its inquiry into the appropriate revenue cap to be applied to the non-contestable elements of TransGrid's network services from 1 July, 1999. In the *Statement of Process* document produced in November, 1998 by the ACCC and IPART co-operatively on their inquiries into TransGrid, the ACCC noted its intention to carry out further work to review the Worley report on TransGrid and the asset roll-forward base issue. The ACCC intends to issue discussion papers on these matters in late January, 1999.

While most NSPs have expressed satisfaction with the review conducted by Worley, some comments have been received regarding various aspects of the review methodology.

The Tribunal will shortly release an Asset Roll-Forward discussion paper which will refer to the Worley reports, covering the above and other asset related issues. This discussion paper is intended to canvass the views of the interested public and seek submissions to assist the Tribunal's considerations in recommending to the Premier appropriate revenue or price paths from 1 July, 1999 for the NSPs. The s12A terms of reference also require the Tribunal to have regard to service quality (including reliability) taking into account the potential for NSPs to offer price/quality trade-offs above minimum standards, as well as to incentive structures in the form of regulatory arrangements. A number of NSPs have stated that improvements in service quality may involve additional capex.

The Tribunal is keen to get the views of as many interested stakeholders as possible to its Asset Roll-Forward discussion paper and has placed the Worley capital expenditure reports on the NSW distributors and TransGrid on the IPART website prior to the release of the discussion paper to allow further time for the consideration of these detailed reports. Any submissions to the Tribunal on these reports will be considered together with submissions to the Asset Roll-Forward discussion paper.

REPORT TO THE INDEPENDENT PRICING AND REGULATORY TRIBUNAL ON CAPITAL EXPENDITURE REVIEW IN NSW ELECTRICITY DISTRIBUTION

FINAL REPORT

WORLEY

In association with
PricewaterhouseCoopers

October 1998 **RP10**

REPORT TO THE INDEPENDENT PRICING AND REGULATORY TRIBUNAL ON CAPITAL EXPENDITURE REVIEW IN NSW ELECTRICITY DISTRIBUTION

FINAL REPORT

Worley International Limited
P O Box 4241
Auckland, New Zealand
October 1998
43 641 75

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Executive Summary

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1.0 APPOINTMENT, TERMS OF REFERENCE AND OBJECTIVES

In May 1998, the Independent Pricing and Regulatory Tribunal of New South Wales (IPART) commissioned Worley International Ltd, Engineering and Management Consultants of Auckland New Zealand (Worley) in association with PricewaterhouseCoopers, Chartered Accountants to investigate and report on :

- the adequacy and appropriateness of the capital expenditure programmes of the six New South Wales electricity distributors.
- the appropriateness of the distributors' capital expenditure assessment and asset management policies considering the regulatory environment and IPART objectives.

The Terms of Reference for the review are given in Appendix 1A. In summary, the objectives of the review were as follows :

- Assess and quantify the appropriateness of the distributors' existing network infrastructure in terms of current and projected capacity and current condition and equipment renewal.
- Identify capital works projects to the year 2009/10 and a suitable materiality threshold.
- Review the distributors' capital works assessment procedures.
- Consider how appropriate the proposed capital work is.
- Consider how the capital works will affect efficiency and service standards such as reliability and safety.
- Compare and contrast the asset management policies of the six distributors and quantify the impact on costs relative to service, reliability and safety levels.

A further task was to accommodate the NSW distributor Boundary Review should it have recommended changes.[1]

2.0 REGULATORY ENVIRONMENT

Regulation of electricity services within NSW is the responsibility of the Independent Pricing and Regulatory Tribunal (IPART). The scope of the Tribunal's regulation is defined under the IPART Act 1992 and the declarations made pursuant to the Act. The National Electricity Bill has recently been passed by the NSW Parliament as part of national competition policy agreements between the federal and state governments. When proclaimed, the Act will give legal backing to the National Electricity Code (NEC). The Act will provide for IPART's regulation of electricity transmission services to cease after June 1999. The Bill also provides for IPART's regulation of electricity distribution network services to cease from after December 2000. Provisions are made for the regulation of electricity services to continue under the NEC. Under the code the Australian Consumer and Competition Commission will regulate transmission services and a jurisdictional regulator (anticipated to be IPART) will regulate distribution network services.

[1] The Boundary Review has since been completed and no changes have been recommended.

Price Regulation

The Tribunal's activities in regulation of electricity prices have been undertaken against a background of major restructuring of the NSW electricity industry and the introduction of competition into the electricity generation and wholesale distribution markets.

Medium term price paths for electricity transmission, distribution and retail supply were released by the Tribunal in March 1996, and minor revisions were made in August 1997. These price paths specifically addressed the ongoing changes in the structure of the industry and factors affecting the introduction of competition. The 1997 report includes pricing of street lighting charges. A revenue cap formula was set for charges for the use of distribution wires.

The Tribunal has recently announced a review of electricity prices to apply from the end of the medium term price path in July 1999 and the capital expenditure review which is the subject of this report has been commissioned by IPART as an input into this process.

3.0 WORK PROGRAMME

Our work on the review commenced on 19 May 1998 with a meeting with IPART and the six distributors. Questionnaires were then prepared and sent to the distributors on 26 May 1998. Most of the questionnaires were completed and returned to us during June.

Each distributor was visited by members of our review team between 22 June and 10 July 1998, after which the review team proceeded with its assessment, seeking further clarifications from the distributors as necessary. An Interim Report was prepared and submitted to IPART on 10 July 1998. A Preliminary Draft Final Report was prepared and submitted to IPART on 10 August 1998 for discussion and our Draft Final Report was submitted to IPART on 31 August for review. The Final Report was submitted on 2 October 1998, incorporating agreed changes after review by IPART and the distributors. A presentation of the Final Report is to be made at IPART's offices in November 1998.

4.0 INTERIM REPORT

The purpose of the Interim Report, sent to IPART on 7 July 1998, was to summarise the work done up to that time and the preliminary conclusions reached from the questionnaire and field visit interviews. The report concentrated on key issues affecting the assessment, their impact and measures proposed to overcome difficulties then foreseen. Its findings are superseded by this Final Report.

5.0 THIS REPORT

This Final Report presents the findings of the review. It is presented in two main parts and twelve sections as follows :

Part I - Regulatory Environment And Review Process

Section 1	:	Introduction and Terms of Reference
Section 2	:	Principles of the Review
Section 3	:	Issues Arising
Section 4	:	Methodology

Part II - Assessment

Section 5	:	Energy Australia
Section 6	:	Integral Energy
Section 7	:	NorthPower
Section 8	:	Great Southern Energy
Section 9	:	Advance Energy
Section 10	:	Australian Inland Energy
Section 11	:	Comparisons
Section 12	:	Summary and Concluding Remarks

Confidential information submitted to us by the distributors (comprising completed questionnaires and detailed capital expenditure projections) are considered confidential to IPART, Worley and the distributor concerned and are presented in a separate volume for IPART's information only.

A supplementary report on TransGrid's capital expenditure projections is presented separately.

6.0 PRINCIPLES AND ISSUES

The two principal determining factors of capital expenditure are asset renewals and augmentation of network capacity to meet growth in demand.

Asset Renewal Expenditures

Use of Standard Lives
Asset renewal expenditures comprise two main types of expenditure, namely replacement and refurbishment. In each case, the need for renewal is brought about through the ageing of the assets.

Asset renewal expenditures are determined mainly by the expected lives of the assets, the standard to which the assets are maintained and the replacement cost of the assets. The correct determination of expected life is therefore important and the impact of assuming different asset lives for projecting future capital expenditures is significant. Since large expansions of electrical networks took place in the 1960's, and since many of these assets are considered to have a useful life of the order of 30-50 years, it follows that the impact of expected life on capex projections over the next ten years is doubly great.

The determination of standard lives is discussed in the report.

It needs to be emphasised, however, that estimates of capital expenditure for asset replacement purposes, prepared using age profiles and standard lives, can only be regarded as approximate. That is, they should be used only for preliminary estimating purposes.

Standard of Maintenance
The second important determinant of asset lives and replacement needs is the standard of maintenance carried out over the life of the asset. This may have more impact on certain classes of asset than on others.

For most purposes, it can be assumed that there is a match between industry accepted lives and the maintenance practices commonly applied and that higher or lower levels of maintenance would result in assets, on average, attaining longer or shorter lives respectively.

Replacement Costs
Not all distributors have used the standard replacement costs given in Table 1 of the NSW Treasury Guidelines. We have accepted the higher costs where considered reasonable.

Details of our approach to asset renewal expenditures are discussed in Sections 2.2 and 3.2 of the report.

Expenditure for Augmentation of Capacity

The second major driver of capital expenditure is demand growth. Growth in demand results in the need for capital expenditure if the loading on components of the power system network reaches the maximum capacity available or threatens security of supply criteria.

Demand growth predictions require knowledge of load growth trends in each area, daily, weekly and yearly load patterns and an assessment of future spot loads. In order to ascertain whether a power network has sufficient capacity to accommodate load growth, it is necessary to understand the permissible loading capacities of network components, the requirements for satisfactory voltage regulation under normal and emergency conditions and the selection of appropriate security levels required for the system.

It is normal to model the power network to determine the load on each component as demand increases. Network augmentations are then considered, sufficient for the network to perform within its permissible load limits and security levels. Once a long term network development plan is determined in this way, the corresponding capital expenditure projections can be deduced.

The detailed justification of augmentation projects follows on from the planning process and is not normally undertaken until one or two years before the planned start of implementation depending on design/construction time.

Not all distributors were able to provide us with comprehensive network development plans, asset management plans or data on existing assets. In cases where detailed plans were not available, long term expenditure for augmentation have been based on the rolling forward of short term figures or in some cases historical figures. We have examined the foundation of the figures put forward and have highlighted any areas of concern.

Details of our approach to augmentation expenditures are discussed in Section 2.3 of the report.

Appropriate Reliability

Another component of capital expenditure is works associated with improving reliability of supply. As in most countries there are no legislated electricity supply reliability standards in New South Wales and the approaches adopted by the distributors towards reliability improvements differ.

Our approach to this issue has been to review the appropriateness of current levels of reliability, given the nature of the load served. Target reliability levels set by the distributors have then been reviewed for reasonableness in this light and in the light of prevailing international practice. The projected capital expenditures for reliability improvement have then been reviewed against the targets and consideration has been given to the balance between implementation of better asset management practices.

Details are discussed in Sections 2.4 and 3.4 of the report.

Capex Evaluation and Approval Processes

Most distributors have formal approval procedures and policies for control of their capital expenditure, reflecting the accepted international approach to capex approval as summarised below :

Step 1 : Establish the Project Need

Step 2 : Identify and Quantify Project Costs and Benefits

Step 3 : Optimise Project Timing

Step 4 : Consideration of Statutory, Safety and Environmental Obligations

Step 5 : Identify Least Cost Solution

Step 6 : Rate of Return Calculation (if feasible)

We believe it is inappropriate to comment on the actual WACC to be used but that it is important to focus instead on the policies and procedures used in assessing capital expenditure programmes. Also, the overall WACC return allowed for by IPART says more about the average return on existing assets in service than it does about the return that can be achieved on proposed additions. This is an important distinction because in this review, it is the margin that is of interest, not the average. In the present low loss and low growth environment, it may be impossible to justify capital works other than essential equipment replacements if a rate of return target related to WACC is used.

This issue is discussed in Sections 2.6 and 3.5 of the report.

Demand Management and Embedded Generation

Demand Side Management (DSM), if taken seriously, has the potential to defer significant capital expenditures for network augmentation projects although it may not have a significant impact on the deferral of expenditure for asset renewals.

Embedded generation may affect network capital expenditure since its presence affects power flows in the network. Power flows in the network may be increased or decreased by the presence of the generation. Also, it may be available only at certain times, leading to a variety of different scenarios to be analysed before it can be concluded an opportunity to defer capital expenditure exists. Generally, embedded generation is installed at short notice and the resulting impact on capital expenditure projections can be hard to predict.

At present, the implementation of advanced DSM programmes is only at an early stage and, with some exceptions, there is relatively little embedded generation in place. Only known programmes have been (or should be) taken into account in the review.

Inadequacy of Some Projected Expenditures

In certain cases, we felt that insufficient expenditure had been allowed and accordingly we increased the estimates made by the distributors.

These cases generally related to expenditures for replacement of assets due to ageing.

IT Systems

Some distribution companies have included capital expenditure for IT systems relating to GIS, financial systems, customer information systems and IT hardware renewals/upgrades. However, there is not a high level of consistency in the presentations.

Where they are discernible, expenditures related to GIS and asset management systems have been shown as a separate item. We have also recorded separately (but not reviewed or commented on) IT expenditures related to financial systems and customer information systems since.

We have reviewed expenditures for SCADA systems.

Treatment of Other Expenditures

The treatment of other expenditures is discussed in Section 3.10 of the report.

Materiality and Accuracy

For the purpose of the review, we have considered items as material if they comprise 5% or more of the total capital expenditure programme of the distributor concerned. Where several such items aggregate to 5% or more, we have considered them material.

Against this, the inherent lack of accuracy in the capital expenditure forecasting process needs to be recognised. In our opinion, it would be misleading to pretend that the projections are accurate within ±10%.

7.0 METHODOLOGY

Review of Policy Documents

A review of policy documents was performed at the start of this project to set the scene and note any particular items impacting on the capital expenditure review.

Questionnaire

A detailed questionnaire was written to speed up the review process, help with the production of consistent information and prevent the necessity for collation and review of large amounts of documentation.

Interviews and Inspections

Visits to the distributors were made and interviews performed with key staff to review the responses to the questionnaires, flesh-out any appropriate areas and to request further information where required to support certain capital expenditure projections. Inspections of assets were made where required.

Assessment and Reporting

Documentation supplied by the distributors, supporting the capital expenditure projections, was reviewed in detail. Discrepancies were either discussed with the distributors or where necessary, adjustments were made by us to the capital expenditure projections.

This report was submitted in draft form and where necessary IPART's comments have been incorporated into the Final Report.

Comparisons

Comparisons between the distributors have been made where possible. Generally, however, comparisons are of limited value in the context of this capital expenditure review due to differences in the nature of the networks, their characteristics and their environment.

8.0 COMPARATIVE ANALYSIS

Asset Management Policies and Practices

All distributors follow broad industry maintenance practices although overall asset management strategies differed. The level of asset management planning documentation available varied considerably between distributors and on the whole was insufficient for us to comment in detail on this subject. The two large distributors have relatively comprehensive documentation, as expected considering their size and history.

NorthPower has an "initial" asset management plan which in time will need to be expanded in order to become a more effective document. On the whole we found NorthPower to have effective and progressive asset management policies and practices.

The other rural distributors are largely in a "catch-up" phase after their recent amalgamation from a number of smaller distributors. It was therefore accepted that more time is required in their cases to consolidate previous policies and practices.

Service Standards

Overall, the distributors' reliability figures are consistent with international trends which show SAIDIs, for example, of 200-400 in rural areas, 100-150 in urban areas and around 70 or less in underground CBD systems (Comparative international figures are given in Appendix 11).

Care must be taken in comparing the SAIDI, SAIFI and CAIDI figures because the method of calculation of the figures may not be consistent between the distributors (also true in the case of international distribution companies).

Furthermore significant variations in individual distributor reliability figures often occur from year to year. An analysis of historical trends is required to show the complete picture but historical data may not be available for various reasons.

Distribution System Utilisation

EnergyAustralia's utilisation figure is lower than might be expected (we normally look for 50-80% utilisation as a target for urban distributors) but this may partially be due to the triplex distribution system design used in the CBD areas. Australian Inland Energy's utilisation appears high but this is likely to have been distorted by large mining customer loads.

Levels of Expenditure

Australian Inland Energy's percentage renewal expenditure appears very low and may be explained by the lower age of its assets. NorthPower's percentage renewal expenditure is also low and may be explained by higher growth-related investment in its area and possibly also by some under-statement of renewal expenditures. Other than that, the breakdown of expenditures between renewals and other categories is consistent.

Total expenditures in relation to present total system asset book values (excluding generation) before depreciation vary greatly. NorthPower's ratio is highest and Australian Inland Energy's is lowest. Integral Energy's and Energy Australia's ratios are comparable but lower than Advance Energy's.

As expected, reliability enhancement works are given a higher priority in rural areas. Growth related expenditures are higher in urban areas except in the case of Australian Inland Energy. Its growth related expenditure appears to be related to horticultural development.

Details of the comparative analysis are given in Section 11 of the report.

9.0 REVIEW FINDINGS

The main findings of the review with respect to each distributor are as follows (references are to the relevant sections in the text) :

energyAustralia

i. The level of 132 kV system security offered to the Sydney inner city area should be improved (Section 5.2).

ii. The initial asset renewal expenditures appeared to have been under-stated but the revised projections considered are appropriate (Section 5.5).

iii. The capital expenditure projections associated with augmentation are appropriate (Section 5.7).

iv. Possible generation plants in the Botany and Kurnell areas could create the need for further network investment (Section 5.8).

Integral Energy

v. Integral Energy's 132 kV and 66 kV networks appear well planned and adequate (Section 6.2).

vi. Asset renewal expenditure projections were found to be high and have been adjusted downwards (Section 6.5).

vii. Integral Energy have a well considered Transmission Network Development Programme (Section 6.7).

NorthPower

viii. The TransGrid network supplying NorthPower's far north region is only marginally adequate for the present load and, with load growth, will become inadequate (Section 7.2).

ix. There is inadequate information on the asset ages to verify the extent of renewal-based expenditure (Section 7.5).

x. The projections do not include potential capital contributions to TransGrid for works of an estimated value of $200 million (Section 7.7).

Great Southern Energy

xi. The capital expenditure projections derived for Great Southern Energy should be considered preliminary until supporting information can be provided (Section 8.9).

Advance Energy

xii. The capital expenditures associated with asset renewals appear to be insufficient and they have been adjusted upwards (Section 9.5).

Australian Inland Energy

xiii. Minor adjustments were made to allow for oil containment facilities (Section 10.5).

General findings of the review are as follows :

xiv. The renewal of aged assets is an important driver of capital expenditure but is not well analysed or documented (Sections 2.2 and 3.2).

xv. Not all distributors were able to provide the comprehensive network development and asset management plans needed for the purpose of the review although there is an awareness of the need for preparation of such documentation where it does not presently exist (Section 3.8).

xvi Expenditures on IT assets for network information and management is a growing area characterised by ill-defined costs and benefits (Section 3.10).

xvii Generally, the performance of the distributors is in line with international practice after making allowance for the nature and distribution of the loads served (Section 11).

The need for further reviews of this type should be anticipated in conjunction with future price determinations. It would therefore be desirable for the distributors to be made aware of the need for improved documentation in some cases if these reviews are to be effective. We anticipate that they themselves will share this view and we know that they have each recognised areas where their own documentation could be improved to the overall benefit of their operations.

Future reviews may show a rising trend in asset replacement needs as the assets installed, during high growth periods experienced in the 1960s and 1970s reach the end of their economic lives.

Acknowledgements

The co-operation and assistance of IPART and the distributors' management and staff during the course of the review and in the preparation of this report is gratefully acknowledged.

Disclaimers

This report reflects the views of Worley International Limited and not necessarily the views of the Secretariat to IPART or the Tribunal.

Secondly, in accordance with our normal business practice, we record here that this report has been prepared solely for IPART as an input into its planned review of electricity prices. No liability is accepted by Worley to any other party or if the report is used for any other purpose.

To view map

please click on

MapsWorley.pdf

(Map 1)

GLOSSARY OF TECHNICAL TERMS AND ABBREVIATIONS USED

Bulk Supply Point	A point (usually a substation) which receives bulk electricity from the transmission system and supplies it to the subtransmission network.
Capex	Capital expenditure.
Contingency Factor	A network design factor to identify the design level of security of supply. Usually shown as n (no automatic restoration), n-1, n-2 etc (automatic restoration for loss of 1 network element, 2 network elements etc) and related to a time period.
Demand Side Management	Active and passive mechanisms put in place to reduce customer maximum demand so that load factor and also network asset utilisation is increased. (DSM).
Distribution	The transfer of electricity to the end user.
Feeder	An electric circuit originating at a main substation and supplying one or more secondary substations.
IPART	Independent Pricing and Regulatory Tribunal.
Live Line Work	Work carried out on an overhead line whilst the line remains energised.
Load Factor	Ratio of the actual energy consumed in a given period of time to the amount of energy in that period if the maximum demand was sustained for that period.
Load Curve	Graphical representation of the observed or expected variation of load as a function of time.
Mesh	An arrangement of electric lines forming a closed loop and supplied from several sources.
NSW	New South Wales.
Nominal Voltage	A suitable approximate value of voltage used to designate or identify a system.
O/H	Overhead line.
PCB	A non-biodegradable synthetic insulation liquid (polychlorobiphenyl).
Peak Load	Maximum value of load during a given period of time e.g. a day, a month, a year.
Quality of Supply	Degree of excellence of the provision of supply to customers, usually relating to limits for voltage, frequency and harmonic content.
Radial Feeder	An electric circuit supplied from one end only.
Reliability of Equipment	A measure of the performance of equipment usually referred to in terms of years between failures.

Reliability of Supply	Measure of the performance of a network, usually expressed in terms of performance factors/indices. SAIDI - "Total Customer Minutes Interrupted" divided by "Average Total Number of Customers". SAIFI - "Total Number of Customer Interruptions" divided by "Average Total Number of Customers". CAIDI - "Total Customer Minutes Interrupted" divided by "Total Number of Customer Interruptions".
Ring Feeder	An arrangement of electric circuits forming a complete ring and supplied only from a single source.
SCADA	Supervisory Control and Data Acquisition of remote network installations at a central position.
Security of Supply	Defined network design parameters (contingency factors) to achieve particular restoration of supply criteria at the time of a fault incident.
Single Line Diagram	A diagram in which the polyphase links are represented by their equivalent single line.
Spur	An electric circuit connected to a main line at a point on its route.
Substation	A part of an electrical system, confined to a given area, mainly including ends of transmission or distribution circuits, electrical switchgear and control gear, buildings and transformers.
Sub-Transmission	The bulk transfer of electricity from bulk supply points to zone substations for dispersal to retail customers.
Transmission	The transfer in bulk of electricity from generating stations to bulk supply points.
U/G	Underground cable.
Worley	Worley International Limited.
Zone Substation	A substation which provides transformation and supply to several feeders distributing electricity to a specific area (zone).

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Part I
Regulatory Environment and Review Process

Section 1.0
Introduction and Terms of Reference

INTRODUCTION AND TERMS OF REFERENCE

CONTENTS

1.1 APPOINTMENT, TERMS OF REFERENCE AND OBJECTIVES

In May 1998, the Independent Pricing and Regulatory Tribunal of New South Wales (IPART) commissioned Worley International Ltd, Engineering and Management Consultants of Auckland New Zealand (Worley) in association with PricewaterhouseCoopers, Chartered Accountants to investigate and report on :

- the adequacy and appropriateness of the capital expenditure programmes of the six New South Wales electricity distributors.

- the appropriateness of the distributors' capital expenditure assessment and asset management policies considering the regulatory environment and IPART objectives.

The Terms of Reference for the review are given in Appendix 1A. In summary, the objectives of the review were as follows :

- Assess and quantify the appropriateness of the distributors' existing network infrastructure in terms of current and projected capacity and current condition and equipment renewal.

- Identify capital works projects to the year 2009/10 and a suitable materiality threshold.

- Review the distributors' capital works assessment procedures.

- Consider how appropriate the proposed capital work is.

- Consider how the capital works will affect efficiency and service standards such as reliability and safety.

- Compare and contrast the asset management policies of the six distributors and quantify the impact on costs relative to service, reliability and safety levels.

A further task was to accommodate the NSW distributor Boundary Review should it have recommended changes.[1]

1.2 REGULATORY ENVIRONMENT AND ELECTRICITY SECTOR DEVELOPMENT

With the release of its Electricity Reform Statement in May 1995, the NSW Government commenced a programme of major reform of the State's electricity industry. The reforms were aimed at :

- improving efficiency and service levels
- providing customers with a choice of supply arrangements and service levels, and
- meeting the community's expectations for substantially reduced environmental impacts from the use of electricity.

[1] The Boundary Review has since been completed and no changes have been recommended.

At the centre of these reforms was the introduction of competition into the production and supply of electricity. Establishing an effective electricity market will provide the opportunity and incentives for competition. In this market generators, retailers, end users and other service providers should be able to participate on equal terms to buy and sell electricity and related energy services.

Substantial progress has since been made on implementing the reforms. Trading in the NSW interim wholesale market commenced in May 1996. In October 1996 the first group of NSW electricity users became eligible to choose their supplier, either in the retail market or the wholesale market. By July 1999 all customers were to have this right.

To support competition, the generation and distribution sectors of the NSW electricity industry have been substantially restructured. Three generators – Delta Electricity, Macquarie Generation and Pacific Power (responsible for the Eraring power station and the State's entitlement from the Snowy scheme) now supply into the State market. TransGrid operates the high voltage grid and the State's twenty-five distributors have been formed into the six energy services corporations which are the subject of this review.[2]

With the introduction of retail competition in New South Wales in October 1996, new wholesale traders and retailers were able to enter the market, providing an expanded range of choice for customers. The Electricity Supply Act establishes the means by which electricity which is traded in the wholesale market can be delivered to customers who are not participants in the wholesale market. The relevant provisions of the Act focus on ensuring that safe, economic and reliable retail market services are available to customers and providing a mechanism for ensuring customer access to competitively supplied retail market services.

Licensing Arrangements

The Act confers power on the Minister to license the providers of retail market services as :

- electricity distributors, and
- retail suppliers.

To enable a smooth transition to the new industry framework, the existing electricity distributors were deemed to hold both types of licence from the commencement of the Act.

Electricity Distributors

The Act prohibits persons from operating distribution systems to convey electricity for retail suppliers unless they have an electricity distributor's licence. Once licensed, electricity distributors :

- can only operate to convey electricity for licensed retail suppliers
- must also hold retail supply licences
- must provide (on application) customer connection services to premises within their districts, and
- must provide customer connection services only under a contract.

2 Appendix 1B lists the previous 25 distributors and the amalgamations.

Retail Supply

The Act provides that electricity supply arrangements are unenforceable by a person other than a customer who is not authorised (in the wholesale market) or licensed. Statutory conditions of retail suppliers' licences are that they :

- may not discriminate against persons on the basis of their association with alternative sources or forms of energy or with demand management systems
- must provide retail supply services to a customer only under a contract, and
- must ensure the supply of electricity to their "franchise customers" (on application) as described below, and generally must not supply electricity to franchise customers from other districts.

All electricity customers are classed as "franchise customers" until declared by the Minister to be "non-franchise customers". Franchise customers lack the right to choose their supplier and can generally only be supplied through the electricity distributor in whose district their premises are situated.

When customers are declared to be "non-franchise", they retain the right to receive electricity supplies through their local electricity distributor (who must hold a retail supply licence), but are free to purchase their electricity supplies by agreement from any retail supplier.

Regulatory Framework

Regulation of electricity services within NSW is the responsibility of the Independent Pricing and Regulatory Tribunal (IPART). The scope of the Tribunal's regulation is defined under the IPART Act 1992 and the declarations made pursuant to the Act. The National Electricity Bill has recently been passed by the NSW Parliament as part of national competition policy agreements between the federal and state governments. When proclaimed, the Act will give legal backing to the National Electricity Code (NEC). The Act will provide for IPART's regulation of electricity transmission services to cease after June 1999. The Bill also provides for IPART's regulation of electricity distribution network services to cease from after December 2000. Provisions are made for the regulation of electricity services to continue under the NEC. Under the code the Australian Consumer and Competition Commission will regulate transmission services and a jurisdictional regulator (anticipated to be IPART) will regulate distribution network services.

Price Regulation

The Tribunal's activities in regulation of electricity prices have been undertaken against a background of major restructuring of the NSW electricity industry and the introduction of competition into the electricity generation and wholesale distribution markets.

Medium term price paths for electricity transmission, distribution and retail supply were released by the Tribunal in March 1996, and minor revisions were made in August 1997. These price paths specifically addressed the ongoing changes in the structure of the industry and factors affecting the introduction of competition. The 1997 report includes pricing of street lighting charges. A revenue cap formula was set for charges for the use of distribution wires.

The Tribunal has recently announced a review of electricity prices to apply from the end of the medium term price path in July 1999 and the capital expenditure review which is the subject of the present report has been commissioned by IPART as an input into this process.

1.3 WORK PROGRAMME

Our work on the review commenced on 19 May 1998 with a meeting with IPART and the six distributors. Questionnaires were then prepared and sent to the distributors on 26 May 1998. Most of the questionnaires were completed and returned to us during June.[3]

Each distributor was visited by members of our review team between 22 June and 10 July 1998, after which the review team proceeded with its assessment, seeking further clarifications from the distributors as necessary. An Interim Report was prepared and submitted to IPART on 10 July 1998. A Preliminary Draft Final Report was prepared and submitted to IPART on 10 August 1998 for discussion and our Draft Final Report was submitted to IPART on 31 August for review. The Final Report was submitted on 2 October 1998, incorporating agreed changes after review by IPART and the distributors[4]. A presentation of the Final Report is to be made at IPART's offices in November 1998.

1.4 INTERIM REPORT

The purpose of the Interim Report, sent to IPART on 7 July 1998, was to summarise the work done up to that time and the preliminary conclusions reached from the questionnaire and field visit interviews. The report concentrated on key issues affecting the assessment, their impact and measures proposed to overcome difficulties then foreseen. Its findings are superseded by this Final Report.

1.5 THIS REPORT

This Final Report presents the findings of the review. It is presented in two main parts and twelve sections as follows :

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[3] Delays were experienced with the provision of information from Great Southern Energy and Australian Inland Energy.

[4] Each distributor was invited to review the section of the report concerning its activities from the viewpoint of accuracy of our interpretation of the information supplied by the distributor to us. Along with other interested parties, all distributors will have the opportunity to review the full report and make submissions to IPART after the completion of our work.

PART I - REGULATORY ENVIRONMENT AND REVIEW PROCESS

Section 1	:	Introduction and Terms of Reference (this section)
Section 2	:	Principles of the Review
Section 3	:	Issues Arising
Section 4	:	Methodology

PART II - ASSESSMENT

Section 5	:	Energy Australia
Section 6	:	Integral Energy
Section 7	:	NorthPower
Section 8	:	Great Southern Energy
Section 9	:	Advance Energy
Section 10	:	Australian Inland Energy
Section 11	:	Comparisons
Section 12	:	Summary and Concluding Remarks

Confidential information submitted to us by the distributors (comprising completed questionnaires and detailed capital expenditure projections) are considered confidential to IPART, Worley and the distributor concerned and are presented in a separate volume for IPART's information only.

A supplementary report on TransGrid's capital expenditure projections is presented separately.

The main conclusions of the review are set out in an Executive Summary which follows the Table of Contents at the commencement of the report.

1.6 ACKNOWLEDGEMENTS

The co-operation and assistance of IPART and the distributors' management and staff during the course of the review and in the preparation of this report is gratefully acknowledged.

1.7 DISCLAIMERS

This report reflects the views of Worley International Limited and not necessarily the views of the Secretariat to IPART or the Tribunal.

Secondly, in accordance with our normal business practice, we record here that this report has been prepared solely for IPART as an input into its planned review of electricity prices. No liability is accepted by Worley to any other party or if the report is used for any other purpose.

Section 2.0
Principles of the Review

CONTENTS

2.1 INTRODUCTION

In this second section of the report, we outline the general principles of capital expenditure (capex) review in electricity distribution businesses with particular reference to the present task. It is assumed that the reader has a sound general knowledge of electric power distribution systems and their operation and accordingly we generally do not go into descriptive detail.

In this section, we first discuss asset renewal expenditures in the context and lifecycle asset management. We then discuss expenditure for the augmentation of network capacity to meet growth in demand. These are the two principal determinants of capex. Other issues are then discussed.

2.2 ASSET RENEWAL EXPENDITURES AND LIFE CYCLE ASSET MANAGEMENT

Asset renewal expenditures make up a significant component of the capital expenditure programme of electricity distribution businesses. They comprise two main types of expenditure, namely replacement and refurbishment. In this context, the latter generally comprise overhauls which are intended to restore the service life of the asset largely to an "as new" condition.[1] In each case, the need for renewal is brought about through the ageing of the assets. Renewals required in order to comply with statutory or safety obligations are discussed separately in Section 2.5.

Asset renewal expenditures are determined mainly by the expected lives of the assets, the standard to which the assets are maintained and the replacement cost of the assets. The correct determination of expected life is therefore important and the impact of assuming different asset lives for projecting future capital expenditures is significant. For example, an increase in the life of a given asset category by say 5 years could shift a considerable amount of expenditure out of any given 10-year financial window. Since large expansions of electrical networks took place in the 1960's, and since many of these assets are considered to have a useful life of the order of 30-50 years, it follows that the impact of expected life on capex projections over the next ten years is doubly great. We therefore discuss the subject of expected lives in detail here.

Standard Lives

Guidance regarding standard lives can be obtained from published guidelines[2] and technical papers. The NSW Treasury Policy Guidelines include a table of standard asset lives for electricity distribution assets. These lives are estimates of the average expected life of the assets and were based on industry experience available at the time of preparation of the guidelines in 1995. Generally the lives given in the Guidelines are still considered reasonable for use today for planning purposes.

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[1] Routine maintenance costs are not treated as capital expenditure in this report.

[2] The NSW Treasury "Policy Guidelines for Valuation of Network Assets of Electricity Network Businesses", 1995 is relevant here. Another example is the "Handbook for Optimised Deprival Valuation of Electricity Line Businesses" published by the New Zealand Ministry of Commerce.

PRINCIPLES OF THE REVIEW

Recent emphasis on the restructuring, valuation, sale and purchase of electricity distribution businesses worldwide continues to bring asset lives into sharper focus. In particular, the drive for reductions in capital investment and in operating costs has resulted in considerable emphasis being placed on improved asset management and life extensions wherever economic. On the other hand, recent network failures have heightened the awareness of the risks of inadequate capacity margins and the uncertainties which accompany older assets.

Determination of Standard Lives

The lives chosen should be the lesser of economic life , safe life or life before becoming obsolete or redundant. They are affected by a large number of factors including :

- Robustness of the original design of the assets
- Materials and methods used in their construction
- Environment in which the assets have operated
- Amount of use or degree of loading
- Standard of maintenance which has been carried out
- Technological advances since the time of installation
- Suitability for refurbishing, up-rating or upgrading for continued use.

Historical service records provide the most compelling evidence for the determination of standard lives but they are often scarce[3]. If available, they can be used to analyse the failure patterns of each asset category. Note, however, that the population in each asset category may not be homogeneous but may be composed of equipment of several different types, manufactured or constructed during different periods, and that their behaviour and survival patterns may not be the same. If sufficient information can be compiled, failure and survival curves such as those shown in Figure 2.1 can be constructed to show probable life curves of each asset category. A set of curves of this type would be needed for each asset category.[4] Generally, there is not sufficient information available for rigorous analysis of this type.

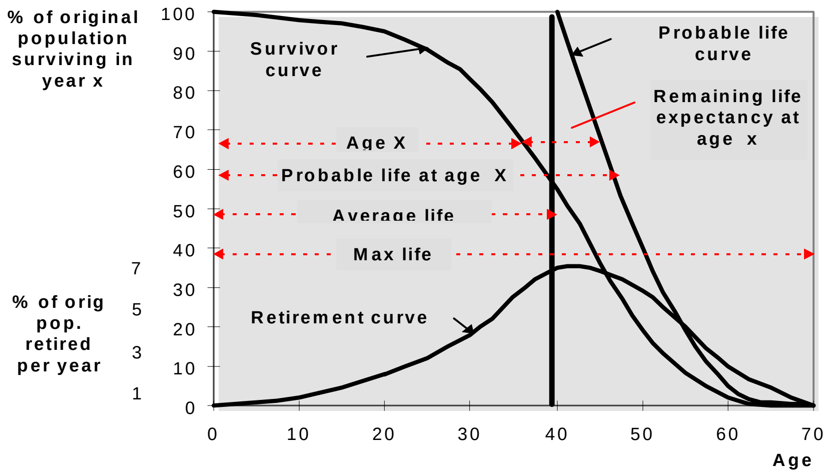
A complicating factor is the somewhat indeterminate nature of certain assets, notably overhead lines. These assets are characterised by the ongoing replacement of components over time.[5] This makes it very difficult to pin down a standard life or the most appropriate year for replacement for these assets.

[3] It has been widely accepted that accelerated age testing is not conclusive in determining an asset's life largely due to the fact that not all factors affecting life are included in the experiments. However, accelerated aging does have a place in predicting and comparing the performance of like assets.

[4] The "survivor" curve shows the pattern of survival of the original population and the "retirement" curve shows the frequency of asset retirement from the original population over time. The "probable life" curve shows the probable life of the survivors from the original group at any age from zero to maximum life.

[5] King Herod's axe is the usual analogy.

Figure 2.1 : Typical Survivor Curves



Once determined, by whatever method, standard lives can be used in conjunction with known asset age profiles to make preliminary assessments of future capex needs for asset renewals[6].

Confirmation of Projected Capex Expenditures

It needs to be emphasised, however, that estimates of capital expenditure for asset replacement purposes, prepared using age profiles and standard lives, can only be regarded as approximate. That is, they should be used only for preliminary estimating purposes.

Actual commitments to capex need to be founded on the known condition of the particular assets concerned[7]. Evidence for this purpose needs to be obtained through measurements or inspections.[8] Unfortunately this level of information is sometimes not available, creating a problem for the capital expenditure reviewer and indeed the distributor itself. The treatment of this important issue for the purpose of the present review is discussed further in Section 3 of this report.

Standard of Maintenance

The second important determinant of asset lives and replacement needs is the standard of maintenance carried out over the life of the asset. This may have more impact on certain classes of asset than on others.[9]

For most purposes, it can be assumed that there is a match between industry accepted lives and the maintenance practices commonly applied and that higher or lower levels of maintenance would result in assets, on average, attaining longer or shorter lives respectively.

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6 Where asset age profiles are not available from historical records, one can use (with care) comparisons with other distributors with a similar historical development to estimate asset age profiles for this purpose.

7 The survivor curves in figure 2.1 illustrates a typical spread of expected retirements and hence the significance of this statement.

8 For example, the measurement of concentrations of furfuraldehyde gives an indication of the condition of the paper insulation in power transformers, a determining factor in the life of this asset group.

9 For example, the maintenance of overhead lines and switchgear may have more impact than that on underground cables.

Replacement Costs

Thirdly, the determination of capital expenditures for asset replacement purposes is dependent on the unit replacement costs assumed. These should reflect the use of modern equivalent assets and efficient construction techniques.

Although some assets may perform the same function as others (for example, overhead lines and underground cables) they nevertheless can have significantly different replacement costs. Any change in construction policy, arising for example from public pressure for a less obtrusive network, may have significant capex implications.

A further complication is that the total installed cost of an asset can vary significantly depending on its location and the terrain. An example is the laying of cable in rocky ground conditions where costs can be considerably greater than laying the same cable in good ground.

The NSW Treasury Policy Guidelines give standard asset replacement costs and provide guidance on the application of multipliers to reflect terrain and other special conditions. These standard costs have been used by most but not all of the distributors in the capital expenditure projections which we have reviewed in this report. This may suggest either a high level of comfort with the standard costs or merely that they were conveniently available. For the purpose of this review, their use can be accepted, along with departures where there is reason.[10]

Life Cycle Asset Management

The fourth factor affecting replacement expenditures is the policy adopted for asset life cycle management. By that we mean the overall optimisation of utilisation, operation, maintenance, refurbishment and replacement of each class of asset and its constituent elements. For this review, we have limited our consideration of maintenance practices to those areas where they impact on asset lives, highlighting any departures from accepted practice in the later sections of this report[11].

2.3 EXPENDITURE FOR AUGMENTATION OF CAPACITY

The second major driver of capital expenditure is demand growth. Growth in demand results in the need for capital expenditure if the loading on components of the power system network reaches the maximum capacity available or threatens security of supply criteria. Development of a horizon year load forecast enables the future configuration of a power system to be determined, making it possible to define a staged development programme for intermediate years. Although the objective is to work towards an optimally planned system, optimality may not be achieved in the short term.

Prediction of the need to augment the capacity of a power network requires knowledge of load growth trends in each area, daily, weekly and yearly load patterns and an assessment of future spot loads.

Load Growth Trends

[10] The standard costs were designed to reflect a partial “greenfield” approach and the economies of large scale construction. These conditions may not, however, be applicable in all cases of asset renewals.

[11] We understand that all six distributors are participating in a benchmarking exercise being carried out for IPART but this material was not available in time for our review. Once completed, the benchmarking work may throw further light on the practices being used.

Future loads can be forecast by several methods, each subject to uncertainty.[12] Changing load patterns also need to be taken into account, for example a shift in the time of day or season of peak demand, since certain equipment may have greater or less capacity under different ambient conditions.

Load growth forecasts should also be reviewed against territorial local body plans and other information such as business forecasts, economic projections and census information to demonstrate that they are reasonable for planning purposes.

A complicating factor to be taken into account by power planners is "diversity". Expressed simply, the peak demands in different parts of the network are not coincident and cannot simply be aggregated.

Changing load patterns in the residential sector are likely to impact on future peak demand growth as the growing energy efficiency of appliances and a resurgence in the use of gas reduce the rate of growth in electricity use.

The use of more sophisticated demand side management (DSM) initiatives may enable electricity distributors to exert a more control over load peaks by switching controllable load or discouraging peak time use.[13]

Future Spot Loads

New concentrated loads imposed generally by major customers may arise as a result of the development of industries, irrigation schemes or for other reasons. They can be difficult to predict and may place significant burdens on power systems at short notice. This may require the in-built provision of some slack capacity, the implementation of ad hoc strengthening measures or more likely a combination of the two. For the capital expenditure reviewer, they introduce an added level of uncertainty.

Planning Considerations

In order to ascertain whether a power network has sufficient capacity to accommodate load growth, it is necessary to understand the permissible loading capacities of network components, the requirements for satisfactory voltage regulation under normal and emergency conditions and the selection of appropriate security levels required for the system. Policies on these matters may differ from one distributor to another reflecting the different conditions and equipment in service. Also, it needs to be noted that there are no defined national standards for security of supply. A detailed review of these items and the issues that underly them is beyond the scope of this review[14]. We therefore limit ourselves here to the question of how these policies affect capital expenditure.

[12] Extrapolation of historical growth trends, econometric forecasting and end-use analysis are three common methods, each with preferred uses.

[13] See Section 2.7.

[14] Although we do discuss the subject further in Section 2.4.

Expenditures Based On Capacity to Meet Load Growth

For planning purposes, it is normal for the power network to be modelled to determine the load on each component as demand increases. This can be done with various power system computer modelling programs available. Network augmentations are then considered, sufficient for the network to perform within its permissible load limits and security levels. Once a long term network development plan is determined in this way, the corresponding capital expenditure projections can be deduced.

Effect of Inaccuracies in Growth Forecast

Variations in actual growth from the forecast figures are normally accommodated by varying the timing of implementation of the capital works that form part of the long term development plan. Slower than expected load growth can be accommodated by deferral of works. Faster load growth can be handled by advancement of works if adequate notice is available. Generally, however, deferral is more easily achieved than advancement. It is considered prudent to maintain some reserve against unexpected increases in demand in the short term.

Rolling Plan Concept

To counter the effects of inaccuracies in the forecast, periodic reviews of the network development plan should be undertaken. It is normal for them to be undertaken as part of a cycle of rolling plans, updated every one or two years or more often if changing circumstances dictate.

Detailed Justification of Capital Works

The detailed justification of augmentation projects follows on from the planning process and is not normally undertaken until one or two years before the planned start of implementation depending on design/construction time.

2.4 APPROPRIATE RELIABILITY AND SECURITY OF SUPPLY

The move towards greater commercialisation and improved customer service within the electricity industry has resulted in a general review of power system service standards. Reliability of supply standards are amongst those that are being reassessed, along with the quality of supply as a whole, including such aspects as harmonic distortion and voltage flicker.

Whilst every customer might like to have 100% reliability, most accept that this is an impractical target. The question to be answered from the planning viewpoint is therefore :

"What level of reliability should be adopted for planning purposes?"

Appropriate Reliability

Determination of the "appropriate" level of reliability is a subject that is receiving attention world-wide at present. The best starting place for this task is with the economic evaluation of specific system improvement projects, either (a) to improve the network at certain points, or (b) to make overall improvements to the network through changes in engineering designs, operating practices, etc. If correctly assessed, "appropriate reliability" will be implicit in the designs. Customer Average Outage Minutes and other system performance indices will then be a reflection of this optimality, rather than a driving force.

The accepted theoretical method of determining an appropriate level of reliability is first to determine the economic cost to customers of supply interruptions. The sum of this cost and the economic cost of making supply available may then be minimised. In practice, application of this methodology is problematic because different customers ascribe different costs to non-supply. Also, electricity utilities are mostly natural monopolies; therefore the value of reliability of supply cannot be tested in a free market. Furthermore, the analysis is of interest from the viewpoint of the economy as a whole but may not be of commercial significance to the utility.

Consumer surveys are one means by which distributors can obtain feedback as to whether their customers would pay more for increased reliability. However, surveys have their drawbacks in that the temptation is for customers to request greater reliability only until such time as tariffs rise.

Comparisons with other utilities provide some answers. However, it is still necessary to research the unique local conditions and take them into account in the formulation of policy.

Factors Determining Reliability

Reliability of supply depends on four main factors :

- The inherent security (configuration) of the system
- The quality (reliability) of system components when purchased
- The effectiveness of preventative maintenance programmes
- The effectiveness of operational procedures.

These factors may interact with each other. For example, poor quality equipment prone to failure, or inadequate maintenance programmes, may overload maintenance staff, leading to a consequential inability to restore equipment to service quickly.

The type of terrain and local climatic conditions may also affect reliability.

Inherent Security

The inherent security of the system is determined primarily by its configuration. This, in turn, is determined by the network planning policies of the utility.

For subtransmission and distribution system planning purposes, it is accepted practice to use “deterministic” as opposed to “probablistic” techniques to assess reliability. In essence, this concept considers what happens when one or more major network elements are out of service or break down. The concept of n, or n-1 or n-2 levels of security are used. n-1 security means that supply is maintained in the event of the loss of one major network item. The concept of n-1 can be further defined by the following categories, manifested by the redundancy of the primary equipment and/or the sophistication of the protection and control systems:

- One fault, no break means full redundancy and supply is continuous.

- One fault, < 1 min break implies automatic restoration of supply.

- One fault, > 1 min break implies manual restoration of supply.

This categorisation recognises that some situations require a delayed restoration of supply because the cost to maintain continuous supply is too great.

Presently accepted practice in the UK, Australia and in New Zealand[15] is to provide, for substations or loads of 25-40 MW capacity or more, supplied that can be maintained at full capacity in the event of a failure of one major item of equipment i.e. an (n-1) firm capacity. Load centres of say 100 MW or larger or main transmission systems, are designed to sustain double contingencies such as a simuiltaneous fault on two circuits, or a fault on a second circuit when one is out of service. For loads of less than 25 MW, either single contingency (n-1) or "restoration" planning is normal. This is considered appropriate for the highest reliability case on most distribution network unless particular customers have special requirements.[16] Where such cases arise, the designs should be prepared after consultation with the customer(s) concerned.

Where "restoration" planning is adopted, the system should be capable of rapidly restoring supply through one or more contingencies for loads over about 20 MW. At lower levels, restoration times increase.

SCADA is commonly employed to improve system control, thereby reducing outage times.

The effect on reliability due to security is therefore dependent on the planning criteria adopted. The criteria have significant cost implications because they dictate the configuration of the system and the types of switchgear, control and protection equipment used.[17][18]

2.5 WORKS TO MEET STATUTORY OBLIGATIONS

There is a need from time to time for capital works to be undertaken to meet statutory obligations. These obligations may relate to statutory voltage limits (usually considered under the heading of augmentation to meet load growth) or works to address safety concerns, environmental concerns or specific local authority requirements.[19]

It is not necessary to go into details here but two common examples are the removal of PCBs and the introduction of oil spillage containment at substations. Usually, such cases are clearly defined.

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[15] Practices in the UK were codified by the Electricity Council but may now vary under the new ownership structure. Practices in Australasia vary but have tended to follow UK practice.

[16] The distribution systems in the Sydney and Newcastle CBDs are exceptions. They have higher levels of security.

[17] It is largely for this reason, and the wide range of circumstances encountered, that there is no documented national standard for security.

[18] The other factors affecting reliability have less impact on capital expenditures and are not discussed here.

[19] A list of Acts and Regulations relevant to the distributors is given in the Electricity Association of NSW Code of Practice for Electricity Transmission and Distribution Asset Management.

Works needed to comply with local authority bylaws and planning determinations are less easily able to be defined for the capital expenditure reviewer as each distributor's network may extend over several such areas. Specific local authority requirements may include underground construction, the removal of oil contamination, screening of installations and noise abatement.

2.6 CAPEX EVALUATION AND APPROVAL PROCESSES

Most distributors have formal approval procedures and policies for control of their capital expenditure, reflecting the accepted international approach to capex approval as summarised below :

Step 1 : Establish the Need

Generally the technical justification of a project should "establish its need". If it fails to do this, then little is to be gained by proceeding further. Technical justifications should be competent and complete. They should be documented with supporting calculations since it is only through documentation that inconsistencies and shortcomings can be exposed.

Step 2 : Identify and Quantify Project Costs and Benefits

Project costs such as construction and operating costs are relatively easy to determine but other costs such as the costs of demand not served if a project does not proceed are harder to quantify. Expected demand not served in terms of outage minutes can be estimated using local or industry averages but determining their dollar value can be problematic. Loss reduction, if appropriate, should also be quantified and included as a project benefit. Non-quantifiable benefits should be listed.

Step 3 : Optimise Project Timing

Careful attention should be given to project timing. Construction should be undertaken as late as possible consistent with necessity, risk and economic justification.

Step 4 : Consideration of Statutory, Safety and Environmental Obligations

As already mentioned, works may be necessary for statutory reasons, for example in cases where voltage regulation exceeds statutory limits or where environmental protection or reinstatement is needed. Works may also be necessary for safety reasons should the safety of the public or company personnel be compromised.

Step 5 : Identify Least Cost Solution

The fifth step entails the identification of the least cost solution to the need. The least cost solution of two or more mutually exclusive options with similar benefits is normally determined by calculating the present value of lifetime project costs, discounted at the company's weighted average cost of capital.

Step 6 : Rate of Return Calculation

Having identified the least cost solution, the internal rate of return (IRR) should be calculated to assess the financial viability of the proposed works.[20] The IRR is the discount rate at which a project's costs and benefits equate (net present value is zero). To decide on the acceptability of projects, a cut-off rate of return should be decided. If the market or agreed price path permits, it should be at greater than or equal to the company's weighted average cost of capital. We discuss the selection of a suitable rate of return in Section 3.5.

It should be noted, however, that in the present low less and low growth environment, it may be impossible to justify capital works other than essential equipment replacements if a rate of return target related to WACC is used.[21]

2.7 DEMAND MANAGEMENT AND EMBEDDED GENERATION

Demand Management

Demand Side Management (DSM), if taken seriously, has the potential to defer significant capital expenditures for network augmentation projects (see Section 2.3) although it may not have a significant impact on the deferral of expenditure for asset renewals. It is a condition of the Electricity Supply Act 1995 and the distributors' licences that distributors investigate the cost-effectiveness of implementing demand management strategies to avoid or defer augmentation works and the distributors are required to submit annual reports to the Licence Compliance Advisory Board in this regard.[22]

The distributors are involved in a working group responsible for preparation of the "Code of Practice - Demand Management for Electricity Distributors". This code has not been accepted (we reviewed version 2.1) and is understood to be undergoing a major revision by a separate group under the Department of Energy at the time of writing this report.

All of the distributors utilise demand side management systems to some extent already. Examples include electric hot water heating controls, the use of time-of-day tariffs, charges for maximum demand and the use of special tariffs in conjunction with interruptible loads. In addition, encouragement is being given by various agencies to energy saving schemes and the use of more efficient appliances.

A review of the distributor's total network load profiles confirms the overall impact of present DSM measures although not necessarily the potential for DSM at individual zone substations.

To the extent that DSM strategies are in use now, their effect can be allowed for in the expenditure projections. However, the feasibility of future programmes and their impact is harder to assess in the absence of detailed analysis and cannot necessarily be counted on in the short-to-medium term.

Embedded Generation

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20 It may not be feasible to assess the financial viability of a project if the requirement is imposed as a result of regulation. Nevertheless, it would be expected that the least cost solution should be identified.

21 This issue is discussed further in Section 3.5.

22 A review of the distributors DSM submissions to the Licence Compliance Advisory Board should show the extent to which the distributor has investigated DSM alternatives.

Embedded generation may affect network capital expenditure since its presence affects power flows in the network. Power flows in the network may be increased or decreased by the presence of the generation. Also, it may be available only at certain times, leading to a variety of different scenarios to be analysed before it can be concluded an opportunity to defer capital expenditure exists. Generally, embedded generation is installed at short notice and the resulting impact on capital expenditure projections can be hard to predict. A further factor is that the generation may be in use only at certain times. At other times full supply capacity may be required through the network.

Embedded generation is therefore expected to have only a limited impact on network capital expenditures in the short to medium term.

2.8 THE ROLE OF ASSET MANAGEMENT IN REDUCING CAPEX

The impact of maintenance (and operational) practices on capital expenditure needs has already been mentioned (Section 2.2). The implementation of sound asset management practices will help result in network assets achieving or exceeding industry standard lives and will also aid the deferral of capital expenditure.

Over the last five to seven years, asset management plans have become recognised internationally as an important tool for the sound stewardship of electricity sector assets. Asset management plans should detail the practices (including maintenance) being employed over the life of the assets from purchase until disposal. The maintenance practices adopted will have an influence on asset lives. Different maintenance practices or combinations of these can be adopted[23] and these should be selected and documented for each type of asset.

A well-prepared asset management plan should also describe the distributors' policies on risk management. Risk can be measured by the combination of probability and consequence of failure and there will be a particular level of risk which can be accepted by the distributor and which will indicate the upper bound of projected capital expenditure.

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[23] Practices may consist of corrective, periodic, condition driven or reliability driven maintenance or a combination of these.

Section 3.0
Issues Arising

ISSUES ARISING

CONTENTS

ISSUES ARISING

3.1 INTRODUCTION

In this section of the report we outline the issues that have arisen during the review and discuss the treatment we have adopted. We discuss these in the same order as in Section 2, starting with asset renewal expenditures, then going on to augmentation expenditures and other issues.

3.2 ASSET RENEWAL EXPENDITURES – USE OF STANDARD LIVES

The point was made in Section 2.2 that estimates of asset renewal expenditures based on known age profiles and standard lives can only be regarded as approximate. Whilst this approach may be suitable for preliminary estimating purposes, actual expenditures should be based on an assessment of the condition of the assets.

Therefore, where distributors used standard lives and known age profiles in their projections without further comment, we have reviewed the expenditures concerned and had them re-submit their projections or have made appropriate adjustments ourselves. Details are given in Sections 5 to 10.

3.3 ASSET REPLACEMENT COSTS

Not all distributors have used the standard replacement costs given in Table 1 of the NSW Tresury Guidelines.[1] Some distributors chose to use the standard asset replacement costs whilst others chose to use their own estimates (in one case considerably higher) based on historical data of their own construction costs. We have accepted the higher costs where considered reasonable. Details are given in Sections 5 to 10.

3.4 JUSTIFICATION OF RELIABILITY IMPROVEMENT EXPENDITURES IN THE ABSENCE OF AGREED STANDARDS

As in most countries and as mentioned in Section 2.4, there are no legislated electricity reliability standards in New South Wales, although distributors are obliged to publicise their annual service standards in accordance with the Electricity Act 1995 and the requirements of the Licence Compliance Board. Interim electricity service standards have been issued by the Licence Compliance Board and we understand that these are currently being finalised in consultation with the industry.

A second point is that the approaches adopted by the distributors towards reliability improvements differ. Some distributors have surveyed customers as to the level of reliability that is expected and the level for which customers would be prepared to pay and have agreed that higher levels of reliability are called for[2]. Others favour the status quo.

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1 See Section 2.2.

2 Care must be used with customer survey information since customer views towards the improvement in reliability often change when tariffs are increased.

Further complications are that although target levels of reliability have been set by most distributors, the targets are not necessarily realistic, nor are they reflected in the capital expenditure projections. This may be due to the present uncertainty as to whether the cost of providing increased reliability will be able to be recovered within future revenue caps.

Our approach to this issue has been to review the appropriateness of current levels of reliability, given the nature of the load served. Target reliability levels set by the distributors have then been reviewed for reasonableness in this light and in the light of prevailing international practice. The projected capital expenditures for reliability improvement have then been reviewed against the targets and consideration has been given to the balance between implementation of better asset management practices. Details are given in Sections 5 to 10 where adjustments have been made.

3.5 INAPPROPRIATENESS OF TARGET RATE OF RETURN

The Terms of Reference suggest that this report should comment on the reasonableness of the discount factors used in any present value or economic value added analysis.

Financial Appraisal Guidelines set out the basis proposed by the New South Wales Treasury for calculating an "appropriate rate of return" using the Weighted Average Cost of Capital (WACC) methodology. WACC provides a widely used approach to calculating target rates of return. However, it requires the assumptions of certain parameters such as risk premium and the value of imputation credits, on which there is considerable scope for judgement.

NSW Treasury policy is to establish a consistent approach for the assessment of the WACC across all NSW Government business enterprises. NSW Treasury has an interest, as owner of the businesses, in maximising the target return on assets. However, Treasury needs to balance its ownership interests in setting a target WACC with its broader policy objectives of encouraging more efficient resource allocation.

We believe it is inappropriate to comment on the actual WACC to be used but that it is important to focus instead on the policies and procedures used in assessing capital expenditure programmes. Individual WACCs, in accordance with policy, should be agreed with NSW Treasury and may be recalculated every year to accommodate changes to the risk free rates (that is the long term government bond rates) or the risk premiums (betas) associated with the industry.

Each distributor will assess the risks relating to achieving the required income from any individual capital expenditure project based on assumptions including income projections and the current WACC estimate. The issue of whether or not a distributor actually achieves the required income depends upon its negotiations with IPART, IPART's assessment of WACC returns and the revenue caps set by IPART. IPART's view on an appropriate real pre-tax WACC is presently understood to be in the range of 7.5% to 9.5%, but this may change over time.

The commitment to capital expenditure is a risk assumed by the distributors and the owners, represented by NSW Treasury. To the extent that IPART sets a lower return on capital than that claimed by the distributors, the shortfall will be seen by the distributors not being able to meet the owner's WACC target. This therefore provides a level of transparency between the WACC requirements of the owner and the WACC return allowed for in the pricing determinations made by IPART.

Return on New Assets May Differ from Average Return

A final point to be made is that the overall WACC return allowed for by IPART says more about the average return on existing assets in service than it does about the return that can be achieved on proposed additions. This is an important distinction because in this review, it is the margin that is of interest, not the average. Also, in a low loss network and low growth situation such as that in NSW, it becomes very difficult to justify capital expenditures on a rate of return basis other than in the case of replacement of essential items or for items that will have a high level of utilisation from the outset. Not all necessary works fall into these categories.

3.6 DEMAND SIDE MANAGEMENT, EMBEDDED GENERATION AND BYPASS

The potential impact of DSM on capital expenditure needs and the difficulty of assessing it has been highlighted in Section 2.7. Likewise, the treatment of embedded generation. At present, the implementation of advanced DSM programmes is only at an early stage and, with some exceptions, there is relatively little embedded generation in place. In this review, each case is treated on its merits and discussed in Sections 5 to 10. Only known programmes have been (or should be) taken into account.

3.7 ACCURACY AND MATERIALITY

The Terms of Reference rightly emphasise the need to take into account the question of materiality in this review. We have taken the view that an item is to be considered material if its inclusion or exclusion would lead to a material change in IPART's determination. Material in the context of general purpose financial reporting is generally considered to be of the order of 5%.

For the purpose of the review, we have considered items as material if they comprise 5% or more of the total capital expenditure programme of the distributor concerned. Where several such items aggregate to 5% or more, we have considered them material.

Accuracy

Against this, the inherent lack of accuracy in the capital expenditure forecasting process needs to be recognised. In our opinion, it would be misleading to pretend that the projections are accurate within ± 10%.

3.8 AVAILABILITY OF INFORMATION

Not all distributors were able to provide us with comprehensive network development plans, asset management plans or data on existing assets. The reason for this may lie in the fact that the distributors have recently been amalgamated from 25 earlier bodies, many of which were small scale operations. Additionally, they did not have common operating practices or standards of network planning. Some but not all of these have been harmonised and updated since the industry was restructured.

The larger distributors had comprehensive network plans before the restructuring took place and were better able to provide the required information and technical justifications.

In some cases, the rationalisation of staff numbers in recent years has contributed to some loss of institutional memory.

In cases where detailed plans were not available, long term expenditure for augmentation has been based on the rolling forward of short term figures or in some cases historical figures. We have examined the foundation of the figures put forward and have highlighted areas of concern in Sections 5 to 10 of this report.

3.9 INADEQUACY OF SOME PROJECTED EXPENDITURES

In certain cases, we felt that insufficient expenditure had been allowed and accordingly we increased the estimates made by the distributors. These cases generally related to expenditures for replacement of assets due to ageing. All such cases are identified and explained in Sections 5 to 10 of this report.

3.10 TREATMENT OF OTHER EXPENDITURES

Capitalisation v. Expensing of Costs

In certain instances, the approaches to capitalisation adopted by the distributors differ. The distributors are required to follow the NSW Treasury guidelines[3] when determining whether expenditure is expensed or capitalised but difficulties still arise largely due to the indeterminate nature of some assets such as overhead lines. The guidelines allow some latitude for assets of lower value. However, although the assets may be low in individual value, the quantities involved may nevertheless result in significant total expenditure and a material overall impact.

We have accepted the different treatments of the distributors in our review and have assumed that their present accounting policies are retained throughout the period under review. However, this is an area where IPART, in preparing its price determinations, should scrutinise the associated maintenance expenses to be satisfied that all costs are accounted for. Details are given in Sections 5 to 10.

3 "Guidelines for Capitalisation of Expenditure in the NSW Public Sector", January 1994.

Generation Assets

Some distributors included capital expenditure for generation assets, for example for small hydro, wind and solar-powered generation. These activities may assist in deferral of future capital expenditure for network augmentation but for the purposes of this review, all such capital expenditures have been deleted. We have made adjustments where necessary to exclude this capital expenditure. Details are given in Sections 5 to 10.

Metering

Most distributors included expenditure for new meters and meter renewals although the projections varied because of uncertainities over dates for the introduction of contestability of metering for small use customers. Expenditure related to metering has not been included in our analysis but is recorded separately for IPART's consideration. We have attempted to separate out expenditures for load control relays where they have been included with metering on the assumption that these will remain network assets.

IT Systems

Some distribution companies have included capital expenditure for IT systems relating to GIS, financial systems, customer information systems and IT hardware renewals/upgrades. However, there is not a high level of consistency in the presentations.

Where they are discernible, expenditures related to GIS and asset management systems have been shown as a separate item.[4] We have also recorded separately (but not reviewed or commented on) IT expenditures related to financial systems and customer information systems[5] since these are outside our area of competence and such expenditures may need to be apportioned between the regulated and non-regulated portions of the business.

We have reviewed expenditures for SCADA systems.

Vehicles and Plant

There was not a consistent approach to the inclusion of vehicles in the capital expenditure projections provided by the distributors since some utilise their own vehicles, others lease, and others use the vehicles through a subsidary company. We have therefore shown vehicles and plant as a separate item for IPART's consideration. We have made adjustments to the projected expenditures for vehicles in one particular case to take account of the vehicle trade-in values.

Contestible Works, Recoverable Works and Capital Contributions

Expenditures and contributions under these headings have been identified separately.

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4 Expenditures of GIS and network information management systems is a growing area, as yet ill defined in terms of costs or benefits.

5 Customer information systems generally relate to the retail function.

Easements

Expenditures for easements have been included where advised to us by the distributors. The amounts are not material.

Other Expenditure Items

Expenditures on street lighting and retail activities is excluded.

3.11 COMPARATIVE ANALYSIS

Comparisons between the distributors and with international best practice are hampered by differences in the nature of the service areas of the six distributors and the load served, giving rise in turn to different network configurations and capital expenditure requirements.

In addition, their operations are of a significantly different scale, resulting in differences in their approach to asset management, their resource requirements and the efficiencies of operation which can be achieved.

Also, differences in environmental conditions affect asset lives and design solutions, particularly in coastal regions where salt spray is deleterious.

A further factor is that the larger distributors experience moderate growth in urban areas whereas the smaller, more rural distributors generally do not.

The factors mentioned are well known and have generally been described in the information provided to us by the distributors. We have taken them into account in our assessments. However, the variations limit the extent to which comparisons can be drawn - a point to which we return in Section 11 of this report.

Part II
Assessment

Section 4.0
Methodology

CONTENTS

4.1 REVIEW OF POLICY DOCUMENTS

As a first step in the review, we gathered and reviewed relevant policy documents published or issued by the NSW Government and its agencies including Treasury and the Department of Energy.[1] We also obtained copies of relevant legislation and information on the formation of the national electricity market and the national electricity code. Additionally, we obtained relevant industry codes of practice and the other documents listed in IPART's minimum reference checklist.

4.2 QUESTIONNAIRE

A detailed questionnaire was then prepared, reviewed with IPART and issued to the distributors. Its purpose was to speed up the review process, help with the production of consistent information and reduce the necessity for collation and review of large amounts of documentation. The questionnaire covered the following broad areas :

- Corporate strategic plan
- Network characteristics
- Capex planning criteria
- Service standard objectives
- Asset maintenance practices
- Capital expenditure[2]
- Previous valuations
- Growth forecasts
- Statutory requirements
- Capex approval process
- Checklist for other information to be supplied.

Additional documentation requested in the questionnaire included :

- Annual Report 1996/97
- Long Term Network Development Plan
- Subtransmission Schematics
- Sample Distribution Schematics
- Latest Asset Management Plan
- Reports on Major Projects included in the Capex Projections
- Copy of Load Forecast Models[3].

A list of documentation received is given in Appendix 4A.

4.3 INTERVIEWS AND INSPECTIONS

Visits to the distributors were made and interviews performed with key staff to review the responses to the questionnaires, clarify any necessary areas and to request further information where required to support the capital expenditure projections. Inspections of assets were made where required. A list of staff interviewed is included in Appendix 4B.

4.4 ASSESSMENT AND REPORTING

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[1] The NSW Government "Capital Works Investment Total Asset Management Manual", November 1993, was drawn to our attention as a possible source of asset management best practice. In our view, however, this document is suited more to local government operations and is not the most relevant document for electricity distributors to follow.

[2] A separate capital expenditure template was provided for recording the future projections into specific categories to facilitate the analysis and review.

[3] These were not provided by the distributors. This did not prove to be an issue since the distributors forecasts were generally for static or low growth of 0-3%.

The initial responses to the questionnaire were checked for completeness and, following the site visits to the distributors, our interim report was prepared and sent to IPART.

Documentation supplied by the distributors, supporting their capital expenditure projections, was reviewed in detail. Discrepancies and any concerns that we had were discussed with the distributors and further information was sought where needed. Following our review, this report was prepared, inclusive of adjusted capital expenditure projections for each distributor.

The distributors were given the opportunity to comment on the accuracy of our interpretation of their submissions prior to the final submission of this report. Their comments have been incorporated only to the extent that they did not contravene our professional judgement.

Note as mentioned in Section 1.5 that the responses of the distributors to the questionnaire have not been included in this report for confidentiality reasons.

4.5 COMPARISONS

Comparisons between the distributors have been made where possible and are discussed in Section 11.

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Section 5.0
energyAustralia

CONTENTS

5.1 DESCRIPTION OF THE NETWORK

The energyAustralia network has three distinct geographic areas, the concentrated greater Sydney area, the Central Coast system (from Sydney to Eraring) and the Newcastle and Hunter Valley region . Maps showing energyAustralia's 132 kV transmission network are provided in Appendix 5A.

The greater Sydney area is a dense load centre served by a heavily interconnected 132 kV network and fed from four TransGrid 330/132 kV substations. Further interconnection of the 132 kV system is planned to improve the security of supply.

The Central Coast is a long narrow region which does not allow full network interconnection as in the case of the Sydney area. This area is served by a few long 132 kV Transmission lines and further development is planned in this region to cater for the high residential growth in this area.

The Newcastle and Hunter Valley area is served by a well interconnected 132 kV network in the Newcastle/Waratah areas and a long 132 kV line to the Muswell Brook area.

Summary information for energyAustralia is shown in Table 5.1.

Table 5.1
Summary Information for energyAustralia as at 1996/1997

Customers Served :		
0 - 20,000 kWh pa	1,304,000	
20,000 - 200,000 kWh pa	55,950	
> 200,000 kWh pa	6,600	
Area Served	22,275 km^2	
Maximum Demands :		
Summer (MW)	3,770	
Winter (MW)	4,660	
Length of Lines (km) :	O/H Lines	U/G Cables
132 kV	826	465 [a]
66 kV	388	1 [a]
33 kV	1,463	860 [a]
11/22 kV (incl. SWER)	10,186	6,972
Total system asset book value before depreciation ($b)	$2.75b	

a/ Figures represent circuit length quantities

5.2 ADEQUACY FOR PRESENT DUTY

Sydney

The Sydney inner city area level of 132 kV system security (supplied from TransGrid's Beaconsfield West substation) should in our view be improved since its security is currently at marginal n-1 levels during peak loads. An analysis of the system indicates that an outage on TransGrid's 330 kV cable 41 (supplying Beaconsfield) results in some system elements being loaded to above 90% of their capacity. EnergyAustralia's 'Network Development Plan' states that this margin is insufficient to cater for statistical load variations (such as due to abnormal weather patterns). We agree.

By the year 2000 at high summer loads, the 132 kV system will struggle to achieve n-1 security of supply. According to energyAustralia's "Network Development Plan", TransGrid's cable 41 will reach its capacity or overload for an outage on any one of a number of energyAustralia's 132 kV feeders. The problem is made worse due to the fact that the peak demand in this area is occuring in summer when the extensive use of air conditioners gives rise to a low power factor (less efficient power transfer) at a time when equipment ratings are at their lowest level due to the higher ambient temperatures. The situation is of concern in that failure of one circuit could lead to a cascade of failures on other circuits. EnergyAustralia and TransGrid are working to address this situation.

Several of the subtransmission systems in the energyAustralia network are approaching their ultimate capacity. These include :

- the Carlingford 66 kV system
- the Warringah 33 kV system.

Other areas require operating restrictions in order to reduce fault levels. These include :

- the Bunnerong 33 kV load area
- Port Hacking Subtransmission Substation.

In the Sydney East load area the system comprises of overhead lines and the large incidence of trees results in a lower than average reliability of supply.

Central Coast

The Central Coast region has a high load growth from residential development. Many of the zone substations in the Gosford region (fed from a local 66 kV network) are heavily loaded which has resulted in problems with equipment ratings and voltage regulation. We do not consider that the 66 kV network is adequate for the level of load and the growth experienced in this area.

Newcastle/Hunter

Many of the subtransmission substations in this area are heavily loaded and at their capacity. This system is operated by transferring load between zone substations to prevent loads exceeding equipment capacities.

Whilst this method of operation will defer capital expenditure, there will be a limit to which these operations can be performed after which the situation becomes untenable and may lead to a compromise in the system security.

The Network Development Plan indicates that several feeders in the Hunter area have the potential to overload during normal operational conditions and other feeders which overload during single contingency outage situations. The firm capacity of several zone substations are exceeded in this area during peak load conditions.

Inner City Distribution Networks

Although the Sydney and Newcastle inner city older networks are in relatively good condition[1] they are now starting to show some signs of age and incidences of faults are likely to increase.

The distribution system design in these areas originated some 50 years ago and includes multi-section 11 kV busbars and a triple distribution transformer and 11 kV feeder arrangement. This design provides a high level of redundancy which may not be appropriate today given that modern equipment is designed to provide improved reliability.

Generally reinforcement of these networks has been the installation of a new point of injection that largely followed the same design to ensure compatibility with the rest of the network. New points of injection will be at 132/11 kV thereby minimising the need for the intermediate 33 kV voltage level.

5.3 ASSET MANAGEMENT POLICIES

EnergyAustralia does not have a formal asset management plan but rather many individual documents which cover the aspects of asset management. Of these we have been provided with their Network Development Plan, Major Works Review Schedules, maintenance standards and a brief schedule of the environmental improvements[2].

The Network Maintenance standard indicates that energyAustralia has comprehensive maintenance policies. These utilise corrective, condition based and periodic maintenance which are appropriate to the nature of the different assets in the network.

From the documentation reviewed, energyAustralia appears to have sound asset management practices, however, we experienced difficulty reviewing this area due to the apparent lack of co-ordination of all the documentation. We recommend that energyAustralia collate this documentation into a comprehensive asset management plan which should also include an assessment of the condition of the network.[3]

5.4 CAPITAL WORKS APPROVAL CRITERIA AND PROCESSES

[1] Statistical data shows a low incidence of faults in these areas as a result of the underground nature of these networks.

[2] EnergyAustralia has certification to ISO 14001 Environmental Management System standard.

[3] EnergyAustralia is in the process of producing a “State of the Network” report incorporating the current condition of both the ex Sydney Electricity and ex Orion networks. Unfortunately this report was in draft form and was not made available to use for this review.

EnergyAustralia have an appropriate formal procedure for identifying and evaluating capital expenditure requirements.

Network capital expenditure is managed through a two tier approach involving :

1. the identification and authorisation of individual projects
2. the aggregation and prioritisation of individual projects into the capital budget.

Capital expenditure arises from the need to remedy system deficiencies. These arise from four main areas for which projects arise : Environment, Reliability, Replacement and Load related Issues. The projects are ranked and prioritised before capital expenditure budgets are set.

Emphasis is placed on using “value management” techniques. Formal value management studies are used to select preferred solutions for major projects. Value management is a Standards Australia specified analysis methodology designed to identify solutions which offer the best value for money, while meeting functional requirements. Analysis covers all relevant issues including costs, environmental, financial, technical and legislative constraints, safety and demand management.

The methodology is structured around five phases :

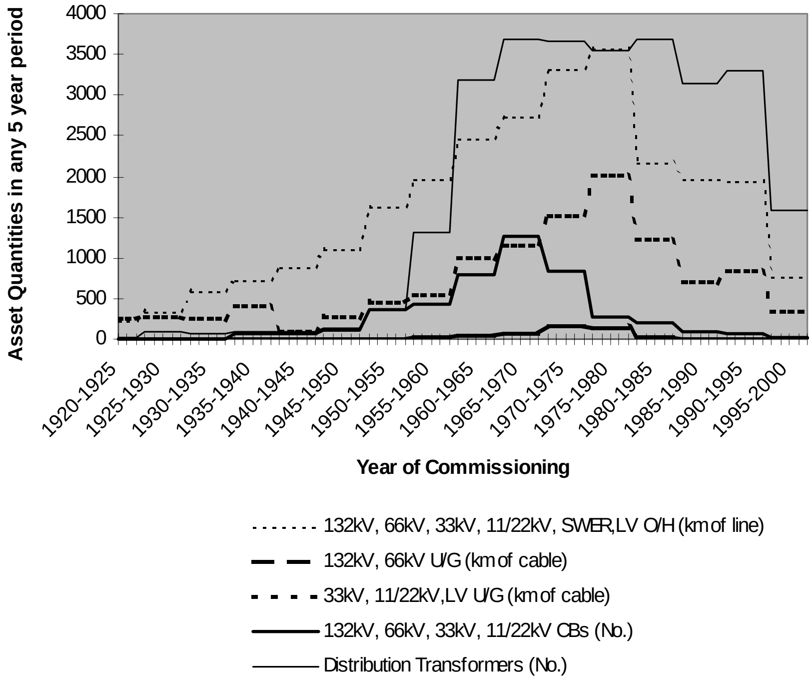
1. Information - problem identification, data collection.
2. Analysis - functionalist (what has to be achieved and why).
3. Creativity and Judgement - brainstorming, creative ideas and ranking of those ideas.
4. Development - detailed performance and cost analysis of the high ranking options.
5. Recommendations - choice of the preferred planning solution.

Once the preferred solution has been identified it is further evaluated in accordance with Energy Australia’s Board approved guidelines. The three financial criteria normally reported are net present value, payback period and cash flow projections. The net present value analysis is generally regarded as the most important measure and analysis is normally limited to 10 year cash flows unless there is reasonable evidence that there may be a more appropriate economic asset life. A narrative report detailing technical and financial justification for the project is then submitted for approval in accordance with delegated levels of authority.

5.5 PLANNED ASSET RENEWALS

EnergyAustralia provided asset age information based on source material available and in some cases it was extrapolated. The data provided gives a reasonable indication of the ages of the assets in services and in our opinion the information was satisfactory. The age profiles of the major asset groups are shown in Figure 5.1.

Figure 5.1 : Age Profiles of The Major Asset Groups



The age profiles show that energyAustralia has a relatively old network and that a large proportion of the assets are underground cables.

EnergyAustralia's capital expenditure projections were on average approximately $34 million pa for assets reaching the end of their economic lives[4] and approximately $5 million pa for asset renewals due to regulatory requirements.

An initial analysis of the asset age profile information indicated to us that an average expenditure of approximately $100 million pa would be required for asset renewals based on age profiles [5] but that actual expenditures for renewals would be less than this for the following reasons :

- some assets would be replaced with different assets for reasons other than age, for example as a result of growth related projects.
- some assets would no longer be required today.
- some assets would likely be decommissioned rather than replaced because of the economies of using different voltages or configurations.
- the replacement of some assets could be part of, and hence funded by, development works by outside parties.
- Replacement of some assets would be deferred.

4 Average taken of the financial years 1997/98 to 2009/10.

5 Note that an average figure disguises the fact that expenditure required for renewals ramps up significantly over the years. This figure also includes the replacement of those assets that should have already been replaced prior to FY 1998/99. We have assumed that they relate to either deferred capex or refurbished assets (that have had added life) but are nevertheless due for replacement within the period under review.

On discussing the differences between our analysis and energyAustralia's projections it was concluded that energyAustralias initial projections appeared to have been under-stated.

Revised projections subsequently provided to us were appropriate. The projections gave an average annualised capital expenditure of approximately $104 million pa (this included capital expenditure for asset renewals due to both assets reaching the end of their economic lives and due to regulatory requirements), based on age profiles. EnergyAustralia's assessment of the actual capital expenditure required, taking into account economies that could be made, averaged approximately $67 million pa from 1999 to 2010. In our opinion such expenditures would be appropriate and were agreed to. The projections finally agreed are shown in Section 5.9.

5.6 RELIABILITY IMPROVEMENT

EnergyAustralia has projected approximately $10 million pa for reliability improvement. This expenditure is for :

- undergrounding of 11 kV distribution mains in suburban areas or the use of covered conductor[6]. This represents 60% of the expenditure.
- replacement of some bare conductor LV mains with aerial bundled conductor.
- works related to the extension of a Distribution Network Management System by the interfacing the existing reclosers on the network.

EnergyAustralia's "Statement of Corporate Intent" indicates that at a minimum, current levels of reliability will be maintained. Their document "The Way Ahead 1998/99 - 2000/01" indicates that one of their objectives is to achieve an average figure for customer minutes without supply per annum of 80 minutes in 1998/99 and 70 minutes in 2000/01. Compared with this, current performance is approximately 100 minutes.[7]

EnergyAustralia already has a relatively high level of overall network performance typical of a large metropolitan utility with an underground network although actual performance does vary from region to region[8]. Should any expenditure be spent on improving reliability we would expect that energyAustralia would likely target those areas where the maximum gains could be achieved.

On review we have accepted these projections.

[6] Historically energyAustralia had a programme of undergrounding 22/11 kV mains to reduce maintenance, improve reliability and visual aesthetics. This programme stopped in the FY 1995/96 due to the uncertainty of the revenue caps at that time. Since that time energyAustralia has concentrated in using covered overhead conductor rather than undergrounding and also focused on the improvement in works management systems, tree trimming, live line maintenance and implementation of network distribution system automation technology.

[7] This figure is based on the average over the last three financial years. Even though the figures exclude major storms and TransGrid interruptions, the figures do fluctuate from year to year due to differences in weather patterns.

[8] FY 1996/97 SAIDIs vary from 16.4 minutes in the Sydney CBD and inner suburbs to 395.8 minutes in Muswellbrook.

5.7 AUGMENTATION OF CAPACITY

EnergyAustralia has a comprehensive Network Development Plan that summarises the proposals for network development up to the year 2007.

Load Growth

Energy Australia have a team of experienced forecasting staff who, with consideration of the views of the planning and operational sectors, have developed load growth forecasts based on :

- historical load data obtained from the SCADA system, adjusted to take account of estimated diversities, load transfers and weather conditions.
- economic cycles with regard to the type of industry in an area.
- social and econometric data including land development information.
- CBD building proposals.

Forecasts based on historical trends of spot loads are also used for the Sydney inner city area and some other critical areas.

EnergyAustralia's peak demand occurs in winter and is currently projected to increase at approximately 1.5% per annum. The majority of the proposed system augmentation is a result of expected growth in the summer demand of 3% pa and the lower equipment capacities at this time of the year. The higher rate of the summer peak growth in Sydney (as is the case for many cities with similar climates) is due to the increasing use of airconditioning in the redevelopment of inner city areas, shopping centres and urban areas.

Apart from the Hunter and Central Coast regions which have some pockets of high load growth levels (Singleton 4.0% pa, Maitland 5.0% pa, Kurri 4.0% pa, Bradford 6.5% pa, Cardiff 5.0% pa, Somersby 5.0% pa, Lake Munmorah 4.0% pa), energyAustralia consider that the forecast in growth is at a "historically low level representative of a mature system"[9].

New substations and network developments are still required as a result of industry relocations to more cost effective sites and increasing demand from existing customers. Furthermore with the continued development of the larger cities one can expect the pattern of "pockets of high load growth to continue albeit in different locations".

Security of Supply

Security of supply planning criteria are intended to ensure that network design is appropriate. During single contingency outages, major loads should continue to be supplied, voltage levels should remain with acceptable limits and equipment ratings should not exceeded.

9 Network Development Plan 1998, page 3.

Energy Australia use a mix of deterministic and risk management criteria which vary according to the magnitude and nature of load. A deterministic n-1 criterion is used as minimum on the 132 kV system. In urban areas, where two circuits share the same line or trench, double circuits outages are considered to be credible contingencies and back up emergency supply is provided. We questioned the appropriateness of this approach. However, energyAustralia advised that double circuit outages are not unknown.

132 kV bus voltages are maintained between 1.05 pu and a lower limit dictated by the need for transformers to maintain regulation so that the associated 11 kV bus voltage is not less than 4% below set level.

66 kV and 33 kV network loads of above 5 MVA[10] generally are planned using an n-1 contingency criterion. Loads of less than 5 MVA can be supplied by a single radial overhead feeder unless duplication of supply is possible at minimal cost. Factors considered in evaluation of the need for duplication include the reliability of the existing line, cost of duplication and nature of load supplied.

Zone substation transformers are planned with a different threshold from lines using a criterion of n-1 contingency for loads above 3 MVA[11]. Loads less than this are supplied by one transformer. Development work is undertaken if the firm rating of a substation is exceeded more than 1% of the time or the annual probability of failures which require load shedding to prevent equipment damage exceeds 1%.

Voltage drops of up to 5% are considered acceptable on the 11 kV system.

In the Central Business District (CBD), distribution substations supplying commercial loads are provided with three transformers each connected to a different feeder. Residential load substations in the CBD are provided with two or three transformers.

Demand Side Management

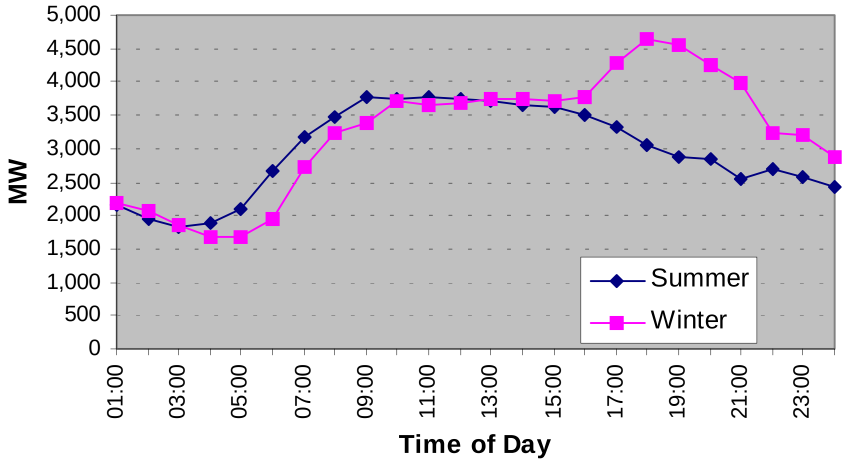
EnergyAustralia reported on its implementation of demand side management strategies in its 1996/1997 annual report and also supplied similar draft information for the 1997/1998 financial year. There is relatively little information available on demand management analysis and strategic programmes performed indicating that this area may yet need to be more fully addressed.

A detailed analysis of demand side management programmes should involve the review of load profiles at an individual zone substation basis to determine the most effective DSM programmes applicable to that part of the network (refer to Section 2.7).

The winter and summer maximum demand curves for energyAustralia's total network are shown in Figure 5.2.

[10] Network Development Plan 1998, Appendix – Planning Guidelines.
[11] Network Development Plan 1998, Appendix – Planning Guidelines.

Figure 5.2 : EnergyAustralia's Maximum Demand Load Curves (FY 1996/97)



The winter curve is characterised by a 6 pm evening peak which indicates that DSM strategies could be targetted at reducing the evening peak at some zone substations by the use of more direct controllable load[12], promotion of energy efficient buildings and lighting[13] in commercial areas and efficient cooking appliances. However, as indicated in an earlier section most augmentation is driven by the summer peak loads and so DSM strategies should be targetted in this area. EnergyAustralia is currently trying to encourage DSM by a "Time-of-Use" network tariff structure and the promotion of energy management through its EnergyFirst program. It is possible that significant capital expenditure for augmentation could be deferred in the case of energyAustralia's network with rigorous application of further DSM strategies, however, the extent of this cannot be determined without detailed analysis.

Augmentation Plan

The need for reinforcement of the Sydney inner city supply was highlighted in Section 5.2 and is discussed further in our supplementary report on TransGrid.

The Network Development Plan indicates that interim measures are being taken to strengthen the interconnection from TransGrid's Sydney South and Sydney North substations into the inner city area supplied from Beaconsfield. These interim 132 kV projects are aimed at providing additional capacity into the central city. Expenditure of $28m is planned for a new Central City zone substation.

At least $23.5m of investment in further 132 kV network development is planned prior to energyAustralia's City Central zone substation being established around 2002 to meet system loading and maintain security of supply. This includes the upgrading of some existing feeders, installing new ones and extending other existing ones.

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[12] Relative to other distributors, EnergyAustralia has a low level of controllable load per customer. This is thought to be due to the older age of the network (with small capacity hot water cylinders not suited as controllable loads) and the high penetration of gas reticulation for hot water heating in this area.

[13] Significant savings could likely be obtained by targeting commercial buildings with the promotion of motion sensors to control lighting loads.

Operational limitations exist in the energyAustralia network, between a number of substations in the city area, where cable ratings limit the ability to transfer load between stations. A number of projects are associated with cabling to the new energyAustralia City Central 132/11 kV zone substation, planned for commissioning in 2003, which in its second year is projected to pick up 113 MVA. With the increasing number of constraints, resource management requirements and urban development planning criteria, we are of the opinion that the costs associated with the installation of a new GIS substation, in an urban centre, are justified as compared to an outdoor substation. We are also of the opinion that the budgeted figure of $28 million should cover the installation of a GIS substation.

Central Coast

The inadequacies apparent in the 66 kV network, particularly around Gosford are planned to be resolved with two new 132/11 kV substations and converting one or maybe two zone substations to 132/11 kV.

EnergyAustralia are working with TransGrid to commission a 330/132 kV substation at Munmorah in 2000 to increase the firm capacity in this section of their network, from 430 MVA to 736 MVA.

Newcastle/Hunter

This area was part of the Orion network and therefore has been treated differently in terms of planning from the remainder of energyAustralia's network. In the Hunter area mention is made of capital deferment opportunities and the operation of subtransmission substations at capacity achieved by transferring load between substations.

TransGrid have a new 330/132 kV substation planned for when the Newcastle substation reaches its full capacity.

2000 Olympic Games

There has been significant development in the last two years in relation to the Olympic Games.

EnergyAustralia has received capital contributions for much of this development as indicated in Table 5.2 in Section 5.9.

Basis of Cost Estimations

The augmentation capital expenditure projections have been estimated from actual expenditure on works presently being constructed or those which have recently been completed for which a significant proportion is contracted out. The proportion of works to be contracted out is projected to increase however the net effect of any efficiencies made is unlikely to be material.

Conclusion

All of the major projects listed by energyAustralia are described in the Network Development Plan except for the Olympics developments (described in a separate report) and The Taylor's Square zone substation. EnergyAustralia advised that the latter is anticipated to be required in the Paddington area of Sydney between other zone substations which are nearing capacity.

We have checked the requirements for all of the major projects given in the capital expenditure projections and found that their justification is satisfactory.

The Network Development Plan included a number of possible projects for which cost estimates were not included. These involved many projects in the Hunter Valley area and other possible network connection projects (e.g. cogeneration and embedded generation options and mining developments). EnergyAustralia advised that they are taking a reactive approach rather than a planned approach for the Hunter valley area since project costs in this area are likely to be small relative to the work required in the Sydney area.

5.8 BYPASS, EMBEDDED GENERATION, COGENERATION AND STANDBY NEGOTIATIONS

A 420 MW cogeneration plant is proposed at Kurnell. If the project proceeds, additional 132 kV switchgear bays and equipment will be required although details of the connection require resolution.

A further cogeneration plant of 120 MW capacity is proposed in the Botany area. Connection options are yet to be finalised and until they are the net effect on energyAustralia's system will not be known, but could involve either augmentation or result in the under-utilisation of existing assets.

Landfill gas generators exist in and around Sydney with generation of up to 11 MW into the Lucas Heights area and 5 MW feeds into the Sydney East area. Output from the landfill gas generation plants may increase in the future, which may require the upgrade of the 33 kV network.

5.9 CAPITAL EXPENDITURE PROJECTIONS AND ADJUSTMENTS

A summary of energyAustralia's revised network capital expenditure projections and our adjustments are shown in Table 5.2. Other capital expenditures that have not been reviewed by us are shown as separate items.

Table 5.2 Capital Expenditure Projections and Adjustments for energyAustralia's Network

$m (1998 Dollars)	Total 1999 – 2010	1995 -96	1996 -97	1997 -98	1998 -99	1999 -00	2000 -01	2001 -02	2002 -03	2003 -04	2004 -05	2005 -06	2006 -07	2007 -08	2008 -09	2009 -10
1. Distributors' Projected Capital Expenditure (See Note 1)																
Renewals (See Note 2)	788.2	44.3	28.5	18.2	23.2	38.5	49.9	56.0	72.2	72.2	72.2	82.2	84.2	84.2	84.2	92.2
Growth Related Projects	598.4	41.6	52.8	50.5	58.3	51.6	50.9	52.5	56.5	66.3	68.1	57.6	51.1	45.6	51.6	46.6
Reliability Enhancement Projects	114.3	19.0	7.5	8.3	9.0	10.4	10.3	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
Total for Network Capital Expenditure	1,500.9	104.9	88.8	77.0	90.5	100.5	111.1	118.9	139.1	148.9	150.7	150.2	145.7	140.2	146.2	149.2
2. Adjustments																
Total Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3. Adjusted Total Network Capital Expenditure																
Adjusted Total Network Capital Expenditure	1,500.9	104.9	88.8	77.0	90.5	100.5	111.1	118.9	139.1	148.9	150.7	150.2	145.7	140.2	146.2	149.2
4. Other Capital Expenditure Items																
IT Related Network Capex (see note 3)	3.6	0.0	0.0	10.0	14.4	2.0	0.9	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Cost Allocations to Network for Customer Information and Financial Systems	126.5	12.0	17.0	23.7	13.2	10.0	8.5	8.5	8.5	8.5	8.5	12.0	15.0	20.0	15.0	12.0
Cost Allocation to Network for Corporate Land & Buildings	16.5	4.2	4.3	4.9	2.8	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Cost Allocations to Network for Office Machines	27.5	6.3	4.6	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Metering	15.0	14.4	13.0	12.5	10.0	10.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Vehicles	39.0	14.7	5.4	8.6	8.6	5.0	5.0	5.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Cost Allocations to Network for Service Provider Plant & Tools	38.5	6.2	2.8	4.4	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Streetlighting	61.4	4.2	4.3	3.0	0.9	7.1	7.1	7.1	7.1	7.1	4.2	4.2	4.2	4.2	4.2	4.9
Capital Contribution Works	174.1	25.4	27.9	30.2	24.3	20.8	16.3	15.0	15.0	15.0	17.0	15.0	15.0	15.0	15.0	15.0
Recoverable Works	0.0	0.3	0.2	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Retail Related Capex	106.4	41.6	23.0	30.9	17.4	10.3	8.1	5.9	5.7	5.7	10.2	11.7	13.7	13.7	11.7	9.7
Total Other Capital Expenditure Items	608.5	129.3	102.5	130.7	97.7	72.7	58.4	49.1	46.9	46.9	50.5	53.5	58.5	63.5	56.5	52.2

Notes

1 Excludes Streetlighting, Capital Contribution Works, Recoverable Works, Metering, IT and Vehicles

2 These are energyAustralia's revised projections for asset renewals (refer to Section 5.5)

3 Includes the following categories used by energyAustralia; GIS and IT Systems

Section 6.0
Integral Energy

CONTENTS

6.1 DESCRIPTION OF NETWORK

Integral Energy is situated in the area immediately to the west and south of Sydney (refer to the map of the NSW Electricity Distribution areas at the front of this report).

The Integral Energy system comprises two electrically separated networks. The northern network serves the Western Sydney and Blue Mountains areas west to the Lithgow area and consists of 132 kV, 66 kV and 33 kV lines. The 132 kV and 66 kV lines are predominantly radial and the 33 kV heavily interconnected.

The Southern network serves the Illawara region and consists of long radial 132 kV and 33 kV lines with significant interconnection at 33 kV in the Wollongong area.

Summary information for Integral Energy is shown in Table 6.1.

Table 6.1
Summary Information for Integral Energy as at 1996/1997

Customers Served :		
0 - 20,000 kWh pa	702,509	
20,000 - 200,000 kWh pa	31,417	
> 200,000 kWh pa	2,740	
Area Served	24,500 km^2	
Maximum Demands :		
Summer (MW)	2,258	
Winter (MW)	2,643	
Length of Lines (km) :	O/H Lines	U/G Cables
132 kV	928	44.5
66 kV	575	9
33 kV	1,490	121
11/22 kV (incl. SWER)	10,156	2,037
Total system asset book value before depreciation ($b)	$1.38 b	

6.2 ADEQUACY FOR PRESENT DUTY

Integral Energy's Transmission Network Development Program indicates that the 132 kV and 66 kV networks are well planned. There is no evidence to indicate the network suffers from any significant overloads or voltage regulation problems during single contingency outage situations.

The new Regentsville transmission substation has only one 330/132 kV transformer (this will be increased to 2 transformers when the load dictates). Although this is effectively only an (n) level contingency, the 132 kV network can currently provide adequate backup to maintain the security of supply. This is in line with international practice for interconnecting transformers, which are very reliable items of equipment.

The 33 kV subtransmission system on the outskirts of Sydney and in the vicinity of Wollongong is heavily interconnected which implies the need for complicated protection arrangements and signalling communications links.

The 11 kV distribution network is a conventional suburban interconnected radial system and is considered appropriate.

6.3 ASSET MANAGEMENT POLICIES

Integral Energy has a Strategic Asset Management Plan (SAMP) that summarises the investment on the network in the areas of capacity driven capital expenditure, maintenance and refurbishment and demand side management for the 1998/99 financial year. The SAMP is an overriding document which draws together other more detailed strategic documents which cover the following areas :

- Asset Refurbishment
- Asset Maintenance
- Network Automation
- Network Protection
- Risk Management
- PCB Management
- Network Property Management
- Technology Development.

The SAMP is the first one produced to date and is currently being revised to cover a five year horizon.

All projects are ranked based on the greatest contribution to risk reduction and costs are based on total expenditure whether, expensed, capitalised or both.

Integral's Asset Refurbishment Plan 1998/99 was provided to us at the end of July and looks in detail at the different asset groups. The plan is the beginnings of a detailed forward looking plan for the renewal of assets and covers asset life extension, asset replacement of aged assets, type faults and compliance with regulatory requirements.

Unfortunately the other detailed strategic documents that feed into the SAMP were being drafted at the time of writing this report and therefore could not be reviewed.

6.4 CAPITAL WORKS APPROVAL CRITERIA AND PROCESSES

Integral Energy have a clear set of policies and procedures to follow in identifying capital works requirements, evaluating those requirements and seeking and obtaining approval. The process is called Major Project Formulation and Approval. This procedure is designed to ensure that a consistent and comprehensive approach is taken to the formulation and approval of major projects. The process is also designed so that non-capital solutions are investigated and built into a solution which is the best option. The process can be described as having three steps.

1. Statement of Network Need (SNN). These statements are being driven and prepared for network capability needs, whether they be based on load growth and capacity, age, condition or serviceability. A more integrated asset and risk related basis is taken.

2. Network Investment Options (NIO). An NIO is prepared to recommend a solution to a network deficiency identified in the SNN. The NIO will first consider the "do nothing" option by looking at load profiles and the options involved in switching load via the distribution

network. It may also consider Demand Side Management (DSM) options to eliminate or defer the need for capital expenditure.

The NIO will discuss all options considered, including their technical, financial and risk (i.e. supply reliability) components. The recommended option must contain financial and economic analysis. This analysis is performed for both direct benefits, that is financial benefits and indirect benefits and costs, including unserved energy.

The preferred financial analysis is NPV, using the Treasury approved Weighted Cost of Capital (WACC) as the discount rate. As a general rule only those projects showing a positive NPV will proceed. However if community and other external benefits are considered to be sufficient, support may be given to projects with negative NPVs.

3. The preparation of the Capital Works Agreement (CWA) is the start of the project management phase of the project. Once the CWA is approved by Network Branch Managers it is sent to the delegated authority for final approval.

NPV analysis considers a project life of 20 years, and takes into account existing installed capacity, proposed installed capacity, forecast maximum demand, inflation, depreciation, tax expense and increases in NUOS.

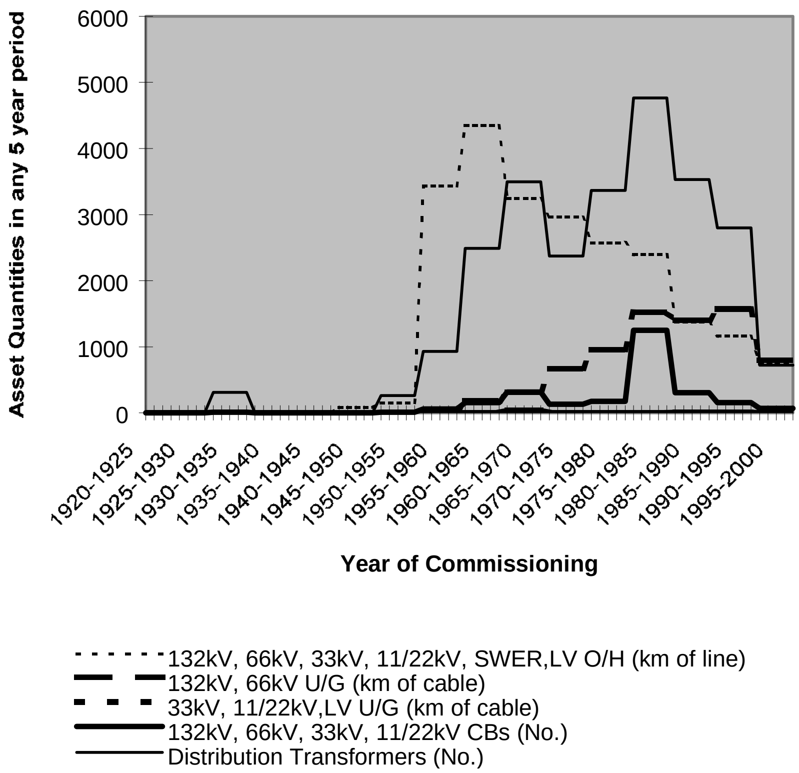
6.5 PLANNED ASSET RENEWALS

Integral Energy’s capital expenditure projections for asset renewals were predominantly based on asset ages. The projections provided included both the renewals due to the ageing of the assets and those due to regulatory requirements. The separation of expenditure related to regulatory requirements could not be provided.

Integral Energy provided age information on the surviving assets. The age profiles of the major asset groups are shown in Figure 6.1.

The age profiles show the use of underground mains from the 1970's onwards. Consequently the majority of mains replacements within the period under review will relate to overhead rather than underground mains.

Figure 6.1 : Age Profiles of The Major Asset Groups



Integral Energy's initial projections for asset renewals averaged $48 million pa and were based on the Treasury's standard asset lives without adjustment. Large expenditures were included for the wholesale replacement of zone and subtransmission substations. At our request, Integral provided further information regarding this expenditure and revised their expenditure projections. Expenditure for each substation was shown separately with substation transformers shown separated as well. The life assumed for the substations was 40 years and that for the substation transformers 50 or 60 years depending on the level of historical maintenance practices. Expenditure for each substation renewal was also spread over a 4 year period with the ratio of expenditure being 10%, 40%, 40% and 10% in each successive year.

The replacement costs of the substations were derived using Integral Energy's substation estimation package. We performed a sample check to verify that the replacement costs were reasonable.

Expenditure for renewals of mains were based on asset ages. A 45 year life was assumed for the mains except for wood poles which were assumed to have a 40 year life. Renewal expenditure for distribution mains was not included since Integral advised that these were already included in the growth related expenditures shown separately.

Expenditure for renewals of distribution transformers were also not included (we were advised that Integral expenses rather than capitalises the renewals of these assets).

Expenditure was included for renewals of meters and load control relays in all years. We have separated out load control relays from metering equipment and shown the latter as a separate item.

Integral Energy's revised expenditure projections (excluding that for meter replacements but including an allowance for load relay replacement) gives an average expenditure of approximately $40 million pa.

An analysis of the age profiles indicates that the expenditure required for assets reaching the end of their economic lives should be approximately $32 million pa[1], however, consideration has to be given to the following points in relation to the age profile information.

- The age profiles do not include substation assets except for circuit breakers (this is discussed further below).

- Integral Energy has largely used asset replacement costs given in the NSW Treasury valuation guidelines which in certain cases may understate actual replacement costs (see Section 2.2)

- We would expect that economies could be achieved due to risk management of aged assets, optimisation of network arrangements, the integration of asset replacements with other projects (see Section 5.5) and the deferral of some replacements.

On face value, Integral Energy's preliminary expenditure projections for asset renewals appear high largely due to the allowance made for the wholesale replacement of zone substations based on a 40 year life. We question the appropriateness of this treatment because the various assets within a substation would be replaced separately on a needs basis and would generally be at different times. For instance substation buildings of masonry construction would in our opinion last in excess of 60 years and not the 40 years as used by Integral.

In our opinion the preliminary projected expenditure of $32 million pa based on age profile information should be reduced to approximately $24 million pa to take account of economies that could be achieved (note this relative reduction is not as great as that expected in energyAustralia's case since the opportunities for efficiencies to be made are likely to be lower in Integral Energy's network).

We have used Integral Energy's Asset Refurbishment Plan to estimate the level of expenditure required to meet regulatory requirements ($3 million pa). This expenditure is to cater for oil containment, noise abatement and PCB related issues. This expenditure is in addition to our estimate for asset renewals due to age shown above.

In our opinion total expenditure for asset renewals of approximately $27 million pa would be appropriate.

We have made adjustments to Integral's capital expenditure projections to reflect this level of expenditure.

6.6 RELIABILITY IMPROVEMENT

Integral Energy's current reliability levels as measured by the SAIDI indice is approximately 130 minutes[2].

Integral Energy has set itself a reliability target of a SAIDI of 100 minutes in 1998/99 and 85 minutes in 2002/03. These targets are said to be based on numerous research projects that reveal that quality of supply (together with price) remain the predominant concerns of customers.

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1 This excludes distribution mains, distribution substations and meters. This treatment is consistent with Integral Energy's expenditure projections under renewals.

2 This is the average taken over the last three years and excludes major storms.

Integral Energy has projected an average expenditure for reliability improvement of $1 million pa based on the targeting of two problem areas per year, mainly rural lines that give rise to outages in urban areas. Expected works are currently non-specific but this situation will change since Integral Energy has just set up Organisational Reliability Improvement task teams whose job will be to develop action plans to meet the reliability targets.

It is difficult to comment on the effect of the $1 million pa expenditure without an analysis of the reliability performance of individual areas[3] and the improvement made by historical projects. Works related to asset renewals and growth related projects will also have an impact on the improvement in reliability through secondary effects. The level of expenditure projected is likely to be insufficient to meet Integral's targets unless considerable expenditure is planned for works under maintenance or for the improvement of response times both of which are expensed rather than capitalised.

No adjustments have been made to Integral's projected expenditure for reliability improvement. We expect that Integral will develop better projections for expenditure in this area in the near future.

6.7 AUGMENTATION OF CAPACITY

Integral Energy have prepared a Network Capability Transmission Network Development Program which details their network augmentation proposals from the years 1997 to 2007. It includes the main planning criteria of design, security levels, voltage regulation and equipment selection and follows a "rolling plan" concept.

Forecasting

Integral Energy's load growth forecasts are based on historic demand growth trends and econometric data. This includes :

- lot release statistics and forecasts
- land zoning information
- development trends
- known spot loads.

Main Areas of Growth

The main areas of growth in Integral Energy's network are to the north and west of Parramatta with annual rates of growth of up to 6.2%. The Shellharbour/Port Kembla area has an annual growth rate of up to 6.4% and the area around Berry and Shoalhaven Heads has a 7.7% growth rate. Isolated pockets of high growth occur at Bylong (5.6%), Portland (5.0%) and Anzac Village (9.0%).

Security Criteria

Justification for Integral Energy's augmentation capital expenditure is not directly based upon the need to enhance security unless requested by major customers. This is because the security design criteria are geographically dependent rather than load dependent as shown in Table 6.2 below.

[3] Different regions can have very different reliability levels which can distort overall performance of the network.

Table 6.2
Integral Energy Security Design Criteria

Security of Supply	Restoration Time (min)	Criteria
n-1	0	Transmission (132 kV) and subtransmission (66 % 33 kV). Major customers (132, 66, 33 or 11 kV) when requested by customer.
n-1	15 - 30	Urban area 11 kV distribution feeders.
n-1	30 - 60	Rural area 11 kV distribution feeders.
n	60+	Remote rural area 11 kV distribution feeders.

Security of supply becomes an issue when load on network components becomes such that security cannot be maintained without overloading the circuits. Ensuring adequate security is also important when new zone substations are required.

Voltage Regulation

Voltage regulation on transmission and subtransmission networks is required to be maintained at less than 10% under first level emergency conditions. This limit is appropriate and in accordance with common practice.

Demand Side Management

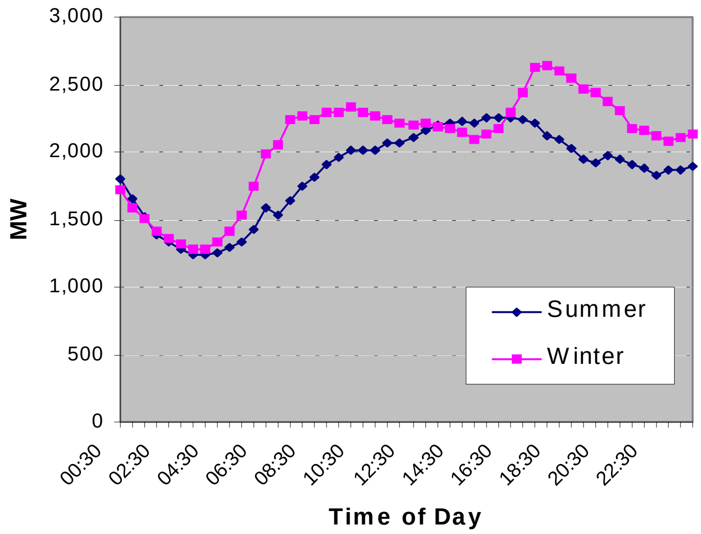
Integral Energy reported on its implementation of demand management strategies in its 1996/97 annual report which stated examples of initiatives undertaken[4]. We have also reviewed Integral Energy's submission (in draft form) to the Licence Advisory Board for the 1997/98 financial year. This submission indicates that Integral Energy has taken as aggressive approach to the deferral of capex using DSM initiatives.

We have not performed a detailed analysis of Integral Energy's demand side management programmes but have reviewed the load profile of the total network demand for which only general comments have been made.

Integral Energy's winter and summer maximum demand curves for the total network are shown in Figure 6.2.

4 The report mentioned projects with three large customers which avoided installation of back-up supplies worth approximately $4.5 million.

Figure 6.2 : Integral Energy Maximum Demand Load Curves (FY 1996/97)



The summer load curve (as in the case of energyAustralia) is likely to be the influencing factor on augmentation in some areas (refer Section 5.7) and Integral Energy has specifically targeted the reduction of the summer peak by curtailable load contracts. The winter curve is characterised by a 6.00 pm evening peak but is relatively smaller than that of energyAustralia due to Integral Energy's high penetration of direct load control. It is difficult to access where other DSM strategies should be targeted without detailed analysis. However, the size of the network, customer mix and geographic features of the network provide the potential opportunity for further DSM initiatives. Figures provided in Integral Energy's draft DSM submission certainly suggest that this is the case. The extent of capital expenditure deferral has not been included in our adjustments due to the absence of results of existing DSM strategies and the lack of low level detail of customer's energy utilisation.

Overload Capacities

Integral Energy undertakes a cyclic load analysis for transformers or underground cables, (in accordance with IEC guidelines) when demand exceeds firm capacity.

Probabilistic risk analysis techniques have recently been used to ascertain whether augmentation of the equipment can be deferred further.

Augmentation Plan

We have analysed Integral Energy's projected capital expenditure and find that it matches that of the Transmission Network Development Program in all but two minor areas considered immaterial.

Some items included in the Transmission Network Development Program for the years after 2006 have not been included in the capex projections since they are now unlikely to proceed.

Project estimates for the network augmentation projects have been prepared using Integral Energy's "in house" substation estimating package for substations and using "in house" estimates for lines. These estimates are based on known equipment costs and actual past project costs. In our opinion, the estimates appear reasonable.

Integral Energy advised that at the Network Investment Option phase of project development, cost estimates are budget estimates, with an accuracy of approximately ± 10%. At the capital approval stage, the estimates are updated to be within ± 5%.

Conclusions

In our opinion, Integral Energy have a well considered Transmission Network Development program and we see no need to adjust Integral Energy's augmentation capital expenditure.

6.8 BYPASS, EMBEDDED GENERATION, COGENERATION AND STANDBY NEGOTIATIONS

Several Embedded Generation schemes exist in the Integral Energy network. The major systems comprise the following :

- Sithe, 3 x 45.4 MW gas turbines and 77.5 MW steam connected to the 33 kV busbars at Guildford.
- Appin Colliery, 54 x 1 MW, methane extraction from Coal Mine, connected to 66 kV network.
- Tower Colliery, 40 x 1 MW, methane extraction from Coal Mine, connected to 66 kV network.
- Westcliff Colliery, 1 x 13.75 MW gas turbine.
- BHP Port Kembla, a range of machine capacities totalling 59.25 MW from processed gas and steam.
- Shell, three machines powered by processed gas totally 18.55 MW in capacity.
- Southern Paper converters, 6 MW coal/gas plant.
- Wyuna Water, two 3.25 MW hydro machines exporting to the 33 kV network.
- Warragamba Power Station

The entire capacity of the Westcliff Colliery, BHP Port Kembla, Shell and Southern Paper converters generation is absorbed by the respective customers. The Westcliff Colliery machine is subject to long down time periods and Integral Energy must therefore be capable of supplying the entire demand of that customer.

At this stage, no firm proposals for further large scale embedded generation exist.

6.9 CAPITAL EXPENDITURE PROJECTIONS AND ADJUSTMENTS

A summary of Integral Energy's network capital expenditure projections and our adjustments are shown in Table 6.3.

Other capital expenditures that have not been reviewed by Worley are shown as separate items. Integral Energy advised that it is likely that they will need to spend significant capital expenditure on IT in relation to a customer service system and integration of their Asset Information Management System. Detailed projections were not provided for these and therefore are not shown in Table 6.3.

Table 6.3 Capital Expenditure Projections and Adjustments for Integral Energy's Network

$m (1998 Dollars)	Total 1999 - 2010	1995 -96	1996 -97	1997 -98	1998 -99	1999 -00	2000 -01	2001 -02	2002 -03	2003 -04	2004 -05	2005 -06	2006 -07	2007 -08	2008 -09	2009 -10
1. Distributors' Projected Capital Expenditure (See Note 1)																
Renewals	445.7	1.3	1.3	9.8	29.8	47.5	43.8	32.6	30.8	27.9	37.8	34.7	38.2	44.1	53.9	54.5
Growth Related Projects	307.7	43.5	35.2	32.3	26.4	31.4	24.2	20.0	27.7	27.1	26.4	24.8	36.7	28.9	31.8	28.6
Reliability Enhancement Projects	11.0	0.0	0.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Total for Network Capital Expenditure	764.4	44.8	36.5	43.1	57.2	79.9	68.9	53.6	59.5	56.0	65.2	60.5	75.9	74.0	86.7	84.1
2. Adjustments																
Reduction in Asset Renewal Expenditure (refer Section 6.5)	-132.0	0.0	0.0	0.0	-12.0	-12.0	-12.0	-12.0	-12.0	-12.0	-12.0	-12.0	-12.0	-12.0	-12.0	-12.0
Inclusion of Load Control Relays (see note 2)	22.0	0.0	0.0	0.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Total Adjustments	-110.0	0.0	0.0	0.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0
3. Adjusted Total Network Capital Expenditure																
Adjusted Total Network Capital Expenditure	654.4	44.8	36.5	43.1	47.2	69.9	58.9	43.6	49.5	46.0	55.2	50.5	65.9	64.0	76.7	74.1
4. Other Capital Expenditure Items																
IT Related Network Capex (see note 3)	15.9	0.0	0.0	0.0	0.0	5.3	5.3	5.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cost Allocations to Network for Customer Information and Financial Systems	12.5	0.0	0.0	4.5	15.5	12.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Metering (see note 4)	81.5	5.5	5.5	5.5	5.0	6.7	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
Streetlighting	65.2	6.0	6.4	6.0	7.0	6.0	5.7	5.5	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Capital Contribution Works	0.0	23.5	17.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Recoverable Works	12.1	2.5	2.5	1.1	1.0	1.0	1.0	1.0	2.1	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Retail Related Capex	12.5	0.0	0.0	4.5	15.5	12.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Other Capital Expenditure Items	199.7	37.5	32.0	21.6	44.0	44.0	19.5	19.3	15.6	14.5	14.5	14.5	14.5	14.5	14.5	14.5

Notes

1 Excludes Streetlighting, Capital Contribution Works, Recoverable Works, Metering, IT and Vehicles

2 Integral included expenditure for load control relays with that for metering. Metering is shown as a separate item and this adjustment is required to include the expenditure for load control relays back into the network projections

3 This relates to GIS and other asset management systems

4 Excludes load control relays

Section 7.0
NorthPower

CONTENTS

7.1 DESCRIPTION OF THE NETWORK

NorthPower is situated in the northern part of NSW and was formed from the amalgamation of 7 smaller utilities covering an area of 230,000 km^2 and serving approximately 335,000 customers.

The backbone of NorthPower's network consists of radial 132 kV and 66 kV lines with a few meshed networks in the north-east and central areas. A map showing NorthPower's subtransmission network is included in the appendices.

The area served by NorthPower is split by the great dividing range. The coastal area experiences significant residential growth largely due to retirement centre development of 3-4% per annum in Port Macquarie and 6-7% per annum in the Tweed Heads region.

The central region has a largely static rural population with increases in demand driven from large spot loads such as cotton gins and irrigation loads.

The west region is served by long radial lines.

Summary information for NorthPower is shown in Table 7.1.

Table 7.1
Summary Information for NorthPower as at 1996/1997

Customers Served :		
0 - 20,000 kWh pa	336,100	
20,0000 - 200,0000 kWh pa	13,500	
> 200,0000 kWh pa	1,100	
Area Served	249,000 km^2	
Maximum Demands :		
Summer (MW)	570	
Winter (MW)	709	
Length of Lines (km) :	O/H Lines	U/G Cables
132 kV	128	-
66 kV	3,368	1
33 kV	1,673	11
11/22 kV (incl. SWER)	50,223	514
Total system asset book value before depreciation ($b)	$0.46 b	

7.2 CONDITION AND ADEQUACY FOR PRESENT DUTY

The 330 / 132 kV network supplying the far north region of NSW is only marginally adequate for the present load with one item of TransGrid 330 kV plant out of service (in particular, the Liddell Muswellbrook 330 kV circuit). This condition is likely to deteriorate with the continuing load growth in the coastal region. Investment is needed to overcome this weakness and NorthPower and TranGrid need to discuss the risks involved and to define a solution to the problem.

The NorthPower network comprises a 132, 66 and 33 kV backbone network feeding 123 zone substations. NorthPower has an extensive 66 kV subtransmission network connected to the 132 kV network, some of which will need to be upgraded to 132 kV because of the long distances involved. Investigation into the performance of this network and its long term future is recommended.

The distribution network is supplied from 33 kV, 22 kV and 11 kV feeders in a conventional configuration of radial feeders.

Most of the assets are in the eastern and central sections of the NorthPower area and are considered appropriate for the distances and population density. Individual supplies at 33 kV and 66 kV have been made available to large industrial loads (coal mines) and irrigation installations.

7.3 ASSET MANAGEMENT POLICIES

NorthPower have produced a Network Asset Management Plan (AMP) covering a five year horizon (1998 - 2003) which complies with the state government policy on Total Asset Management.

The AMP has three main sections as follows :

- Capital Investment Strategic Plan
- Refurbished Strategic Plan
- Maintenance Plan

Capital Investment Strategy and Refurbishment are discussed under Augmentation in Section 7.7 and Renewals in Section 7.5 and maintenance is discussed in this section.

Historically maintenance policies of the previous smaller distributors prior to amalgamation consisted of periodic maintenance for O/H lines (inspected and maintained on a 4½ yearly cycle) and corrective maintenance on zone substation assets.

NorthPower has adopted sound asset management practices with regards to maintenance. Instead of broad based policies based on inspections and corrective work, maintenance policies and methods are now targeted at specific problems. This has been brought about by the use of sophisticated Asset Management Systems:

- Distribution Asset Management System (DAMS) for O/H line assets and field assets. This system allows the condition of the assets to be recorded in the field during periodic inspections (4½ yearly) using hand-held units for later downloading to the main data system.

- Mainpac system for the zone substation assets. It is likely that the use of this system will be phased out in favour of the DAMS system.

Analysis is performed on the data captured in the systems to determine the optimal maintenance practices and timing for each asset class and individual type of asset in each class. Maintenance practices may consist of corrective, condition based, reliability driven[1] or preventative maintenance depending on the outcome of analysis of the defects recorded in the system.

An improvement in maintenance practices is expected through the targeting of specific areas as more information is collected from the field and analysed.

Asset based valuations of the distributors' networks were performed in 1995 and in NorthPower's case these identified significant opportunities for optimisation. In reaction to this NorthPower has for the last two years curtailed capital expenditure in an effort to increase utilisation rates for the existing assets. Current capacity utilisations of zone substations transformers and distribution transformers are approximately 30% and 27% respectively. In our opinion the capacity utilisation of the distribution transformers matches that of a typical rural distributor with significant irrigation loads operating outside of times of maximum demand[2]. The low zone substation transformer utilisation suggests further rationalisation can be achieved and this has been taken into account in our review.

7.4 CAPITAL WORKS APPROVAL CRITERIA AND PROCESSES

NorthPower's capital expenditure approval process is outlined in two policy documents :

1. Capital Expenditure Executive Policy
2. Capital Expenditure Procedures and Practices

Capital expenditure is considered in two distinct categories within the process, network system assets and non-system assets. NorthPower funded capital expenditure is further defined as growth driven, mandatory or operational. Cost benefit analysis is undertaken using NPV analysis with a range of discount factors to test sensitivity. 7% is the minimum discount rate considered acceptable. Income levels and cost savings are also tested in sensitivity analysis. NorthPower note the difficulty in undertaking NPV analysis for capital expenditure to improve or maintain system reliability.

The Capital Expenditure Procedures and Practices document requires a minimum analysis based on three options :

1. Do Nothing. What is the worst that can happen, what is the risk of it happening and what are the costs if it does happen.

2. Minimum cost option. What is the minimum work necessary to rectify the problem.

3. Best Solution Option. What is the best solution using current best engineering practice.

A cost benefit analysis is then provided for the variations in cost between solutions two and three, listing advantages and the expected IRR etc. as required by the policy document. Once the submission has been

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[1] NorthPower has recently started to record faults on a feeder basis to enable the faults to be analysed and to develop specific strategies to improve the reliability.

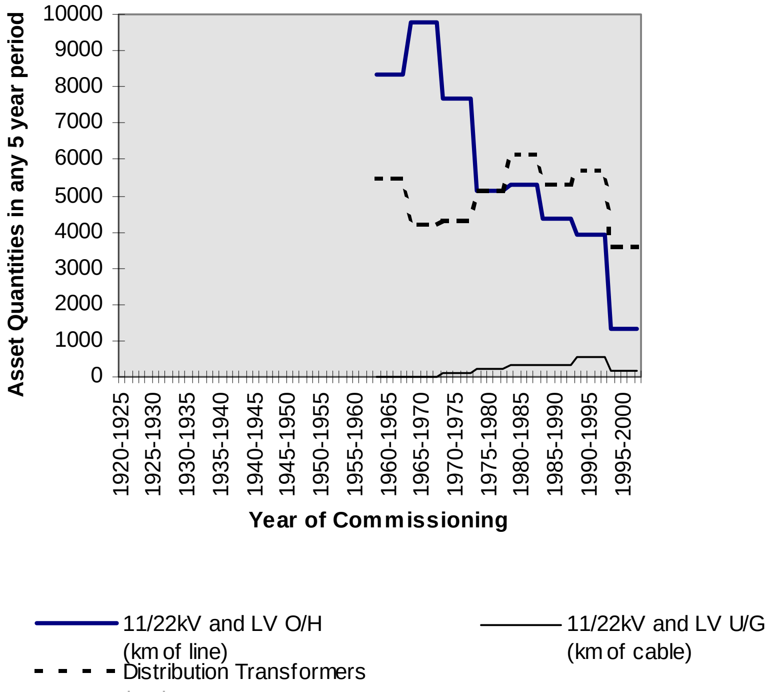
[2] Note in NorthPower's case the timing of irrigation loads is dictated by a small window where significant river flows allows for irrigation.

completed it is submitted for approval by the appropriate delegated authority.

7.5 PLANNED ASSET RENEWALS

Prior to the amalgamation the smaller distributors kept asset records of varying accuracy and format. Information on the actual ages of the assets installed prior to 1960 is unavailable. Limited reliance was therefore given to the age profiles in assessing the requirement of asset renewals. The age profiles of the major assets are shown in Figure 7.1 below. Note 132kV, 66kV and 33kV age profile information is not shown since the data provided was unreliable and profiles pre 1960 are missing for the reason stated above.

Figure 7.1 : Known age profiles of the major asset groups



NorthPower's age profile information is insufficient to draw any conclusions on the extent of renewals required due to the ageing of the assets. We recommend that NorthPower undertake further work in this area as a preliminary stage to establish the extent of future renewals required. We anticipate that significant additional capital expenditure, in addition to that already projected, will be required within the period under review.

Capex projections for renewals of mains relate to 66 kV, 33 kV, 22 kV/11 kV and low voltage O/H lines. The 132 kV O/H line assets and underground assets for all voltages are relatively new and therefore are not expected to require replacement within the period under review. As noted earlier insufficient data is available pre 1960 for the 66 kV assets and NorthPower have used historical figures to make capex provisions for replacement of equipment due to ageing.

A nominal amount (based on capex in the last two years) has been included for renewal of SWER lines. This is predominantly due to degradation of the galvanised steel conductor in the coastal regions. Note steel conductor in the western areas have long lives due to the relatively dry climate in these areas.

Capex projections for distribution transformers renewals are based on historical levels of failures. Statistics are not available on the types of faults but the majority of these assets are situated in the coastal area and would likely suffer from tank corrosion related problems.

Expenditure has been included for the replacement of a SCADA master station and communications equipment. While we question the level of expenditure included, they are nevertheless immaterial and have been accepted on this basis.

Significant capital expenditure was lumped together under a single heading “Other”. This was later split by NorthPower into the following headings :

- IT Systems
- Buildings
- Motor Vehicles - Light and Heavy Fleet
- Generators
- Computer/Office Equipment

Expenditure for IT systems related to financial and customer service systems. Details were not provided of a particular allowance for a major IT system replacement in the future but we have assumed this to be related to corporate systems. IT expenditure has been excluded from our analysis and is shown as a separate item in Table 7.3 in section 7.9.

The capital expenditure for motor vehicles was particularly significant. This item has been excluded from our review of network expenditure and is shown as a separate item in Table 7.3 although we have made adjustments in consultation with NorthPower to take account of the trade in value of the replaced vehicles but further adjustments may be necessary.[3]

Capital expenditure related to the generation assets have been excluded in line with our treatment of this particular item stated in Section 3.10.

Capital expenditure for computer and office equipment included replacements and upgrades of personal computers and computer support/software development costs. These are shown as a separate item in Table 7.3. In our opinion the expenditures for personal computer upgrades were high based on NorthPower’s staff numbers[4]. The costs for the computer support/software development were described by NorthPower as contract expense costs.

[3] We note that NorthPower has been successful in winning asset inspection and maintenance works for two other Network Businesses. This brings into question the appropriateness of including capital expenditure for all NorthPower’s vehicles since some of these would be used in generating revenue not regulated by IPART.

[4] Staff numbers were taken from NorthPower’s 1996/97 annual report.

NorthPower included the replacement of load management systems as major projects under the heading of renewals. The works relate to the replacement of frequency injection plant and the replacement of load control relays of customer premises. These projects are based on a comprehensive report on NorthPower's load management systems and in our opinion the expenditures are reasonable.

Capital expenditure has been included for the following asset renewals due to safety reasons.

- Reconstruction of Bonalbo substation due to the existence of line clearances not meeting current standards[5] and condemned poles. Note a nominal sum has also been included for the review of all zone substations and subsequent remedial work.

- Replacement of a certain PVC insulated O/H service cable (type fault) which present a risk to the customers.

- Replacement of porcelain gap type surge arrestors.

- Works required to remedy lines found to be too low to the ground and other situations that present a risk to the public.

NorthPower has a programme of identifying situations with environmental risk in compliance with ISO14001 the International Standard for Environmental Management Systems. Environmental problems such as the potential for oil spills and the existence of PCB's are identified then ranked on a probability x consequence basis. Once ranked a cut-off is made identifying those which are to be remedied. A nominal sum has been allowed for such works.

The capital expenditures for renewals due to regulatory requirements in our opinion are reasonable and any adjustments required in this area would likely be immaterial.

Total capital expenditure for asset renewals is reasonable given the information provided however, these estimates should be revised when NorthPower develops better asset age information.

7.6 RELIABILITY IMPROVEMENT

On review of supporting information, it was apparent that NorthPower had included under the heading of "Reliability Enhancement" certain capital expenditure relating to asset renewals, regulatory requirements and augmentation. We have reviewed all expenditure under Reliability Enhancement on the merits of the individual projects.

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[5] Design standards varied among the smaller distributors prior to their amalgamation into NorthPower.

Supply reliability has become more of an issue in recent years. NorthPower's east coast area is predominantly a service area for customers who expect a high supply reliability (many retirees from metropolitan areas). In the west, where long radial lines once used to only serve small lighting and other rudimentary loads, now serve air conditioners and electronic equipment such as computers and fax machines.

NorthPower's current reliability performance is approximately around their target of 201 minutes[6]. For the last two years NorthPower has been improving reliability through better operating and maintenance practices (expenditure which is expensed rather than capitalised). Such activities include an increase in the use of live line works and better vegetation control[7].

Figures provided for distribution mains, SWER, distribution substations and LV mains were based on historical figures and amount to approximately $2.5 million pa. We were advised that this amount predominantly relates to asset renewals and where it does relate to reliability, it is for the maintenance of reliability rather than reliability improvement.

NorthPower has also included approximately $2 million pa to address specific feeder[8] problems and for the improvement in reliability. While we question the need for this level of expenditure, in our opinion any adjustments required would be immaterial.

Capital expenditure has also been included for the following items :

- Ongoing data capture/conversion and data validation for GIS, hardware upgrades and the integration of software packages to the GIS system. We have shown this as a separate item in Table 7.3 in a similar manner to other IT expenditure (refer section 7.5).
- Implementation of SCADA into existing substations at the rate of 2-3 year after a major installation in the year 1998/99.
- Development and upgrading of existing communications systems and facilities.
- The retrofitting of counters on reclosers for remote reading.
- Data communication, computer and GPS installation in vehicles. We question whether there is an economic justification for this expenditure of approximately $7.8 million but have not made any adjustments on account of its immateriality.
- Demand management initiatives.

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6 SAIDI of 201 minutes is a good level of reliability given the rural nature of the network. Current performance was assessed based on a trend of historical figures up to and including the results in 1997/98. NorthPower SAIDI results excluding major storms were 186 minutes in FY 1996/97 and 225 minutes in FY 1997/98 against a target of 201 minutes.

7 Tree maintenance is now contracted out with vegetation control cycles being reduced from 4 yearly to 2 yearly periods.

8 NorthPower has recently performed analysis of reliability on a feeder by feeder basis the results of which show wide variation in feeder reliability indices.

- A contingency allowance of a total of $18 million. As a point of consistency between distributors and because of the inherent errors associated with forward projections we have made adjustments to exclude these contingency amounts.

- Allowance for the replacement of old meters. We have excluded this expenditure from our review of network expenditures and have shown it as a separate item in Table 7.3.

7.7 AUGMENTATION OF CAPACITY

As described in Section 7.3, there has generally been no capital expenditure over the last two years for growth related projects. Works to improve the utilisation of the assets has included the relocation of existing distribution transformers, and relocation of zone substation transformers and the closure of one zone substation.

A nominal amount has been included in the capital expenditure projections for easements on new lines.

Although NorthPower generally do not carry out a full cost justification of capital projects until approximately one year prior to the project starting, there is some formal documentation justifying the projected capex to the year 2010. This includes computer simulations of the power network, short reports and memoranda. The rationales behind the augmentation projects were discussed with NorthPower during the field visit and accepted.

NorthPower's Asset Management Plan included a section from TransGrids Network Management Plan indicating that investment in the area by TransGrid is expected to be approximately $200 million up to 2005. The funding for this work has yet to be finalised. This is discussed further in the TransGrid supplementary report.

A number of NorthPower augmentation projects are planned and designed for 66 kV although initially being commissioned at 33 kV. Although this can be beneficial in the long term, this policy results in a greater risk of underutilised assets[9].

Choice of Load Growth Figures

NorthPower forecast load growth using the historical peak demands at each zone substation over the past five years. For coastal areas, population statistics and economic projections are also considered. One difficulty experienced is that often little warning is given of future planning for new subdivisions.

It is also difficult to forecast load increases for the more rural areas due to large spot loads, particularly in the sparsely populated western region, where augmentation may be required at short notice.

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[9] An example is the dual circuit 132 kV line from Lismore to Mullumbimby operating at 66 kV, for which there are no plans to utilise at 132 kV in this planning period.

Variations in actual growth from the forecast figures will be accommodated by varying the timing of implementation of the planned capital works. Slower than expected load growth can be accommodated by deferral of works and faster load growth can be handled by advancement of the works assuming adequate notice is available.

Security of Supply

In their Asset Management Plan, NorthPower state the following design security level criteria for augmentation in order that their corporate targets are realised (Table 7.2).

Table 7.2 : NorthPower Security Design Criteria

Security Level	Restoration Time (min)	Load
n-1	0	> 15 MVA
n-1	10	10 - 15 MVA
n-1	< 60	5 - 10 MVA
n	< 300	2 - 5 MVA
n	> 300	< 2 MVA

Guidelines for the planning of additional lines, methods of switching and design of zone substations are also given in the Asset Management Plan.

The choice of these criteria and guidelines impacts on the amount of projected capital expenditure in that achieving greater security levels in a power system involves more capital expenditure than a system with lesser security levels.

Demand Side Management

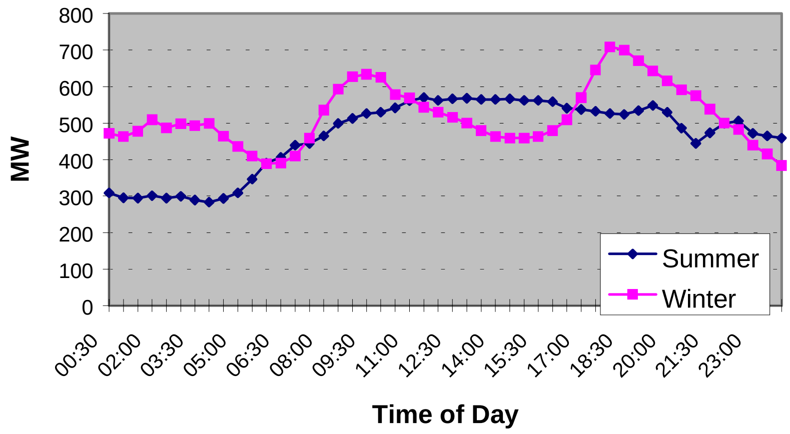
NorthPower's draft "Electricity Distributor's Licence Compliance Annual Report – Demand Management" for the 1997/1998 financial year outlines some specific DSM strategies which defer capital expenditure. The Report largely indicates that the feasibility of these strategies is still being investigated.

NorthPower's summer and winter maximum demand load curves are shown in Figure 7.2.

The load curves highlight the significant peaks experienced in winter.[10] We would expect that significant growth related capital expenditure could be deferred with a rigorous application of DSM initiatives and the shifting of peak load.

[10] The winter load factor = 0.732 and in summer 0.817.

Figure 7.2 : NorthPower Maximum Demand Load Curves (FY 1996/97)



NorthPower has undertaken a review of its DSM strategies especially in the area of direct load control for which expenditure has been included by NorthPower in their projections. The demand side management systems presently in place throughout the NorthPower system operate with varying degrees of effectiveness. In some areas of the system a peak occurs due to the concurrent switching of large water heating loads. More effective control of these loads will result in lower peak demands and deferral of capital expenditures in some areas.

It is likely that the summer load curve will be an influencing factor in some localities due to the lower ratings for equipment during summer. We did not see any evidence of DSM programmes targetting base load reductions or programmes involving curtailable load. Opportunities of the latter are unlikely to be as significant as in the case of energyAustralia's and Integral Energy's networks.

Augmentation Plan

Generally, we are satisfied that the proposed augmentation projects are justified. However, there may be scope for deferring the replacement of zone substation transformers by permitting heavier loading under emergency conditions. NorthPower, as part of their planning policy, operate their transformers under emergency conditions at 125% of the rated capacity. It may be possible that the transformers could tolerate a higher emergency load without significant deterioration. NorthPower as a joint study with Newcastle University are undertaking a study to confirm the appropriateness of the emergency loading factor for transformers.

The proposed upgrade of the Load Control System should reduce the substation load peaks resulting in the possible deferral of capital works. However, the actual capital expenditure deferred will largely be outside the review period.

NorthPowers projections for augmentation are reasonable and no adjustments are required.

7.8 BYPASS, EMBEDDED GENERATION, COGENERATION AND STANDBY NEGOTIATIONS

There are presently no known bypass opportunities in NorthPower's network.

Large gas fields exist to the north of NorthPower's territory but the viability of any gas pipelines running through NorthPower's territory is presently uncertain.

Embedded generation currently includes :

- three existing small cogeneration power stations, each of 6 MW capacity or less associated with sugar mills.
- several small hydro generation stations.

Possible future embedded generation includes :

- **Wind generation**. (NorthPower has made investigations into the possibilities of wind generation).
- **Solar power generation** (mainly funded by private investors). There is one 5 MW project due for commissioning in less than two years. This may lead to further similar generation stations.
- **Biomass generation**. Possibilities exist for electricity generation from biomass utilising the cotton trash and stalks to generate electricity in cotton growing areas. Likewise, generation from burning timber offcuts at high temperature is a possibility in the Armidale area.
- **Remote Area Power Systems**. NorthPower is promoting the use of Remote Area Power Systems (RAPS). The exact number and capacity of these units is not known but is thought to be anywhere between 100 and 200 units.

7.9 CAPITAL EXPENDITURE PROJECTIONS AND ADJUSTMENTS

A summary of NorthPower's capital expenditure projections and our adjustments are shown in Table 7.3. Other capital expenditures that have not be reviewed by Worley are shown as separate items..

Table 7.3 : Capital Expenditure Projections and Adjustments for NorthPower's Network

$m (1998 Dollars)	Total 1999 - 2010	1995 -96	1996 -97	1997 -98	1998 -99	1999 -00	2000 -01	2001 -02	2002 -03	2003 -04	2004 -05	2005 -06	2006 -07	2007 -08	2008 -09	2009 -10
1. Distributors' Projected Capital Expenditure (See Note 1)																
Renewals	114.0	0.0	6.3	11.9	11.7	9.3	9.7	9.8	10.1	10.7	10.3	10.8	10.3	10.9	11.2	10.9
Growth Related Projects	312.7	0.0	8.9	12.0	30.0	31.2	32.1	28.6	27.7	28.8	27.5	26.5	27.9	27.2	27.1	28.1
Reliability Enhancement Projects	114.4	0.0	3.3	4.7	7.1	8.2	8.0	8.2	8.4	8.5	11.3	11.6	11.6	11.7	13.5	13.5
Total for Network Capital Expenditure	541.0	0.0	18.4	28.6	48.9	48.7	49.8	46.7	46.2	47.9	49.1	48.8	49.7	49.9	51.7	52.5
2. Adjustments																
Exclusion of capex related to generation	-6.2	0.0	0.0	-0.2	-0.5	-0.5	-0.5	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6
Exclusion of a contingency allowance	-18.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-3.0	-3.0	-3.0	-3.0	-3.0	-3.0
Inclusion of Load Control Relays (See note 2)	20.9	0.0	0.0	0.0	1.8	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Total Adjustments	-3.3	0.0	0.0	-0.2	1.3	1.4	1.4	1.3	1.3	1.3	-1.7	-1.7	-1.7	-1.7	-1.7	-1.7
3. Adjusted Total Network Capital Expenditure																
Adjusted Total Network Capital Expenditure	537.7	0.0	18.4	28.3	50.1	50.1	51.2	48.0	47.6	49.3	47.4	47.1	48.0	48.2	50.0	50.8
4. Other Capital Expenditure Items																
IT Related Capex (see note 3)	64.0	0.0	2.8	5.6	9.9	9.4	4.3	8.9	4.0	4.1	3.9	3.8	3.9	13.8	3.7	4.1
Metering (see note 4)	19.4	0.0	4.0	4.1	2.6	3.0	4.7	7.0	5.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Vehicles (see note 5)	28.0	0.0	4.5	2.1	2.5	2.5	2.6	2.7	2.6	2.6	2.6	2.5	2.5	2.5	2.5	2.4
Streetlighting	15.0	0.0	0.9	0.8	0.7	1.9	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.4	1.4	1.4
Capital Contribution Works	91.5	0.0	15.5	12.5	9.5	6.9	7.2	7.4	7.7	8.0	8.3	8.6	8.9	9.2	9.5	9.8
Recoverable Works	11.0	0.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Retail Related Capex	19.8	0.0	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Total for Other Capital Expenditure Items	248.7	0.0	30.4	27.9	28.0	26.5	22.9	30.0	23.5	18.8	18.9	18.9	19.4	29.6	19.8	20.4

Notes

1 Excludes Streetlighting, Capital Contribution Works, Recoverable Works, Metering, IT and Vehicles

2 NorthPower included expenditure for load control relays with that for metering. Metering is shown as a separate item and this adjustment is required to include the expenditure for load control relays back into the network projections

3 Includes the following categories; GIS, IT Systems, Computer/Office Equipment, Data Network, Environmental Management module,

GIS Integration, Integration of work management/GIS/Design Automation tools and Deployment of Electronic Maps to Staff

4 Excludes load control relays

5 NorthPower's projected expenditures were adjusted to take account of the trade-in value of the vehicles

Section 8.0
Great Southern Energy

CONTENTS

8.1 DESCRIPTION OF THE NETWORK

Great Southern Energy's network covers an area of 176,000 km^2 resulting from a merger of nine electricity distributor networks in 1996. The network provides energy to a variety of industrial, residential and rural customers. Power is sourced from 19 TransGrid bulk supply points and distributed by the network which comprise predominantly long radial lines.

There are seven TransGrid 330/132 kV substations from which 132 kV and 66 kV radial feeders cover the Great Southern Energy area. Several of the 132 kV radial feeders are owned by Great Southern Energy as are all the 66 kV circuits.

Summary information for Great Southern Energy is shown in Table 8.1.

Table 8.1
Summary Information for Great Southern Energy as at 1996/1997

Customers Served :		
0 - 20,000 kWh pa	212,800	
20,000 – 200,000 kWh pa	12,400	
> 200,000 kWh pa	1,000 (97/98)	
Area Served	176,240 km^2	
Maximum Demands :		
Summer (MW)	504	
Winter (MW)	576	
Length of Lines (km) :	O/H Lines	U/G Cables
132 kV	788	-
66 kV	1,930	-
33 kV	2,143	15
11/22 kV (incl. SWER)	41,373	249
Total system asset book value before depreciation ($b)	$0.354b	

8.2 ADEQUACY FOR PRESENT DUTY

Insufficient data was provided to assess the adequacy of the transmission system.

The distribution network is served by 114 zone substations which have a total installed capacity of 2,459 MVA providing a firm capacity of 1,180 MVA. The zone substations vary in capacity from 123 MVA of 132/22 kV transformers at Union Rd, Albury to 1 x 0.5 MVA 33/11 kV transformer at Widgelli. Utilisation of installed capacity at multi-unit substations ranged between 13% to 67%, whereas the expectation would be to have at least 50% utilisation. Insufficient information was available to explain the lower utilisation levels. The overall installed capacity is adequate for the present demand. However, there are some zone substations (e.g. Albury, Griffith) where the load exceeded the nominated firm supply.

The distribution network of Great Southern Energy is operated at 33 kV, 22 kV and 11 kV with a small amount of 6.6 kV and is transformed to LV 3 phase and 1 phase reticulation. Some SWER at 19.1 kV and 12.7 kV forms part of this network. There are approximately 37,000 transformers on the distribution network with an installed capacity of 2030 MVA. The utilisation of 32% is typical for the type of network where almost 80% of the transformers are in rural areas (5, 10, 16 and 25 kVA).

8.3 ASSET MANAGEMENT POLICIES

Great Southern Energy does not have an Asset Management Plan and documentation relating to asset management was not supplied.

Great Southern Energy's area is split into three, the western, central and eastern regions. Each region has its own asset manager. Different policies may be adopted by each of the regions[1]

Fire risk is relatively significant in the area and so is one of the main drivers in the management of the assets.

Maintenance practices appear to be in line with general industry practice except in the case of 66kV and 33kV transformers where electrical tests and DGA analysis are currently not performed.

Discussion with staff revealed that local knowledge is applied to maintenance issues but that consideration is being given to the adoption of a common standard.

8.4 CAPITAL WORKS APPROVAL CRITERIA AND PROCESSES

Great Southern Energy has a formal capital evaluation policy which has been adopted from NSW Treasury policy documentation and subsequently updated to suit their own circumstances.

Great Southern Energy's policy includes the requirements to evaluate projects on an NPV basis, using a Treasury agreed WACC of 10.5% (pre-tax real).

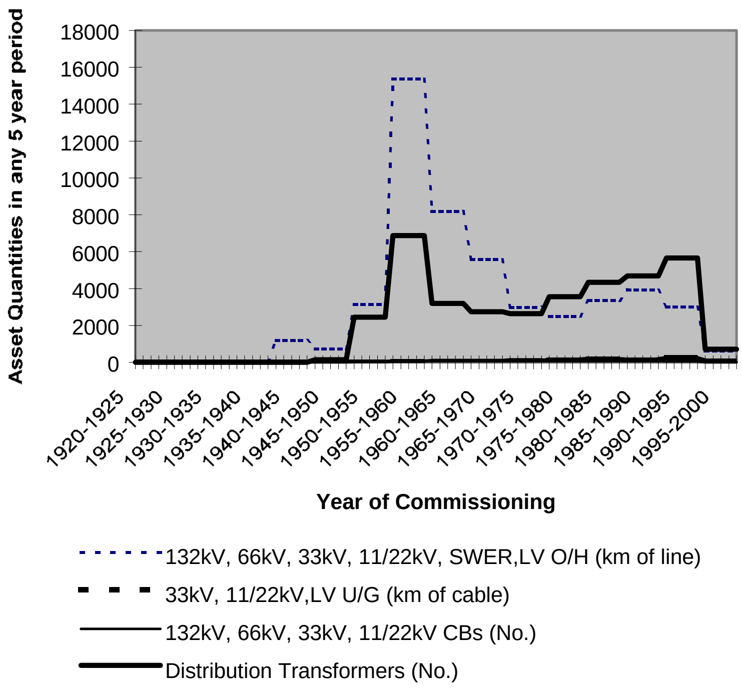
Projects only expected to proceed in the following 12 months are subjected to the capital expenditure approval process. Projects listed in Great Southern Energy's capital expenditure projections had not been subjected to the approval process at the time of writing this report.

8.5 PLANNED ASSET RENEWALS

Great Southern Energy provided asset age information. The age profiles of the major asset groups are shown in Figure 8.1.

[1] One example is in the use of live line maintenance which is used in the western region but not so much in the other regions.

Figure 8.1 : Age Profiles of The Major Asset Groups



The age profiles show that the network was developed from the 1940's with significant development in the 1960's and consists predominately of an overhead network. An analysis of the asset age profiles indicates that an average expenditure of as much as $25 million pa[2] would be required for the replacement of the older assets during the period under review. The actual level of expenditure required would be less than this due to economies that could be made today (refer to our Section 5.5 on energyAustralia for a list of these).

There is very little information available with which to base estimates on the economies that can be made.[3] We have made a preliminary estimate that approximately 16 million pa will be required for asset renewals. This is more than Great Southern Energy's projected expenditure for all the categories totalling approximately 15 million pa.

Great Southern Energy's capital expenditure projections for asset renewals were not shown separately. Rather all expenditures for asset renewals and augmentation were provided in three lists, one for each of the western, central and eastern regions. The list totalled approximately 1700 line items. We have reviewed the list and checked some of the more significant projects for reasonableness although insufficient information was provided to support the projects.

Given the age of Great Southern Energy's network we would expect that PCB removal and disposal is likely to be an issue although this would need to be confirmed. Similarly a large number of zone substations may require oil containment facilities. We have not estimated the level of expenditure required due to the lack of information supplied but flag that this has not been included in our adjustments.

[2] Great Southern Energy provided an asset replacement plan towards the end of this assignment which indicated asset renewals of the order of $28 million pa taken over a 15 year period (1995 – 2010).

[3] Great Southern Energy have a large number of small zone substations (114) which need to be rationalised. This could not be confirmed, however, since Great Southern Energy were only able to supply maximum demands for only a few of these.

Further comment on Great Southern Energy's capital expenditure projections is made in section 8.7, augmentation of capacity.

8.6 RELIABILITY IMPROVEMENT

Great Southern Energy has improved its level of network fault monitoring to identify potential faults and target any specific opportunities for improving reliability through specific asset replacement and maintenance opportunities including the increased use of live line maintenance. No reliability figures were provided since data has only been collected in the last 12 months for 6 out of the 9 former distributors now making up Great Southern Energy.

Reliability has improved since 1995 as shown by Great Southern Energy's Annual Report which gives figures of lost supply in customer minutes of approximately 115 minutes in 1995 to 85 minutes in 1997.

Great Southern Energy did not identify separately capital expenditure for reliability improvement . These expenditures were included in one list of all expenditures.

8.7 AUGMENTATION OF CAPACITY

Great Southern Energy was not able to supply a completed questionnaire and therefore comments below are limited to the information that was provided.

Load Growth

Great Southern Energy has a cautious approach to forecasting due to the nature of the loads in its area (load growth in rural areas tends to be lumpy due to the requirements of large spot loads). Load forecasts are based on population forecasts in each area of supply taking into account a nominal after diversity maximum demand (ADMD) per person of 0.8kVA (2.5kVA per customer). The population forecasts show that most areas have low (in some cases negative) to moderate growth and a few regions with high growth as follows :

- Eurobodalla (East Coast)
- Bega Valley (East Coast below Eurobodalla)
- Wagga Wagga (Largest population centre in Great Southern Energy's territory)
- Queanbeyan City (Close to Canberra)
- Yarrowlumia Shire (Borders A.C.T.)
- Albury City (2nd largest population centre in Great Southern Energy's territory)
- Griffith City (in the western area)

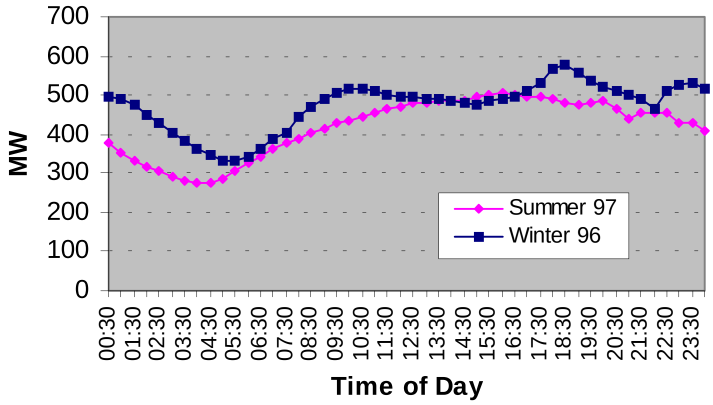
While these population forecasts give a good indication of future residential loads, other customer sectors such as industrial or commercial loads are not included. Consideration should be given to the requirements of future large spot loads or expected industrial loads and business sector developments. No consideration appears to be given to trends in historical maximum demands or disaggregated forecasting models.

Great Southern Energy has adopted a short planning horizon approach together with a rapid response to new demands. Great Southern Energy views this as a better approach than using forecasts based on linear trends which in the past have given rise to under-utilised assets. This approach has prevented an assessment of long term projections for capital expenditure due to growth.

Demand Side Management

Little information was supplied by Great Southern Energy on its Demand Side Management programmes. Great Southern Energy's maximum demand load curves are shown in Figure 8.2.

Figure 8.2 Great Southern Energy's Maximum Demand Load Curve



These curves show a predominant peak in the evenings which when analysed at a zone substation level indicates that better demand side management practices are required at some zone substations.

Current demand side management programmes include the use of direct load control and the use of time clocks. Some of the load curves at individual substations show that the maximum demand is likely to be attributed to the switching in of controllable load. In our opinion Great Southern Energy should be performing a review of all demand side management opportunities to further improve load factor and defer capital investment.

The extent to which the apparent lack of effective demand side management impacts on any future capital expenditure due to growth is unclear, largely due to the lack of information supplied to support the projected capital expenditures.

Augmentation Plan

Great Southern Energy does not as yet have a long term network development plan. Some network studies have been performed by an outside consultant in one area and further studies are presently being performed. Approximately half the network has now been modelled and this modelling process is continuing. Until further studies are completed the future requirements are largely unknown.

Great Southern Energy provided a schedule of potential capital expenditure projects for all categories up to year 2009/10. The capital projections contain a list of projects that may be required. No specific analysis has been performed to determine the timing of each project, some of the projects may not proceed at all and others have been duplicated in subsequent years. These schedules incorporated some 1700 items which totalled $180 million for the period. This sum included $73 million for augmentation which equates to an average expenditure of approximately $6 million pa. More precise expenditure projections for augmentation cannot be provided without a comprehensive load forecast model, network performance analysis and formulation of a long term network plan.

Conclusion

We were not able to review in detail Great Southern Energy's growth related projects due to the lack of information supplied. An analysis of their list of future projects indicated that total projected expenditure for growth related projects averaged approximately $6 million pa. We believe this level of expenditure is an appropriate preliminary estimate given the relatively low growth of the network and low utilisation rates at some zone substations.

Significant work is required by Great Southern Energy to gather better information in order to plan for future capital expenditures.

8.8 BYPASS, EMBEDDED GENERATION, COGENERATION AND STANDBY NEGOTIATIONS

Great Southern Energy included capital expenditure to upgrade lines and equipment to cater for likely co-generation at Bomen. This expenditure is required to meet the Generator's requirements for exporting energy to the network and also to cater for increased fault levels as a result of the generator's locality on the network. It is likely that a large proportion of the expenditure would be funded by the generator and so should not be included in the projections.

There is a possibility of a future windfarm near the existing 5 MW complex at Crookwell. Other generation possibilities include a co-generation plant at Morven near Albury. This may defer expenditure required for a new 132/66kV zone substation there.

A gas pipeline runs through Great Southern Energy's territory which provides opportunities for gas reticulation and embedded generation. Since Great Southern Energy owns and operates both an Electricity Lines Business and a Gas business, there are additional demand side management opportunities in this area.

8.9 CAPITAL EXPENDITURE PROJECTIONS AND ADJUSTMENTS

Great Southern Energy provided a list of capital expenditures relating to all categories which amounted to approximately $15 million pa. We have used this list to derive projected expenditures of approximately $6 million pa for growth related projections. We have used our own assessment of projected expenditures for asset renewals of $16 million pa.

These expenditures have been shown in Table 8.2. We emphasise that these projections should be considered preliminary until such time as Great Southern Energy gather further information, prepare network plans and provide supporting information for future capital expenditure.

Table 8.2 Capital Expenditure Projections and Adjustments For Great Southern Energy's Network

$m (1998 Dollars)	Total 1999 - 2010	1995 -96	1996 -97	1997 -98	1998 -99	1999 -00	2000 -01	2001 -02	2002 -03	2003 -04	2004 -05	2005 -06	2006 -07	2007 -08	2008 -09	2009 -10
1. Distributors' Projected Capital Expenditure (See Note 1)																
Renewals, Growth Related and Reliability Enhancement Projects	146.7	0.0	0.0	17.7	14.8	24.4	22.7	15.5	16.4	10.2	13.0	11.9	11.1	9.8	7.3	4.2
Total for Network Capital Expenditure	146.7	0.0	0.0	17.7	14.8	24.4	22.7	15.5	16.4	10.2	13.0	11.9	11.1	9.8	7.3	4.2
2. Adjustments / Revised Projections																
Estimate of Capex Required for Asset Renewals (see note 2)	176.0	0.0	0.0	0.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0
Great Southern Energy's Projections for Augmentation as an average annualised figure	66.0	0.0	0.0	0.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Total Adjustments	242.0	0.0	0.0	0.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
3. Adjusted Total Network Capital Expenditure																
Adjusted Total Network Capital Expenditure (see note 3)	242.0	0.0	0.0	0.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
4. Other Capital Expenditure Items (see note 4)																
Metering	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Streetlighting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capital Contribution Work	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Recoverable Works	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Retail Related Capex	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Other Capital Expenditure Items	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Notes

1 Excludes Streetlighting, Capital Contribution Work, Recoverable Works, Metering, IT and Vehicles
2 Actual expenditures are likely to change form year to year but are shown here as average annualised figures.
3 Note this total is based soley on figures given under Adjustments and supersedes those figures shown in 1 "Distributors Projected Capital Expenditure" above.
4 Information was not supplied for other capital expenditure Items

Section 9.0
Advance Energy

CONTENTS

9.1 DESCRIPTION OF THE NETWORK

Advance Energy was formed from the amalgamation of five smaller utilities and covers a large area in the middle of New South Wales surrounded by all other distributors discussed in this report except energyAustralia.

Advance Energy's network consists of long 132 kV and 66 kV radial lines serving a predominantly rural population with some large spot loads from mines and irrigation (refer to Appendix 9A for a map of Advance's transmission network).

Summary information for Advance Energy is shown in Table 9.1.

Table 9.1
Summary Information for Advance Energy

Customers Served :		
0 - 20,000 kWh pa	114,000	
20,000 - 200,000 kWh pa	3,030	
> 200,000 kWh pa	370	
Area Served	167,272 km^2	
Maximum Demands (1997 - 1998) :		
Summer (MW)	365	
Winter (MW)	402	
Length of Lines (km) :	O/H Lines	U/G Cables
132 kV	249	-
66 kV	1,489	-
33 kV	262	-
11/22 kV (incl. SWER)	35,860	153
Total system asset book value before depreciation ($b)	$0.24b	

9.2 CONDITION AND ADEQUACY FOR PRESENT DUTY

The TransGrid high voltage network supplying Advance Energy is focused in a region close to the inland side of the Great Dividing Range. Advance Energy is supplied from two 330kV substations and a number of smaller 132kV substations.

The 132 and 66kV subtransmission networks are of radial configuration with more than adequate line capacity to meet the present load demand. There are some instances where large customers would benefit from increased security of supply but the large investment has been found to be uneconomic. An example is at the Elura, CSA and Peak mines which are supplied from the same overhead line.

The distribution system comprises a conventional radial network of 22 kV and 11 kV single, three phase and SWER overhead lines.

Advance Energy advised that the network is in relatively good condition since historical maintenance practices have generally been sound. We could not confirm this but suspect that the level of maintenance would have varied amongst the earlier utilities.

9.3 ASSET MANAGEMENT POLICIES

Advance Energy is in the early stages of implementing Asset Management practices and has been in a catch up phase since the amalgamation.

Advance Energy does not yet have an Asset Management Plan. The initial focus and priority has been to rationalise the different policies used by the previous smaller utilities into a standard documented form. A significant amount of documentation has been produced to date but the process is still ongoing. Advance Energy will consolidate the individual documents into an Asset Management Plan once they have been completed[1].

A comprehensive list of the documents was provided that were completed or in the process of being completed. The only recommendation we have in regard to the list is that in addition to the Network Development Plan, the subjects of asset renewals and risk assessment be covered under the heading of Capital Works Policies and Procedures.

We have reviewed Advance Energy's Maintenance Procedures developed for distribution substations, switchgear and zone substation maintenance. These comply with generally accepted industry practices and are a mixture of periodic and condition based maintenance.

9.4 CAPITAL WORKS APPROVAL CRITERIA AND PROCESSES

Advance Energy has a formal policy document called Investment Evaluation Guidelines which is used to ensure that all investment proposals and business cases are properly prepared and evaluated on a common basis. The Investment Evaluation Guidelines set out in some detail the process for evaluating capital expenditure proposals and the use of discounted cash flow analysis and net present value (NPV) analysis.

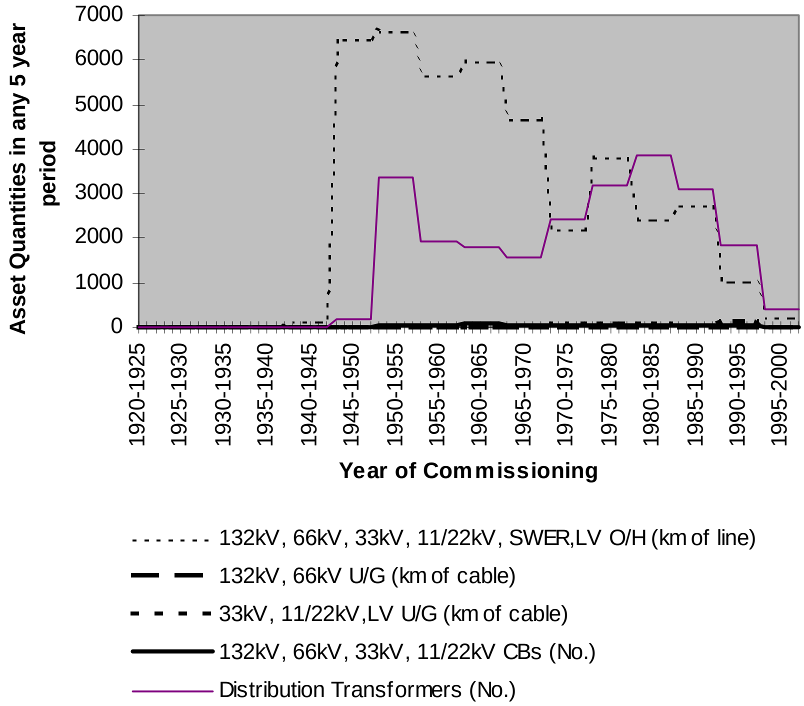
The decision making process provides a quantitative means of ranking investment opportunities. Although funds are directed to those investments providing the best return, there are many instances where less economic investments must be undertaken. Examples include capital expenditure for environmental concerns, health and safety, system security, quality and reliability of supply, risk management or regulatory requirements. On a stand alone financial analysis these instances show little or no commercial return.

1 Advance Energy advised that this would be completed within 12 months.

9.5 PLANNED ASSET RENEWALS

Advance Energy provided asset age information based on the assets of two of the 5 older utilities that were amalgamated to form Advance Energy. The two utilities on which the age information is based represents approximately 50% of Advance Energy's assets and these are considered representative of all of the assets. Age profiles of the major asset groups are shown in Figure 9.1.

Figure 9.1 : Age Profiles of Advance's Major Asset Groups



The age profiles show Advance Energy's network is predominantly overhead with large scale development since the 1950's. The age profiles indicate that significant expenditures would be required for asset renewals in the period under review.

Advance Energy's expenditure projections for the renewal of assets reaching the end of their economic lives average approximately $2.2 million pa. An analysis of age profile information indicates that approximately $20 million pa would be required over the period under review. However, it is unlikely that all these assets would be replaced due to the efficiencies that could be made today. The level of efficiency that could be made is largely subjective without detailed analysis of all assets. We have assumed as a preliminary estimate that capital expenditure for asset renewals would be approximately $14 million pa taking into account the following points :

- Some of the assets might not be replaced today but rather decommissioned.

- Efficiency in replacement costs should be able to be achieved in future years by contracting out certain works and because of improvements in operational and maintenance practices. The level of efficiency that we have suggested is similar to that applied to one of the larger distributors.

- Some assets would be replaced as a secondary effect of growth related projects.
- There is an element of uncertainty as to the expected lives of the overhead circuits since the climatic conditions and low loads are favourable to longer lives and the extent of asset replacement under maintenance activities is unknown.

Advance Energy included small expenditure projections (approximately $400 thousand pa) for asset renewals due to regulatory requirements. These were based on the following known problems :

- safety clearance problems
- insulator type faults
- oil containment and other high risk problems identified in Advance Energy's Environmental Plan.
- inherent design faults of some of the two pole distribution substations which give rise to safety problems.
- replacement of one LV conductor with aerial bundled conductor or conversion to underground mains due to inability to implement vegetation control in some areas.

The total expenditure projected for renewals due to regulatory requirements is immaterial and any adjustments we would likely suggest would also be immaterial.

9.6 RELIABILITY IMPROVEMENT

Advance Energy included in their 1997/98 business plan a target reliability performance of SAIDI = 180 minutes. This was based on the belief at that time that the network was operating at just above this level. Since then, better information systems[2] have been implemented which have provided more accurate information. The new information indicates that the network is not as reliable as first thought and has reliability performance of approximately 327 minutes. This level is consistent with the rural nature of Advance Energy's network.

Advance Energy has projected an average capital expenditure of approximately $3.8 million pa for reliability improvement targetting the worst performing parts of the system. Proposed works include :

- the installation of distribution protection equipment (reclosers, sectionalisers, fault indicators) for radial systems,
- reinforcement of ring networks or tie capacity to improve the flexibility of supply or due to transfer restrictions,
- conductor replacement where it is annealed or rusted,
- installing new feeders,
- improving the accessibility to lines in remote areas,
- using ABC conductor or undergrounding.

An allowance has also been included for the rationalisation of feeders across substation buses to improve security/reliability.

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[2] Since July 1997 fault records for reliability analysis were recorded by Advance Energy's System Control Group. The methods of recording and the quality of the data prior to July 1997 is inconsistent.

The three main causes of loss of supply to customers (in order of frequency) are lightning, defective equipment and tree contacts. We believe that a programme should be adopted to address these particular causes of faults.

We do not believe that expenditure projections should be reduced given the present performance of the network. Any adjustments to increase the expenditures would need to take account of more realistic reliability targets based on the current known performance.

9.7 AUGMENTATION OF CAPACITY

Load Growth

Advance Energy has a computerised load forecast model based on historical demands, seasonal indicators and expected future step loads. The forecasts consider temperature sensitivity. The addition of large mining step loads results in significant step increases in load growth.

A review has been made for subtransmission circuits and zone substation transformers using growth rates of 2 and 4 % per annum. The review made of zone substation transformers indicated that there was adequate capacity to meet the estimated demand for the next 10 years. The main problem relating to load growth is low voltage problems.

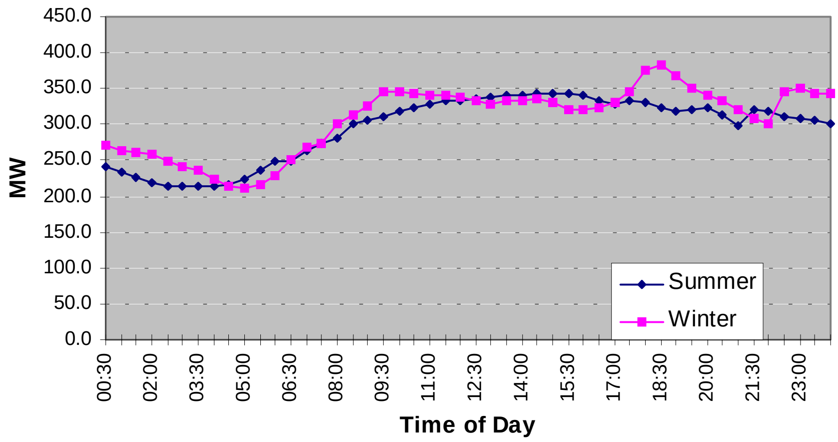
The prediction of spot loads occurring as a result of mining proposals is known usually 2 - 3 years in advance. The magnitude of the expected load sometimes requires an individual supply from the 132 kV system to minimise interference with existing customers.

Demand Side Management

We have reviewed Advance Energy's Licence Compliance Annual Report. This document discusses broad programmes but indicates that Advance Energy is working to address some of the load related problems on the network using more effective load management.

Advance Energy's maximum demand load curves for the network are shown in Figure 9.2. These show that overall the network has a relatively flat load profile (a load factor greater than 0.8 for both the winter and summer curves).

Figure 9.2 : Advance Energy's Maximum Demand Load Curves (FY 1996/97)



A review of some of the maximum demand load profiles at individual zone substations indicates that improvements can be made in the area of demand side management. However, the level of capital expenditure deferral is unlikely to be significant due to the rural nature of the network, the low customer densities and the low load growth on the network.

Projected Expenditure

Advance Energy has projected an average annual capital expenditure related to growth of approximately $5.5 million pa (excluding that for metering). Some major projects were separately identified but apart from the construction of a new switching station at Nevertire, they are relatively immaterial.

The majority of the capital expenditure is related to distribution mains. This projected expenditure is based on a 5 year list of small projects relative to three areas (Cowra subsystem, Bathurst/Oberon and the former Ulan County Council system). The expenditures have been rolled forward in the anticipation that other areas in Advance Energy's network will require similar work. We have reviewed sample projects in the list for reasonableness.

In our opinion Advance Energy's projection of $5.5 million pa is a reasonable estimate of that required for growth related projects. These estimates may need to be revised when more sophisticated planning techniques are introduced, such as Advance's proposal to introduce reliability based planning criteria into their overall network planning approach.

9.8 BYPASS, EMBEDDED GENERATION, COGENERATION AND STANDBY NEGOTIATIONS

There are four known or likely future opportunities for embedded generation :

a. Wind generation at Blayney (5 to 20 MW). This would feed into Orange 132/66 kV substation 66 kV and result in the deferment of the increased capacity at the 132/66 kV substations. No allowance has been made for this as the exact details of the generation is currently unknown.

b. Small hydro near Nevertire (1.5 MW) feeding into the 22 kV system near Nevertire and 1 MW hydro on an existing weir at Dubbo. No significant expenditure is expected for either of these units and no provision has been included.

c. Possible gas generator adjacent to the gas pipe line near Cobar in 5 - 10 years time. This will involve the construction of lines to bring the generator onto the system but no provision has been made at present.

9.9 CAPITAL EXPENDITURE PROJECTIONS AND ADJUSTMENTS

A summary of Advance Energy's capital expenditure projections and our adjustments are shown in Table 9.2. Other capital expenditures that have not been reviewed by Worley are shown as separate items.

Table 9.2 Capital Expenditure Projections And Adjustments For Advance Energy’s Network

$m (1998 Dollars)	Total 1999 - 2010	1995 -96	1996 -97	1997 -98	1998 -99	1999 -00	2000 -01	2001 -02	2002 -03	2003 -04	2004 -05	2005 -06	2006 -07	2007 -08	2008 -09	2009 -10
1. Distributors' Projected Capital Expenditure (See Note 1)																
Renewals	29.3	0.0	0.9	2.0	2.9	3.0	2.9	2.9	3.0	3.0	2.5	2.5	2.5	2.5	2.5	2.5
Growth Related Projects	59.1	0.0	2.9	5.3	4.5	5.8	4.8	4.8	7.1	5.3	4.9	5.0	5.9	5.1	5.2	5.3
Reliability Enhancement Projects	43.2	0.0	0.8	3.1	2.7	3.9	3.9	4.1	3.8	3.0	3.4	3.3	5.8	4.1	3.8	3.9
Total for Network Capital Expenditure	131.7	0.0	4.7	10.4	10.1	12.7	11.6	11.8	13.9	11.2	10.8	10.8	14.1	11.7	11.5	11.7
2. Adjustments																
Addition to Asset Renewals (see Section 9.5) (see note 2)	129.8	0.0	0.0	0.0	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8
Inclusion of Load Control Relays (see note 3)	3.9	0.0	0.0	0.0	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total Adjustments	133.7	0.0	0.0	0.0	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2
3. Adjusted Total Network Capital Expenditure																
Adjusted Total Network Capital Expenditure	265.3	0.0	4.7	10.4	22.2	24.8	23.7	23.9	26.0	23.4	23.0	22.9	26.3	23.9	23.6	23.8
4. Other Capital Expenditure Items																
IT Related Network Capex (GIS/Asset Management)	0.6	0.0	0.0	0.0	0.4	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Other Network IT Systems	6.3	0.0	0.0	0.0	1.0	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Corporate IT Systems apportioned to Network	1.7	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Other Network Related Capex (see note 4)	5.5	0.0	1.0	1.7	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Metering (see note 5)	9.4	0.0	1.2	1.5	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Streetlighting	1.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Capital Contribution Works	119.4	0.0	9.3	8.0	8.0	8.4	8.8	9.3	9.7	10.2	10.7	11.3	11.8	12.4	13.0	13.7
Recoverable Works	7.2	0.0	0.7	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Retail IT Expenditure incl. Corporate IT Systems apportioned	8.5	0.0	0.0	0.0	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Other Retail Related Capex	13.6	0.7	0.8	1.5	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3
Total Other Capital Expenditure Items	173.2	0.7	12.9	13.6	13.5	13.2	13.6	14.1	14.6	15.1	15.6	16.2	16.8	17.4	18.0	18.7

Notes

1 Excludes Streetlighting, Capital Contribution Works, Recoverable Works, Metering, IT and Vehicles

2 The addition of $11.8 million pa on average increases Advances projections to approximately $14 million pa

3 Expenditure for load control relays was included with Metering. Metering is shown as a separate item and this adjustment is required to include the expenditure for load control relays back into the network projections

4 This includes computer hardware, software, buildings, mobile plant, office furniture, etc.

5 Excludes load control relays

Section 10.0
Australian Inland Energy

CONTENTS

10.1 DESCRIPTION OF NETWORK

Australian Inland Energy covers a vast area at the west of New South Wales extending from the Victoria State boundary in the south to the Queensland State boundary in the north. The area includes Broken Hill, Wentworth and Dareton, Balranald and Moulamein, Menindee, Wilcannia and Tibooburra.

The area is characterised by low rainfall with extensive sheep farming with some pockets such as Menindee and Tandou where fruit, cotton or grain is grown.

Summary information for Australian Inland Energy is shown in Table 10.1.

Table 10.1
Summary Information for Australian Inland Energy as at 1996/1997

Customers Served :		
0 - 20,000 kWh pa	18,118	
20,000 - 200,000 kWh pa	1,000	
> 200,000 kWh pa	10	
Area Served	155,100 km^2	
Maximum Demands :		
Summer (MW)	65.2	
Winter (MW)	66.9	
Length of Lines (km) :	O/H Lines	U/G Cables
220 kV	3	0
66 kV	310	0
33 kV	631	0.3
6.6/22 kV (incl. SWER)	7,646	6
Total system asset book value before depreciation ($b)	$0.026b	

10.2 CONDITION AND ADEQUACY FOR PRESENT DUTY

The network is supplied by two TransGrid substations. Broken Hill network is supplied by a single 220 kV line and 2 x 100 MVA 220/22 kV transformers at TransGrid’s Broken Hill Substation. Security of supply to Broken Hill is enhanced by two 25 MW gas turbines owned by Pacific Power. Supply to the southern sector of the network is provided by a 66 kV supply at Deniliquin TransGrid substation. Other sectors of the network adjacent to the NSW/Victoria border at Wentworth, Euston and Dareton are supplied from PowerCor of Victoria.

The majority of the Australian Inland Energy’s present distribution network is operated at 22 kV 3 phase and 19.1 kV 1 phase SWER with small areas of 6.6 kV, 33 kV and some 66 kV loads. Except for specific loads the transformers are mostly below 100 kVA in size. This is due to the sparsely populated areas and the long distances involved.

The network is configured with radial distributors in the rural areas. In the urban localities the distributors are also radial but have some degree of interconnection. LV networks in the urban areas are interconnected between adjacent distribution substations.

Fault levels are typically low on such networks except adjacent to grid substations. Australian Inland Energy have recognised this in the purchase of network equipment. However, any substantial changes to the network resulting in higher fault levels will mean that some assets may need to be modified or replaced to ensure safe operation.

Voltage regulators are utilised on some long 22 kV distributors to overcome low voltage problems. These provide an appropriate solution as long as load growth is at a low level. The limitation has been recognised and negotiations are in progress to establish a new grid substation at one location.

The present network is generally adequate for the load served and the design of the network is appropriate to meet the present requirements.

10.3 ASSET MANAGEMENT POLICIES

Australian Inland Energy does not have a formal Asset Management Plan but rather a Network Asset Management Code (essentially a copy of the Code of Practice for Electricity Transmission and Distribution Asset Management) that gives guidance on the following topics:

- Design and Construction
- Maintenance (Discussions with Australian Inland Energy indicate that network maintenance policies follow accepted industry practice)
- Safe Electrical Operation and Work Practices

In the absence of a formal Asset Management Plan these documents provide a realistic basis for custody of the network assets. However, an Asset Management Plan is a higher level document typically incorporating company policies including financial projections for asset renewal and a development plan. In our opinion all distributors should be working to produce these documents.

10.4 CAPITAL WORKS APPROVAL CRITERIA AND PROCESSES

Australian Inland Energy advises that as most capital expenditure works are individually less than $100,000, no formal NPV financial analysis is carried out to determine the viability of any works. In terms of works to improve system reliability, the benefits are not quantified in financial terms - the obligation to maintain supply quality and reliability is of more concern.

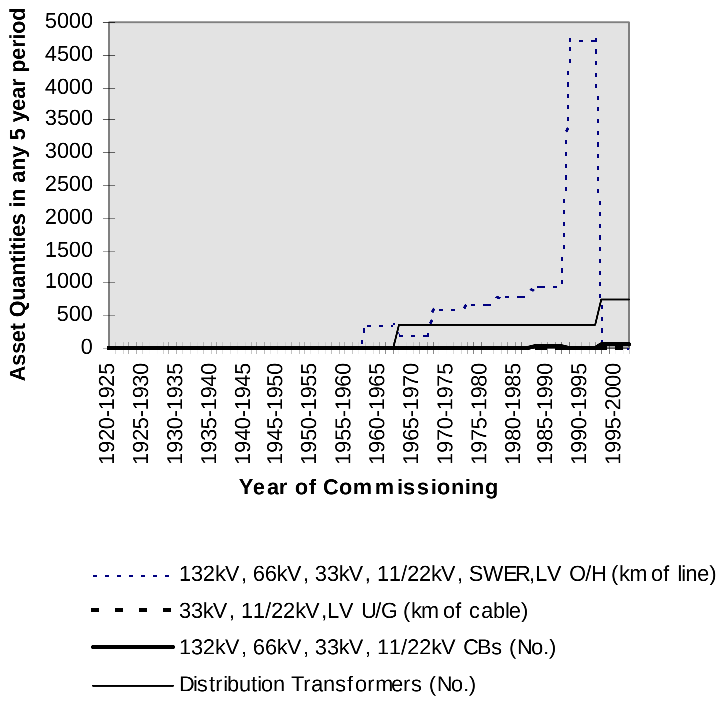
Australian Inland Energy states that capital expenditure is primarily driven by new connection or augmented supply requirements for new developments or subdivisions, increased irrigation pumping and wine production. Capital contributions from customers fund most of the capital requirements.

For Australian Inland Energy funded projects, the works are generally submitted as part of the annual estimates process, where the overall cost and expected benefits are discussed with the Chief Executive Officer at the submission stage.

10.5 PLANNED ASSET RENEWALS

Australian Inland Energy provided asset age information for their network. The age profiles of the major asset groups are shown in Figure 10.1.

Figure 10.1 : Age Profiles of The Major Asset Groups



The age profiles show that the network is relatively new with steady development since the 1960s. Significant development occurred in the 1990s and is associated with the Far West Electrification Scheme.

Australian Inland Energy has projected an average expenditure of approximately $0.1 million pa for renewal of assets reaching the end of their economic lives. This is in line with our analysis of age profiles and assumes that the assets in this region have longer lives due to the dry arid conditions. The analysis also assumes that the replacement of one particular long 66 kV radial line (built in the 1960's) will not be required in the period under review. If this project is required then the capital expenditure would need to be increased by a total of approximately $3 million over the review period.

Australian Inland Energy has not projected any capital expenditure to meet regulatory requirements although their annual report indicates that they manage their impact on the environment in accordance with the AS/NZS ISO 14001 standard (Environment Management Systems).

Australian Inland Energy advised that PCB removal and disposal is not an issue with their network, largely because of the relatively young age of equipment in service.

Zone substations in the southern region have oil containment facilities whereas those in the northern region do not. We have made a nominal adjustment to the projections with the addition of $0.05 million pa to allow for oil containment facilities for the north region zone substation transformers.

10.6 RELIABILITY IMPROVEMENT

Although Australian Inland Energy has no set target reliability levels at this time, it does have a continued commitment to the improvement in reliability and the reduction of outages. Australian Inland Energy's current reliability performance is indicated by a SAIDI of 259 minutes. An analysis of the interruptions shows a significant contribution from scheduled outages, most likely due to the radial nature of the network. More intensive use of live line techniques could reduce these scheduled outages considerably.

The network does not have a full SCADA system and as with most pre-dominantly rural networks, reliance is placed upon customers advising when and where power is off.

Expenditures for reliability improvement include five major projects. Two of these relate to the installation of voltage regulators to resolve voltage problems caused by load growth in certain specific areas. The other three major projects relate to :

- the upgrading of the Broken Hill CBD kiosk substations
- the upgrade of the Broken Hill 66 kV protection system
- the installation of additional surge protection on rural substations.

Nominal capital expenditure amounts have also been included for distribution mains, distribution substations, LV mains, some SCADA implementation and power quality monitoring equipment. These expenditures are in our opinion reasonable.

10.7 AUGMENTATION

Australian Inland Energy's network is characterised by low load density (kVA/km^2) and low load growth. The methods therefore used in forecasting network augmentation requirements differ from those used by urban distributors.

Load Growth

In recent years the population of Broken Hill has been declining due to the reduction in mining activities. Mining is projected to cease in the Broken Hill area in 2008 and a drop of 20 MVA in load demand is projected.[1]

In the Wentworth/GolGol and Merindee and Tandou areas, significant horticultural development is occurring. Growth in load demand in these areas results from the increasing use of irrigation.

Far West Electrification Project

Several of Australian Inland Energy's augmentation schemes in recent years have been subsidised by the State Government. For example, in 1988, Wilcannia was provided with a supply at 33 kV from Sunset Strip near Menindee.

[1] The actual fall in demand will likely be greater than that projected because the reduction in service sector demand has not been factored in.

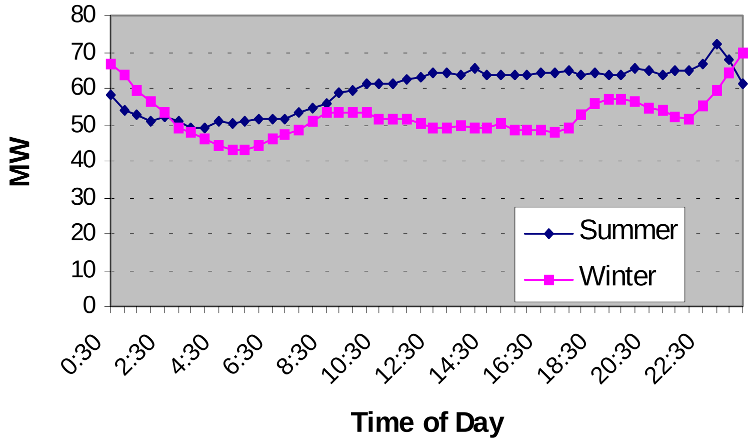
AUSTRALIAN INLAND ENERGY

In 1995 the Far West Electrification Project was implemented to reticulate Tibooburra from Broken Hill and White Cliffs from Wilcannia, and to provide supply by SWER lines to rural properties within the Unincorporated Area and Central Darling Shire. This project was funded through pre-defined capital contributions from each customer and a State Government subsidy. The scheme allows potential customers the opportunity for supply under the same rules until the year 2005.

Demand Side Management

Australian Inland Energy's maximum demand load curves are shown in Figure 10.2. The maximum demand load curves are close to optimal with a load factor of 0.83 in summer and 0.75 in winter. However, a load peak occurs at 11 pm on the summer curve and 12 am on the winter curve. It is likely that this is caused by the switching back in of controlled load. Australian Inland Energy are trying to reduce these peaks, however, they indicated that this will be countered over time by increased retail competition and altered tariff structures traditionally controlled by the distributors.

Figure 10.2 Australian Inland Energy's Maximum Demand Load Curve (FY 1996/97)



Forecasting

Because of the overall low growth in the area, Australian Inland Energy respond to individual customer requests as and when they occur rather than utilising state population and econometric data to forecast load growth or historical trends in maximum demand.

Design Criteria

Australian Inland Energy do not consider security of supply to be a driver for augmentation works. This is because the network is based on low contingency with either zero or partial interconnection ability between radial segments. The costs associated with increasing the security of supply to rural areas in Australian Inland Energy's jurisdiction are uneconomic due to the low customer densities.

Voltage drop minimisation and increased reliability are Australian Inland Energy's main drivers for network design. This is reflected in their capital expenditure projections where most augmentation works identified pertain to the installation of voltage regulators.

Capital Contributions

Capex is driven primarily by customer capital contributions for new or augmented connections. This is particularly so in the southern region with the large scale of irrigation pumping loads.

Augmentation Capex

Because of the sporadic nature of load growth, it is difficult for Australian Inland Energy to predict expenditure requirements beyond five years. Capital expenditure included under the heading of "Other Works" has been derived by extrapolating the actual expenditures spent over the last two years.

In our opinion the augmentation capital expenditure projects are appropriate although we have made adjustments to include $40 thousand to cover proposed forced cooling of transformers at Koraleigh.

10.8 BYPASS, EMBEDDED GENERATION, COGENERATION AND STANDBY NEGOTIATIONS

The only embedded generation presently existing is a 550 kW diesel plant at Tibooburra and a 25 kW solar powered plant at White Cliffs which is currently being refurbished. No other embedded generation exists or is planned.

Bypass Opportunities

Australian Inland Energy advised that as mining operations in Broken Hill are in decline, bypass opportunities from these customers is unlikely due to the short time-frame in which mining will continue (2008). Opportunities for bypass are possible in the Wentworth area but are not attractive because the magnitude of load is small and hence the revenue streams are not significant.

10.9 ADJUSTED CAPITAL EXPENDITURE PROJECTIONS

A summary of Australian Inland Energy's capital expenditure projections and our adjustments are shown in Table 10.2. Other capital expenditures that have not been reviewed by Worley are shown as separate items.

Table 10.2 Capital Expenditure Projections And Adjustments For Australian Inland Energy's Network

$m (1998 Dollars)	Total 1999 - 2010	1995 -96	1996 -97	1997 -98	1998 -99	1999 -00	2000 -01	2001 -02	2002 -03	2003 -04	2004 -05	2005 -06	2006 -07	2007 -08	2008 -09	2009 -10
1. Distributors' Projected Capital Expenditure (See Note 1)																
Renewals	0.72	0.00	0.05	0.05	0.25	0.25	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Growth Related Projects	5.70	0.00	0.00	1.26	1.05	1.70	2.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Reliability Enhancement Projects	1.04	0.06	0.06	0.11	0.99	0.49	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Total for Network Capital Expenditure	7.45	0.06	0.10	1.41	2.28	2.43	2.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
2. Adjustments																
Adjustments to allow for oil containment facilities for Northern Substations	0.55	0.00	0.00	0.00	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Adjustment for proposed forced cooling of transformers at Koraleigh	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Adjustments	0.55	0.00	0.00	0.00	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
3. Adjusted Total Network Capital Expenditure																
Adjusted Total Network Capital Expenditure	8.00	0.06	0.10	1.41	2.33	2.48	2.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
4. Other Capital Expenditure Items																
IT Related Network Capex	0.25	0.00	0.00	0.00	0.25	0.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Metering	0.72	0.00	0.03	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Streetlighting	0.22	0.02	0.05	0.02	0.40	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Capital Contribution Works	15.40	0.00	1.48	1.46	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40
Recoverable Works	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Retail Related Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Other Capital Expenditure Items	16.59	0.02	1.55	1.60	2.12	1.74	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49

Notes

1 Excludes Streetlighting, Capital Contribution Works, Recoverable Works, Metering, IT and Vehicles

Section 11.0
Comparative Analysis

COMPARATIVE ANALYSIS

CONTENTS

11.1 INTRODUCTION

The Terms of Reference call for a comparative analysis of the distributors' asset management policies and practices, service standard levels and other important factors in capital expenditure decisions. This is the subject of this section, which also reviews key parameters against international best practice.

By way of a word of caution, the reader's attention is drawn to the factors which make such comparisons difficult. These factors are outlined in Section 3.11 of the report and are mentioned again in their context in the sections that follow. Generally, comparisons of this type are of more relevance to studies of operational efficiency than they are to capital expenditure reviews.

11.2 KEY CHARACTERISTICS

Key characteristics of the distributors are shown in Table 11.1 in terms of customer densities and maximum demand. As can be seen, the six distributors exhibit widely differing characteristics and significant differences in the scale of their operations.

Table 11.1
Comparison of Inherent Characteristics of Distributors

	Energy Australia	**Integral Energy**	**NorthPower**	**Great Southern Energy**	**Advance Energy**	**Australian Inland Energy**
Customers/ km^2	61	30	1.5	1.3	0.7	0.1
Customers/ km of distribution line[a/]	40	29	5	5	3	2.3
Maximum Demand (MVA)	4,660	2,640	710	580	400	70
Customers/ Employee	404	342	283	300 (approx)	233	197

a/ Includes distribution and LV lines and cables, and SWER lines excluding street lighting mains where separately itemised

The two largest distributors, energyAustralia and Integral Energy have high customer densities which enable efficiencies to be made in electricity supply and which provide the opportunities for higher security and reliability performance.

The figures also clearly show the rural nature of the other four distributors.

11.3 ASSET MANAGEMENT POLICIES AND PRACTICES

All distributors follow broad industry maintenance practices although overall asset management strategies differed. The level of asset management planning documentation available varied considerably between distributors and on the whole was insufficient for us to comment in detail on this subject. The two large distributors have relatively comprehensive documentation, as expected considering their size and history. However, both would benefit from the consolidation of separate policy and practice documents into one asset management plan. This need has been recognised and Integral Energy for example demonstrated positive steps in this regard.

NorthPower has an "initial" asset management plan which in time will need to be expanded in order to become a more effective document. On the whole we found NorthPower to have effective and progressive asset management policies and practices.

The other rural distributors are largely in a "catch-up" phase after their recent amalgamation from a number of smaller distributors. It was therefore accepted that more time is required in their cases to consolidate previous policies and practices. The present limited resources of these distributors in the areas of network planning may be a factor holding back progress in this area.

11.4 SERVICE STANDARDS

Reliability figures of the six distributors are compared in Table 11.2.

Table 11.2
Comparison of Reliability Figures

	Energy Australia	Integral Energy	NorthPower	Great Southern Energy	Advance Energy	Australian Inland Energy
SAIDI	105	141	186	-	327	259
SAIFI	1.16	0.84	1.65	-	2.46	2.5
CAIDI	90	167	113	-	133	103

The table shows the higher reliabilities achieved by the bigger urban distributors with their higher customer densities, compared with rural areas. Overall, the figures are consistent with international trends which show SAIDIs, for example, of 200-400 in rural areas, 100-150 in urban areas and around 70 or less in underground CBD systems. Comparative international figures are given in Appendix 11.

Care must be taken in comparing the SAIDI, SAIFI and CAIDI figures because the method of calculation of the figures may not be consistent between the distributors (also true in the case of international distribution companies)[1].

Furthermore significant variations in individual distributor reliability figures often occur from year to year. An analysis of historical trends is required to show the complete picture but historical data may not be available for various reasons.

1 Major differences can occur through the inclusion or otherwise of certain faults. For example, differences often arise through the exclusion of LV faults, faults of short durations (say less than one minute) bulk supply outages or major events such as storms.

11.5 SYSTEM UTILISATION

Table 11.3 compares distribution transformer capacity utilisations (ratio of maximum demand to installed transformer capacity)[2].

Utilisation rates of other assets are not presented here because of the complexity of the issue.[3]

Table 11.3
Comparison of Distribution Transformer Utilisations

	Energy Australia	Integral Energy	NorthPower	Great Southern Energy	Advance Energy	Australian Inland Energy
Distribution System Utilisation	45%	55%	27%	32%	33%	40%

EnergyAustralia's utilisation figure is lower than might be expected (we normally look for 50-80% utilisation as a target for urban distributors) but this may partially be due to the triplex distribution system design used in the CBD areas (see also Section 5.2). NorthPower's utilisation is slightly lower than would be expected (although utilisation of around 30% is typical for rural distributors) but may be due to significant irrigation loads in this region (see Section 7.3). Australian Inland Energy's utilisation appears high but this is likely to have been distorted by large mining customer loads.

11.6 LOSSES

Information published by ESAA (49th Annual Issue of Electricity Australia, 1996) indicates that the NSW distribution industry as a whole does not have an inappropriate level of losses.

11.7 LEVELS OF EXPENDITURE

Total adjusted network-related capital expenditures for the period 1999/2000 to 2009/10 for the six distributors are shown in Table 11.4 below. The table shows the breakdown of the projected expenditures into three categories and also compares the projected expenditures with the present book value of network assets prior to depreciation.

2 Care must be taken in making comparisons of this nature because system maximum demand figures may or may not include the load of customers supplied direct at HV.
3 As an example, calculation of the utilisation of lines is difficult due to varying line configurations and generation and load patterns.

Table 11.4
Total Adjusted Network Capital Expenditures FY 1999/2000 – 2009/10

	Energy Australia	Integral Energy	NorthPower	Great Southern Energy	Advance Energy	Australian Inland Energy
Renewals (% of total)	53	51	24	-	61	16
Growth Related Projects (% of total)	40	47	58	-	22	71
Reliability Enhancement Projects (% of total)	7	2	18	-	17	13
Total Adjusted (Network) Expenditure ($m)	1,529	652	538	242	260	8
Total system asset book value before depreciation ($m) 1996/97	2,748	1,379	459	354	244	26
Total Adjusted (Network) Expenditure to Total System asset book value before depreciation	0.56	0.47	1.17	0.68	1.06	0.31

Australian Inland Energy's percentage renewal expenditure appears very low and maybe explained by the lower age of its assets. NorthPower's percentage renewal expenditure is also low and may be due to the need for significant expenditure to cater for the high growth in the area and underestimated renewal expenditure. Other than that, the breakdown of expenditures between renewals and other categories is consistent.

Total expenditures in relation to 1996/97 total system asset book values (excluding generation) before depreciation vary greatly. NorthPower's ratio is highest and Australian Inland Energy's is lowest. Integral Energy's and Energy Australia's ratios are comparable but lower than Advance Energy's.

As expected, reliability enhancement works are given a higher priority in rural areas. Growth related expenditures are higher in urban areas except in the case of Australian Inland Energy. Its growth related expenditure appears to be related to horticultural development.

Section 12.0
Summary and Concluding Remarks

SUMMARY AND CONCLUDING REMARKS

CONTENTS

SUMMARY AND CONCLUDING REMARKS

12.1 SUMMARY

In conclusion, this capital expenditure review, commissioned by IPART, is a component of IPART's planned review of electricity prices to apply from the end of the medium term price path in July 1999.

In this final section of the review, we summarise our findings and set out our concluding remarks in the light of the objectives of the review which were to :

- Assess and quantify the appropriateness of the distributors' existing network infrastructure in terms of current and projected capacity and current condition and equipment renewal.
- Identify capital works projects to the year 2009/10 and a suitable materiality threshold.
- Review the distributors' capital works assessment procedures.
- Consider how appropriate the proposed capital work is.
- Consider how the capital works will affect efficiency and service standards such as reliability and safety.
- Compare and contrast the asset management policies of the six distributors and quantify the impact on costs relative to service, reliability and safety levels.

Summary of Findings

The main findings of the review with respect to each distributor are as follows (references are to the relevant sections in the text) :

energyAustralia

i. The level of 132 kV system security offered to the Sydney inner city area should be improved (Section 5.2).

ii. The initial asset renewal expenditures appeared to have been under-stated but the revised projections considered are appropriate (Section 5.5).

iii. The capital expenditure projections associated with augmentation are appropriate (Section 5.7).

iv. Possible generation plants in the Botany and Kurnell areas could create the need for further network investment (Section 5.8).

Integral Energy

v. Integral Energy's 132 kV and 66 kV networks appear well planned and adequate (Section 6.2).

vi. Asset renewal expenditure projections were found to be high and have been adjusted downwards (Section 6.5).

vii. Integral Energy have a well considered Transmission Network Development Programme (Section 6.7).

NorthPower

viii. The TransGrid network supplying NorthPower's far north region is only marginally adequate for the present load and, with load growth, will become inadequate (Section 7.2).

ix. There is inadequate information on the asset ages to verify the extent of renewal-based expenditure (Section 7.5).

x. The projections do not include potential capital contributions to TransGrid for works of an estimated value of $200 million (Section 7.7).

Great Southern Energy

xi. The capital expenditure projections derived for Great Southern Energy should be considered preliminary until supporting information can be provided (Section 8.9).

Advance Energy

xii. The capital expenditures associated with asset renewals appear to be insufficient and they have been adjusted upwards (Section 9.5).

Australian Inland Energy

xiii. Minor adjustments were made to allow for oil containment facilities (Section 10.5).

General findings of the review are as follows :

xiv. The renewal of aged assets is an important driver of capital expenditure but is not well analysed or documented (Sections 2.2 and 3.2).

xv. Not all distributors were able to provide the comprehensive network development and asset management plans needed for the purpose of the review although there is an awareness of the need for preparation of such documentation where it does not presently exist (Section 3.8).

xvi. Expenditures on IT assets for network information and management is a growing area characterised by ill-defined costs and benefits (Section 3.10).

xvii. Generally, the performance the distributions is in line with international practice after making allowance for the nature and distribution of the loads served (Section 11).

12.2 ADJUSTED CAPITAL EXPENDITURE PROJECTIONS

Our adjusted capital expenditure projections are shown in Sections 5.9, 6.9, 7.9, 8.9, 9.9 and 10.9 for each distributor. A comparison of capital expenditures between distributors is made in Section 11.7. Note again that we have not offered any opinion on expenditures on IT.

12.3 CONCLUDING REMARKS

The need for further reviews of this type should be anticipated in conjunction with future price determinations. It would therefore be desirable for the distributors to be made aware of the need for improved documentation in some cases if these reviews are to be effective. We anticipate that they themselves will share this view and we know that they have each recognised areas where their own documentation could be improved to the overall benefit of their operations.

Future reviews may show a rising trend in asset replacement needs as the assets installed, during high growth periods experienced in the 1960s and 1970s reach the end of their economic lives.

Finally, we thank the Tribunal for entrusting this commission to us and we gratefully acknowledge the help and cooperation of all parties in the completion of this review.

APPENDICES

1A Terms of Reference
1B List of Amalgamated Distributors

4A List of Documentation Received
4B List of the Distributor’s Staff Interviewed

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11A Comparative International Reliability Performance Figures

Appendix 1A
Terms of Reference

INDEPENDENT PRICING AND REGULATORY TRIBUNAL
OF NEW SOUTH WALES

CONSULTANCY TERMS OF REFERENCE

CAPITAL EXPENDITURE REVIEW IN NSW ELECTRICITY DISTRIBUTION

Background

The Independent Pricing and Regulatory Tribunal is conducting an inquiry into the prices for declared monopoly services of the electricity distribution business for the period following the expiration of the current medium term price paths on June 30, 1999. The review will examine the pricing of access to electricity networks, prices for the supply of electricity to franchise customers and other monopoly services provided by the scheduled agencies. These agencies are:

Advance Energy	Great Southern Energy
Australian Inland Energy	Integral Energy
EnergyAustralia	NorthPower

As part of the inquiry, an asset management review is required to assist the Tribunal in assessing the overall performance of the distributors relative to the matters listed in section 15 of the Act:

- efficient costs of providing the relevant services
- the protection of consumers from the abuse of monopoly power
- the appropriate rate of return and payment of dividends to the owner
- the impact of pricing policies and the need to renew or increase relevant assets on the capital structure and funding requirements of the distribution businesses' funding of new assets or increased capacity
- the promotion of competition in the supply of electricity services
- standards of quality, reliability and safety of services
- social impacts of its determinations and recommendations
- the impact of pricing policies on ecologically sustainable development and considerations of demand management and least cost planning.

Issues

As part of its review and determination of a medium-term price/revenue path for the distributors the Tribunal will need to have regard to:

- The efficiency and sufficiency of capital expenditures since the previous determinations.

- The future capital expenditure requirements necessary to meet future service requirements most efficiently.

The Tribunal is concerned to ensure that the regulatory caps are sufficient to provide for the efficient operation and expansion of the system while maintaining service and safety standards at agreed levels. It is also concerned that caps should not reward inefficient investment or asset management decision.

The consultancy will assist the Tribunal to achieve this objective by reviewing past and future capital expenditures and asset management policies, using industry benchmarks wherever possible.

Terms of Reference

Objectives of Consultancy

The objectives of the consultancy in respect of the distribution business are to:

1. Assess and quantify the appropriateness of the existing network infrastructure in terms of:

    - current and projected capacity.
    - current condition and renewal requirements.

    This assessment should be benchmarked to an assessment of best practice standards for efficient maintenance and utilisation of network assets.

2. Identify the capital works projects through to 2009/10, separately identifying projects satisfying a materiality threshold to be set by the Tribunal.

3. Identify and comment on the appropriateness of procedures for assessing capital expenditure including the reasonableness of the discount factors used in any present value or economic value added analysis.

4. Ascertain the appropriateness of the capital projects in No. 2 above given:

   - The existing infrastructure and renewal requirements.
   - The demographic circumstances.
   - Increasing contestability in the provision of electricity services.
   - Future by-pass, embedded generation, co-generation and standby negotations.

5. Assess and quantify the impact of the capital projects, if judged appropriate in No. 3 above, in terms of the following:

   - Efficient costs of providing the relevant services.
   - Standards of customer service.
   - Reliability and safety of the distribution system.

6. Compare and contrast the asset management policies of the six NSW distributors and quantify the impact on costs relative to service, reliability and safety levels.

7. Identify industry best practice with respect to asset provision, asset utilisation and service standards.

It is expected that the consultancy should advise the Tribunal about how each of the distributors have achieved their levels of service, reliability and safety in relation to their asset management practices, and their expected continuing performance in this regard.

Scope

1. The study should cover the distributor (network) businesses of each of the six distributors in NSW. Any capital works associated with the retail businesses should be separately identified. In carrying out the study, the consultant should:

   i. Identify the capital works that are intended to be contracted-out and that which are intended to be carried out in-house or by the distributor's internal contracting arm.

Independent Pricing and Regulatory Tribunal of New South Wales
Level 2, 44 Market Street, Sydney NSW 2000
Telephone: (02) 9290 8400 Fax: (02) 9290 2061
Email: ipart@tpgi.com.au Homepage: www.ipart.nsw.gov.au
All correspondence to P.O. Box Q290, QVB Post Office, NSW 1230

ii. Identify and segregate renewal, replacement and growth-related projects for the (i) and (ii) above.

iii. Identify and segregate the capital works projects associated with:

- recoverable works (see Capital Contributions Determination 10, 1996 for discussion on recoverable works).
- existing assets and future capital projects for the streetlighting system (see Streetlighting Determination 5.2, 1997).
- contestable works.

2. The consultancy is likely to also involve infrastructure and capital project inspections.

3. In undertaking the study, the consultant should have regard to:

- current electricity determinations handed down and various guideline documents endorsed by the Tribunal.
- the requirements of the National Electricity Code.
- any relevant legislation, government policies and industry codes of practice.

Further background information is available on the Tribunal's website at *www.ipart.nsw.gov.au*. A minimum references checklist is attached.

Timing

The *Final Consultancy Report* should be available and presented by 21 August, 1998. A draft will be required for review by IPART by 7 August, 1998.

The consultancy will start with energyAustralia and Integral Energy. This will be followed by NorthPower and Advance Energy, then Great Southern Energy and Australian Inland Energy.

Preliminary Findings Reports will be required. Regular progress meetings are expected. The consultancy workplan should reflect these.

Conditions of Tender

Consultancy Information and Documentation

The consultancy reports will be public documents. IPART will undertake to make the reports available to distributors and/or other parties as appropriate.

All documents, information and references provided by the distributors and other relevant parties in electronic and hardcopy formats to the consultants for the purpose of this consultancy will become the property of IPART at the conclusion of the consultancy, or earlier if required.

Confidentiality

Under no circumstances at any time is the consultancy to divulge any of the information obtained from any of the distributors or IPART for the purpose of this consultancy to any party except with the expressed agreement of the distributor/s concerned and IPART.

Conflicts of Interest

The consultancy company and its nominated officers for the purpose of this consultancy are required to affirm that there is no, and will not be, any conflict of interests arising from undertaking this work.

Fee

The fee quoted is to be inclusive of all expenses and disbursements. Total payment will be due within 28 days of receiving an invoice at the conclusion of the review. A detailed breakdown of the consultancy costs is required with the proposal. Staff costs should be reconciled to the detailed proposal workplan.

Consultancy Resources

The tenderer is required to disclose in their proposal the names, experience and qualifications of the staff assigned to the consultancy. A detailed workplan is also required.

Insurance

The tender is required to include appropriate authorised documentation satisfying section 9.4 of the draft IPART standard contract.

Proposal

The consultancy proposal should demonstrate an appreciation for the task as well as describe the intended approach for carrying out the study.

Presentation

Shortlisted tenderers may be required to make a presentation as part of the tender evaluation process.

Acceptance of Tender

IPART reserves the right to:

- Accept no tender, or one or more tenderers to undertake the asset management review.
- Approve or reject any sub-contractors the lead consultant may wish to appoint.

Contract

The successful tenderer will be obliged to adhere to the terms of the IPART contract. A draft copy of the standard contract is attached. IPART reserves the right to modify contract terms for the final contract as appropriate.

Parties to the Consultancy

The party managing and commissioning the consultancy is the Independent Pricing and Regulatory Tribunal. Contacts are:

Ms. Chien-Ching Lim	Financial Analyst tel: 61-2-9290 8410
Mr. Scott Young	Programme Manager – Electricity tel: 61-2-9290 8404

Lodgement of Tender

The tender should be lodged no later than 9:00 a.m. Sydney time, on 6 April, 1998. Proposals should be provided in 3 bound copies and 1 loose-leaf copy.

The tender should be lodged in a sealed envelope marked "**ELECTRICITY CAPITAL EXPENDITURE REVIEW**" addressed to:

Mr. John Dulley
General Manager, Secretariat
Independent Pricing and Regulatory Tribunal
P.O. Box Q290
QVB Post Office
NSW 1230

Appendix 1B
List of Amalgamated Distributors

APPENDIX 1B

New Entities	Amalgamating
EnergyAustralia	Sydney Electricity Orion Energy
Integral Energy	Prospect Electricity Illawarra Electricity
NorthPower Energy	Namoi Valley Electricity New England Electricity NorthPower Northern Rivers Electricity North-West Electricity P-CCC Electricity Tenterfield Shire Council Electricity Division
Advance Energy	Central West Electricity Ophir Electricity Southern Mitchell Electricity Ulan Electricity Western Power
Great Southern Energy	Monaro Electricity Murray River Electricity Murrumbidgee Electricity Northern Riverina Electricitiy Southern Riverina Electricity Southern Tablelands Electricity South-West Slopes Electriciity Tumut River Electricity
Australian Inland Energy	Broken Hill Electricity

Appendix 4A
List of Documents Received

APPENDIX 4A

Documentation received from the distributors for the capital expenditure review :

1. Energy Australia

- Response to the questionnaire
- Capex projections using the template provided
- Annual Report 1996/97
- Major Works Review Schedules (13 June 1997)
- Network Development Plan (May 1998)
- Subtransmission System Diagrams (received June 1998)
- Value Management Study Reports :

  (i) Supplying Homebush Bay
  (ii) Warringah Substation and Subtransmission Network
  (iii) Supplying Central Cost - Northern Sector subtransmission and zone substation capacity

- Network Maintenance - Network Standards NZ0150 Volume 1
- Other miscellaneous information.

2. Integral Energy

- Response to the questionnaire
- Capex projections using the template provided
- Annual Report 1996/97.
- Transmission Network Development Programme (April 1998)
- Strategic Asset Management Plan 1998/99
- Property Valuation detailed report. MetSouth (Integral) Energy, Appendix 3 to consolidated consultants report
- Network drawings
- First Level Emergency Report (June 1998)
- Asset Refurbishment Plan 1998/99, towards 2001/01
- Project planning reports :

  (i) Narellan zone substation Network Investment Options study No. 156 (May 1997)
  (ii) Penrith substation - capital works agreement No. 204 (May 1995)
  (iii) Technical Report No. 143 - siting of Regentville Bulk Supply Point - Implications for 132 kV system (October 1992).
  (iv) Peachtree zone substation, Network Expansion Options study No. 152 (May 1994).
  (v) Regentville supply point and Associated Works. Capital Works Agreement No. 296 (March 1996).
  (vi) Kangaroo Valley - Report on current performance and future options (May 1998).
  (vii) Supplies in the Yatte Yattah Area (May 1993).

- Branch Procedures/Work Instructions :

  (i) NCP1100 - Major Project Formulation and Approval.
  (ii) NCP 1102 - Statement of Network Need
  (iii) NCP 1103 - Produce Network Investment Options
  (iv) WCP1200 - Produce Capital Works Agreement

- Routine Mains Maintenance Activities

3. NorthPower

- Response to the questionnaire
- Capex projections using the template provided
- Annual Report 1996/97
- 66/33 kV Substation/Submission Loading - Network diagrams

- Network Asset Management Plan
- Demand Management Opportunities in the Northern Rivers Area Volume 1 (October 1995)
- Zone Substation load forecasts
- Distribution Asset Management System - system overview (May 1997)
- Capital expenditure document - Procedures and Practices (May 1998)
- NorthPower Communications Overview
- Zone Substation/Feeder and Bulk Supply Point daily load profiles
- Tweed Area Project Summary Work sheet
- Enermet Report executive summary on NorthPower's Load Management (July 1997)
- Manning Subtransmission - Strategic Report
- Hastings Subtransmission - Strategic Report

4. Great Southern Energy

- Partial Response to the questionnaire
- List of capex projections
- Annual Report 1996/97
- Forecasted Population changes
- Some substation and bulk supply point load curves.

5. Advance Energy

- Response to the questionnaire
- List of capex projections
- Annual Report 1996/97
- Network diagrams
- Sample project details including load flow information supporting future capex projections
- Sample historical capital project evaluation reports :

  (i) Wellington Substation 132 kV Augmentation report (February 1994)
  (ii) Report on the options for improving the performance of the Coonabarabran subtransmission system (1996)
  (iii) Geurie 66/11 kV substation project (December 1994)
  (iv) Reconductoring of the Yeoval Feeder (September 1994)
  (v) Additional 11 kV Feeder - Wellington Town (April 1995)
  (vi) Reconductor 22 kV Feeders - Cobar Town (June 1995)

- Parkes Commercial District - low voltage network re-cabling report.
- Zone substation Inspection and Maintenance Procedures (July 1998)
- Distribution Substation and Switchgear Maintenance Procedures (July 1998)
- Investment Evaluation Guidelines (March 1998)
- Summary DGA results in support of transformer refurbishment at Dubbo and Nyngan
- Miscellaneous information :

  (i) Substation load curves
  (ii) Details in support of expenditure for communications
  (iii) Forecast transformer and line loads.

6. Australian Inland Energy

- Response to the questionnaire
- Capex projections using the template provided
- Annual Report 1996/97
- Australian Inland Energy's Code of Practice for Electricity Transmission and Distribution Asset Management
- Safety and Operating Plan (February 1998)
- Network drawings
- Equipment Inspection Schedules
- Draft 5 year Network Plan (4 pages).

■

Appendix 4B
List of the Distributor's Staff Interviewed

APPENDIX 4B

The following is a list of staff interviewed during the visits to the distributors.

1. EnergyAustralia

M Davies	General Manager - Network
T Fagan	Senior Engineer - Subtransmission Planning
P Howarth	Senior Engineer - System Data and Performance
R Funnell	Senior Engineer - Planning Co-ordinator
P York	Senior Engineer - Distribution Planning
P Russell	Network Contracts Engineer
J Battersby	Asset Strategist - Distribution Substations and Mains

2. Integral Energy

J Allen	General Manager - Integral Energy Networks
M Tamp	Manager Network Capability
T Christopher	Asset Strategy Manager South
M Webb	Asset Strategy Manager North
M Thompson	Mains Design Policy and Standards Manager
J Cook	Substation Technical Support Manager

3. NorthPower

T Holmes	Assets Manager
N Cooper	Network Planning Engineer

4. Great Southern Energy

L Elder	Asset Development Manager

5. Advance Energy

L Zulli	Networks Investment Manager
M McDonald	Networks Investment Officer
S Wilson	Substation Policy Engineering Officer

6. Australian Inland Energy

A Ray	Manager Network

■

Appendix 5A
EnergyAustralia - Maps of Subtransmission System

To view map

please click on

MapsWorley.pdf

(Map 2)

To view map

please click on

MapsWorley.pdf

(Map 3)

To view map

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(Map 4)

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Appendix 7A
NorthPower - Map of Subtransmission System

To view map

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MapsWorley.pdf

(Map 5)

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Appendix 8A
Great Southern Energy - Map of Subtransmission System

To view map

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(Map 6)

■

Appendix 9A
Advance Energy - Map of Subtransmission System

To view map

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MapsWorley.pdf

(Map 7)

Appendix 11A
Comparative International Reliability Performance Figures

APPENDIX 11A

International Reliability Performance Figures

Utility	SAIDI (minutes)	SAIFI	CAIDI
Australian Utilities (year end 30 June 1995) :			
SEQEB	364	1.4	258
SWQEB	358	3.0	120
FNQEB	243	3.3	74
United Kingdom (1994/95) :[a/]			
London	58	0.40	145
Midlands	128	1.21	106
Southern	78	0.75	104
SWALEC	212	2.2	96
Canadian Utilities (1995) :			
Urban Utilities (19)	64	1.42	45
Urban/Rural Utilities (15)	212	3.12	68
New Zealand (1996) :			
Urban Companies	83	1.59	52
Mainly Urban Companies	184	2.79	66
Mainly Rural Companies	297	4.32	69
Rural Companies	409	4.97	81

Source : Power Company Customer Reliability Statistics Year Ended 31 March 1996, Electricity Supply Association of New Zealand Inc.

a/ More recent information from the UK indicates SAIDs as follows :

Seeboard Urban : 20 - 50 minutes
Seeboard Rural : 120 - 140 minutes
Liverpool (has a highly interconnected 11 kV network) : 10 minutes

Coroners Act, 1980

FIRE INQUIRY BEFORE CORONER SITTING ALONE

New South Wales }
To wit,
PENRITH

INQUIRY held at the Coroners Court sitting at Penrith in the State of New South Wales on the Seventh day of March, 2003, before Michael Price, Coroner, concerning the
destruction by fire of certain property situated on The Appin Road, Appin.

I FIND that on the 25th December, 2001, bushland, and other property (as set out in the attached schedule), situated in and near Appin, Wedderburn, Helensburgh and Waterfall in the State of New South Wales was destroyed by fire, such fire having started from the arcing of overhead electrical wiring and molten metal igniting vegetation immediately beneath along The Appin Road, Appin. This arcing occurred during high velocity winds.

There are no suspicious circumstances.

GIVEN under my hand at Penrith this Seventh

day of March 2003.

(M. Price)
Coroner

File
Police
Interested parties

Appendix 6

DESIGN, RELIABILITY AND PERFORMANCE

LICENCE CONDITIONS

IMPOSED ON

DISTRIBUTION NETWORK SERVICE PROVIDERS

BY THE MINISTER FOR ENERGY AND UTILITIES

1 AUGUST 2005

DESIGN, RELIABILITY AND PERFORMANCE LICENCE CONDITIONS IMPOSED ON DISTRIBUTION NETWORK SERVICE PROVIDERS BY THE MINISTER FOR ENERGY AND UTILITIES

EXPLANATORY NOTE

Purpose of the reliability performance conditions:

The Minister for Energy and Utilities has imposed on licences held by distribution network service providers under the *Electricity Supply Act 1995* additional conditions relating to reliability performance.

The purpose of these conditions is to facilitate the delivery of a safe and reliable supply of electricity. The conditions impose design, reliability and performance standards on distribution network service providers. When fully implemented, distribution network service providers will be required to report to the Minister to ensure compliance with the conditions. The new standards are as follows:

Design planning criteria:

The *design planning criteria* set out standards to be used by a distribution network service provider in planning, developing, managing and operating its distribution system to ensure that it:

- meets the *reliability standards*; and
- provides an adequate supply with an appropriate level of redundancy, consistent with its regulatory obligations.

Reliability standards:

The purposes of the *reliability standards* are to:

- define minimum average reliability performance, by feeder type, for a distribution network service provider across its distribution network; and
- provide a basis against which a distribution network service provider's reliability performance can be assessed.

Individual feeder standards:

The purposes of the *individual feeder standards* are to:

- specify minimum standards of reliability performance for individual feeders;
- require a distribution network service provider to focus continually on improving the reliability of its feeders; and
- enable the reliability performance of feeders to be monitored over time.

Customer service standards:

The purpose of the *customer service standards* is to provide financial recognition to eligible customers who have experienced poor reliability of supply from a distribution network service provider.

Commencement:

The licence conditions are imposed by the Minister pursuant to item 6(1)(b) of Schedule 2 of the *Electricity Supply Act 1995*. The conditions are imposed on 1 August 2005 and take effect from that date, except where expressly stated otherwise.

Relationship with existing conditions and other obligations:

These conditions are additional to conditions that the Minister has previously imposed on licences held by distribution network service providers and licence conditions imposed under the *Electricity Supply Act 1995* and other regulatory instruments. These conditions are also supplementary to obligations imposed on distribution network service providers by the *Electricity Supply Act 1995*, the *Electricity Supply (General) Regulation 2001*, the *Electricity Supply (Safety and Network Management) Regulation 2002*, and other regulatory instruments.

Enforcement:

These conditions are enforceable under the *Electricity Supply Act 1995* by the Independent Pricing and Regulatory Tribunal and the Minister. These conditions are not intended to create standards which are enforceable against a licence holder by individual customers.

Consultation:

Before imposing these conditions the Minister undertook consultation with stakeholders including the licence holders, the Independent Pricing and Regulatory Tribunal and the Minister administering the *Protection of the Environment Administration Act 1991*. The Minister has given due consideration to submissions received during consultation.

Reporting:

To allow for the development of business, reporting and information technology systems, condition 18.17 provides that the first performance and audit reports under these licence conditions will not be required until after 1 July 2007. Reliability performance reporting will continue to be implemented under the Electricity Supply (Safety and Network Management) Regulation 2002.

Review:

It is intended that these design, reliability and performance conditions will be reviewed within two years to assess their effectiveness in facilitating the delivery of a reliable supply of electricity at reasonable cost. To ensure a well researched, rigorous and timely review, the process will commence within three months. The Department of Energy, Utilities and Sustainability and Treasury will prepare terms of reference within one month, coordinate the review, appoint an independent consultant and consult with stakeholders, including DNSPs and the Independent Pricing and Regulatory Tribunal.

RELIABILITY PERFORMANCE CONDITIONS

14. Design planning criteria

14.1 A licence holder must comply with the applicable *design planning criteria* in Schedule 1 in relation to all of its *network elements* from 1 July 2009.

14.2 A licence holder must comply with the applicable *design planning criteria* in Schedule 1 in relation to its *network elements* installed from 1 July 2007 from the date of installation.

14.3 A licence holder may agree with a customer to apply higher or lower standards of service at the customer's point of supply than the *design planning criteria* relevant to that customer. In cases where negotiations are with developers rather than the ultimate end-use customer, the licence holder must take into account anticipated end-use customer expectations and asset management considerations.

15. Reliability standards

15.1 Subject to 15.4, a licence holder must not, when *excluded interruptions* are disregarded, exceed in a *financial year* the *SAIDI average standards* that apply to its *feeder types.*

15.2 Subject to 15.4, a licence holder must not, when *excluded interruptions* are disregarded, exceed in a *financial year* the *SAIFI average standards* that apply to its *feeder types.*

15.3 The requirements under this condition 15 are the *reliability standards* and take effect from 1 August 2005.

15.4 The *reliability standards* for the 11 month period from 1 August 2005 to 30 June 2006, are to be calculated by applying 11/12 of the *SAIDI average standards* and 11/12 of the *SAIFI average standards.*

16. Individual feeder performance

16.1 This condition applies where one or more of the feeders of a licence holder exceed the relevant *individual feeder standards* for any 12 month period ending at the end of March, June, September or December, when *excluded interruptions* are disregarded.

16.2 A licence holder must:

(a) immediately investigate the causes for each *feeder* exceeding the *individual feeder standards*;

(b) by the end of the quarter following the quarter in which the *feeder* first exceeded the *individual feeder standards*, complete an investigation report identifying the causes and as appropriate, any action required to improve the performance of each feeder to the *individual feeder standards*; and

(c) complete any actions identified in the investigation report to improve the performance of each feeder to the *individual feeder standards* by the end of the third quarter following the quarter in which each feeder first exceeded the *individual feeder standards.*

16.3 The investigation report is to include a documented rectification plan where action is found to be warranted in order to improve the performance of a feeder to the *individual feeder* standards. The action that is required may involve work to other network elements, or may involve only repair or maintenance work where capital works are not warranted taking into account any one-off events and previous performance trends.

16.4 The requirements under this condition 16 take effect from 1 October 2005, for the 12 month period ending on 30 September 2006.

17. Customer service standards

17.1 A licence holder must pay the sum of $80 (including GST) to a customer where the licence holder exceeds the *interruption duration standard* at the customer's premises and the customer has made a claim to the licence holder within three months of the interruption.

17.2 A licence holder must pay the sum of $80 (including GST) to a customer where the licence holder exceeds the *interruption frequency standard* at the customer's premises in a *financial year* and the customer has made a claim to the licence holder within three months of the end of the *financial year* to which the interruptions relate.

17.3 A licence holder is required to make payments under this condition within one month of receipt of a valid claim.

17.4 A licence holder is required to take reasonable steps (such as publishing information on its website and annually writing to customers) to make customers aware of the availability of payments under condition 17. A licence holder is required to advise customers in writing of the terms of condition 17 before it comes into effect.

17.5 A licence holder is required to make only one payment of $80 to a customer per premises in a financial year for exceeding the *interruption frequency standard.*

17.6 A licence holder is required to pay no more than $320 under condition 17 to a customer per premises in any one financial year.

17.7 A payment under this condition does not:

(a) In any way alter or diminish any rights that a customer may have against any person under any trade practices or other applicable legislation, common law or contract;

(b) Represent any admission of legal liability by the licence holder; or

(c) Alter, vary or exclude the operation of the section 119 of the new *National Electricity Law* or any other statutory limitations on liability or immunities applicable to a licence holder.

17.8 The requirements under this condition 17 (aside from condition 17.4) take effect from 1 July 2006.

18. Performance monitoring and reporting

Design planning criteria report

18.1 Subject to Clause 18.17 a licence holder must submit an annual *design planning criteria* report to the Minister by 30 September each year in relation to the following matters:

(a) each of its *network elements* or classes of network elements that did not comply with the *design planning criteria* in Schedule 1 on 1 July of the relevant year;

(b) the remedial action that it intends to take to ensure compliance of those feeders and substations with the *design planning criteria* in Schedule 1; and

(c) any other matter formally notified by the Minister in writing.

Reliability standards report

18.2 Subject to clause 18.17 a licence holder must submit a quarterly reliability standards report to the Minister within one month of the end of each *quarter*.

18.3 Subject to clause 18.17 each reliability standards report must include the following matters for the preceding *quarter* and for the previous 12 month period to the end of that *quarter*:

(a) performance against the *SAIDI average standards* and *SAIFI average standards* by *feeder type*, disregarding *excluded interruptions*;

(b) reasons for any non-compliance by the licence holder with the *reliability standards* and plans to improve performance; and

(c) any other matter formally notified by the Minister in writing.

Individual feeder standards report

18.4 Subject to clause 18.17 a licence holder must submit, within one month of the end of each *quarter*, a quarterly *individual feeder standards* report to the Minister on feeders that did not comply with the *individual feeder standards* during the previous 24 month period, together with, for each feeder:

(a) the date at which the feeder first failed to comply, together with the actual *SAIDI* and *SAIFI* performance of the feeder;

(b) details of the remedial action that the licence holder intends taking, or has taken, to improve the performance of those feeders; and

(c) the date of completion of the remedial action plan, and the actual *SAIDI* and *SAIFI* performance of the feeder during the 12 month period following completion of the remedial action.

Customer service standards report

18.5 Subject to clause 18.17 a licence holder must submit a quarterly customer service standards report to the Minister on the following matters within one month of the end of each *quarter*, for the preceding *quarter* and for the previous 12 month period to the end of that *quarter:*

(a) the number of payments given under condition 17 to customers serviced from each feeder type;

(b) the number of claims under condition 17 by category; and

(c) the number of rejected claims under condition 17 by category.

Major incident reporting

18.6 A licence holder must report to the Minister within 24 hours any major network incidents involving significant injury to persons, loss of property or widespread supply interruptions (e.g. involving the simultaneous interruption of numerous high voltage feeders or the loss of electricity to one or more sections of distribution busbar). High level severity incidents should be advised immediately.

Independent audit report

18.7 Subject to clause 18.17, an independent audit must be conducted after the end of each financial year to audit the licence holder's performance against the:

(a) *design planning criteria;*

(b) *reliability standards*;

(c) *individual feeder standards*; and

(d) *customer service standards.*

18.8 A licence holder is required to nominate a person to conduct the independent audit by notice in writing to IPART. The licence holder must give notice in accordance with any time specified by IPART in writing to the licence holder, or, if no time has been specified, no later than 1 July of the year in which the report is to be submitted to the Minister and IPART.

18.9 The person nominated is to be a person who is:

(a) independent of the licence holder; and

(b) competent to exercise the functions of an auditor in respect of the matters to be audited.

18.10 The nomination of an auditor by a licence holder ceases to have effect if IPART advises the licence holder, by notice in writing, that the nomination is not acceptable or has ceased to be acceptable.

18.11 IPART may nominate an auditor to carry out an audit, and the person so nominated is taken to have been nominated by the licence holder, if:

(a) the nomination of an auditor by the licence holder ceases to have effect; or

(b) the licence holder fails to nominate an auditor to carry out the audit in accordance with any requirements specified by IPART by notice in writing to the licence holder.

18.12 Subject to clause 18.17 a licence holder must provide a copy of the auditor's report by 30 September each year to IPART and the Minister.

General matters concerning reports

18.13 Where the Minister determines the format of a report required by this condition, a licence holder must submit the report in that format.

18.14 The Minister may from time to time establish guidelines to be followed by the licence holder in complying with reports required by this condition and the licence holder must comply with any such guidelines.

18.15 The Minister may from time to time require, by notice in writing to the licence holder, further reports relating to these licence conditions including, without limitation, reports relating to capital expenditure works, network refurbishment and maintenance programs.

18.16 A licence holder must provide a report submitted to the Minister under this condition to IPART, if requested to do so by IPART by notice in writing.

Timing of initial reports

18.17 To allow adequate time to adopt appropriate systems, reports until 1 July 2007 shall be made under the Electricity Supply (Safety and Network Management) Regulation 2002. From 1 July 2007 reports against the new standards will be submitted as follows:

(a) Within three months of the end of each financial year on compliance with *design planning criteria*, the first being by 30 September 2007;

(b) Within three months of the end of each financial year, for each annual audit report, the first being by 30 September 2007; and

(c) Within one month of the end of each quarter for reports on *reliability standards*, *individual feeder standards* and *customer service standards*, the first being by 31 July 2007.

19 Interpretation and definitions

19.1 These licence conditions are imposed by the Minister pursuant to item 6(1)(b) of Schedule 2 of the Act.

19.2 These licence conditions are in addition to other licence conditions imposed by the Minister, licence conditions under the Act or Regulations, and other obligations imposed on licence holders by the Act and Regulations.

19.3 These conditions are imposed on 1 August 2005 and take effect from that date, except where otherwise stated in the conditions or the Schedules to the conditions.

19.4 Expressions used in these licence conditions that are defined in the Act or the Regulations made under the Act have, unless otherwise stated, the meanings set out in the Act or the Regulations.

19.5 In these licence conditions:

Act	means the *Electricity Supply Act 1995.*
Best practice repair time	means the minimum practicable time period to restore supply.
CBD feeder	means a feeder supplying predominantly commercial high-rise buildings, supplied by the Sydney triplex underground distribution network
customer	means a wholesale customer or a retail customer in the licence holder's distribution district.
design planning criteria	means the load magnitude, security standard and customer interruption time specified in Schedule 1 to these conditions.

distribution feeder	means a high-voltage line operating over 1000V and at or below 22kV that connects between a zone substation and a distribution substation, excluding short radial sections off the trunk feeder used to supply a small number of distribution substations (e.g. a spur line into a peninsula or valley).
distribution substation	means a *substation* forming part of the distribution system, which provides the network link between a *distribution feeder* and elements of the distribution system below 1000V.
excluded interruptions	means excluded interruptions listed in Schedule 4 to these conditions.
feeder	means a *distribution feeder.*
feeder type	means a *CBD feeder*, *long-rural feeder*, *short-rural feeder* or *urban feeder* as the case may be.
financial year	means a year commencing 1 July and ending 30 June.
Greater Sydney Metropolitan Area	the region bounded by, and including: ▪ Kiama, Shellharbour, Wollongong, Campbelltown, Camden, Liverpool, Penrith, Hawkesbury, Gosford, Wyong, Lake Macquarie, Newcastle and Maitland local government areas; and ▪ the east coast of New South Wales.
GST	has the meaning it has in the *A New Tax System (Goods and Services Tax) Act 1999* (Cth).
individual feeder standards	means the individual feeder standards in Schedule 3 to these conditions.
interruption	means any temporary unavailability of electricity supply to a customer associated with an outage of the distribution system including outages affecting a single premises, but does not include disconnection.
interruption duration standards	means the interruption duration standards set out in Schedule 5 to these conditions.
interruption frequency standards	means the interruption frequency standards set out in Schedule 5 to these conditions.

IPART	means the Independent Pricing and Regulatory Tribunal established under the *Independent Pricing and Regulatory Tribunal Act 1992*.
licence holder	means the holder of a distribution network service providers' licence.
load-at-risk	means the difference between the load and the maximum supportable load following a credible contingency.
long rural feeder	means a feeder with a total feeder length greater than 200 km which is not a *CBD feeder* or an *urban feeder*.
major event day	means a day determined under Schedule 6.
metro rural	means all areas within the *Greater Sydney Metropolitan Area* other than *metro urban* areas.
metro urban	means urban areas within the *Greater Sydney Metropolitan Area* with a population exceeding 5,000.
Minister	means the Minister administering the Act.
MVA	means mega volt amperes.
N-1, N-2	N-1 is designing for one unplanned system element contingency outage and N-2 is designing for two. An unplanned contingency outage will result in: ▪ *Interruption* to customers up to the time indicated; ▪ Acceptable voltage levels being maintained at the secondary busbars of transformers; ▪ Remaining in-service elements being loaded within their thermal limits. This standard is based on consideration of credible contingencies generally limited to major plant with either significant failure rates and/or requiring routine outages for maintenance e.g. zone transformers
network elements	means the following parts of a licence holder's distribution system: *sub-transmission lines, sub-transmission substations, zone substations, distribution feeders and distribution substations.*

non-metro rural	means all areas outside of the *Greater Sydney Metropolitan Area* other than *non-metro urban* areas.
non-metro urban	means any urban area outside of the *Greater Sydney Metropolitan Area* with a population exceeding 5,000.
planned interruption	means an *interruption* for which advance notice has been provided or which has been requested by a customer.
quarter	means a period of three months commencing 1 January, 1 April, 1 July and 1 October as the case may be.
regional centre	means: until 30 June 2012, the towns of Tweed Heads, Wagga Wagga, Coffs Harbour (including Sawtell), Albury, Port Macquarie, Queanbeyan, Orange, Tamworth, Dubbo, Bathurst and Lismore; and also: from 1 July 2012, the additional towns of Goulburn, Forster-Tuncurry, Armidale, Broken Hill, Grafton, Griffith, Ballina and Taree.
Regulations	means Regulations made under the Act.
regulatory period	means the period for which the economic regulator provides for a price path for network income and for the purpose of this document will be taken to be a period of five years.
reliability standards	means the requirements imposed under condition 15 of these conditions.
SAIDI	means the sum of the duration of each sustained customer interruption (measured in minutes), divided by the total number of customers (averaged over the *financial year*) of the licence holder.
SAIFI	means the total number of sustained customer interruptions divided by the total number of customers (averaged over the *financial year*) of that licence holder.
SAIDI average standards	means the standards set out in item 1, Schedule 2.
SAIFI average standards	means the standards set out in item 2, Schedule 2.

SAIDI individual feeder standards	means the standards set out in item 1, Schedule 3.
SAIFI individual feeder standards	means the standards set out in item 2, Schedule 3.
short-rural feeder	means a feeder with a total feeder route length less than 200 km, and which is not a *CBD feeder* or an *urban feeder*.
substation	means a part of an electrical network, confined to a given area, mainly including ends of transmission or distribution lines, electrical switchgear and control gear, and one or more transformers. A substation generally includes safety or control devices (for example protection).
sub-transmission	means those parts of the distribution system (including power lines and towers, cables and substations as the case may be) that transfer electricity from the regional bulk supply points supplying areas of consumption to individual *zone substations*, operating at nominal voltages between 132 kV and 33 kV inclusive, that may also fulfil a transmission role by operating in parallel to, and providing support to, the higher voltage transmission network.
table 1	means the table in Schedule 5 to these conditions.
third party	does not include a person or body contracted or authorised by the licence holder to take action, or any animal or plant life.
urban feeder	means a feeder with actual maximum demand over the reporting period per total feeder route length greater than 0.3 MVA/km and which is not a *CBD Feeder*, *short-rural* feeder or *long-rural feeder*.
zone substation	means a *substation* forming part of the distribution system, which provides the network link between the *sub-transmission* network and elements of the distribution system at or below 22kV.

SCHEDULE 1
DESIGN PLANNING CRITERIA

Network Element	**Load Type**	**Load Magnitude**	**From 1 July 2009 (all *network elements*) 1 July 2007 to 30 June 2009 (new *network elements*)**	
			Security Standard	**Customer Interruption Time**
Sub Transmission Line	CBD[1]	Any	N-2	< 1 minute (1st outage); <1 hour (2nd outage)
	Urban & Non-Urban[2]	≥ 5 MVA	N-1	< 1 minute
	Non-Urban[2]	< 5 MVA	N	*Best practice repair time*
Sub Transmission Substation	CBD[1, 3]	Any	N-2	< 1 minute (1st outage); <1 hour (2nd outage)
	Urban & Non-Urban[3]	Any	N-1	< 1 minute
Zone Substation	CBD[1, 3]	Any	N-2	< 1 minute (1st outage); <1 hour (2nd outage)
	Urban & Non-Urban[2, 3]	≥ 5 MVA	N-1	< 1 minute
	Non-Urban[2]	< 5 MVA	N	*Best practice repair time*
Distribution Feeder	CBD[1, 6]	Any	N-1	< 1 minute
	Urban (town ≥ 15,000[4])[5]	Any	N-1	< 4 Hours
	Urban (town < 15,000[4])	Any	N	*Best practice repair time*
	Non-Urban	Any	N	*Best practice repair time*
Distribution Substation	CBD[1]	Any	N-1	< 1 minute
	Urban & Non-Urban	Any	N	*Best practice repair time*

1. CBD means the Sydney central business district only.
2. For Integral Energy Australia, 5MVA is replaced by 10MVA until 30 June 2014. For Country Energy, 5MVA is replaced by 15MVA.
3. In any *financial year*, *load-at-risk* is permitted where the probability is <1% that load may not be able to be sustained following a failure. This applies except :
   a. for sub-transmission and Sydney CBD zone substations, all *load-at-risk* must be eliminated from 30 June 2012;
   b. for all other zone substations ≥20MVA, all *load-at-risk* must be eliminated within the next two *regulatory periods* following the present *regulatory period*;
4. For Country Energy, "town ≥ 15,000" is replaced by "*regional centres"* and "town < 15,000" is replaced by "other than *regional centres"*
5. This standard does not apply to interim supplies to developments prior to completion of the development. The timeframe is expected based on the need to carry out 3-5 manual field switching operations and does not apply in cases of numerous coincident outages (e.g. during major storms), traffic gridlock or other factors outside the control of the electricity distributor. For Integral Energy Australia existing urban *distribution feeders* must comply by the end of the next *regulatory period* following the present *regulatory period.*
6. The actual security standard is an enhanced N-1. For a second distribution feeder loss in the CBD, restricted essential load can still be supplied (approximately 50% of peak load; percentage of load at time of outage is dependent on time of year and daily load cycle).

SCHEDULE 2 – RELIABILITY STANDARDS

1. SAIDI average standards

SAIDI – Average Reliability Duration Standards (Minutes per customer)						
EnergyAustralia						
Feeder Type	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**
CBD	60	57	54	51	48	45
Urban	90	88	86	84	82	80
Short-rural	400	380	360	340	320	300
Long-rural	900	860	820	780	740	700
Integral Energy						
Feeder Type	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**
Urban	90	88	86	84	82	80
Short-rural	300	292	284	276	268	260
Long-rural	n/a	n/a	n/a	n/a	n/a	n/a
Country Energy						
Feeder Type	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**
Urban	140	137	134	131	128	125
Short-rural	340	332	324	316	308	300
Long-rural	750	740	730	720	710	700

2. *SAIFI average standards*

SAIFI – Average Reliability Frequency Standards (Number per customer)						
EnergyAustralia						
Feeder Type	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**
CBD	0.35	0.34	0.33	0.32	0.31	0.3
Urban	1.3	1.28	1.26	1.24	1.22	1.2
Short-rural	4.4	4.2	3.9	3.7	3.4	3.2
Long-rural	8.5	8	7.5	7	6.5	6
Integral Energy						
Feeder Type	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**
Urban	1.3	1.28	1.26	1.24	1.22	1.2
Short-rural	2.8	2.76	2.72	2.68	2.64	2.6
Long-rural	n/a	n/a	n/a	n/a	n/a	n/a
Country Energy						
Feeder Type	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**
Urban	2	1.96	1.92	1.88	1.84	1.8
Short-rural	3.3	3.24	3.18	3.12	3.06	3.0
Long-rural	5	4.9	4.8	4.7	4.6	4.5

SCHEDULE 3 – INDIVIDUAL FEEDER STANDARDS

1. SAIDI Individual Feeder Standards

SAIDI – Standards (Minutes per customer)	
EnergyAustralia	
Feeder Type	**Minutes per customer**
CBD	100
Urban	350
Short-rural	1000
Long-rural	1400
Integral Energy	
Feeder Type	**Minutes per customer**
Urban	350
Short-rural	800
*Long-rural**	1200
Country Energy	
Feeder Type	**Minutes per customer**
Urban	400
Short-rural	1000
Long-rural	1400

2. SAIFI Individual Feeder Standards

SAIFI – Standards (Number per customer)	
EnergyAustralia	
Feeder Type	**Number per customer**
CBD	1.4
Urban	4
Short-rural	8
Long-rural	10
Integral Energy	
Feeder Type	**Number per customer**
Urban	4
Short-rural	6.5
*Long-rural**	10
Country Energy	
Feeder Type	**Number per customer**
Urban	6
Short-rural	8
Long-rural	10

SCHEDULE 4 - EXCLUDED INTERRUPTIONS

The following types of *interruptions* (and no others) are *excluded interruptions:*

(a) an *interruption* of a duration of one minute or less;

(b) an *interruption* resulting from:

- (i) load shedding due to a shortfall in generation;
- (ii) a direction or other instrument issued under the *National Electricity Law*, *Energy and Utilities Administration Act 1987*, the *Essential Services Act 1988* or the *State Emergency and Rescue Management Act 1989* to interrupt the supply of electricity;
- (iii) automatic shedding of load under the control of under-frequency relays following the occurrence of a power system under-frequency condition described in the *Power System Security and Reliability Standards* made under the National Electricity Rules;
- (iv) a failure of the shared *transmission system*;

(c) a *planned interruption*;

(d) any *interruption* to the supply of electricity on a licence holder's distribution system which commences on a *major event day*; and

(e) an *interruption* caused by a customer's electrical installation or failure of that electrical installation.

SCHEDULE 5 – CUSTOMER SERVICE STANDARDS

Interruption duration standard:

1. The *interruption duration standard* is the maximum duration, set out in column 2 of *table 1*, of an *interruption* to a customer's *premises* located in the relevant area in column 1 of *table 1*

Interruption frequency standard:

2. The *interruption frequency standard* is the maximum number of *interruptions* in a financial year set out in column 3 of *table 1*, to a customer's premises located in the relevant area in column 1 of *table 1*:

Table 1

Column 1	Column 2	Column 3	
Type of area in which customer's premises is located	***Interruption duration standard*** **(hours)**	***Interruption frequency standard*** **(number of interruptions)**	
		From 1 July 2006 to 30 June 2008	**After 1 July 2008**
Metro urban	10	9	6
Metro rural	18	15	12
Non-metro urban	18	12	9
Non-metro rural	24	20	15

Interruptions to be disregarded

3. In calculating the *interruption duration standard* or the *interruption frequency standard* the following types of *interruptions* (and no others) are excluded:

   (a) an *interruption* of a duration of one minute or less;

   (b) an *interruption* resulting from the following external causes:

      (i) a shortfall in generation;

      (ii) a failure or instability of the shared *transmission system*;

      (iii) a request or direction from the State Emergency Service; or

      (iv) a failure of another licence holder's *distribution system.*

   (c) a *planned* interruption;

(d) an *interruption* within a region in which a natural disaster has occurred and:

(i) the Minister responsible for administering the *State Emergency Service Act* has notified the Commonwealth of the occurrence of an eligible disaster under the *Natural Disaster Relief Arrangements* in respect of that natural disaster for that region; and

(ii) the *interruption* occurred during the period for which the *Natural Disaster Relief Arrangements* have been notified.

(e) an interruption caused by a storm which is categorised by the Bureau of Meteorology as a "severe storm".

(f) an interruption caused by *third party* actions other than animal or vegetation interference (e.g. vehicle-hit-pole, vandalism) where the interruption is not also caused by any failure of the licence holder to comply with relevant plans, codes, guides or standards (e.g. low conductor clearance).

SCHEDULE 6 – MAJOR EVENT DAY

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Explanation and Purpose

The following process ("**Beta Method**") is used to identify *major event days* which are to be excluded from the *reliability standards* and *individual feeder standards.*

Its purpose is to allow major events to be studied separately from daily operation, and in the process, to better reveal trends in a daily operation that would be hidden by the large statistical effect of major events.

A *major event day* under the Beta Method is one in which the daily total system (i.e. not on a *feeder type* basis) *SAIDI* value ("**daily *SAIDI* value**") exceeds a threshold value, T_{MED}. The *SAIDI* is used as the basis of determining whether a day is a *major event day* since it leads to consistent results regardless of utility size and because *SAIDI* is a good indicator of operational and design stress.

In calculating the daily total system *SAIDI*, any *interruption* that spans multiple days is deemed to accrue on the day on which the *interruption* begins. That is, all minutes without supply resulting from an *interruption* beginning on a *major event day* are deemed to have occurred in the *major event day*, including those minutes without supply occurring on following days.

Determining a major event day

The *major event day* identification threshold value T_{MED} is calculated at the end of each *financial year* for each *DNSP* for use during the next *financial year* as follows:

a) Collect daily *SAIDI* values for the last five *financial years.* If fewer than five years of historical data are available, use all available historical data for the lesser period.

b) Only those days that have a daily *SAIDI* value will be used to calculated the T_{MED} (i.e. days that did not have any *interruptions* are not included).

c) Take the natural logarithm (ln) of each daily *SAIDI* value in the data set.

d) Find α (Alpha), the average of the logarithms (also known as the log-average) of the data set.

e) Find β (Beta), the standard deviation of the logarithms (also knows as the log-standard deviation) of the data set.

f) Complete the major event day threshold T_{MED} using the following equation:

$$T_{MED} = e^{(\alpha + 2.5\beta)}$$

g) Any day with daily *SAIDI* value greater than the threshold value T_{MED} which occurs during the subsequent *financial year* is classified as *a major event day.*

Treatment of a major event day

To avoid doubt, a *major event day*, and all *interruptions* beginning on that day, are excluded from the calculation of a *DNSP's SAIDI* and *SAIFI* in respect of all of its *feeder types.*

DESIGN, RELIABILITY AND PERFORMANCE

LICENCE CONDITIONS

for

DISTRIBUTION NETWORK SERVICE PROVIDERS

Ian Macdonald, MLC
MINISTER FOR ENERGY

1 DECEMBER 2007

EXPLANATORY NOTE

Purpose of the design, reliability and performance conditions:

On 1 August 2005, the then Minister for Energy imposed additional conditions relating to reliability performance on licences held by distribution network service providers under the *Electricity Supply Act 1995*.

Following a review of the licence conditions conducted by the *Minister*, those conditions are being replaced with updated and revised conditions relating to reliability performance, with effect from 1 December 2007.

The purpose of the conditions is to facilitate the delivery of a safe and reliable supply of electricity. The conditions impose design, reliability and performance standards on distribution network service providers. Distribution network service providers will be required to report to the *Minister* to ensure compliance with the conditions. The new standards are as follows:

Design planning criteria:

The *design planning criteria* set out:

- input standards to be used by a *licence holder* in planning its network; and
- requirements for load-forecasting and contingency-planning methodologies intended to achieve operational outcomes.

The baseline levels of planned redundancy required under the *design planning criteria* will underpin the *licence holder*'s plans and strategies designed to ensure, as far as is reasonably practicable, that it:

- meets the *reliability standards*; and
- provides an adequate supply of electricity with an appropriate level of redundancy, consistent with its regulatory obligations.

Reliability standards:

The purposes of the *reliability standards* are to:

- define minimum average reliability performance, by *feeder type*, for a distribution network service provider across its distribution network; and
- provide a basis against which a distribution network service provider's reliability performance can be assessed.

Individual feeder standards:

The purposes of the *individual feeder standards* are to:

- specify minimum standards of reliability performance for individual feeders;

- require a distribution network service provider to focus continually on improving the reliability of its feeders; and
- enable the reliability performance of feeders to be monitored over time.

Customer service standards:

The purpose of the *customer service standards* is to provide financial recognition to eligible *customers* who have experienced poor reliability of supply from a distribution network service provider.

Commencement:

The licence conditions are imposed by the *Minister* pursuant to item 6(1)(b) of Schedule 2 of the *Electricity Supply Act 1995*. The conditions are imposed on 1 December 2007 and take effect from that date, except where expressly stated otherwise.

Relationship with existing conditions and other obligations:

These conditions are additional to conditions that the *Minister* has previously imposed on licences held by distribution network service providers and licence conditions imposed under the *Electricity Supply Act 1995* and other regulatory instruments, other than the conditions relating to reliability performance imposed by the Minister on 1 August 2005. These conditions replace the design, reliability and performance licence conditions imposed by the Minister on 1 August 2005 (as amended on 1 July 2006).

These conditions are also supplementary to obligations imposed on distribution network service providers by the *Electricity Supply Act 1995*, the *Electricity Supply (General) Regulation 2001*, the *Electricity Supply (Safety and Network Management) Regulation 2002*, and other regulatory instruments.

Network management generally

Network management requires long-term planning, investment decisions and prioritisation of work to ensure, as far as is reasonably practicable, reliable supply. The *licence holder* has discretion to plan its investment for compliance with these licence conditions to suit its individual circumstances.

These conditions do not reduce or alter the responsibility of *licence holders* under their Network Management Plans to assure delivery of a safe and reliable supply. Design Planning Criteria described in these conditions provide minimum standards for various categories of network elements.

Higher standards may apply when it is prudent to do so. Capital investment plans cannot be limited by exclusive adherence to input standards. Key operating and risk management requirements to meet reliability outcomes also need to be addressed when developing capital plans.

Enforcement:

These conditions are enforceable under the *Electricity Supply Act 1995* by *IPART* and the *Minister*. These conditions are not intended to create standards which are enforceable against a *licence holder* by individual *customers*.

Consultation:

Before imposing these conditions the *Minister* undertook consultation with stakeholders including the *licence holders*, *IPART* and the *Minister* administering the *Protection of the Environment Administration Act 1991*. The *Minister* has given due consideration to submissions received during consultation.

Reporting:

Performance and audit reports will be required under these licence condition. Reliability performance reporting will continue to be implemented under the *Electricity Supply (Safety and Network Management) Regulation 2002.*

Review:

It is intended that these licence conditions will be reviewed by the *Minister* by June 2010 with any changes or amendments to become effective from 1 July 2014 to coincide with the commencement of the 2014 - 2019 regulatory period.

The *Minister* may, at his discretion, review the licence conditions at other times in accordance with the *Electricity Supply Act 1995.*

DESIGN, RELIABILITY AND PERFORMANCE CONDITIONS

14. Design planning criteria

14.1 A *licence holder* must develop and implement a plan to comply with the applicable *design planning criteria* in Schedule 1 in relation to all new *network elements* for which planning commences after the commencement of these conditions.

14.2 A *licence holder* must be, in relation to all existing *network elements*:

- as compliant as reasonably practicable with the applicable *design planning criteria* in Schedule 1, except as varied by conditions 14.4 and 14.5, in relation to all *network elements* by 1 July 2014; and
- fully compliant with the applicable *design planning criteria* in Schedule 1, except as varied by conditions 14.4 and 14.5, in relation to all *network elements* by 1 July 2019.

14.3 In undertaking network planning processes, a *licence holder* must adopt methodologies:

- for determining the *forecast demand* and *expected demand* (as applicable); and
- for contingency planning for credible *network element* maintenance and/or failure;

which ensure that, as far as is reasonably practicable, the *thermal capacity* of *network elements* is sufficient to meet the actual load through the *network elements* under the following conditions:

- all *network elements* in service, for *network elements* required to meet *N security standards* in Schedule 1;
- *credible contingencies* involving any one *network element* out of service, for *network elements* required to meet *N-1 security standards* in Schedule 1, except as permitted by Schedule 1; and
- *credible contingencies* involving any two *network elements* out of service, for *network elements* required to meet *N-2 security standards* in Schedule 1, except as permitted by Schedule 1.

14.4 For Country Energy *sub-transmission* lines, 10 *MVA* in Schedule 1 is replaced by 15 *MVA*.

14.5 For Country Energy zone *substations*, 10 *MVA* in Schedule 1 is replaced by 15 *MVA* until 30 June 2014.

14.6 A *licence holder* may only apply higher design planning criteria where the *licence holder* considers it is prudent to do so. When considering what is prudent, the *licence holder* must take into account:

- the costs and benefits of the revised *design planning criteria*;

- the actual configuration and limitations of *the network elements* (which may not be reflected in Schedule 1);
- the specific condition of the *network elements* in service; and
- the likely impact of alternative investment options on the reliability of the *network elements*.

Note: For example very large or geographically and electrically remote zone substations may prudently have N-1 redundancy for all forecast demand levels (rather than 99% of time as described in Schedule 1).

14.7 A *licence holder* may agree with a *customer* to apply higher or lower standards of service at the *customer*'s point of supply than the *design planning criteria* relevant to that *customer*. In cases where negotiations are with developers rather than the ultimate end-use *customer*, the *licence holder* must take into account anticipated end-use *customer* expectations and asset management considerations before agreeing to apply higher or lower standards of service at the *customer's* point of supply. Where a lower standard of service is agreed with a *customer*, compliance with the *design planning criteria* is not required at the *customer's* point of supply.

15. Reliability standards

15.1 Subject to 15.4, a *licence holder* must not, when *excluded interruptions* are disregarded, exceed in a *financial year* the *SAIDI average standards* that apply to its *feeder types*.

15.2 Subject to 15.4, a *licence holder* must not, when *excluded interruptions* are disregarded, exceed in a *financial year* the *SAIFI average standards* that apply to its *feeder types*.

15.3 The requirements under this condition 15 are the *reliability standards* and take effect from 1 December 2007.

15.4 The *reliability standards* for the 6 month period from 1 January 2008 to 30 June 2008, are to be calculated by applying 1/2 of the *SAIDI average standards* and 1/2 of the *SAIFI average standards*.

16. Individual feeder performance

16.1 This condition applies where one or more of the feeders of a *licence holder* exceed the relevant *individual feeder standards* for any 12 month period ending at the end of March, June, September or December, when *excluded interruptions* are disregarded.

16.2 A *licence holder* must:

(a) immediately investigate the causes for each *feeder* exceeding the *individual feeder standards*;

(b) by the end of the quarter following the quarter in which the *feeder* first exceeded the *individual feeder standards*, complete an investigation report identifying the causes and as appropriate, any action required to improve the performance of each feeder to the *individual feeder standards*;

(c) complete any operational actions identified in the investigation report to improve the performance of each feeder to the *individual feeder standards* by the end of the third quarter following the quarter in which each feeder first exceeded the *individual feeder standards*;

(d) except as permitted by condition 16.2(e), where the investigation report identifies actions, other than operational actions, required to improve the performance of each feeder to the *individual feeder standards*, develop a project plan, including implementation timetable, and commence its implementation by the end of the second quarter following the quarter in which the *feeder* first exceeded the *individual feeder standards*;

(e) where non-network solutions would provide acceptable alternative outcomes for *customers* in a more cost-effective manner, these solutions may be adopted where they are separately justified in the investigation report;

(f) ensure that the implementation timetable for the network project plan or alternative non-network solutions is as short as is reasonably practicable.

16.3 The investigation report is to include a documented rectification plan where action is found to be warranted in order to improve the performance of a feeder to the *individual feeder* standards. The action that is required may involve work to other network elements, or may involve only repair or maintenance work where capital works are not warranted taking into account any one-off events and previous performance trends.

16.4 The requirements under this condition 16 take effect from 1 January 2008.

17. Customer service standards

17.1 A *licence holder* must pay the sum of $80 (including GST) to a *customer* where the *licence holder* exceeds the *interruption duration standard* at the *customer*'s premises and the *customer* has made a claim to the *licence holder* within three months of the interruption.

17.2 A *licence holder* must pay the sum of $80 (including GST) to a *customer* where the *licence holder* exceeds the *interruption frequency standard* at the *customer*'s premises in a *financial year* and the *customer* has made a claim to the *licence holder* within three months of the end of the *financial year* to which the interruptions relate.

17.3 A *licence holder* must determine a claim for payment under condition 17, and notify the *customer* of the determination in writing, within one month of receipt of a claim. For *customers* eligible for payment, the notice of determination must include the amount to be paid, the manner of payment and the timing of payment. Where the claim is not paid (whether in part or in full), the notice of determination must include reasons for the decision.

17.4 A *licence holder* is required to take reasonable steps to make *customers* aware of the availability of payments on the terms set out in condition 17. Reasonable steps include, as a minimum, publication of information on the *licence holder's* website and annual newspaper advertisements. On request from a *customer*, a licence holder must provide written information on the availability of payments on the terms set out in condition 17.

17.5 A *licence holder* is required to make only one payment of $80 to a *customer* per premises in a financial year for exceeding the *interruption frequency standard*.

17.6 A *licence holder* is required to pay no more than $320 under condition 17 to a *customer* per premises in any one financial year.

17.7 A payment under this condition does not:

(a) In any way alter or diminish any rights that a *customer* may have against any person under any trade practices or other applicable legislation, common law or contract;

(b) Represent any admission of legal liability by the *licence holder*; or

(c) Alter, vary or exclude the operation of the section 119 of the *National Electricity Law* or any other statutory limitations on liability or immunities applicable to a *licence holder*.

17.8 The requirements under this condition 17 (aside from condition 17.4) take effect from 1 December 2007.

18. Performance monitoring and reporting

Design planning criteria report

18.1 Subject to condition 18.17 a *licence holder* must submit an annual *design planning criteria* report to the *Minister* by 30 September each year in relation to the following matters:

(a) The *licence holder*'s strategy and plan to comply with condition 14 for each class of *network element* in Schedule 1;

(b) Progress against the *licence holder*'s plan for each class of *network element*;

(c) For sub-transmission lines, sub-transmission substations and zone substations, each of its *network elements* that will not, from a planning perspective, comply with condition 14.1 or condition 14.2;

(d) For distribution feeders and substations, a summary report for each class of network element that will not, from a planning perspective, comply with condition 14.1 or condition 14.2; and

(e) any other matter formally notified by the *Minister* in writing.

18.1A Conditions 18.1 (c) and (d) do not apply to *network elements* during routine maintenance, provided planning requirements are met at all other times and the *licence holder*, acting reasonably, schedules routine maintenance (and develops contingency plans) to minimise the impact of outages in the event of a *credible contingency* during routine maintenance.

Reliability standards report

18.2 Subject to condition 18.17 a *licence holder* must submit a quarterly reliability standards report to the *Minister* within one month of the end of each *quarter*.

18.3 Subject to condition 18.17 each reliability standards report must include the following matters for the previous 12 month period to the end of that *quarter*:

(a) performance against the pro-rata *SAIDI average standards* and pro-rata *SAIFI average standards* by *feeder type*, disregarding *excluded interruptions*;

(b) reasons for any non-compliance by the *licence holder* with the pro-rata *reliability standards* and plans to improve performance; and

(c) any other matter formally notified by the *Minister* in writing.

Individual feeder standards report

18.4 Subject to condition 18.17 a *licence holder* must submit, within one month of the end of each *quarter*, a quarterly *individual feeder standards* report to the *Minister* on feeders that exceeded the relevant *individual feeder standards* during the previous 12 month period to the end of that quarter, together with, for each feeder:

(a) the date at which the feeder first exceeded the relevant *individual feeder standard*, together with the actual *SAIDI* and *SAIFI* performance of the feeder for the 12 month period;

(b) details of the remedial action that the *licence holder* intends taking, or has taken, to improve the performance of those feeders; and

(c) the date of completion, or the date of planned completion, of the remedial action plan.

Customer service standards report

18.5 Subject to condition 18.17 a *licence holder* must submit a quarterly *customer service standards* report to the *Minister* on the following matters within one month of the end of each *quarter*, for the preceding *quarter* and for the previous 12 month period to the end of that *quarter:*

(a) the number of payments given under condition 17 to *customer*s by each type of area listed in Column 1 of Table 1 and by the type of standard, as shown in Columns 2 and 3 of Table 1

(b) the number of claims not paid (whether in part or full) under condition 17 by each type of area listed in Column 1 of Table 1 and by the type of standard, as shown in Columns 2 and 3 of Table 1.

Major incident reporting

18.6 A *licence holder* must report to the *Minister* within 24 hours any major network incidents involving significant injury to persons, loss of property or widespread supply interruptions. High level severity incidents are to be advised immediately.

Independent audit report

18.7 Subject to condition 18.17, an independent audit must be conducted after the end of each financial year to audit the *licence holder*'s performance against the:

(a) *design planning criteria;*

(b) *reliability standards*;

(c) *individual feeder standards*; and

(d) *customer service standards*.

18.8 A *licence holder* is required to nominate a person to conduct the independent audit by notice in writing to IPART. The *licence holder* must give notice in accordance with any time specified by IPART in writing to the *licence holder*, or, if no time has been specified, no later than 1 July of the year in which the report is to be submitted to the *Minister* and IPART.

18.9 The person nominated is to be a person who is:

(a) independent of the *licence holder*; and

(b) competent to exercise the functions of an auditor in respect of the matters to be audited.

18.10 The nomination of an auditor by a *licence holder* ceases to have effect if IPART advises the *licence holder*, by notice in writing, that the nomination is not acceptable or has ceased to be acceptable.

18.11 IPART may nominate an auditor to carry out an audit, and the person so nominated is taken to have been nominated by the *licence holder*, if:

(a) the nomination of an auditor by the *licence holder* ceases to have effect; or

(b) the *licence holder* fails to nominate an auditor to carry out the audit in accordance with any requirements specified by IPART by notice in writing to the *licence holder*.

18.12 Subject to condition 18.17 a *licence holder* must provide a copy of the auditor's report by 30 September each year to IPART and the *Minister*.

General matters concerning reports

18.13 Where the *Minister* determines the format of a report required by this condition, a *licence holder* must submit the report in that format.

18.14 The *Minister* may from time to time establish guidelines to be followed by the *licence holder* in complying with reports required by this condition and the *licence holder* must comply with any such guidelines.

18.15 The *Minister* may from time to time require, by notice in writing to the *licence holder*, further reports relating to these licence conditions including, without limitation, reports relating to capital expenditure works, network refurbishment and maintenance programs.

18.16 A *licence holder* must provide a report submitted to the *Minister* under this condition to IPART, if requested to do so by IPART by notice in writing.

Timing of initial reports

18.17 Reports against the new standards will be submitted as follows:

(a) Within three months of the end of each financial year on compliance with *design planning criteria*, the first being by 30 September 2008;

(b) Within three months of the end of each financial year, for each annual audit report, the first being by 30 September 2008; and

(c) Within one month of the end of each quarter for reports on *reliability standards*, *individual feeder standards* and *customer service standards*, the first being by 31 January 2008.

19 Interpretation and definitions

19.1 These licence conditions are imposed by the *Minister* pursuant to item 6(1)(b) of Schedule 2 of the *Act*.

19.2 These licence conditions replace the design, reliability and performance licence conditions imposed by the *Minister* on distribution network service providers on 1 August 2005 (as amended on 1 July 2006).

19.3 These licence conditions are in addition to other licence conditions imposed by the *Minister*, licence conditions under the *Act* or *Regulations*, and other obligations imposed on *licence holder*s by the *Act* and *Regulations*.

19.4 These conditions are imposed on 1 December 2007 and take effect from that date, except where otherwise stated in the conditions or the Schedules to the conditions.

19.5 Expressions used in these licence conditions that are defined in the *Act* or the *Regulations* made under the *Act* have, unless otherwise stated, the meanings set out in the *Act* or the *Regulations*.

19.6 The Explanatory Note to these licence conditions does not form part of the licence conditions.

19.7 Footnotes contained in these licence conditions do form part of the licence conditions.

19.8 In these licence conditions:

Act	means the *Electricity Supply Act 1995.*
Best practice repair time	means the minimum practicable time period to restore supply.
CBD	means the area within the City of Sydney that is supplied by the triplex 11kV cable system.
CBD feeder	means a feeder supplying predominantly commercial high-rise buildings, supplied by the City of Sydney's triplex 11kV cable system.
Credible contingency	means an outage on one line or item of *electrical apparatus*, or a coincident outage on more than one line and /or items of *electrical apparatus* that a *licence holder*, acting reasonably, could expect to arise as a result of a single electrical failure or mechanical event affecting those lines or items. *Note: Credible contingencies are generally limited to major items of equipment with significant probabilities of failure or outage.*

customer	means a wholesale customer or a retail customer in the *licence holder*'s distribution district.
customer service standards	means the customer service standards in Schedule 5 to these conditions.
design planning criteria	means the load magnitude, security standard and customer interruption time specified in Schedule 1 to these conditions.
distribution feeder	means a high-voltage line operating over 1000V and at or below 22kV that connects between a zone substation and a distribution substation, excluding short radial sections off the trunk feeder used to supply a small number of distribution substations (eg a spur line into a peninsula or valley).
distribution substation	means a *substation* forming part of the distribution system, which provides the network link between a *distribution feeder* and elements of the distribution system below 1000V.
electrical apparatus	means a transformer within a *substation*
Emergency service organisation	has the same meaning as in section 3 of the *State Emergency and Rescue Management Act 1989.*
excluded interruptions	means excluded interruptions listed in Schedule 4 to these conditions.
expected demand	means peak demand expected to occur for *distribution feeders* and *distribution substations*, based on: • loads connected or expected to be connected, and/or • actual demand and/or • underlying growth rates
feeder	means a *distribution feeder.*
feeder type	means a *CBD feeder*, *long rural feeder*, *short rural feeder* or *urban feeder* as the case may be.
financial year	means a year commencing 1 July and ending 30 June.
forecast demand	means the *licence holder*'s seasonal peak demand forecast with 50% probability of being exceeded

	(i.e. 1 in 2 years), normally performed on an annual basis, and based on underlying growth rates plus an allowance for spot loads and transfers.
GST	has the meaning it has in the *A New Tax System (Goods and Services Tax) Act 1999* (Cth).
individual feeder standards	means the individual feeder standards in Schedule 3 to these conditions.
interruption	means any temporary unavailability of electricity supply to a *customer* associated with an outage of the distribution system including outages affecting a single premises, but does not include disconnection.
interruption duration standards	means the interruption duration standards set out in Schedule 5 to these conditions.
interruption frequency standards	means the interruption frequency standards set out in Schedule 5 to these conditions.
IPART	means the Independent Pricing and Regulatory Tribunal established under the *Independent Pricing and Regulatory Tribunal Act 1992.*
licence holder	means the holder of a distribution network service provider's licence.
local government area	has the same meaning as in the *Local Government Act 1993*
long rural feeder	means a feeder with a total feeder length greater than 200 km which is not a *CBD feeder* or an *urban feeder.*
major event day	means a day determined under Schedule 6.
metropolitan	means the areas comprising the *local government areas* and *suburbs* listed in Schedule 7
Minister	means the Minister administering the *Act.*
MVA	means mega volt amperes.
N, N-1, N-2	N is designing the *network elements* for no *credible contingencies;* N-1 is designing for a single *credible contingency* (normally involving an outage of one line or one item of *electrical*

	apparatus within a *substation*) and N-2 is designing for *credible contingencies* (normally involving outages of two lines or two items of *electrical apparatus* within a *substation*). The relevant number of *credible contingencies* will result in: ▪ *interruption* to *customer*s up to the time indicated in Schedule 1; ▪ acceptable voltage levels being maintained at the secondary busbars of transformers; ▪ remaining in-service *network elements* and *electrical apparatus* being loaded within their thermal limits.
network elements	means the following parts of a *licence holder*'s distribution system: *sub-transmission lines, sub-transmission substations, zone substations, distribution feeders and distribution substations*.
non-metropolitan	means areas in New South Wales other than areas defined as *metropolitan*
non-urban	means areas which are not *urban*.
planned interruption	means an *interruption* for which advance notice has been provided or which has been requested by a *customer*.
quarter	means a period of three months commencing 1 January, 1 April, 1 July and 1 October as the case may be.
regional centre	means: until 30 June 2014, the towns of Tweed Heads, Wagga Wagga, Coffs Harbour (including Sawtell), Albury, Port Macquarie, Queanbeyan, Orange, Tamworth, Dubbo, Bathurst and Lismore; and from 1 July 2014, the towns listed above as well as the towns of Goulburn, Forster-Tuncurry, Armidale, Broken Hill, Grafton, Griffith, Ballina and Taree.
Regulations	means Regulations made under the *Act*.
regulatory period	means the period for which the economic regulator provides for a price path for network income and for the purpose of this document will be taken to be a period of five years.

reliability standards	means the requirements imposed under condition 15 of these conditions.
SAIDI	means the sum of the duration of each sustained *customer* interruption (measured in minutes), divided by the total number of *customers* (averaged over the *financial year*) of the *licence holder*.
SAIFI	means the total number of sustained *customer* interruptions divided by the total number of *customers* (averaged over the *financial year*) of that *licence holder*.
SAIDI average standards	means the standards set out in item 1, Schedule 2.
SAIFI average standards	means the standards set out in item 2, Schedule 2.
SAIDI individual feeder standards	means the standards set out in item 1, Schedule 3.
SAIFI individual feeder standards	means the standards set out in item 2, Schedule 3.
Security Standards	means the *Security Standards* specified in Schedule 1 which require the network to be planned to supply all *forecast demand* or *expected demand* (as applicable), except where varied by the notes to Schedule 1, within the *thermal capacity* of all *network elements* and maintain voltage levels within limits published by *licence holders* with: • all lines and *electrical apparatus* in service, N • outages of lines and *electrical apparatus* arising from any one *credible contingency* N-1 • outages of lines and *electrical apparatus* arising from any two *credible contingencies*, N-2
Severe thunderstorm or Severe weather	*means an event set out in Column 2 or Column 3 of table 2*
short rural feeder	means a feeder with a total feeder route length less than 200 km, and which is not a *CBD feeder* or an *urban feeder*.
suburb	means an area defined by boundaries determined and gazetted by the Geographical Names Board of New South Wales.

substation	means a part of an electrical network, confined to a given area, mainly including ends of transmission or distribution lines, electrical switchgear and control gear, and one or more transformers. A substation generally includes safety or control devices (for example protection).
sub-transmission	means those parts of the distribution system (including power lines and towers, cables and substations as the case may be) that transfer electricity from the regional bulk supply points supplying areas of consumption to individual *zone substations*, operating at nominal voltages between 132 kV and 33 kV inclusive, that may also fulfil a transmission role by operating in parallel to, and providing support to, the higher voltage transmission network.
sub-transmission line – Overhead	means *sub-transmission* generally of overhead construction which would reasonably be expected to have a restoration time of less than 8 hours following a *credible contingency.*
sub-transmission line – Underground	means *sub-transmission* generally of underground construction, or *sub-transmission overhead* with a section of underground construction which would reasonably be expected to have a restoration time in excess of 8 hours following a *credible contingency.*
table 1	means Table 1 in Schedule 5 to these conditions.
table 2	means Table 2 in Schedule 5 to these conditions.
thermal capacity	means the maximum allowable thermal capability of a particular *network element*, taking into consideration the supply security level (N, N-1, N-2) required of the *network element(s)* and having regard to the technical and economic life of the *network element(s)*. When considering *thermal capacity* of more than one *network element* operating in parallel, the actual load sharing characteristics of the parallel network elements should be considered.
third party	does not include a person or body contracted or authorised by the *licence holder* to take action, or any animal or plant life.

urban feeder	means a feeder with actual maximum demand over the reporting period per total feeder route length greater than 0.3 *MVA*/km and which is not a *CBD Feeder*.
urban	For EnergyAustralia and Integral Energy, means an area where the majority of land is zoned for residential and/or commercial and/or industrial use within a town or city type of area which is contiguous with other similar town or city areas with an aggregated population of at least 5,000 people. For Country Energy, means areas within a *regional centre*.
zone substation	means a *substation* forming part of the distribution system, which provides the network link between the *sub-transmission* network and elements of the distribution system at or below 22kV.

SCHEDULE 1 DESIGN PLANNING CRITERIA

Network Element	***Load Type***	***Forecast Demand or Expected Demand***	***Security Standard***	***Customer Interruption Time***
Sub Transmission Line	CBD	Any	N-2[6]	Nil for 1st credible contingency <1 hr for 2nd credible contingency
	Urban & Non-Urban	≥ 10 *MVA*	N-1[1]	< 1 minute
	Urban & Non-Urban	< 10 *MVA*	N[2]	*Best practice repair time*
Sub Transmission Substation	CBD	Any	N-2[6]	Nil for 1st credible contingency <1 hr for 2nd credible contingency
	Urban & Non-Urban	Any	N-1	< 1 minute
Zone Substation	CBD	Any	N-2[6]	Nil for 1st credible contingency <1 hr for 2nd credible contingency
	Urban & Non-Urban	≥ 10*MVA*	N-1[1]	< 1 minute
	Urban & Non-Urban	< 10 *MVA*	N[2]	*Best practice repair time*
Distribution Feeder	CBD	Any	N-1[3]	Nil
	Urban	Any	N-1[4]	< 4 Hours[5]
	Non-Urban	Any	N	*Best practice repair time*
Distribution Substation	CBD	Any	N-1[3]	Nil
	Urban & Non-Urban	Any	N[7]	*Best practice repair time*

1. For a *Sub-transmission line - Overhead* and a Zone Substation:
   a. under N-1 conditions, the *forecast demand* is not to exceed the *thermal capacity* for more than 1% of the time i.e. a total aggregate time of 88 hours per annum, up to a maximum of 20% above the *thermal capacity* under N-1 conditions. For Country Energy, in other than regional centres, the *forecast demand* must not exceed the *thermal capacity* under N-1 conditions.
   b. under N conditions, a further criterion is that the *thermal capacity* is required to meet at least 115% of forecast demand.

   For a *Sub-transmission line – Underground*, any overhead section may be designed as if it was a *Sub-transmission line – Overhead*, providing the *forecast demand* does not exceed the *thermal capacity* of the underground section at any time under N-1 conditions.

2. Under N conditions, *thermal capacity* is to be provided for greater than 115% of *forecast demand.*

3. The actual *Security Standard* is an enhanced N-1. For a second coincident credible contingency on the CBD triplex system, restricted essential load can still be supplied.

4. By 30 June 2014, expected demand is to be no more than 80% of feeder *thermal capacity* (under system normal operating conditions) with switchable interconnection to adjacent feeders enabling restoration for an unplanned *network element* failure. By 30 June 2019, *expected demand* is to be no more than 75% of feeder *thermal capacity*. In order to achieve compliance, feeder reinforcement projects may need to be undertaken over more than one *regulatory period*. In those cases where a number of feeders form an interrelated system (such as a meshed network), the limits apply to the average loading of the feeders within the one system.

5. The timeframe is expected only, and is based on the need to carry out the isolation and restoration switching referred to in note 4. This standard does not apply to interim/staged supplies, i.e. prior to completion of the entire development or to *excluded interruptions* outside the control of the *licence holder*.

6. In the *CBD* area, N-2 equivalent is achieved by the network being normally configured on the basis of N-1 with no interruption of supply when any one line or item of *electrical apparatus* within a *substation* is out of service. The *licence holder* must plan the *CBD* network to cater for two *credible contingencies* involving the loss of multiple lines or items of electrical apparatus within a substation, by being able to restore supply within 1 hour. Restoration may be via alternative arrangements (e.g. 11kV interconnections).

7. Urban Distribution substations shared, or available to be shared, by multiple *customers* are generally expected to have some level of redundancy for an unplanned contingency, eg via low voltage manual interconnection to adjacent substations enabling at least partial restoration.

SCHEDULE 2 – RELIABILITY STANDARDS

1. SAIDI average standards

SAIDI – Average Reliability Duration Standards (Minutes per *customer*)						
EnergyAustralia						
Feeder Type	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**From 2010/11**
CBD	60	57	54	51	48	45
Urban	90	88	86	84	82	80
Short-rural	400	380	360	340	320	300
Long-rural	900	860	820	780	740	700
Integral Energy						
Feeder Type	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**From 2010/11**
Urban	90	88	86	84	82	80
Short-rural	300	300	300	300	300	300
Long-rural	n/a	n/a	n/a	n/a	n/a	n/a
Country Energy						
Feeder Type	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**From 2010/11**
Urban	140	137	134	131	128	125
Short-rural	340	332	324	316	308	300
Long-rural	750	740	730	720	710	700

2. SAIFI average standards

SAIFI – Average Reliability Frequency Standards (Number per *customer*)						
EnergyAustralia						
Feeder Type	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**From 2010/11**
CBD	0.35	0.34	0.33	0.32	0.31	0.3
Urban	1.3	1.28	1.26	1.24	1.22	1.2
Short-rural	4.4	4.2	3.9	3.7	3.4	3.2
Long-rural	8.5	8	7.5	7	6.5	6
Integral Energy						
Feeder Type	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**From 2010/11**
Urban	1.3	1.28	1.26	1.24	1.22	1.2
Short-rural	2.8	2.8	2.8	2.8	2.8	2.8
Long-rural	n/a	n/a	n/a	n/a	n/a	n/a
Country Energy						
Feeder Type	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**From 2010/11**
Urban	2	1.96	1.92	1.88	1.84	1.8
Short-rural	3.3	3.24	3.18	3.12	3.06	3.0
Long-rural	5	4.9	4.8	4.7	4.6	4.5

SCHEDULE 3 – INDIVIDUAL FEEDER STANDARDS

1. SAIDI Individual Feeder Standards

SAIDI – Standards (Minutes per *customer*)	
EnergyAustralia	
Feeder Type	**Minutes per *customer***
CBD	100
Urban	350
Short-rural	1000
Long-rural	1400
Integral Energy	
Feeder Type	**Minutes per *customer***
Urban	350
Short-rural	1000
Long-rural	1400
Country Energy	
Feeder Type	**Minutes per *customer***
Urban	400
Short-rural	1000
Long-rural	1400

2. SAIFI Individual Feeder Standards

SAIFI – Standards (Number per *customer*)	
EnergyAustralia	
Feeder Type	**Number per *customer***
CBD	1.4
Urban	4
Short-rural	8
Long-rural	10
Integral Energy	
Feeder Type	**Number per *customer***
Urban	4
Short-rural	8
Long-rural	10
Country Energy	
Feeder Type	**Number per *customer***
Urban	6
Short-rural	8
Long-rural	10

SCHEDULE 4 - EXCLUDED INTERRUPTIONS

The following types of *interruptions* (and no others) are *excluded interruptions:*

(a) an *interruption* of a duration of one minute or less;

(b) an *interruption* resulting from:

- (i) load shedding due to a shortfall in generation;
- (ii) a direction or other instrument issued under the *National Electricity Law*, *Energy and Utilities Administration Act 1987*, the *Essential Services Act 1988* or the *State Emergency and Rescue Management Act 1989* to interrupt the supply of electricity;
- (iii) automatic shedding of load under the control of under-frequency relays following the occurrence of a power system under-frequency condition described in the *Power System Security and Reliability Standards* made under the National Electricity Rules;
- (iv) a failure of the shared *transmission system*;

(c) a *planned interruption*;

(d) any *interruption* to the supply of electricity on a *licence holder*'s distribution system which commences on a *major event day*; and

(e) an *interruption* caused by a *customer*'s electrical installation or failure of that electrical installation.

SCHEDULE 5 – CUSTOMER SERVICE STANDARDS

Interruption duration standard:

1. The *interruption duration standard* is the maximum duration, set out in column 2 of *table 1*, of an *interruption* to a customer's premises located in the relevant area in column 1 of *table 1*.

Interruption frequency standard:

2. The *interruption frequency standard* is the maximum number of *interruptions* in a financial year set out in column 3 of *table 1*, to a customer's premises located in the relevant area in column 1 of *table 1*:

Table 1

Column 1	**Column 2**	**Column 3**
Type of area in which customer's premises is located	**Interruption duration standard (hours)**	**Interruption frequency standard (number of interruptions of ≥hours)**
metropolitan	12	4 interruptions ≥ 4 hours
non-metropolitan	18	4 interruptions ≥ 5 hours

Interruptions to be disregarded

3. In calculating the *interruption duration standard* or the *interruption frequency standard* the following types of *interruptions* (and no others) are excluded:

   (a) an *interruption* resulting from the following external causes:

   (i) a shortfall in generation;

   (ii) a failure or instability of the shared *transmission system*;

   (iii) a request or direction from an *emergency service organisation;*

   (b) a *planned* interruption;

   (c) an *interruption* within a region in which a natural disaster has occurred and:

   (i) the responsible Minister has notified the Commonwealth of the occurrence of an eligible disaster under the *Natural Disaster Relief Arrangements* in respect of that natural disaster for that region; and

   (ii) the *interruption* occurred during the period for which *Natural Disaster Relief Arrangements* have been notified;

   (d) an *interruption* caused by the effects of a *severe thunderstorm or severe weather*. These effects may include the necessary operation of a circuit protection device which interrupts supply to *customers* in areas not directly impacted by the *severe thunderstorm or severe weather.*

(e) an *interruption* caused by *third party* actions other than animal or vegetation interference (e.g. vehicle-hit-pole, vandalism) where the interruption is not also caused by any failure of the *licence holder* to comply with relevant plans, codes, guides or standards (e.g. low conductor clearance).

Table 2

Column 1	**Column 2**	**Column 3**
Phenomenon	**Severe Thunderstorm Warning**	**Severe Weather Warning**
Wind (Gusts)	Gusts 90km/h or more	Gusts 90km/h or more
Wind (Average)		Widespread winds over land of 63km/h or more (Gale force)
Tornado	All tornados	
Blizzard		Widespread blizzards in Alpine areas
Flash Flood	Heavy Rainfall that is conducive to flash flooding or a reported flash flood	Heavy Rainfall that is conducive to flash flooding or a reported flash flood
Large Hail	Hail with diameter of at least 2cm	

SCHEDULE 6 – MAJOR EVENT DAY

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Explanation and Purpose

The following process ("**Beta Method**") is used to identify *major event days* which are to be excluded from the *reliability standards* and *individual feeder standards.*

Its purpose is to allow major events to be studied separately from daily operation, and in the process, to better reveal trends in a daily operation that would be hidden by the large statistical effect of major events.

A *major event day* under the Beta Method is one in which the daily total system (i.e. not on a *feeder type* basis) *SAIDI* value ("**daily *SAIDI* value**") exceeds a threshold value, $T_{MED.}$ The *SAIDI* is used as the basis of determining whether a day is a *major event day* since it leads to consistent results regardless of utility size and because *SAIDI* is a good indicator of operational and design stress.

In calculating the daily total system *SAIDI*, any *interruption* that spans multiple days is deemed to accrue on the day on which the *interruption* begins. That is, all minutes without supply resulting from an *interruption* beginning on a *major event day* are deemed to have occurred in the *major event day*, including those minutes without supply occurring on following days.

Determining a major event day

The *major event day* identification threshold value T_{MED} is calculated at the end of each *financial year* for each *DNSP* for use during the next *financial year* as follows:

a) Collect daily *SAIDI* values for the last five *financial years.* If fewer than five years of historical data are available, use all available historical data for the lesser period.

b) Only those days that have a daily *SAIDI* value will be used to calculate the T_{MED} (i.e. days that did not have any *interruptions* are not included).

c) Take the natural logarithm (ln) of each daily *SAIDI* value in the data set.

d) Find α (Alpha), the average of the logarithms (also known as the log-average) of the data set.

e) Find β (Beta), the standard deviation of the logarithms (also known as the log-standard deviation) of the data set.

f) Complete the major event day threshold T_{MED} using the following equation:

$$T_{MED} = e^{(\alpha + 2.5\beta)}$$

g) Any day with daily *SAIDI* value greater than the threshold value T_{MED} which occurs during the subsequent *financial year* is classified as *a major event day.*

Treatment of a major event day

To avoid doubt, a *major event day*, and all *interruptions* beginning on that day, are excluded from the calculation of a *DNSP's SAIDI* and *SAIFI* in respect of all of its *feeder types*.

SCHEDULE 7 – LIST OF METROPOLITAN AREAS		
1. Local Government Areas		
ASHFIELD	HUNTERS HILL	PITTWATER
AUBURN	HURSTVILLE	RANDWICK
BANKSTOWN	KOGARAH	ROCKDALE
BAULKHAM HILLS	KU-RING-GAI	RYDE
BLACKTOWN	LAKE MACQUARIE	SHELLHARBOUR
BOTANY BAY	LANE COVE	STRATHFIELD
BURWOOD	LEICHHARDT	SUTHERLAND
CAMDEN	LIVERPOOL	SYDNEY
CAMPBELLTOWN	MANLY	WARRINGAH
CANTERBURY	MARRICKVILLE	WAVERLEY
CANADA BAY	MOSMAN	WILLOUGHBY
FAIRFIELD	NEWCASTLE	WOLLONGONG
GOSFORD	NORTH SYDNEY	WOOLLAHRA
HOLROYD	PARRAMATTA	WYONG
HORNSBY	PENRITH	

2. Suburbs	
A. *Blue Mountains area*	
BLACKHEATH	LINDEN
BLAXLAND	MEDLOW BATH
BULLABURRA	MOUNT RIVERVIEW
FAULCONBRIDGE	MOUNT VICTORIA
GLENBROOK	SPRINGWOOD
HAWKESBURY HEIGHTS	VALLEY HEIGHTS
HAZELBROOK	WARRIMOO
KATOOMBA	WENTWORTH FALLS
LAPSTONE	WINMALEE
LAWSON	WOODFORD

LEURA	YELLOW ROCK
B. *Cessnock-Bellbird area*	
ABERDARE	CESSNOCK
BELLBIRD	KEARSLEY
BELLBIRD HEIGHTS	NULKABA
C. *Kiama area*	
BOMBO	KIAMA HEIGHTS
KIAMA	MINNAMURRA
KIAMA DOWNS	
D. *Kurri Kurri-Weston area*	
ABERMAIN	PELAW MAIN
HEDDON GRETA	STANFORD MERTHYR
KURRI KURRI	WESTON
NEATH	
E. *Maitland area*	
ABERGLASSLYN	MOUNT DEE
ASHTONFIELD	OAKHAMPTON
BOLWARRA	OAKHAMPTON HEIGHTS
BOLWARRA HEIGHTS	PITNACREE
EAST MAITLAND	RAWORTH
HORSESHOE BEND	RUTHERFORD
LARGS	SOUTH MAITLAND
LORN	TELARAH
LOUTH PARK	TENAMBIT
MAITLAND	THORNTON
METFORD	WOODBERRY
MORPETH	

F. *Newcastle Industrial area*	
FERN BAY	WILLIAMTOWN
FULLERTON COVE	
G. *Port Stephens area*	
CORLETTE	SALAMANDER BAY
FINGAL BAY	SHOAL BAY
NELSON BAY	SOLDIERS POINT
H. *Raymond Terrace area*	
HEATHERBRAE	TOMAGO
RAYMOND TERRACE	
I. *Richmond-Windsor area*	
BLIGH PARK	NORTH RICHMOND
CLARENDON	RICHMOND
HOBARTVILLE	SOUTH WINDSOR
MCGRATHS HILL	VINEYARD
MULGRAVE	WINDSOR

Appendix 8

RAPID RESPONSE

IMPLEMENTING NECESSARY BUT UNPOPULAR CHANGE

Endeavour Energy

BE CLEAR ON DRIVERS

- Reduce fatigue safety risks
- Improve customer response times
- Provide greater equity of overtime earnings
- Provide cost savings

Endeavour Energy

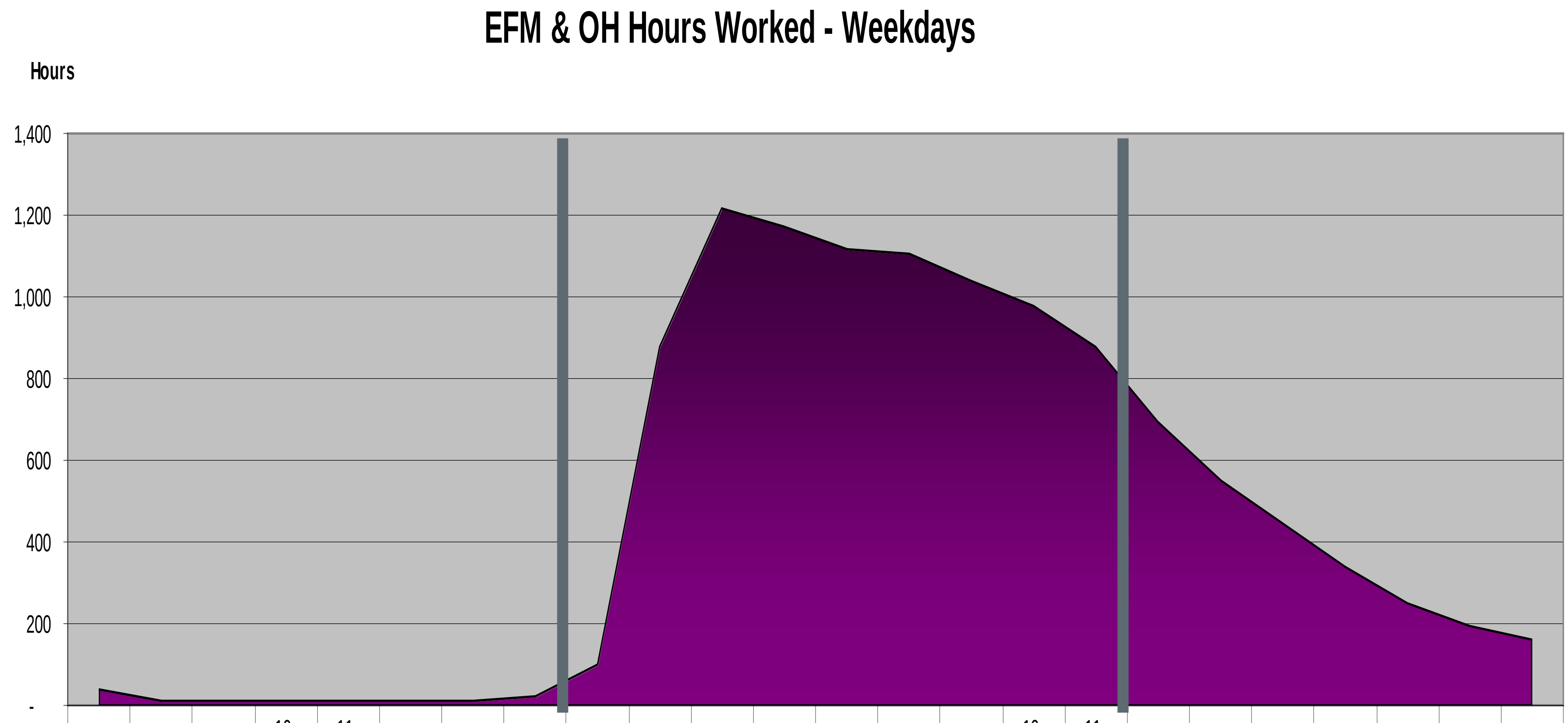
BE PREPARED FOR A ROUGH RIDE

COVERAGE MAP

61% of all Standby Calls within 45min travel of Lighthorse Interchange

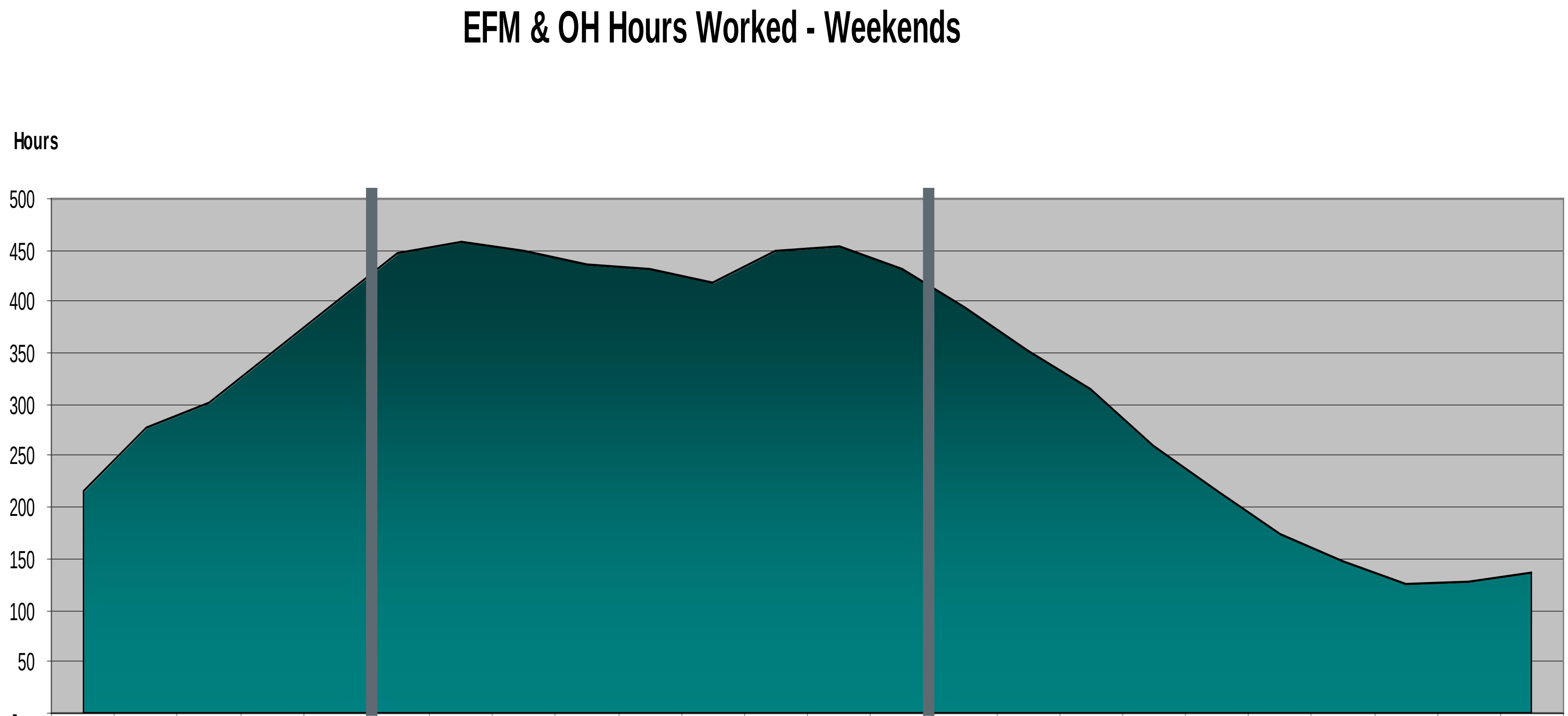
Endeavour Energy

WHEN DOES THE F&E OCCUR?



	7-8am	8-9am	9 -10am	10-11am	11-12pm	12 -1pm	1-2pm	2-3pm	3-4pm	4-5pm	5-6pm	6- 7pm	7-8pm	8-9pm	9-10pm	10-11pm	11-12pm	00-1am	1 - 2am	2-3am	3-4am	4-5am	5-6am	6-7am
Hours Worked	40	12	11	12	10	10	12	21	98	876	1,217	1,175	1,119	1,107	1,038	977	876	697	551	446	340	248	194	159

WHEN DOES THE F&E OCCUR? (WEEKENDS)



	7-8am	8-9am	9 -10am	10-11am	11-12pm	12 -1pm	1-2pm	2-3pm	3-4pm	4-5pm	5-6pm	6- 7pm	7-8pm	8-9pm	9-10pm	10-11pm	11-12pm	00-1am	1 - 2am	2-3am	3-4am	4-5am	5-6am	6-7am
Hours Worked	217	277	301	351	398	447	459	449	436	432	419	449	453	432	395	352	315	260	217	174	147	126	128	137

RAPID RESPONSE ROSTER

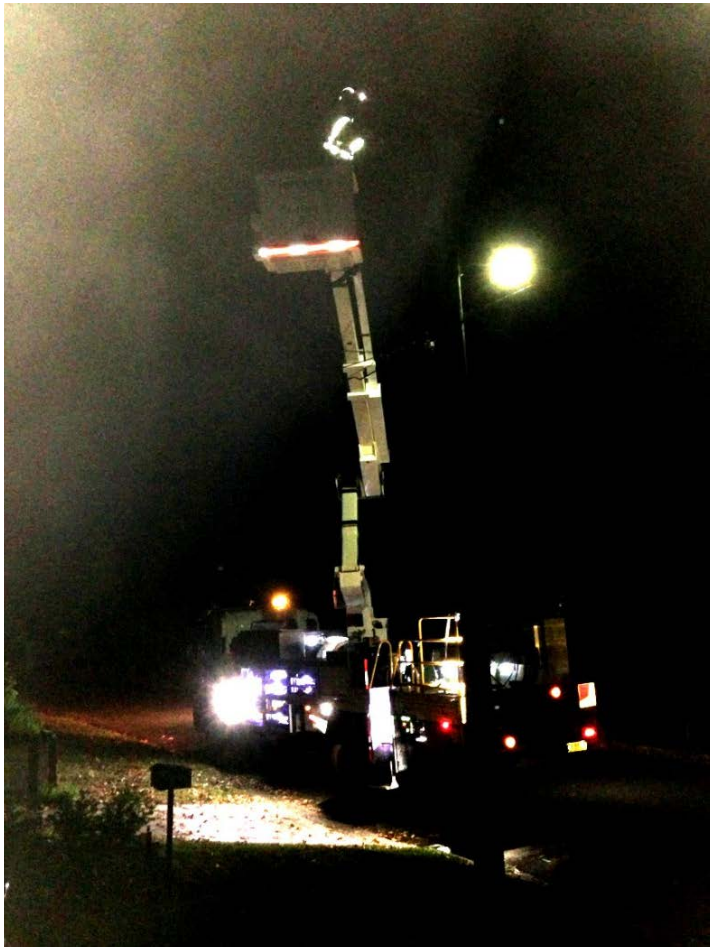
- Rapids work a four week, nine hour day rotation shift roster

Position	SAT	SUN	MON	TUE	WED	THU	FRI
1	12/9	12/9	3/12			7/4	3/12
2				3/12	3/12	3/12	
3	7/4	7/4	3/12			7/4	3/12
4				3/12	3/12	3/12	

- There are eight Rapid Response staff (4 x 2 person teams)
- Skill sets include live line, fitter, jointers, multiskill

RAPID RESPONSE FLEET

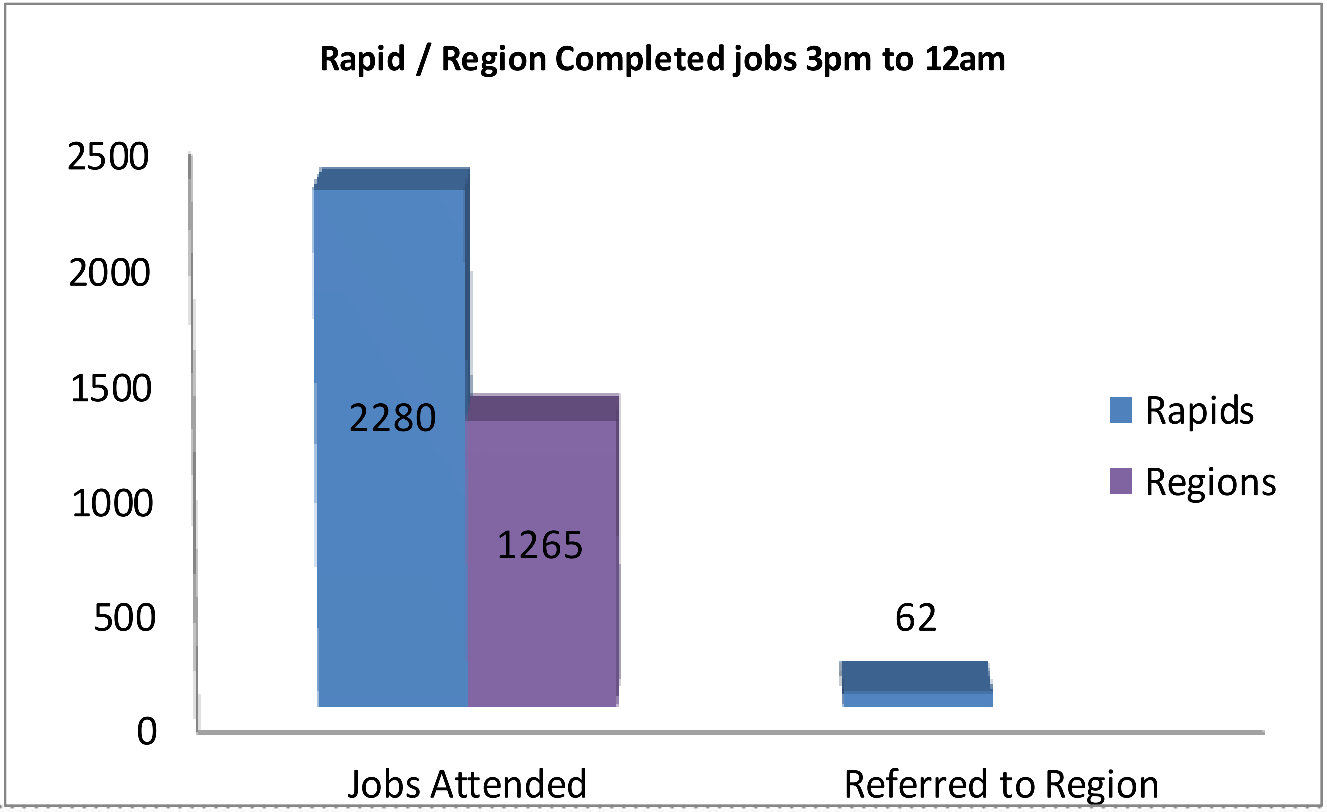
- Street light EWP
- Live line EWP
- Single cab line truck with a palfinger crane
- Additional lighting
- OH and UG repair equipment



Endeavour Energy

RAPID RESPONSE VS THE REGIONS

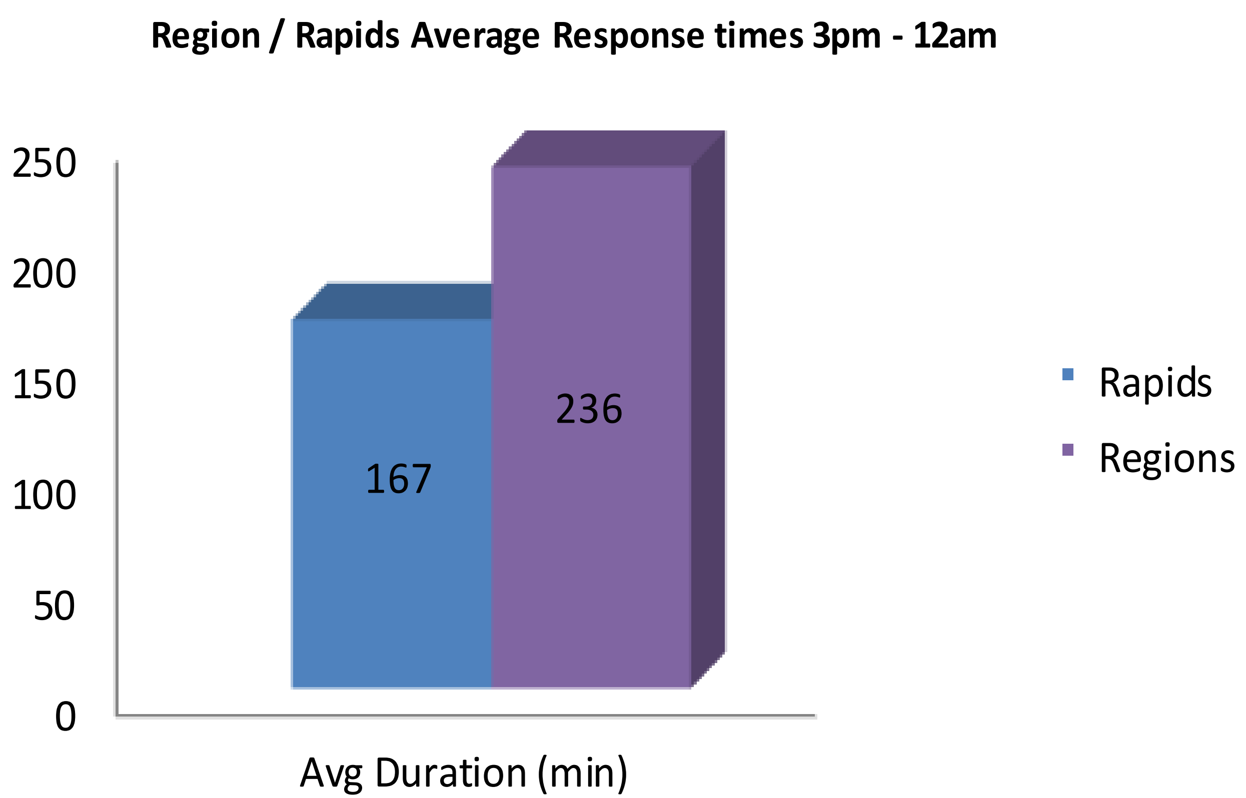
- Rapids on average complete four jobs per night per crew
- 64% of the jobs are completed by the Rapids



Endeavour Energy

RAPID RESPONSE VS THE REGIONS

- Rapids complete jobs 30% more efficiently



Endeavour Energy

BUT WHAT ABOUT THE DOWN TIME…?

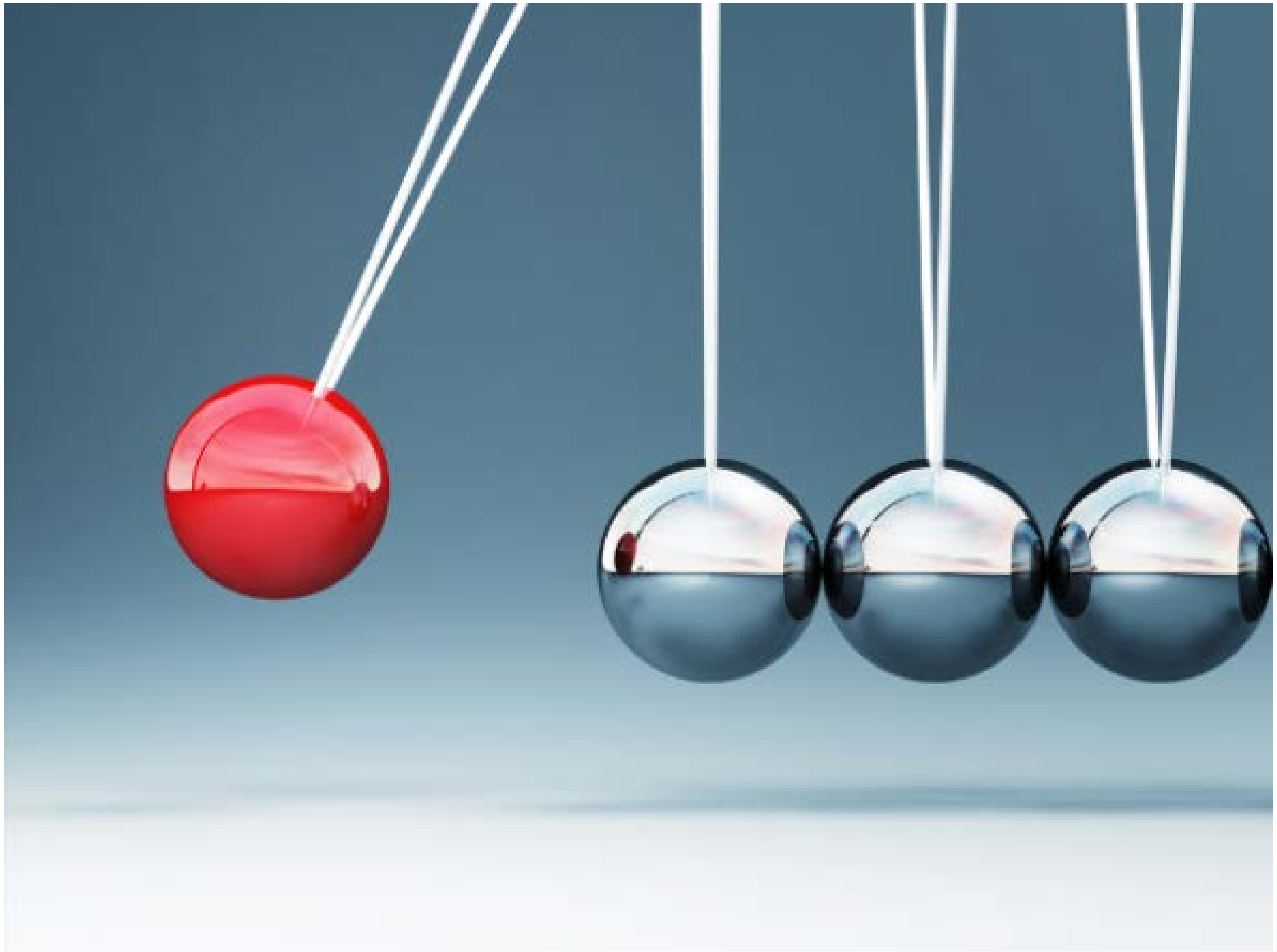
- Interruptible work is issued between F&E works
- 450 jobs completed over the past 12 months
- The work includes:
  - Pole cap replacement/de-sap poles
  - Cross arm repairs/replacement
  - Spreader installs for bush fire management
  - Pin insulator replacement
  - MDI reads
  - Customer connection point verification (update G-net)
  - Distribution cable repairs / stolen earth replacement.
- 40 live line jobs over the past 6 months

TELL ’EM THE PRICE

~$600k saving

SUPPORT TEAM

THE PENDULUM SWINGS



Memorandum

To	GM Network Operations, COO	File no	AK 008_14
From	Manager Network Connections	Date	3 September 2014
Subject	Network Connections Staff Increase		

Purpose:

To inform the ELT of observed trends indicating increases in Contestable Works activity, its effect on Customer Service provided by Network Connections and to request additional resources to allow adequate customer service levels to be maintained in the areas of Contestable Works Officers/Engineers (CWO/E) and Contestable Project Management.

Background:

In support of the Company's drive to lower costs and increased approval hurdles to replace vacancies NC CWO/E staff reduced by 3 and PM staff by one. These reductions were facilitated by certain changes to work practices and somewhat offset by filling of CWO/E vacancies with contract staff on 40 hr weeks rather than award.

Over the last six months there has been a noticeable elevation of issues by Network Connections' Customers and Staff and review of many of these cases has provided evidence that our quoted turnaround times are being exceeded. It is also evident that quality of our interaction with customers and the level of scrutiny of contestable works projects has been compromised due to insufficient time being available to process projects.

There are also a number of organisational factors, that combined, result in more time being required to adequately review many of the projects being dealt with:

- The introduction of NECF in July 2013 increased the number of applications received and consequently more technical reviews by CWO/E's.

- The introduction of NECF Cost share reimbursement scheme in July 2014 now resulting in greater complexity in evaluating reimbursements, registration of schemes and customer interaction regarding reimbursement calculations and rules of the scheme.

- Significant changes to a large number of engineering standards including property and environmental, resulting in an increase design checking, rejection, certification iterations and the need to refer matters to Engineering for expert advice and dispensations.

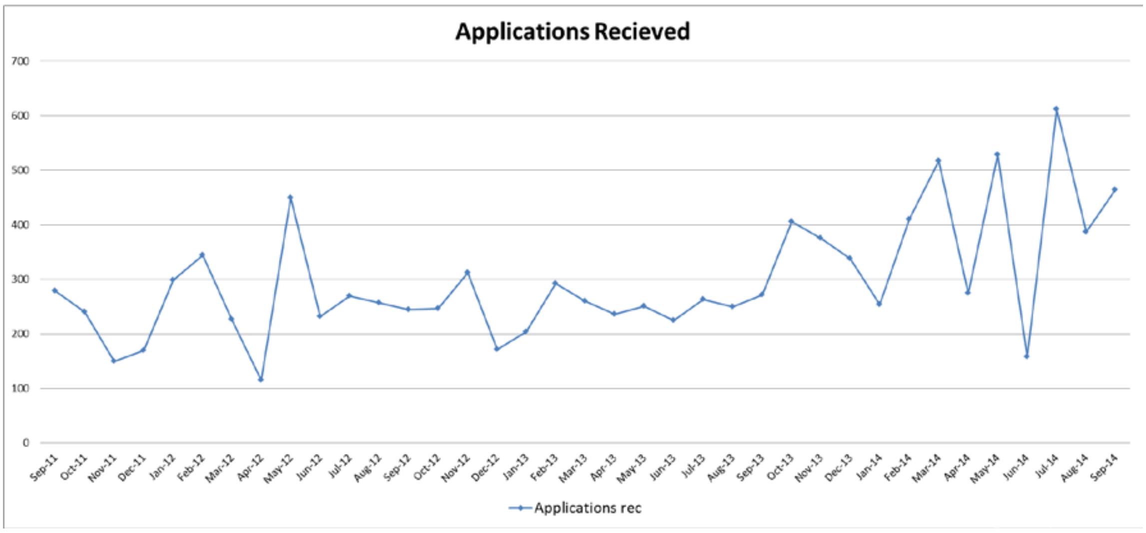
- Substantial increase in underground residential subdivision projects in response to land shortages and the Government's 10,000 lot/year program.

- Increases in large government lead infrastructure investments including, Defence, South West Rail, North West Rail, Roads program.

- Much of the land earmarked and zoned for property development being effected by transmission lines (Sth West Sector and Nth West Sector) requiring organisational multi stakeholder agreements and generally protracted negotiations.

In addition the following data provides evidence of the trends associated with increased market activity.

One of the coarsest measures correlating closely to Network Connection's workload is the number of applications received. Data has been extracted from CAMS and it can be clearly seen in the graph below that there has been a steady increase in the number of applications received over the three year period.



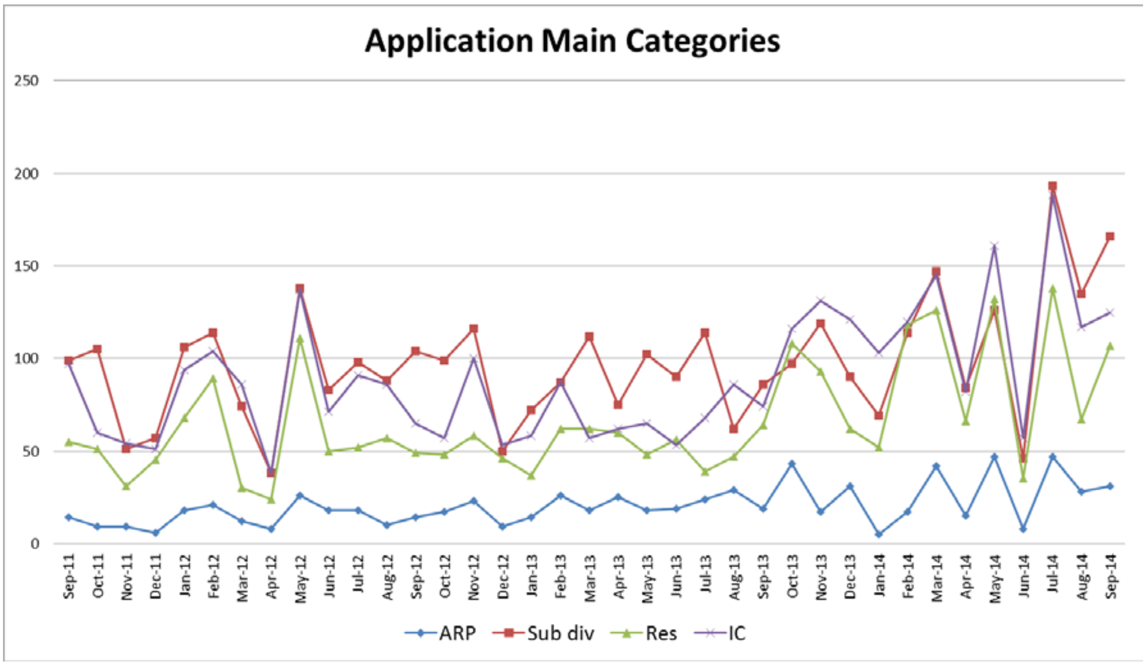
The volatility of the number of applications processed in the last 12 months is thought to be due more to backlogs in processing in the Contestable Works Administration area, which is now slowly coming under control as resources in this area have been added and are now becoming productive.

The data shows that over the last 12 months there have been on average of 380 applications per month as compared to a 250 application per month average during the preceding 12 month period. This represents a 50% increase in workload.

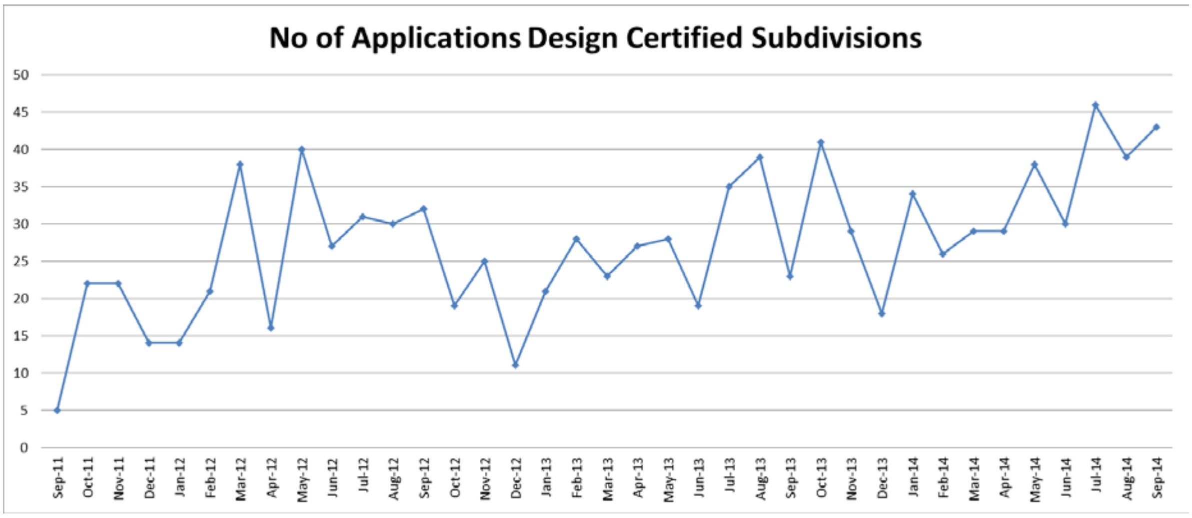
Using a linear trend over the three years of data it is evident that the number of applications has doubled.

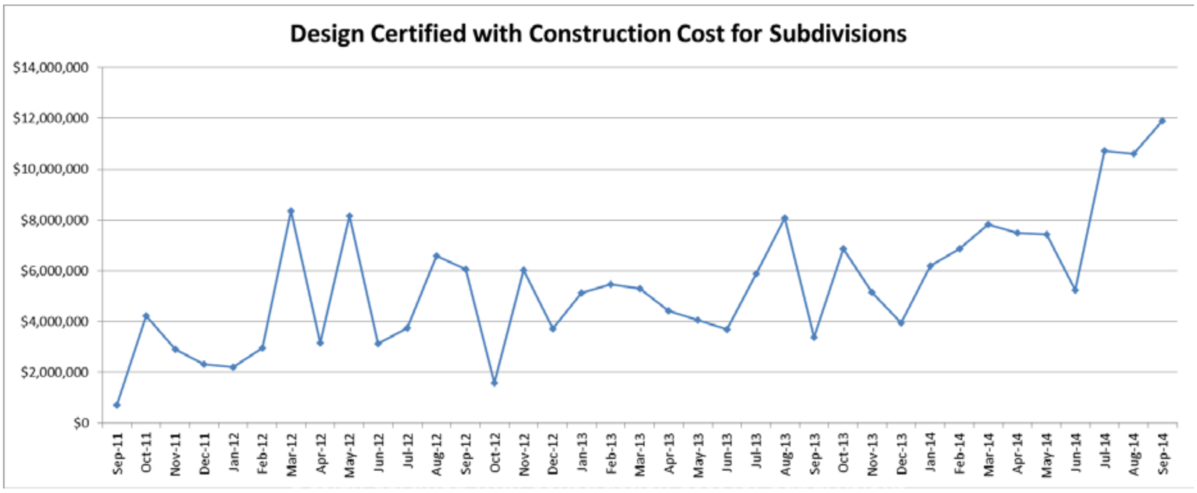
Not all applications result in the same workload but it is recognised that the negotiation and processing of Asset Relocations, Underground Residential Subdivisions, Residential loads and Industrial Commercial loads can be the most demanding.

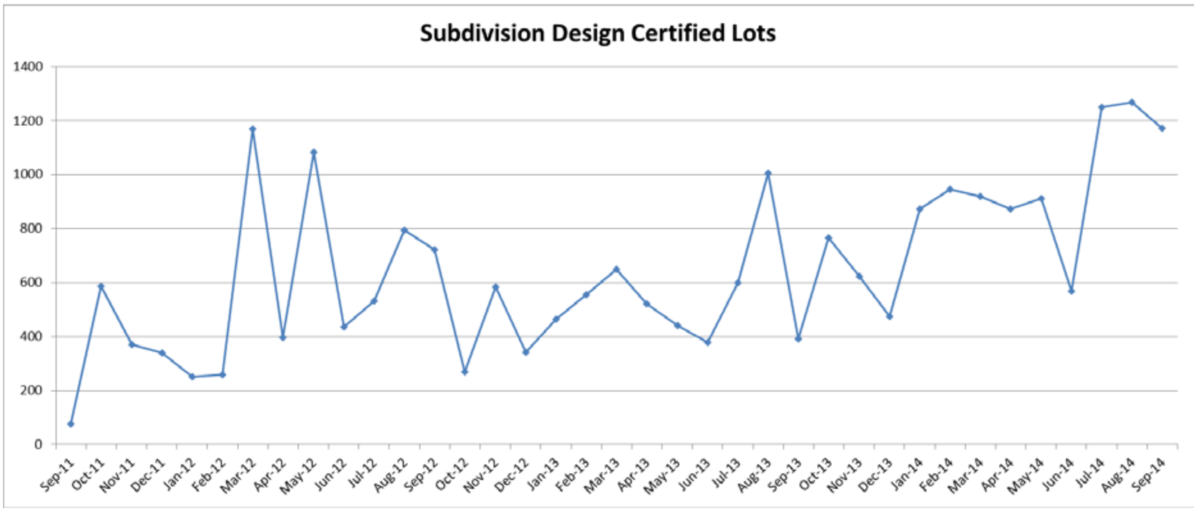
From the following graph it can be seen there has been a consistent increase in all of these labour intensive projects. Interestingly the industrial and commercial projects growth is lagging the residential developments but there is a definite increase in activity in this area which has ramped up over the last 12 months.



It is acknowledged that in addition to volume of applications received there are other factors that need consideration when analysing Network Connections work load. The number proceeding to certification, size of the projects and complexity needs also to be considered. The following series of charts provides further evidence that all factors indicate significant growth. The following three charts provide a view of activity in residential subdivisions, a major area of connections activity.

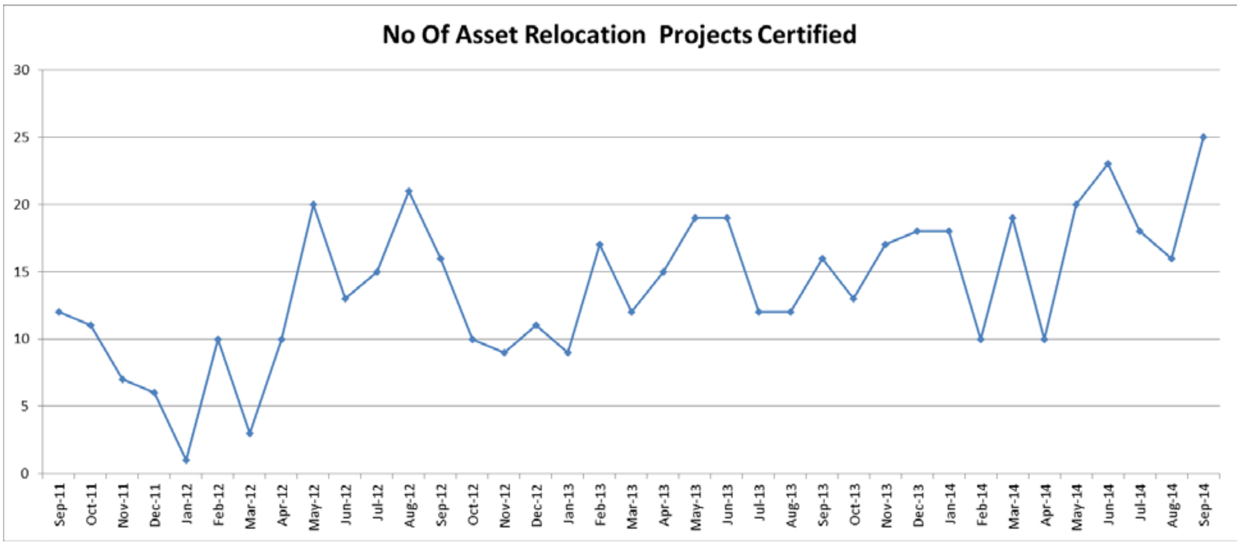


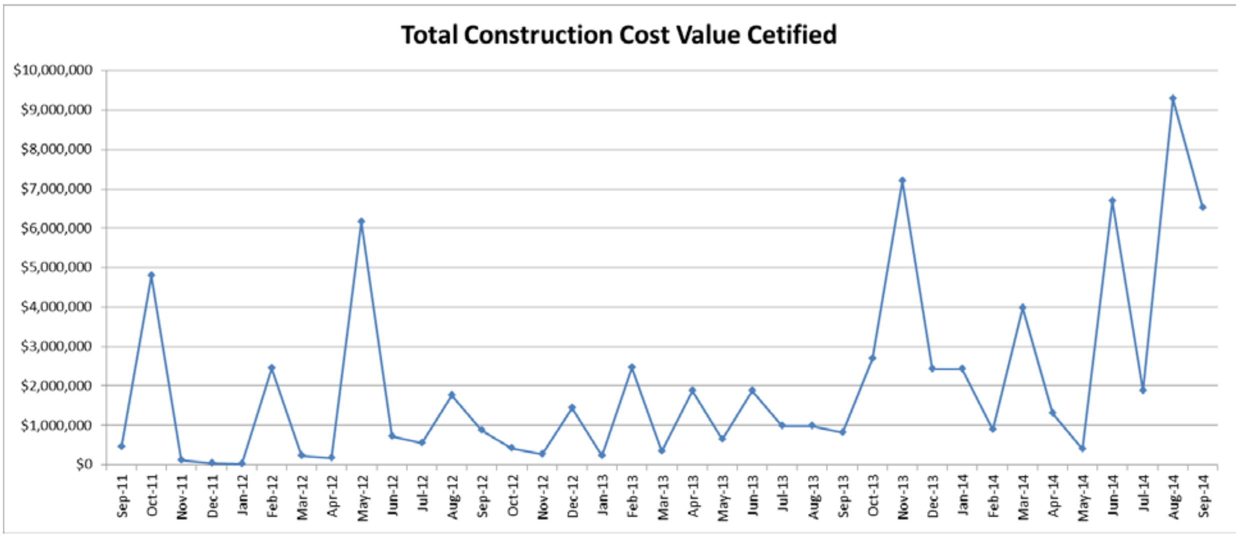




As can be seen from the graphs, not only have the number of projects increased but also the total number of lots developed and overall value of the works has increased proportionally or even at a higher rate than the number of projects. This indicates consistently that the growth has been sustained since the GFC and there is a likelihood of this trend continuing. The discussions within the development industry and government also support an ongoing need to facilitate development of residential lots in NSW and particularly in the South West and North West of Sydney.

A similar trend is observed in the following two graphs which show the number of projects that progress from application to certification and the total project construction value for asset relocation projects.



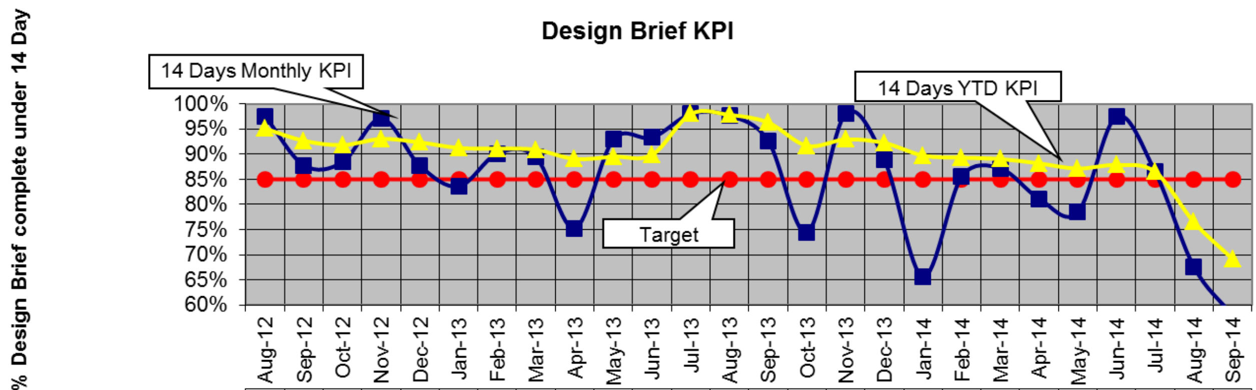


Anecdotally there has been growing evidence that performance and quality is suffering, there have been an increased number of elevations by developers.

Claims have been:

- Turnaround times have been increasing (average days in the graph below) and targets are not being met.
- The number of iterations of design comments and submissions has increased due to less detailed checking in the first instance.
- CWO/E's are not able to start reviewing projects following receipt of information. In many instances CWO/Es start reviewing designs near the end of the time period and therefore detailed and complete comments are compromised as officers attempt to meet turnaround times.

Design Brief KPI

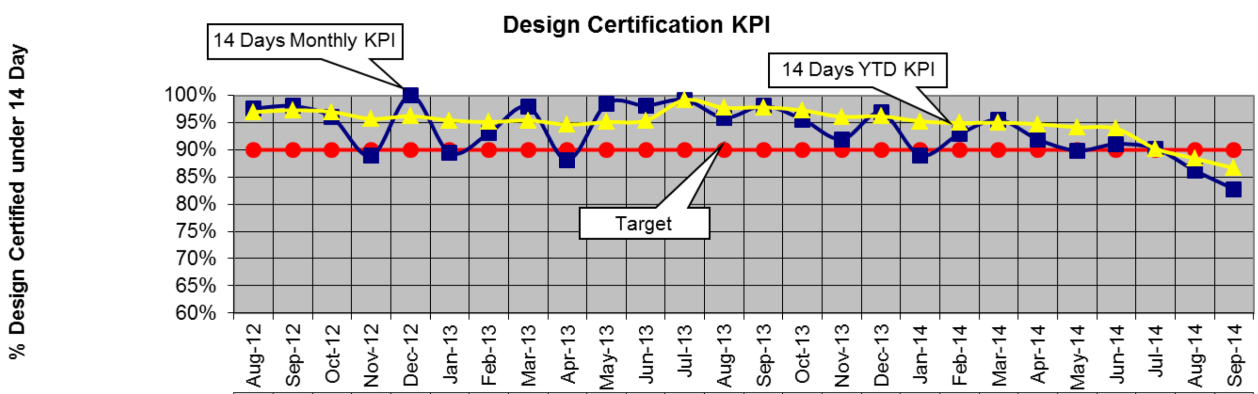


	Aug 12	Sep 12	Oct 12	Nov 12	Dec 12	Jan 13	Feb 13	Mar 13	Apr 13	May 13	Jun 13	Jul 13	Aug 13	Sep 13	Oct 13	Nov 13	Dec 13	Jan 14	Feb 14	Mar 14	Apr 14	May 14	Jun 14	Jul 14	Aug 14	Sep 14
Target	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
14Days Monthly KPI	98%	88%	88%	97%	88%	84%	90%	89%	75%	93%	93%	98%	98%	93%	74%	98%	89%	66%	86%	87%	81%	78%	98%	86%	68%	58%
14Days YTD KPI	95%	93%	92%	93%	92%	91%	91%	91%	89%	89%	90%	98%	98%	96%	92%	93%	92%	90%	89%	89%	88%	87%	88%	86%	76%	69%

Significant decrease in the Design Brief KPI as shown in the graph above is a real indication that performance is far below expectations. The provision of a Design Brief of adequate quality to the ASPs is a critical milestone that is essential in order for a designer to prepare and submit a valid design. In order to provide an effective service the design brief needs to be well defined and provided in a timely manner to avoid delays and further complications in design certification.

As can be seen in the graph below the certification milestone that has previously been fairly stable now shows early signs of degradation.

Design Certification KPI



	Aug 12	Sep 12	Oct 12	Nov 12	Dec 12	Jan 13	Feb 13	Mar 13	Apr 13	May 13	Jun 13	Jul 13	Aug 13	Sep 13	Oct 13	Nov 13	Dec 13	Jan 14	Feb 14	Mar 14	Apr 14	May 14	Jun 14	Jul 14	Aug 14	Sep 14
Target	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
14Days Monthly KPI	98%	98%	96%	89%	100	89%	93%	98%	88%	98%	98%	99%	96%	98%	96%	92%	97%	89%	93%	95%	92%	90%	91%	90%	86%	83%
14Days YTD KPI	97%	97%	97%	96%	96%	95%	95%	95%	95%	95%	95%	99%	98%	98%	97%	96%	96%	95%	95%	95%	95%	94%	94%	90%	88%	87%

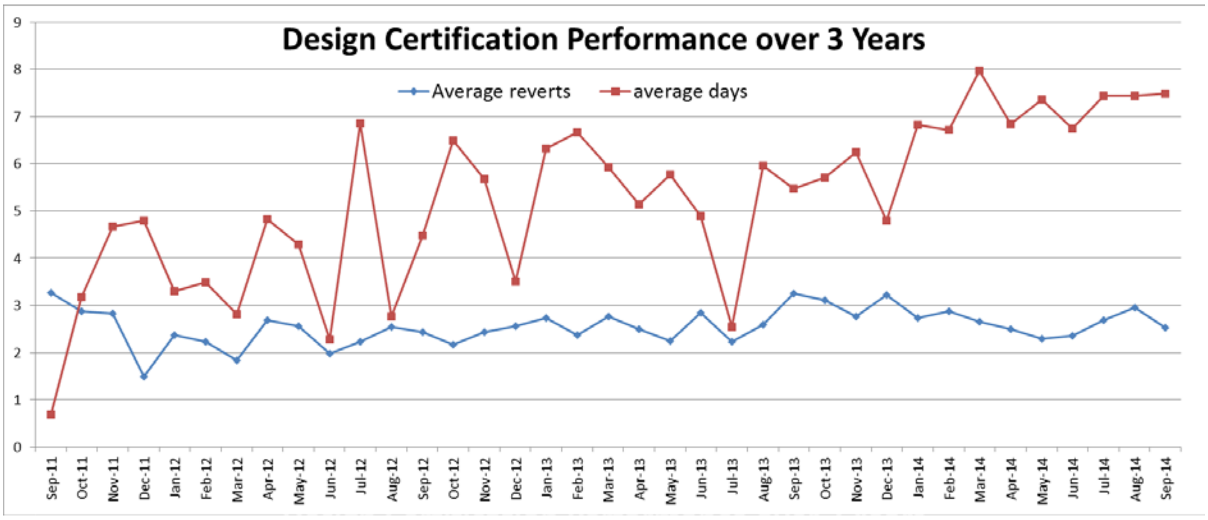
It should be stressed that our performance is really a lot worse than shown in the graphs below because of limitations in our CAMS system. Previously when the workload was previously in control, it was acceptable that there may be a lag of one or two days to input data into the system and start milestones. Currently the workload is such that staff are unable to upload the documents within that acceptable time frame so a milestone that appears to be achieved within 14 days may have actually been received for a week before we started the clock. These were occasional anomalies that were noticed in the past but given the number of such cases of late, developers have started to log their own dates and elevate issues where turn-around times are not achieved. This in turn increases significantly the level of involvement by managers and staff in explaining the differences in data and responding to Clients.

A request to alter the CAMS system to require staff to enter the date received manually as well as other corrective actions to improve data integrity is in progress. However it is understood that our Service level Guarantees quoted to and expected by customers will fall well below acceptable levels until the workload can be managed.

It is considered that if we accounted for the instances where receiving delays were factored into the processing time our performance levels may fall below 60%.

It has become evident that designers are also challenged as their own work load increases and their efforts to service the requirements of developers leads to less quality.

The increase in work available has also had the effect that the industry is employing relatively inexperienced staff. The new entrants' design quality is often low and therefore results in more work in reviewing and resubmissions (reverts in the graph below) of their designs. If not picked up at certification stage, which can be the case, in particular when CWO/E resources are stretched, these design issues result in significant elevation at later stages, thus involving Project management resources.

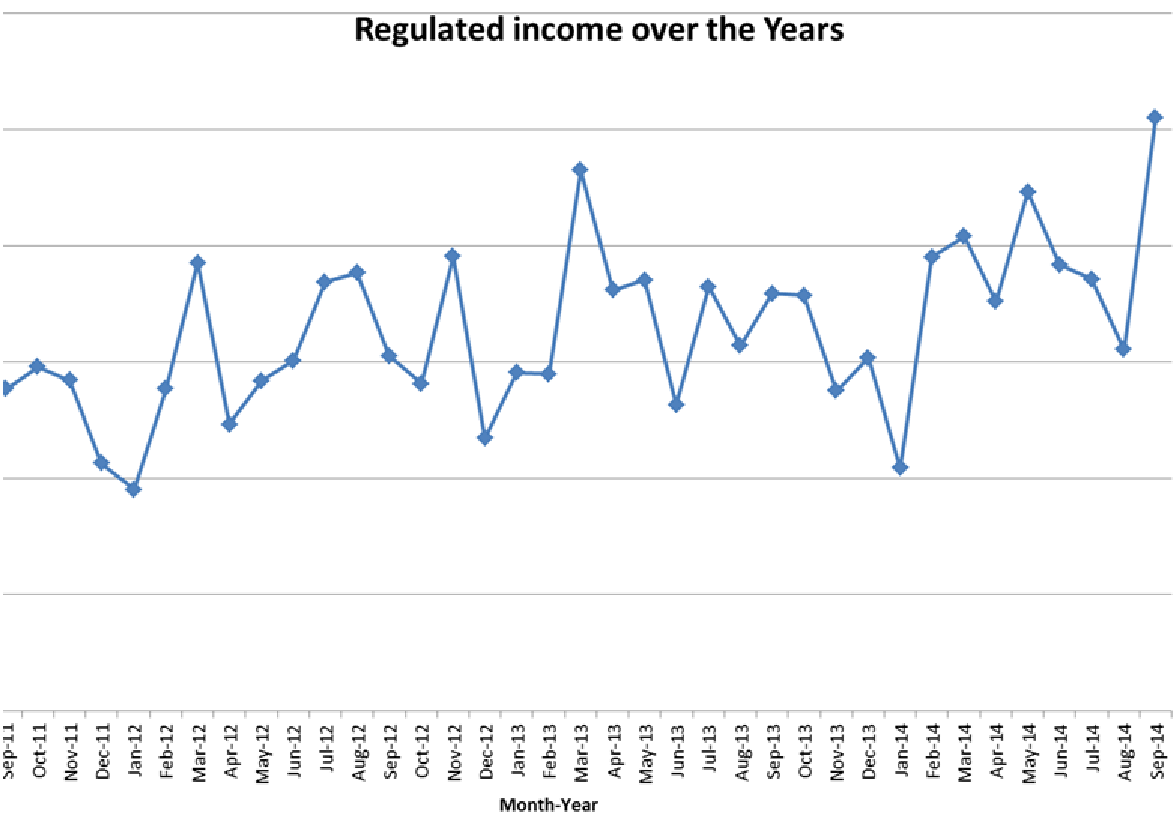


All data and evidence suggests increased volumes of work, decreased quality in designs, decreased quality of design certification resulting in increased rework, increased elevation of project issues and increased personal interaction to resolve issues.

The graph above does not acknowledge that the delay between the actual documentation being received and being registered is not captured. This is discussed later in the report but it can be seen that a delay in registration of 1 or two days is not noticeable when certification is averaging four or five days, however it becomes very evident to customers when the registration and certification slips to 5 and ten days respectively.

It should also be noted that the Network Connection Branch and particularly the Contestable Networks section derive significant revenue from processing connection and asset relocation applications. Only the revenue streams that relate directly to the CWO/E and CWA functions have been considered when analysing the revenue due to the additional workload.

From the graph below it is observed that revenue has increased proportionally with workload. This is understandable as each project incurs fees. However the level of resources allocated to each project are decreasing due to staff numbers declining at the same time that the number of projects has increased.



Given that the ancillary fees are mainly based on a reasonable estimate of time needed to complete a task , recovered by application of a reasonable regulated labour rate, it would appear that we are not employing sufficient resources to provide the service levels estimated and are thus under servicing and over recovering. As we are not achieving our customer's desired service levels and continue to allocate insufficient resources, there is a fear that it would be difficult to justify the rate of recovery and therefore jeopardise our ability to maintain a reasonable fee structure for the future as fees are assessed and approved by the AER.

Also it should be noted that on 1 July 2015 the fees are increasing. In particular additional fees have been created for activities that are currently not recovering costs. In summary the revenue that we derive from these regulated rates will increase and it is an opportune time to adjust our resources so that we are able to meet the expectations of our paying customers and the Australian Energy Regulator.

Determining the exact resource requirement is difficult using data, however it is evident that we need to return to the staffing levels in the CWO/E and PM area that existed prior to the GFC and then monitor performance closely.

This would mean an additional 3 CWO/Es and an additional PM being recommended. The current CWO/E headcount is 12 with the recommended level to be increased to 15 and the number of contestable works Project managers increasing from 4 to 5.

The placement of these positions if agreed should not be thought of as an opportunity for placing deployed staff or secondments as a short term strategy as there is considerable on the job training requiring at least a year experience to become fully productive. The design experience level of the project manager chosen is also critical given that the RMS requires more dedicated assistance in coordination and added scrutiny of their aggressive road development program and associated design and construction issues resolution.

Recommendation

Increase the Network Connections Staff Establishment by 3 Contestable Works Engineers and one Contestable Works Project Manager and proceed with the recruitment process.

Recommended By:

Anthony Kavaliauskas
Manager Network Connections

Endorsed By: **Approved By:**

Scott Ryan
GM Network Operations

Rod Howard
Chief Operating Officer

[2013] FWCA 3159

FAIR WORK COMMISSION

DECISION

Fair Work Act 2009
s.185 - Application for approval of a single-enterprise agreement

Endeavour Energy
(AG2013/6476)

ENDEAVOUR ENERGY ENTERPRISE AGREEMENT 2012

Electrical power industry

SENIOR DEPUTY PRESIDENT HAMBERGER SYDNEY, 21 MAY 2013

Application for approval of the Endeavour Energy Enterprise Agreement 2012.

[1] An application has been made for approval of an enterprise agreement known as the *Endeavour Energy Enterprise Agreement 2012* (the Agreement). The application was made pursuant to s.185 of the *Fair Work Act 2009* (the Act).

[2] I am satisfied that each of the requirements of ss.186, 187 and 188 of the Act as are relevant to this application for approval have been met.

[3] The Communications, Electrical, Electronic, Energy, Information, Postal, Plumbing and Allied Services Union of Australia (CEPU), the Australian Municipal, Administrative, Clerical and Services Union (New South Wales Local Government, Clerical, Administrative, Energy, Airlines & Utilities Branch) (ASU) and The Association of Professional Engineers, Scientists and Managers, Australia (APESMA) being bargaining representatives for the Agreement, have given notice under s.183 of the Act that they want the Agreement to cover it. In accordance with s.201(2) of the Act I note that the Agreement covers the organisations.

[4] The Agreement is approved and will operate from 28 May 2013. The nominal expiry date of the Agreement is 24 December 2014.

SENIOR DEPUTY PRESIDENT

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ENDEAVOUR ENERGY
ENTERPRISE AGREEMENT 2012

Endeavour Energy

Table of Contents

1. APPLICATION AND OPERATION OF THE AGREEMENT

1.1 *Objects of the Agreement*

The objects of the Agreement are:

(a) to outline the basic conditions relating to the work performed by the employees of Endeavour Energy;

(b) to enable Endeavour Energy to meet the expectations of its customers; and

(c) to give employees the greatest possible chance of employment security, through the ability to adapt to a changing environment.

1.2 *Term of the Agreement*

The Agreement shall operate from 25 December 2012 until 24 December 2014 inclusive. This is the nominal term of the agreement. The agreement and all terms contained therein shall continue to apply beyond the expiry date until renegotiated, agreed and ratified.

1.3 *Coverage of the Agreement*

1.3.1 Those covered by the Agreement are:

(a) Endeavour Energy Australia;

(b) Communications, Electrical, Electronics, Energy, Information, Postal, Plumbing and Allied Services Union of Australia, NSW Divisional Branch (ETU NSW);

(c) Australian Municipal, Administrative, Clerical and Services Union NSW United Services Branch;

(d) Association of Professional Engineers, Scientists and Managers, Australia;

The "Union(s)" represents those unions as outlined in clauses 1.3.1(b), (c) and (d) only

1.3.2 The Agreement shall be applicable to Endeavour Energy and its employees, other than above Agreement classification positions that are Fair Work Act 2009 compliant contract positions.

1.3.3 Continuing employees who are employed as at the date of this Agreement, in positions evaluated with a range below Manager/Specialist 9-13 have the right to refuse the offer of a fixed term or open term employment contract and their employment will continue to be subject to this Agreement.

2. INTENT AND COMMITMENT

2.1 *Intent*

This Agreement is based on the understanding that Endeavour Energy and its employees have an obligation to serve the people of New South Wales by providing a high standard of service in the most efficient way. As part of its obligations, Endeavour Energy is committed to the continued development of its skilled workforce to provide an effective service and job security for its employees.

2.2 *Commitment*

The employees of Endeavour Energy are committed to:

(a) Working together towards achieving Endeavour Energy's vision of generating performance through innovation.

(b) Achieving success through values of:

- We provide excellent customer service;
- We live and work safely;
- We deliver outstanding business success;
- We promote high achievement;
- We behave with respect and integrity.

(c) Ensuring that they act with honesty, fairness and dignity in all that they do.

(d) Only using information of a commercial or confidential nature in an authorised manner.

(e) Subject to clauses 2, 3 and 4, implementing work practices that:

(i) provide for more co-operative work arrangements;

(ii) improve competitiveness, efficiency, flexibility and productivity; and

(iii) assist positively to enable Endeavour Energy to be a low cost, reliable supplier of electricity.

2.3 *Commitments of the Parties*

Endeavour Energy, its employees and the unions representing their members are committed to the Objects of this Agreement.

2.4 *Relationship of this Agreement to other Agreements*

2.4.1 In this Agreement "Core Agreement" means Clauses 1 to 34 of this Agreement and includes all appendices.

2.4.2 Any dispute(s) in relation to this clause may be referred to clause 29 (Disputes) of this Agreement by any Party.

2.5 *No Extra Claims*

It is a term of this Agreement that the parties to this Agreement undertake that for the period of the duration of the Agreement that they will not pursue any extra claims.

2.6 *Definitions*

2.6.1 "Ordinary Week's Pay" means an employee's ordinary week's pay is their rate of pay for their ordinary hours of work plus any allowances which are paid on a normal weekly basis.

2.6.2 "Act" means the Fair Work Act (Cth) 2009.

2.7 *Competency Based Progression System*

The parties are committed to maintaining the Competency Based Progression System which was introduced in 2005. Variations to the system will be made using a consultative process.

2.8 *Consultation for next Agreement*

Negotiations will commence with the relevant parties 6 months before the expiry of this Agreement for a replacement Agreement.

3. CONSULTATION AND COMMUNICATION

3.1 *Consultative Committee Formation*

Endeavour Energy will form Consultative Committees from time to time consisting of representatives of Endeavour Energy employees, the unions and Endeavour Energy management.

During the term of this agreement, proposed changes (other than in direct response to a statutory obligation) that will materially impact employees will be subject to consultation using Consultative Committees.

Consultative Committees will seek to apply interest-based techniques to assist in understanding the interests and concerns of Endeavour Energy employees, the unions and Endeavour Energy management.

As part of the formation of any Consultative Committee, the Committee will establish an agreed consultation plan, clearly describing the subject nature of the consultation, the intended consultative process steps and the timetable for completion of these steps.

Should the representatives on a Consultative Committee be unable to agree upon a consultation plan as described in this clause, they will have recourse to the Disputes Procedure.

3.2 *Consultative Committee Objectives*

The objectives relate to major and strategic issues that may affect the relationship between Endeavour Energy and its employees and include:

a) to enable Endeavour Energy to keep its employees, and the unions representing them, informed;
b) to enable unions and their members to keep Endeavour Energy informed;
c) to enable employees to have input to the decisions of management;
d) to facilitate the exchange of views between employees and management.
e) to provide a forum for the exploration and understanding of "best practice" and its application within Endeavour Energy
f) to act as a 'think tank' to raise ideas and concepts and provide a forum to discuss improvements in Endeavour Energy's performance and efficiency.
g) to enable the establishment of mechanisms to gauge and report upon productivity improvement.

3.3 *Disputes*

At any time during the process outlined in this clause either party may refer the matter to the Disputes Procedure (Clause 29 of this Agreement) for resolution.

4. WORK PRACTICE CHANGE

4.1 *Continuous Improvement and Best Practice*

Endeavour Energy seeks continuous improvement and best practice in all that we do. Endeavour Energy employees, the unions and Endeavour Energy management commit to actively supporting and contributing to the "process" of change.

The primary focus for improvement will be upon internally developing and implementing efficiencies to address Endeavour Energy's performance challenges while ensuring safety, cost effectiveness and service to our customers. Our collective aim is to be safe, competitive and achieve best practice with the goal of achieving sustainable internal employment levels.

As part of the search for continuous improvement and best practice, Endeavour Energy will seek to benchmark across regions and depots for best practice and to identify and prioritise the areas where productivity improvement can or should be achieved.

The parties including relevant work groups/employees may, via the consultative process in this agreement, utilise external benchmarking prior to market testing to permit internal efforts to improve efficiencies and become more competitive.

4.2 *Change following Consultation*

Any change will only occur following the consultation process outlined in Clause 3.

Consistent with the overall intent of this clause Endeavour Energy employees, the unions and Endeavour Energy management will seek to adopt ways to most efficiently utilise the resources and time commitment required from those involved in consultation processes (such as shop floor people, line management, delegates, union officials and senior managers).

4.3 *Assessment Criteria*

Assessment criteria will include but is not limited to:

- safety;
- hardship;
- workload;
- job security;
- building mutual respect and job satisfaction;
- tangible productivity improvement; and,
- any other legislative requirements.

5. CONTRACT OF EMPLOYMENT

5.1 *Duties of Endeavour Energy*

The duties of Endeavour Energy, consistent with the Agreement and other relevant legislation, include the following:

(a) to provide work;

(b) to pay for the work performed; and

(c) to provide a safe working environment.

5.2 *Duties of Employees*

The duties of employees, consistent with the Agreement and other relevant legislation, include the following:

(a) to work in a skilled and competent manner;

(b) to work in a manner which does not threaten the safety of themselves, work colleagues or the public;

(c) to provide faithful service;

(d) to obey lawful commands;

(e) to not act in a manner hostile to or against the interests of Endeavour Energy;

(f) to respect and maintain the confidentiality of certain information;

(g) to account for all moneys and property received in the course of employment;

(h) to make available to Endeavour Energy all inventions made in the course of employment; and

(i) to disclose to Endeavour Energy any information it has a right to know.

5.3 *Obligation to Use Skills*

(a) An employer may direct an employee to carry out such duties as are within the employee's skill, competence and training consistent with their classification structure of this Agreement provided that such duties are not designed to promote deskilling.

(b) An employer may direct an employee to carry out such duties and use such tools and equipment as may be required provided that the employee has been properly trained in the use of such tools and equipment.

5.4 *Categories of Working Environment*

As required by Endeavour Energy, an employee's work may be performed in an office; depot; workshop; in the field or other location remote from the office, depot, workshop; or, where pre-approved by management, in the employee's home.

5.5 *Categories of Employment*

CATEGORY	DESCRIPTION	BENEFITS UNDER AGREEMENT
Permanent / Full time	Employee is engaged to work full time hours.	Full extent of relevant benefits.
Fixed term / Full time	Employee is engaged for a fixed term to work full time hours.	Full extent of relevant benefits according to the period of employment.
Permanent / Part time	Employee is engaged to work for regular but less than full time hours.	All relevant benefits on a pro-rata (part time hours as a proportion of the full time hours) basis.
Fixed term / Part time	Employee is engaged for a fixed term tenure to work less than full time hours.	All relevant benefits on a pro-rata (part time hours as a proportion of the full time hours) basis according to the period of employment.
Casual	An employee engaged on an hourly basis in a roster to be determined by Endeavour Energy.	The relevant hourly rate according to the appropriate classification plus 23% **(casual employee loading)** for each hour worked. A minimum of 4 hours will apply for casual employees. The casual employee loading is in compensation for all Agreement benefits other than overtime, below.
Fixed Term Employment	Term employment covers employees engaged on a temporary basis and shall not include a casual employee. Term appointments may be made for a period of up to 12 months. At the expiration of that period, work requirements shall be reviewed by the parties. Term employment shall not be used as an alternative to full time employment	A Term employee shall be paid a rate of pay and receive Agreement conditions as is appropriate to either comparable full time or part time equivalent employment under this Agreement.

5.5.1 A part-time employee who agrees to work additional hours will be paid single time for those additional hours up to the equivalent full time hours. The pro rata accrual of leave will be adjusted for those additional hours.

5.5.2 Where a part-time employee is instructed to work greater than 8 hours per day, they will be paid the relevant overtime rate.

5.5.3 The span of hours shall be in accordance with clause 8.1.

5.5.4 Where a casual employee is instructed to work greater than 8 hours per day, they will be paid the relevant overtime rate. These overtime rates shall be in lieu of the casual employee loading.

5.5.5 The span of hours shall be in accordance with clause 8.1.

5.6 *Wages and Salaries*

5.6.1 Endeavour Energy will allocate a pay point to each employee. The pay points are set out in Appendix A to this Agreement.

5.6.2 Endeavour Energy will increase rates of pay including all wage related allowances (but excluding ESRA) by the following:

(a) 2.7% on 25 December 2012; and

(b) 2.7% on 24 December 2013.

5.7 *Superannuation*

5.7.1 At the commencement date of this agreement, employees covered by the agreement will receive the legislated Superannuation Guarantee Contribution (SGC) of 9% and an additional 6% contribution as a result of previous wage negotiation outcomes.

5.7.2 The legislated increases in the SGC contribution during the term of this agreement (0.25% on 1 July 2013 and 0.25% on 1 July 2014) will be absorbed within the 15% employer contribution set out in clause 5.7.1 above.

5.7.3 Subject to the provision of relevant superannuation legislation, employees under this Agreement will have their superannuation contributions paid into the Energy Industries Superannuation Scheme (EISS).

5.7.4 An employee may elect in lieu of being paid an amount of Agreement Wages to have an equivalent amount paid by way of superannuation contributions in accordance with the relevant provisions of their scheme to the maximum extent permitted by law.

5.7.5 Subject to the provisions of relevant superannuation legislation, these contributions shall be paid to the relevant scheme.

5.7.6 The employee's election to vary their superannuation benefit must be in writing and would occur no more than once per calendar year, with effect from 1 July each year.

5.8 *Apprentices and Trainees*

5.8.1 The conditions of this Agreement will apply to apprentices and trainees during the period of their traineeship or apprenticeship.

5.8.2 A traineeship or apprenticeship does not guarantee continuing employment upon completion of the indentured period.

5.8.3 Any offer of continued employment would be based on the staffing requirements of Endeavour Energy and the satisfactory performance of the apprentice or trainee.

5.9 *Equal Employment Opportunity*

5.9.1 Endeavour Energy is an Equal Opportunity Employer.

5.9.2 Endeavour Energy and its employees will work together to achieve the objective of a work environment free from discrimination or harassment and where all people treat, and are treated, with respect.

5.9.3 Endeavour Energy is committed to providing equal remuneration and conditions of employment for work of equal or comparable value.

5.10 *Anti-Discrimination*

5.10.1 It is the intention of the parties to this Agreement to prevent and eliminate discrimination, bullying and harassment in the workplace. This includes discrimination on the grounds of sex, pregnancy, race, religion, age, marital or domestic status, homosexuality, disability, transgender status or carer's responsibilities.

5.10.2 It follows that in fulfilling their obligations under the dispute resolution procedure prescribed by this Agreement the parties have obligations to take all reasonable steps to ensure that the operation of the provisions of this Agreement are not directly or indirectly discriminatory in their effects. It will be consistent with the fulfilment of these obligations for the parties to make application to vary any provision of the Agreement which, by its terms of operation, has a direct or indirect discriminatory effect.

5.10.3 Under the Anti-Discrimination Act 1977, it is unlawful to victimise an employee because the employee has made or may make or has been involved in a complaint of unlawful discrimination or harassment. Nothing in this clause is to be taken to affect:

(a) any conduct or act which is specifically exempted from anti-discrimination legislation;

(b) offering or providing junior rates of pay to persons under 21 years of age;

(c) any act or practice of a body established to propagate religion which is exempted under section 56(d) of the Anti-Discrimination Act 1977;

(d) a party to this Agreement from pursuing matters of unlawful discrimination in any State or Federal jurisdiction.

5.10.4 Consistent with Anti-Discrimination and Equal Employment Opportunity principles, workplace harassment, including bullying is not acceptable. Any incidents of workplace discrimination, bullying or harassment will be managed in accordance with Clause 29 Disputes.

5.10.5 This clause does not create legal rights or obligations in addition to those imposed upon the parties by the legislation referred to in this clause.

5.11 *Payment of Employment Separation Entitlements to Next of Kin*

Employees may authorise Endeavour Energy to pay their employment separation entitlement to a person nominated by them in the event of them dying whilst still in the service of Endeavour Energy by completing a form to be prepared by Endeavour Energy. In the absence of such written authorisation, employment separation entitlement will be paid to the deceased employee's estate.

5.12 *Termination of Employment*

5.12.1 The amount of notice, of termination of employment, to be given by an employee shall be two weeks.

5.12.2 If an employee's employment is terminated for reasons other than those justifying summary dismissal, the amount of notice which will be given by Endeavour Energy will be as follows:

AMOUNT OF EMPLOYEE'S SERVICE	AMOUNT OF NOTICE
Not more than 1 year	1 week
More than 1 year but not more than 3 years	2 weeks
More than 3 years but not more than 5 years	3 weeks
More than 5 years	4 weeks

NOTE: Where an employee is over 45 years of age with at least 2 years continuous service the amount of notice in the above table is to be increased by 1 week.

5.12.3 As an alternative to notice being given, payment may be made by Endeavour Energy to the employee for all or part of the notice period at the employee's ordinary rate of pay.

5.12.4 Where circumstances warrant and by agreement, the required period of notice may be waived.

5.12.5 Summary Dismissal will apply where an employee has engaged in serious misconduct. In this case an employee will be paid only up to the date of dismissal.

5.12.6 An employee who has been absent for a continuous period of 5 working days or more without the consent of Endeavour Energy and/or without notification will be treated as having abandoned their employment.

5.12.7 The employee will be given a period of 14 days of last attending to give a satisfactory explanation. The termination pay shall be up to the date of the employee's last attendance.

5.12.8 A contract of employment may be terminated as follows:

TYPE	DESCRIPTION
Resignation	Where an employee decides of their own free will to leave.
Retirement	This is where the employee decides of their own free will to leave the workforce generally.
Dismissal	This is where Endeavour Energy decides that the employee should no longer be employed for a reason for which the employee is responsible.
Redundancy	This is where Endeavour Energy decides that the position held by the employee no longer exists.
Abandonment	This is where an employee has been absent from his or her place of employment without notification or permission for a period of 5 working days or more.

TYPE	DESCRIPTION
Retirement Ill Health	This is where a doctor certifies that an employee will never work again in accordance with the requirements of the superannuation fund.
Death	Where an employee dies while employed by Endeavour Energy.

5.13 *Redundancy*

The redundancy policy for the term of this Agreement is Endeavour Energy Policy number 7.8.2, version 4, previous approval date: 18 May 2011, new approval date: 8 April 2013.

5.14 *Salary maintenance*

The Salary Maintenance Policy for the term of this Agreement is Endeavour Energy Policy number 7.8.3, version 4, previous approval date: 21 December 2011, new approval date: 8 April 2013.

5.15 *Safety Clothing and/or Equipment*

5.15.1 Employees must ensure they wear and/or use appropriate safety clothing and/or equipment for the purpose for which it was provided.

5.15.2 An employee who fails to comply with the above requirement may not be paid for the time taken to comply including travelling home to get the appropriate safety clothing or equipment.

5.16 *Probationary Periods*

5.16.1 The purpose of probationary periods is to enable both the employee and Endeavour Energy to determine the suitability of the employment relationship.

5.16.2 The probationary period served by employees shall be 3 months from the commencement of employment with Endeavour Energy. Upon satisfactory completion of the probationary period, the employee shall have his or her appointment confirmed.

5.16.3 If an employee does not satisfactorily complete the probationary period their employment may be terminated or the probationary period may be extended for a further 3 months. Where a probationary period is being extended, and the employee is a union member, Endeavour Energy will notify the relevant union organiser of the organisation's intention to extend the probationary period.

5.16.4 Probationary periods shall be included as service in the position.

5.17 *Protection of Rate of Pay*

Employees may from time to time, consistent with their skills and competencies and as part of their employment with Endeavour Energy, be required to do work for which a lower rate of pay is prescribed. Employees will continue to be paid their ordinary rate of pay.

5.18 *Working Reasonable Overtime*

5.18.1 Employees shall work reasonable overtime as directed to meet the needs of Endeavour Energy.

5.18.2 Where possible employees shall be given reasonable notice of the overtime they will be required to work.

5.19 *Deductions from Wages*

5.19.1 Employees may request, in writing, for deductions to be made from their wages or salary for the purpose of contributions or payment approved by Endeavour Energy.

5.19.2 Employees may request in writing for deductions to be made from their wages or salary for the purpose of contributions to unions, which are parties to the Agreement.

5.19.3 Endeavour Energy may deduct from an employee's wages or salary payment for any time he or she was absent from work without permission.

5.20 *Calculation of Service*

Service with Endeavour Energy shall, in the main, be from the date of commencement to the date of termination inclusive and according to the following:

CATEGORY	DETAIL
Included as Service	• Annual leave • Long service leave • Special leave with pay • Sick leave • Family / Carers leave • Special leave without pay specifically approved as being included as service • Time off with the Defence Force Reserve during employment • Period of absence under New South Wales workers compensation legislation.
NOT included as Service	• All periods absent from work not specifically approved as service • Parental leave (including maternity, paternity and adoption leave) *(the period of absence does not break the continuity of employment)*

6. ENTERPRISE WORKGROUP FLEXIBILITY

6.1 *Objects*

This clause is intended to facilitate flexibility agreements between management at all levels and staff with the assistance of their representatives. It is intended to apply to classifications or workgroups.

A "Workgroup Arrangement" may be reached between Endeavour Energy and the relevant workgroup employees and their representatives. The purpose of reaching such an arrangement is to establish greater flexibility. The Workgroup Arrangement cannot provide for condition(s) less favourable than this Agreement.

6.2 *Basis of Reaching Agreement*

6.2.1 Discussions between Endeavour Energy and the relevant employees and/or their representatives will be undertaken once a desire for a Workgroup Arrangement has been identified and the proposals should encompass all relevant details, including:

- (a) The nature of the work to be performed
- (b) How the work is to be performed
- (c) Who is to perform the work
- (d) When the work is to be done
- (e) The basis on which payment, or otherwise, is to be made

6.2.2 Negotiations will involve the relevant Workgroup Manager with Human Resources assistance, the relevant Workgroup employees and the relevant Union or appointed representatives.

6.2.3 The final draft Workplace Arrangement arising from these negotiations will be distributed to employees directly affected and covered by the Workplace Arrangement before being put to a meeting of all Workgroup employees directly concerned with the Workgroup Arrangement.

6.2.4 A majority of the relevant employees voting (in any manner) in favour of the proposals shall finalise the Workplace Arrangement.

6.2.5 After a vote in favour of the proposed Workplace Arrangement, the Unions and/or representatives will endorse this arrangement.

6.2.6 The employees directly affected will be given a copy of the Workgroup Arrangement.

6.2.7 The current Workgroup Arrangements can be found at Appendix D and form part of this agreement.

6.2.8 At any time during the process outlined in this clause, either party may refer the matter to the Dispute Procedure (Clause 29 of this Agreement) for resolution.

6.3 *Commencement*

6.3.1 A Workgroup Arrangement shall commence on the 7th day after the date of approval or the next pay cycle, which ever is the later.

7. INDIVIDUAL FLEXIBILITY TERM

An employer and employee covered by this enterprise agreement may agree to make an individual flexibility arrangement to vary the effect of terms of the agreement if:

7.1.1 the agreement deals with 1 or more of the following matters:

(a) taking accumulated RDOs;

(b) Salary Sacrifice

7.1.2 the arrangement meets the genuine needs of the employer and employee in relation to 1 or more of the matters mentioned in this clause; and

7.1.3 the arrangement is genuinely agreed to by the employer and employee.

7.1.4 The employer must ensure that the terms of the individual flexibility arrangement:

(a) are about permitted matters under section 172 of the Fair Work Act 2009; and

(b) are not unlawful terms under section 194 of the Fair Work Act 2009; and

(c) result in the employee being better off overall than the employee would be if no arrangement was made.

7.1.5 The employer must ensure that the individual flexibility arrangement:

(a) is in writing; and

(b) includes the name of the employer and employee; and

(c) is signed by the employer and employee and if the employee is under 18 years of age, signed by a parent or guardian of the employee; and

(d) includes details of:

(i) the terms of the enterprise agreement that will be varied by the arrangement; and

(ii) how the arrangement will vary the effect of the terms; and

(iii) how the employee will be better off overall in relation to the terms and conditions of his or her employment as a result of the arrangement; and

(e) states the day on which the arrangement commences.

7.1.6 The employer must give the employee a copy of the individual flexibility arrangement within 14 days after it is agreed to.

7.1.7 The employer or employee may terminate the individual flexibility arrangement:

(a) by giving no more than 28 days written notice to the other party to the arrangement; or

(b) if the employer and employee agree in writing at any time.

8. WORKING HOURS

8.1 *Ordinary Hours*

The arrangements relating to the ordinary hours of work of day workers shall be as follows:

Category	Arrangement
Ordinary Hours of Work: **'Field' staff** **'Office' staff**	 36 hours per week 35 hours per week
Ordinary Days of Work	Monday to Friday inclusive
Span of Hours	6:00 am to 6:00 pm
Lunch Break	Not less than 30 minutes unpaid An employee directed by their immediate manager/supervisor to continue to work beyond 5 hours after their starting time without a lunch break will be paid at the rate of time and one half until they have a lunch break.

8.2 *Starting and finishing times*

Starting and finishing times, within the span of hours, may be changed by agreement between Endeavour Energy and the employees affected (with support from the relevant union/s) to meet customer needs.

8.3 *Rostering of Ordinary Working Hours*

The basic rostering arrangement of ordinary hours of work shall be the nine-day fortnight.

9. PENALTY RATES

9.1 *Work Outside Ordinary Hours*

9.1.1 The following overtime penalties shall apply:

OVERTIME SITUATION	PENALTY APPLICABLE
Monday to Friday	First 2 hours at time and one half. Additional hours at double time.
Saturday (morning) **Saturday (afternoon)**	First 2 hours at time and one half. Additional hours at double time. All hours at double time.
Hours in excess of ordinary weekly hours	First 2 hours at time and one half Additional hours at double time

OVERTIME SITUATION	PENALTY APPLICABLE
Sunday	All hours at double time
Public Holiday (inside what would have been ordinary hours) **Public Holiday (outside what would have been ordinary hours)**	All hours at double time plus payment for the public holiday (or time in lieu for the day) All hours at double time and one half
Pre-arranged Overtime on Saturday, Sunday or Public Holiday	Minimum of 4 hours at the appropriate penalty according to when it is worked
Call Out	Minimum of 4 hours at the appropriate penalty according to when it is worked.
Continuous overtime – both before and after the normal days work	Overtime hours worked are added together to determine when double time is payable
Travelling Time	Time and one half – based on 2 minutes per kilometre, capped at 40 kilometres each way.
Minimum Break	All employees must have a 10 hour break immediately prior to the commencement of their next rostered or ordinary shift, without loss of pay for ordinary working time occurring during the absence/break. In addition if an employee has worked between the hours of 11.00pm and 5.00am prior to the commencement of their next rostered or ordinary shift, the employee must take a 10 hour break from the end of the work and immediately prior to the commencement of their rostered or ordinary shift, without loss of pay for ordinary working time occurring during the absence/break. Employees covered by the Network Shiftwork Workgroup arrangement will be able to reduce this break to 8 hours for normal rostered shifts only.

9.1.2 Meal breaks and allowances on overtime shall be as follows:

SITUATION	BENEFIT APPLICABLE
Meal Break: **Length of Break** **Frequency of Breaks**	20 minutes for each break without loss of pay. For overtime which is continuous with an ordinary days work: • after 1.5 hours of overtime worked; • after a total of 4 hours of overtime worked; and • after a total of 8 hours of overtime worked. *(a maximum of 3 meal breaks)* For overtime which is not continuous with an ordinary days work: • after 4 hours of overtime worked; • after a total of 8 hours of overtime worked; and

SITUATION	BENEFIT APPLICABLE
	after a total of 12 hours of overtime worked. *(a maximum of 3 meal breaks)*
Meal Allowance	One meal allowance, for each meal break permitted as above *(a maximum of 3 meal allowances also applies)* As an alternative Endeavour Energy will provide a meal to an equivalent value. Refer Appendix B for the value of the meal allowance.

9.1.3 Time off in lieu of overtime worked will be as follows:

ASPECT	PROVISION
Basis of the arrangement	Time off in lieu by agreement with the employee's manager.
Basis of calculating the time in lieu	According to the penalty rates applicable to the overtime worked. (Example: 4 hours overtime at double time = 8 hours and thus 8 hours can be taken)
Taking of time in lieu	The employee is to take the time off within eight weeks of the overtime being worked or the overtime will be paid.

9.1.4 The parties agree to support and facilitate the clarification of leave in lieu and time in lieu and to ensure that employees take their leave in lieu entitlements in accordance with our agreement/workplace arrangements.

9.2 *Shift Work*

9.2.1 The following definitions apply:

TERM	DEFINITION
Shift work	Work carried out according to a roster that provides for 2 or more shifts per day and also requires them to rotate or alternate the shifts worked.
Night shift	Any shift finishing before but not later than 8.00am.
Afternoon shift	Any shift finishing after 6.00pm but not later than midnight.
Permanent afternoon or night shift	Working the same shift each afternoon or night without rotating with any other span of hours.
Meal Break	a 20 minute break taken as part of the shift at a time to meet work needs.

9.2.2 Shift workers who work regular shift work shall be paid a shift allowance of 15% for each shift worked (refer Appendix B) in addition to his or her ordinary rate of pay and weekend penalties. (A "week" shall mean 5 shifts).

9.2.3 Variations to the above have been made via formal Workplace Arrangement negotiations (Network Shiftwork Workgroup arrangement 2008 and CIC Shiftwork Workplace Arrangement 2007).

9.2.4 Shift workers (including permanent afternoon or night shift workers) who work ordinary rostered shifts on a Saturday, Sunday or Public Holiday shall be paid as follows:

WORKING DAY	PENALTY RATE
Saturday	time and one half
Sunday and Public Holiday	double time

9.2.5 A shift worker who is rostered to work on a public holiday will have a day added to his or her time in lieu leave balance.

9.2.6 A shift is said to be on a Saturday, Sunday or public holiday if the majority of the shift worked is on that day.

9.2.7 Situations attracting overtime will be paid as follows:

SITUATION	PENALTY APPLICABLE
Rostered Day Off	All hours at double time.
Recreation Day	The first 2 hours at time and one half and the remaining hours at double time.
Other Overtime	Refer to "overtime" above.

9.2.8 Situations not attracting overtime are as follows:

SITUATION	DESCRIPTION
'Mutual Arrangement' Shifts	Any extra hours worked as a result of mutual agreement between employees *shall not* attract overtime rates.
Customary Rotation of Shifts	The rotation of shifts inside a roster or the change over from one roster to another.

9.3 ***Change of Roster***

9.3.1 Shift workers should normally be given at least five days notice of a change of shift or a change of roster. Where this is not possible the employee will be paid double time for the first shift after the change.

9.3.2 Where an employee is given less than five days notice of a change of shift or roster and the change results in the employee working additional shifts, then the employee shall be allowed an equal amount of time off at a mutually agreed time. If this is not practical for the employee to be allowed time off within four weeks, the employee shall be paid for the extra shifts at double time.

9.3.3 These provisions do not apply to employees who are classified as relief shift workers.

9.3.4 This clause applies except where a local workplace arrangement or enterprise agreement is in place.

9.4 *On Call and Stand By*

9.4.1 With After Hours Emergency and/or Breakdown Service, the work performed by employees will include:

(a) restoring continuity of supply to Endeavour Energy's system and customers;

(b) returning to a safe and proper operating condition any plant and/or equipment which has failed or is likely to fail;

(c) performing maintenance work which is of such an urgent nature that if not carried out an interruption of supply may occur; and

(d) all aspects of consumer's installation, plant, equipment or appliances which if not attended to or temporarily overcome, will cause distress, hardship or loss to the customer and/or other occupants of the premises.

9.4.2 An employee rostered on the on call and stand by roster is required to be available for emergency and/or breakdown work at all times outside his or her usual hours of work.

9.4.3 Employees rostered on call or standby will have their hours monitored for safety reasons.

9.4.4 Employees who are on call are not confined to their homes but they must be reasonably available so that they would not be delayed by more than 15 minutes in addition to the time it would normally take to travel from their homes to the place where the work is to be performed. Any delays in excess of 15 minutes will not be paid unless specifically authorised.

9.4.5 An employee may be required to attend any other calls which arise prior to returning home.

9.4.6 An employee shall not engage in an activity or make a commitment that will adversely affect their obligations when rostered on.

9.4.7 On call and stand by employees will be paid as follows:

SITUATION	ENTITLEMENT
On Call / Stand By Allowance **(Refer Appendix B)**	An employee shall be paid the On Call / Stand By Allowance for each day the employee is rostered on.
Time worked on a call	All time at double time. *(a "call" shall be from the time the call is received to the time the employee has returned home)*
Minimum payment	2 hours at double time.
Attending to the call	Employee to proceed directly to and from the call without unnecessary delay or deviation.
Work on Public Holidays	1 day shall be added to time in lieu for each public holiday worked.

10. ELECTRICAL SAFETY RULES ALLOWANCE

10.1 *Payment of Allowance*

The Electrical Safety Rules Allowance is paid to employees appointed to electrical positions who have passed a test of their knowledge of the rules and who are required to work or supervise or direct work in accordance with those rules. Employees will be required to undergo periodic refresher training. Apprentice electricians are paid the allowance from the date they complete the Electrical Safety Rules Test. Paid for all purposes. (Appendix B – Allowances)

10.2 *Trade Classifications*

Employees in trade classifications (as defined) other than electrician are entitled to 80% of the Electrical Safety Rules Allowance paid to electricians.

10.3 *Pro-rata Safety Rules Allowance*

Pro-rata Safety Rules Allowance paid to Electricity Workers who have passed the Safety Rules Test. This allowance is calculated at 60% of the Electrical Safety Rules Allowance. To be known as Safety Rules Electricity Workers Allowance.

11. TRANSFER OF DEPOT

11.1 *Normal journey*

An employee is required to make their own way to and from their normal place of work each day.

Permanent or temporary transfer

Transfer situation	Provision
Transfer where employee uses their own vehicle	The excess travel resulting from an employee being transferred will be paid at the rate of $1.57 per kilometre for a maximum period of 6 months; OR by a negotiated alternative arrangement.
Transfer where employee uses an Endeavour Energy vehicle	The excess travel resulting from the employee being transferred will be paid at the rate of $1.57 per kilometre (less the Endeavour Energy rate for private vehicle) for each kilometre for a maximum period of 6 months; OR by a negotiated alternative arrangement.

The time component of the transfer of depot allowance will be linked to Agreement increases, and the vehicle component will be linked to the Australian Tax Office guidelines for casual car allowance for a vehicle over 2600cc.

12. ANNUAL LEAVE

12.1 *Basis of Accruing Annual Leave*

The accrual of annual leave and long service leave shall be on the following basis:

CATEGORY OF EMPLOYEE	BASIS OF ACCRUAL
35 hour week Employees	35 hour week ÷ 5 days = 7 hours per day
36 hour week Employees	36 hour week ÷ 5 days = 7.2 hours per day

12.2 *Basis of Taking Annual Leave*

Leave taken by employees shall be deducted from the employee's leave balance and calculated on the basis of his or her rostering of work.

12.3 *Quantum and Loading*

The following quantum annual leave shall be granted to an employee after each year of service:

CATEGORY OF EMPLOYEE	LEAVE	LOADING
Normal day workers and 5 day shift workers	4 weeks (140 hours or 144 hours)	Included in employee's ordinary rate of pay
6 day shift workers	4.5 weeks (157.5 hours or 162 hours)	Included in employee's ordinary rate of pay
7 day shift workers	5 weeks (175 hours or 180 hours)	Included in employee's ordinary rate of pay

12.4 *Taking Annual Leave*

SITUATION	REQUIREMENT
Taking Annual Leave	In one or two separate periods by mutual agreement within 12 months of the leave falling due. The number of periods may be varied by mutual agreement with the employee's manager. Annual leave of less than 1 week may be taken with approval of the employee's manager.
Notification of taking Annual Leave	Employee: 2 weeks notice *(this may be waived in special circumstances by agreement)* Endeavour Energy: 4 weeks notice
Leave in Advance	Where the employee is allowed to take leave in advance, the payment shall be regarded as an over-payment (and may be recovered from the employee's termination pay) until further accrual of leave covers the amount taken in advance.

12.5 *Accrual of Annual Leave*

12.5.1 Except as provided for below, an annual holiday is expected to be taken by an employee and will be given by Endeavour Energy before the expiration of the period 1 year after the date on which the right to take the annual leave accrued.

12.5.2 The above clause will not apply where an employee is accumulating annual leave up to 40 days (50 days for shift workers) for a special purpose. Examples of a special purpose include but are not limited to an overseas holiday or a family reunion.

12.5.3 Employees who have more than two years annual leave accrued will be notified by Endeavour Energy of the expectation to clear such excess accrual.

12.6 *Payment on Termination*

SITUATION	ENTITLEMENT
Less than 12 months Service	Proportion of the leave that would have fallen due upon completion of 12 month's service. Calculation of the proportion is based on the weeks and days service as a proportion of 48 weeks *(47 weeks for 7 day shift workers).*
More than 12 months Service	Any untaken leave plus a proportion of the forthcoming leave accrual. Calculation of the proportion is based on the weeks and days service as a proportion of 48 weeks *(47 weeks for 7 day shift workers).*

13. 48/52 WEEKS PER YEAR WORKING ARRANGEMENTS DEFINED

13.1 *Conditions of the 48/52 weeks per year working arrangements*

The 48/52 weeks per year working arrangements (48/52) is a scheme under which a full-time or part time employee may work 44 weeks of a negotiated 12 month period. An employee participating in the 48/52 scheme has effectively had four weeks leave without pay approved but rather than lose the value of the four weeks salary in one period, the employee has obtained approval to spread the salary impact of four weeks leave without pay averaged over the 52 week period.

This process will be available after the first twelve months of the agreement to give the organisation the ability to implement the appropriate mechanisms to facilitate this process.

13.2 *Entitlement and arrangements*

13.2.1 All full-time continuing, part time fixed and term employees are eligible to apply to their Manager or other delegated officer for approval to take up to eight (8) weeks annual leave in a year and receive 48 weeks salary, which would be payable over the full 52 weeks. Application and approval must be in writing and agreement between the supervisor and the employee.

13.2.2 Once approved, such arrangements will commence at a mutually agreed time and remain in place for a period of 12 months.

13.2.3 Under this arrangement an employee will become a fractional employee at 48/52 of a full time or part time work load, with all benefits accruing on that basis.

13.3 *Annual leave*

13.3.1 Employees electing to move to this become a fractional employee at 48/52 of a full time or part time work load, with all benefits accruing on that basis including annual leave.

13.3.2 Under these arrangements an employee is required to apply for annual leave via the organisations usual leave procedures within the 12 month period.

13.3.3 In taking leave in any one year, it will not be necessary for eight weeks leave to be taken in one block, but this could be an option available to the employee.

13.4 *Long service leave / sick leave*

13.4.1 Employees availing themselves of this option will retain benefits accrued on a full-time or part time fractional time basis up to the nominated commencement date. Long service leave and sick leave benefits accrued after this nominated date will be at the new fractional rate.

13.5 *When leave may be taken*

13.5.1 The eight weeks leave must be taken within its agreed 12 month period.

13.5.2 It will be necessary for the employee and supervisor to agree on the time of taking leave as early as possible upon entering into these arrangements.

13.6 *Termination of employment*

An employee who terminates their services whilst on these arrangements will be paid for the unexpired period of leave at the appropriate fractional rate based on the credit accrued. Where entitlements have accrued at the full-time rate any termination payments will be made at the full time rate.

13.7 *Reallocation of workloads*

Where an employee converts to a 48/52 scheme, the supervisor will ensure that any reallocation of workloads is the subject of consultation with affected employees and does not create an unreasonable workload for any other employee.

13.8 *Superannuation*

Where an employee elects to take up the 48/52 option, superannuation contributions for the employee and the organisation will reduce on a pro-rata basis, except where the employee chooses to maintain, subject to the requirements of the relevant superannuation scheme, the employee and/or employer's superannuation contributions on a full-time employment basis, but the organisation shall only be obliged to cover the cost of employer contributions at the 48/52 rate.

14. PUBLIC HOLIDAYS

14.1 *Entitlement to Public Holidays*

Employees of Endeavour Energy shall be entitled to the following public holidays, plus any additional holidays gazetted by the NSW Government, without loss of pay:

- New Years Day
- Australia Day
- Good Friday
- Easter Saturday
- Easter Monday
- Endeavour Energy Employees Day
- Anzac Day
- Queens Birthday
- Labour Day
- Christmas Day
- Boxing Day

14.2 *Alternate Religious Beliefs*

In order to recognise genuinely held non-Christian religious beliefs an employee may, where it meets customer needs and with the agreement of his or her manager, substitute public holidays listed above for those relevant to that religion.

14.3 *Non Payment of Public Holidays*

Employees shall not be entitled to payment for a public holiday or holidays if:

(a) they are absent on the normal working day before and the day after the public holiday or holidays;

unless

(b) they give the Chief Executive Officer or his or her nominee satisfactory evidence that the absence was due to a good and satisfactory cause.

15. LONG SERVICE LEAVE

15.1 *Quantum*

BASIS OF ACCRUAL	QUANTUM	
After 10 years	13 weeks	(455 hours or 468 hours)
After 15 years	an extra 8.5 weeks	(297.5 hours or 306 hours)
After 20 years	An extra 13.5 weeks	(472.5 hours or 486 hours)
After each additional 5 years	An extra 13 weeks	(455 hours or 468 hours)

15.2 *Taking Long Service Leave*

SITUATION	REQUIREMENT
Taking Long Service Leave	Endeavour Energy expects that Long Service leave be taken as soon as possible after the entitlement arises. Long Service leave may be taken in periods of not less than 4 weeks, by mutual agreement. Long Service leave may be taken at half pay in which case the employee is entitled to twice the duration of Long Service leave.
Notification of Taking Long Service Leave	Employee: 1 month's notice Endeavour Energy: 1 month's notice The amount of notice may be reduced by agreement between the employee and his or her manager.

15.3 *Payment on Termination*

SITUATION	ENTITLEMENT
Less than 5 years	Nil
5 Years or more service **BUT** **Less than 10 Years Service**	Accrued long service leave on a pro-rata basis but only if the reason for termination is: • Redundancy; or • Resignation due to domestic or other pressing necessity.
10 Years or more Service	Any untaken leave plus a proportion of the forthcoming leave accrual. Calculation of the proportion is based on the weeks and days service as a proportion of 48 weeks *(47 weeks for 7 day shift workers).*

15.4 *Recognition of Service for Long Service Leave*

Employees transferring to Endeavour Energy from a public service organisation or State Owned Corporation who have an entitlement to long service leave will have the option to either have the long service leave paid out prior to commencing with Endeavour Energy, or transfer the accrued entitlement. Transfer of Long Service Leave will only be approved where the employee has an accrued entitlement and a cheque is forwarded from the employee's previous employer to Endeavour Energy.

16. BEREAVEMENT LEAVE

16.1.1 An employee other than a casual employee shall be entitled to up to two days bereavement leave without deduction of pay on each occasion of the death of a person prescribed in clause 20.1.3.

16.1.2 The employee must notify Endeavour Energy as soon as practicable of the intention to take bereavement leave and will, if required by Endeavour Energy, provide to the satisfaction of Endeavour Energy proof of death.

16.1.3 Bereavement leave shall be available to an employee in respect to the death of a person prescribed for the purposes of Family/Carer's Leave in clause 20.1.3 provided that for the purpose of bereavement leave, the employee need not have been responsible for the care of the person concerned.

16.1.4 An employee shall not be entitled to bereavement leave under this clause during any period in respect of which the employee has been granted other leave.

16.1.5 Bereavement leave may be taken in conjunction with other leave available under this Agreement. In determining such a request, Endeavour Energy will give consideration to the circumstances of the employee and the reasonable operational requirements of the business.

16.1.6 Bereavement leave entitlements for casual employees are as follows:

16.1.7 Subject to evidentiary and notice requirements in 16.1.2, casual employees are entitled to be not available to work, or to leave work upon the death in Australia of a person prescribed in 16.1.3 of this clause.

16.1.8 The employer and the employee shall agree on the period for which the employee will be entitled to not be available to attend work. In the absence of agreement, the employee is entitled to not be available to attend work for up to 48 hours (i.e. 2 days) per occasion. The casual employee is not entitled to any payment for the period of non-attendance.

16.1.9 An employer must not fail to re-engage a casual employee because the employee accessed the entitlements provided for in this clause. The rights of an employer to engage or not engage a casual employee are otherwise not affected.

17. PARENTAL LEAVE

The following provisions shall also apply in addition to those set out in Chapter 2, Part 2-2, Division 5 – 'Parental leave and related entitlements' of the National Employment Standard (NES) under the Fair Work Act 2009 (Cth); and the Paid Parental Leave Act 2010 (Cth).

The provisions within this clause shall also operate in conjunction with the relevant policies and procedures adopted by Endeavour Energy from time to time.

17.1 *Parental Leave*

17.1.1 Employees who are eligible for Parental leave without pay shall be entitled to receive up to 14 weeks of paid leave (or 28 weeks at half pay) included in the 12 months approved at their ordinary rate of remuneration to assist the employee's ability to reconcile work and family responsibilities and to return to work within the maximum timeframe, if consented, in accordance with this agreement.

17.1.2 An employer must not fail to re-engage a regular casual employee because the:

(a) employee or employee's spouse is pregnant;

(b) employee is or has been immediately absent on parental leave;

(c) rights of an employer in relation to engagement and re-engagement of casual employees are not affected, other than in accordance with this clause.

17.2 *Right to request*

17.2.1 An employee entitled to parental leave may request the employer to allow the employee to:

(a) extend the period of simultaneous unpaid parental leave use up to a maximum of eight (8) weeks

(b) extend the period of unpaid parental leave for a further continuous period of leave not exceeding 12 months

(c) return from a period of parental leave on a part-time basis until the child reaches school age

(d) assistance in reconciling work and parental responsibilities.

17.2.2 The employer shall consider the request having regard to the employee's circumstances and, provided the request is genuinely based on the employee's parental responsibilities, may only refuse the request on reasonable grounds related to the effect on the workplace or the employer's business. Such grounds might include cost, lack of adequate replacement staff, loss of efficiency and the impact on customer service.

17.3 *Employee's request and the employer's decision to be in writing*

17.3.1 The employee's request and the employer's decision must be recorded in writing in accordance with this agreement.

17.3.2 Request to return to work part-time

(a) Where an employee wishes to make a request in accordance with this agreement, such a request must be made as soon as possible but no less than seven (7) weeks prior to the date upon which the employee is due to return to work from parental leave.

17.4 *Other Parent Leave*

An employee who is not the primary care giver is entitled to an unbroken period of one week paid leave at the time of the birth of their child or other termination of pregnancy.

17.5 *Communication during all forms of parental leave*

17.5.1 Where an employee is on parental leave and a definite decision has been made to introduce significant change at the workplace, the employer shall take reasonable steps to:

(a) make information available in relation to any significant effect the change will have on the status or responsibility level of the position the employee held before commencing parental leave, and

(b) provide an opportunity for the employee to discuss any significant effect the change will have on the status or responsibility level of the position the employee held before commencing parental leave.

17.5.2 The employee shall take reasonable steps to inform the employer about any significant matter that will affect the employee's decision regarding the duration of parental leave to be taken, whether the employee intends to return to work and whether the employee intends to request to return to work on a part-time basis.

17.5.3 The employee shall also notify the employer of changes of address or other contact details which might affect the employer's capacity to comply with the terms of this Agreement.

17.6 *Adoption Leave*

Any employee may take unpaid leave in connection with the adoption of a child under the age of 5 years up to a maximum of 52 weeks.

18. ABSENCE BENEFITS SCHEME

18.1 *Purpose for sick leave*

To provide income protection in circumstances where the employee is not able to perform his or her work because of illness or personal injury; or needs to obtain appropriate medical advice and/or treatment for a personal illness or injury.

18.2 *Sick leave granted*

Paid sick leave will be provided to an employee if he or she is genuinely sick and unable to perform his or her duties.

18.3 *Sick leave not granted*

18.3.1 Sick leave shall not be granted in the following circumstances:

(a) where a payment is made for Accident Pay under this Agreement;

(b) where the employee receives payment from an organisation other than Endeavour Energy, in the form of income protection, as a result of participation in an outside activity; or

(c) where in the view of the Chief Executive Officer or his or her nominee the illness or injury resulted from a wilful act, misconduct or the negligence of the employee.

18.4 *Sick Leave and Public Holidays*

A public holiday that occurs during a period of sick leave taken by an employee shall not be counted as sick leave. However a Medical Certificate or Statutory Declaration will be required if an employee is absent due to illness either side of a public holiday.

18.5 *Infectious Diseases*

An employee who comes in contact with a person suffering from a contagious disease (where restrictions are imposed on that employee by law), as confirmed by a Doctor, and therefore cannot come to work may take sick leave.

18.6 *Sick Leave Forms*

Employees claiming sick leave must fill in the required sick leave form on the day they return to work, or their supervisor can complete the form when the staff member calls in sick.

18.7 *Re-crediting of Annual Leave and Long Service Leave*

In order for Long Service Leave or Annual Leave to be re-credited due to illness the following conditions must be met:

(a) For annual leave the employee must be ill for a minimum of 1 working day or shift and provide a Doctor's Certificate/Statutory Declaration covering the entire period

(b) For long service leave the employee must be ill for a minimum of 5 consecutive working days or shifts and provide a Doctor's Certificate/Statutory Declaration covering the entire period;

(c) the employee must be able to demonstrate that as a consequence of the illness or injury their leave was disrupted; and

(d) all requests for leave to be re-credited must be made in writing and sent to the respective Branch Manager.

18.8 *Medical Certificates and Statutory Declarations*

A Medical Certificate or Statutory Declaration will be required if an employee is absent for more than two consecutive working days, or when a repeatable or excessive pattern of sick days develops.

18.9 *Notification*

Staff must notify their supervisor as soon as practicable, on the first day of absence, when they know they will not be able to attend work.

19. PRE 93 SICK LEAVE

Consistent with the outcome of matter number B2010/3579 the value of Pre 93 Sick leave balances will remain at the value of the balance as at the date of the resolution of this matter.

20. FAMILY / CARERS LEAVE

20.1 *Use of leave*

20.1.1 An employee, other than a casual employee, with responsibilities in relation to a class of person set out in accordance with this agreement who needs the employee's care and support shall be entitled to use, in accordance with the sub-clause, up to 10 days sick leave (which is accumulated as per the NES), for absences to provide care for such persons when they are ill. Such leave may be taken for part of a single day. Applications for carers leave in excess of 10 days need to be approved by the Manager Employee Relations on a case by case basis.

20.1.2 The employee shall, if required, establish either by production of a medical certificate or statutory declaration, the illness of the person concerned and that the illness is such as to require care by another person. In normal circumstances an employee must not take Carer's leave under this sub-clause where another person has taken leave to care for the same person.

20.1.3 The entitlement to use sick leave in accordance with this sub-clause is subject to:

(a) the employee being responsible for the care of the person concerned; and

(b) the person concerned being:

(i) a spouse of the employee; or

(ii) a de facto spouse, who, in relation to a person, is a person of the opposite sex to the first-mentioned person who lives with the first-mentioned person as the husband or wife of that person on a bona fide domestic basis although not legally married to that person; or

(iii) a child or an adult child (including an adopted child, a step child, a foster child or an ex-nuptial child), parent (including a foster parent and legal guardian), grandparent, grandchild or sibling of the employee or spouse or de facto spouse of the employee; or

(iv) a same sex partner who lives with the employee as the de facto partner of that employee on a bona fide domestic basis; or

(v) a relative of the employee who is a member of the employee's household, consistent with the NES, where for the purposes of this paragraph:

A. "relative" means a person related by blood; marriage or affinity;

B. "affinity" means a relationship that one spouse because of marriage has to blood relatives of the other; and

C. "household" means a family group living in the same domestic dwelling.

20.1.4 An employee must, wherever practicable, give Endeavour Energy notice prior to the absence of the intention to take leave, the name of the person requiring care and their relationship to the employee, the reasons for taking such leave and the estimated length of absence. If it is not practicable for the employee to give prior notice of absence, the employee must notify Endeavour Energy by telephone of such absence at the first opportunity on the day of absence.

20.2 *Unpaid leave for Family Purpose*

An employee may elect, with the consent of Endeavour Energy, to take unpaid leave for the purpose of providing care and support of a member of a class of person set out in clause 20.1.3 above who is ill.

20.3 *Single day absences on annual leave for family/carers leave*

An employee may elect with the consent of Endeavour Energy, to take annual leave not exceeding ten days in single day periods or part thereof, in any calendar year at a time or times agreed by the parties.

20.4 *Family/carers entitlement for casual employees*

20.4.1 Subject to the evidentiary requirements set out in 20.1.2 and the notice requirement set out in 20.1.4 casual employees are entitled to not be available to attend work, or to leave work if they need to care for a person prescribed in subclause 20.1.3(b) of this clause who are sick and require care and support, or who require care due to an unexpected emergency, or the birth of a child.

20.4.2 Endeavour Energy and the employee shall agree on the period for which the employee will be entitled to not be available to attend work. In the absence of agreement, the employee is entitled to not be available to attend work for up to 48 hours (i.e. two days) per occasion. The casual employee is not entitled to any payment for the period of non-attendance.

20.4.3 Endeavour Energy must not fail to re-engage a casual employee because the employee accessed the entitlements provide for in this clause. The rights of an employer to engage or not to engage a casual employee are otherwise not affected.

20.5 *Family/Carers leave – use of annual leave*

An employee with family/carers leave responsibilities may elect, with Endeavour Energy's agreement, to take annual leave at any time within a period of 24 months from the date at which it falls due. Such applications should be made to the Manager, Employee Relations.

21. DOMESTIC VIOLENCE

21.1 *General Principle*

Endeavour Energy recognises that employees sometimes face situations of violence or abuse in their personal life that may affect their attendance or performance at work. Therefore, Endeavour Energy is committed to providing support to staff that experience domestic violence.

21.2 *Definition of Domestic Violence*

Domestic violence includes physical, sexual, financial, verbal or emotional abuse by an immediate family member as defined in this Agreement.

21.3 *General Measures*

(a) Proof of domestic violence may be required and can be in the form of an agreed document issued by the Police Service, a Court, a Doctor, a Domestic Violence Support Service or Lawyer.

(b) All personal information concerning domestic violence will be kept confidential in line with Endeavour Energy Policy and relevant legislation. No information will be kept on an employee's personnel file without their express written permission.

(c) No adverse action will be taken against an employee if their attendance or performance at work suffers as a result of experiencing domestic violence.

(d) Endeavour Energy will identify a contact in Human Resources who will be trained in domestic violence and privacy issues. Endeavour Energy will advertise the name of the contact within the organisation.

(e) An employee experiencing domestic violence may raise the issue with their immediate supervisor or the Human Resources contact. The supervisor may seek advice from Human Resources if the employee chooses not to see the Human Resources contact.

(f) Where requested by an employee, the Human Resources contact will liaise with the employee's supervisor on the employee's behalf, and will make a recommendation on the most appropriate form of support to provide in accordance with sub clauses 4 and 5.

(g) Endeavour Energy will develop guidelines to supplement this clause which detail the appropriate action to be taken in the event that an employee reports domestic violence.

21.4 *Leave*

(a) An employee experiencing domestic violence will have access to paid special leave for medical appointments, legal proceedings and other matters and activities arising from domestic violence.

This leave will be in addition to existing leave entitlements and may be taken as consecutive or single days or as a fraction of a day and can be taken without prior approval.

(b) An employee who supports a person experiencing domestic violence may take special leave to accompany them to court, to hospital, or to mind children.

21.5 *Individual Support*

(a) In order to provide support to an employee experiencing domestic violence and to provide a safe work environment to all employees, Endeavour Energy will support any reasonable request from an employee experiencing domestic violence for:

(i) changes to their span of hours or pattern or hours and/or shift patterns;

(ii) job redesign or changes to duties;

(iii) relocation to suitable employment within the Endeavour Energy;

(iv) a change to their telephone number or email address to avoid harassing contact;

(v) any other appropriate measure including those available under existing provisions for family friendly and flexible work arrangements.

(b) An employee experiencing domestic violence will be referred to the Employee Assistance Program (EAP) and/or other local resources. The EAP shall include professionals trained specifically in domestic violence.

22. JURY SERVICE

SITUATION	PROVISION
Time spent on Jury Duty	Special leave with pay for the days and/or part days service on jury service.
Adjustment of Employee's pay	The employee's pay will be adjusted by the amount the employee received from the court for his or her attendance

23. SAFETY AT WORK

23.1 *Parties Obligations*

23.1.1 The parties recognise that both Endeavour Energy and its employees have obligations under the New South Wales Occupational Health and Safety Act 2000 to ensure the workplace is safe.

23.1.2 Endeavour Energy's primary concern is the health and safety of its employees, contractors, visitors, customers and the general public. The parties to this Agreement agree to share an ongoing commitment to promote the health, safety and welfare of all employees, contractors, customers, visitors and the general public and nothing in this Agreement shall be designed or applied in ways that reduce or diminish this objective.

23.1.3 The parties commit, consistent with the recommendation of Fair Work Australia (B2010/3579) to the development of policy and implementation of i-Safe vehicle location system in all relevant Endeavour Energy vehicles during the life of this agreement.

24. WORK RELATED ACCIDENT

An employee who suffers a work-related injury within the meaning of the New South Wales workers' compensation legislation will be entitled to benefits provided by Endeavour Energy (a self-insurer) in accordance with the relevant legislation.

24.1 *Evaluation of a Claim*

24.1.1 To overcome employees facing financial hardship during the process of evaluating a claim, employees may elect to take sick leave.

24.1.2 Upon acceptance of the claim any sick leave taken by the employee will be re-classified as workers compensation leave.

24.2 *A Denied Claim*

Where a denied claim is settled or an agreement is made by the Workers Compensation Commission against Endeavour Energy the payment made by Endeavour Energy for sick leave shall be reimbursed by the employee from the settlement or Agreement.

24.3 *Accident Pay*

An employee who has received an injury shall, subject to this clause, be entitled to accident pay while their employment by Endeavour Energy and their entitlement to weekly payment for compensation (pursuant to the Act) for incapacity flowing from such injury continues, for a combined total period up to 52 weeks.

24.4 *Occupational Health and Safety*

(a) For the purposes of this subclause, the following definitions shall apply:

(i) A "labour hire business" is a business (whether an organisation, business enterprise, company, partnership, co-operative, sole trader, family trust or unit trust, corporation and/or person) which has as its business function, or one of its business functions, to supply staff employed or engaged by it to another employer for the purpose of such staff performing work or services for that other employer.

(ii) A "contract business" is a business (whether an organisation, business enterprise, company, partnership, co-operative, sole trader, family trust or unit trust, corporation and/or person) which is contracted by another employer to provide a specified service or services or to produce a specific outcome or result for that other employer which might otherwise have been carried out by that other employer's own employees.

(b) Where Endeavour Energy engages a labour hire business and/or a contract business to perform work wholly or partially on Endeavour Energy's premises, Endeavour Energy shall do the following (either directly, or through the agency of the labour hire or contract business):

(i) provide employees of the labour hire business and/or contract business with appropriate occupational health and safety induction training including the appropriate training required for such employees to perform their jobs safely;

(ii) ensure that those employees of the labour hire business are provided with appropriate personal protective equipment and/or clothing by their employer; and

(iii) ensure employees of the labour hire business and/or contract business are made aware of any risks identified in the workplace and the procedures to control those risks.

(c) Nothing in this subclause 24.4 is intended to affect or detract from any obligation or responsibility upon a labour hire business or contract business arising under the Occupational Health and Safety Act 2000 or the Workplace Injury Management and Workers Compensation Act 1998.

25. SECURE EMPLOYMENT

25.1 *Objective of this Clause*

The objective of this clause is for Endeavour Energy to take all reasonable steps to provide its employees with secure employment by maximising the number of permanent positions in Endeavour Energy's workforce, in particular by ensuring that casual employees have an opportunity to elect to become full-time or part-time employees.

25.2 *Casual Conversion*

(a) A casual employee engaged by Endeavour Energy on a regular and systematic basis for a sequence of periods of employment under this Award during a calendar period of six month shall thereafter have the right to elect to have his or her ongoing contract of employment converted to permanent full-time employment or part-time employment if the employment is to continue beyond the conversion process prescribed by this subclause.

(b) Endeavour Energy shall give the employee notice in writing of the provisions of this sub-clause within four weeks of the employee having attained such period of six months. However, the employee retains his or her right of election under this subclause if the employer fails to comply with this notice requirement.

(c) Any casual employee who has a right to elect under this agreement and in accordance with the Fair Work Act 2009 or after the expiry of the time for giving such notice, may give four weeks' notice in writing to Endeavour Energy that he or she seeks to elect to convert his or her ongoing contract of employment to full-time or part-time employment, and within four weeks of receiving such notice from the employee Endeavour Energy shall consent to or refuse the election, but shall not unreasonably so refuse. Where an employer refuses an election to convert, the reasons for doing so shall be fully stated and discussed with the employee concerned, and a genuine attempt shall be made to reach agreement. Any dispute about a refusal of an election to convert an ongoing contract of employment shall be dealt with through the disputes procedure at Clause 29.

(d) Any casual employee who does not, within four weeks of receiving written notice from Endeavour Energy, elect to convert his or her ongoing contract of employment to full-time employment or part-time employment will be deemed to have elected against any such conversion.

(e) Once a casual employee has elected to become and been converted to a full-time employee or a part-time employee, the employee may only revert to casual employment by written agreement with Endeavour Energy.

(f) If a casual employee has elected to have his or her contract of employment converted to full-time or part-time employment in accordance with this Agreement.

(i) whether the employee will convert to full-time or part-time employee; and

(ii) if it is agreed that the employee will become a part-time employee, the number of hours and the pattern of hours that will be worked shall be consistent with any other part-time employment provisions of this award pursuant to a part time work agreement made under the Act;

(iii) Provided that an employee who has worked on a full-time basis throughout the period of casual employment has the right to elect to convert his or her contract of employment to full-time employment and an employee who has worked on a part-time basis during the period of casual employment has the right to elect to convert his or her contract of employment to part-time employment, on the basis of the same number of hours and times of work as previously worked, unless other arrangements are agreed between the employer and the employee.

(g) Following an agreement being reached pursuant to paragraph (f), the employee shall convert to full-time or part-time employment. If there is any dispute about the arrangements to apply to an employee converting from casual employment to full-time or part-time employment, it shall be dealt with through the disputes procedure at clause 29.

(h) An employee must not be engaged and re-engaged, dismissed or replaced in order to avoid any obligation under this subclause.

26. LABOR HIRE/AGENCY HIRE WORKERS

26.1 Parties to this agreement recognise the need for Endeavour Energy to engage labour hire workers from time to time to meet short term business needs.

26.2 Endeavour Energy will consult with the relevant parties in relation to the prospective need for labour hire engagement.

26.3 In this context, the parties recognise short term as a maximum of six months except in circumstances where consultation has taken place prior to any extension of this time frame.

26.4 As part of this process Endeavour Energy will meet with the relevant unions on a 6 monthly basis to discuss labour requirements, Endeavour Energy will provide a report as to the composition of labour hire agency workers at each of these meetings.

26.5 The company agrees that in deciding to utilise labour hire, workers undertaking work will have wages and conditions that are no less favourable than that provided for in their relevant industrial instrument.

26.6 The parties will consult before introducing a new area of labour hire where labour hire has not traditionally been used. This will entail contact with the relevant union official.

26.7 Endeavour Energy agrees that labour hire will not be used as an alternative to permanent employment and will not diminish the job security or result in alterations to the working conditions of employees.

27. OUTSOURCING/CONTRACTING OUT

27.1 *Basic Principles*

Outsourcing or contracting out will not diminish the working conditions of this agreement.

27.2 Work will only be outsourced or contracted out when it can be demonstrated that:

(a) peak workloads cannot be met by Endeavour Energy's workforce including reasonable overtime; or

(b) where specific expertise, not available in Endeavour Energy's workforce, is required. Where recurring work requires such expertise, Endeavour Energy will make efforts to obtain this expertise by training and/or reorganising its existing workforce. Endeavour Energy will keep the relevant union(s) informed about such training and reorganisation; or

(c) the use of outsourcing or contracting out the work is commercially the most advantageous option taking into account safety, quality, performance, and cost.

27.3 In circumstances where Endeavour Energy is examining outsourcing or contracting out of work activities:

a) A Contracting Consultation Committee (CCC) shall be formed comprising appropriate representation from Endeavour Energy and the applicable unions. The purpose of the CCC will be to serve as a forum for Endeavour Energy to inform and consult the Unions and their members on all contracting and outsourcing proposals.

b) Utilising the CCC - Endeavour Energy will consult the employees and their union(s) and provide them the appropriate time (relevant to the nature of the proposal) to respond with suitable proposals in respect of possible alternative arrangements to outsourcing or contracting out;

c) Prior to expressions of interest or tenders being called, where employee generated alternatives are received, such alternatives will be considered;

d) Expressions of interest or tenders when advertised shall be timed so as to provide the employees with an opportunity to submit a conforming expression of interest or tender. If an employee generated conforming expression of interest or tender is submitted, it will be evaluated together with external submissions consistent with the tendering and probity procedures of Endeavour Energy.

27.4 When a decision is made by Endeavour Energy to outsource/contract out work not already outsourced or contracted out, or in a review of existing contracts, Endeavour Energy will consider a contract to a contractor that demonstrates:

a) contractor(s) undertaking the outsourced /contracted out work will have wages and conditions that are no less favourable than that provided for in their relevant industrial instrument.

b) it has established appropriate industrial relations policies and practices which promote harmonious employee relations and minimise the risk of industrial disputes and that it complies with appropriate safety standards, environmental standards and quality standards to a level commensurate with the standards Endeavour Energy expects.

c) If after engagement of a contractor a party to this agreement provides sufficient evidence that a contractor is not providing its employees with correct statutory entitlements, Endeavour Energy will use an independent organisation to audit compliance with these entitlements. If the audit confirms that there is a breach of the statutory entitlements of the Contractor's employees, Endeavour Energy will take appropriate action.

27.5 In the event that Endeavour Energy has determined to outsource or contract out work, affected employees will have access to the full range of options available under all relevant Endeavour Energy policies which apply at the time. These options will include training and / or retraining.

27.6 Either party may refer this process to the Dispute Procedure in this agreement.

27.7 The parties will comply with their obligations under clauses 3 and 4 of this agreement prior to enacting the above. Nothing in this clause diminishes the parties' obligations under clauses 3 and 4.

28. TEMPORARY RECLASSIFICATION

Temporary reclassification of employees will be on the following basis:

SITUATION	REQUIREMENT OR ENTITLEMENT
Access to temporary reclassification	The manager must require the position to be filled and the employee carries out the full duties of the position.
Period of reclassification and payment:	
Minimum rate to be paid	The minimum rate applicable to the higher position
Minimum period	1 day or shift
Maximum period	3 months

SITUATION	REQUIREMENT OR ENTITLEMENT
	unless: • The position is advertised to be filled permanently; or • the normal incumbent is on long service leave or is working on a project.
Payment on holidays	Public Holidays: Higher rate is payable Sick, Annual Leave: Only payable where employee is acting for 3 months or more
Gaining competencies in higher position	Payment at a higher level than the base acting position will depend on the relevant competencies acquired by the employees and used in the higher grade position.

29. DISPUTES

29.1 *Dispute Resolution Procedure*

The dispute resolution procedure will be used to deal with all disputes arising out of the employer-employee relationship.

While a dispute is being dealt with under the dispute resolution procedure the status quo is to be maintained; that is the situation that existed immediately prior to the issue that gave rise to the dispute.

While a dispute is being dealt with under the dispute resolution procedure work is to continue as normal. The process will not be accompanied by industrial action.

Disputes should, as far as possible, be resolved at their source and at the lowest possible level.

Disputes should remain in the part of the organisation concerned without interference from employees not involved.

All those involved in dealing with a dispute should adopt an interest-based approach. They should appreciate the interests and points of view of the other parties, approach discussions in good faith, work co-operatively to try and resolve the matter, and arrange and attend meetings without unnecessary delay. Endeavour Energy will, where possible, take the needs of employees into account when making decisions.

29.2 *Local matters*

Tier 1: Resolution of local matters will be sought at their source with the involvement of the following:

- the employee(s) concerned and the union delegate (if requested by the employee(s));
- the supervisor and manager (if required);
- the relevant union(s).

Tier 2: If the issue or dispute is not resolved at the local level, it may be referred to the corporate level with involvement of the following:

- the union organiser(s), relevant local delegate and employee(s) concerned if necessary;
- Executive Manager(s) affected local manager(s), Group General Manager Corporate Services and Manager Employee Relations.

An independent third party facilitator may be engaged to assist in resolving the issue or dispute, if agreed by all affected parties.

Tier 3: if the issue or dispute remains unresolved, it may be referred to the Fair Work Commission for conciliation and/or arbitration, by either Endeavour Energy and/or the relevant union(s) with the rights of the parties to appeal being reserved. If both parties agree, a person other than the Fair Work Commission can be asked to deal with the issue or dispute, as provided for under s. 740 of the Fair Work Act 2009.

29.3 *Corporate-wide issues*

Tier 2: Claims or issues may be raised by either:

- Employee(s);
- Relevant Union(s); or
- Endeavour Energy.

Resolution of the issues raised should involve:

- Relevant member(s) of Executive Management and any other necessary resources, and
- Union Organisers and relevant Delegates to ensure input reflects the organisation or the issues raised.

Tier 3: If the issues remain unresolved the matter may be referred to the Fair Work Commission for conciliation and/or arbitration with the rights of the parties to appeal being reserved. If both parties agree, a person other than the Fair Work Commission can be asked to deal with the issue or dispute, as provided for under s. 740 of the Fair Work Act 2009.

29.4 *Other agreed initiatives*

There will be joint training of union delegates and line managers in dispute resolution.

The parties will work together actively to identify any "grey areas" in the agreement and seek to agree on the correct interpretation before disputes arise. The Manager Employee Relations will collate the various interpretations made by FWA of provisions in the agreement and share these with the unions, together with all workgroup arrangements and other understandings. The Employee Relations team will circulate a regular update providing information on pay and conditions issues.

30. UNION DELEGATES RIGHTS

Subject to the relevant sections of the Fair Work Act 2009, the following applies:

30.1 *Endeavour Energy shall be able to:*

30.1.1 Expect that employees, be they Union Delegates or not, will perform the job in which they are employed.

30.1.2 Be given reasonable notice by Delegates that they intend to carry out their Union duties.

30.1.3 Expect that Union Delegate(s) shall not be able to claim or be paid overtime for attendance at Delegates meetings organised during normal working hours.

30.2 *Union Delegates shall be able to:*

30.2.1 Approach, or be approached by a member for the payment of Union dues or other payments, or to discuss any matter related to this member's employment, during working hours.

30.2.2 After obtaining the permission of the employer, move freely for the purpose of consulting other Delegates during working hours.

30.2.3 Have access to Union officials as required within operational hours and on business premises as required for the purposes of Union business.

30.2.4 Be able to represent employees or request a Union official to represent the employee.

30.2.5 To negotiate with management together with other union delegates on behalf of all or part of the members on any matters in accord with Union policy affecting the employment of members who work in Endeavour Energy.

30.2.6 Call meetings and for members to attend these meetings on the job. Such meetings are to be outside of work time unless prior permission is obtained from management.

30.2.7 Have protection from victimisation and this right to be expressed in prohibiting the employer from seeking to separate the delegate from the union members who elected them without first consulting the union.

30.2.8 Have access to a telephone and computer, including email and to have within their work proximity suitable cupboards and furniture to enable them to keep records, union circulars, receipt books etc. so as to efficiently carry out their union responsibilities.

30.2.9 Attend meetings and training held by the Union in which they hold office without loss of any rights or pay following the approval of Endeavour Energy.

30.2.10 Attendance at these meetings shall not be unreasonably withheld. Leave granted for this purpose may be accessed by the relevant special leave provisions and or relevant training leave provisions.

30.2.11 Have all agreements and arrangements negotiated with Endeavour

Energy set out in writing and for these agreements and arrangements, including Agreements, to be provided to delegates on request.

30.2.12 Place notices on defined union notice boards.

31. DEDUCTION OF UNION MEMBERSHIP FEES

The union shall provide the employer with a schedule setting out union weekly membership fees payable by members of the union in accordance with the union's rules.

(a) The union shall advise the employer of any change to the amount of weekly membership fees made under its rules. Any variation to the schedule of union weekly membership fees payable shall be provided to the employer at least one month in advance of the variation taking effect.

(b) Subject to the above, the employer shall deduct union weekly membership fees from the pay of any employee who is a member of the union in accordance with the union's rules, provided that the employee has authorised the employer to make such deductions.

(c) Monies so deducted from employees' pay shall be forwarded regularly to the union together with all necessary information to enable the union to reconcile and credit subscriptions to employees' union membership accounts.

(d) Unless other arrangements are agreed to by the employer and the union, all union membership fees shall be deducted on a weekly basis.

(e) Where an employee has already authorised the deduction of union membership fees from his or her pay prior to this clause taking effect, nothing in this clause shall be read as requiring the employee to make a fresh authorisation in order for such deductions to continue.

32. SALARY SACRIFICE

Endeavour Energy employees can at their own discretion salary sacrifice the following subject to ATO guidelines:

(a) Electricity Account

(b) Superannuation

(c) In-house child care

(d) ICARE

(e) In-house Gym Membership

(f) Any other item that meets ATO guidelines

Employees acknowledge that these arrangements are for their own benefit.

33. RELATIONSHIP TO PREVIOUS AGREEMENTS

This Agreement applies to the exclusion of the Electrical Power Industry Award 2010 and replaces and supersedes all other agreements between the parties including but not limited to the Endeavour Energy Enterprise Agreement 2010.

34. LEAVE RESERVED

34.1 *Compliance Allowance*

That the parties agree to review the application of a Compliance Allowance and any potential cost offsets associated with the implementation of any such allowance.

34.2 *Pay Points*

The Parties will, during the first twelve months of this Agreement, work together in order to rationalise the pay points in Appendix A of the 2008 Award. Should there be any disputes in relation to this process such matter(s) will be referred to the Disputes Procedure of the Agreement.

It is a term of this Award that the parties to this Award undertake that for the period of the duration of the Award that they will not pursue any extra claims, except where consistent with this clause.

Appendix A – Common Pay Points

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z002	98	$ 987.80	$ 51,534		$ 1,014.50	$ 52,926
Z003	98	$ 1,018.80	$ 53,151		$ 1,046.30	$ 54,585
Z005	98	$ 1,050.00	$ 54,779		$ 1,078.40	$ 56,260
Z006	98	$ 1,081.10	$ 56,401		$ 1,110.30	$ 57,924
Z008	98	$ 1,112.50	$ 58,039		$ 1,142.50	$ 59,604
Z009	98	$ 1,156.20	$ 60,319		$ 1,187.40	$ 61,947
Z001	01	$ 1,097.00	$ 57,230		$ 1,126.60	$ 58,775
Z002	21	$ 987.60	$ 51,523		$ 1,014.30	$ 52,916
Z003	21	$ 1,018.80	$ 53,151		$ 1,046.30	$ 54,585
Z005	21	$ 1,050.00	$ 54,779		$ 1,078.40	$ 56,260
Z006	21	$ 1,126.50	$ 58,770		$ 1,156.90	$ 60,355
Z008	21	$ 1,145.20	$ 59,745		$ 1,176.10	$ 61,357
Z009	21	$ 1,156.20	$ 60,319		$ 1,187.40	$ 61,947
Z011	98	$ 1,081.10	$ 56,401		$ 1,110.30	$ 57,924
Z012	98	$ 1,112.50	$ 58,039		$ 1,142.50	$ 59,604
Z014	98	$ 1,156.20	$ 60,319		$ 1,187.40	$ 61,947
Z015	98	$ 1,196.90	$ 62,442		$ 1,229.20	$ 64,127
Z017	98	$ 1,219.90	$ 63,642		$ 1,252.80	$ 65,359
Z018	98	$ 1,249.70	$ 65,197		$ 1,283.40	$ 66,955
Z018	88	$ 1,312.50	$ 68,473		$ 1,347.90	$ 70,320
Z019	98	$ 1,281.50	$ 66,856		$ 1,316.10	$ 68,661

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z019	88	$ 1,343.70	$ 70,101		$ 1,380.00	$ 71,995
Z041	98	$ 1,207.90	$ 63,016		$ 1,240.50	$ 64,717
Z042	98	$ 1,238.80	$ 64,628		$ 1,272.20	$ 66,371
Z044	98	$ 1,271.20	$ 66,319		$ 1,305.50	$ 68,108
Z045	98	$ 1,301.40	$ 67,894		$ 1,336.50	$ 69,725
Z047	98	$ 1,333.10	$ 69,548		$ 1,369.10	$ 71,426
Z041	95	$ 1,161.80	$ 60,611		$ 1,193.20	$ 62,249
Z042	95	$ 1,196.90	$ 62,442		$ 1,229.20	$ 64,127
Z044	95	$ 1,223.20	$ 63,814		$ 1,256.20	$ 65,536
Z045	95	$ 1,249.70	$ 65,197		$ 1,283.40	$ 66,955
Z047	95	$ 1,281.50	$ 66,856		$ 1,316.10	$ 68,661
Z041	97	$ 1,161.80	$ 60,611		$ 1,193.20	$ 62,249
Z042	97	$ 1,196.90	$ 62,442		$ 1,229.20	$ 64,127
Z044	97	$ 1,219.90	$ 63,642		$ 1,252.80	$ 65,359
Z045	97	$ 1,249.70	$ 65,197		$ 1,283.40	$ 66,955
Z047	97	$ 1,281.50	$ 66,856		$ 1,316.10	$ 68,661
Z041	01	$ 1,161.80	$ 60,611		$ 1,193.20	$ 62,249
Z042	02	$ 1,196.90	$ 62,442		$ 1,229.20	$ 64,127
Z044	03	$ 1,219.90	$ 63,642		$ 1,252.80	$ 65,359
Z045	04	$ 1,249.70	$ 65,197		$ 1,283.40	$ 66,955
Z047	05	$ 1,281.50	$ 66,856		$ 1,316.10	$ 68,661
Z021	98	$ 1,187.10	$ 61,931		$ 1,219.20	$ 63,606

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z023	98	$ 1,219.90	$ 63,642		$ 1,252.80	$ 65,359
Z024	98	$ 1,249.70	$ 65,197		$ 1,283.40	$ 66,955
Z026	98	$ 1,281.50	$ 66,856		$ 1,316.10	$ 68,661
Z027	98	$ 1,313.70	$ 68,536		$ 1,349.20	$ 70,388
Z029	98	$ 1,349.00	$ 70,377		$ 1,385.40	$ 72,276
Z030	98	$ 1,376.80	$ 71,828		$ 1,414.00	$ 73,768
Z030	88	$ 1,438.90	$ 75,067		$ 1,477.80	$ 77,097
Z032	98	$ 1,411.30	$ 73,628		$ 1,449.40	$ 75,615
Z032	88	$ 1,474.10	$ 76,904		$ 1,513.90	$ 78,980
Z033	98	$ 1,446.80	$ 75,480		$ 1,485.90	$ 77,519
Z033	88	$ 1,509.10	$ 78,730		$ 1,549.80	$ 80,853
Z036	98	$ 1,482.50	$ 77,342		$ 1,522.50	$ 79,429
Z024	95	$ 1,313.70	$ 68,536		$ 1,349.20	$ 70,388
Z026	95	$ 1,333.10	$ 69,548		$ 1,369.10	$ 71,426
Z027	95	$ 1,365.60	$ 71,243		$ 1,402.50	$ 73,168
Z029	95	$ 1,400.40	$ 73,059		$ 1,438.20	$ 75,031
Z030	95	$ 1,429.00	$ 74,551		$ 1,467.60	$ 76,565
Z032	95	$ 1,462.90	$ 76,319		$ 1,502.40	$ 78,380
Z033	95	$ 1,498.50	$ 78,177		$ 1,539.00	$ 80,290
Z024	96	$ 1,249.70	$ 65,197		$ 1,283.40	$ 66,955
Z026	96	$ 1,281.50	$ 66,856		$ 1,316.10	$ 68,661
Z027	96	$ 1,313.70	$ 68,536		$ 1,349.20	$ 70,388

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z029	96	$ 1,349.00	$ 70,377		$ 1,385.40	$ 72,276
Z030	96	$ 1,376.80	$ 71,828		$ 1,414.00	$ 73,768
Z032	96	$ 1,411.30	$ 73,628		$ 1,449.40	$ 75,615
Z033	96	$ 1,446.80	$ 75,480		$ 1,485.90	$ 77,519
Z036	96	$ 1,482.50	$ 77,342		$ 1,522.50	$ 79,429
Z030	97	$ 1,429.00	$ 74,551		$ 1,467.60	$ 76,565
Z032	97	$ 1,462.90	$ 76,319		$ 1,502.40	$ 78,380
Z033	97	$ 1,498.50	$ 78,177		$ 1,539.00	$ 80,290
Z036	97	$ 1,534.20	$ 80,039		$ 1,575.60	$ 82,199
Z020	01	$ 1,313.80	$ 68,541		$ 1,349.30	$ 70,393
Z022	01	$ 1,359.10	$ 70,904		$ 1,395.80	$ 72,819
Z010	11	$ 1,018.80	$ 53,151		$ 1,046.30	$ 54,585
Z010	12	$ 1,050.00	$ 54,779		$ 1,078.40	$ 56,260
Z010	13	$ 1,081.10	$ 56,401		$ 1,110.30	$ 57,924
Z010	14	$ 1,111.50	$ 57,987		$ 1,141.50	$ 59,552
Z010	21	$ 1,050.00	$ 54,779		$ 1,078.40	$ 56,260
Z010	22	$ 1,081.10	$ 56,401		$ 1,110.30	$ 57,924
Z010	23	$ 1,111.50	$ 57,987		$ 1,141.50	$ 59,552
Z010	24	$ 1,156.20	$ 60,319		$ 1,187.40	$ 61,947
Z010	31	$ 1,081.10	$ 56,401		$ 1,110.30	$ 57,924
Z010	32	$ 1,111.50	$ 57,987		$ 1,141.50	$ 59,552
Z010	33	$ 1,156.20	$ 60,319		$ 1,187.40	$ 61,947

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z010	34	$ 1,196.90	$ 62,442		$ 1,229.20	$ 64,127
Z010	41	$ 1,111.50	$ 57,987		$ 1,141.50	$ 59,552
Z010	42	$ 1,156.20	$ 60,319		$ 1,187.40	$ 61,947
Z010	43	$ 1,196.90	$ 62,442		$ 1,229.20	$ 64,127
Z010	44	$ 1,219.70	$ 63,632		$ 1,252.60	$ 65,348
Z010	51	$ 1,156.20	$ 60,319		$ 1,187.40	$ 61,947
Z010	52	$ 1,196.90	$ 62,442		$ 1,229.20	$ 64,127
Z010	53	$ 1,219.70	$ 63,632		$ 1,252.60	$ 65,348
Z010	54	$ 1,249.70	$ 65,197		$ 1,283.40	$ 66,955
Z010	61	$ 1,196.90	$ 62,442		$ 1,229.20	$ 64,127
Z010	62	$ 1,219.70	$ 63,632		$ 1,252.60	$ 65,348
Z010	63	$ 1,249.70	$ 65,197		$ 1,283.40	$ 66,955
Z010	64	$ 1,281.50	$ 66,856		$ 1,316.10	$ 68,661
Z025	11	$ 1,219.70	$ 63,632		$ 1,252.60	$ 65,348
Z025	12	$ 1,249.70	$ 65,197		$ 1,283.40	$ 66,955
Z025	13	$ 1,281.50	$ 66,856		$ 1,316.10	$ 68,661
Z025	14	$ 1,313.70	$ 68,536		$ 1,349.20	$ 70,388
Z025	21	$ 1,249.70	$ 65,197		$ 1,283.40	$ 66,955
Z025	22	$ 1,281.50	$ 66,856		$ 1,316.10	$ 68,661
Z025	23	$ 1,313.70	$ 68,536		$ 1,349.20	$ 70,388
Z025	24	$ 1,349.00	$ 70,377		$ 1,385.40	$ 72,276
Z025	31	$ 1,281.50	$ 66,856		$ 1,316.10	$ 68,661

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z025	32	$ 1,313.70	$ 68,536		$ 1,349.20	$ 70,388
Z025	33	$ 1,349.00	$ 70,377		$ 1,385.40	$ 72,276
Z025	34	$ 1,376.80	$ 71,828		$ 1,414.00	$ 73,768
Z025	41	$ 1,313.70	$ 68,536		$ 1,349.20	$ 70,388
Z025	42	$ 1,349.00	$ 70,377		$ 1,385.40	$ 72,276
Z025	43	$ 1,376.80	$ 71,828		$ 1,414.00	$ 73,768
Z025	44	$ 1,411.00	$ 73,612		$ 1,449.10	$ 75,600
Z020	11	$ 1,156.10	$ 60,314		$ 1,187.30	$ 61,941
Z020	12	$ 1,196.80	$ 62,437		$ 1,229.10	$ 64,122
Z020	13	$ 1,219.70	$ 63,632		$ 1,252.60	$ 65,348
Z020	14	$ 1,249.70	$ 65,197		$ 1,283.40	$ 66,955
Z020	21	$ 1,196.80	$ 62,437		$ 1,229.10	$ 64,122
Z020	22	$ 1,219.70	$ 63,632		$ 1,252.60	$ 65,348
Z020	23	$ 1,249.70	$ 65,197		$ 1,283.40	$ 66,955
Z020	24	$ 1,281.50	$ 66,856		$ 1,316.10	$ 68,661
Z020	31	$ 1,219.70	$ 63,632		$ 1,252.60	$ 65,348
Z020	32	$ 1,249.70	$ 65,197		$ 1,283.40	$ 66,955
Z020	33	$ 1,281.50	$ 66,856		$ 1,316.10	$ 68,661
Z020	34	$ 1,313.70	$ 68,536		$ 1,349.20	$ 70,388
Z020	41	$ 1,249.70	$ 65,197		$ 1,283.40	$ 66,955
Z020	42	$ 1,281.50	$ 66,856		$ 1,316.10	$ 68,661
Z020	43	$ 1,313.70	$ 68,536		$ 1,349.20	$ 70,388

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z020	44	$ 1,349.00	$ 70,377		$ 1,385.40	$ 72,276
Z020	51	$ 1,281.50	$ 66,856		$ 1,316.10	$ 68,661
Z020	52	$ 1,313.70	$ 68,536		$ 1,349.20	$ 70,388
Z020	53	$ 1,349.00	$ 70,377		$ 1,385.40	$ 72,276
Z020	54	$ 1,376.80	$ 71,828		$ 1,414.00	$ 73,768
Z020	61	$ 1,313.70	$ 68,536		$ 1,349.20	$ 70,388
Z020	62	$ 1,349.00	$ 70,377		$ 1,385.40	$ 72,276
Z020	63	$ 1,376.80	$ 71,828		$ 1,414.00	$ 73,768
Z020	64	$ 1,411.00	$ 73,612		$ 1,449.10	$ 75,600
Z020	65	$ 1,376.20	$ 71,796		$ 1,413.40	$ 73,737
Z020	66	$ 1,411.30	$ 73,628		$ 1,449.40	$ 75,615
Z020	67	$ 1,438.90	$ 75,067		$ 1,477.80	$ 77,097
Z020	68	$ 1,474.10	$ 76,904		$ 1,513.90	$ 78,980
Z048	11	$ 1,238.70	$ 64,623		$ 1,272.10	$ 66,365
Z048	12	$ 1,271.00	$ 66,308		$ 1,305.30	$ 68,098
Z048	13	$ 1,301.30	$ 67,889		$ 1,336.40	$ 69,720
Z048	14	$ 1,333.00	$ 69,543		$ 1,369.00	$ 71,421
Z048	21	$ 1,271.00	$ 66,308		$ 1,305.30	$ 68,098
Z048	22	$ 1,301.30	$ 67,889		$ 1,336.40	$ 69,720
Z048	23	$ 1,333.00	$ 69,543		$ 1,369.00	$ 71,421
Z048	24	$ 1,365.40	$ 71,233		$ 1,402.30	$ 73,158
Z048	31	$ 1,301.30	$ 67,889		$ 1,336.40	$ 69,720

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z048	32	$ 1,333.00	$ 69,543		$ 1,369.00	$ 71,421
Z048	33	$ 1,365.40	$ 71,233		$ 1,402.30	$ 73,158
Z048	34	$ 1,400.40	$ 73,059		$ 1,438.20	$ 75,031
Z048	41	$ 1,333.00	$ 69,543		$ 1,369.00	$ 71,421
Z048	42	$ 1,365.40	$ 71,233		$ 1,402.30	$ 73,158
Z048	43	$ 1,400.40	$ 73,059		$ 1,438.20	$ 75,031
Z048	44	$ 1,428.90	$ 74,546		$ 1,467.50	$ 76,559
Z048	51	$ 1,365.40	$ 71,233		$ 1,402.30	$ 73,158
Z048	52	$ 1,400.40	$ 73,059		$ 1,438.20	$ 75,031
Z048	53	$ 1,428.90	$ 74,546		$ 1,467.50	$ 76,559
Z048	54	$ 1,462.90	$ 76,319		$ 1,502.40	$ 78,380
Z028	21	$ 1,249.70	$ 65,197		$ 1,283.40	$ 66,955
Z028	22	$ 1,281.50	$ 66,856		$ 1,316.10	$ 68,661
Z028	23	$ 1,313.70	$ 68,536		$ 1,349.20	$ 70,388
Z028	24	$ 1,349.00	$ 70,377		$ 1,385.40	$ 72,276
Z028	31	$ 1,281.50	$ 66,856		$ 1,316.10	$ 68,661
Z028	32	$ 1,313.70	$ 68,536		$ 1,349.20	$ 70,388
Z028	33	$ 1,349.00	$ 70,377		$ 1,385.40	$ 72,276
Z028	34	$ 1,376.80	$ 71,828		$ 1,414.00	$ 73,768
Z028	41	$ 1,313.70	$ 68,536		$ 1,349.20	$ 70,388
Z028	42	$ 1,349.00	$ 70,377		$ 1,385.40	$ 72,276
Z028	43	$ 1,376.80	$ 71,828		$ 1,414.00	$ 73,768

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z028	44	$ 1,411.00	$ 73,612		$ 1,449.10	$ 75,600
Z028	51	$ 1,349.00	$ 70,377		$ 1,385.40	$ 72,276
Z028	52	$ 1,376.80	$ 71,828		$ 1,414.00	$ 73,768
Z028	53	$ 1,411.00	$ 73,612		$ 1,449.10	$ 75,600
Z028	54	$ 1,446.70	$ 75,474		$ 1,485.80	$ 77,514
Z028	61	$ 1,376.80	$ 71,828		$ 1,414.00	$ 73,768
Z028	62	$ 1,411.00	$ 73,612		$ 1,449.10	$ 75,600
Z028	63	$ 1,446.70	$ 75,474		$ 1,485.80	$ 77,514
Z028	64	$ 1,482.50	$ 77,342		$ 1,522.50	$ 79,429
Z028	66	$ 1,474.10	$ 76,904		$ 1,513.90	$ 78,980
Z028	67	$ 1,509.10	$ 78,730		$ 1,549.80	$ 80,853
Z028	68	$ 1,544.90	$ 80,597		$ 1,586.60	$ 82,773
Z028	71	$ 1,411.00	$ 73,612		$ 1,449.10	$ 75,600
Z028	72	$ 1,446.70	$ 75,474		$ 1,485.80	$ 77,514
Z028	73	$ 1,482.50	$ 77,342		$ 1,522.50	$ 79,429
Z028	74	$ 1,520.00	$ 79,298		$ 1,561.00	$ 81,437
Z028	81	$ 1,446.70	$ 75,474		$ 1,485.80	$ 77,514
Z028	82	$ 1,482.50	$ 77,342		$ 1,522.50	$ 79,429
Z028	83	$ 1,520.00	$ 79,298		$ 1,561.00	$ 81,437
Z028	84	$ 1,550.90	$ 80,910		$ 1,592.80	$ 83,096
Z028	91	$ 1,482.50	$ 77,342		$ 1,522.50	$ 79,429
Z028	92	$ 1,520.00	$ 79,298		$ 1,561.00	$ 81,437

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z028	93	$ 1,550.90	$ 80,910		$ 1,592.80	$ 83,096
Z028	94	$ 1,587.90	$ 82,841		$ 1,630.80	$ 85,079
Z028	95	$ 1,582.40	$ 82,554		$ 1,625.10	$ 84,781
Z031	31	$ 1,333.00	$ 69,543		$ 1,369.00	$ 71,421
Z031	32	$ 1,365.40	$ 71,233		$ 1,402.30	$ 73,158
Z031	33	$ 1,400.40	$ 73,059		$ 1,438.20	$ 75,031
Z031	34	$ 1,428.90	$ 74,546		$ 1,467.50	$ 76,559
Z031	41	$ 1,365.40	$ 71,233		$ 1,402.30	$ 73,158
Z031	42	$ 1,400.40	$ 73,059		$ 1,438.20	$ 75,031
Z031	43	$ 1,428.90	$ 74,546		$ 1,467.50	$ 76,559
Z031	44	$ 1,462.90	$ 76,319		$ 1,502.40	$ 78,380
Z031	51	$ 1,400.40	$ 73,059		$ 1,438.20	$ 75,031
Z031	52	$ 1,428.90	$ 74,546		$ 1,467.50	$ 76,559
Z031	53	$ 1,462.90	$ 76,319		$ 1,502.40	$ 78,380
Z031	54	$ 1,498.40	$ 78,172		$ 1,538.90	$ 80,284
Z031	61	$ 1,428.90	$ 74,546		$ 1,467.50	$ 76,559
Z031	62	$ 1,462.90	$ 76,319		$ 1,502.40	$ 78,380
Z031	63	$ 1,498.40	$ 78,172		$ 1,538.90	$ 80,284
Z031	64	$ 1,533.80	$ 80,018		$ 1,575.20	$ 82,178
Z031	71	$ 1,462.90	$ 76,319		$ 1,502.40	$ 78,380
Z031	72	$ 1,498.40	$ 78,172		$ 1,538.90	$ 80,284
Z031	73	$ 1,533.80	$ 80,018		$ 1,575.20	$ 82,178

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z031	74	$ 1,565.40	$ 81,667		$ 1,607.70	$ 83,874
Z031	81	$ 1,498.40	$ 78,172		$ 1,538.90	$ 80,284
Z031	82	$ 1,533.80	$ 80,018		$ 1,575.20	$ 82,178
Z031	83	$ 1,565.40	$ 81,667		$ 1,607.70	$ 83,874
Z031	84	$ 1,596.80	$ 83,305		$ 1,639.90	$ 85,554
Z031	91	$ 1,533.80	$ 80,018		$ 1,575.20	$ 82,178
Z031	92	$ 1,565.50	$ 81,672		$ 1,607.80	$ 83,879
Z031	93	$ 1,596.80	$ 83,305		$ 1,639.90	$ 85,554
Z031	94	$ 1,633.60	$ 85,225		$ 1,677.70	$ 87,526
Z037	98	$ 1,565.50	$ 81,672		$ 1,607.80	$ 83,879
Z037	01	$ 1,565.50	$ 81,672		$ 1,607.80	$ 83,879
Z037	03	$ 1,565.50	$ 81,672		$ 1,607.80	$ 83,879
Z037	05	$ 1,565.50	$ 81,672		$ 1,607.80	$ 83,879
Z037	07	$ 1,565.50	$ 81,672		$ 1,607.80	$ 83,879
Z037	09	$ 1,565.50	$ 81,672		$ 1,607.80	$ 83,879
Z037	11	$ 1,565.50	$ 81,672		$ 1,607.80	$ 83,879
Z037	13	$ 1,565.50	$ 81,672		$ 1,607.80	$ 83,879
Z037	15	$ 1,565.50	$ 81,672		$ 1,607.80	$ 83,879
Z037	17	$ 1,565.50	$ 81,672		$ 1,607.80	$ 83,879
Z037	19	$ 1,565.50	$ 81,672		$ 1,607.80	$ 83,879
Z037	21	$ 1,565.50	$ 81,672		$ 1,607.80	$ 83,879
Z037	23	$ 1,565.50	$ 81,672		$ 1,607.80	$ 83,879

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z037	25	$ 1,565.50	$ 81,672		$ 1,607.80	$ 83,879
Z037	27	$ 1,565.50	$ 81,672		$ 1,607.80	$ 83,879
Z038	98	$ 1,597.00	$ 83,315		$ 1,640.10	$ 85,564
Z038	01	$ 1,597.00	$ 83,315		$ 1,640.10	$ 85,564
Z038	03	$ 1,597.00	$ 83,315		$ 1,640.10	$ 85,564
Z038	05	$ 1,597.00	$ 83,315		$ 1,640.10	$ 85,564
Z038	07	$ 1,597.00	$ 83,315		$ 1,640.10	$ 85,564
Z038	09	$ 1,597.00	$ 83,315		$ 1,640.10	$ 85,564
Z038	11	$ 1,597.00	$ 83,315		$ 1,640.10	$ 85,564
Z038	13	$ 1,597.00	$ 83,315		$ 1,640.10	$ 85,564
Z038	15	$ 1,597.00	$ 83,315		$ 1,640.10	$ 85,564
Z039	98	$ 1,633.60	$ 85,225		$ 1,677.70	$ 87,526
Z039	01	$ 1,633.60	$ 85,225		$ 1,677.70	$ 87,526
Z039	03	$ 1,633.80	$ 85,235		$ 1,677.90	$ 87,536
Z039	05	$ 1,633.80	$ 85,235		$ 1,677.90	$ 87,536
Z039	07	$ 1,633.80	$ 85,235		$ 1,677.90	$ 87,536
Z039	09	$ 1,633.80	$ 85,235		$ 1,677.90	$ 87,536
Z039	11	$ 1,633.80	$ 85,235		$ 1,677.90	$ 87,536
Z039	13	$ 1,633.80	$ 85,235		$ 1,677.90	$ 87,536
Z039	15	$ 1,633.80	$ 85,235		$ 1,677.90	$ 87,536
Z039	17	$ 1,633.80	$ 85,235		$ 1,677.90	$ 87,536
Z039	27	$ 1,633.80	$ 85,235		$ 1,677.90	$ 87,536

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z039	28	$ 1,670.60	$ 87,155		$ 1,715.70	$ 89,508
Z508	01	$ 1,126.50	$ 58,770		$ 1,156.90	$ 60,355
Z508	03	$ 1,231.80	$ 64,263		$ 1,265.10	$ 66,000
Z489	01	$ 1,177.00	$ 61,404		$ 1,208.80	$ 63,063
Z490	01	$ 1,215.00	$ 63,387		$ 1,247.80	$ 65,098
Z491	01	$ 1,260.80	$ 65,776		$ 1,294.80	$ 67,550
Z492	01	$ 1,363.20	$ 71,118		$ 1,400.00	$ 73,038
Z065	01	$ 1,349.40	$ 70,398		$ 1,385.80	$ 72,297
Z065	02	$ 1,375.70	$ 71,770		$ 1,412.80	$ 73,706
Z065	03	$ 1,400.40	$ 73,059		$ 1,438.20	$ 75,031
Z065	04	$ 1,445.60	$ 75,417		$ 1,484.60	$ 77,452
Z065	05	$ 1,462.90	$ 76,319		$ 1,502.40	$ 78,380
Z065	06	$ 1,516.40	$ 79,111		$ 1,557.30	$ 81,244
Z066	01	$ 1,349.40	$ 70,398		$ 1,385.80	$ 72,297
Z066	02	$ 1,375.90	$ 71,781		$ 1,413.00	$ 73,716
Z066	03	$ 1,445.50	$ 75,412		$ 1,484.50	$ 77,446
Z066	04	$ 1,516.40	$ 79,111		$ 1,557.30	$ 81,244
Z067	01	$ 1,298.30	$ 67,732		$ 1,333.40	$ 69,563
Z067	02	$ 1,324.40	$ 69,094		$ 1,360.20	$ 70,962
Z067	03	$ 1,349.00	$ 70,377		$ 1,385.40	$ 72,276
Z067	04	$ 1,376.80	$ 71,828		$ 1,414.00	$ 73,768
Z067	05	$ 1,411.00	$ 73,612		$ 1,449.10	$ 75,600

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z067	06	$ 1,446.70	$ 75,474		$ 1,485.80	$ 77,514
Z067	07	$ 1,482.50	$ 77,342		$ 1,522.50	$ 79,429
Z067	08	$ 1,520.00	$ 79,298		$ 1,561.00	$ 81,437
Z068	01	$ 1,349.40	$ 70,398		$ 1,385.80	$ 72,297
Z068	02	$ 1,375.90	$ 71,781		$ 1,413.00	$ 73,716
Z068	03	$ 1,400.40	$ 73,059		$ 1,438.20	$ 75,031
Z068	04	$ 1,445.60	$ 75,417		$ 1,484.60	$ 77,452
Z068	05	$ 1,462.90	$ 76,319		$ 1,502.40	$ 78,380
Z068	06	$ 1,516.50	$ 79,116		$ 1,557.40	$ 81,250
Z068	07	$ 1,534.20	$ 80,039		$ 1,575.60	$ 82,199
Z068	08	$ 1,571.50	$ 81,985		$ 1,613.90	$ 84,197
Z078	19	$ 1,602.60	$ 83,608		$ 1,645.90	$ 85,867
Z078	21	$ 1,639.70	$ 85,543		$ 1,684.00	$ 87,854
Z078	23	$ 1,676.40	$ 87,458		$ 1,721.70	$ 89,821
Z069	01	$ 1,349.40	$ 70,398		$ 1,385.80	$ 72,297
Z069	02	$ 1,376.10	$ 71,791		$ 1,413.30	$ 73,732
Z069	03	$ 1,400.40	$ 73,059		$ 1,438.20	$ 75,031
Z069	04	$ 1,429.00	$ 74,551		$ 1,467.60	$ 76,565
Z069	05	$ 1,462.90	$ 76,319		$ 1,502.40	$ 78,380
Z069	06	$ 1,516.50	$ 79,116		$ 1,557.40	$ 81,250
Z069	51	$ 1,543.50	$ 80,524		$ 1,585.20	$ 82,700
Z069	50	$ 1,508.80	$ 78,714		$ 1,549.50	$ 80,837

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z088	11	$ 1,131.80	$ 59,046		$ 1,162.40	$ 60,642
Z088	12	$ 1,177.00	$ 61,404		$ 1,208.80	$ 63,063
Z088	13	$ 1,215.00	$ 63,387		$ 1,247.80	$ 65,098
Z088	14	$ 1,231.80	$ 64,263		$ 1,265.10	$ 66,000
Z088	16	$ 1,284.80	$ 67,028		$ 1,319.50	$ 68,838
Z088	17	$ 1,311.60	$ 68,426		$ 1,347.00	$ 70,273
Z088	18	$ 1,335.80	$ 69,689		$ 1,371.90	$ 71,572
Z088	19	$ 1,365.90	$ 71,259		$ 1,402.80	$ 73,184
Z088	20	$ 1,397.70	$ 72,918		$ 1,435.40	$ 74,885
Z088	21	$ 1,434.10	$ 74,817		$ 1,472.80	$ 76,836
Z088	22	$ 1,469.20	$ 76,648		$ 1,508.90	$ 78,719
Z088	23	$ 1,506.70	$ 78,605		$ 1,547.40	$ 80,728
Z088	24	$ 1,538.40	$ 80,258		$ 1,579.90	$ 82,423
Z088	25	$ 1,574.50	$ 82,142		$ 1,617.00	$ 84,359
Z088	26	$ 1,611.60	$ 84,077		$ 1,655.10	$ 86,347
Z088	27	$ 1,642.70	$ 85,700		$ 1,687.10	$ 88,016
Z088	28	$ 1,681.80	$ 87,740		$ 1,727.20	$ 90,108
Z088	29	$ 1,714.40	$ 89,440		$ 1,760.70	$ 91,856
Z088	30	$ 1,744.90	$ 91,031		$ 1,792.00	$ 93,489
Z088	31	$ 1,785.40	$ 93,144		$ 1,833.60	$ 95,659
Z764	03	$ 1,433.70	$ 74,796		$ 1,472.40	$ 76,815
Z769	09	$ 1,538.40	$ 80,258		$ 1,579.90	$ 82,423

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z766	05	$ 1,574.50	$ 82,142		$ 1,617.00	$ 84,359
Z769	10	$ 1,611.60	$ 84,077		$ 1,655.10	$ 86,347
Z766	07	$ 1,642.70	$ 85,700		$ 1,687.10	$ 88,016
Z769	11	$ 1,681.80	$ 87,740		$ 1,727.20	$ 90,108
Z769	08	$ 1,817.40	$ 94,814		$ 1,866.50	$ 97,375
Z064	09	$ 1,053.00	$ 54,935		$ 1,081.40	$ 56,417
Z064	19	$ 1,231.80	$ 64,263		$ 1,265.10	$ 66,000
Z064	25	$ 1,335.80	$ 69,689		$ 1,371.90	$ 71,572
Z064	28	$ 940.30	$ 49,055		$ 965.70	$ 50,381
Z070	02	$ 1,335.90	$ 69,694		$ 1,372.00	$ 71,577
Z071	02	$ 1,363.70	$ 71,144		$ 1,400.50	$ 73,064
Z072	02	$ 1,397.70	$ 72,918		$ 1,435.40	$ 74,885
Z072	3	$ 1,434.10	$ 74,817		$ 1,472.80	$ 76,836
Z073	02	$ 1,469.20	$ 76,648		$ 1,508.90	$ 78,719
Z074	02	$ 1,506.70	$ 78,605		$ 1,547.40	$ 80,728
Z075	02	$ 1,538.40	$ 80,258		$ 1,579.90	$ 82,423
Z075	03	$ 1,574.50	$ 82,142		$ 1,617.00	$ 84,359
Z075	04	$ 1,611.60	$ 84,077		$ 1,655.10	$ 86,347
Z075	08	$ 1,031.20	$ 53,798		$ 1,059.00	$ 55,248
ZINSINSP	01	$ 1,537.70	$ 80,222		$ 1,579.20	$ 82,387
ZINSINSP	02	$ 1,577.20	$ 82,283		$ 1,619.80	$ 84,505
ZINSINSP	03	$ 1,658.20	$ 86,508		$ 1,703.00	$ 88,846

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
ZINSINSP	04	$ 1,700.10	$ 88,694		$ 1,746.00	$ 91,089
ZINSINSP	05	$ 1,735.80	$ 90,557		$ 1,782.70	$ 93,003
ZINSINSP	06	$ 1,777.10	$ 92,711		$ 1,825.10	$ 95,215
ZINSINSP	07	$ 1,818.10	$ 94,850		$ 1,867.20	$ 97,412
Z077	01	$ 1,289.80	$ 67,289		$ 1,324.60	$ 69,104
Z077	06	$ 1,316.70	$ 68,692		$ 1,352.30	$ 70,549
Z077	07	$ 1,341.00	$ 69,960		$ 1,377.20	$ 71,849
Z077	02	$ 1,369.30	$ 71,436		$ 1,406.30	$ 73,367
Z077	03	$ 1,404.00	$ 73,247		$ 1,441.90	$ 75,224
Z077	04	$ 1,475.20	$ 76,961		$ 1,515.00	$ 79,038
Z077	05	$ 1,544.30	$ 80,566		$ 1,586.00	$ 82,742
Z077	08	$ 1,581.20	$ 82,491		$ 1,623.90	$ 84,719
Z070	01	$ 1,284.50	$ 67,012		$ 1,319.20	$ 68,823
Z071	01	$ 1,335.80	$ 69,689		$ 1,371.90	$ 71,572
Z072	01	$ 1,363.70	$ 71,144		$ 1,400.50	$ 73,064
Z073	01	$ 1,397.70	$ 72,918		$ 1,435.40	$ 74,885
Z074	01	$ 1,469.20	$ 76,648		$ 1,508.90	$ 78,719
Z075	01	$ 1,538.40	$ 80,258		$ 1,579.90	$ 82,423
Z577	01	$ 1,649.70	$ 86,065		$ 1,694.20	$ 88,386
Z577	02	$ 1,688.60	$ 88,094		$ 1,734.20	$ 90,473
Z577	03	$ 1,792.90	$ 93,536		$ 1,841.30	$ 96,061
Z577	04	$ 1,889.60	$ 98,580		$ 1,940.60	$ 101,241

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z577	05	$ 2,008.10	$ 104,763		$ 2,062.30	$ 107,590
Z577	06	$ 2,054.20	$ 107,168		$ 2,109.70	$ 110,063
Z577	07	$ 2,105.90	$ 109,865		$ 2,162.80	$ 112,833
Z575	01	$ 1,642.40	$ 85,684		$ 1,686.70	$ 87,995
Z575	02	$ 1,681.80	$ 87,740		$ 1,727.20	$ 90,108
Z575	03	$ 1,785.40	$ 93,144		$ 1,833.60	$ 95,659
Z575	04	$ 1,881.60	$ 98,163		$ 1,932.40	$ 100,813
Z575	05	$ 1,999.50	$ 104,314		$ 2,053.50	$ 107,131
Z576	25	$ 1,574.50	$ 82,142		$ 1,617.00	$ 84,359
Z576	26	$ 1,611.10	$ 84,051		$ 1,654.60	$ 86,320
Z576	27	$ 1,642.40	$ 85,684		$ 1,686.70	$ 87,995
Z576	28	$ 1,681.80	$ 87,740		$ 1,727.20	$ 90,108
Z576	29	$ 1,714.40	$ 89,440		$ 1,760.70	$ 91,856
Z576	30	$ 1,744.90	$ 91,031		$ 1,792.00	$ 93,489
Z576	31	$ 1,785.40	$ 93,144		$ 1,833.60	$ 95,659
ZAO	01	$ 522.30	$ 27,248		$ 536.40	$ 27,984
ZAO	02	$ 596.00	$ 31,093		$ 612.10	$ 31,933
ZAO	03	$ 699.30	$ 36,482		$ 718.20	$ 37,468
ZAO	04	$ 847.30	$ 44,204		$ 870.20	$ 45,398
ZAO	05	$ 964.70	$ 50,328		$ 990.70	$ 51,685
ZAO	06	$ 969.90	$ 50,600		$ 996.10	$ 51,967
ZAO	07	$ 999.30	$ 52,133		$ 1,026.30	$ 53,542

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
ZAO	08	$ 1,024.80	$ 53,464		$ 1,052.50	$ 54,909
ZAO	09	$ 1,053.00	$ 54,935		$ 1,081.40	$ 56,417
ZAO	10	$ 1,084.00	$ 56,552		$ 1,113.30	$ 58,081
ZAO	11	$ 1,131.80	$ 59,046		$ 1,162.40	$ 60,642
ZAO	12	$ 1,177.00	$ 61,404		$ 1,208.80	$ 63,063
ZAO	13	$ 1,215.00	$ 63,387		$ 1,247.80	$ 65,098
ZAO	14	$ 1,231.80	$ 64,263		$ 1,265.10	$ 66,000
ZAO	15	$ 1,260.80	$ 65,776		$ 1,294.80	$ 67,550
ZAO	16	$ 1,284.80	$ 67,028		$ 1,319.50	$ 68,838
ZAO	17	$ 1,311.60	$ 68,426		$ 1,347.00	$ 70,273
ZAO	18	$ 1,335.80	$ 69,689		$ 1,371.90	$ 71,572
ZAO	19	$ 1,365.90	$ 71,259		$ 1,402.80	$ 73,184
ZAO	20	$ 1,397.70	$ 72,918		$ 1,435.40	$ 74,885
ZAO	21	$ 1,434.10	$ 74,817		$ 1,472.80	$ 76,836
ZAO	22	$ 1,469.20	$ 76,648		$ 1,508.90	$ 78,719
ZAO	23	$ 1,506.70	$ 78,605		$ 1,547.40	$ 80,728
ZAO	24	$ 1,538.40	$ 80,258		$ 1,579.90	$ 82,423
ZAO	25	$ 1,574.50	$ 82,142		$ 1,617.00	$ 84,359
ZAO	26	$ 1,611.60	$ 84,077		$ 1,655.10	$ 86,347
ZAO	27	$ 1,642.70	$ 85,700		$ 1,687.10	$ 88,016
ZAO	28	$ 1,681.80	$ 87,740		$ 1,727.20	$ 90,108
ZAO	29	$ 1,714.40	$ 89,440		$ 1,760.70	$ 91,856

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
ZAO	30	$ 1,744.90	$ 91,031		$ 1,792.00	$ 93,489
ZAO	31	$ 1,785.40	$ 93,144		$ 1,833.60	$ 95,659
ZAO	32	$ 1,822.30	$ 95,069		$ 1,871.50	$ 97,636
ZAO	33	$ 1,860.00	$ 97,036		$ 1,910.20	$ 99,655
Z557	09	$ 1,231.80	$ 64,263		$ 1,265.10	$ 66,000
Z557	07	$ 1,260.70	$ 65,771		$ 1,294.70	$ 67,544
Z557	19	$ 1,284.50	$ 67,012		$ 1,319.20	$ 68,823
Z557	21	$ 1,311.50	$ 68,421		$ 1,346.90	$ 70,268
Z557	23	$ 1,335.80	$ 69,689		$ 1,371.90	$ 71,572
ZAOS	05	$ 934.20	$ 48,737		$ 959.40	$ 50,052
ZAOS	06	$ 973.90	$ 50,808		$ 1,000.20	$ 52,180
ZAOS	07	$ 1,003.40	$ 52,347		$ 1,030.50	$ 53,761
ZAOS	08	$ 1,029.00	$ 53,683		$ 1,056.80	$ 55,133
ZAOS	09	$ 1,056.90	$ 55,138		$ 1,085.40	$ 56,625
ZAOS	10	$ 1,088.50	$ 56,787		$ 1,117.90	$ 58,321
ZAOS	11	$ 1,136.30	$ 59,281		$ 1,167.00	$ 60,882
ZAOS	12	$ 1,181.90	$ 61,660		$ 1,213.80	$ 63,324
ZAOS	13	$ 1,220.00	$ 63,647		$ 1,252.90	$ 65,364
ZAOS	14	$ 1,237.00	$ 64,534		$ 1,270.40	$ 66,277
ZAOS	15	$ 1,265.80	$ 66,037		$ 1,300.00	$ 67,821
ZAOS	16	$ 1,289.80	$ 67,289		$ 1,324.60	$ 69,104
ZAOS	17	$ 1,316.70	$ 68,692		$ 1,352.30	$ 70,549

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
ZAOS	18	$ 1,341.00	$ 69,960		$ 1,377.20	$ 71,849
ZAOS	19	$ 1,369.30	$ 71,436		$ 1,406.30	$ 73,367
ZAOS	20	$ 1,404.00	$ 73,247		$ 1,441.90	$ 75,224
Z600	01	$ 1,553.30	$ 81,036		$ 1,595.20	$ 83,222
Z600	02	$ 1,577.10	$ 82,277		$ 1,619.70	$ 84,500
Z600	03	$ 1,617.20	$ 84,369		$ 1,660.90	$ 86,649
Z600	04	$ 1,658.40	$ 86,519		$ 1,703.20	$ 88,856
Z600	05	$ 1,700.00	$ 88,689		$ 1,745.90	$ 91,084
Z600	06	$ 1,743.50	$ 90,958		$ 1,790.60	$ 93,416
Z600	07	$ 1,780.00	$ 92,863		$ 1,828.10	$ 95,372
Z600	08	$ 1,822.10	$ 95,059		$ 1,871.30	$ 97,626
Z600	09	$ 1,864.50	$ 97,271		$ 1,914.80	$ 99,895
Z600	10	$ 1,900.70	$ 99,160		$ 1,952.00	$ 101,836
Z600	11	$ 1,945.80	$ 101,512		$ 1,998.30	$ 104,251
Z600	12	$ 1,994.50	$ 104,053		$ 2,048.40	$ 106,865
Z700	01	$ 1,361.10	$ 71,009		$ 1,397.80	$ 72,923
Z700	02	$ 1,404.80	$ 73,288		$ 1,442.70	$ 75,266
Z700	03	$ 1,425.10	$ 74,347		$ 1,463.60	$ 76,356
Z700	04	$ 1,458.20	$ 76,074		$ 1,497.60	$ 78,130
Z700	05	$ 1,486.30	$ 77,540		$ 1,526.40	$ 79,632
Z700	06	$ 1,516.50	$ 79,116		$ 1,557.40	$ 81,250
Z700	07	$ 1,544.90	$ 80,597		$ 1,586.60	$ 82,773

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z700	08	$ 1,577.10	$ 82,277		$ 1,619.70	$ 84,500
Z700	09	$ 1,617.10	$ 84,364		$ 1,660.80	$ 86,644
Z700	10	$ 1,658.40	$ 86,519		$ 1,703.20	$ 88,856
Z700	11	$ 1,701.90	$ 88,788		$ 1,747.90	$ 91,188
Z700	12	$ 1,743.30	$ 90,948		$ 1,790.40	$ 93,405
Z700	13	$ 1,779.80	$ 92,852		$ 1,827.90	$ 95,362
Z700	14	$ 1,822.10	$ 95,059		$ 1,871.30	$ 97,626
Z700	15	$ 1,864.40	$ 97,266		$ 1,914.70	$ 99,890
Z700	16	$ 1,900.70	$ 99,160		$ 1,952.00	$ 101,836
Z700	17	$ 1,945.80	$ 101,512		$ 1,998.30	$ 104,251
Z700	18	$ 1,984.00	$ 103,505		$ 2,037.60	$ 106,302
Z079	17	$ 1,311.60	$ 68,426		$ 1,347.00	$ 70,273
Z079	18	$ 1,335.80	$ 69,689		$ 1,371.90	$ 71,572
Z079	19	$ 1,363.70	$ 71,144		$ 1,400.50	$ 73,064
Z079	20	$ 1,397.70	$ 72,918		$ 1,435.40	$ 74,885
Z079	21	$ 1,436.30	$ 74,932		$ 1,475.10	$ 76,956
Z079	22	$ 1,469.20	$ 76,648		$ 1,508.90	$ 78,719
Z079	23	$ 1,506.70	$ 78,605		$ 1,547.40	$ 80,728
Z079	24	$ 1,538.40	$ 80,258		$ 1,579.90	$ 82,423
Z079	25	$ 1,574.50	$ 82,142		$ 1,617.00	$ 84,359
Z079	26	$ 1,611.60	$ 84,077		$ 1,655.10	$ 86,347
Z079	27	$ 1,642.70	$ 85,700		$ 1,687.10	$ 88,016

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z079	28	$ 1,681.80	$ 87,740		$ 1,727.20	$ 90,108
Z079	29	$ 1,714.40	$ 89,440		$ 1,760.70	$ 91,856
Z079	30	$ 1,744.90	$ 91,031		$ 1,792.00	$ 93,489
Z079	31	$ 1,785.40	$ 93,144		$ 1,833.60	$ 95,659
Z708	01	$ 1,173.50	$ 61,221		$ 1,205.20	$ 62,875
Z708	03	$ 1,215.00	$ 63,387		$ 1,247.80	$ 65,098
Z708	05	$ 1,231.80	$ 64,263		$ 1,265.10	$ 66,000
Z708	06	$ 1,260.80	$ 65,776		$ 1,294.80	$ 67,550
Z708	08	$ 1,311.60	$ 68,426		$ 1,347.00	$ 70,273
Z708	07	$ 1,284.80	$ 67,028		$ 1,319.50	$ 68,838
Z486	01	$ 1,284.50	$ 67,012		$ 1,319.20	$ 68,823
Z486	04	$ 1,681.80	$ 87,740		$ 1,727.20	$ 90,108
Z486	02	$ 1,397.70	$ 72,918		$ 1,435.40	$ 74,885
EEGD	01	$ 1,384.90	$ 72,250		$ 1,422.30	$ 74,201
EEGD	02	$ 1,446.80	$ 75,480		$ 1,485.90	$ 77,519
EEGD	03	$ 1,518.40	$ 79,215		$ 1,559.40	$ 81,354
EEGD	04	$ 1,587.50	$ 82,820		$ 1,630.40	$ 85,058
EEGD	05	$ 1,660.60	$ 86,634		$ 1,705.40	$ 88,971
Z270	02	$ 747.00	$ 38,971		$ 767.20	$ 40,025
Z270	03	$ 853.70	$ 44,538		$ 876.70	$ 45,737
Z271	03	$ 436.20	$ 22,757		$ 448.00	$ 23,372
Z270	04	$ 924.40	$ 48,226		$ 949.40	$ 49,530

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z271	04	$ 471.60	$ 24,603		$ 484.30	$ 25,266
Z090	03	$ 600.60	$ 31,333		$ 616.80	$ 32,178
Z091	98	$ 736.30	$ 38,413		$ 756.20	$ 39,451
Z091	03	$ 736.30	$ 38,413		$ 756.20	$ 39,451
Z091	11	$ 736.30	$ 38,413		$ 756.20	$ 39,451
Z091	21	$ 736.30	$ 38,413		$ 756.20	$ 39,451
Z092	98	$ 843.10	$ 43,985		$ 865.90	$ 45,174
Z092	03	$ 843.10	$ 43,985		$ 865.90	$ 45,174
Z092	11	$ 843.10	$ 43,985		$ 865.90	$ 45,174
Z092	21	$ 843.10	$ 43,985		$ 865.90	$ 45,174
Z093	98	$ 949.10	$ 49,515		$ 974.70	$ 50,850
Z093	03	$ 949.10	$ 49,515		$ 974.70	$ 50,850
Z094	01	$ 1,018.80	$ 53,151		$ 1,046.30	$ 54,585
Z094	02	$ 1,081.10	$ 56,401		$ 1,110.30	$ 57,924
Z094	03	$ 1,050.00	$ 54,779		$ 1,078.40	$ 56,260
ZSPA	01	$ 1,547.50	$ 80,733		$ 1,589.30	$ 82,914
ZSPB	01	$ 1,628.00	$ 84,933		$ 1,672.00	$ 87,228
ZSPA	02	$ 1,586.80	$ 82,783		$ 1,629.60	$ 85,016
ZSPB	02	$ 1,669.40	$ 87,093		$ 1,714.50	$ 89,445
ZSPA	03	$ 1,619.40	$ 84,484		$ 1,663.10	$ 86,764
ZSPB	03	$ 1,704.00	$ 88,898		$ 1,750.00	$ 91,298
ZSPA	04	$ 1,658.30	$ 86,514		$ 1,703.10	$ 88,851

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
ZSPB	04	$ 1,744.40	$ 91,005		$ 1,791.50	$ 93,463
ZSPA	05	$ 1,697.50	$ 88,559		$ 1,743.30	$ 90,948
ZSPB	05	$ 1,785.70	$ 93,160		$ 1,833.90	$ 95,675
ZSPA	06	$ 1,729.90	$ 90,249		$ 1,776.60	$ 92,685
ZSPB	06	$ 1,820.00	$ 94,949		$ 1,869.10	$ 97,511
ZSPA	07	$ 1,770.80	$ 92,383		$ 1,818.60	$ 94,876
ZSPB	07	$ 1,862.90	$ 97,187		$ 1,913.20	$ 99,812
ZHG61	01	$ 1,843.70	$ 96,186		$ 1,893.50	$ 98,784
ZHG61	02	$ 1,932.00	$ 100,792		$ 1,984.20	$ 103,516
ZHG62	01	$ 1,888.30	$ 98,513		$ 1,939.30	$ 101,173
ZHG62	02	$ 1,978.90	$ 103,239		$ 2,032.30	$ 106,025
ZHG63	01	$ 1,933.90	$ 100,892		$ 1,986.10	$ 103,615
ZHG63	02	$ 2,026.50	$ 105,723		$ 2,081.20	$ 108,576
ZHG64	01	$ 1,978.70	$ 103,229		$ 2,032.10	$ 106,015
ZHG64	02	$ 2,073.70	$ 108,185		$ 2,129.70	$ 111,106
ZHG65	01	$ 2,023.70	$ 105,576		$ 2,078.30	$ 108,425
ZHG65	02	$ 2,120.80	$ 110,642		$ 2,178.10	$ 113,631
ZHG66	01	$ 2,070.60	$ 108,023		$ 2,126.50	$ 110,940
ZHG66	02	$ 2,169.90	$ 113,204		$ 2,228.50	$ 116,261
ZHG67	01	$ 2,131.20	$ 111,185		$ 2,188.70	$ 114,184
ZHG67	02	$ 2,233.50	$ 116,522		$ 2,293.80	$ 119,668
ZHG68	01	$ 2,191.90	$ 114,351		$ 2,251.10	$ 117,440

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
ZHG68	02	$ 2,296.60	$ 119,814		$ 2,358.60	$ 123,048
ZHG69	01	$ 2,251.80	$ 117,476		$ 2,312.60	$ 120,648
ZHG69	02	$ 2,359.40	$ 123,090		$ 2,423.10	$ 126,413
NOGR1	15	$ 1,409.70	$ 73,544		$ 1,447.80	$ 75,532
NOGR2	16	$ 1,436.50	$ 74,942		$ 1,475.30	$ 76,966
NOGR3	17	$ 1,466.10	$ 76,486		$ 1,505.70	$ 78,552
NOGR4	18	$ 1,493.40	$ 77,911		$ 1,533.70	$ 80,013
NOGR5	19	$ 1,527.50	$ 79,690		$ 1,568.70	$ 81,839
NOGR6	20	$ 1,563.50	$ 81,568		$ 1,605.70	$ 83,769
NOGR7	21	$ 1,604.00	$ 83,681		$ 1,647.30	$ 85,940
NOGR8	22	$ 1,643.40	$ 85,736		$ 1,687.80	$ 88,053
NOGR9	23	$ 1,685.00	$ 87,906		$ 1,730.50	$ 90,280
NOGR10	24	$ 1,720.20	$ 89,743		$ 1,766.60	$ 92,164
NOGR11	25	$ 1,761.50	$ 91,897		$ 1,809.10	$ 94,381
NOGR12	26	$ 1,802.50	$ 94,036		$ 1,851.20	$ 96,577
NOGR13	27	$ 1,837.40	$ 95,857		$ 1,887.00	$ 98,445
NOGR14	28	$ 1,881.10	$ 98,137		$ 1,931.90	$ 100,787
ZOFF01	17	$ 1,479.60	$ 77,191		$ 1,519.50	$ 79,272
ZOFF02	18	$ 1,515.00	$ 79,038		$ 1,555.90	$ 81,171
ZOFF03	19	$ 1,538.40	$ 80,258		$ 1,579.90	$ 82,423
ZOFF04	20	$ 1,577.20	$ 82,283		$ 1,619.80	$ 84,505
ZOFF05	21	$ 1,617.70	$ 84,395		$ 1,661.40	$ 86,675

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
ZOFF06	22	$ 1,658.20	$ 86,508		$ 1,703.00	$ 88,846
ZOFF07	23	$ 1,700.10	$ 88,694		$ 1,746.00	$ 91,089
ZOFF08	24	$ 1,735.80	$ 90,557		$ 1,782.70	$ 93,003
ZOFF09	25	$ 1,777.10	$ 92,711		$ 1,825.10	$ 95,215
ZOFF10	26	$ 1,818.10	$ 94,850		$ 1,867.20	$ 97,412
ZOFF11	27	$ 1,853.70	$ 96,708		$ 1,903.70	$ 99,316
ZOFF12	28	$ 1,898.00	$ 99,019		$ 1,949.20	$ 101,690
ZOFF13	29	$ 1,944.90	$ 101,465		$ 1,997.40	$ 104,204
ZOFF14	30	$ 1,982.10	$ 103,406		$ 2,035.60	$ 106,197
ZSEM01	21	$ 1,617.70	$ 84,395		$ 1,661.40	$ 86,675
ZSEM02	22	$ 1,658.20	$ 86,508		$ 1,703.00	$ 88,846
ZSEM03	23	$ 1,700.10	$ 88,694		$ 1,746.00	$ 91,089
ZSEM04	24	$ 1,735.80	$ 90,557		$ 1,782.70	$ 93,003
ZSEM05	25	$ 1,777.10	$ 92,711		$ 1,825.10	$ 95,215
ZSEM06	26	$ 1,818.10	$ 94,850		$ 1,867.20	$ 97,412
ZSEM07	27	$ 1,853.70	$ 96,708		$ 1,903.70	$ 99,316
ZSEM08	28	$ 1,898.00	$ 99,019		$ 1,949.20	$ 101,690
ZSEM09	29	$ 1,944.90	$ 101,465		$ 1,997.40	$ 104,204
ZSEM10	30	$ 1,982.10	$ 103,406		$ 2,035.60	$ 106,197
ZSEM11	31	$ 2,037.90	$ 106,317		$ 2,092.90	$ 109,187
ZSEM12	32	$ 2,085.60	$ 108,806		$ 2,141.90	$ 111,743
ZSEM13	33	$ 2,134.40	$ 111,352		$ 2,192.00	$ 114,357

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
TECN00		$ 1,207.90	$ 63,016		$ 1,240.50	$ 64,717
TECN01		$ 1,230.90	$ 64,216		$ 1,264.10	$ 65,948
TECN02		$ 1,253.50	$ 65,395		$ 1,287.30	$ 67,158
TECN03		$ 1,276.40	$ 66,590		$ 1,310.90	$ 68,390
TECN04		$ 1,298.70	$ 67,753		$ 1,333.80	$ 69,584
TECN05		$ 1,321.50	$ 68,943		$ 1,357.20	$ 70,805
TECN06		$ 1,344.10	$ 70,122		$ 1,380.40	$ 72,015
TECN07		$ 1,366.80	$ 71,306		$ 1,403.70	$ 73,231
TECN08		$ 1,389.70	$ 72,501		$ 1,427.20	$ 74,457
TECN09		$ 1,412.50	$ 73,690		$ 1,450.60	$ 75,678
TECN10		$ 1,435.30	$ 74,880		$ 1,474.10	$ 76,904
TECN11		$ 1,457.90	$ 76,059		$ 1,497.30	$ 78,114
TECN12		$ 1,480.90	$ 77,259		$ 1,520.90	$ 79,345
TECN13		$ 1,503.60	$ 78,443		$ 1,544.20	$ 80,561
TECN14		$ 1,526.40	$ 79,632		$ 1,567.60	$ 81,782
TECN15		$ 1,549.10	$ 80,817		$ 1,590.90	$ 82,997
TECN16		$ 1,572.00	$ 82,011		$ 1,614.40	$ 84,223
TECN17		$ 1,594.20	$ 83,169		$ 1,637.20	$ 85,413
TECN18		$ 1,617.20	$ 84,369		$ 1,660.90	$ 86,649
TECN19		$ 1,639.90	$ 85,554		$ 1,684.20	$ 87,865
TECN20		$ 1,662.70	$ 86,743		$ 1,707.60	$ 89,085
TECN21		$ 1,685.40	$ 87,927		$ 1,730.90	$ 90,301

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
TECN22		$ 1,708.00	$ 89,106		$ 1,754.10	$ 91,511
TECN23		$ 1,730.90	$ 90,301		$ 1,777.60	$ 92,737
TECN24		$ 1,753.90	$ 91,501		$ 1,801.30	$ 93,974
TECN25		$ 1,776.50	$ 92,680		$ 1,824.50	$ 95,184
REOG01	AO 9	$ 1,187.10	$ 61,931		$ 1,219.20	$ 63,606
REOG02	AO 10	$ 1,222.00	$ 63,752		$ 1,255.00	$ 65,473
REOG03	AO 11	$ 1,276.40	$ 66,590		$ 1,310.90	$ 68,390
REOG04	AO 12	$ 1,327.40	$ 69,250		$ 1,363.20	$ 71,118
REOG05	AO 13	$ 1,370.10	$ 71,478		$ 1,407.10	$ 73,408
REOG06	AO 14	$ 1,389.40	$ 72,485		$ 1,426.90	$ 74,441
REOG07	AO 15	$ 1,421.80	$ 74,175		$ 1,460.20	$ 76,179
REOG08	AO 16	$ 1,449.00	$ 75,594		$ 1,488.10	$ 77,634
REOG09	AO 17	$ 1,479.50	$ 77,186		$ 1,519.40	$ 79,267
LWKR	01	$ 1,112.50	$ 58,039		$ 1,142.50	$ 59,604
LWKR	02	$ 1,175.90	$ 61,347		$ 1,207.60	$ 63,000
LWKR	03	$ 1,235.30	$ 64,446		$ 1,268.70	$ 66,188
LWKR	04	$ 1,268.30	$ 66,167		$ 1,302.50	$ 67,951
LWKR	05	$ 1,311.80	$ 68,437		$ 1,347.20	$ 70,283
LWKR	06	$ 1,364.50	$ 71,186		$ 1,401.30	$ 73,106
LWKR	GB	$ 1,426.90	$ 74,441		$ 1,465.40	$ 76,450
EWKR	01	$ 987.80	$ 51,534		$ 1,014.50	$ 52,926
EWKR	02	$ 1,024.70	$ 53,459		$ 1,052.40	$ 54,904

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
EWKR	03	$ 1,061.70	$ 55,389		$ 1,090.40	$ 56,886
EWKR	04	$ 1,099.00	$ 57,335		$ 1,128.70	$ 58,884
EWKR	05	$ 1,136.30	$ 59,281		$ 1,167.00	$ 60,882
EWKR	06	$ 1,188.30	$ 61,994		$ 1,220.40	$ 63,668
ELWST	01	$ 987.60	$ 51,523		$ 1,014.30	$ 52,916
ELWST	02	$ 1,024.70	$ 53,459		$ 1,052.40	$ 54,904
ELWST	03	$ 1,061.70	$ 55,389		$ 1,090.40	$ 56,886
ELWST	04	$ 1,153.00	$ 60,152		$ 1,184.10	$ 61,774
ELWST	05	$ 1,175.30	$ 61,315		$ 1,207.00	$ 62,969
ELWST	06	$ 1,188.40	$ 61,999		$ 1,220.50	$ 63,673
PWKR	01	$ 1,161.80	$ 60,611		$ 1,193.20	$ 62,249
PWKR	02	$ 1,196.90	$ 62,442		$ 1,229.20	$ 64,127
PWKR	03	$ 1,235.30	$ 64,446		$ 1,268.70	$ 66,188
PWKR	04	$ 1,268.30	$ 66,167		$ 1,302.50	$ 67,951
PWKR	05	$ 1,311.80	$ 68,437		$ 1,347.20	$ 70,283
EFMT	01	$ 1,207.90	$ 63,016		$ 1,240.50	$ 64,717
EFMT	02	$ 1,246.50	$ 65,030		$ 1,280.20	$ 66,788
EFMT	03	$ 1,286.90	$ 67,138		$ 1,321.60	$ 68,948
EFMT	04	$ 1,324.50	$ 69,099		$ 1,360.30	$ 70,967
EFMT	05	$ 1,364.50	$ 71,186		$ 1,401.30	$ 73,106
LHLW	01	$ 1,187.10	$ 61,931		$ 1,219.20	$ 63,606
LHLW	02	$ 1,219.90	$ 63,642		$ 1,252.80	$ 65,359

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
LHLW	03	$ 1,269.40	$ 66,225		$ 1,303.70	$ 68,014
LHLW	04	$ 1,319.80	$ 68,854		$ 1,355.40	$ 70,711
LHLW	05	$ 1,362.40	$ 71,076		$ 1,399.20	$ 72,996
LHLW	06	$ 1,411.00	$ 73,612		$ 1,449.10	$ 75,600
LHLW	07	$ 1,459.80	$ 76,158		$ 1,499.20	$ 78,213
LHL7	GB	$ 1,522.00	$ 79,403		$ 1,563.10	$ 81,547
LHLW	08	$ 1,494.50	$ 77,968		$ 1,534.90	$ 80,076
LHL8	GB	$ 1,556.90	$ 81,223		$ 1,598.90	$ 83,415
LHLW	09	$ 1,529.90	$ 79,815		$ 1,571.20	$ 81,970
LHL9	GB	$ 1,592.10	$ 83,060		$ 1,635.10	$ 85,303
LHLW	10	$ 1,565.60	$ 81,677		$ 1,607.90	$ 83,884
LHEW	01	$ 1,204.90	$ 62,860		$ 1,237.40	$ 64,555
LHEW	02	$ 1,243.70	$ 64,884		$ 1,277.30	$ 66,637
LHEW	03	$ 1,281.90	$ 66,877		$ 1,316.50	$ 68,682
LHEW	04	$ 1,313.60	$ 68,531		$ 1,349.10	$ 70,383
LHEW	05	$ 1,345.90	$ 70,216		$ 1,382.20	$ 72,109
LHEF	03	$ 1,313.70	$ 68,536		$ 1,349.20	$ 70,388
LHEF	04	$ 1,341.00	$ 69,960		$ 1,377.20	$ 71,849
LHEF	05	$ 1,381.10	$ 72,052		$ 1,418.40	$ 73,998
LHEF	06	$ 1,423.80	$ 74,280		$ 1,462.20	$ 76,283
LHEF	07	$ 1,460.40	$ 76,189		$ 1,499.80	$ 78,245
LHEF	08	$ 1,494.40	$ 77,963		$ 1,534.70	$ 80,065

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
LHEF	09	$ 1,529.90	$ 79,815		$ 1,571.20	$ 81,970
MECH	01	$ 1,161.80	$ 60,611		$ 1,193.20	$ 62,249
MECH	02	$ 1,221.40	$ 63,720		$ 1,254.40	$ 65,442
MECH	03	$ 1,265.90	$ 66,042		$ 1,300.10	$ 67,826
MECH	04	$ 1,310.80	$ 68,384		$ 1,346.20	$ 70,231
MECH	05	$ 1,364.50	$ 71,186		$ 1,401.30	$ 73,106
LHMM	03	$ 1,249.70	$ 65,197		$ 1,283.40	$ 66,955
LHMM	04	$ 1,305.90	$ 68,129		$ 1,341.20	$ 69,970
LHMM	05	$ 1,356.40	$ 70,763		$ 1,393.00	$ 72,673
LHMM	06	$ 1,409.90	$ 73,554		$ 1,448.00	$ 75,542
LHMM	07	$ 1,459.90	$ 76,163		$ 1,499.30	$ 78,218
LHMM	08	$ 1,494.60	$ 77,973		$ 1,535.00	$ 80,081
LHMM	09	$ 1,530.10	$ 79,825		$ 1,571.40	$ 81,980
MAIL	09	$ 1,088.40	$ 56,782		$ 1,117.80	$ 58,316
MAIL	10	$ 1,124.10	$ 58,644		$ 1,154.50	$ 60,230
MAIL	11	$ 1,178.40	$ 61,477		$ 1,210.20	$ 63,136
CSOF	01	$ 1,364.50	$ 71,186		$ 1,401.30	$ 73,106
CSOF	02	$ 1,443.00	$ 75,281		$ 1,482.00	$ 77,316
CSOF	03	$ 1,607.20	$ 83,848		$ 1,650.60	$ 86,112
CSOF	04	$ 1,765.50	$ 92,106		$ 1,813.20	$ 94,595
CSOF	40	$ 1,961.70	$ 102,342		$ 2,014.70	$ 105,107
SCSO	35	$ 1,751.00	$ 91,350		$ 1,798.30	$ 93,817

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
SCSO	36	$ 1,800.90	$ 93,953		$ 1,849.50	$ 96,488
SCSO	40	$ 2,001.10	$ 104,397		$ 2,055.10	$ 107,215
SO35	01	$ 1,682.80	$ 87,792		$ 1,728.20	$ 90,160
SO40	01	$ 1,923.50	$ 100,349		$ 1,975.40	$ 103,057
CPMG	01	$ 1,805.70	$ 94,203		$ 1,854.50	$ 96,749
CPMG	02	$ 1,886.90	$ 98,440		$ 1,937.80	$ 101,095
CPMG	03	$ 1,988.50	$ 103,740		$ 2,042.20	$ 106,542
CPMG	04	$ 2,083.00	$ 108,670		$ 2,139.20	$ 111,602
EXEC	15	$ 1,888.40	$ 98,518		$ 1,939.40	$ 101,178
EXEC	16	$ 1,922.70	$ 100,307		$ 1,974.60	$ 103,015
EXEC	17	$ 1,965.30	$ 102,530		$ 2,018.40	$ 105,300
EXEC	18	$ 2,001.20	$ 104,403		$ 2,055.20	$ 107,220
ACCP	15	$ 1,326.70	$ 69,214		$ 1,362.50	$ 71,082
ACCP	16	$ 1,378.40	$ 71,911		$ 1,415.60	$ 73,852
ACCP	17	$ 1,436.50	$ 74,942		$ 1,475.30	$ 76,966
APTL	18	$ 1,617.50	$ 84,385		$ 1,661.20	$ 86,665
APTL	19	$ 1,682.10	$ 87,755		$ 1,727.50	$ 90,124
APTL	20	$ 1,751.00	$ 91,350		$ 1,798.30	$ 93,817
PY35	18	$ 1,465.00	$ 76,429		$ 1,504.60	$ 78,495
PY35	19	$ 1,523.00	$ 79,455		$ 1,564.10	$ 81,599
PY35	20	$ 1,585.60	$ 82,721		$ 1,628.40	$ 84,954
PY40	18	$ 1,674.20	$ 87,343		$ 1,719.40	$ 89,701

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
PY40	19	$ 1,740.70	$ 90,812		$ 1,787.70	$ 93,264
PY40	20	$ 1,812.20	$ 94,542		$ 1,861.10	$ 97,094
BA35	15	$ 1,326.70	$ 69,214		$ 1,362.50	$ 71,082
BA35	16	$ 1,349.20	$ 70,388		$ 1,385.60	$ 72,287
BA35	17	$ 1,374.20	$ 71,692		$ 1,411.30	$ 73,628
BA35	18	$ 1,396.80	$ 72,871		$ 1,434.50	$ 74,838
BA35	19	$ 1,424.80	$ 74,332		$ 1,463.30	$ 76,340
BA35	20	$ 1,454.70	$ 75,892		$ 1,494.00	$ 77,942
BA35	21	$ 1,488.20	$ 77,639		$ 1,528.40	$ 79,737
BA35	22	$ 1,521.20	$ 79,361		$ 1,562.30	$ 81,505
BA35	23	$ 1,556.10	$ 81,182		$ 1,598.10	$ 83,373
BA35	24	$ 1,585.60	$ 82,721		$ 1,628.40	$ 84,954
BA40	15	$ 1,516.30	$ 79,105		$ 1,557.20	$ 81,239
BA40	16	$ 1,541.60	$ 80,425		$ 1,583.20	$ 82,596
BA40	17	$ 1,570.30	$ 81,923		$ 1,612.70	$ 84,135
BA40	18	$ 1,596.40	$ 83,284		$ 1,639.50	$ 85,533
BA40	19	$ 1,628.20	$ 84,943		$ 1,672.20	$ 87,239
BA40	20	$ 1,662.40	$ 86,727		$ 1,707.30	$ 89,070
BA40	21	$ 1,701.00	$ 88,741		$ 1,746.90	$ 91,136
BA40	22	$ 1,738.50	$ 90,698		$ 1,785.40	$ 93,144
BA40	23	$ 1,778.40	$ 92,779		$ 1,826.40	$ 95,283
BA40	24	$ 1,812.30	$ 94,548		$ 1,861.20	$ 97,099

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
BS35	12	$ 1,202.10	$ 62,714		$ 1,234.60	$ 64,409
BS35	13	$ 1,270.90	$ 66,303		$ 1,305.20	$ 68,092
BS35	14	$ 1,300.80	$ 67,863		$ 1,335.90	$ 69,694
BS40	12	$ 1,373.60	$ 71,661		$ 1,410.70	$ 73,596
BS40	13	$ 1,452.40	$ 75,772		$ 1,491.60	$ 77,817
BS40	14	$ 1,486.70	$ 77,561		$ 1,526.80	$ 79,653
DA35	15	$ 1,465.00	$ 76,429		$ 1,504.60	$ 78,495
DA35	16	$ 1,500.00	$ 78,255		$ 1,540.50	$ 80,368
DA35	17	$ 1,539.70	$ 80,326		$ 1,581.30	$ 82,496
DA35	18	$ 1,585.60	$ 82,721		$ 1,628.40	$ 84,954
DA40	15	$ 1,674.20	$ 87,343		$ 1,719.40	$ 89,701
DA40	16	$ 1,714.30	$ 89,435		$ 1,760.60	$ 91,851
DA40	17	$ 1,759.80	$ 91,809		$ 1,807.30	$ 94,287
DA40	18	$ 1,812.20	$ 94,542		$ 1,861.10	$ 97,094
EO35	01	$ 1,353.50	$ 70,612		$ 1,390.00	$ 72,516
EO35	02	$ 1,379.40	$ 71,963		$ 1,416.60	$ 73,904
EO35	03	$ 1,408.00	$ 73,455		$ 1,446.00	$ 75,438
EO35	04	$ 1,434.20	$ 74,822		$ 1,472.90	$ 76,841
EO35	05	$ 1,463.90	$ 76,372		$ 1,503.40	$ 78,432
EO35	06	$ 1,500.50	$ 78,281		$ 1,541.00	$ 80,394
EO35	07	$ 1,541.80	$ 80,436		$ 1,583.40	$ 82,606
EO35	08	$ 1,577.30	$ 82,288		$ 1,619.90	$ 84,510

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
EO35	09	$ 1,617.30	$ 84,375		$ 1,661.00	$ 86,654
EO35	10	$ 1,651.30	$ 86,148		$ 1,695.90	$ 88,475
EO35	11	$ 1,690.30	$ 88,183		$ 1,735.90	$ 90,562
EO35	12	$ 1,730.10	$ 90,259		$ 1,776.80	$ 92,696
EO35	13	$ 1,763.50	$ 92,002		$ 1,811.10	$ 94,485
EO35	14	$ 1,805.30	$ 94,183		$ 1,854.00	$ 96,723
EO35	15	$ 1,840.30	$ 96,008		$ 1,890.00	$ 98,601
EO35	16	$ 1,873.40	$ 97,735		$ 1,924.00	$ 100,375
EO35	17	$ 1,916.60	$ 99,989		$ 1,968.30	$ 102,686
EO35	18	$ 1,959.80	$ 102,243		$ 2,012.70	$ 105,003
EO35	19	$ 2,002.80	$ 104,486		$ 2,056.90	$ 107,308
EO35	20	$ 2,048.20	$ 106,855		$ 2,103.50	$ 109,740
EO35	21	$ 2,104.80	$ 109,807		$ 2,161.60	$ 112,771
EO35	22	$ 2,163.30	$ 112,859		$ 2,221.70	$ 115,906
EO35	23	$ 2,220.70	$ 115,854		$ 2,280.70	$ 118,984
EO40	1	$ 1,546.90	$ 80,702		$ 1,588.70	$ 82,882
EO40	2	$ 1,576.30	$ 82,236		$ 1,618.90	$ 84,458
EO40	3	$ 1,609.10	$ 83,947		$ 1,652.50	$ 86,211
EO40	4	$ 1,639.10	$ 85,512		$ 1,683.40	$ 87,823
EO40	5	$ 1,673.10	$ 87,286		$ 1,718.30	$ 89,644
EO40	6	$ 1,714.90	$ 89,466		$ 1,761.20	$ 91,882
EO40	7	$ 1,762.20	$ 91,934		$ 1,809.80	$ 94,417

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
EO40	8	$ 1,802.50	$ 94,036		$ 1,851.20	$ 96,577
EO40	9	$ 1,848.50	$ 96,436		$ 1,898.40	$ 99,040
EO40	10	$ 1,887.40	$ 98,466		$ 1,938.40	$ 101,126
EO40	11	$ 1,931.70	$ 100,777		$ 1,983.90	$ 103,500
EO40	12	$ 1,977.40	$ 103,161		$ 2,030.80	$ 105,947
EO40	13	$ 2,015.50	$ 105,149		$ 2,069.90	$ 107,987
EO40	14	$ 2,063.10	$ 107,632		$ 2,118.80	$ 110,538
EO40	15	$ 2,103.50	$ 109,740		$ 2,160.30	$ 112,703
EO40	16	$ 2,151.20	$ 112,228		$ 2,209.30	$ 115,259
EO40	17	$ 2,199.40	$ 114,743		$ 2,258.80	$ 117,842
EO40	18	$ 2,247.30	$ 117,242		$ 2,308.00	$ 120,408
EO40	19	$ 2,295.30	$ 119,746		$ 2,357.30	$ 122,980
DOPS	22	$ 1,541.90	$ 80,441		$ 1,583.50	$ 82,611
DOPS	24	$ 1,738.50	$ 90,698		$ 1,785.40	$ 93,144
DOPS	25	$ 1,843.10	$ 96,155		$ 1,892.90	$ 98,753
DOIT	18	$ 1,404.20	$ 73,257		$ 1,442.10	$ 75,234
DOIT	19	$ 1,436.20	$ 74,927		$ 1,475.00	$ 76,951
DOIT	20	$ 1,475.50	$ 76,977		$ 1,515.30	$ 79,053
DOIT	22	$ 1,556.30	$ 81,192		$ 1,598.30	$ 83,383
CMGR	01	$ 2,521.60	$ 131,552		$ 2,589.70	$ 135,105
NTWC	01	$ 2,028.20	$ 105,811		$ 2,083.00	$ 108,670
NTWC	02	$ 2,069.90	$ 107,987		$ 2,125.80	$ 110,903

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
NTWC	03	$ 2,181.00	$ 113,783		$ 2,239.90	$ 116,856
NTWC	04	$ 2,283.90	$ 119,151		$ 2,345.60	$ 122,370
EMSO	16	$ 1,352.40	$ 70,555		$ 1,388.90	$ 72,459
EMSO	17	$ 1,398.50	$ 72,960		$ 1,436.30	$ 74,932
EMSO	18	$ 1,440.20	$ 75,135		$ 1,479.10	$ 77,165
EMSO	19	$ 1,488.50	$ 77,655		$ 1,528.70	$ 79,752
EMSO	20	$ 1,541.90	$ 80,441		$ 1,583.50	$ 82,611
DESP	01	$ 1,721.80	$ 89,826		$ 1,768.30	$ 92,252
DESP	02	$ 1,843.10	$ 96,155		$ 1,892.90	$ 98,753
CI36	25	$ 1,663.60	$ 86,790		$ 1,708.50	$ 89,132
CI36	26	$ 1,711.30	$ 89,279		$ 1,757.50	$ 91,689
CI36	27	$ 1,751.20	$ 91,360		$ 1,798.50	$ 93,828
CI36	28	$ 1,800.90	$ 93,953		$ 1,849.50	$ 96,488
CI40	25	$ 1,848.60	$ 96,441		$ 1,898.50	$ 99,045
CI40	26	$ 1,901.40	$ 99,196		$ 1,952.70	$ 101,872
CI40	27	$ 1,945.80	$ 101,512		$ 1,998.30	$ 104,251
CI40	28	$ 2,001.10	$ 104,397		$ 2,055.10	$ 107,215
OM40	25	$ 2,100.00	$ 109,557		$ 2,156.70	$ 112,515
OM40	26	$ 2,148.80	$ 112,103		$ 2,206.80	$ 115,129
OM40	27	$ 2,190.60	$ 114,284		$ 2,249.70	$ 117,367
OM40	28	$ 2,243.10	$ 117,023		$ 2,303.70	$ 120,184
OM40	29	$ 2,298.60	$ 119,918		$ 2,360.70	$ 123,158

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
OM40	30	$ 2,331.10	$ 121,613		$ 2,394.00	$ 124,895
OM40	31	$ 2,391.40	$ 124,759		$ 2,456.00	$ 128,130
OM36	25	$ 1,890.10	$ 98,607		$ 1,941.10	$ 101,267
OM36	26	$ 1,933.80	$ 100,886		$ 1,986.00	$ 103,610
OM36	27	$ 1,971.60	$ 102,858		$ 2,024.80	$ 105,634
OM36	28	$ 2,018.80	$ 105,321		$ 2,073.30	$ 108,164
OM36	29	$ 2,068.70	$ 107,924		$ 2,124.60	$ 110,840
OM36	30	$ 2,098.20	$ 109,463		$ 2,154.90	$ 112,421
OM36	31	$ 2,152.40	$ 112,291		$ 2,210.50	$ 115,322
RTCO	25	$ 1,697.10	$ 88,538		$ 1,742.90	$ 90,927
RTCO	26	$ 1,733.40	$ 90,431		$ 1,780.20	$ 92,873
RTCO	27	$ 1,763.80	$ 92,017		$ 1,811.40	$ 94,501
RTCO	28	$ 1,801.70	$ 93,995		$ 1,850.30	$ 96,530
RT40	25	$ 1,885.80	$ 98,382		$ 1,936.70	$ 101,038
RT40	26	$ 1,926.00	$ 100,479		$ 1,978.00	$ 103,192
RT40	27	$ 1,959.70	$ 102,238		$ 2,012.60	$ 104,997
RT40	28	$ 2,001.80	$ 104,434		$ 2,055.80	$ 107,251
TT36	25	$ 1,574.50	$ 82,142		$ 1,617.00	$ 84,359
TT36	26	$ 1,614.50	$ 84,228		$ 1,658.10	$ 86,503
TT36	27	$ 1,648.00	$ 85,976		$ 1,692.50	$ 88,298
TT36	28	$ 1,690.10	$ 88,173		$ 1,735.70	$ 90,551
TT36	29	$ 1,725.20	$ 90,004		$ 1,771.80	$ 92,435

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
TT36	30	$ 1,758.00	$ 91,715		$ 1,805.50	$ 94,193
TT36	31	$ 1,801.70	$ 93,995		$ 1,850.30	$ 96,530
TT40	25	$ 1,749.50	$ 91,271		$ 1,796.70	$ 93,734
TT40	26	$ 1,794.00	$ 93,593		$ 1,842.40	$ 96,118
TT40	27	$ 1,831.10	$ 95,528		$ 1,880.50	$ 98,106
TT40	28	$ 1,877.70	$ 97,960		$ 1,928.40	$ 100,605
TT40	29	$ 1,917.10	$ 100,015		$ 1,968.90	$ 102,718
TT40	30	$ 1,953.60	$ 101,919		$ 2,006.30	$ 104,669
TT40	31	$ 2,001.80	$ 104,434		$ 2,055.80	$ 107,251
TECM	01	$ 1,324.50	$ 69,099		$ 1,360.30	$ 70,967
TECH	1X	$ 1,360.80	$ 70,993		$ 1,397.50	$ 72,908
TECM	02	$ 1,378.30	$ 71,906		$ 1,415.50	$ 73,847
TECM	03	$ 1,519.40	$ 79,267		$ 1,560.40	$ 81,406
TECM	04	$ 1,663.60	$ 86,790		$ 1,708.50	$ 89,132
PO35	21	$ 1,785.70	$ 93,160		$ 1,833.90	$ 95,675
PO35	22	$ 1,806.70	$ 94,256		$ 1,855.50	$ 96,801
PO35	23	$ 1,829.10	$ 95,424		$ 1,878.50	$ 98,001
PO35	24	$ 1,847.90	$ 96,405		$ 1,897.80	$ 99,008
PO35	25	$ 1,869.30	$ 97,521		$ 1,919.80	$ 100,156
PO35	26	$ 1,891.30	$ 98,669		$ 1,942.40	$ 101,335
PO35	27	$ 1,909.80	$ 99,634		$ 1,961.40	$ 102,326
PO35	28	$ 1,932.90	$ 100,839		$ 1,985.10	$ 103,563

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
PO40	21	$ 2,040.90	$ 106,474		$ 2,096.00	$ 109,348
PO40	22	$ 2,064.90	$ 107,726		$ 2,120.70	$ 110,637
PO40	23	$ 2,090.40	$ 109,056		$ 2,146.80	$ 111,999
PO40	24	$ 2,111.80	$ 110,173		$ 2,168.80	$ 113,146
PO40	25	$ 2,136.30	$ 111,451		$ 2,194.00	$ 114,461
PO40	26	$ 2,161.60	$ 112,771		$ 2,220.00	$ 115,817
PO40	27	$ 2,182.60	$ 113,866		$ 2,241.50	$ 116,939
PO40	28	$ 2,209.30	$ 115,259		$ 2,269.00	$ 118,374
TS36	21	$ 1,663.60	$ 86,790		$ 1,708.50	$ 89,132
TS36	22	$ 1,683.20	$ 87,813		$ 1,728.60	$ 90,181
TS36	23	$ 1,704.10	$ 88,903		$ 1,750.10	$ 91,303
TS36	24	$ 1,721.60	$ 89,816		$ 1,768.10	$ 92,242
TS36	25	$ 1,741.60	$ 90,859		$ 1,788.60	$ 93,311
TS36	26	$ 1,762.20	$ 91,934		$ 1,809.80	$ 94,417
TS36	27	$ 1,779.60	$ 92,842		$ 1,827.60	$ 95,346
TS36	28	$ 1,800.90	$ 93,953		$ 1,849.50	$ 96,488
TS40	21	$ 1,848.60	$ 96,441		$ 1,898.50	$ 99,045
TS40	22	$ 1,870.20	$ 97,568		$ 1,920.70	$ 100,203
TS40	23	$ 1,893.40	$ 98,779		$ 1,944.50	$ 101,445
TS40	24	$ 1,912.90	$ 99,796		$ 1,964.50	$ 102,488
TS40	25	$ 1,935.30	$ 100,965		$ 1,987.60	$ 103,693
TS40	26	$ 1,958.00	$ 102,149		$ 2,010.90	$ 104,909

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
TS40	27	$ 1,977.40	$ 103,161		$ 2,030.80	$ 105,947
TS40	28	$ 2,001.10	$ 104,397		$ 2,055.10	$ 107,215
BBLD	01	$ 1,161.80	$ 60,611		$ 1,193.20	$ 62,249
BBLD	02	$ 1,205.90	$ 62,912		$ 1,238.50	$ 64,613
BBLD	03	$ 1,234.50	$ 64,404		$ 1,267.80	$ 66,141
BBLD	04	$ 1,271.70	$ 66,345		$ 1,306.00	$ 68,134
BBLD	05	$ 1,311.70	$ 68,431		$ 1,347.10	$ 70,278
BBLD	06	$ 1,364.50	$ 71,186		$ 1,401.30	$ 73,106
LHBB	01	$ 1,448.40	$ 75,563		$ 1,487.50	$ 77,603
BD35	21	$ 1,617.50	$ 84,385		$ 1,661.20	$ 86,665
BD35	22	$ 1,662.60	$ 86,738		$ 1,707.50	$ 89,080
BD35	23	$ 1,710.50	$ 89,237		$ 1,756.70	$ 91,647
BD35	24	$ 1,751.00	$ 91,350		$ 1,798.30	$ 93,817
BD40	21	$ 1,848.60	$ 96,441		$ 1,898.50	$ 99,045
BD40	22	$ 1,900.20	$ 99,133		$ 1,951.50	$ 101,810
BD40	23	$ 1,954.70	$ 101,977		$ 2,007.50	$ 104,731
BD40	24	$ 2,001.10	$ 104,397		$ 2,055.10	$ 107,215
DS35	21	$ 1,617.50	$ 84,385		$ 1,661.20	$ 86,665
DS35	22	$ 1,662.60	$ 86,738		$ 1,707.50	$ 89,080
DS35	23	$ 1,710.50	$ 89,237		$ 1,756.70	$ 91,647
DS35	24	$ 1,751.00	$ 91,350		$ 1,798.30	$ 93,817
DS40	21	$ 1,848.60	$ 96,441		$ 1,898.50	$ 99,045

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
DS40	22	$ 1,900.20	$ 99,133		$ 1,951.50	$ 101,810
DS40	23	$ 1,954.70	$ 101,977		$ 2,007.50	$ 104,731
DS40	24	$ 2,001.10	$ 104,397		$ 2,055.10	$ 107,215
TM36	18	$ 1,444.80	$ 75,375		$ 1,483.80	$ 77,410
TM36	19	$ 1,477.10	$ 77,060		$ 1,517.00	$ 79,142
TM36	20	$ 1,511.70	$ 78,865		$ 1,552.50	$ 80,994
TM36	21	$ 1,663.60	$ 86,790		$ 1,708.50	$ 89,132
TM36	22	$ 1,683.20	$ 87,813		$ 1,728.60	$ 90,181
TM36	23	$ 1,704.10	$ 88,903		$ 1,750.10	$ 91,303
TM36	24	$ 1,721.60	$ 89,816		$ 1,768.10	$ 92,242
TM40	18	$ 1,605.40	$ 83,754		$ 1,648.70	$ 86,013
TM40	19	$ 1,641.40	$ 85,632		$ 1,685.70	$ 87,943
TM40	20	$ 1,679.70	$ 87,630		$ 1,725.10	$ 89,998
TM40	21	$ 1,848.60	$ 96,441		$ 1,898.50	$ 99,045
TM40	22	$ 1,870.20	$ 97,568		$ 1,920.70	$ 100,203
TM40	23	$ 1,893.40	$ 98,779		$ 1,944.50	$ 101,445
TM40	24	$ 1,912.90	$ 99,796		$ 1,964.50	$ 102,488
PHOF21	21	$ 1,465.00	$ 76,429		$ 1,504.60	$ 78,495
PHOF22	22	$ 1,505.80	$ 78,558		$ 1,546.50	$ 80,681
PHOF23	23	$ 1,549.00	$ 80,811		$ 1,590.80	$ 82,992
PHOF24	24	$ 1,585.60	$ 82,721		$ 1,628.40	$ 84,954
IA35	21	$ 1,617.50	$ 84,385		$ 1,661.20	$ 86,665

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
IA35	22	$ 1,662.60	$ 86,738		$ 1,707.50	$ 89,080
IA35	23	$ 1,710.50	$ 89,237		$ 1,756.70	$ 91,647
IA35	24	$ 1,751.00	$ 91,350		$ 1,798.30	$ 93,817
IA40	21	$ 1,848.60	$ 96,441		$ 1,898.50	$ 99,045
IA40	22	$ 1,900.20	$ 99,133		$ 1,951.50	$ 101,810
IA40	23	$ 1,954.70	$ 101,977		$ 2,007.50	$ 104,731
IA40	24	$ 2,001.10	$ 104,397		$ 2,055.10	$ 107,215
BTO351	01	$ 1,202.10	$ 62,714		$ 1,234.60	$ 64,409
BTO35	02	$ 1,274.90	$ 66,512		$ 1,309.30	$ 68,306
BTO35	03	$ 1,350.70	$ 70,466		$ 1,387.20	$ 72,370
BTO35	04	$ 1,436.50	$ 74,942		$ 1,475.30	$ 76,966
BTO4	01	$ 1,373.60	$ 71,661		$ 1,410.70	$ 73,596
BTO4	02	$ 1,457.30	$ 76,027		$ 1,496.60	$ 78,078
BTO4	03	$ 1,543.80	$ 80,540		$ 1,585.50	$ 82,716
BTO4	04	$ 1,641.80	$ 85,653		$ 1,686.10	$ 87,964
CSNS	09	$ 1,053.00	$ 54,935		$ 1,081.40	$ 56,417
CSNS	10	$ 1,095.60	$ 57,157		$ 1,125.20	$ 58,702
CSNS	11	$ 1,160.90	$ 60,564		$ 1,192.20	$ 62,197
CSNS	12	$ 1,223.50	$ 63,830		$ 1,256.50	$ 65,552
CSNS	13	$ 1,275.60	$ 66,548		$ 1,310.00	$ 68,343
CSNS	14	$ 1,326.90	$ 69,224		$ 1,362.70	$ 71,092
CSR7	09	$ 1,085.70	$ 56,641		$ 1,115.00	$ 58,170

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
CSR7	10	$ 1,128.30	$ 58,863		$ 1,158.80	$ 60,455
CSR7	11	$ 1,193.80	$ 62,281		$ 1,226.00	$ 63,960
CSR7	12	$ 1,256.50	$ 65,552		$ 1,290.40	$ 67,320
CSR7	13	$ 1,308.50	$ 68,264		$ 1,343.80	$ 70,106
CSR7	14	$ 1,331.50	$ 69,464		$ 1,367.50	$ 71,342
HU6D	09	$ 1,130.10	$ 58,957		$ 1,160.60	$ 60,549
HU6D	10	$ 1,164.20	$ 60,736		$ 1,195.60	$ 62,374
HU6D	11	$ 1,216.80	$ 63,480		$ 1,249.70	$ 65,197
HU6D	12	$ 1,266.80	$ 66,089		$ 1,301.00	$ 67,873
HU6D	13	$ 1,308.60	$ 68,270		$ 1,343.90	$ 70,111
HU6D	14	$ 1,327.00	$ 69,230		$ 1,362.80	$ 71,097
CN6D	09	$ 1,120.00	$ 58,430		$ 1,150.20	$ 60,006
CN6D	10	$ 1,156.20	$ 60,319		$ 1,187.40	$ 61,947
CN6D	11	$ 1,211.20	$ 63,188		$ 1,243.90	$ 64,894
CN6D	12	$ 1,263.70	$ 65,927		$ 1,297.80	$ 67,706
CN6D	13	$ 1,307.90	$ 68,233		$ 1,343.20	$ 70,075
CN6D	14	$ 1,327.00	$ 69,230		$ 1,362.80	$ 71,097
CSRG	09	$ 985.70	$ 51,424		$ 1,012.30	$ 52,812
CSRG	10	$ 1,044.90	$ 54,512		$ 1,073.10	$ 55,984
CSRG	11	$ 1,135.90	$ 59,260		$ 1,166.60	$ 60,862
CSRG	12	$ 1,222.50	$ 63,778		$ 1,255.50	$ 65,499
CSRG	13	$ 1,294.90	$ 67,555		$ 1,329.90	$ 69,381

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
CSRG	14	$ 1,326.70	$ 69,214		$ 1,362.50	$ 71,082
EQ35	01	$ 1,202.10	$ 62,714		$ 1,234.60	$ 64,409
EQ35	02	$ 1,270.90	$ 66,303		$ 1,305.20	$ 68,092
EQ35	03	$ 1,300.80	$ 67,863		$ 1,335.90	$ 69,694
EQ35	04	$ 1,326.70	$ 69,214		$ 1,362.50	$ 71,082
EQ35	05	$ 1,378.40	$ 71,911		$ 1,415.60	$ 73,852
EQ35	06	$ 1,436.50	$ 74,942		$ 1,475.30	$ 76,966
EQ35	07	$ 1,465.00	$ 76,429		$ 1,504.60	$ 78,495
EQ35	08	$ 1,523.00	$ 79,455		$ 1,564.10	$ 81,599
EQ35	09	$ 1,585.60	$ 82,721		$ 1,628.40	$ 84,954
EQ35	10	$ 1,617.50	$ 84,385		$ 1,661.20	$ 86,665
EQ35	11	$ 1,682.00	$ 87,750		$ 1,727.40	$ 90,118
EQ35	12	$ 1,751.00	$ 91,350		$ 1,798.30	$ 93,817
EQ35	13	$ 1,785.70	$ 93,160		$ 1,833.90	$ 95,675
EQ35	14	$ 1,835.50	$ 95,758		$ 1,885.10	$ 98,346
EQ35	15	$ 1,888.20	$ 98,507		$ 1,939.20	$ 101,168
EQ35	16	$ 1,932.80	$ 100,834		$ 1,985.00	$ 103,557
EQ40	01	$ 1,373.60	$ 71,661		$ 1,410.70	$ 73,596
EQ40	02	$ 1,452.40	$ 75,772		$ 1,491.60	$ 77,817
EQ40	03	$ 1,486.70	$ 77,561		$ 1,526.80	$ 79,653
EQ40	04	$ 1,516.20	$ 79,100		$ 1,557.10	$ 81,234
EQ40	05	$ 1,575.40	$ 82,189		$ 1,617.90	$ 84,406

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
EQ40	06	$ 1,641.80	$ 85,653		$ 1,686.10	$ 87,964
EQ40	07	$ 1,674.20	$ 87,343		$ 1,719.40	$ 89,701
EQ40	08	$ 1,740.70	$ 90,812		$ 1,787.70	$ 93,264
EQ40	09	$ 1,812.20	$ 94,542		$ 1,861.10	$ 97,094
EQ40	10	$ 1,848.60	$ 96,441		$ 1,898.50	$ 99,045
EQ40	11	$ 1,922.20	$ 100,281		$ 1,974.10	$ 102,989
EQ40	12	$ 2,001.10	$ 104,397		$ 2,055.10	$ 107,215
EQ40	13	$ 2,040.90	$ 106,474		$ 2,096.00	$ 109,348
EQ40	14	$ 2,098.00	$ 109,453		$ 2,154.60	$ 112,405
EQ40	15	$ 2,158.00	$ 112,583		$ 2,216.30	$ 115,624
EQ40	16	$ 2,209.20	$ 115,254		$ 2,268.80	$ 118,363
ZAO12A	12a	$ 1,202.10	$ 62,714		$ 1,234.60	$ 64,409
ZAO17A	17a	$ 1,326.70	$ 69,214		$ 1,362.50	$ 71,082
MS0011		$ 2,368.80	$ 123,580		$ 2,432.80	$ 126,919
MS0012		$ 2,405.50	$ 125,495		$ 2,470.40	$ 128,881
MS0013		$ 2,442.20	$ 127,410		$ 2,508.10	$ 130,848
MS0014		$ 2,478.80	$ 129,319		$ 2,545.70	$ 132,809
MS0015		$ 2,515.40	$ 131,228		$ 2,583.30	$ 134,771
MS0016		$ 2,551.30	$ 133,101		$ 2,620.20	$ 136,696
MS0021		$ 2,421.60	$ 126,335		$ 2,487.00	$ 129,747
MS0022		$ 2,458.80	$ 128,276		$ 2,525.20	$ 131,740
MS0023		$ 2,496.00	$ 130,216		$ 2,563.40	$ 133,733

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
MS0024		$ 2,533.40	$ 132,167		$ 2,601.80	$ 135,736
MS0025		$ 2,571.20	$ 134,140		$ 2,640.60	$ 137,760
MS0026		$ 2,608.40	$ 136,080		$ 2,678.80	$ 139,753
MS0031		$ 2,474.90	$ 129,116		$ 2,541.70	$ 132,600
MS0032		$ 2,513.30	$ 131,119		$ 2,581.20	$ 134,661
MS0033		$ 2,551.60	$ 133,117		$ 2,620.50	$ 136,711
MS0034		$ 2,589.90	$ 135,115		$ 2,659.80	$ 138,762
MS0035		$ 2,627.80	$ 137,092		$ 2,698.80	$ 140,796
MS0036		$ 2,666.70	$ 139,122		$ 2,738.70	$ 142,878
MS0041		$ 2,528.10	$ 131,891		$ 2,596.40	$ 135,454
MS0042		$ 2,567.10	$ 133,926		$ 2,636.40	$ 137,541
MS0043		$ 2,606.80	$ 135,997		$ 2,677.20	$ 139,670
MS0044		$ 2,645.80	$ 138,031		$ 2,717.20	$ 141,756
MS0045		$ 2,685.00	$ 140,076		$ 2,757.50	$ 143,859
MS0046		$ 2,724.20	$ 142,122		$ 2,797.80	$ 145,961
MS0051		$ 2,580.60	$ 134,630		$ 2,650.30	$ 138,266
MS0052		$ 2,620.40	$ 136,706		$ 2,691.20	$ 140,400
MS0053		$ 2,660.60	$ 138,804		$ 2,732.40	$ 142,549
MS0054		$ 2,701.20	$ 140,922		$ 2,774.10	$ 144,725
MS0055		$ 2,741.60	$ 143,029		$ 2,815.60	$ 146,890
MS0056		$ 2,781.30	$ 145,100		$ 2,856.40	$ 149,018
MS0061		$ 2,636.90	$ 137,567		$ 2,708.10	$ 141,282

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
MS0062		$ 2,677.80	$ 139,701		$ 2,750.10	$ 143,473
MS0063		$ 2,718.90	$ 141,845		$ 2,792.30	$ 145,674
MS0064		$ 2,759.80	$ 143,979		$ 2,834.30	$ 147,865
MS0065		$ 2,800.70	$ 146,113		$ 2,876.30	$ 150,057
MS0066		$ 2,841.70	$ 148,251		$ 2,918.40	$ 152,253
MS0071		$ 2,707.40	$ 141,245		$ 2,780.50	$ 145,059
MS0072		$ 2,749.50	$ 143,441		$ 2,823.70	$ 147,312
MS0073		$ 2,791.80	$ 145,648		$ 2,867.20	$ 149,582
MS0074		$ 2,834.20	$ 147,860		$ 2,910.70	$ 151,851
MS0075		$ 2,876.50	$ 150,067		$ 2,954.20	$ 154,121
MS0076		$ 2,918.80	$ 152,274		$ 2,997.60	$ 156,385
MS0081		$ 2,778.20	$ 144,939		$ 2,853.20	$ 148,851
MS0082		$ 2,822.10	$ 147,229		$ 2,898.30	$ 151,204
MS0083		$ 2,865.60	$ 149,498		$ 2,943.00	$ 153,536
MS0084		$ 2,908.80	$ 151,752		$ 2,987.30	$ 155,847
MS0085		$ 2,952.00	$ 154,006		$ 3,031.70	$ 158,164
MS0086		$ 2,995.90	$ 156,296		$ 3,076.80	$ 160,517
MS0091		$ 2,849.00	$ 148,632		$ 2,925.90	$ 152,644
MS0092		$ 2,893.90	$ 150,975		$ 2,972.00	$ 155,049
MS0093		$ 2,938.20	$ 153,286		$ 3,017.50	$ 157,423
MS0094		$ 2,983.00	$ 155,623		$ 3,063.50	$ 159,823
MS0095		$ 3,027.50	$ 157,945		$ 3,109.20	$ 162,207

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
MS0096		$ 3,072.20	$ 160,277		$ 3,155.10	$ 164,602
MS09X 1		$ 2,913.70	$ 152,008		$ 2,992.40	$ 156,114
MS09X2		$ 2,959.20	$ 154,381		$ 3,039.10	$ 158,550
MS09X3		$ 3,005.00	$ 156,771		$ 3,086.10	$ 161,002
MS09X4		$ 3,050.90	$ 159,165		$ 3,133.30	$ 163,464
MS09X5		$ 3,096.00	$ 161,518		$ 3,179.60	$ 165,880
MS09X6		$ 3,142.30	$ 163,934		$ 3,227.10	$ 168,358
MS9XX1		$ 2,978.50	$ 155,388		$ 3,058.90	$ 159,583
MS9XX2		$ 3,025.30	$ 157,830		$ 3,107.00	$ 162,092
MS9XX3		$ 3,071.90	$ 160,261		$ 3,154.80	$ 164,586
MS9XX4		$ 3,118.70	$ 162,703		$ 3,202.90	$ 167,095
MS9XX5		$ 3,165.00	$ 165,118		$ 3,250.50	$ 169,579
MS9XX6		$ 3,211.50	$ 167,544		$ 3,298.20	$ 172,067
MS1001		$ 3,014.20	$ 157,251		$ 3,095.60	$ 161,497
MS1002		$ 3,061.90	$ 159,739		$ 3,144.60	$ 164,054
MS1003		$ 3,109.10	$ 162,202		$ 3,193.00	$ 166,579
MS1004		$ 3,156.40	$ 164,669		$ 3,241.60	$ 169,114
MS1005		$ 3,204.20	$ 167,163		$ 3,290.70	$ 171,676
MS1006		$ 3,251.50	$ 169,631		$ 3,339.30	$ 174,211
MS10X1		$ 3,091.90	$ 161,304		$ 3,175.40	$ 165,661
MS10X2		$ 3,140.40	$ 163,835		$ 3,225.20	$ 168,259
MS10X3		$ 3,189.10	$ 166,375		$ 3,275.20	$ 170,867

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
MS10X4		$ 3,238.00	$ 168,926		$ 3,325.40	$ 173,486
MS10X5		$ 3,286.70	$ 171,467		$ 3,375.40	$ 176,095
MS10X6		$ 3,335.30	$ 174,003		$ 3,425.40	$ 178,703
MS1101		$ 3,170.20	$ 165,389		$ 3,255.80	$ 169,855
MS1102		$ 3,220.30	$ 168,003		$ 3,307.20	$ 172,537
MS1103		$ 3,270.40	$ 170,617		$ 3,358.70	$ 175,223
MS1104		$ 3,320.70	$ 173,241		$ 3,410.40	$ 177,921
MS1105		$ 3,370.60	$ 175,844		$ 3,461.60	$ 180,592
MS1106		$ 3,420.90	$ 178,468		$ 3,513.30	$ 183,289
MS11X1		$ 3,252.40	$ 169,678		$ 3,340.20	$ 174,258
MS11X2		$ 3,303.30	$ 172,333		$ 3,392.50	$ 176,987
MS11X3		$ 3,355.00	$ 175,030		$ 3,445.60	$ 179,757
MS11X4		$ 3,406.60	$ 177,722		$ 3,498.60	$ 182,522
MS11X5		$ 3,457.60	$ 180,383		$ 3,551.00	$ 185,256
MS11X6		$ 3,509.20	$ 183,075		$ 3,603.90	$ 188,015
MS1201		$ 3,347.20	$ 174,623		$ 3,437.60	$ 179,340
MS1202		$ 3,400.10	$ 177,383		$ 3,491.90	$ 182,172
MS1203		$ 3,453.50	$ 180,169		$ 3,546.70	$ 185,031
MS1204		$ 3,506.50	$ 182,934		$ 3,601.20	$ 187,875
MS1205		$ 3,559.70	$ 185,710		$ 3,655.80	$ 190,723
MS1206		$ 3,612.40	$ 188,459		$ 3,709.90	$ 193,545
MS12X1		$ 3,448.90	$ 179,929		$ 3,542.00	$ 184,786

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
MS12X2		$ 3,503.50	$ 182,778		$ 3,598.10	$ 187,713
MS12X3		$ 3,558.20	$ 185,631		$ 3,654.30	$ 190,645
MS12X4		$ 3,613.30	$ 188,506		$ 3,710.90	$ 193,598
MS12X5		$ 3,668.20	$ 191,370		$ 3,767.20	$ 196,535
MS12X6		$ 3,722.80	$ 194,218		$ 3,823.30	$ 199,462
MS1301		$ 3,551.30	$ 185,271		$ 3,647.20	$ 190,274
MS1302		$ 3,607.90	$ 188,224		$ 3,705.30	$ 193,306
MS1303		$ 3,663.80	$ 191,140		$ 3,762.70	$ 196,300
MS1304		$ 3,721.10	$ 194,130		$ 3,821.60	$ 199,373
MS1305		$ 3,777.80	$ 197,088		$ 3,879.80	$ 202,409
MS1306		$ 3,834.20	$ 200,030		$ 3,937.70	$ 205,430
EOMS1A		$2,419.00	$ 126,199		$2,484.30	$ 129,606
EOMS14		$2,442.20	$ 127,410		$2,508.10	$ 130,848
EOMS15		$2,482.20	$ 129,496		$2,549.20	$ 132,992
EOMS16		$2,522.10	$ 131,578		$2,590.20	$ 135,131
EOMS17		$2,562.10	$ 133,665		$2,631.30	$ 137,275
EOMS18		$2,602.00	$ 135,746		$2,672.30	$ 139,414
EOMS19		$2,642.00	$ 137,833		$2,713.30	$ 141,553
EOMS2A		$2,473.80	$ 129,058		$2,540.60	$ 132,543
EOMS24		$2,497.50	$ 130,295		$2,564.90	$ 133,811
EOMS25		$2,538.30	$ 132,423		$2,606.80	$ 135,997
EOMS26		$2,579.20	$ 134,557		$2,648.80	$ 138,188

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
EOMS27		$2,620.10	$ 136,691		$2,690.80	$ 140,379
EOMS28		$2,661.00	$ 138,824		$2,732.80	$ 142,570
EOMS29		$2,701.80	$ 140,953		$2,774.70	$ 144,756
EOMS3A		$2,529.30	$ 131,954		$2,597.60	$ 135,517
EOMS34		$2,553.50	$ 133,216		$2,622.40	$ 136,811
EOMS35		$2,595.30	$ 135,397		$2,665.40	$ 139,054
EOMS36		$2,637.10	$ 137,578		$2,708.30	$ 141,292
EOMS37		$2,678.90	$ 139,758		$2,751.20	$ 143,530
EOMS38		$2,720.70	$ 141,939		$2,794.20	$ 145,773
EOMS39		$2,762.40	$ 144,114		$2,837.00	$ 148,006
EOMS4A		$2,584.30	$ 134,823		$2,654.10	$ 138,464
EOMS44		$2,609.10	$ 136,117		$2,679.50	$ 139,790
EOMS45		$2,651.80	$ 138,344		$2,723.40	$ 142,080
EOMS46		$2,694.50	$ 140,572		$2,767.30	$ 144,370
EOMS47		$2,737.20	$ 142,800		$2,811.10	$ 146,655
EOMS48		$2,779.90	$ 145,027		$2,855.00	$ 148,945
EOMS49		$2,822.60	$ 147,255		$2,898.80	$ 151,230
EOMS5A		$2,639.70	$ 137,713		$2,711.00	$ 141,433
EOMS54		$2,664.90	$ 139,028		$2,736.90	$ 142,784
EOMS55		$2,708.50	$ 141,302		$2,781.60	$ 145,116
EOMS56		$2,752.20	$ 143,582		$2,826.50	$ 147,459
EOMS57		$2,795.70	$ 145,852		$2,871.20	$ 149,791

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
EOMS58		$2,839.30	$ 148,126		$2,916.00	$ 152,128
EOMS59		$2,883.00	$ 150,406		$2,960.80	$ 154,465
EOMS6A		$2,697.70	$ 140,739		$2,770.50	$ 144,537
EOMS64		$2,723.60	$ 142,090		$2,797.10	$ 145,925
EOMS65		$2,768.20	$ 144,417		$2,842.90	$ 148,314
EOMS66		$2,812.70	$ 146,739		$2,888.60	$ 150,698
EOMS67		$2,857.30	$ 149,065		$2,934.40	$ 153,088
EOMS68		$2,901.90	$ 151,392		$2,980.30	$ 155,482
EOMS69		$2,946.50	$ 153,719		$3,026.10	$ 157,872
EOMS7A		$2,770.20	$ 144,521		$2,845.00	$ 148,424
EOMS74		$2,796.70	$ 145,904		$2,872.20	$ 149,843
EOMS75		$2,842.50	$ 148,293		$2,919.20	$ 152,295
EOMS76		$2,888.30	$ 150,683		$2,966.30	$ 154,752
EOMS77		$2,934.00	$ 153,067		$3,013.20	$ 157,199
EOMS78		$2,979.80	$ 155,456		$3,060.30	$ 159,656
EOMS79		$3,025.60	$ 157,846		$3,107.30	$ 162,108
EOMS8A		$2,844.90	$ 148,418		$2,921.70	$ 152,425
EOMS84		$2,872.10	$ 149,837		$2,949.60	$ 153,881
EOMS85		$2,919.10	$ 152,289		$2,997.90	$ 156,400
EOMS86		$2,966.20	$ 154,747		$3,046.30	$ 158,925
EOMS87		$3,013.10	$ 157,193		$3,094.50	$ 161,440
EOMS88		$3,060.20	$ 159,651		$3,142.80	$ 163,960

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
EOMS89		$3,107.20	$ 162,103		$3,191.10	$ 166,480
EOMS9A		$2,918.40	$ 152,253		$2,997.20	$ 156,364
EOMS94		$2,946.30	$ 153,708		$3,025.90	$ 157,861
EOMS95		$2,994.50	$ 156,223		$3,075.40	$ 160,444
EOMS96		$3,042.70	$ 158,738		$3,124.90	$ 163,026
EOMS97		$3,091.00	$ 161,257		$3,174.50	$ 165,614
EOMS98		$3,139.10	$ 163,767		$3,223.90	$ 168,191
EOMS99		$3,187.40	$ 166,287		$3,273.50	$ 170,778
MSBAI5		$2,765.90	$ 144,297		$2,840.60	$ 148,194
PEMS1A		$2,643.70	$ 137,922		$2,715.10	$ 141,647
PEMS14		$2,669.00	$ 139,242		$2,741.10	$ 143,003
PEMS15		$2,712.60	$ 141,516		$2,785.80	$ 145,335
PEMS16		$2,756.30	$ 143,796		$2,830.70	$ 147,678
PEMS17		$2,800.00	$ 146,076		$2,875.60	$ 150,020
PEMS18		$2,843.70	$ 148,356		$2,920.50	$ 152,362
PEMS19		$2,887.30	$ 150,630		$2,965.30	$ 154,700
PEMS2A		$2,698.00	$ 140,755		$2,770.80	$ 144,553
PEMS24		$2,723.80	$ 142,101		$2,797.30	$ 145,935
PEMS25		$2,768.40	$ 144,427		$2,843.10	$ 148,325
PEMS26		$2,813.00	$ 146,754		$2,889.00	$ 150,719
PEMS27		$2,857.50	$ 149,076		$2,934.70	$ 153,103
PEMS28		$2,902.10	$ 151,403		$2,980.50	$ 155,493

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
PEMS29		$2,946.70	$ 153,729		$3,026.30	$ 157,882
PEMS3A		$2,753.30	$ 143,640		$2,827.60	$ 147,516
PEMM34		$2,779.60	$ 145,012		$2,854.60	$ 148,924
PEMM35		$2,825.10	$ 147,385		$2,901.40	$ 151,366
PEMM36		$2,870.60	$ 149,759		$2,948.10	$ 153,802
PEMM37		$2,916.10	$ 152,133		$2,994.80	$ 156,239
PEMM38		$2,961.60	$ 154,507		$3,041.60	$ 158,680
PEMM39		$3,007.10	$ 156,880		$3,088.30	$ 161,117
PEMS4A		$2,807.90	$ 146,488		$2,883.70	$ 150,443
PEMS44		$2,834.80	$ 147,892		$2,911.30	$ 151,883
PEMS45		$2,881.20	$ 150,312		$2,959.00	$ 154,371
PEMS46		$2,927.60	$ 152,733		$3,006.60	$ 156,854
PEMS47		$2,974.00	$ 155,154		$3,054.30	$ 159,343
PEMS48		$3,020.40	$ 157,574		$3,102.00	$ 161,831
PEMS49		$3,066.70	$ 159,990		$3,149.50	$ 164,309
PEMS5A		$2,862.70	$ 149,347		$2,940.00	$ 153,380
PEMS54		$2,890.00	$ 150,771		$2,968.00	$ 154,841
PEMS55		$2,937.30	$ 153,239		$3,016.60	$ 157,376
PEMS56		$2,984.60	$ 155,707		$3,065.20	$ 159,911
PEMS57		$3,031.90	$ 158,174		$3,113.80	$ 162,447
PEMS58		$3,079.20	$ 160,642		$3,162.30	$ 164,977
PEMS59		$3,126.50	$ 163,110		$3,210.90	$ 167,513

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
PEMS6A		$2,920.90	$ 152,383		$2,999.80	$ 156,500
PEMS64		$2,948.80	$ 153,839		$3,028.40	$ 157,992
PEMS65		$2,997.10	$ 156,359		$3,078.00	$ 160,579
PEMS66		$3,045.30	$ 158,873		$3,127.50	$ 163,162
PEMS67		$3,093.50	$ 161,388		$3,177.00	$ 165,744
PEMS68		$3,141.80	$ 163,908		$3,226.60	$ 168,332
PEMS69		$3,190.10	$ 166,428		$3,276.20	$ 170,919
PEMS7A		$2,993.80	$ 156,187		$3,074.60	$ 160,402
PEMS74		$3,022.50	$ 157,684		$3,104.10	$ 161,941
PEMS75		$3,072.00	$ 160,266		$3,154.90	$ 164,591
PEMS76		$3,121.40	$ 162,843		$3,205.70	$ 167,241
PEMS77		$3,170.90	$ 165,426		$3,256.50	$ 169,892
PEMS78		$3,220.40	$ 168,008		$3,307.40	$ 172,547
PEMS79		$3,269.80	$ 170,585		$3,358.10	$ 175,192
PEMS8A		$3,067.00	$ 160,005		$3,149.80	$ 164,325
PEMS84		$3,096.40	$ 161,539		$3,180.00	$ 165,901
PEMS85		$3,147.00	$ 164,179		$3,232.00	$ 168,613
PEMS86		$3,197.80	$ 166,829		$3,284.10	$ 171,331
PEMS87		$3,248.40	$ 169,469		$3,336.10	$ 174,044
PEMS88		$3,299.10	$ 172,114		$3,388.20	$ 176,762
PEMS89		$3,349.80	$ 174,759		$3,440.20	$ 179,475
PEMS9A		$3,140.30	$ 163,829		$3,225.10	$ 168,253

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
PEMS94		$3,170.30	$ 165,395		$3,255.90	$ 169,860
PEMS95		$3,222.20	$ 168,102		$3,309.20	$ 172,641
PEMS96		$3,274.10	$ 170,810		$3,362.50	$ 175,422
PEMS97		$3,325.90	$ 173,512		$3,415.70	$ 178,197
PEMS98		$3,377.90	$ 176,225		$3,469.10	$ 180,983
PEMS99		$3,429.80	$ 178,933		$3,522.40	$ 183,764
PEM9XA		$3,207.00	$ 167,309		$3,293.60	$ 171,827
PEM9X4		$3,237.70	$ 168,911		$3,325.10	$ 173,470
PEM9X5		$3,290.70	$ 171,676		$3,379.50	$ 176,309
PEM9X6		$3,343.70	$ 174,441		$3,434.00	$ 179,152
PEM9X7		$3,396.70	$ 177,206		$3,488.40	$ 181,990
PEM9X8		$3,449.60	$ 179,966		$3,542.70	$ 184,823
PEM9X9		$3,502.60	$ 182,731		$3,597.20	$ 187,666
PE9XXA		$3,274.20	$ 170,815		$3,362.60	$ 175,427
PE9XX4		$3,305.50	$ 172,448		$3,394.70	$ 177,101
PE9XX5		$3,359.60	$ 175,270		$3,450.30	$ 180,002
PE9XX6		$3,413.70	$ 178,093		$3,505.90	$ 182,903
PE9XX7		$3,467.90	$ 180,920		$3,561.50	$ 185,803
PE9XX8		$3,521.90	$ 183,738		$3,617.00	$ 188,699
PE9XX9		$3,576.00	$ 186,560		$3,672.60	$ 191,600
OMMS1A		$2,643.40	$ 137,906		$2,714.80	$ 141,631
OMMS14		$2,668.80	$ 139,231		$2,740.90	$ 142,993

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
OMMS15		$2,712.40	$ 141,506		$2,785.60	$ 145,325
OMMS16		$2,756.10	$ 143,786		$2,830.50	$ 147,667
OMMS17		$2,799.70	$ 146,060		$2,875.30	$ 150,004
OMMS18		$2,843.50	$ 148,345		$2,920.30	$ 152,352
OMMS19		$2,887.10	$ 150,620		$2,965.10	$ 154,689
OMMS2A		$2,680.80	$ 139,857		$2,753.20	$ 143,634
OMMS24		$2,706.40	$ 141,193		$2,779.50	$ 145,007
OMMS25		$2,750.70	$ 143,504		$2,825.00	$ 147,380
OMMS26		$2,795.00	$ 145,815		$2,870.50	$ 149,754
OMMS27		$2,839.20	$ 148,121		$2,915.90	$ 152,123
OMMS28		$2,883.50	$ 150,432		$2,961.40	$ 154,496
OMMS29		$2,927.90	$ 152,749		$3,007.00	$ 156,875
OMMS3A		$2,750.10	$ 143,473		$2,824.40	$ 147,349
OMMS34		$2,776.40	$ 144,845		$2,851.40	$ 148,758
OMMS35		$2,821.80	$ 147,213		$2,898.00	$ 151,189
OMMS36		$2,867.30	$ 149,587		$2,944.70	$ 153,625
OMMS37		$2,912.70	$ 151,956		$2,991.30	$ 156,056
OMMS38		$2,958.20	$ 154,329		$3,038.10	$ 158,498
OMMS39		$3,003.60	$ 156,698		$3,084.70	$ 160,929
OMMS4A		$2,775.70	$ 144,808		$2,850.60	$ 148,716
OMMS44		$2,802.30	$ 146,196		$2,878.00	$ 150,145
OMMS45		$2,848.10	$ 148,585		$2,925.00	$ 152,597

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
OMMS46		$2,894.00	$ 150,980		$2,972.10	$ 155,054
OMMS47		$2,939.80	$ 153,369		$3,019.20	$ 157,512
OMMS48		$2,985.70	$ 155,764		$3,066.30	$ 159,969
OMMS49		$3,031.60	$ 158,159		$3,113.50	$ 162,431
OMMS5A		$2,800.60	$ 146,107		$2,876.20	$ 150,051
OMMS54		$2,827.40	$ 147,505		$2,903.70	$ 151,486
OMMS55		$2,873.60	$ 149,916		$2,951.20	$ 153,964
OMMS56		$2,920.00	$ 152,336		$2,998.80	$ 156,447
OMMS57		$2,966.20	$ 154,747		$3,046.30	$ 158,925
OMMS58		$3,012.50	$ 157,162		$3,093.80	$ 161,404
OMMS59		$3,058.80	$ 159,578		$3,141.40	$ 163,887
OMMS6A		$2,827.50	$ 147,511		$2,903.80	$ 151,491
OMMS64		$2,854.60	$ 148,924		$2,931.70	$ 152,947
OMMS65		$2,901.30	$ 151,361		$2,979.60	$ 155,446
OMMS66		$2,948.00	$ 153,797		$3,027.60	$ 157,950
OMMS67		$2,994.70	$ 156,233		$3,075.60	$ 160,454
OMMS68		$3,041.50	$ 158,675		$3,123.60	$ 162,958
OMMS69		$3,088.20	$ 161,111		$3,171.60	$ 165,462
OMMS7A		$2,861.10	$ 149,264		$2,938.30	$ 153,291
OMMS74		$2,888.40	$ 150,688		$2,966.40	$ 154,757
OMMS75		$2,935.80	$ 153,161		$3,015.10	$ 157,298
OMMS76		$2,983.00	$ 155,623		$3,063.50	$ 159,823

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
OMMS77		$3,030.30	$ 158,091		$3,112.10	$ 162,358
OMMS78		$3,077.50	$ 160,553		$3,160.60	$ 164,889
OMMS79		$3,124.90	$ 163,026		$3,209.30	$ 167,429
Y0136P		$599.90	$ 31,297		$616.10	$ 32,142
Y0335		$833.20	$ 43,468		$855.70	$ 44,642
Y0336		$841.70	$ 43,911		$864.40	$ 45,096
Y0435		$939.40	$ 49,008		$964.80	$ 50,334
Y0436		$948.20	$ 49,468		$973.80	$ 50,803
Y0535		$963.40	$ 50,261		$989.40	$ 51,617
Y0536		$986.80	$ 51,481		$1,013.40	$ 52,869
Y0536		$972.60	$ 50,741		$998.90	$ 52,113
Y0536T		$986.80	$ 51,481		$1,013.40	$ 52,869
Y0735		$998.60	$ 52,097		$1,025.60	$ 53,506
Y0735		$914.30	$ 47,699		$939.00	$ 48,988
Y0736		$767.80	$ 40,056		$788.50	$ 41,136
Y0736		$1,017.70	$ 53,093		$1,045.20	$ 54,528
Y0736		$979.20	$ 51,085		$1,005.60	$ 52,462
Y0835		$1,051.80	$ 54,872		$1,080.20	$ 56,354
Y0836		$1,044.90	$ 54,512		$1,073.10	$ 55,984
Y0836T		$1,049.30	$ 54,742		$1,077.60	$ 56,218
Y0935		$1,069.50	$ 55,796		$1,098.40	$ 57,304
Y0936		$1,078.50	$ 56,265		$1,107.60	$ 57,783
Y0936T		$1,080.30	$ 56,359		$1,109.50	$ 57,883

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Y1035		$1,176.50	$ 61,378		$1,208.30	$ 63,037
Y1036		$1,111.50	$ 57,987		$1,141.50	$ 59,552
Y10LH		$1,218.60	$ 63,574		$1,251.50	$ 65,291
Y1136		$1,125.80	$ 58,733		$1,156.20	$ 60,319
Y1235		$1,184.80	$ 61,811		$1,216.80	$ 63,480
Y1236		$1,144.30	$ 59,698		$1,175.20	$ 61,310
Y1236W		$1,155.50	$ 60,282		$1,186.70	$ 61,910
Y12LH		$1,248.90	$ 65,155		$1,282.60	$ 66,913
Y1335		$1,214.30	$ 63,350		$1,247.10	$ 65,061
Y1335P		$1,038.70	$ 54,189		$1,066.70	$ 55,650
Y1335P		$1,152.10	$ 60,105		$1,183.20	$ 61,728
Y1336		$1,160.90	$ 60,564		$1,192.20	$ 62,197
Y1336M		$1,160.90	$ 60,564		$1,192.20	$ 62,197
Y1336O		$1,231.10	$ 64,226		$1,264.30	$ 65,959
Y1336R		$1,214.30	$ 63,350		$1,247.10	$ 65,061
Y1336T		$1,206.90	$ 62,964		$1,239.50	$ 64,665
Y13LH		$1,300.60	$ 67,852		$1,335.70	$ 69,683
Y1435		$1,260.00	$ 65,734		$1,294.00	$ 67,508
Y1435P		$1,126.90	$ 58,790		$1,157.30	$ 60,376
Y1435P		$1,231.10	$ 64,226		$1,264.30	$ 65,959
Y1436		$1,196.20	$ 62,406		$1,228.50	$ 64,091
Y1436T		$1,238.00	$ 64,586		$1,271.40	$ 66,329
Y14LH		$1,280.90	$ 66,825		$1,315.50	$ 68,630

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Y14LHT		$1,332.50	$ 69,517		$1,368.50	$ 71,395
Y1536		$1,222.00	$ 63,752		$1,255.00	$ 65,473
Y1536E		$1,248.90	$ 65,155		$1,282.60	$ 66,913
Y1536O		$1,213.20	$ 63,293		$1,246.00	$ 65,004
Y1536T		$1,260.00	$ 65,734		$1,294.00	$ 67,508
Y15LH		$1,399.60	$ 73,017		$1,437.40	$ 74,989
Y1635		$1,284.10	$ 66,991		$1,318.80	$ 68,802
Y1636		$1,248.90	$ 65,155		$1,282.60	$ 66,913
Y1636O		$1,284.10	$ 66,991		$1,318.80	$ 68,802
Y1636T		$1,270.40	$ 66,277		$1,304.70	$ 68,066
Y16LH		$1,348.10	$ 70,330		$1,384.50	$ 72,229
Y16LHT		$1,364.40	$ 71,181		$1,401.20	$ 73,101
Y1736		$1,248.90	$ 65,155		$1,282.60	$ 66,913
Y1835		$1,270.20	$ 66,266		$1,304.50	$ 68,056
Y1836		$1,280.90	$ 66,825		$1,315.50	$ 68,630
Y1836E		$1,300.60	$ 67,852		$1,335.70	$ 69,683
Y1836M		$1,280.90	$ 66,825		$1,315.50	$ 68,630
Y1836S		$1,270.20	$ 66,266		$1,304.50	$ 68,056
Y18LH		$1,410.20	$ 73,570		$1,448.30	$ 75,558
Y18LHM		$1,427.60	$ 74,478		$1,466.10	$ 76,486
Y18LHT		$1,399.60	$ 73,017		$1,437.40	$ 74,989
Y1935		$1,310.60	$ 68,374		$1,346.00	$ 70,221
Y1935P		$1,275.20	$ 66,527		$1,309.60	$ 68,322

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Y1936O		$1,275.20	$ 66,527		$1,309.60	$ 68,322
Y2035		$1,335.00	$ 69,647		$1,371.00	$ 71,525
Y2036		$1,332.50	$ 69,517		$1,368.50	$ 71,395
Y20LH		$1,408.90	$ 73,502		$1,446.90	$ 75,485
Y20LH		$1,427.60	$ 74,478		$1,466.10	$ 76,486
Y2135		$542.50	$ 28,302		$557.10	$ 29,064
Y2135		$1,329.50	$ 69,360		$1,365.40	$ 71,233
Y2136		$1,338.30	$ 69,819		$1,374.40	$ 71,702
Y2136L		$1,343.30	$ 70,080		$1,379.60	$ 71,974
Y2136N		$1,348.70	$ 70,362		$1,385.10	$ 72,261
Y2136T		$1,393.30	$ 72,688		$1,430.90	$ 74,650
Y21LH		$1,420.90	$ 74,128		$1,459.30	$ 76,132
Y21LH		$1,433.40	$ 74,780		$1,472.10	$ 76,799
Y21LHL		$1,473.00	$ 76,846		$1,512.80	$ 78,923
Y2235		$1,364.50	$ 71,186		$1,401.30	$ 73,106
Y2235O		$1,468.40	$ 76,606		$1,508.00	$ 78,672
Y2236		$1,364.50	$ 71,186		$1,401.30	$ 73,106
Y2236I		$1,397.20	$ 72,892		$1,434.90	$ 74,859
Y2236N		$1,375.20	$ 71,744		$1,412.30	$ 73,680
Y2236O		$1,364.50	$ 71,186		$1,401.30	$ 73,106
Y22LH		$1,461.70	$ 76,257		$1,501.20	$ 78,318
Y2335		$1,397.20	$ 72,892		$1,434.90	$ 74,859
Y23LH		$1,467.10	$ 76,539		$1,506.70	$ 78,605

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Y2435		$1,435.60	$ 74,895		$1,474.40	$ 76,919
Y2435A		$1,465.30	$ 76,445		$1,504.90	$ 78,511
Y2436		$1,444.60	$ 75,365		$1,483.60	$ 77,399
Y2436E		$1,435.60	$ 74,895		$1,474.40	$ 76,919
Y2436I		$1,537.40	$ 80,206		$1,578.90	$ 82,371
Y2436S		$1,543.70	$ 80,535		$1,585.40	$ 82,710
Y24LH		$1,527.10	$ 79,669		$1,568.30	$ 81,818
Y2535		$1,506.60	$ 78,599		$1,547.30	$ 80,723
Y2536		$1,515.60	$ 79,069		$1,556.50	$ 81,203
Y2536O		$1,506.60	$ 78,599		$1,547.30	$ 80,723
Y2635		$1,537.40	$ 80,206		$1,578.90	$ 82,371
Y2635O		$1,610.70	$ 84,030		$1,654.20	$ 86,300
Y2636E		$1,610.70	$ 84,030		$1,654.20	$ 86,300
Y2636O		$1,520.80	$ 79,340		$1,561.90	$ 81,484
Y2636T		$1,610.40	$ 84,015		$1,653.90	$ 86,284
Y2735		$1,565.80	$ 81,688		$1,608.10	$ 83,895
Y2735D		$1,610.40	$ 84,015		$1,653.90	$ 86,284
Y2735O		$1,573.70	$ 82,100		$1,616.20	$ 84,317
Y2736		$1,565.80	$ 81,688		$1,608.10	$ 83,895
Y2736E		$1,573.70	$ 82,100		$1,616.20	$ 84,317
Y2736I		$1,642.00	$ 85,663		$1,686.30	$ 87,974
Y2736S		$1,580.50	$ 82,455		$1,623.20	$ 84,682
Y2835		$1,642.00	$ 85,663		$1,686.30	$ 87,974

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Y2836		$1,624.70	$ 84,761		$1,668.60	$ 87,051
Y2836E		$1,642.00	$ 85,663		$1,686.30	$ 87,974
Y2836N		$1,632.30	$ 85,157		$1,676.40	$ 87,458
Y2935		$1,680.60	$ 87,677		$1,726.00	$ 90,045
Y2936		$1,648.50	$ 86,002		$1,693.00	$ 88,324
Y2936E		$1,680.60	$ 87,677		$1,726.00	$ 90,045
Y2936M		$1,657.40	$ 86,467		$1,702.10	$ 88,799
Y3035		$1,713.70	$ 89,404		$1,760.00	$ 91,819
Y3036		$1,695.90	$ 88,475		$1,741.70	$ 90,864
Y3036C		$1,713.70	$ 89,404		$1,760.00	$ 91,819
Y3136		$1,745.20	$ 91,047		$1,792.30	$ 93,504
Y3136C		$1,792.20	$ 93,499		$1,840.60	$ 96,024
Y3235		$1,784.50	$ 93,097		$1,832.70	$ 95,612
Y3335		$1,806.80	$ 94,261		$1,855.60	$ 96,807
Y3336C		$1,947.70	$ 101,612		$2,000.30	$ 104,356
Y3435		$1,884.80	$ 98,330		$1,935.70	$ 100,985
Y3436C		$1,888.40	$ 98,518		$1,939.40	$ 101,178
Y4035		$2,430.60	$ 126,804		$2,496.20	$ 130,227
Y4135		$2,570.30	$ 134,093		$2,639.70	$ 137,713
Y4135		$2,549.60	$ 133,013		$2,618.40	$ 136,602
Y5040		$1,821.30	$ 95,017		$1,870.50	$ 97,584
YI420		$1,618.40	$ 84,432		$1,662.10	$ 86,712
YI557		$1,183.40	$ 61,738		$1,215.40	$ 63,407

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
YI559		$1,213.10	$ 63,287		$1,245.90	$ 64,999
YI576		$1,270.80	$ 66,298		$1,305.10	$ 68,087
YLLW31		$1,312.90	$ 68,494		$1,348.30	$ 70,341
YLW4T1		$1,280.70	$ 66,814		$1,315.30	$ 68,619
YLW5T1		$1,312.90	$ 68,494		$1,348.30	$ 70,341
YP317		$1,703.00	$ 88,846		$1,749.00	$ 91,245
YP322		$1,754.90	$ 91,553		$1,802.30	$ 94,026
YP353		$1,703.00	$ 88,846		$1,749.00	$ 91,245
YP356		$1,846.10	$ 96,311		$1,895.90	$ 98,909
YP393		$1,250.00	$ 65,213		$1,283.80	$ 66,976
YP466		$1,198.70	$ 62,536		$1,231.10	$ 64,226
YP527		$1,254.20	$ 65,432		$1,288.10	$ 67,200
YP537		$1,336.90	$ 69,746		$1,373.00	$ 71,629
YP779		$1,175.80	$ 61,341		$1,207.50	$ 62,995
YP826		$961.70	$ 50,172		$987.70	$ 51,528
Z00101		$1,096.00	$ 57,178		$1,125.60	$ 58,723
Z00298		$986.80	$ 51,481		$1,013.40	$ 52,869
Z00521		$1,049.10	$ 54,732		$1,077.40	$ 56,208
Z00598		$1,049.10	$ 54,732		$1,077.40	$ 56,208
Z00621		$1,125.80	$ 58,733		$1,156.20	$ 60,319
Z00698		$1,080.30	$ 56,359		$1,109.50	$ 57,883
Z00821		$1,144.40	$ 59,703		$1,175.30	$ 61,315
Z00850		$1,144.40	$ 59,703		$1,175.30	$ 61,315

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z00898		$1,111.50	$ 57,987		$1,141.50	$ 59,552
Z00921		$1,155.50	$ 60,282		$1,186.70	$ 61,910
Z00998		$1,155.50	$ 60,282		$1,186.70	$ 61,910
Z01022		$1,080.30	$ 56,359		$1,109.50	$ 57,883
Z01041		$1,111.00	$ 57,961		$1,141.00	$ 59,526
Z01042		$1,155.50	$ 60,282		$1,186.70	$ 61,910
Z01051		$1,155.50	$ 60,282		$1,186.70	$ 61,910
Z01052		$1,196.20	$ 62,406		$1,228.50	$ 64,091
Z01053		$1,219.00	$ 63,595		$1,251.90	$ 65,312
Z01061		$1,196.20	$ 62,406		$1,228.50	$ 64,091
Z01062		$1,219.00	$ 63,595		$1,251.90	$ 65,312
Z01064		$1,280.70	$ 66,814		$1,315.30	$ 68,619
Z01198		$1,080.30	$ 56,359		$1,109.50	$ 57,883
Z01298		$1,111.50	$ 57,987		$1,141.50	$ 59,552
Z01498		$1,155.50	$ 60,282		$1,186.70	$ 61,910
Z01598		$1,196.20	$ 62,406		$1,228.50	$ 64,091
Z01798		$1,219.00	$ 63,595		$1,251.90	$ 65,312
Z01898		$1,248.90	$ 65,155		$1,282.60	$ 66,913
Z01988		$1,343.20	$ 70,075		$1,379.50	$ 71,969
Z01988		$1,343.10	$ 70,070		$1,379.40	$ 71,963
Z01998		$1,280.70	$ 66,814		$1,315.30	$ 68,619
Z02011		$1,155.40	$ 60,277		$1,186.60	$ 61,905
Z02011		$1,155.50	$ 60,282		$1,186.70	$ 61,910

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z02031		$1,218.60	$ 63,574		$1,251.50	$ 65,291
Z02031		$1,219.00	$ 63,595		$1,251.90	$ 65,312
Z02042		$1,280.70	$ 66,814		$1,315.30	$ 68,619
Z02051		$1,280.70	$ 66,814		$1,315.30	$ 68,619
Z02051		$1,240.40	$ 64,712		$1,273.90	$ 66,459
Z02052		$1,312.90	$ 68,494		$1,348.30	$ 70,341
Z02053		$1,347.80	$ 70,315		$1,384.20	$ 72,214
Z02062		$1,347.80	$ 70,315		$1,384.20	$ 72,214
Z02066		$1,410.50	$ 73,586		$1,448.60	$ 75,573
Z02198		$1,186.20	$ 61,884		$1,218.20	$ 63,553
Z02398		$1,219.00	$ 63,595		$1,251.90	$ 65,312
Z02495		$1,300.60	$ 67,852		$1,335.70	$ 69,683
Z02498		$1,248.90	$ 65,155		$1,282.60	$ 66,913
Z02512		$1,248.90	$ 65,155		$1,282.60	$ 66,913
Z02522		$1,280.70	$ 66,814		$1,315.30	$ 68,619
Z02542		$1,347.80	$ 70,315		$1,384.20	$ 72,214
Z02695		$1,332.50	$ 69,517		$1,368.50	$ 71,395
Z02698		$1,280.70	$ 66,814		$1,315.30	$ 68,619
Z02795		$1,364.50	$ 71,186		$1,401.30	$ 73,106
Z02796		$1,312.90	$ 68,494		$1,348.30	$ 70,341
Z02844		$1,410.40	$ 73,581		$1,448.50	$ 75,568
Z02852		$1,375.90	$ 71,781		$1,413.00	$ 73,716
Z02871		$1,410.40	$ 73,581		$1,448.50	$ 75,568

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z02872		$1,446.10	$ 75,443		$1,485.10	$ 77,478
Z02874		$1,519.30	$ 79,262		$1,560.30	$ 81,401
Z02881		$1,446.10	$ 75,443		$1,485.10	$ 77,478
Z02882		$1,481.90	$ 77,311		$1,521.90	$ 79,398
Z02891		$1,481.90	$ 77,311		$1,521.90	$ 79,398
Z02893		$1,549.90	$ 80,858		$1,591.70	$ 83,039
Z02895		$1,581.60	$ 82,512		$1,624.30	$ 84,740
Z02995		$1,399.70	$ 73,022		$1,437.50	$ 74,994
Z02996		$1,347.80	$ 70,315		$1,384.20	$ 72,214
Z02998		$1,347.80	$ 70,315		$1,384.20	$ 72,214
Z03095		$1,428.00	$ 74,499		$1,466.60	$ 76,513
Z03096		$1,375.90	$ 71,781		$1,413.00	$ 73,716
Z03097		$1,428.00	$ 74,499		$1,466.60	$ 76,513
Z03098		$1,375.90	$ 71,781		$1,413.00	$ 73,716
Z03162		$1,461.80	$ 76,262		$1,501.30	$ 78,323
Z03181		$1,497.80	$ 78,140		$1,538.20	$ 80,248
Z03184		$1,596.20	$ 83,274		$1,639.30	$ 85,522
Z03191		$1,533.30	$ 79,992		$1,574.70	$ 82,152
Z03192		$1,564.60	$ 81,625		$1,606.80	$ 83,827
Z03295		$1,461.80	$ 76,262		$1,501.30	$ 78,323
Z03296		$1,410.40	$ 73,581		$1,448.50	$ 75,568
Z03297		$1,461.80	$ 76,262		$1,501.30	$ 78,323
Z03298		$1,410.40	$ 73,581		$1,448.50	$ 75,568

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z03388		$1,508.30	$ 78,688		$1,549.00	$ 80,811
Z03388		$1,508.70	$ 78,709		$1,549.40	$ 80,832
Z03395		$1,497.80	$ 78,140		$1,538.20	$ 80,248
Z03396		$1,446.10	$ 75,443		$1,485.10	$ 77,478
Z03397		$1,497.80	$ 78,140		$1,538.20	$ 80,248
Z03398		$1,446.10	$ 75,443		$1,485.10	$ 77,478
Z03696		$1,481.90	$ 77,311		$1,521.90	$ 79,398
Z03697		$1,533.30	$ 79,992		$1,574.70	$ 82,152
Z03698		$1,481.90	$ 77,311		$1,521.90	$ 79,398
Z03701		$1,564.60	$ 81,625		$1,606.80	$ 83,827
Z03801		$1,596.20	$ 83,274		$1,639.30	$ 85,522
Z03805		$1,596.20	$ 83,274		$1,639.30	$ 85,522
Z03813		$1,596.10	$ 83,269		$1,639.20	$ 85,517
Z03815		$1,596.20	$ 83,274		$1,639.30	$ 85,522
Z03898		$1,596.20	$ 83,274		$1,639.30	$ 85,522
Z03903		$1,633.00	$ 85,194		$1,677.10	$ 87,494
Z03905		$1,633.00	$ 85,194		$1,677.10	$ 87,494
Z03917		$1,633.00	$ 85,194		$1,677.10	$ 87,494
Z03927		$1,633.00	$ 85,194		$1,677.10	$ 87,494
Z03928		$1,669.60	$ 87,103		$1,714.70	$ 89,456
Z04195		$1,161.20	$ 60,580		$1,192.60	$ 62,218
Z04198		$1,206.90	$ 62,964		$1,239.50	$ 64,665
Z04295		$1,196.20	$ 62,406		$1,228.50	$ 64,091

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z04297		$1,196.20	$ 62,406		$1,228.50	$ 64,091
Z04298		$1,238.00	$ 64,586		$1,271.40	$ 66,329
Z04298		$1,237.90	$ 64,581		$1,271.30	$ 66,324
Z04495		$1,222.50	$ 63,778		$1,255.50	$ 65,499
Z04497		$1,219.00	$ 63,595		$1,251.90	$ 65,312
Z04498		$1,270.40	$ 66,277		$1,304.70	$ 68,066
Z04595		$1,248.90	$ 65,155		$1,282.60	$ 66,913
Z04597		$1,248.90	$ 65,155		$1,282.60	$ 66,913
Z04598		$1,300.60	$ 67,852		$1,335.70	$ 69,683
Z04795		$1,280.70	$ 66,814		$1,315.30	$ 68,619
Z04798		$1,332.50	$ 69,517		$1,368.50	$ 71,395
Z04798		$1,332.40	$ 69,511		$1,368.40	$ 71,389
Z04811		$1,238.00	$ 64,586		$1,271.40	$ 66,329
Z04821		$1,270.40	$ 66,277		$1,304.70	$ 68,066
Z04822		$1,300.60	$ 67,852		$1,335.70	$ 69,683
Z04823		$1,332.50	$ 69,517		$1,368.50	$ 71,395
Z04831		$1,300.60	$ 67,852		$1,335.70	$ 69,683
Z04832		$1,332.50	$ 69,517		$1,368.50	$ 71,395
Z04833		$1,364.50	$ 71,186		$1,401.30	$ 73,106
Z04841		$1,332.50	$ 69,517		$1,368.50	$ 71,395
Z04842		$1,364.50	$ 71,186		$1,401.30	$ 73,106
Z04843		$1,399.70	$ 73,022		$1,437.50	$ 74,994
Z04851		$1,364.50	$ 71,186		$1,401.30	$ 73,106

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z04852		$1,399.70	$ 73,022		$1,437.50	$ 74,994
Z06409		$1,052.10	$ 54,888		$1,080.50	$ 56,370
Z06425		$1,335.10	$ 69,652		$1,371.10	$ 71,530
Z06426		$1,362.90	$ 71,102		$1,399.70	$ 73,022
Z06427		$1,396.90	$ 72,876		$1,434.60	$ 74,843
Z06501		$1,348.70	$ 70,362		$1,385.10	$ 72,261
Z06502		$1,375.20	$ 71,744		$1,412.30	$ 73,680
Z06502		$1,322.70	$ 69,005		$1,358.40	$ 70,868
Z06503		$1,399.70	$ 73,022		$1,437.50	$ 74,994
Z06601		$1,348.70	$ 70,362		$1,385.10	$ 72,261
Z06602		$1,375.20	$ 71,744		$1,412.30	$ 73,680
Z06603		$1,399.70	$ 73,022		$1,437.50	$ 74,994
Z06604		$1,444.70	$ 75,370		$1,483.70	$ 77,405
Z06701		$1,297.50	$ 67,691		$1,332.50	$ 69,517
Z06702		$1,323.70	$ 69,057		$1,359.40	$ 70,920
Z06801		$1,348.70	$ 70,362		$1,385.10	$ 72,261
Z06802		$1,375.20	$ 71,744		$1,412.30	$ 73,680
Z06802		$1,374.90	$ 71,729		$1,412.00	$ 73,664
Z06803		$1,399.70	$ 73,022		$1,437.50	$ 74,994
Z06804		$1,444.70	$ 75,370		$1,483.70	$ 77,405
Z06805		$1,461.80	$ 76,262		$1,501.30	$ 78,323
Z06806		$1,515.70	$ 79,074		$1,556.60	$ 81,208
Z06807		$1,533.30	$ 79,992		$1,574.70	$ 82,152

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z06808		$1,570.70	$ 81,943		$1,613.10	$ 84,155
Z06901		$1,348.70	$ 70,362		$1,385.10	$ 72,261
Z06902		$1,375.20	$ 71,744		$1,412.30	$ 73,680
Z06903		$1,399.70	$ 73,022		$1,437.50	$ 74,994
Z06904		$1,428.00	$ 74,499		$1,466.60	$ 76,513
Z06905		$1,461.80	$ 76,262		$1,501.30	$ 78,323
Z06906		$1,515.70	$ 79,074		$1,556.60	$ 81,208
Z07101		$1,335.10	$ 69,652		$1,371.10	$ 71,530
Z07201		$1,362.90	$ 71,102		$1,399.70	$ 73,022
Z07202		$1,396.90	$ 72,876		$1,434.60	$ 74,843
Z07301		$1,396.90	$ 72,876		$1,434.60	$ 74,843
Z07302		$1,468.40	$ 76,606		$1,508.00	$ 78,672
Z07401		$1,468.40	$ 76,606		$1,508.00	$ 78,672
Z07402		$1,505.80	$ 78,558		$1,546.50	$ 80,681
Z07501		$1,537.40	$ 80,206		$1,578.90	$ 82,371
Z07502		$1,537.40	$ 80,206		$1,578.90	$ 82,371
Z07503		$1,573.70	$ 82,100		$1,616.20	$ 84,317
Z07504		$1,610.70	$ 84,030		$1,654.20	$ 86,300
Z07701		$1,289.00	$ 67,247		$1,323.80	$ 69,063
Z07702		$1,368.70	$ 71,405		$1,405.70	$ 73,335
Z07702		$1,316.20	$ 68,666		$1,351.70	$ 70,518
Z07704		$1,474.50	$ 76,925		$1,514.30	$ 79,001
Z07704		$1,418.60	$ 74,008		$1,456.90	$ 76,006

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z07705		$1,543.70	$ 80,535		$1,585.40	$ 82,710
Z07705		$1,484.80	$ 77,462		$1,524.90	$ 79,554
Z07706		$1,316.00	$ 68,656		$1,351.50	$ 70,508
Z07706		$1,265.90	$ 66,042		$1,300.10	$ 67,826
Z07707		$1,340.30	$ 69,923		$1,376.50	$ 71,812
Z07707		$1,289.20	$ 67,258		$1,324.00	$ 69,073
Z07708		$1,580.50	$ 82,455		$1,623.20	$ 84,682
Z07708		$1,520.20	$ 79,309		$1,561.20	$ 81,448
Z07819		$1,602.00	$ 83,576		$1,645.30	$ 85,835
Z07821		$1,639.10	$ 85,512		$1,683.40	$ 87,823
Z07823		$1,675.70	$ 87,421		$1,720.90	$ 89,779
Z07917		$1,310.60	$ 68,374		$1,346.00	$ 70,221
Z07918		$1,335.10	$ 69,652		$1,371.10	$ 71,530
Z07919		$1,362.90	$ 71,102		$1,399.70	$ 73,022
Z07920		$1,396.90	$ 72,876		$1,434.60	$ 74,843
Z07921		$1,435.50	$ 74,890		$1,474.30	$ 76,914
Z07922		$1,468.40	$ 76,606		$1,508.00	$ 78,672
Z07923		$1,505.80	$ 78,558		$1,546.50	$ 80,681
Z07923		$1,505.70	$ 78,552		$1,546.40	$ 80,676
Z07924		$1,537.40	$ 80,206		$1,578.90	$ 82,371
Z07925		$1,573.70	$ 82,100		$1,616.20	$ 84,317
Z07926		$1,610.70	$ 84,030		$1,654.20	$ 86,300
Z07926		$1,610.40	$ 84,015		$1,653.90	$ 86,284

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z07927		$1,642.00	$ 85,663		$1,686.30	$ 87,974
Z07927		$1,641.80	$ 85,653		$1,686.10	$ 87,964
Z07927		$1,642.00	$ 85,663		$1,686.30	$ 87,974
Z07928		$1,680.60	$ 87,677		$1,726.00	$ 90,045
Z07929		$1,713.70	$ 89,404		$1,760.00	$ 91,819
Z07930		$1,744.10	$ 90,990		$1,791.20	$ 93,447
Z07931		$1,784.50	$ 93,097		$1,832.70	$ 95,612
Z08814		$1,231.00	$ 64,221		$1,264.20	$ 65,953
Z08815		$1,260.00	$ 65,734		$1,294.00	$ 67,508
Z08817		$1,310.80	$ 68,384		$1,346.20	$ 70,231
Z08818		$1,335.10	$ 69,652		$1,371.10	$ 71,530
Z08820		$1,396.90	$ 72,876		$1,434.60	$ 74,843
Z08821		$1,433.30	$ 74,775		$1,472.00	$ 76,794
Z08822		$1,468.40	$ 76,606		$1,508.00	$ 78,672
Z08823		$1,505.80	$ 78,558		$1,546.50	$ 80,681
Z08824		$1,537.40	$ 80,206		$1,578.90	$ 82,371
Z08825		$1,573.70	$ 82,100		$1,616.20	$ 84,317
Z08826		$1,610.70	$ 84,030		$1,654.20	$ 86,300
Z09003		$599.90	$ 31,297		$616.10	$ 32,142
Z09103		$735.40	$ 38,366		$755.30	$ 39,404
Z09203		$842.00	$ 43,927		$864.70	$ 45,111
Z09211		$842.00	$ 43,927		$864.70	$ 45,111
Z09221		$842.00	$ 43,927		$864.70	$ 45,111

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z09303		$948.10	$ 49,462		$973.70	$ 50,798
Z09398		$948.10	$ 49,462		$973.70	$ 50,798
Z09401		$1,017.90	$ 53,104		$1,045.40	$ 54,539
Z09403		$1,049.10	$ 54,732		$1,077.40	$ 56,208
Z27003		$853.00	$ 44,501		$876.00	$ 45,701
Z27004		$924.00	$ 48,205		$948.90	$ 49,504
Z48601		$1,283.80	$ 66,976		$1,318.50	$ 68,786
Z48602		$1,396.90	$ 72,876		$1,434.60	$ 74,843
Z48901		$1,176.40	$ 61,373		$1,208.20	$ 63,032
Z49001		$1,214.30	$ 63,350		$1,247.10	$ 65,061
Z49101		$1,260.00	$ 65,734		$1,294.00	$ 67,508
Z49201		$1,362.30	$ 71,071		$1,399.10	$ 72,991
Z50801		$1,125.80	$ 58,733		$1,156.20	$ 60,319
Z50803		$1,231.00	$ 64,221		$1,264.20	$ 65,953
Z55707		$1,260.00	$ 65,734		$1,294.00	$ 67,508
Z55709		$1,231.00	$ 64,221		$1,264.20	$ 65,953
Z55723		$1,335.10	$ 69,652		$1,371.10	$ 71,530
Z57625		$1,573.70	$ 82,100		$1,616.20	$ 84,317
Z57627		$1,642.00	$ 85,663		$1,686.30	$ 87,974
Z57628		$1,680.60	$ 87,677		$1,726.00	$ 90,045
Z57629		$1,713.70	$ 89,404		$1,760.00	$ 91,819
Z57631		$1,784.50	$ 93,097		$1,832.70	$ 95,612
Z57701		$1,649.00	$ 86,028		$1,693.50	$ 88,350

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z57701		$1,586.10	$ 82,747		$1,628.90	$ 84,980
Z57702		$1,688.10	$ 88,068		$1,733.70	$ 90,447
Z57702		$1,623.60	$ 84,703		$1,667.40	$ 86,988
Z57703		$1,792.20	$ 93,499		$1,840.60	$ 96,024
Z57703		$1,723.80	$ 89,931		$1,770.30	$ 92,357
Z57704		$1,888.80	$ 98,539		$1,939.80	$ 101,199
Z57704		$1,816.60	$ 94,772		$1,865.60	$ 97,328
Z57705		$2,007.20	$ 104,716		$2,061.40	$ 107,543
Z57705		$1,930.50	$ 100,714		$1,982.60	$ 103,432
Z60001		$1,552.60	$ 80,999		$1,594.50	$ 83,185
Z60002		$1,576.30	$ 82,236		$1,618.90	$ 84,458
Z60003		$1,616.40	$ 84,328		$1,660.00	$ 86,602
Z60004		$1,657.70	$ 86,482		$1,702.50	$ 88,819
Z60005		$1,699.20	$ 88,647		$1,745.10	$ 91,042
Z60006		$1,742.90	$ 90,927		$1,790.00	$ 93,384
Z60007		$1,779.10	$ 92,816		$1,827.10	$ 95,320
Z60008		$1,821.30	$ 95,017		$1,870.50	$ 97,584
Z60009		$1,863.70	$ 97,229		$1,914.00	$ 99,853
Z60010		$1,900.00	$ 99,123		$1,951.30	$ 101,799
Z60011		$1,944.80	$ 101,460		$1,997.30	$ 104,199
Z60012		$1,993.70	$ 104,011		$2,047.50	$ 106,818
Z60016		$1,465.40	$ 76,450		$1,505.00	$ 78,516
Z70001		$1,360.40	$ 70,972		$1,397.10	$ 72,887

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z70002		$1,404.10	$ 73,252		$1,442.00	$ 75,229
Z70003		$1,424.20	$ 74,301		$1,462.70	$ 76,309
Z70004		$1,457.40	$ 76,033		$1,496.70	$ 78,083
Z70005		$1,485.50	$ 77,499		$1,525.60	$ 79,591
Z70006		$1,515.70	$ 79,074		$1,556.60	$ 81,208
Z70007		$1,544.20	$ 80,561		$1,585.90	$ 82,736
Z70008		$1,576.30	$ 82,236		$1,618.90	$ 84,458
Z70009		$1,616.30	$ 84,322		$1,659.90	$ 86,597
Z70010		$1,657.70	$ 86,482		$1,702.50	$ 88,819
Z70011		$1,701.00	$ 88,741		$1,746.90	$ 91,136
Z70012		$1,742.50	$ 90,906		$1,789.50	$ 93,358
Z70013		$1,779.00	$ 92,810		$1,827.00	$ 95,315
Z70014		$1,821.30	$ 95,017		$1,870.50	$ 97,584
Z70015		$1,863.60	$ 97,224		$1,913.90	$ 99,848
Z70016		$1,900.00	$ 99,123		$1,951.30	$ 101,799
Z70017		$1,944.80	$ 101,460		$1,997.30	$ 104,199
Z70018		$1,983.10	$ 103,458		$2,036.60	$ 106,249
Z70801		$1,172.60	$ 61,175		$1,204.30	$ 62,828
Z70803		$1,214.30	$ 63,350		$1,247.10	$ 65,061
Z70805		$1,231.00	$ 64,221		$1,264.20	$ 65,953
Z70806		$1,260.00	$ 65,734		$1,294.00	$ 67,508
Z70807		$1,284.00	$ 66,986		$1,318.70	$ 68,797
Z70808		$1,310.80	$ 68,384		$1,346.20	$ 70,231

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
Z76605		$1,573.70	$ 82,100		$1,616.20	$ 84,317
Z76607		$1,642.00	$ 85,663		$1,686.30	$ 87,974
Z76909		$1,537.40	$ 80,206		$1,578.90	$ 82,371
Z76910		$1,610.70	$ 84,030		$1,654.20	$ 86,300
Z76911		$1,680.60	$ 87,677		$1,726.00	$ 90,045
Z87305		$1,231.10	$ 64,226		$1,264.30	$ 65,959
ZA014		$1,231.00	$ 64,221		$1,264.20	$ 65,953
ZAO01		$521.40	$ 27,201		$535.50	$ 27,937
ZAO02		$595.00	$ 31,041		$611.10	$ 31,881
ZAO03		$698.40	$ 36,436		$717.30	$ 37,422
ZAO04		$846.80	$ 44,178		$869.70	$ 45,372
ZAO04		$846.70	$ 44,172		$869.60	$ 45,367
ZAO05		$963.90	$ 50,287		$989.90	$ 51,643
ZAO06		$969.10	$ 50,558		$995.30	$ 51,925
ZAO07		$998.60	$ 52,097		$1,025.60	$ 53,506
ZAO08		$1,024.10	$ 53,427		$1,051.80	$ 54,872
ZAO09		$1,052.10	$ 54,888		$1,080.50	$ 56,370
ZAO10		$1,083.20	$ 56,511		$1,112.40	$ 58,034
ZAO11		$1,130.90	$ 58,999		$1,161.40	$ 60,590
ZAO12		$1,176.40	$ 61,373		$1,208.20	$ 63,032
ZAO13		$1,214.30	$ 63,350		$1,247.10	$ 65,061
ZAO14		$1,231.00	$ 64,221		$1,264.20	$ 65,953
ZAO15		$1,260.00	$ 65,734		$1,294.00	$ 67,508

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
ZAO16		$1,284.00	$ 66,986		$1,318.70	$ 68,797
ZAO17		$1,310.80	$ 68,384		$1,346.20	$ 70,231
ZAO18		$1,335.10	$ 69,652		$1,371.10	$ 71,530
ZAO19		$1,364.70	$ 71,196		$1,401.50	$ 73,116
ZAO20		$1,396.90	$ 72,876		$1,434.60	$ 74,843
ZAO20		$1,396.70	$ 72,866		$1,434.40	$ 74,833
ZAO20		$1,396.90	$ 72,876		$1,434.60	$ 74,843
ZAO21		$1,433.30	$ 74,775		$1,472.00	$ 76,794
ZAO22		$1,468.40	$ 76,606		$1,508.00	$ 78,672
ZAO23		$1,505.80	$ 78,558		$1,546.50	$ 80,681
ZAO24		$1,537.40	$ 80,206		$1,578.90	$ 82,371
ZAO25		$1,573.70	$ 82,100		$1,616.20	$ 84,317
ZAO25		$1,573.60	$ 82,095		$1,616.10	$ 84,312
ZAO26		$1,610.70	$ 84,030		$1,654.20	$ 86,300
ZAO26		$1,610.40	$ 84,015		$1,653.90	$ 86,284
ZAO27		$1,642.00	$ 85,663		$1,686.30	$ 87,974
ZAO28		$1,680.60	$ 87,677		$1,726.00	$ 90,045
ZAO29		$1,713.70	$ 89,404		$1,760.00	$ 91,819
ZAO30		$1,744.10	$ 90,990		$1,791.20	$ 93,447
ZAO31		$1,784.50	$ 93,097		$1,832.70	$ 95,612
ZAOS05		$933.40	$ 48,695		$958.60	$ 50,010
ZAOS06		$973.10	$ 50,767		$999.40	$ 52,139
ZAOS07		$1,002.50	$ 52,300		$1,029.60	$ 53,714

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
ZAOS08		$1,028.00	$ 53,631		$1,055.80	$ 55,081
ZAOS09		$1,055.90	$ 55,086		$1,084.40	$ 56,573
ZAOS10		$1,087.80	$ 56,751		$1,117.20	$ 58,284
ZAOS11		$1,135.50	$ 59,239		$1,166.20	$ 60,841
ZAOS12		$1,180.70	$ 61,597		$1,212.60	$ 63,261
ZAOS13		$1,219.30	$ 63,611		$1,252.20	$ 65,327
ZAOS13		$1,219.40	$ 63,616		$1,252.30	$ 65,332
ZAOS14		$1,236.20	$ 64,493		$1,269.60	$ 66,235
ZAOS15		$1,265.10	$ 66,000		$1,299.30	$ 67,784
ZAOS16		$1,289.00	$ 67,247		$1,323.80	$ 69,063
ZAOS17		$1,316.00	$ 68,656		$1,351.50	$ 70,508
ZAOS18		$1,340.30	$ 69,923		$1,376.50	$ 71,812
ZAOS19		$1,368.70	$ 71,405		$1,405.70	$ 73,335
ZAOS20		$1,403.00	$ 73,195		$1,440.90	$ 75,172
ZCAS01		$1,002.60	$ 52,306		$1,029.70	$ 53,719
ZCAS02		$748.20	$ 39,034		$768.40	$ 40,087
ZCAS03		$807.30	$ 42,117		$829.10	$ 43,254
ZHG622		$1,978.30	$ 103,208		$2,031.70	$ 105,994
ZINS01		$1,537.40	$ 80,206		$1,578.90	$ 82,371
ZINS02		$1,576.40	$ 82,241		$1,619.00	$ 84,463
ZINS03		$1,657.40	$ 86,467		$1,702.10	$ 88,799
ZINS04		$1,699.30	$ 88,652		$1,745.20	$ 91,047
ZINS05		$1,734.90	$ 90,510		$1,781.70	$ 92,951

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
ZINS06		$1,776.30	$ 92,670		$1,824.30	$ 95,174
ZINS07		$1,817.40	$ 94,814		$1,866.50	$ 97,375
ZOFF00		$1,421.20	$ 74,144		$1,459.60	$ 76,147
ZOFF01		$1,478.90	$ 77,154		$1,518.80	$ 79,236
ZOFF01		$1,478.90	$ 77,154		$1,518.80	$ 79,236
ZOFF02		$1,514.10	$ 78,991		$1,555.00	$ 81,124
ZOFF03		$1,537.40	$ 80,206		$1,578.90	$ 82,371
ZOFF04		$1,576.40	$ 82,241		$1,619.00	$ 84,463
ZOFF05		$1,616.90	$ 84,354		$1,660.60	$ 86,634
ZOFF06		$1,657.40	$ 86,467		$1,702.10	$ 88,799
ZOFF07		$1,699.30	$ 88,652		$1,745.20	$ 91,047
ZOFF08		$1,734.90	$ 90,510		$1,781.70	$ 92,951
ZOFF09		$1,776.30	$ 92,670		$1,824.30	$ 95,174
ZOFF10		$1,817.40	$ 94,814		$1,866.50	$ 97,375
ZOFF11		$1,852.80	$ 96,661		$1,902.80	$ 99,269
ZOFF12		$1,897.30	$ 98,982		$1,948.50	$ 101,653
ZOFF13		$1,944.20	$ 101,429		$1,996.70	$ 104,168
ZOFF14		$1,981.30	$ 103,364		$2,034.80	$ 106,156
ZSEM01		$1,616.90	$ 84,354		$1,660.60	$ 86,634
ZSEM02		$1,657.40	$ 86,467		$1,702.10	$ 88,799
ZSEM03		$1,699.30	$ 88,652		$1,745.20	$ 91,047
ZSEM04		$1,734.90	$ 90,510		$1,781.70	$ 92,951
ZSEM05		$1,776.30	$ 92,670		$1,824.30	$ 95,174

Class		After 2.7% as at 25 December 2012			After 2.7% as at 24 December 2013	
		Weekly Rate	Annual Rate		Weekly Rate	Annual Rate
ZSEM06		$1,817.40	$ 94,814		$1,866.50	$ 97,375
ZSEM07		$1,852.80	$ 96,661		$1,902.80	$ 99,269
ZSEM08		$1,897.30	$ 98,982		$1,948.50	$ 101,653
ZSEM09		$1,944.20	$ 101,429		$1,996.70	$ 104,168
ZSEM10		$1,981.30	$ 103,364		$2,034.80	$ 106,156
ZSPA01		$1,546.80	$ 80,697		$1,588.60	$ 82,877
ZSPA03		$1,618.80	$ 84,453		$1,662.50	$ 86,733
ZSPA04		$1,657.60	$ 86,477		$1,702.40	$ 88,814
ZSPA05		$1,696.70	$ 88,517		$1,742.50	$ 90,906
ZSPA06		$1,729.20	$ 90,212		$1,775.90	$ 92,649
ZSPA07		$1,770.00	$ 92,341		$1,817.80	$ 94,835
ZSPB01		$1,627.20	$ 84,891		$1,671.10	$ 87,181
ZSPB02		$1,668.60	$ 87,051		$1,713.70	$ 89,404
ZSPB03		$1,703.10	$ 88,851		$1,749.10	$ 91,251
ZSPB04		$1,743.60	$ 90,964		$1,790.70	$ 93,421
ZSPB05		$1,784.90	$ 93,118		$1,833.10	$ 95,633
ZSPB06		$1,819.10	$ 94,902		$1,868.20	$ 97,464
ZSPB07		$1,861.80	$ 97,130		$1,912.10	$ 99,754

Appendix B – Allowances

ALLOWANCE	From 25 December 2012	From 24 December 2013	BASIS OF PAYMENT
On Call / Stand by Allowance	$200.34 $28.61	$205.75 $29.40	Per week on the on call roster *(payable on a proportionate basis according to the roster cycle)*; OR Per day on the on call roster *(This allowance, while paid on a regular basis, is an annual allowance)*
Late Finishing Shift Allowance	$27.01	$27.74	For each late finishing shift in Frontline Services; *(This allowance, while paid on a regular basis, is an annual allowance)*
General First Aid Allowance	$21.00	$21.57	Paid each week for authorised employees appropriately qualified. Endeavour Energy will pay for first aid training conducted during work hours for nominated first aid officers. *(This allowance, while paid on a regular basis, is an annual allowance)*
Aircraft Allowance	$21.08	$21.65	Per day whilst performing line patrols by helicopter.
Electrical Safety Rules Allowance	$120.00 (100%) $96.00 (80%) $72.00 (60% Safety Rules Electricity Workers Allowance)	$120.00 (100%) $96.00 (80%) $72.00 (60% Safety Rules Electricity Workers Allowance)	Paid as per clause 10 and in recognition of: ▪ Drug and Alcohol testing, ▪ Tightening of responsibilities, and ▪ Sign on to worksite hazard and risk assessment form (WHRA).

Appendix B – Allowances (cont)

RE-IMBURSEMENT TYPE ALLOWANCE	AMOUNT	BASIS OF PAYMENT	
Meal Allowance	$14.14	Per meal *(to a maximum of 3 meals)*	
Subsistence Allowances	$20.19	Lunch	OR Negotiated alternate arrangement
	$32.94	Dinner	
	$35.09	Overnight stay	
Casual Car Allowance *Per kilometre where the employee uses his or her private vehicle*	63.0 cents	Under 1600cc	
	74.0 cents	1600cc to 2600cc	
	75.0 cents	Over 2600cc	

Casual Car Allowance will be adjusted in accordance with Australian Tax Office guidelines.

Electrical Safety Rules Allowance

ESRA will be maintained at 2010 levels.

Switching Allowance

The activity of operating or switching the network (not including control room) is undertaken by a number of roles within Endeavour Energy. Regional or Work Party Switching is the term used to describe switching undertaken by work crews, where the switching is an addition to their ordinary role and is for their worksite only.

Where Regional staff undertake the role of regional/work party switching an allowance will be paid.

Where staff are receiving the allowance requests to undertake switching within an employees ability and competence shall be carried out in line with Field switching principles. As per document Field Switching principles dated 5 March 2003.

Electrician's Licence Allowance

An employee who holds a current Qualified Supervisors Certificate / Electrical Licence or its equivalent and the position requires the incumbent to hold the above qualification to fulfil their duties and the incumbent in the position has received it in accordance with past practice will be paid $31.94 per week from 25 December 2012 and $32.80 from 24 December 2013. This allowance is paid as an all purpose allowance.

Management of allowances

Consistent with the outcome of matter number B2010/3579 before Fair Work Australia, the Employer will improve the management of allowances and thus meet the savings objectives noted against this matter number.

The process underpinning the operation of this item will include the consultative procedure of this Agreement and, if necessary, application of the DSP.

Appendix C - Benefits of Employees Employed Prior to 27 July 1996

1. *Experience / Maturing Allowance*

1.1 Quantum

ELIGIBILITY	MULTIPLIER
10 years but less than 20 years service	1 week's pay per completed year of service; OR
20 years or more service	2 week's pay per completed year of service

1.2 Eligibility

Endeavour Energy must pay Experience/Maturing Allowance to employees in the following circumstances:

BASIS OF ELIGIBILITY	▪ ***Retirement*** - this is where the employee is aged 55 years or older. ▪ ***Retirement Ill Health*** - this is where the employee is medically unable to perform the work required of their classification. ▪ ***Death*** - this is where the employee dies whilst in the employment of Endeavour Energy. ▪ ***Redundancy*** - this is where the employee's position is made redundant or under an approved 'bona fide' redundancy scheme.

1.3 Service Recognised

SERVICE RECOGNISED	The period of continuous employment with Endeavour Energy (including Integral Energy, Illawarra Electricity and Prospect Electricity) The period of employment with the County Councils which were amalgamated into Prospect County Council and Illawarra County Council on 1 January 1980 is also included. The period of employment shall not go further back than the date of formation of Prospect County Council (1 January 1957) or Illawarra County Council (1 March 1958)

2. *Agreement Special Leave*

ELIGIBILITY	QUANTUM
Employees of the former Illawarra Electricity who were entitled to this leave immediately prior to 27 July 1996 only	4 days per year and the employee works a 36 hour week

3. *Sick Leave (pre 15 February 1993)*

ENTITLEMENT	ELIGIBILITY TO PAYMENT
The employees preserved untaken sick leave as at 15 February 1993	• Resignation • Retirement • Death • Redundancy • On request and approval by the Group General Manager Corporate Services. **Note:** *An employee is <u>not</u> eligible to payment where he or she is dismissed for misconduct*

Appendix D

- CIC Shiftwork Workplace Agreement 2007
- E S O Customer Operation Group Workplace Arrangement 1999
- Executive Assistant to General Manager WPA 2007
- Field Officers Incentive Workplace Arrangement 2005
- Endeavour Energy Manager/Specialists Workplace Arrangement 2005
- IE Supervisors Workplace Arrangement 2003
- Endeavour Energy Network Shift work Workplace Arrangement 2005
- Network Officers' Workplace Arrangement 1999
- Network Shiftwork Workplace Arrangement 2008
- Integral Street Lighting Agreement 2010

Signatory Requirements

Fair Work Act 2009 – Section 185

Employer's and Bargaining Representatives Signatures certifying the Endeavour Energy Enterprise Agreement 2012

Signed by **Endeavour Energy Employer** covered by the *Endeavour Energy Enterprise Agreement 2012*

....

Mark Greenhill

51 Huntingwood Drive Huntingwood NSW 2148
....

Manager Employee Relations Human Resources
Endeavour Energy, authorised to sign this
Agreement on behalf of the Employer

Bargaining representative signatures

....

Signature

Steve Butler
Secretary, Level 5, 370 Pitt Street, Sydney NSW 2000
....

[Position], duly authorised to sign on behalf
of the **Communications, Electrical, Electronic, Energy, Information, Postal, Plumbing and Allied Services Union of Australia, NSW Divisional Branch**

....

Signature

Graeme Kelly
Level 7, 321 Pitt Street
Sydney NSW 2000

GENERAL SECRETARY
....

[Position], duly authorised to sign on behalf
of the **Australian Municipal, Administrative, Clerical and Services Union NSW United Services Branch**

Mark O'Connell
Signature
LEVEL 1 491 KENT ST SYDNEY 2000

DIRECTOR, NSW
[**Position**], duly authorised to sign on behalf
of the **Association of Professional Engineers,**
Scientists and Managers, Australia

ENDEAVOUR ENERGY

ENTERPRISE AGREEMENT 2014

Without Prejudice Union Draft

Endeavour Energy

Table of Contents

1. APPLICATION AND OPERATION OF THE AGREEMENT

1.1 *Objects of the Agreement*

The objects of the Agreement are:

(a) to outline the basic conditions relating to the work performed by the employees of Endeavour Energy;

(b) to enable Endeavour Energy to meet the expectations of its customers; and

(c) to give employees the greatest possible chance of employment security, through the ability to adapt to a changing environment.

1.2 *Term of the Agreement*

The Agreement shall operate from 25 December 2014 until 24 December 2016 inclusive. This is the nominal term of the agreement. The agreement and all terms contained therein shall continue to apply beyond the expiry date until renegotiated, agreed and ratified.

1.3 *Coverage of the Agreement*

1.3.1 Those covered by the Agreement are:

(a) Endeavour Energy Australia;

(b) Communications, Electrical, Electronics, Energy, Information, Postal, Plumbing and Allied Services Union of Australia, NSW Divisional Branch (ETU NSW);

(c) Australian Municipal, Administrative, Clerical and Services Union NSW United Services Branch;

(d) Association of Professional Engineers, Scientists and Managers, Australia;

The "Union(s)" represents those unions as outlined in clauses 1.3.1(b), (c) and (d) only

1.3.2 The Agreement shall be applicable to Endeavour Energy and its employees, other than above Agreement classification positions that are Fair Work Act 2009 compliant contract positions.

~~1.3.3 Continuing employees who are employed as at the date of this Agreement, in positions evaluated with a range below Manager/Specialist 9-13 have the right to refuse the offer of a fixed term or open term employment contract and their employment will continue to be subject to this Agreement.~~

This clause to be amended to relect the outcome/resolution of the current dispute around this issue (FWC Matter number C2013/7033)

2. INTENT AND COMMITMENT

2.1 *Intent*

This Agreement is based on the understanding that Endeavour Energy and its employees have an obligation to serve the people of New South Wales by providing a high standard of service in the most efficient way. As part of its obligations, Endeavour Energy is committed to the continued development of its skilled workforce to provide an effective service and job security for its employees.

2.2 *Commitment*

The employees of Endeavour Energy are committed to:

(a) Working together towards achieving Endeavour Energy's vision of generating performance through innovation.

(b) Achieving success through values of:

- We provide excellent customer service;
- We live and work safely;
- We deliver outstanding business success;
- We promote high achievement;
- We behave with respect and integrity.

(c) Ensuring that they act with honesty, fairness and dignity in all that they do.

(d) Only using information of a commercial or confidential nature in an authorised manner.

(e) Subject to clauses 2, 3 and 4, implementing work practices that:

(i) provide for more co-operative work arrangements;

(ii) improve competitiveness, efficiency, flexibility and productivity; and

(iii) assist positively to enable Endeavour Energy to be a low cost, reliable supplier of electricity.

2.3 *Commitments of the Parties*

Endeavour Energy, its employees and the unions representing their members are committed to the Objects of this Agreement.

2.4 *Relationship of this Agreement to other Agreements*

2.4.1 In this Agreement “Core Agreement” means Clauses 1 to 34 of this Agreement and includes all appendices.

2.4.2 Any dispute(s) in relation to this clause may be referred to clause 29 (Disputes) of this Agreement by any Party.

2.5 *No Extra Claims*

It is a term of this Agreement that the parties to this Agreement undertake that for the period of the duration of the Agreement that they will not pursue any extra claims.

2.6 *Definitions*

2.6.1 "Ordinary Week's Pay" means an employee's ordinary week's pay is their rate of pay for their ordinary hours of work plus any allowances which are paid on a normal weekly basis.

2.6.2 "Act" means the Fair Work Act (Cth) 2009.

2.7 *Competency Based Progression System*

The parties are committed to maintaining the Competency Based Progression System which was introduced in 2005. Variations to the system will be made using a consultative process.

2.8 *Job Evaluation and Training*

2.8.1 Skill development and continuous learning is a critical foundation for the continued success of the organisation.

2.8.2 Changes to an employee's work shall not justify an increase in pay unless the change in the work constitutes such a significant net addition to the work requirements that it warrants creation of or advancement to a new classification. Changes in work value can only arise from changes in the nature of work, the level of skill required or the level of responsibility exercised.

2.8.3 Whether or not a job warrants re-classification shall be determined by the relevant Human Resource Manager in consultation with relevant persons.

2.8.4 Where it is determined that the job warrants re-classification the evaluation will be carried out by a properly constituted job evaluation committee. A properly constituted job evaluation committee shall comprise one union representative, a management representative and the Job Evaluation Administrator.

2.8.5 It is recognised that skill and learning differences between specific work areas or locations will exist despite organisation wide requirements for fairness and employee mobility.

2.8.6 Supporting Mechanisms

2.8.6.1 To support the competency/skills-based classification structures, employees may be given the opportunity to become skilled in:

a) Workplace Training (the delivery of workplace training);

b) Skill Module Development (the design of competency-based modules);

c) Workplace Assessment (the assessment of competency against agreed competency standards); and

d) Reading, writing, numeracy, spoken communication and computer skills.

2.8.7 Learning Time

2.8.7.1 On and off the job learning opportunities will be available to employees to meet the training needs of the organisation.

2.8.7.2 Wherever practicable, this will take place in normal working time.

2.8.7.3 Where learning and skill development takes place out of hours, employee family commitments will be taken into consideration.

2.8.7.4 Payments for learning undertaken outside normal hours will be determined on a case by case basis, prior to commencement of the program. However, when it is agreed, where such training is linked to a competency/skills based structure, payments will be made at the rate agreed between the persons covered by this Agreement, not to be less than ordinary rates.

2.8.7.5 Penalty rates shall apply to all management-directed and/or regulatory training that occurs outside normal working hours.

2.9 *Consultation for next Agreement*

Negotiations will commence with the relevant parties no later than 3 months before the nominal expiry date of this Agreement for a replacement Agreement.

3. CONSULTATION AND COMMUNICATION

3.1 *Consultative Committee Formation*

Endeavour Energy will form Consultative Committees from time to time consisting of representatives of Endeavour Energy employees, the unions and Endeavour Energy management.

During the term of this agreement, proposed changes (other than in direct response to a statutory obligation) that will materially impact employees will be subject to consultation using Consultative Committees.

Consultative Committees will seek to apply interest-based techniques to assist in understanding the interests and concerns of Endeavour Energy employees, the unions and Endeavour Energy management.

As part of the formation of any Consultative Committee, the Committee will establish an agreed consultation plan, clearly describing the subject nature of the consultation, the intended consultative process steps and the timetable for completion of these steps.

Should the representatives on a Consultative Committee be unable to agree upon a consultation plan as described in this clause, they will have recourse to the Disputes Procedure.

3.2 *Consultative Committee Objectives*

The objectives relate to major and strategic issues that may affect the relationship between Endeavour Energy and its employees and include:

a) to enable Endeavour Energy to keep its employees, and the unions representing them, informed;
b) to enable unions and their members to keep Endeavour Energy informed;
c) to enable employees to have input to the decisions of management;
d) to facilitate the exchange of views between employees and management.
e) to provide a forum for the exploration and understanding of “best practice” and its application within Endeavour Energy
f) to act as a ‘think tank’ to raise ideas and concepts and provide a forum to discuss improvements in Endeavour Energy’s performance and efficiency.
g) to enable the establishment of mechanisms to gauge and report upon productivity improvement.

3.3 *Disputes*

At any time during the process outlined in this clause either party may refer the matter to the Disputes Procedure (Clause 29 of this Agreement) for resolution.

4. WORK PRACTICE CHANGE

4.1 *Continuous Improvement and Best Practice*

Endeavour Energy seeks continuous improvement and best practice in all that we do. Endeavour Energy employees, the unions and Endeavour Energy management commit to actively supporting and contributing to the "process" of change.

The primary focus for improvement will be upon internally developing and implementing efficiencies to address Endeavour Energy's performance challenges while ensuring safety, cost effectiveness and service to our customers. Our collective aim is to be safe, competitive and achieve best practice with the goal of achieving sustainable internal employment levels.

As part of the search for continuous improvement and best practice, Endeavour Energy will seek to benchmark across regions and depots for best practice and to identify and prioritise the areas where productivity improvement can or should be achieved.

The parties including relevant work groups/employees may, via the consultative process in this agreement, utilise external benchmarking prior to market testing to permit internal efforts to improve efficiencies and become more competitive.

4.2 *Change following Consultation*

Any change will only occur following the consultation process outlined in Clause 3.

Consistent with the overall intent of this clause Endeavour Energy employees, the unions and Endeavour Energy management will seek to adopt ways to most efficiently utilise the resources and time commitment required from those involved in consultation processes (such as shop floor people, line management, delegates, union officials and senior managers).

4.3 *Assessment Criteria*

Assessment criteria will include but is not limited to:

- safety;
- hardship;
- workload;
- job security;
- building mutual respect and job satisfaction;
- tangible productivity improvement; and,
- any other legislative requirements.

5. CONTRACT OF EMPLOYMENT

5.1 *Duties of Endeavour Energy*

The duties of Endeavour Energy, consistent with the Agreement and other relevant legislation, include the following:

(a) to provide work;

(b) to pay for the work performed; and

(c) to provide a safe working environment.

5.2 *Duties of Employees*

The duties of employees, consistent with the Agreement and other relevant legislation, include the following:

(a) to work in a skilled and competent manner;

(b) to work in a manner which does not threaten the safety of themselves, work colleagues or the public;

(c) to provide faithful service;

(d) to obey lawful commands;

(e) to not act in a manner hostile to or against the interests of Endeavour Energy;

(f) to respect and maintain the confidentiality of certain information;

(g) to account for all moneys and property received in the course of employment;

(h) to make available to Endeavour Energy all inventions made in the course of employment; and

(i) to disclose to Endeavour Energy any information it has a right to know.

5.3 *Obligation to Use Skills*

(a) An employer may direct an employee to carry out such duties as are within the employee's skill, competence and training consistent with their classification structure of this Agreement provided that such duties are not designed to promote deskilling.

(b) An employer may direct an employee to carry out such duties and use such tools and equipment as may be required provided that the employee has been properly trained in the use of such tools and equipment.

5.4 *Categories of Working Environment*

As required by Endeavour Energy, an employee's work may be performed in an office; depot; workshop; in the field or other location remote from the office, depot, workshop; or, where pre-approved by management, in the employee's home.

5.5 *Categories of Employment*

CATEGORY	DESCRIPTION	BENEFITS UNDER AGREEMENT
Permanent / Full time	Employee is engaged to work full time hours.	Full extent of relevant benefits.
Fixed term / Full time	Employee is engaged for a fixed term to work full time hours.	Full extent of relevant benefits according to the period of employment.
Permanent / Part time	Employee is engaged to work for regular but less than full time hours.	All relevant benefits on a pro-rata (part time hours as a proportion of the full time hours) basis.
Fixed term / Part time	Employee is engaged for a fixed term tenure to work less than full time hours.	All relevant benefits on a pro-rata (part time hours as a proportion of the full time hours) basis according to the period of employment.
Casual	An employee engaged on an hourly basis in a roster to be determined by Endeavour Energy.	The relevant hourly rate according to the appropriate classification plus 23% **(casual employee loading)** for each hour worked. A minimum of 4 hours will apply for casual employees. The casual employee loading is in compensation for all Agreement benefits other than overtime, below.
Fixed Term Employment	Term employment covers employees engaged on a temporary basis and shall not include a casual employee. Term appointments may be made for a period of up to 12 months. At the expiration of that period, work requirements shall be reviewed by the parties. Term employment shall not be used as an alternative to full time employment	A Term employee shall be paid a rate of pay and receive Agreement conditions as is appropriate to either comparable full time or part time equivalent employment under this Agreement.

5.5.1 A part-time employee who agrees to work additional hours will be paid single time for those additional hours up to the equivalent full time hours. The pro rata accrual of leave will be adjusted for those additional hours.

5.5.2 Where a part-time employee is instructed to work greater than 8 hours per day, they will be paid the relevant overtime rate.

5.5.3 The span of hours shall be in accordance with clause 8.1.

5.5.4 Where a casual employee is instructed to work greater than 8 hours per day, they will be paid the relevant overtime rate. These overtime rates shall be in lieu of the casual employee loading.

5.5.5 The span of hours shall be in accordance with clause 8.1.

5.5.6 LABOR HIRE/AGENCY HIRE WORKERS

(a) Persons covered by this agreement recognise the need for Endeavour Energy to engage labour hire workers from time to time to meet short term business needs. Endeavour Energy will consult with the relevant persons in relation to the prospective need for labour hire engagement. In this context, the persons covered by this Agreement recognise short term as a maximum of six months except in circumstances where consultation has taken place prior to any extension of this time frame.

(b) Endeavour Energy will only engage contractors/labour hire employee who provide to their employees,' wages and conditions that are overall no less favourable than those provided for in this Agreement .

(c) The persons covered by this Agreement will consult before introducing a new area of labour hire

5.5.7 FIXED TERM EMPLOYMENT

(a) Fixed term employees shall be paid and be entitled to all the conditions under this Agreement which are appropriate.

(b) A fixed term employee does not include a casual employee.

(c) Fixed term appointments may be made for a maximum period of up to 12 months unless agreed by the Endeavour Energy and the relevant union. At the expiration of that period work the ongoing requirements will be reviewed by the parties

(d) Fixed term employment shall not be used as an alternative to full time employment.

(e) The persons covered by this Agreement will consult before introducing a new area of fixed term employment

5.6 *Wages and Salaries*

5.6.1 Endeavour Energy will allocate a pay point to each employee. The pay points are set out in Appendix A to this Agreement.

5.6.2 Endeavour Energy will increase rates of pay including all wage related allowances (including ESRA) by the following:

(a) X.X% on 25 December 2014; and

(b) X.X% on 24 December 2015.

5.7 *Superannuation*

5.7.1 At the commencement date of this agreement, employees covered by the agreement will receive the legislated Superannuation Guarantee Contribution (SGC) of 9% and an additional 6% contribution as a result of previous wage negotiation outcomes.

5.7.2 Should any increase to the Commonwealth Government Superannuation Guarantee occur during the nominal term of this Agreement, the Endeavour Energy additional increases will not be absorbed within the 15% employer contribution set out in clause 5.7.1 above.

5.7.3 Subject to the provision of relevant superannuation legislation, employees under this Agreement will have their superannuation contributions paid into the Energy Industries Superannuation Scheme (EISS).

5.7.4 An employee may elect in lieu of being paid an amount of Agreement Wages to have an equivalent amount paid by way of superannuation contributions in accordance with the relevant provisions of their scheme to the maximum extent permitted by law.

5.7.5 Subject to the provisions of relevant superannuation legislation, these contributions shall be paid to the relevant scheme.

5.7.6 The employee's election to vary their superannuation benefit must be in writing and would occur no more than once per calendar year, with effect from 1 July each year.

5.8 *Apprentices and Trainees*

5.8.1 The conditions of this Agreement will apply to apprentices and trainees during the period of their traineeship or apprenticeship.

5.8.2 A traineeship or apprenticeship does not guarantee continuing employment upon completion of the indentured period.

5.8.3 Any offer of continued employment would be based on the staffing requirements of Endeavour Energy and the satisfactory performance of the apprentice or trainee.

5.9 *Equal Employment Opportunity*

5.9.1 Endeavour Energy is an Equal Opportunity Employer.

5.9.2 Endeavour Energy and its employees will work together to achieve the objective of a work environment free from discrimination or harassment and where all people treat, and are treated, with respect.

5.9.3 Endeavour Energy is committed to providing equal remuneration and conditions of employment for work of equal or comparable value.

5.10 *Anti-Discrimination*

5.10.1 It is the intention of the parties to this Agreement to prevent and eliminate discrimination, bullying and harassment in the workplace. This includes discrimination on the grounds of sex, pregnancy, race, religion, age, marital or domestic status, homosexuality, disability, transgender status or carer's responsibilities.

5.10.2 It follows that in fulfilling their obligations under the dispute resolution procedure prescribed by this Agreement the parties have obligations to take all reasonable steps to ensure that the operation of the provisions of this Agreement are not directly or indirectly discriminatory in their effects. It will be consistent with the fulfilment of these obligations for the parties to make application to vary any provision of the Agreement which, by its terms of operation, has a direct or indirect discriminatory effect.

5.10.3 Under the Anti-Discrimination Act 1977, it is unlawful to victimise an employee because the employee has made or may make or has been involved in a complaint of unlawful discrimination or harassment. Nothing in this clause is to be taken to affect:

(a) any conduct or act which is specifically exempted from anti-discrimination legislation;

(b) offering or providing junior rates of pay to persons under 21 years of age;

(c) any act or practice of a body established to propagate religion which is exempted under section 56(d) of the Anti-Discrimination Act 1977;

(d) a party to this Agreement from pursuing matters of unlawful discrimination in any State or Federal jurisdiction.

5.10.4 Consistent with Anti-Discrimination and Equal Employment Opportunity principles, workplace harassment, including bullying is not acceptable. Any incidents of workplace discrimination, bullying or harassment will be managed in accordance with Clause 29 Disputes.

5.10.5 This clause does not create legal rights or obligations in addition to those imposed upon the parties by the legislation referred to in this clause.

5.11 *Payment of Employment Separation Entitlements to Next of Kin*

Employees may authorise Endeavour Energy to pay their employment separation entitlement to a person nominated by them in the event of them dying whilst still in the service of Endeavour Energy by completing a form to be prepared by Endeavour Energy. In the absence of such written authorisation, employment separation entitlement will be paid to the deceased employee's estate.

5.12 *Termination of Employment*

5.12.1 The amount of notice, of termination of employment, to be given by an employee shall be two weeks.

5.12.2 If an employee's employment is terminated for reasons other than those justifying summary dismissal, the amount of notice which will be given by Endeavour Energy will be as follows:

AMOUNT OF EMPLOYEE'S SERVICE	AMOUNT OF NOTICE
Not more than 1 year	1 week
More than 1 year but not more than 3 years	2 weeks
More than 3 years but not more than 5 years	3 weeks
More than 5 years	4 weeks

NOTE: Where an employee is over 45 years of age with at least 2 years continuous service the amount of notice in the above table is to be increased by 1 week.

5.12.3 As an alternative to notice being given, payment may be made by Endeavour Energy to the employee for all or part of the notice period at the employee's ordinary rate of pay.

5.12.4 Where circumstances warrant and by agreement, the required period of notice may be waived.

5.12.5 Summary Dismissal will apply where an employee has engaged in serious misconduct. In this case an employee will be paid only up to the date of dismissal.

5.12.6 An employee who has been absent for a continuous period of 5 working days or more without the consent of Endeavour Energy and/or without notification will be treated as having abandoned their employment.

5.12.7 The employee will be given a period of 14 days of last attending to give a satisfactory explanation. The termination pay shall be up to the date of the employee's last attendance.

5.12.8 A contract of employment may be terminated as follows:

TYPE	DESCRIPTION
Resignation	Where an employee decides of their own free will to leave.
Retirement	This is where the employee decides of their own free will to leave the workforce generally.
Dismissal	This is where Endeavour Energy decides that the employee should no longer be employed for a reason for which the employee is responsible.
Redundancy	This is where Endeavour Energy decides that the position held by the employee no longer exists.
Abandonment	This is where an employee has been absent from his or her place of employment without notification or permission for a period of 5 working days or more.
Retirement Ill Health	This is where a doctor certifies that an employee will never work again in accordance with the requirements of the superannuation fund.
Death	Where an employee dies while employed by Endeavour Energy.

5.13 *Redeployment, Redundancy and Salary Maintenance*

5.13.1 Objective

To provide a procedure which ensures that redeployment and redundancy are consistently and fairly managed at Endeavour Energy.

5.13.2 Scope

5.13.2.1 When consider offering redeployment or redundancy to employees of Endeavour Energy will;

a) Provide for fairly administered process and fully informing affected employees about redeployment or redundancy options at all stages of organisational review and change.

b) Redeployment is preferred to redundancy.

c) Positions rather than people are identified as excess to requirements. Redeployment is the first consideration for employees whose positions are declared excess.

d) Personnel with needed skills are retained, and appropriate retraining is provided.

e) While this Agreement is in place Endeavour Energy will not forcibly retrench, make redundant or displace or otherwise terminate the employment of an employee covered by this Agreement in order to replace such employee with a contractor or the employees of a contractor.

5.13.2.2 Mix and Match

a) Employees are not able to decide that their position has become redundant. However, where an employee in an existing position wishes to voluntarily give up their current position to a surplus employee and if the surplus employee has the skills and ability to fill that position, then Endeavour Energy may agree to a “mix and match” process. In these circumstances the person wishing to relinquish their position would be offered voluntary redundancy. The “mix and match” process is at the discretion of the management however consultation on all mix and match proposals would need to occur in accordance with the Clauses 3 and 4 of this agreement. An employee is not entitled to determine that they are eligible for a “mix and match” process.

5.13.3 Process

5.13.3.1 Employees are fully informed about redeployment programs.

a) Such a program is based on an organisational review and employees are fully informed of the circumstances behind it. Before any redeployment program commences there is consultation with employees and unions. Employees are fully informed of the options available to affected staff and the scope of assistance and entitlements provided.

b) Training assistance can enhance redeployment options.

c) All affected employees are offered retaining where it will enable them to fill another position within a reasonable time. Such employees will receive study leave or a subsidy for course fees if training cannot be provided by Endeavour Energy.

d) The redeployment process is fairly administered.

e) Employees cannot be forcibly redeployed to an unlimited range of classifications without being offered the option of voluntary redundancy. Division/Branch managers ensure that redeployment options across Endeavour Energy are made known and affected employees are selected for vacant positions according to the merit appointments procedure.

5.13.4. Salary Maintenance

Salary is defined as the same meaning as sub-clause 2.6.1 – "Ordinary Week's Pay" contained within this agreement.

5.13.4.1 Employees whose positions are declared surplus and who elect not to accept an offer of a voluntary redundancy package shall receive salary maintenance from the date of being informed in writing.

5.13.4.2 Such employee shall be guaranteed salary maintenance for a minimum period of twelve (12) months from that date.

5.13.4.3 Salary maintenance will be continued on the proviso that employees are able to demonstrate commitment to seek external opportunities for alternative employment and any internal vacancies (including redeployment opportunities) using the criteria set out below:

a) This review will commence within the initial twelve (12) months salary maintenance period and will be ongoing.

b) Throughout the review process employees will be provided with assistance and access to counselling in relation to their performance.

c) At the end of the guaranteed minimum twelve (12) months salary maintenance period where an employee's performance against the criteria is not satisfactory, the employee will be given a further month to meet the performance criteria. If by the end of that month the employee meets the performance criteria, salary will be maintained. Should the employee's performance fail to meet the criteria either by the end of the month, or at any subsequent review time, salary will be adjusted to reflect the appropriate rate of pay, determined through job evaluation, for the work being done.

d) In the event that problems and difficulties arise from the application of this clause, the existing Agreement dispute resolution mechanism will be used to resolve the matters.

5.13.5. Review Criteria

5.13.5.1 An employee's continued access to salary maintenance beyond the guaranteed twelve (12) month period shall be determined by the ongoing achievement of a satisfactory overall evaluation of performance against the following review criteria:

5.13.5.1.2 Acceptance of appropriate special projects and performing other suitable work as directed while awaiting redeployment and/or alternative external employment.

5.13.5.1.3 Seeking mix and match opportunities for redeployment within the Company, which will include taking up training and development opportunities offered by appropriate to this process.

5.13.5.1.4 Acceptance of the first or second suitable offer for a redeployed position.

5.13.5.1.5 Making a concerted effort after redeployment to obtain a position of at least equivalent value to the original salary maintenance level including:

a) Attendance at training and retraining opportunities offered;

b) Continuation of efforts to seek promotion through applying for suitable advertised vacancies, and/or attending interviews for higher graded redeployment opportunities.

At all times redeployed employees are expected to maintain a satisfactory performance level in the redeployed position.

Where a job and work redesign broadens the scope of positions, redeployed employees would be expected to attend all training required to meet the full scope of the newly designed jobs and to apply for such jobs as they become available.

5.13.5.1.6 Demonstration of concerted efforts to locate alternative employment external to the Company, as evidenced by the employee:

(a) Taking advantage of the range of individually tailored employment services offered by Endeavour Energy (such as the Employment Assistance Services referred to below) and/or;

(b) Actively pursuing employment through self-initiated job search activities, such as responding to press advertisements and/or cold canvassing potential employers and/or by pursuing alternative employment service.

5.13.5.2 Continued maintenance of a satisfactory punctuality, safety and work output record.

5.13.6. Employment Assistance Service

In relation to the Employment Assistance Service provided by Endeavour Energy, the Parties understand that this outplacement service plays an important role in assisting surplus employees to find work and is operated by a highly professional and reputable service provider, whose performance is the subject of ongoing monitoring and review.

The Unions will participate in the review of this service to ensure it provides an effective and user-friendly range of outplacement services. As part of the salary maintenance policy, Unions will make their members aware of the availability of the Employee Assistance Service.

5.13.6.1 Transition arrangements for redeployed employees are clearly defined.

a) Potential increments or any service progression arrangements do not necessarily carry over with the redeployed employee into the new position.

b) Subject to award conditions, travelling time is paid for six (6) months, where through redeployment, employees are required to travel additional distances.

5.13.6.2 Redundancy is voluntary, but not available indefinitely.

a) No forced redundancy will occur at Endeavour Energy. An incentive payment for employees taking voluntary redundancy is only available during a two-week period from the date of a firm offer.

b) Voluntary redundancy is offered when there is an approved program and there are no redeployment options in Endeavour Energy for a surplus employee. Voluntary redundancy is available to employees as an alternative to accepting redeployment to a grade lower than the currently held position.

c) Employees are reminded that voluntary redundancy is offered in at specific time, and may not be available in the future.

d) Expressions of interest in redundancy are not binding.

e) These expressions are not binding until offer and acceptance of redundancy have been formalised.

f) Disproportionate impact on particular groups is avoided.

g) Managers involved in offering redundancy ensure that the final outcome of any program does not show a disproportionate effect on target groups covered by the Anti-Discrimination Act.

h) Managers also avoid singling out union representatives in the process

l) Managers recognise that it is unlawful to put pressure on employees to retire on the grounds of age and they do not use years of service as the determinant for offering redundancy.

5.13.7. *Redundancy package - eligibility, conditions and benefits*

5.13.7.1 *Eligibility*

The following employees are ineligible to receive a redundancy offer:

a) Employees engaged for a short term period and/or on a casual basis. (b) Temporary employees with less than 12 months service.

b) Apprentices, trainees and cadets.

c) Employees who have no agreed arrangement with Endeavour Energy on any workers' compensation claim. (The manager compensation must verify any such agreement.)

d) Employees subject to termination on the grounds of misconduct or unsatisfactory service.

5.13.7.2 Redundancy Benefits

On termination the employee will be entitled to the following benefits.

Category of Employee	Payment in Lieu of Notice		Incentive Payment Provision		Maturing/Experience Allowance Provision		Redundancy Payment
This section applies to Employees employed **before** 27th July, 1996.							
Under 45 years of age OR age 45 years of age with less than 2 years service	4 Weeks	+	8 Weeks	+	1 to 19 years of Service = 1 week per completed years of service. OR 20 or more years of Service = 2 weeks per completed year of service.	+	2 Weeks per completed year of service
Aged 45 years of age or older with 2 or more years service	5 Weeks	+					
This section applies to Employees employed **after** 27th July, 1996							
Under 45 years of age OR age 45 years of age with less than 2 years service	4 Weeks	+	8 Weeks	+	Nil Entitlements	+	2 Weeks per completed year of service
Aged 45 years of age or older with 2 or more years service	5 Weeks	+					

5.14 *Safety Clothing and/or Equipment*

5.14.1 Employees must ensure they wear and/or use appropriate safety clothing and/or equipment for the purpose for which it was provided.

5.14.2 An employee who fails to comply with the above requirement may not be paid for the time taken to comply including travelling home to get the appropriate safety clothing or equipment.

5.15 *Probationary Periods*

5.15.1 The purpose of probationary periods is to enable both the employee and Endeavour Energy to determine the suitability of the employment relationship.

5.15.2 The probationary period served by employees shall be 3 months from the commencement of employment with Endeavour Energy. Upon satisfactory completion of the probationary period, the employee shall have his or her appointment confirmed.

5.15.3 If an employee does not satisfactorily complete the probationary period their employment may be terminated or the probationary period may be extended for a further 3 months. Where a probationary period is being extended, and the employee is a union member, Endeavour Energy will notify the relevant union organiser of the organisation's intention to extend the probationary period.

5.15.4 Probationary periods shall be included as service in the position.

5.16 *Protection of Rate of Pay*

Employees may from time to time, consistent with their skills and competencies and as part of their employment with Endeavour Energy, be required to do work for which a lower rate of pay is prescribed. Employees will continue to be paid their Ordinary Week's Pay.

5.17 *Working Reasonable Overtime*

5.17.1 Employees shall work reasonable overtime as directed to meet the needs of Endeavour Energy.

5.17.2 Where possible employees shall be given reasonable notice of the overtime they will be required to work.

5.18 *Deductions from Wages*

5.18.1 Employees may request, in writing, for deductions to be made from their wages or salary for the purpose of contributions or payment approved by Endeavour Energy.

5.18.2 Employees may request in writing for deductions to be made from their wages or salary for the purpose of contributions to unions, which are parties to the Agreement.

5.18.3 Endeavour Energy may deduct from an employee's wages or salary payment for any time he or she was absent from work without permission.

5.20 Calculation of Service

Service with Endeavour Energy shall, in the main, be from the date of commencement to the date of termination inclusive according to the following:

CATEGORY	DETAIL
Included as Service	▪ Annual leave ▪ Long service leave ▪ Special leave with pay ▪ Sick leave ▪ Family / Carers leave ▪ Special leave without pay specifically approved as being included as service ▪ Time off with the Defence Force Reserve during employment ▪ Period of absence under New South Wales workers compensation legislation. ▪ Parental leave (including maternity, paternity and adoption leave) *(the period of absence does not break the continuity of employment)*
NOT included as Service	▪ All periods absent from work not specifically approved.

5.20.1 For persons party to the Defined Benefits Superannuation scheme, all leave included as service shall be defined as 'worked'

5.20.2 Special Leave and other leave not identified in Table 5.20 will be covered under (Other Leave) for the term of this Agreement. Endeavour Energy Policy number 7.2.7, Amendment 7, previous Approval Date 3/9/12, Review Date 3/9/14.

6. PROJECT ARRANGEMENTS

6.1 Objects

This clause is intended to facilitate flexibility agreements between management at all levels and staff with the assistance of their representatives. It is intended to apply to classifications or workgroups.

A "Project Arrangement" may be reached between Endeavour Energy and the relevant workgroup employees and their representatives. The purpose of reaching such an arrangement is to establish greater flexibility. The Project Arrangement cannot provide for condition(s) less favourable than the Enterprise Agreement.

6.2 Basis of Reaching Agreement

6.2.1 Discussions between Endeavour Energy and the relevant employees and/or their representatives will be undertaken once a desire for a Project Arrangement has been identified and the proposals should encompass all relevant details, including:

(a) The nature of the work to be performed

(b) How the work is to be performed

(c) Who is to perform the work

(d) When the work is to be done

(e) The basis on which payment, or otherwise, is to be made

6.2.2 Negotiations will involve the relevant Workgroup Manager with Human Resources assistance, the relevant Workgroup employees and the relevant Union or appointed representatives.

6.2.3 The final draft Project Arrangement arising from these negotiations will be distributed to employees directly affected and covered by the Project Arrangement before being put to a meeting of all Workgroup employees directly concerned with the Project Arrangement.

6.2.4 A majority of the relevant employees voting (in any manner) in favour of the proposals shall finalise the Project Arrangement.

6.2.5 After a vote in favour of the proposed Project Arrangement, the Unions and/or representatives will endorse this arrangement.

6.2.6 The employees directly affected will be given a copy of the Project Arrangement.

6.2.7 At any time during the process outlined in this clause, either party may refer the matter to the Dispute Settlement Procedure within the Current EBA (Clause 29 of this Agreement) for resolution.

6.3 Commencement

6.3.1 A Project Arrangement shall commence on the 7th day after the date of approval or the next pay cycle, which ever is the later.

7. INDIVIDUAL FLEXIBILITY TERM

An employer and employee covered by this enterprise agreement may agree to make an individual flexibility arrangement to vary the effect of terms of the agreement if:

7.1.1 the agreement deals with 1 or more of the following matters:

(a) taking accumulated RDOs;

(b) Salary Sacrifice

7.1.2 the arrangement meets the genuine needs of the employer and employee in relation to 1 or more of the matters mentioned in this clause; and

7.1.3 the arrangement is genuinely agreed to by the employer and employee.

7.1.4 The employer must ensure that the terms of the individual flexibility arrangement:

(a) are about permitted matters under section 172 of the Fair Work Act 2009; and

(b) are not unlawful terms under section 194 of the Fair Work Act 2009; and

(c) result in the employee being better off overall than the employee would be if no arrangement was made.

7.1.5 The employer must ensure that the individual flexibility arrangement:

(a) is in writing; and

(b) includes the name of the employer and employee; and

(c) is signed by the employer and employee and if the employee is under 18 years of age, signed by a parent or guardian of the employee; and

(d) includes details of:

(i) the terms of the enterprise agreement that will be varied by the arrangement; and

(ii) how the arrangement will vary the effect of the terms; and

(iii) how the employee will be better off overall in relation to the terms and conditions of his or her employment as a result of the arrangement; and

(e) states the day on which the arrangement commences.

7.1.6 The employer must give the employee a copy of the individual flexibility arrangement within 14 days after it is agreed to.

7.1.7 The employer or employee may terminate the individual flexibility arrangement:

(a) by giving no more than 28 days written notice to the other party to the arrangement; or

(b) if the employer and employee agree in writing at any time.

8. WORKING HOURS

8.1 *Ordinary Hours*

The arrangements relating to the ordinary hours of work of day workers shall be as follows:

Category	Arrangement
Ordinary Hours of Work: **'Field' staff** **'Office' staff**	 36 hours per week 35 hours per week
Ordinary Days of Work	Monday to Friday inclusive
Span of Hours	6:00 am to 6:00 pm
Lunch Break	Not less than 30 minutes unpaid An employee directed by their immediate manager/supervisor to continue to work beyond 5 hours after their starting time without a lunch break will be paid at the rate of time and one half until they have a lunch break.

8.2 *Starting and finishing times*

Starting and finishing times, within the span of hours, may be changed by agreement between Endeavour Energy and the employees affected (with support from the relevant union/s) to meet customer needs.

8.3 *Rostering of Ordinary Working Hours*

The basic rostering arrangement of ordinary hours of work shall be the nine-day fortnight.

9. PENALTY RATES

9.1 *Work Outside Ordinary Hours*

9.1.1 The following overtime penalties shall apply:

OVERTIME SITUATION	PENALTY APPLICABLE
Monday to Friday	First 2 hours at time and one half. Additional hours at double time.
Saturday (morning) **Saturday (afternoon)**	First 2 hours at time and one half. Additional hours at double time. All hours at double time.
Hours in excess of ordinary weekly hours	First 2 hours at time and one half Additional hours at double time
Sunday	All hours at double time

OVERTIME SITUATION	PENALTY APPLICABLE
Public Holiday (inside what would have been ordinary hours) **Public Holiday (outside what would have been ordinary hours)**	All hours at double time plus payment for the public holiday (or time in lieu for the day) All hours at double time and one half
Pre-arranged Overtime on Saturday, Sunday or Public Holiday	Minimum of 4 hours at the appropriate penalty according to when it is worked
Call Out	Minimum of 4 hours at the appropriate penalty according to when it is worked.
Continuous overtime – both before and after the normal days work	Overtime hours worked are added together to determine when double time is payable
Travelling Time	Time and one half – based on 2 minutes per kilometre, capped at 40 kilometres each way.
Minimum Break	All employees must have a 10 hour break immediately prior to the commencement of their next rostered or ordinary shift, without loss of pay for ordinary working time occurring during the absence/break. In addition if an employee has worked between the hours of 11.00pm and 5.00am prior to the commencement of their next rostered or ordinary shift, the employee must take a 10 hour break from the end of the work and immediately prior to the commencement of their rostered or ordinary shift, without loss of pay for ordinary working time occurring during the absence/break. Employees covered by the Network Shiftwork Workgroup arrangement will be able to reduce this break to 8 hours for normal rostered shifts only.

9.1.2 Meal breaks and allowances on overtime shall be as follows:

SITUATION	BENEFIT APPLICABLE
Meal Break: **Length of Break** **Frequency of Breaks**	20 minutes for each break without loss of pay. For overtime which is continuous with an ordinary days work: • after 1.5 hours of overtime worked; • after a total of 4 hours of overtime worked; and • after a total of 8 hours of overtime worked. *(a maximum of 3 meal breaks)* For overtime which is not continuous with an ordinary days work: • after 4 hours of overtime worked; • after a total of 8 hours of overtime worked; and after a total of 12 hours of overtime worked. *(a maximum of 3 meal breaks)*

SITUATION	BENEFIT APPLICABLE
Meal Allowance	One meal allowance, for each meal break permitted as above *(a maximum of 3 meal allowances also applies)* As an alternative Endeavour Energy will provide a meal to an equivalent value. Refer Appendix B for the value of the meal allowance.

9.1.3 Time off in lieu of overtime worked will be as follows:

ASPECT	PROVISION
Basis of the arrangement	Time off in lieu by agreement with the employee's manager.
Basis of calculating the time in lieu	According to the penalty rates applicable to the overtime worked. (Example: 4 hours overtime at double time = 8 hours and thus 8 hours can be taken)
Taking of time in lieu	The employee is to take the time off within eight weeks of the overtime being worked or the overtime will be paid.

9.1.4 The parties agree to support and facilitate the clarification of leave in lieu and time in lieu and to ensure that employees take their leave in lieu entitlements in accordance with our agreement/workplace arrangements.

9.2 ***Shift Work***

9.2.1 The following definitions apply:

TERM	DEFINITION
Shift work	Work carried out according to a roster that provides for 2 or more shifts per day and also requires them to rotate or alternate the shifts worked.
Night shift	Any shift finishing before but not later than 8.00am.
Afternoon shift	Any shift finishing after 6.00pm but not later than midnight.
Permanent afternoon or night shift	Working the same shift each afternoon or night without rotating with any other span of hours.
Meal Break	a 20 minute break taken as part of the shift at a time to meet work needs.

9.2.2 Shift workers who work regular shift work shall be paid a shift allowance of 15% for each shift worked (refer Appendix B) in addition to his or her ordinary rate of pay and weekend penalties. (A "week" shall mean 5 shifts).

9.2.3 Variations to the above have been made via formal Workplace Arrangement negotiations (Network Shiftwork Workgroup arrangement 2008 and CIC Shiftwork Workplace Arrangement 2007).

9.2.4 Shift workers (including permanent afternoon or night shift workers) who work ordinary rostered shifts on a Saturday, Sunday or Public Holiday shall be paid as follows:

WORKING DAY	PENALTY RATE
Saturday	time and one half
Sunday and Public Holiday	double time

9.2.5 A shift worker who is rostered to work on a public holiday will have a day added to his or her time in lieu leave balance.

9.2.6 A shift is said to be on a Saturday, Sunday or public holiday if the majority of the shift worked is on that day.

9.2.7 Situations attracting overtime will be paid as follows:

SITUATION	PENALTY APPLICABLE
Rostered Day Off	All hours at double time.
Recreation Day	The first 2 hours at time and one half and the remaining hours at double time.
Other Overtime	Refer to "overtime" above.

9.2.8 Situations not attracting overtime are as follows:

SITUATION	DESCRIPTION
'Mutual Arrangement' Shifts	Any extra hours worked as a result of mutual agreement between employees *shall not* attract overtime rates.
Customary Rotation of Shifts	The rotation of shifts inside a roster or the change over from one roster to another.

9.3 *Change of Roster*

9.3.1 Shift workers should normally be given at least five days notice of a change of shift or a change of roster. Where this is not possible the employee will be paid double time for the first shift after the change.

9.3.2 Where an employee is given less than five days notice of a change of shift or roster and the change results in the employee working additional shifts, then the employee shall be allowed an equal amount of time off at a mutually agreed time. If this is not practical for the employee to be allowed time off within four weeks, the employee shall be paid for the extra shifts at double time.

9.3.3 These provisions do not apply to employees who are classified as relief shift workers.

9.3.4 This clause applies except where a local workplace arrangement or enterprise agreement is in place.

9.4 On Call and Stand By

9.4.1 With After Hours Emergency and/or Breakdown Service, the work performed by employees will include:

(a) restoring continuity of supply to Endeavour Energy's system and customers;

(b) returning to a safe and proper operating condition any plant and/or equipment which has failed or is likely to fail;

(c) performing maintenance work which is of such an urgent nature that if not carried out an interruption of supply may occur; and

(d) all aspects of consumer's installation, plant, equipment or appliances which if not attended to or temporarily overcome, will cause distress, hardship or loss to the customer and/or other occupants of the premises.

9.4.2 An employee rostered on the on call and stand by roster is required to be available for emergency and/or breakdown work at all times outside his or her usual hours of work.

9.4.3 Employees rostered on call or standby will have their hours monitored for safety reasons.

9.4.4 Employees who are on call are not confined to their homes but they must be reasonably available so that they would not be delayed by more than 15 minutes in addition to the time it would normally take to travel from their homes to the place where the work is to be performed. Any delays in excess of 15 minutes will not be paid unless specifically authorised.

9.4.5 An employee may be required to attend any other calls which arise prior to returning home.

9.4.6 An employee shall not engage in an activity or make a commitment that will adversely affect their obligations when rostered on.

9.4.7 On call and stand by employees will be paid as follows:

SITUATION	ENTITLEMENT
On Call / Stand By Allowance **(Refer Appendix B)**	An employee shall be paid the On Call / Stand By Allowance for each day the employee is rostered on.
Time worked on a call	All time at double time. *(a "call" shall be from the time the call is received to the time the employee has returned home)*
Minimum payment	2 hours at double time.
Attending to the call	Employee to proceed directly to and from the call without unnecessary delay or deviation.
Work on Public Holidays	1 day shall be added to leave in lieu for each public holiday that an employee is rostered on the On Call/Stand-By roster regardless if the employees is called out or not.

10. ELECTRICAL SAFETY RULES ALLOWANCE

10.1 *Payment of Allowance*

The Electrical Safety Rules Allowance is paid to employees appointed to electrically qualified positions who have passed a test of their knowledge of the rules and who are required to work or supervise or direct work in accordance with those rules are entitled to 100% payment. Employees will be required to undergo periodic refresher training. Apprentice electricians are paid the allowance from the date they complete the Electrical Safety Rules Test. Paid for all purposes. (Appendix B – Allowances)

10.2 *Trade Classifications*

Employees in trade classifications (as defined) other than electrician are entitled to 80% of the Electrical Safety Rules Allowance paid to electricians.

10.3 *Pro-rata Safety Rules Allowance*

Pro-rata Safety Rules Allowance paid to Electricity Workers who have passed the Safety Rules Test. This allowance is calculated at 60% of the Electrical Safety Rules Allowance. To be known as Safety Rules Electricity Workers Allowance.

11. TRANSFER OF DEPOT

11.1 *Normal journey*

An employee is required to make their own way to and from their normal place of work each day.

Permanent or temporary transfer

Transfer situation	Provision
Transfer where employee uses their own vehicle	The excess travel resulting from an employee being transferred will be paid at the rate of $1.57 per kilometre for a maximum period of 6 months; OR by a negotiated alternative arrangement.
Transfer where employee uses an Endeavour Energy vehicle	The excess travel resulting from the employee being transferred will be paid at the rate of $1.57 per kilometre (less the Endeavour Energy rate for private vehicle) for each kilometre for a maximum period of 6 months; OR by a negotiated alternative arrangement.

The time component of the transfer of depot allowance will be linked to Agreement increases, and the vehicle component will be linked to the Australian Tax Office guidelines for casual car allowance for a vehicle over 2600cc.

12. ANNUAL LEAVE

12.1 *Basis of Accruing Annual Leave*

The accrual of annual leave and long service leave shall be on the following basis:

CATEGORY OF EMPLOYEE	BASIS OF ACCRUAL
35 hour week Employees	35 hour week ÷ 5 days = 7 hours per day
36 hour week Employees	36 hour week ÷ 5 days = 7.2 hours per day

12.2 *Basis of Taking Annual Leave*

Leave taken by employees shall be deducted from the employee’s leave balance and calculated on the basis of his or her rostering of work.

12.3 *Quantum and Loading*

The following quantum annual leave shall be granted to an employee after each year of service:

CATEGORY OF EMPLOYEE	LEAVE	LOADING
Normal day workers and **5 day shift workers**	4 weeks (140 hours or 144 hours)	Included in employee’s ordinary rate of pay
6 day shift workers	4.5 weeks (157.5 hours or 162 hours)	Included in employee’s ordinary rate of pay
7 day shift workers	5 weeks (175 hours or 180 hours)	Included in employee’s ordinary rate of pay

12.4 *Taking Annual Leave*

SITUATION	REQUIREMENT
Taking Annual Leave	In one or two separate periods by mutual agreement within 12 months of the leave falling due. The number of periods may be varied by mutual agreement with the employee’s manager. Annual leave of less than 1 week may be taken with approval of the employee’s manager.
Notification of taking Annual Leave	Employee: 2 weeks notice *(this may be waived in special circumstances by agreement)* Endeavour Energy: 4 weeks notice
Leave in Advance	Where the employee is allowed to take leave in advance, the payment shall be regarded as an over-payment (and may be recovered from the employee’s termination pay) until further accrual of leave covers the amount taken in advance.

12.5 *Accrual of Annual Leave*

12.5.1 Except as provided for below, an annual holiday is expected to be taken by an employee and will be given by Endeavour Energy before the expiration of the period 1 year after the date on which the right to take the annual leave accrued.

12.5.2 The above clause will not apply where an employee is accumulating annual leave up to 40 days (50 days for shift workers) for a special purpose. Examples of a special purpose include but are not limited to an overseas holiday or a family reunion.

12.5.3 Employees who have more than two years annual leave accrued will be notified by Endeavour Energy of the expectation to clear such excess accrual.

12.6 *Payment on Termination*

SITUATION	ENTITLEMENT
Less than 12 months Service	Proportion of the leave that would have fallen due upon completion of 12 month's service. Calculation of the proportion is based on the weeks and days service as a proportion of 48 weeks *(47 weeks for 7 day shift workers)*.
More than 12 months Service	Any untaken leave plus a proportion of the forthcoming leave accrual. Calculation of the proportion is based on the weeks and days service as a proportion of 48 weeks *(47 weeks for 7 day shift workers)*.

13. 48/52 WEEKS PER YEAR WORKING ARRANGEMENTS DEFINED

13.1 *Conditions of the 48/52 weeks per year working arrangements*

The 48/52 weeks per year working arrangements (48/52) is a scheme under which a full-time or part time employee may work 44 weeks of a negotiated 12 month period. An employee participating in the 48/52 scheme has effectively had four weeks leave without pay approved but rather than lose the value of the four weeks salary in one period, the employee has obtained approval to spread the salary impact of four weeks leave without pay averaged over the 52 week period.

This process will be available after the first twelve months of the agreement to give the organisation the ability to implement the appropriate mechanisms to facilitate this process.

13.2 *Entitlement and arrangements*

13.2.1 All full-time continuing, part time fixed and term employees are eligible to apply to their Manager or other delegated officer for approval to take up to eight (8) weeks annual leave in a year and receive 48 weeks salary, which would be payable over the full 52 weeks. Application and approval must be in writing and agreement between the supervisor and the employee.

13.2.2 Once approved, such arrangements will commence at a mutually agreed time and remain in place for a period of 12 months.

13.2.3 Under this arrangement an employee will become a fractional employee at 48/52 of a full time or part time work load, with all benefits accruing on that basis.

13.3 *Annual leave*

13.3.1 Employees electing to move to this become a fractional employee at 48/52 of a full time or part time work load, with all benefits accruing on that basis including annual leave.

13.3.2 Under these arrangements an employee is required to apply for annual leave via the organisations usual leave procedures within the 12 month period.

13.3.3 In taking leave in any one year, it will not be necessary for eight weeks leave to be taken in one block, but this could be an option available to the employee.

13.4 *Long service leave / sick leave*

13.4.1 Employees availing themselves of this option will retain benefits accrued on a full-time or part time fractional time basis up to the nominated commencement date. Long service leave and sick leave benefits accrued after this nominated date will be at the new fractional rate.

13.5 *When leave may be taken*

13.5.1 The eight weeks leave must be taken within its agreed 12 month period.

13.5.2 It will be necessary for the employee and supervisor to agree on the time of taking leave as early as possible upon entering into these arrangements.

13.6 *Termination of employment*

An employee who terminates their services whilst on these arrangements will be paid for the unexpired period of leave at the appropriate fractional rate based on the credit accrued. Where entitlements have accrued at the full-time rate any termination payments will be made at the full time rate.

13.7 *Reallocation of workloads*

Where an employee converts to a 48/52 scheme, the supervisor will ensure that any reallocation of workloads is the subject of consultation with affected employees and does not create an unreasonable workload for any other employee.

13.8 *Superannuation*

Where an employee elects to take up the 48/52 option, superannuation contributions for the employee and the organisation will reduce on a pro-rata basis, except where the employee chooses to maintain, subject to the requirements of the relevant superannuation scheme, the employee and/or employer's superannuation contributions on a full-time employment basis, but the organisation shall only be obliged to cover the cost of employer contributions at the 48/52 rate.

14. PUBLIC HOLIDAYS

14.1 *Entitlement to Public Holidays*

Employees of Endeavour Energy shall be entitled to the following public holidays, plus any additional holidays gazetted by the NSW Government, without loss of pay:

- New Years Day
- Australia Day
- Good Friday
- Easter Saturday
- Easter Monday
- Endeavour Energy Employees Day
- Anzac Day
- Queens Birthday
- Labour Day
- Christmas Day
- Boxing Day

14.2 *Alternate Religious Beliefs*

In order to recognise genuinely held non-Christian religious beliefs an employee may, where it meets customer needs and with the agreement of his or her manager, substitute public holidays listed above for those relevant to that religion.

14.3 *Non Payment of Public Holidays*

Employees shall not be entitled to payment for a public holiday or holidays if:

(a) they are absent on the normal working day before and the day after the public holiday or holidays;

unless

(b) they give the Chief Executive Officer or his or her nominee satisfactory evidence that the absence was due to a good and satisfactory cause.

15. LONG SERVICE LEAVE

15.1 *Quantum*

BASIS OF ACCRUAL	QUANTUM	
After 10 years	13 weeks	(455 hours or 468 hours)
After 15 years	an extra 8.5 weeks	(297.5 hours or 306 hours)
After 20 years	An extra 13.5 weeks	(472.5 hours or 486 hours)
After each additional 5 years	An extra 13 weeks	(455 hours or 468 hours)

15.2 *Taking Long Service Leave*

SITUATION	REQUIREMENT
Taking Long Service Leave	Endeavour Energy expects that Long Service leave be taken as soon as possible after the entitlement arises. Long Service leave may be taken in periods of not less than 4 weeks, by mutual agreement. Long Service leave may be taken at half pay in which case the employee is entitled to twice the duration of Long Service leave.
Notification of Taking Long Service Leave	Employee: 1 month's notice Endeavour Energy: 1 month's notice The amount of notice may be reduced by agreement between the employee and his or her manager.

15.3 *Payment on Termination*

SITUATION	ENTITLEMENT
Less than 5 years	Nil
5 Years or more service **BUT** **Less than 10 Years Service**	Accrued long service leave on a pro-rata basis but only if the reason for termination is: • Redundancy; or • Resignation due to domestic or other pressing necessity.
10 Years or more Service	Any untaken leave plus a proportion of the forthcoming leave accrual. Calculation of the proportion is based on the weeks and days service as a proportion of 48 weeks *(47 weeks for 7 day shift workers)*.

15.4 *Recognition of Service for Long Service Leave*

Employees transferring to Endeavour Energy from a public service organisation or State Owned Corporation who have an entitlement to long service leave will have the option to either have the long service leave paid out prior to commencing with Endeavour Energy, or transfer the accrued entitlement. Transfer of Long Service Leave will only be approved where the employee has an accrued entitlement and a cheque is forwarded from the employee's previous employer to Endeavour Energy.

16. BEREAVEMENT LEAVE

16.1.1 An employee other than a casual employee shall be entitled to up to two days bereavement leave without deduction of pay on each occasion of the death of a person prescribed in clause 20.1.3.

16.1.2 The employee must notify Endeavour Energy as soon as practicable of the intention to take bereavement leave and will, if required by Endeavour Energy, provide to the satisfaction of Endeavour Energy proof of death.

16.1.3 Bereavement leave shall be available to an employee in respect to the death of a person prescribed for the purposes of Family/Carer's Leave in clause 20.1.3 provided that for the purpose of bereavement leave, the employee need not have been responsible for the care of the person concerned.

16.1.4 An employee shall not be entitled to bereavement leave under this clause during any period in respect of which the employee has been granted other leave.

16.1.5 Bereavement leave may be taken in conjunction with other leave available under this Agreement. In determining such a request, Endeavour Energy will give consideration to the circumstances of the employee and the reasonable operational requirements of the business.

16.1.6 Bereavement leave entitlements for casual employees are as follows:

16.1.7 Subject to evidentiary and notice requirements in 16.1.2, casual employees are entitled to be not available to work, or to leave work upon the death in Australia of a person prescribed in 16.1.3 of this clause.

16.1.8 The employer and the employee shall agree on the period for which the employee will be entitled to not be available to attend work. In the absence of agreement, the employee is entitled to not be available to attend work for up to 48 hours (i.e. 2 days) per occasion. The casual employee is not entitled to any payment for the period of non-attendance.

16.1.9 An employer must not fail to re-engage a casual employee because the employee accessed the entitlements provided for in this clause. The rights of an employer to engage or not engage a casual employee are otherwise not affected.

17. PARENTAL LEAVE

The following provisions shall also apply in addition to those set out in Chapter 2, Part 2-2, Division 5 – 'Parental leave and related entitlements' of the National Employment Standard (NES) under the Fair Work Act 2009 (Cth); and the Paid Parental Leave Act 2010 (Cth).

The provisions within this clause shall also operate in conjunction with the relevant policies and procedures adopted by Endeavour Energy from time to time.

17.1 *Parental Leave*

17.1.1 Employees who are eligible for Parental leave without pay shall be entitled to receive up to 14 weeks of paid leave (or 28 weeks at half pay) included in the 12 months approved at their ordinary rate of remuneration to assist the employee's ability to reconcile work and family responsibilities and to return to work within the maximum timeframe, if consented, in accordance with this agreement.

17.1.2 An employer must not fail to re-engage a regular casual employee because the:

(a) employee or employee's spouse is pregnant;

(b) employee is or has been immediately absent on parental leave;

(c) rights of an employer in relation to engagement and re-engagement of casual employees are not affected, other than in accordance with this clause.

17.2 *Right to request*

17.2.1 An employee entitled to parental leave may request the employer to allow the employee to:

(a) extend the period of simultaneous unpaid parental leave use up to a maximum of eight (8) weeks

(b) extend the period of unpaid parental leave for a further continuous period of leave not exceeding 12 months

(c) return from a period of parental leave on a part-time basis until the child reaches school age

(d) assistance in reconciling work and parental responsibilities.

17.2.2 The employer shall consider the request having regard to the employee’s circumstances and, provided the request is genuinely based on the employee’s parental responsibilities, may only refuse the request on reasonable grounds related to the effect on the workplace or the employer’s business. Such grounds might include cost, lack of adequate replacement staff, loss of efficiency and the impact on customer service.

17.3 *Employee’s request and the employer’s decision to be in writing*

17.3.1 The employee’s request and the employer’s decision must be recorded in writing in accordance with this agreement.

17.3.2 Request to return to work part-time

(a) Where an employee wishes to make a request in accordance with this agreement, such a request must be made as soon as possible but no less than seven (7) weeks prior to the date upon which the employee is due to return to work from parental leave.

17.4 *Other Parent Leave*

An employee who is not the primary care giver is entitled to an unbroken period of one week paid leave at the time of the birth of their child or other termination of pregnancy.

17.5 *Communication during all forms of parental leave*

17.5.1 Where an employee is on parental leave and a definite decision has been made to introduce significant change at the workplace, the employer shall take reasonable steps to:

(a) make information available in relation to any significant effect the change will have on the status or responsibility level of the position the employee held before commencing parental leave, and

(b) provide an opportunity for the employee to discuss any significant effect the change will have on the status or responsibility level of the position the employee held before commencing parental leave.

17.5.2 The employee shall take reasonable steps to inform the employer about any significant matter that will affect the employee's decision regarding the duration of parental leave to be taken, whether the employee intends to return to work and whether the employee intends to request to return to work on a part-time basis.

17.5.3 The employee shall also notify the employer of changes of address or other contact details which might affect the employer's capacity to comply with the terms of this Agreement.

17.6 *Adoption Leave*

Any employee may take unpaid leave in connection with the adoption of a child under the age of 5 years up to a maximum of 52 weeks.

18. ABSENCE BENEFITS SCHEME

18.1 *Purpose for sick leave*

To provide income protection in circumstances where the employee is not able to perform his or her work because of illness or personal injury; or needs to obtain appropriate medical advice and/or treatment for a personal illness or injury.

18.2 *Sick leave granted*

Paid sick leave will be provided to an employee if he or she is genuinely sick and unable to perform his or her duties.

18.3 *Sick leave not granted*

18.3.1 Sick leave shall not be granted in the following circumstances:

(a) where a payment is made for Accident Pay under this Agreement;

(b) where the employee receives payment from an organisation other than Endeavour Energy, in the form of income protection, as a result of participation in an outside activity; or

(c) where in the view of the Chief Executive Officer or his or her nominee the illness or injury resulted from a wilful act, misconduct or the negligence of the employee.

18.4 *Sick Leave and Public Holidays*

A public holiday that occurs during a period of sick leave taken by an employee shall not be counted as sick leave. However a Medical Certificate or Statutory Declaration will be required if an employee is absent due to illness either side of a public holiday.

18.5 *Infectious Diseases*

An employee who comes in contact with a person suffering from a contagious disease (where restrictions are imposed on that employee by law), as confirmed by a Doctor, and therefore cannot come to work may take sick leave.

18.6 *Sick Leave Forms*

Employees claiming sick leave must fill in the required sick leave form on the day they return to work, or their supervisor can complete the form when the staff member calls in sick.

18.7 *Re-crediting of Annual Leave and Long Service Leave*

In order for Long Service Leave or Annual Leave to be re-credited due to illness the following conditions must be met:

(a) For annual leave the employee must be ill for a minimum of 1 working day or shift and provide a Doctor's Certificate/Statutory Declaration covering the entire period

(b) For long service leave the employee must be ill for a minimum of 5 consecutive working days or shifts and provide a Doctor's Certificate/Statutory Declaration covering the entire period;

(c) the employee must be able to demonstrate that as a consequence of the illness or injury their leave was disrupted; and

(d) all requests for leave to be re-credited must be made in writing and sent to the respective Branch Manager.

18.8 *Medical Certificates and Statutory Declarations*

A Medical Certificate or Statutory Declaration will be required if an employee is absent for more than two consecutive working days, or when a repeatable or excessive pattern of sick days develops.

18.9 *Notification*

Staff must notify their supervisor as soon as practicable, on the first day of absence, when they know they will not be able to attend work.

19. PRE 93 SICK LEAVE

Consistent with the outcome of matter number B2010/3579 the value of Pre 93 Sick leave balances will remain at the value of the balance as at the date of the resolution of this matter.

20. FAMILY / CARERS LEAVE

20.1 *Use of leave*

20.1.1 An employee, other than a casual employee, with responsibilities in relation to a class of person set out in accordance with this agreement who needs the employee's care and support shall be entitled to use, in accordance with the sub-clause, up to 10 days sick leave (which is accumulated as per the NES), for absences to provide care for such persons when they are ill. Such leave may be taken for part of a single day. Applications for carers leave in excess of 10 days need to be approved by the Manager Employee Relations on a case by case basis.

20.1.2 The employee shall, if required, establish either by production of a medical certificate or statutory declaration, the illness of the person concerned and that the illness is such as to require care by another person. In normal circumstances an employee must not take Carer's leave under this sub-clause where another person has taken leave to care for the same person.

20.1.3 The entitlement to use sick leave in accordance with this sub-clause is subject to:

(a) the employee being responsible for the care of the person concerned; and

(b) the person concerned being:

(i) a spouse of the employee; or

(ii) a de facto spouse, who, in relation to a person, is a person of the opposite sex to the first-mentioned person who lives with the first-mentioned person as the husband or wife of that person on a bona fide domestic basis although not legally married to that person; or

(iii) a child or an adult child (including an adopted child, a step child, a foster child or an ex-nuptial child), parent (including a foster parent and legal guardian), grandparent, grandchild or sibling of the employee or spouse or de facto spouse of the employee; or

(iv) a same sex partner who lives with the employee as the de facto partner of that employee on a bona fide domestic basis; or

(v) a relative of the employee who is a member of the employee's household, consistent with the NES, where for the purposes of this paragraph:

A. "relative" means a person related by blood; marriage or affinity;

B. "affinity" means a relationship that one spouse because of marriage has to blood relatives of the other; and

C. "household" means a family group living in the same domestic dwelling.

20.1.4 An employee must, wherever practicable, give Endeavour Energy notice prior to the absence of the intention to take leave, the name of the person requiring care and their relationship to the employee, the reasons for taking such leave and the estimated length of absence. If it is not practicable for the employee to give prior notice of absence, the employee must notify Endeavour Energy by telephone of such absence at the first opportunity on the day of absence.

20.2 *Unpaid leave for Family Purpose*

An employee may elect, with the consent of Endeavour Energy, to take unpaid leave for the purpose of providing care and support of a member of a class of person set out in clause 20.1.3 above who is ill.

20.3 *Single day absences on annual leave for family/carers leave*

An employee may elect with the consent of Endeavour Energy, to take annual leave not exceeding ten days in single day periods or part thereof, in any calendar year at a time or times agreed by the parties.

20.4 *Family/carers entitlement for casual employees*

20.4.1 Subject to the evidentiary requirements set out in 20.1.2 and the notice requirement set out in 20.1.4 casual employees are entitled to not be available to attend work, or to leave work if they need to care for a person prescribed in subclause 20.1.3(b) of this clause who are sick and require care and support, or who require care due to an unexpected emergency, or the birth of a child.

20.4.2 Endeavour Energy and the employee shall agree on the period for which the employee will be entitled to not be available to attend work. In the absence of agreement, the employee is entitled to not be available to attend work for up to 48 hours (i.e. two days) per occasion. The casual employee is not entitled to any payment for the period of non-attendance.

20.4.3 Endeavour Energy must not fail to re-engage a casual employee because the employee accessed the entitlements provide for in this clause. The rights of an employer to engage or not to engage a casual employee are otherwise not affected.

20.5 *Family/Carers leave – use of annual leave*

An employee with family/carers leave responsibilities may elect, with Endeavour Energy's agreement, to take annual leave at any time within a period of 24 months from the date at which it falls due. Such applications should be made to the Manager, Employee Relations.

21. DOMESTIC VIOLENCE

21.1 *General Principle*

Endeavour Energy recognises that employees sometimes face situations of violence or abuse in their personal life that may affect their attendance or performance at work. Therefore, Endeavour Energy is committed to providing support to staff that experience domestic violence.

21.2 *Definition of Domestic Violence*

Domestic violence includes physical, sexual, financial, verbal or emotional abuse by an immediate family member as defined in this Agreement.

21.3 *General Measures*

(a) Proof of domestic violence may be required and can be in the form of an agreed document issued by the Police Service, a Court, a Doctor, a Domestic Violence Support Service or Lawyer.

(b) All personal information concerning domestic violence will be kept confidential in line with Endeavour Energy Policy and relevant legislation. No information will be kept on an employee's personnel file without their express written permission.

(c) No adverse action will be taken against an employee if their attendance or performance at work suffers as a result of experiencing domestic violence.

(d) Endeavour Energy will identify a contact in Human Resources who will be trained in domestic violence and privacy issues. Endeavour Energy will advertise the name of the contact within the organisation.

(e) An employee experiencing domestic violence may raise the issue with their immediate supervisor or the Human Resources contact. The supervisor may seek advice from Human Resources if the employee chooses not to see the Human Resources contact.

(f) Where requested by an employee, the Human Resources contact will liaise with the employee's supervisor on the employee's behalf, and will make a recommendation on the most appropriate form of support to provide in accordance with sub clauses 4 and 5.

(g) Endeavour Energy will develop guidelines to supplement this clause which detail the appropriate action to be taken in the event that an employee reports domestic violence.

21.4 *Leave*

(a) An employee experiencing domestic violence will have access to paid special leave for medical appointments, legal proceedings and other matters and activities arising from domestic violence.

This leave will be in addition to existing leave entitlements and may be taken as consecutive or single days or as a fraction of a day and can be taken without prior approval.

(b) An employee who supports a person experiencing domestic violence may take special leave to accompany them to court, to hospital, or to mind children.

21.5 *Individual Support*

(a) In order to provide support to an employee experiencing domestic violence and to provide a safe work environment to all employees, Endeavour Energy will support any reasonable request from an employee experiencing domestic violence for:

(i) changes to their span of hours or pattern or hours and/or shift patterns;

(ii) job redesign or changes to duties;

(iii) relocation to suitable employment within the Endeavour Energy;

(iv) a change to their telephone number or email address to avoid harassing contact;

(v) any other appropriate measure including those available under existing provisions for family friendly and flexible work arrangements.

(b) An employee experiencing domestic violence will be referred to the Employee Assistance Program (EAP) and/or other local resources. The EAP shall include professionals trained specifically in domestic violence.

22. JURY SERVICE

SITUATION	PROVISION
Time spent on Jury Duty	Special leave with pay for the days and/or part days service on jury service.
Adjustment of Employee's pay	The employee's ordinary week's pay will be adjusted by the amount the employee received from the court for his or her attendance

23. SAFETY AT WORK

23.1 *Parties Obligations*

23.1.1 The parties recognise that both Endeavour Energy and its employees have obligations under the New South Wales Occupational Health and Safety Act 2000 to ensure the workplace is safe.

23.1.2 Endeavour Energy's primary concern is the health and safety of its employees, contractors, visitors, customers and the general public. The parties to this Agreement agree to share an ongoing commitment to promote the health, safety and welfare of all employees, contractors, customers, visitors and the general public and nothing in this Agreement shall be designed or applied in ways that reduce or diminish this objective.

23.1.3 The parties commit, consistent with the recommendation of Fair Work Australia (B2010/3579) to the development of policy and implementation of i-Safe vehicle location system in all relevant Endeavour Energy vehicles during the life of this agreement.

24. WORK RELATED ACCIDENT

An employee who suffers a work-related injury within the meaning of the New South Wales workers' compensation legislation will be entitled to benefits provided by Endeavour Energy (a self-insurer) in accordance with the relevant legislation.

24.1 *Evaluation of a Claim*

24.1.1 To overcome employees facing financial hardship during the process of evaluating a claim, employees may elect to take sick leave.

24.1.2 Upon acceptance of the claim any sick leave taken by the employee will be re-classified as workers compensation leave.

24.2 *A Denied Claim*

Where a denied claim is settled or an agreement is made by the Workers Compensation Commission against Endeavour Energy the payment made by Endeavour Energy for sick leave shall be reimbursed by the employee from the settlement or Agreement.

24.3 *Accident Pay*

An employee who has received an injury shall, subject to this clause, be entitled to accident pay while their employment by Endeavour Energy and their entitlement to weekly payment for compensation (pursuant to the Act) for incapacity flowing from such injury continues, for a combined total period up to 52 weeks.

24.4 *Occupational Health and Safety*

(a) For the purposes of this subclause, the following definitions shall apply:

(i) A “labour hire business” is a business (whether an organisation, business enterprise, company, partnership, co-operative, sole trader, family trust or unit trust, corporation and/or person) which has as its business function, or one of its business functions, to supply staff employed or engaged by it to another employer for the purpose of such staff performing work or services for that other employer.

(ii) A “contract business” is a business (whether an organisation, business enterprise, company, partnership, co-operative, sole trader, family trust or unit trust, corporation and/or person) which is contracted by another employer to provide a specified service or services or to produce a specific outcome or result for that other employer which might otherwise have been carried out by that other employer’s own employees.

(b) Where Endeavour Energy engages a labour hire business and/or a contract business to perform work wholly or partially on Endeavour Energy’s premises, Endeavour Energy shall do the following (either directly, or through the agency of the labour hire or contract business):

(i) provide employees of the labour hire business and/or contract business with appropriate occupational health and safety induction training including the appropriate training required for such employees to perform their jobs safely;

(ii) ensure that those employees of the labour hire business are provided with appropriate personal protective equipment and/or clothing by their employer; and

(iii) ensure employees of the labour hire business and/or contract business are made aware of any risks identified in the workplace and the procedures to control those risks.

(c) Nothing in this subclause 24.4 is intended to affect or detract from any obligation or responsibility upon a labour hire business or contract business arising under the Occupational Health and Safety Act 2000 or the Workplace Injury Management and Workers Compensation Act 1998.

25. AUTOMATED EXTERNAL DEFIBRILLATORS (AED'S)

25.1 Endeavour Energy recognises the importance of AED's and the need to be taught as part of the Annual Electrical Safety Training. We commit to providing these devices, understanding that the works performed by selected field employees of Endeavour Energy are in a high risk environment. We understand that as part of working in and around this high risk environment, that AED's may become an essential safety tool identified as part of the risk assessment process.

Considerations to be made as part of the Risk Assessment Process

25.2 Operations Managers and workers are required to consider the following factors in deciding when to allocate an AED to site:

(a) The potential exposure of the body to live electrical apparatus - If a substantive part of the job to be done on the worksite involves working on or near live apparatus then the AED should be available.

(b) Distance to medical assistance - If you are going to be undertaking work at a worksite that is remote and there is a potential for the response by emergency services to be delayed, then the AED should be considered.

(c) Large worksite – If you have a large worksite with a significant number of people then it may be appropriate to consider having the AED available.

(d) As requested by workers – Anybody can identify risks associated with a worksite that may make the AED appropriate. These factors should be discussed with the Operations Manager or supervisor for the site.

The aim is to have these devices available at worksites, as required, based on an appropriate risk assessment.

Actions to be taken where an AED is not available

25.3 If you identify a worksite using the risk factors above that the AED should be available but there is not an AED available in the FSC then the Operations Manager will make the decision, in conjunction with the leading hand and workers, on where the devices are to be for that period. This will be determined on a risk-basis, using the criteria noted above.

25.4 In this event the Operations Manager should also log this event using MySafe as a near miss.

25.5 The near miss should include details of the site where the AED was requested and why it was not available. This MySafe system will be used to validate the quantity and ongoing use of the devices.

Responsibility for deciding that the AED should be taken to a site

25.6 The AED is supplied for the use of all workers and is to be managed locally. Those planning work need to consider the risk factors that would be mitigated by the availability of the AED and should plan accordingly. However, the decision on making the AED available at a site is to be based on an open ongoing discussion between workers and their managers.

How the AED is to be managed

25.7 The AED does not require routine maintenance or calibration but does contain batteries that must be monitored. As with all safety equipment there are a number of responsibilities that come with the purchase of the equipment:

(a) Depot Managers are required to make sure that a Designated First Aider is identified to check that the unit in line with GSY0036.

(b) Each depot must have a system to monitor the use and whereabouts of these assets. This includes the signing out of the equipment.

(c) Each user must check the unit prior to taking to a site. Where the unit is not operating as required the employee must report this to their supervisor / manager.

(d) This equipment must be stored, treated and used appropriately.

26. **DRUG AND ALCOHOL TESTING**

26.1 Consistent with the outcome of the most recent Fair Work Commission, Matter Number C2013/1559, made on the 15th January 2014, that Drug and Alcohol Testing will be conducted in accordance with Company Procedure GHR 9004, Version Number - Amendment 4, Approval Date 4th January 2013, Review Date 4th January 2016.

26.2 Endeavour Energy, its successors or assigns shall not seek to vary, modify, transfer or assign by or through any agent, representative, contractor, Medical Review Officer (MRO), Independent Medical Examiner (IME), medical practitioner or alike the required mode of testing other than as prescribed within Company Procedure GHR 9004, as referred to and in accordance with the outcome of the most recent Fair Work Commission Matter Number C2013/1559, made on the 15th January 2014.

27. SECURE EMPLOYMENT

27.1 *Objective of this Clause*

The objective of this clause is for Endeavour Energy to take all reasonable steps to provide its employees with secure employment by maximising the number of permanent positions in Endeavour Energy's workforce, in particular by ensuring that casual employees have an opportunity to elect to become full-time or part-time employees.

27.2 *Casual Conversion*

(a) A casual employee engaged by Endeavour Energy on a regular and systematic basis for a sequence of periods of employment under this Award during a calendar period of six month shall thereafter have the right to elect to have his or her ongoing contract of employment converted to permanent full-time employment or part-time employment if the employment is to continue beyond the conversion process prescribed by this subclause.

(b) Endeavour Energy shall give the employee notice in writing of the provisions of this sub-clause within four weeks of the employee having attained such period of six months. However, the employee retains his or her right of election under this subclause if the employer fails to comply with this notice requirement.

(c) Any casual employee who has a right to elect under this agreement and in accordance with the Fair Work Act 2009 or after the expiry of the time for giving such notice, may give four weeks' notice in writing to Endeavour Energy that he or she seeks to elect to convert his or her ongoing contract of employment to full-time or part-time employment, and within four weeks of receiving such notice from the employee Endeavour Energy shall consent to or refuse the election, but shall not unreasonably so refuse. Where an employer refuses an election to convert, the reasons for doing so shall be fully stated and discussed with the employee concerned, and a genuine attempt shall be made to reach agreement. Any dispute about a refusal of an election to convert an ongoing contract of employment shall be dealt with through the disputes procedure at Clause 29.

(d) Any casual employee who does not, within four weeks of receiving written notice from Endeavour Energy, elect to convert his or her ongoing contract of employment to full-time employment or part-time employment will be deemed to have elected against any such conversion.

(e) Once a casual employee has elected to become and been converted to a full-time employee or a part-time employee, the employee may only revert to casual employment by written agreement with Endeavour Energy.

(f) If a casual employee has elected to have his or her contract of employment converted to full-time or part-time employment in accordance with this Agreement.

(i) whether the employee will convert to full-time or part-time employee; and

(ii) if it is agreed that the employee will become a part-time employee, the number of hours and the pattern of hours that will be worked shall be consistent with any other part-time employment provisions of this award pursuant to a part time work agreement made under the Act;

(iii) Provided that an employee who has worked on a full-time basis throughout the period of casual employment has the right to elect to convert his or her contract of employment to full-time employment and an employee who has worked on a part-time basis during the period of casual employment has the right to elect to convert his or her contract of employment to part-time employment, on the basis of the same number of hours and times of work as previously worked, unless other arrangements are agreed between the employer and the employee.

(g) Following an agreement being reached pursuant to paragraph (f), the employee shall convert to full-time or part-time employment. If there is any dispute about the arrangements to apply to an employee converting from casual employment to full-time or part-time employment, it shall be dealt with through the disputes procedure at clause 29.

(h) An employee must not be engaged and re-engaged, dismissed or replaced in order to avoid any obligation under this subclause.

28. LABOR HIRE/AGENCY HIRE WORKERS

28.1 Parties to this agreement recognise the need for Endeavour Energy to engage labour hire workers from time to time to meet short term business needs.

28.2 Endeavour Energy will consult with the relevant parties in relation to the prospective need for labour hire engagement.

28.3 In this context, the parties recognise short term as a maximum of six months except in circumstances where consultation has taken place prior to any extension of this time frame.

28.4 As part of this process Endeavour Energy will meet with the relevant unions on a 6 monthly basis to discuss labour requirements, Endeavour Energy will provide a report as to the composition of labour hire agency workers at each of these meetings.

28.5 The company agrees that in deciding to utilise labour hire, workers undertaking work will have wages and conditions that are no less favourable than that provided for in their relevant industrial instrument.

28.6 The parties will consult before introducing a new area of labour hire where labour hire has not traditionally been used. This will entail contact with the relevant union official.

28.7 Endeavour Energy agrees that labour hire will not be used as an alternative to permanent employment and will not diminish the job security or result in alterations to the working conditions of employees.

29. OUTSOURCING/CONTRACTING OUT

29.1 *Basic Principles*

Outsourcing or contracting out will not diminish the working conditions of this agreement.

29.2 Work will only be outsourced or contracted out when it can be demonstrated that:

(a) peak workloads cannot be met by Endeavour Energy's workforce including reasonable overtime; and

(b) where specific expertise, not available in Endeavour Energy's workforce, is required. Where recurring work requires such expertise, Endeavour Energy will make efforts to obtain this expertise by training and/or reorganising its existing workforce. Endeavour Energy will keep the relevant union(s) informed about such training and reorganisation; and

(c) the use of outsourcing or contracting out the work is commercially the most advantageous option taking into account safety, quality, performance, and cost, and

(d) Endeavour Energy will not have work normally performed by Endeavour Energy Employees undertaken by a contractor/labour hire employee or the employees of a contractor where the effect would be to create any stranded resources with their internal staff, displacing the Endeavour Energy Employee(s) from their duties.

29.3 In circumstances where Endeavour Energy is examining outsourcing or contracting out of work activities:

a) A Contracting Consultation Committee (CCC) shall be formed comprising appropriate representation from Endeavour Energy and the applicable unions. The purpose of the CCC will be to serve as a forum for Endeavour Energy to inform and consult the Unions and their members on all contracting and outsourcing proposals.

b) Utilising the CCC - Endeavour Energy will consult the employees and their union(s) and provide them the appropriate time (relevant to the nature of the proposal) to respond with suitable proposals in respect of possible alternative arrangements to outsourcing or contracting out;

c) Prior to expressions of interest or tenders being called, where employee generated alternatives are received, such alternatives will be considered;

d) Expressions of interest or tenders when advertised shall be timed so as to provide the employees with an opportunity to submit a conforming expression of interest or tender. If an employee generated conforming expression of interest or tender is submitted, it will be evaluated together with external submissions consistent with the tendering and probity procedures of Endeavour Energy.

29.4 When a decision is made by Endeavour Energy to outsource/contract out work not already outsourced or contracted out, or in a review of existing contracts, Endeavour Energy will consider a contract to a contractor that demonstrates:

a) contractor(s) undertaking the outsourced /contracted out work will have wages and conditions that are no less favourable than that provided for in their relevant industrial instrument.

b) it has established appropriate industrial relations policies and practices which promote harmonious employee relations and minimise the risk of industrial disputes and that it complies with appropriate safety standards, environmental standards and quality standards to a level commensurate with the standards Endeavour Energy expects.

c) If after engagement of a contractor a party to this agreement provides sufficient evidence that a contractor is not providing its employees with correct statutory entitlements, Endeavour Energy will use an independent organisation to audit compliance with these entitlements. If the audit confirms that there is a breach of the statutory entitlements of the Contractor's employees, Endeavour Energy will take appropriate action.

29.5 In the event that Endeavour Energy has determined to outsource or contract out work, affected employees will have access to the full range of options available under all relevant Endeavour Energy policies which apply at the time. These options will include training and / or retraining.

29.6 Any party may refer this process to the Dispute Procedure in this agreement.

29.7 The parties will comply with their obligations under clauses 3 and 4 of this agreement prior to enacting the above. Nothing in this clause diminishes the parties' obligations under clauses 3 and 4.

30. TEMPORARY RECLASSIFICATION

Temporary reclassification of employees will be on the following basis:

SITUATION	REQUIREMENT OR ENTITLEMENT
Access to temporary reclassification	The manager must require the position to be filled and the employee carries out the full duties of the position.
Period of reclassification and payment:	
Minimum rate to be paid	The minimum rate applicable to the higher position
Minimum period	1 day or shift
Maximum period	3 months unless: • The position is advertised to be filled permanently; or • the normal incumbent is on long service leave or is working on a project.
Payment on holidays	Public Holidays: Higher rate is payable Sick, Annual Leave: Only payable where employee is acting for 3 months or more
Gaining competencies in higher position	Payment at a higher level than the base acting position will depend on the relevant competencies acquired by the employees and used in the higher grade position.

31. DISPUTES

31.1 *Dispute Resolution Procedure*

The dispute resolution procedure will be used to deal with all disputes arising out of the employer-employee relationship.

While a dispute is being dealt with under the dispute resolution procedure the status quo is to be maintained; that is the situation that existed immediately prior to the issue that gave rise to the dispute.

While a dispute is being dealt with under the dispute resolution procedure work is to continue as normal. The process will not be accompanied by industrial action.

Disputes should, as far as possible, be resolved at their source and at the lowest possible level.

Disputes should remain in the part of the organisation concerned without interference from employees not involved.

All those involved in dealing with a dispute should adopt an interest-based approach. They should appreciate the interests and points of view of the other parties, approach discussions in good faith, work co-operatively to try and resolve the matter, and arrange and attend meetings without unnecessary delay. Endeavour Energy will, where possible, take the needs of employees into account when making decisions.

31.2 *Local matters*

Tier 1: Resolution of local matters will be sought at their source with the involvement of the following:

- the employee(s) concerned and the union delegate (if requested by the employee(s));
- the supervisor and manager (if required);
- the relevant union(s).

Tier 2: If the issue or dispute is not resolved at the local level, it may be referred to the corporate level with involvement of the following:

- the union organiser(s), relevant local delegate and employee(s) concerned if necessary;
- Executive Manager(s) affected local manager(s), Group General Manager Corporate Services and Manager Employee Relations.

An independent third party facilitator may be engaged to assist in resolving the issue or dispute, if agreed by all affected parties.

Tier 3: if the issue or dispute remains unresolved, it may be referred to the Fair Work Commission for conciliation and/or arbitration, by either Endeavour Energy and/or the relevant union(s) with the rights of the parties to appeal being reserved. If both parties agree, a person other than the Fair Work Commission can be asked to deal with the issue or dispute, as provided for under s. 740 of the Fair Work Act 2009.

31.3 *Corporate-wide issues*

Tier 2: Claims or issues may be raised by either:

- Employee(s);

- Relevant Union(s); or
- Endeavour Energy.

Resolution of the issues raised should involve:

- Relevant member(s) of Executive Management and any other necessary resources, and
- Union Organisers and relevant Delegates to ensure input reflects the organisation or the issues raised.

Tier 3: If the issues remain unresolved the matter may be referred to the Fair Work Commission for conciliation and/or arbitration with the rights of the parties to appeal being reserved. If both parties agree, a person other than the Fair Work Commission can be asked to deal with the issue or dispute, as provided for under s. 740 of the Fair Work Act 2009.

31.4 *Other agreed initiatives*

There will be joint training of union delegates and line managers in dispute resolution.

The parties will work together actively to identify any "grey areas" in the agreement and seek to agree on the correct interpretation before disputes arise. The Manager Employee Relations will collate the various interpretations made by FWA of provisions in the agreement and share these with the unions, together with all workgroup arrangements and other understandings. The Employee Relations team will circulate a regular update providing information on pay and conditions issues.

32. UNION DELEGATES RIGHTS

Subject to the relevant sections of the Fair Work Act 2009, the following applies:

32.1 *Endeavour Energy shall be able to:*

32.1.1 Expect that employees, be they Union Delegates or not, will perform the job in which they are employed.

32.1.2 Be given reasonable notice by Delegates that they intend to carry out their Union duties.

32.1.3 Expect that Union Delegate(s) shall not be able to claim or be paid overtime for attendance at Delegates meetings organised during normal working hours.

32.2 *Union Delegates shall be able to:*

32.2.1 Approach, or be approached by a member for the payment of Union dues or other payments, or to discuss any matter related to this member's employment, during working hours.

32.2.2 After obtaining the permission of the employer, move freely for the purpose of consulting other Delegates during working hours.

32.2.3 Have access to Union officials as required within operational hours and on business premises as required for the purposes of Union business.

32.2.4 Be able to represent employees or request a Union official to represent the employee.

32.2.5 To negotiate with management together with other union delegates on behalf of all or part of the members on any matters in accord with Union policy affecting the employment of members who work in Endeavour Energy.

32.2.6 Call meetings and for members to attend these meetings on the job. Such meetings are to be outside of work time unless prior permission is obtained from management.

32.2.7 Have protection from victimisation and this right to be expressed in prohibiting the employer from seeking to separate the delegate from the union members who elected them without first consulting the union.

32.2.8 Have access to a telephone and computer, including email and to have within their work proximity suitable cupboards and furniture to enable them to keep records, union circulars, receipt books etc. so as to efficiently carry out their union responsibilities.

32.2.9 Attend meetings and training held by the Union in which they hold office without loss of any rights or pay following the approval of Endeavour Energy.

32.2.10 Attendance at these meetings shall not be unreasonably withheld. Leave granted for this purpose may be accessed by the relevant special leave provisions and or relevant training leave provisions.

32.2.11 Attendance at the Fair Work Commission without loss of any rights or pay.

32.2.12 Have all agreements and arrangements negotiated with Endeavour Energy set out in writing and for these agreements and arrangements, including Agreements, to be provided to delegates on request.

32.2.13 Place notices on defined union notice boards.

33. DEDUCTION OF UNION MEMBERSHIP FEES

The union shall provide the employer with a schedule setting out union weekly membership fees payable by members of the union in accordance with the union's rules.

(a) The union shall advise the employer of any change to the amount of weekly membership fees made under its rules. Any variation to the schedule of union weekly membership fees payable shall be provided to the employer at least one month in advance of the variation taking effect.

(b) Subject to the above, the employer shall deduct union weekly membership fees from the pay of any employee who is a member of the union in accordance with the union's rules, provided that the employee has authorised the employer to make such deductions.

(c) Monies so deducted from employees' pay shall be forwarded regularly to the union together with all necessary information to enable the union to reconcile and credit subscriptions to employees' union membership accounts.

(d) Unless other arrangements are agreed to by the employer and the union, all union membership fees shall be deducted on a weekly basis.

(e) Where an employee has already authorised the deduction of union membership fees from his or her pay prior to this clause taking effect, nothing in this clause shall be read as requiring the employee to make a fresh authorisation in order for such deductions to continue.

34. SALARY SACRIFICE

Endeavour Energy employees can at their own discretion salary sacrifice the following subject to ATO guidelines:

(a) Electricity Account

(b) Superannuation

(c) In-house child care

(d) ICARE

(e) In-house Gym Membership

(f) Any other item that meets ATO guidelines

Employees acknowledge that these arrangements are for their own benefit.

35. RELATIONSHIP TO PREVIOUS AGREEMENTS

This Agreement applies to the exclusion of the Electrical Power Industry Award 2010 and replaces and supersedes all other agreements between the parties including but not limited to the Endeavour Energy Enterprise Agreement 2012.

36. LEAVE RESERVED

36.1 *Compliance Allowance*

That the parties agree to review the application of a Compliance Allowance and any potential cost offsets associated with the implementation of any such allowance.

36.2 *Pay Points*

The Parties will, during the first twelve months of this Agreement, work together in order to rationalise the pay points in Appendix A of the 2008 Award. Should there be any disputes in relation to this process such matter(s) will be referred to the Disputes Procedure of the Agreement.

It is a term of this Award that the parties to this Award undertake that for the period of the duration of the Award that they will not pursue any extra claims, except where consistent with this clause.

Appendix A – Common Pay Points

Appendix B - Endeavour Energy Allowances

Allowance Description	Ref Code	Value as at 24th Dec 2013	Value as at 24th Dec 2014	Value as at 24th Dec 2015
Electrical Safety Rules Allowance paid as an All Purpose Allowance in accordance with Clause 10.				
Electrical Safety Rules - 100%	145	$120.00		
Electrical Safety Rules - 80%	146	$96.00		
Electrical Safety Rules - 60%	147	$72.00		
Electricians Licence	148	$32.80		
Paid per kilometre where the employee uses their private vehicle and adjusted IAW ATO Guidelines.				
Casual Car Allowance (Under 1600cc)	O70	$0.63		
Casual Car Allowance (1600 to 2600cc)	O71	$0.74		
Casual Car Allowance (Over 2600cc)	O72	$0.75		
Transfer of HQ – Time paid @ per km	O52	$1.07		
Transfer of HQ – per KMs	O50	$0.63		
Travel on OT – per KMs	O55	$0.63		
Travel Time on OT – Paid @ per time travelled	O56	x1.5/hr		
Start & Finish On Site - EnE Vehicle	O57	$15.96		
Start & Finish On Site - Own Vehicle	O58	$25.08		
Leading Hand - Daily	100	$14.13		
Leading Hand - Weekly	101	$70.67		
Vehicle Inspection	131	$11.91		
Tower Allowance	132	$19.51		
On Call/Stand by Allowances. *(While paid on a regular basis, is an annual allowance).*				
Stand-by (daily x5)	O92	$41.11		
Stand-by (daily x7)	O93	$29.36		
Stand-by 1 in 4	O94	$51.40		
Stand-by 1 in 2	O95	$102.80		
Stand-by Weekly	O96	$205.60		
Shift Allowances paid as per appropriate Workplace Agreement.				
Day Shift (Network Agmnt)	O86	$22.76		
Aft/Night Shift (Network Agmnt)	O87	$45.54		
Night Shift (Network Agmnt)	O88	$50.31		
Day Shift (CIC Agmnt)	170	$21.27		
Aft/Night Shift (CIC Agmnt)	171	$42.51		
Night Shift (CIC Agmnt)	172	$46.96		
Network Switching Allowances. *(As per document "Field Switching Principles dated 5th March 2003).*				
Switching DN1	O97	$19.83		
Switching DN2	O98	$13.26		
Switching DN3	O99	$13.26		
Meal Allowance paid per meal (up to a maximum of 3 meals).Varied as per Take Away/Fast foods CPI				
Meal Allowance	O65	$13.67		
Subsistence Allowance (code 067) total of all 3 paid per day or an agreed negotiated arrangement.				
Subsistence Allowance - Lunch	O67	$20.37		
Subsistence Allowance - Dinner	O67	$33.23		
Subsistence Allowance - Overnight Stay	O67	$35.38		
Note: Above varied in line with Domestic Holiday Travel & Accommodation sub-group of the CPI				

Appendix B - Endeavour Energy Allowances Cont..

Allowance Description	Ref Code	Value as at 24th Dec 2013	Value as at 24th Dec 2014	Value as at 24th Dec 2015
Bonus Incentive Allowances paid as per appropriate Workplace Agreement.				
Streetlight Bonus Scheme Incentive	113	$4.04		
Streetlight Bonus Scheme Incentive	114	$10.07		
Field Officers Bonus	116	$6.77		
Field Officers Bonus	117	$16.26		
First Aid Allowance paid per week for authorised employees appropriately qualified. Endeavour Energy will pay for First Aid training conducted during work hours for nominated First Aid Officers. *(This allowance, while paid on a regular basis, is an annual allowance).*				
General First Aid Allowance	128	$21.57		
Aerial Line/Aircraft Allowance, paid per day whilst performing line patrols by helicopter.				
Aerial Line/Aircraft Allowance	130	$21.65		
-				
Late Finishing Shift Allowance, paid for each late finishing shift in Frontline Services *(This allowance, while paid on a regular basis, is an annual allowance).*				
Late Finishing Shift Allowance		$27.74		
Late Lunch Break-paid @ until taken	038	x1.5/hr		
No Lunch Break Taken-paid @ until shift end	039	X2.0/hr		
No Meal Break after 4hrs OT	060	20 mins @ 2.0		
No Meal Break after 1.5hrs OT	061	20 mins @ 1.5		

Electrician's Licence Allowance (Ref Code 148)

An employee who holds a current Qualified Supervisors Certificate / Electrical Licence or its equivalent and the position requires the incumbent to hold the above qualification to fulfil their duties and the incumbent in the position has received it in accordance with past practice will be paid as per the above table. This allowance is paid as an all purpose allowance.

NOTE: This clause is to be amended to relect the outcome/resolution of the current dispute around this issue (FWC Matter number C2014/1137).

Network Switching Allowance (Ref Codes 097, 098 & 099.)

The activity of operating or switching the network (not including control room) is undertaken by a number of roles within Endeavour Energy. Regional or Work Party Switching is the term used to describe switching undertaken by work crews, where the switching is an addition to their ordinary role and is for their worksite only.

Where Regional staff undertake the role of regional/work party switching an allowance will be paid.

Where staff are receiving the allowance, requests to undertake switching within an employees ability and competence shall be carried out in line with Field switching principles. As per document Field Switching principles dated 5 March 2003.

Appendix C - Benefits of Employees Employed Prior to 27 July 1996

1. *Experience / Maturing Allowance*

1.1 Quantum

ELIGIBILITY	MULTIPLIER
10 years but less than 20 years service	1 week's pay per completed year of service; OR
20 years or more service	2 week's pay per completed year of service

1.2 Eligibility

Endeavour Energy must pay Experience/Maturing Allowance to employees in the following circumstances:

BASIS OF ELIGIBILITY	▪ ***Retirement*** - this is where the employee is aged 55 years or older. ▪ ***Retirement Ill Health*** - this is where the employee is medically unable to perform the work required of their classification. ▪ ***Death*** - this is where the employee dies whilst in the employment of Endeavour Energy. ▪ ***Redundancy*** - this is where the employee's position is made redundant or under an approved 'bona fide' redundancy scheme.

1.3 Service Recognised

SERVICE RECOGNISED	The period of continuous employment with Endeavour Energy (including Integral Energy, Illawarra Electricity and Prospect Electricity) The period of employment with the County Councils which were amalgamated into Prospect County Council and Illawarra County Council on 1 January 1980 is also included. The period of employment shall not go further back than the date of formation of Prospect County Council (1 January 1957) or Illawarra County Council (1 March 1958)

2. *Agreement Special Leave*

ELIGIBILITY	QUANTUM
Employees of the former Illawarra Electricity who were entitled to this leave immediately prior to 27 July 1996 only	4 days per year and the employee works a 36 hour week

3. Sick Leave (pre 15 February 1993)

ENTITLEMENT	ELIGIBILITY TO PAYMENT
The employees preserved untaken sick leave as at 15 February 1993	• Resignation • Retirement • Death • Redundancy • On request and approval by the Group General Manager Corporate Services. **Note:** *An employee is <u>not</u> eligible to payment where he or she is dismissed for misconduct*

Appendix D : Specific Classifications/Groups Employment Agreement Schedules:

1. CIC Shiftwork Workplace Agreement
2. E S O Customer Operation Group Workplace Arrangement
3. Executive Assistant to General Manager WPA
4. Field Officers Incentive Workplace Arrangement
5. Endeavour Energy Manager/Specialists Workplace Arrangement
6. IE Supervisors Workplace Arrangement
7. Endeavour Energy Network Shift work Workplace Arrangement
8. Network Officers' Workplace Arrangement
9. Network Shiftwork Workplace Arrangement
10. Integral Street Lighting Agreement

Mains Maintenance Instruction

Clearances to be maintained between network assets and vegetation

IMPORTANT DISCLAIMER

As the information contained in this publication is subject to change from time to time, Endeavour Energy gives no warranty that the information is correct or complete or is a definitive statement of procedures. Endeavour Energy reserves the right to vary the content of this publication as and when required. You should make independent inquiries to satisfy yourself as to correctness and currency of the content. Endeavour Energy expressly disclaims all and any liability to any persons whatsoever in respect of anything done or not done by any such person in reliance, whether in whole or in part, on this document.

Document no. MMI 0013

Amendment no. 9

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Endeavour Energy

MAINS MAINTENANCE INSTRUCTION

NETWORK ENGINEERING	Document no. Amendment no. Approved by Approval date	MMI 0013 9 MNEB _ _ _ _ _ _ _ _ 03 February 2012

MMI 0013 Clearances to be maintained between network assets and vegetation

Contents

1.0 PURPOSE

To set out in detail the clearances that shall be maintained between network assets (overhead lines, structures, wires and other electrical apparatus) and vegetation.

2.0 SCOPE

This instruction provides details for both the vegetation trimming clearances and ground line vegetation management to be achieved relating to all network assets, such as substations, poles, structures, streetlight lanterns, aerial pilot cables, access tracks and other electrical apparatus, that form part of Endeavour Energy's network.

This instruction also covers all privately-owned low voltage overhead lines. It does **not** include high voltage customer lines, which are managed by the Customer and Process Development Manager of System Operations (refer section 5.0).

This instruction includes the clearances required at all voltage levels for bare or covered conductor lines, aerial bundled cable (ABC) and covered conductor thick (CCT) lines, streetlight lanterns, aerial pilot cables, and overhead service lines.

This document does not apply to Broadband communication cables (BCC) or to streetlight lanterns in URD areas (refer to MCI 0002, clause 5.11.2 for clearances to BCC cables). The responsibility for maintaining clearances around streetlight lanterns in areas where electricity is supplied by underground mains lies with the local council.

Trimming of new vegetation planted by residents after the public lighting network has been energised in new overhead developments is the responsibility of the public lighting customer.

3.0 REFERENCES

- Company Policy 9.1.3 - Authorisations
- Company Policy 9.9.1 - Network Asset Maintenance
- Company Procedure GSY 0031 - Operating or observing plant near overhead electrical apparatus
- ENA National Electricity Network Safety Code (Doc 01-2008)
- Network Management Plan 2009-2014
- Electrical Safety Rules
- *Catchment Management Authorities Act* 2003
- *Electricity Supply Act* 1995
- Electricity Supply (Safety and Network Management) Regulation 2002
- Electricity (Tree Preservation) Regulation 1995
- *Environmental Planning and Assessment Act* 1979
- *Local Government Act* 1993
- *Native Vegetation Act* 2003 and Regulation 2005
- *National Parks and Wildlife Service Act* 1974
- *Noxious Weeds Act* 1993 and Regulation 2003
- *Occupational Health and Safety Act* 2000
- Occupational Health and Safety Regulation 2001
- *Pesticides Act* 1999 and Regulation 2009
- Planning for Bushfire Protection - RFS Guidelines
- *Protection of the Environment Operations Act* 1997
- *Rural Fires Act* 1997
- *Rural Fires and Environmental Assessment Legislation Amendment Act* 2002 (Amendment Act)
- RTA Manual, Traffic Control at Worksites

- State Environmental Planning Polices (SEPPs) 14,19,26,44,46.56.58c and 71
- *Threatened Species Conservation Act* 1995
- *Waste Management and Minimisation Act* 1995 *Environment Protection & Conservation of Biodiversity Act* 1999 (Commonwealth)
- *Heritage Act* 1977
- NSW WorkCover Documentation for the Production of Hazard Assessment Forms
- WorkCover NSW Code of practice - Work near overhead power lines - 2006
- Environmental Management Standard EMS 0004 - Vegetation management
- Mains Construction Instruction MCI 0002 - Attachment of Broadband communication cables to Integral Energy poles
- Mains Design Instruction MDI 0031 - Overhead distribution: Design standards manual.
- Mains Maintenance Instruction MMI 0021 - Guide to the installation and maintenance of Endeavour Energy mains on private property
- MMI 0031 - Sharing of poles
  Note: This instruction applies to Endeavour Energy and Ausgrid poles only.)
- Substation Maintenance Instruction SMI 112 - Distribution data entry - maintenance and defect prioritisation
- AS 1742.3:2002 - Traffic Control Devices for Works on Roads
- AS 3560.1:2000 Electric cables - Cross linked polyethylene insulated - Aerial bundled
- AS 3599.1:2000 Electric cables - Aerial bundled - Polymeric insulated, Metallic Screened.
- AS 3599.21999 Electric cables - Aerial bundled - Polymeric insulated, Non-Metallic Screened
- AS 3675:2002 - Conductors - covered overhead
- AS 4373:2007 - Pruning of Amenity Trees
- Code of Practice: Amenity Tree Industry, 1998, issued by NSW WorkCover
- ENA National Electricity Network Operator and Service Provider Safety Assurance Guidelines (NENS 02-2001)
- ENA National Guidelines for Safe Access to Electrical and Mechanical Apparatus (NENS 03-2006)
- ENA National Guidelines for Safe Approach Distances to Electrical Apparatus (NENS 04-2006)
- ENA National Fall Protection Guidelines For The Electricity Industry (NENS 05-2006)
- EC/ISSC Guidelines (remain in force unless an Endeavour Energy guideline or procedure exists)
- ISSC 3, Guide to Vegetation Management near Powerlines - December 2005
- ISSC 20, Guidelines for the management of electricity easements - November 2001
- Interim Guide for Operating Cranes and Plant in Proximity to Overhead Power Lines – EA of NSW, Sept 2001
- Branch Form FAE 3156 - Vegetation management: request to vary standard clearances form

4.0 DEFINITIONS AND ABBREVIATIONS

ac	alternating current
aerial bundled cable (ABC)	Two (2) or more cores twisted together into a single bundled cable assembly. Two (2) types of aerial bundled cable are used: • Low voltage aerial bundled cable **(LVABC)**, a cable that meets the requirements of AS 3560. • High voltage aerial bundled cable **(HVABC)**, a cable that meets the requirements of AS 3599 Part 1 or AS 3599 Part 2.
accredited	A person trained in vegetation management near power lines
asset protection zone (APZ)	An area of land, adjacent to a network asset (for example, substation), where the bushfire fuel load is managed by ground line techniques, to significantly minimise the impacts of fire on that asset. An APZ will reduce the likelihood of damage to the asset and protect firefighters and staff during bushfires.
annual pre-summer bushfire inspection	The identification and rectification of powerline defects on an annual basis prior to the start of the declared bushfire season. Maps prepared by local councils and certified by the Commissioner for the Rural Fire Service shall be used to identify all assets to be patrolled as part of this program.
authorisations	A person with technical knowledge or sufficient experience who has been approved and authorised in writing by the Company to perform the function requiring authorisation as described in Schedule 1 of Company Policy 9.1.3. This definition is relevant to the terms *authorisation*, *authorise* and *authorised person*.
bushfire prone areas	Bushfire prone areas are defined by maps prepared by local councils (in accordance with the requirements of the *Rural Fires and Environmental Assessment Legislation Amendment Act*, 2002). Maps prepared by local councils are reviewed by the Rural Fire Service prior to being certified by the Commissioner for the Rural Fire Service. Endeavour Energy uses these certified maps for the determination of bushfire prone areas within its network franchise area.
contract	An agreement between Endeavour Energy and the contractor.
contractor	The person bound to execute the work under the contract; this includes Endeavour Energy vegetation management staff.
covered conductor thick (CCT)	A conductor around which is applied a specified thickness of insulating material. AS 3675 specifies two (2) types of covered conductor: CCT is where the nominal covering thickness is dependent upon the working voltage.
dead, dying, dangerous and visually damaged vegetation (including limbs/trees)	Any vegetation that has the potential to adversely impact on the reliability of the network under normal or adverse weather conditions. This includes vegetation that is dead, dying, dangerous and visually damaged (including vegetation that has sustained damage from external agencies, bushfires and/or has inherent structural faults), or is potentially unsafe for any reason.
Ellipse	Endeavour Energy's database of all network assets

groundline vegetation management	Management of vegetation adjacent to network assets in order to maintain safety clearances, maintenance access and to provide hazard reduction by reducing fuel loads so as to protect built assets and reduce the likelihood of bushfires.
hazard trees	Trees that are outside the minimum trimming clearances, including the allowance for bushfire prone areas, that could come into contact with an electric power line having regard to foreseeable local conditions.
hazard reduction	The process of providing bushfire fuel reduction, using groundline techniques, to protect network assets (for example, power lines), and community assets, plus reduce the likelihood of bushfires being initiated by network assets.
inspection space	Space, additional to the minimum trimming clearing space, in which further clearing may be required where, in the opinion of the delegated officer of the electricity distributor, a part of a tree constitutes a serious hazard to bare or insulated aerial conductors or other electrical equipment under extreme storm or wind conditions.
insulated conductor	A conductor that is completely covered with specified insulation material of adequate thickness for the voltage at which the conductor is operated. The insulating material and the thickness are nominated in the appropriate standard or specification for the operating voltage.
live	Means energised or subject to hazardous induced or capacitive voltages.
minimum safety clearance	The clearance around network assets, such as substations, poles, structures, access tracks and other electrical apparatus, that shall be kept clear of any vegetation.
minimum trimming clearance	The clearance around network assets such as substations, poles, structures, access tracks and other electrical apparatus, where the contractor shall clear vegetation to a minimum. This includes an average annual regrowth allowance.
Network assets	All components of the Endeavour Energy network, such as substations, poles (either wood, concrete or steel), conductors (either bare or covered), structures, such as lattice steel towers or support structures in switchyards, switchyard fencing, transformers and associated switchgear, insulators and crossarms, brackets and associated mounting hardware, streetlight lanterns, access tracks, and the like. Buildings that form part of switchyards, and covering structures such as padmount and switchgear cubicles are also included.
non-urban	Areas outside urban areas.
protected area	a) Any area within a national park or nature reserve within the meaning of the *National Parks and Wildlife Service Act*, 1974; or, b) land that is reserved or zoned for environmental protection purposes under the *Environmental Planning and Assessment Act*, 1979; or, c) a public reserve within the meaning of the *Local Government Act,* 1993.

protected land/vulnerable land

(under the *Native Vegetation Act* 2003 and Regulation 2005)

a) land identified on a map, a copy of which has been deposited in the office of a district soil conservationist in accordance with Section 21B; or,

b) any land (not being land referred to in paragraph (a)) that is situated within, or within 20 metres of, the bed or bank of any river or lake, which (with reference to the *Water Act* 1912) was listed in the Gazettes referred to in the Sixth Schedule, but does not include:

- any State Forest, national forest, timber reserve or flora reserve, within the meaning of the *Forestry Ac*t 1916; or,
- any National Park, historic site, nature reserve or state game reserve, within the meaning of the *National Parks and Wildlife Act*, 1974.

protected tree

Protected tree means a tree that is:

- the subject of or within the area, as defined in section 48 of the *Electricity Supply Act*, 1995 (NSW);
- that is subject of an Interim Heritage Order, is listed on the State Heritage Register; is subject of an order in force under section 136 of the *Heritage Act*, 1977;
- is subject of an Interim Protection Order under the *National Parks & Wildlife Service Act*, 1974;
- is listed individually or as part of a place or area listed on a Local Government Authority's Local Environmental Plan or a Regional Environmental Plan made under the *Environmental Planning & Assessment Act*, 1979; or,
- a protection conferred by any similar law.

Size and age criteria differ between local government authorities, and these should be checked in the first instance. It also means a tree within a protected area.

Restricted Tree Trimming Agreement

An agreement, on a case-by-case basis, between Endeavour Energy and the contractor where for environmental or other valid reasons, minimum tree trimming clearances cannot be maintained. Form FAE 3156 is used to register individual agreements.

RFS Rural Fire Service

shall A statement is mandatory

should A statement is advisory

significant tree	Any tree classified by the National Trust of Australia (NSW) as significant, recognised by a government authority or by a recognised community group, or listed by a local government authority on a Significant Tree Register (STR). Significant trees may be individually heritage listed, or form part of a larger place listed as a heritage item, area or heritage conservation area (for instance street trees within a conservation area). Significance is generally in relation to one or more historic, aesthetic, scientific (for example, botanical, ecological or horticultural value) or social value. Heritage significance in NSW is defined in reference to the NSW State Heritage Register criteria along with other criteria.
tree	A tree taller than three (3) metres, or having a canopy of more than three (3) metres in maximum diameter, or having a trunk with a circumference at a height of one (1) metre from the ground of more than 0.3 metres. Trees can include shrubs and other plants for the purposes of the *Electricity Supply Act*, 1995 (NSW).
urban	A built-up area, as designated by street lighting or subdivision into smaller allotments, or other areas agreed to by the network operator and the local council.
URD	Underground residential distribution - a distribution system where the conductors of the electrical distribution network are placed underground.
vegetation	Plant life in general or specifically the flora of a specific region.
vegetation clearing	Refers to both the trimming of vegetation in proximity to network assets and the ground line vegetation management to ensure public safety, the security and reliability of the network assets, and to provide suitable access for essential maintenance purposes.
voltage detector	Voltage sensor device, non-contact, typically *Wattmaster Volt Stick,* with sound and visual indication.
water crossing sign	A notice located adjacent to bodies of water, warning of the presence of overhead or underground electricity power lines crossing the body of water.

5.0 ACTIONS

Vegetation clearing near overhead lines and structures is carried out to ensure public safety, the security and reliability of the network, and to provide suitable access for essential maintenance purposes.

Falling tree limbs can cause overhead power lines to break or become dislodged and fall to the ground. Children can climb trees and come into contact with live overhead wires.

Bushfires can result from tree branches clashing with overhead power lines, particularly where high fuel loads exist beneath and adjacent to network assets.

The **clearances between network assets and vegetation** shall comply with the requirements of this instruction.

Vegetation defects shall be recorded and rectified as below;

Any vegetation that comes within these clearances detailed in this instruction shall be considered to be a defect and shall be recorded as such in Endeavour Energy's Ellipse database.

On high voltage customer lines, the customer and Process Development Manager of System Operations writes annually to every high voltage customer advising them of their legal obligation to confirm to Endeavour Energy in writing that all defects on their high voltage network that could initiate a bushfire have been identified and rectified by the start of the declared bushfire season.

The Customer and Process Development Manager of System Operations also advises that if this written confirmation is not received, Endeavour Energy may be obliged to take further action under clause 5 of the Electricity Supply (Safety and Network Management) Regulation 2008.

Defects found on privately-owned low voltage overhead lines including services on a customer's property are to be notified to the customer in writing within two (2) weeks.

Bushfire defects shall be cleared immediately within any current declared bushfire season or before the commencement of any subsequent bushfire season. All other defects that are not contained within bushfire maps shall be cleared within 12 months (refer to SMI 112, section 5.2 for defect priorities).

5.1 Authorisation, accreditation and training

The clearing of vegetation near network assets shall be carried out only by persons authorised in accordance with Company Policy 9.1.3 and accredited and trained to do so by Endeavour Energy. All vegetation clearing personnel shall receive annual training, re-assessment and certification.

Persons operating plant near live overhead electrical apparatus or within the normal confines of electrical substations for the purpose of vegetation management shall be authorised in accordance with Company Procedure GSY 0031 and must not approach closer to live apparatus than the distances specified in the tables below;

Table 1: Minimum safe approach distances of plant and loads - to live electrical apparatus operated by authorised and non-authorised persons

Nominal voltage	**Minimum safe approach distance**	
	Authorised person - with observer	***Non-authorised person***
Up to 1,000V	500mm	3 metres
Above 1,000V but not exceeding 11,000V	700mm	3 metres
Above 11,000V but not exceeding 66 000V	1000mm	3 metres
Above 66,000V but not exceeding 132,000V	1500mm	3 metres

Table 2: Minimum approach distances of employees and hand held tools to live electrical apparatus

Nominal voltage	Minimum approach distances for employees and hand held tools (refer notes below)	
A	Electrically qualified employees B	Non-electrically qualified employees C
Up to 1,000V	500mm	1000mm
Above 1,000V but not exceeding 11,000V	700mm	1200mm
Above 11,000V but not exceeding 66 000V	1000mm	1500mm
Above 66,000V but not exceeding 132,000V	1500mm	2000mm

Notes to table 2:

1. Electrical apparatus that is covered with temporary insulation must be regarded as live unless the temporary insulation has been confirmed as being approved insulation by Endeavour Energy (refer to section 5.11 of Company Procedure GSY 0031).
2. Where two (2) or more different voltages are located on the same worksite, the minimum safe approach distance to all voltages must be maintained at all times.
3. During work near live overhead electrical conductors that are supported on poles or other structures, all distances given in Tables 1 and 2 must be increased horizontally by the distance the conductor may swing at the point of work.
4. Where the minimum approach distance provided in this section cannot be maintained, or the provisions of Company Procedure GSY 0031 cannot be complied with, the electrical apparatus shall be de-energised by agreement with Endeavour Energy to allow safe operation of the plant. Work must not proceed unless the electrical apparatus has been de-energised and made safe.

The clearing shall be carried out in accordance with the requirements of Endeavour Energy's vegetation management contract and associated instructions and procedures, to the clearances specified in this instruction.

5.1.1 Safety precautions

Before commencing any vegetation activities involving metal, concrete, steel or wood poles, such as groundline clearing, the contractor shall carry out a visual overhead inspection of the pole followed by a voltage leakage check (as described in clauses 5.1.2, 5.1.3, 5.1.4 and 5.1.5) to check for any hazardous voltages on the pole surface.

Note: A voltage check of the pole is not required when working with insulated tools and/or working from an insulated EWP.

5.1.2 Visual overhead inspection

Before any vegetation clearing takes place around a power pole, the contractor shall carry out a visual inspection of the above ground portion of the pole for any serious defects that may present a safety hazard.

Defects may include the condition of all high voltage conductors and fittings on the pole, lightning damage and vehicle impact damage.

If, for example, a high voltage conductor is dislodged from an insulator, or if any component is so loose that it could fall during the vegetation clearing, the area around the pole is to be cordoned off and the pole reported to the local Depot Operations Manager for immediate action.

In an **emergency,** call the **Network Controller, System Operations Branch** on **131 003**.

5.1.3 Multimeter voltage check

The multimeter used to perform the voltage check shall have a function to measure both LOW and HIGH impedance (proximity test), for example, *Fluke 117*.

Prior to and after checking any pole for voltage leakage, the multimeter must be checked for integrity. This test shall be performed in accordance with the manufacturer's instructions by either:

- using a known voltage point, such as a power point or another known live circuit; or,
- as this meter is sensitive to static electricity, it can be checked for functionality by vigorously rubbing the meter on a cotton shirt sleeve.

When used as a proximity tester (*Volt Alert* setting), the multimeter will indicate the presence of an electrical field with a light and an audible buzz.

A spare 9v alkaline battery must be carried by the pole inspector as a back-up for the meter as replacement of the battery may be required at any time.

5.1.4 Voltage leakage check

The inspector must be suitably attired with low voltage insulating gloves worn on both hands to perform the voltage leakage test and to prove the pole safe to touch before direct contact is made with the pole and attachments.

The integrity of the meter must be checked in accordance with clause 5.1.3. After each pole check, the functionality of the device must be re-checked in accordance with the manufacturer's instructions.

5.1.5 Test procedure

Approach the pole and visually inspect for burnt grass, electrical tracking on pole, or any other indication of an electrical failure.

Using a high impedance (Z) capacitively coupled measuring device, such as a *Fluke 117* meter on the ***Volt Alert*** setting and on ***Lo*** RANGE, stand approx one (1) metre from the pole and extend at elbow height, moving towards the pole, and touch the surface.

- Repeat for all metal (conductive) surfaces.
- A *positive* indication (light and buzz sound) must be treated with caution and the voltage level confirmed using the *Fluke 117* meter set to the *AUTO-V LoZ* setting, as described in the voltage test below.

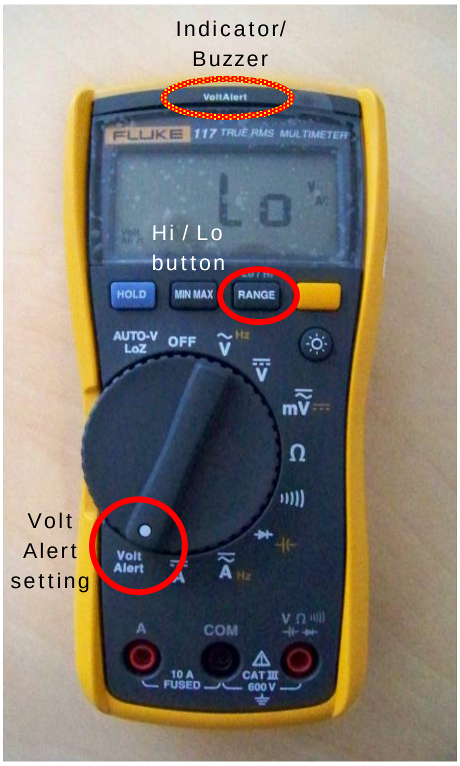


Figure 1 (right): Multimeter voltage tester

Voltage test

Upon receiving a positive high impedance indication, perform a voltage test measurement using a low impedance resistively coupled device, such as the *Fluke 117* set to AUTO-V LoZ.

Probes are to be connected between an earth/ground stake or similar driven into the ground a minimum of approximately one (1) metre from the pole and the pole surface. Where available, the test is to be performed at a metallic fitting, such as a pole disk indicator or pole number aluminium plate tag (see pictures below).

If the voltage on the *AUTO-V LoZ* setting is less than 5V, no further action is required and work may proceed on the pole.

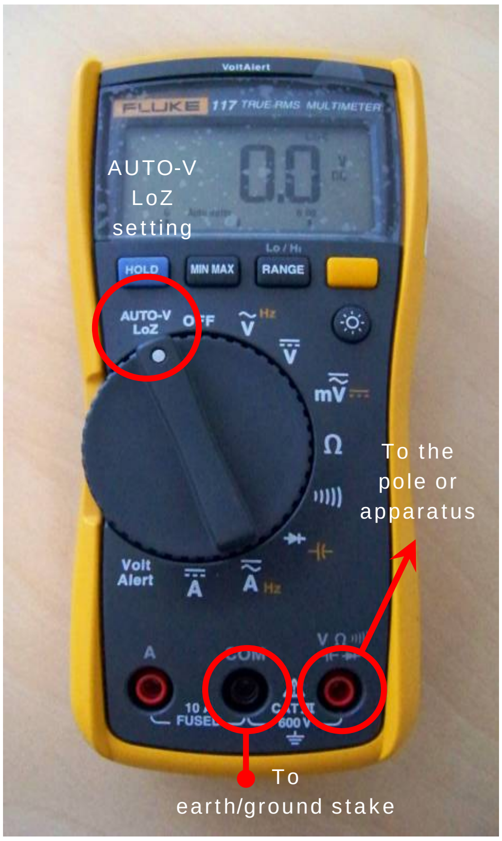


Figure 2: Settings for voltage test.

Figure 3: Pole number, disk indicator and aluminium pole number plate

If the voltage on *AUTO-V LoZ* is equal to or greater than 5V, guard the pole and immediately report the problem for attention by qualified staff.

If a hazardous condition and/or an unsafe situation, such as a live or failed steel pole, is found, the above test should be repeated to validate the initial result.

If a hazardous condition and/or an unsafe situation is confirmed it must be reported immediately to the local Depot Operations Manager for immediate action. In an **emergency**, call the **Network Controller, Systems Operations Branch, on 131 003**.

In addition, the following actions shall be taken:

The persons shall:

- **cordon off the area where the hazardous conditions exists;**
- **prevent the public from entering the area;**
- **notify the supervisor that a hazardous condition has been found;**
- **stand by until emergency employees have arrived and proceed to measure the voltage reading with a digital voltmeter; and,**
- **not proceed with any further work on the pole until advised that it is safe by an authorised person, and a further voltage leakage check confirms that the pole is safe.**

5.1.6 Minimum safety clearances

The minimum safety clearances around network assets shall be in accordance with the requirements of Table 3, below.

All dead, dying, dangerous, visually damaged vegetation or trees that can be climbed, or that reside within or above the designated minimum safety or trimming clearances, shall be removed.

If vegetation is within minimum safety clearances, the entire tree shall be considered live. Techniques employing insulated tools, live line or an access authority, shall be employed to remove the offending vegetation.

Hazard trees that could come into contact with powerlines shall be removed, having regard to foreseeable local conditions.

This dead and dangerous tree must be removed

Hazard tree outside minimum trimming clearances that could impact the powerline should be trimmed in accordance with clause 5.1.7

Trees within minimum safety and trimming clearance shall be trimmed.

Trees and vines shall be trimmed and removed from LV service lines

Table 3: Minimum safety clearances

Minimum safety clearance (metres)					
Voltage of overhead line	**Type of overhead line**	**Spans up to 50 metres**	**Spans from 50-100m**	**Spans from 100-200m**	**Spans from 200-300m**
Up to and including 1,000 Volts	Bare low voltage and bare S/L wires	1.0	1.0	2.5	4.0
	LVABC	0.5	0.5	1.0	N/A
	XLPE and PVC covered S/L wires and service lines, pilot cables	0.5	0.5	2.5	4.0
1,000 Volts up to and including 22,000 Volts	Bare overhead lines	2.0	2.5	3.5	5.0
	HVABC	0.5	0.5	1.0	N/A
	CCT in urban areas	0.5	0.5	1.0	N/A
	CCT in non urban areas	1.0	2.0	2.5	N/A
33,000 Volts up to and including 66,000 Volts	Bare overhead lines	2.0	3.0	4.0	6.0
132,000 Volts	Bare overhead lines	3.0	4.0	5.0	6.5

Notes to Table 3:

1. In designated bushfire prone areas, add 0.5 metres to the above clearances for all bare conductors.

2. The clearances within this table are for tree trimming, **NOT** safe approach distances for working. Minimum safe approach distances for plant and equipment near overhead electrical apparatus are fully described in Company Procedure GSY 0031.

3. Existing LVABC, low voltage XLPE insulated cables, large limbs or tree trunks that are not climbable are permitted within the minimum safety clearances provided there is no evidence of direct physical contact between the mains and the trunk or limb. The trunk or limb shall be removed if there is any evidence of sheath damage, cable contact or the opportunity to climb the tree.

Tree in physical contact with LVABC shall be removed

4. For spans greater than 300 metres, refer to Endeavour Energy's specific construction types and design criteria.

5. In specific circumstances, Endeavour Energy may increase the minimum safety clearance required due to other network constraints, for example, high reliability requirements for hospitals and the like.

5.1.7 Minimum trimming clearances

The contractor shall, as a minimum, ensure that all vegetation is trimmed back to the distances shown in Table 4 below. These clearances include an average annual regrowth factor. However, trimming to greater than these distances, or increased frequency of trimming, may be required to ensure that vegetation does not enter into the safety clearance zone prior to the next programmed trimming cycle.

All dead, dying, dangerous or visually damaged vegetation, including limbs/trees, that resides within or above the designated minimum safety or trimming clearances, shall be removed. Hazard trees shall be removed that could come into contact with powerlines having regard to foreseeable local conditions.

Table 4: Minimum trimming clearances

Minimum trimming clearance in metres					
Voltage of overhead line	**Type of overhead line**	**Spans up to 50 metres**	**Spans from 50-100m**	**Spans from 100-200m**	**Spans from 200-300m**
Up to and including 1,000 Volts	Bare low voltage and bare S/L wires	2.0	2.0	3.5	5.0
	LVABC	0.5	0.5	1.0	N/A
	XLPE and PVC covered S/L wires and service lines, pilot cables	0.5	0.5	N/A	N/A
1,000 Volts up to and including 22,000 Volts	Bare overhead lines	3.0	3.5	4.5	6.0
	HVABC	0.5	0.5	1.0	N/A
	CCT in urban areas	0.5	0.5	1.0	N/A
	CCT in non urban areas	1.0	2.0	2.5	N/A
33,000 Volts up to and including 66,000 Volts	Bare overhead lines	3.0	4.0	5.0	7.0
132,000 Volts	Bare overhead lines	4.0	5.0	6.0	7.5

Notes to Table 4:

1. In designated bushfire prone areas, add 0.5 metres to the above clearances for all overhead lines, except low voltage insulated service lines.

2. In situations where minimum trimming clearances will impact upon the health or amenity of protected areas, protected lands and/or protected significant/heritage trees, a submission to the Manager Network Engineering may be made in order to temporarily reduce the trimming clearance until remedial actions can be taken that will restore minimum trimming clearances. No minimum trimming clearance shall be reduced until approved by the Manager Network Engineering. Any situation approved by the Manager Network Engineering shall be completed within 12 months and audited for completion by the Manager Network Engineering.

3. Submission of form FAE 3156 is required to initiate this process.
4. Existing LVABC, low voltage XLPE insulated cables, large limbs or tree trunks that are not climbable are permitted within the minimum safety clearances provided there is no evidence of direct physical contact between the mains and the trunk or limb.
5. The trunk or limb shall be removed if there is any evidence of sheath damage or cable contact or the opportunity to climb the tree.
6. For spans greater than 300 metres, refer to Endeavour Energy's specific construction and design criteria.
7. In specific circumstances, Endeavour Energy may increase the minimum trimming clearance required due to other network constraints, for example, high reliability requirements for hospitals and the like.
8. The minimum clearance envelope required above the 11kV and LV conductors is four (4) metres.

Left: Example of significant trees. The temporary clearance process followed by action to restore minimum clearances is appropriate (see note 2).

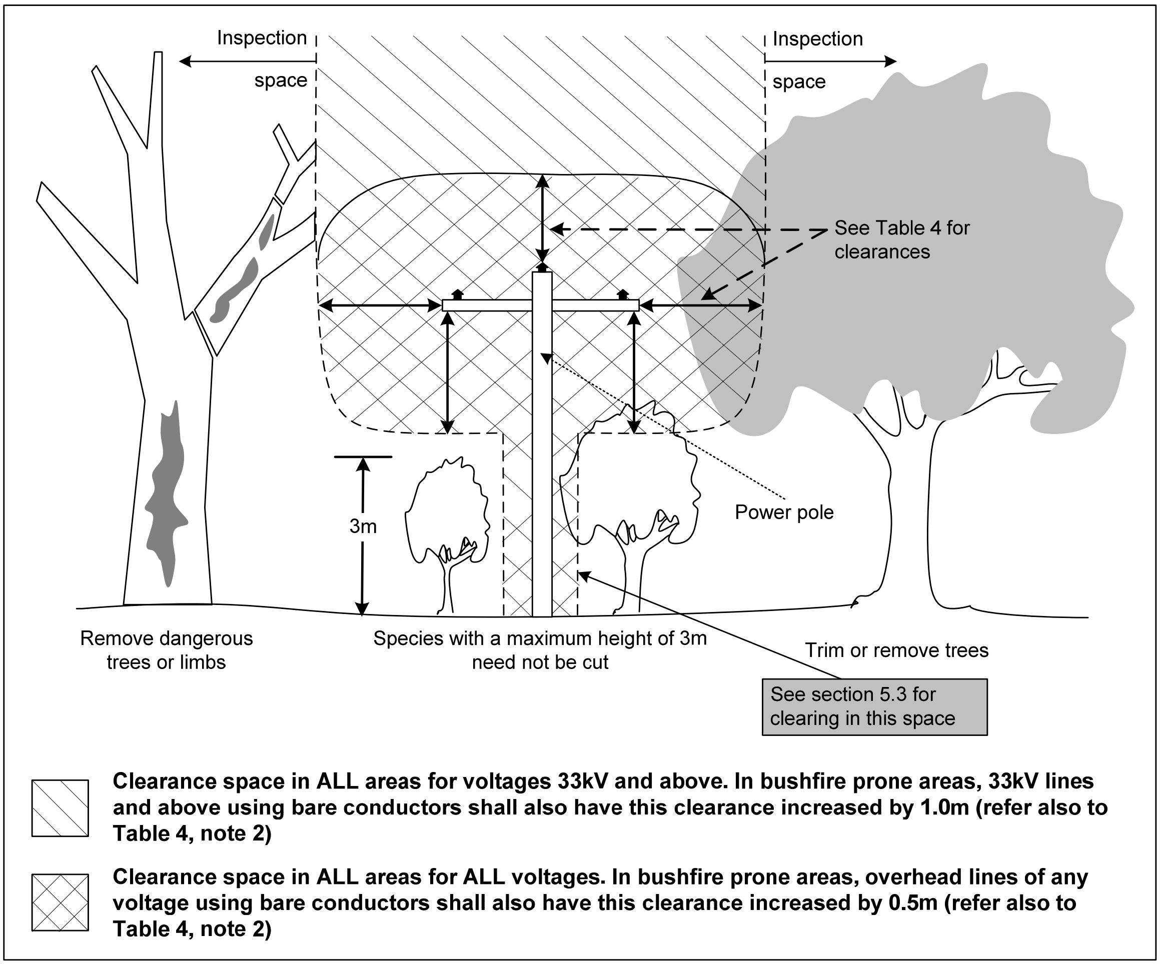


Figure 4: Illustration of tree trimming clearances

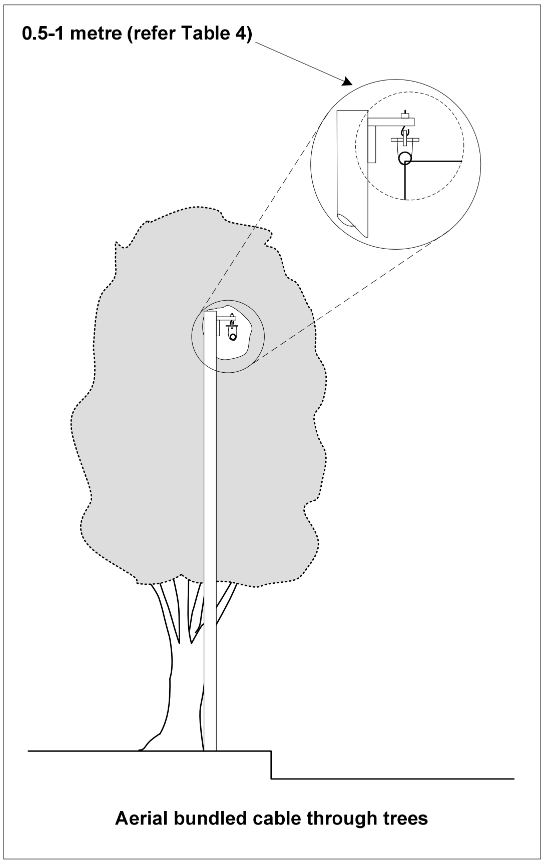


Figure 5: Trimming clearance around LVABC and HVABC

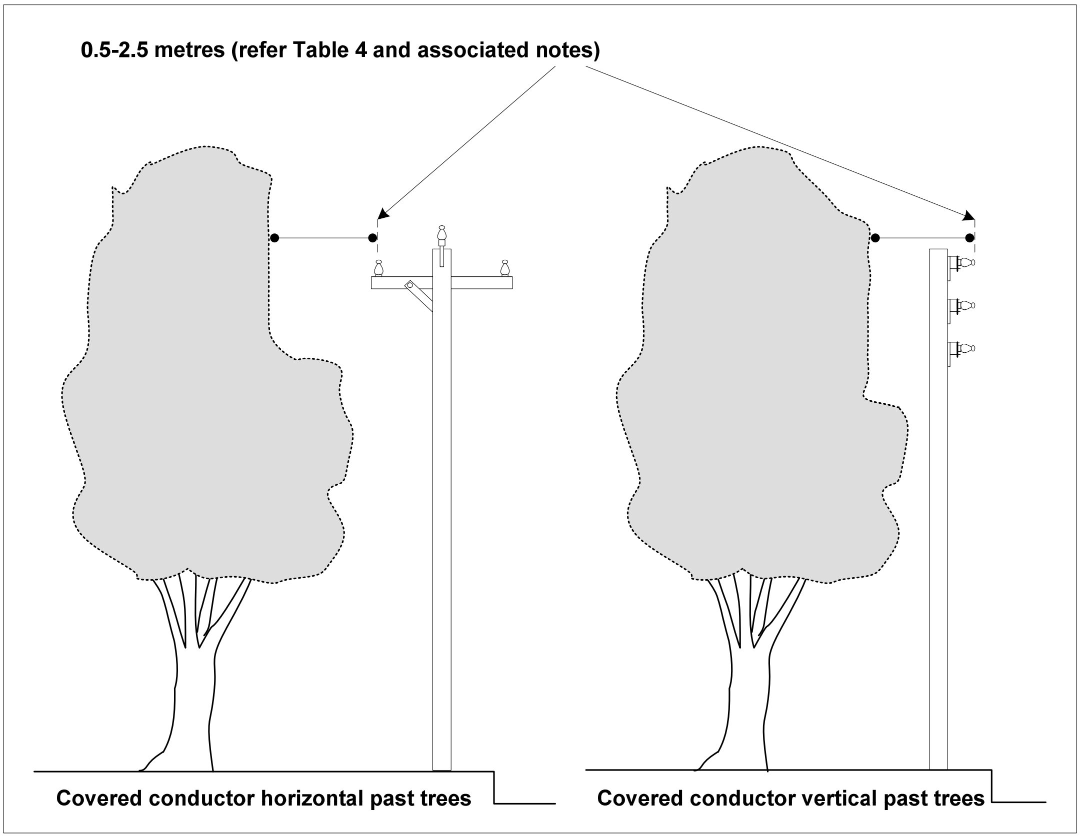


Figure 6: Trimming clearance around CCT

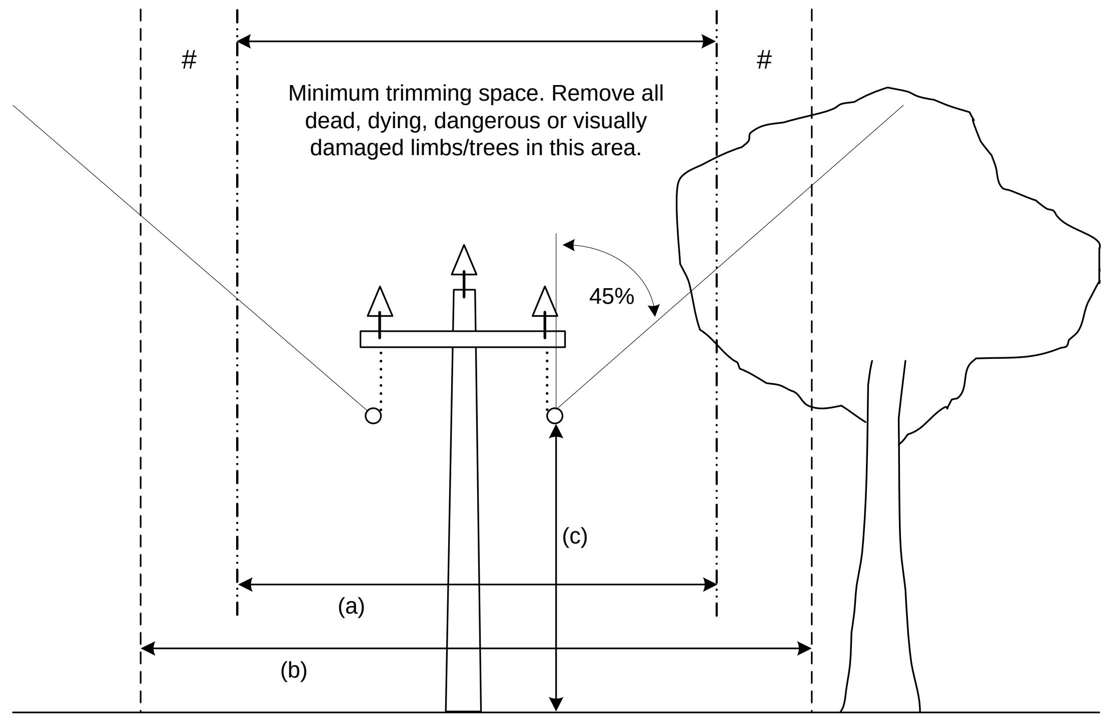
Note: In Figures 5 and 6, a clearing space of two (2) metres diameter is required around poles for voltages of 22kV and below for access and maintenance purposes (see clause 5.3.1 and Figure 11). A five (5) metre clearing space shall be established around poles and maintained in non-urban bushfire prone areas.

5.1.8 Vegetation outside the minimum trimming space

For all uncovered network assets, including but not limited to bare conductors, substation equipment and switching components, the following describes the additional clearing requirements to apply to vegetation located outside the minimum trimming clearance space (that is, within the inspection space):

1. To a distance up to the established easement width, or in its absence the nominal easement width (refer to section 5.2), all dead, dying, dangerous or visually damaged tree **limbs** that have a diameter equal to or greater than 75mm and are situated above a line projected at 45° from the vertical from the lowest conductor design height [refer note (c) below], shall be removed.
2. All hazard, dead, dying, dangerous or visually damaged **trees** that are situated above a line projected at 45° from the vertical from the lowest conductor design height [refer note (c) below], shall be either trimmed to at least the lowest conductor height or removed if requested by the landowner/manager.

Note: Where dead, dying, dangerous or visually damaged limbs/trees are located on private property, it is essential that prior negotiation with the landowner/manager take place.



 # Remove all dead, dying, dangerous and visually damaged limbs ≥ 75mm diameter.

(a) Minimum trimming clearance space.

(b) Established easement width or, in its absence, the nominal easement width.

(c) Conductor at its lowest design height of 7.3m for HV and 5.5m for LV above ground.

Figure 7: Removal of dead trees/branches near overhead power lines

5.1.9 Overhead service conductors

Customers are responsible for keeping vegetation clear of service lines over their own properties. The clearances required are in accordance with clauses 5.1.6 and 5.1.7. Endeavour Energy inspects service clearances and monitors outcomes to ensure compliance.

5.1.10 Streetlight lanterns where electricity is supplied by overhead mains

Vegetation shall be cleared to allow a minimum of two (2) metres horizontal clearance from the head of a streetlighting lantern and extending in the vertical plane from one (1) metre above the lantern to two (2) metres below the lantern, as shown in the diagrams below.

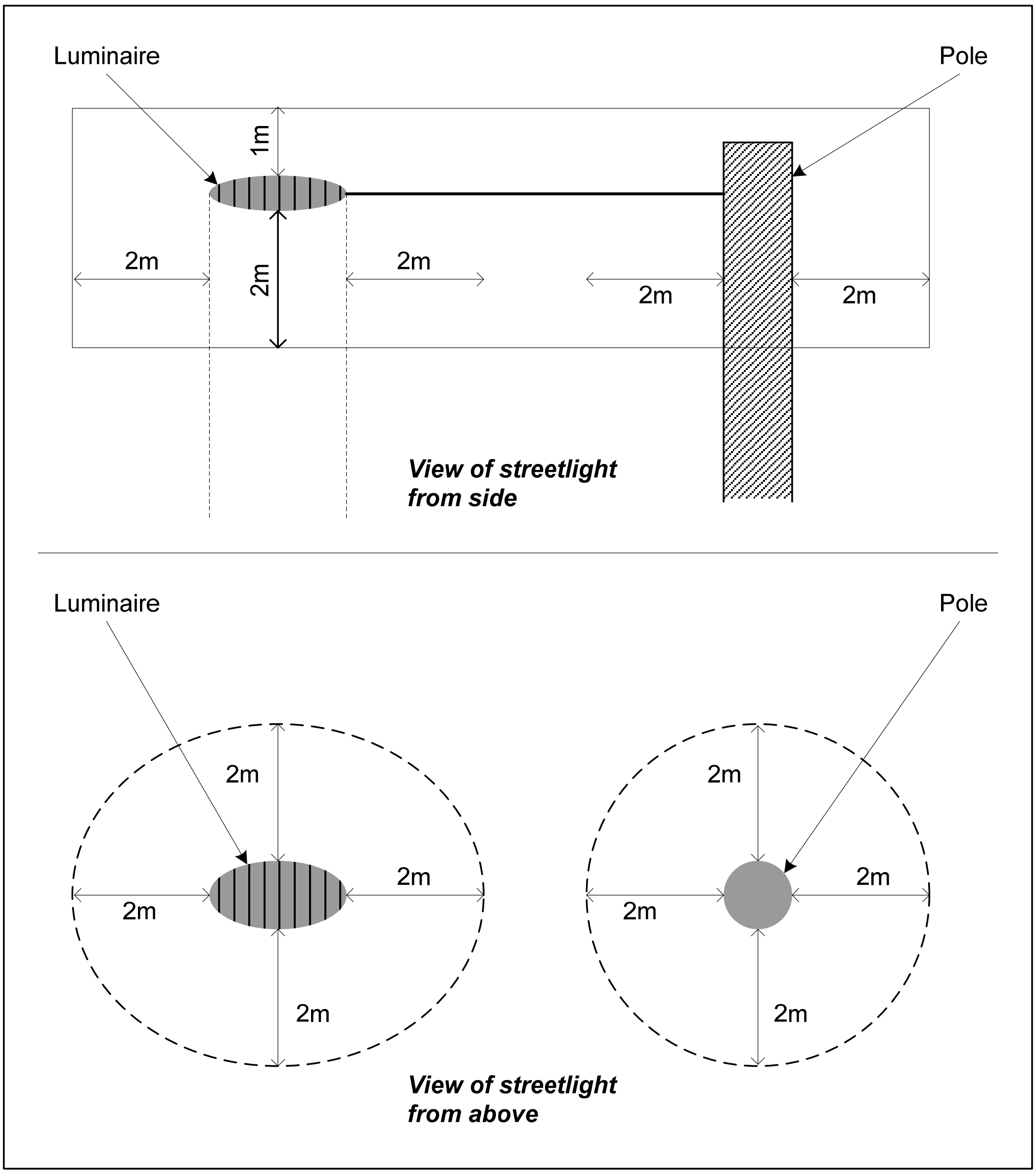


Figure 9: Clearances around streetlights

Trimming of new vegetation planted by residents after the public lighting network has been energised in new overhead developments is the responsibility of the public lighting customer.

The responsibility for maintaining clearances around streetlight lanterns in areas where electricity is supplied by underground mains lies with the local council.

5.1.11 Identification of significant/heritage trees or sensitive issue trees

Significant/heritage or sensitive issue trees shall be identified by placing an approved indicating device, such as preformed bird diverters or equivalent, on the overhead mains adjacent to the tree.

This device shall be easily recognisable and not damage or impose significant additional load on the overhead mains conductors/cable.

Records shall be kept for all such trees and the locations identified on tree trimming maps, where possible.

Aerial bundled cables (ABC) and covered conductor thick (CCT) shall be used in place of bare conductors once a significant/heritage or sensitive tree issue is identified in order to provide for reduced trimming clearances that these conductors provide.

5.2 Standard easement widths

Unless specified otherwise, the following standard easement widths apply within the Endeavour Energy franchise area (refer Table 5 below). Easement widths may vary and should be verified where required.

Table 5: Standard easement widths

Overhead system		
Description	***Voltage***	***Nominal easement width***
Aerial bundled conductors	230/400V	6m
Aerial bundled conductors (NMS)	11kV - 22kV	6m
CCT – vertical construction	400V - 22kV	6m
Bare conductor and CCT horizontal construction	400V - 22kV	9m
Single pole with cross arm construction	33kV	18m
Single pole with cross arm construction	66kV	25m
Double pole/H-pole	33kV - 132kV	30m
Single pole vertical/delta post insulators	66kV	18m
Single pole vertical/delta post insulators	132kV	25m
Steel tower twin circuit	132kV	30m
Pole stays/ground stays		6m

Notes to Table 5:

1. The standard easement width is measured equidistant from the centre line of the conductor(s) route.
2. Standard easement widths do not apply in urban areas, where assets are located within roadside corridors. However, the trimming contractor should ensure that clearances are maintained in accordance with Tables 3 and 4.
3. The prescribed standard easements widths are within the maximum clearing distances of the *Native Vegetation Act*, 2003 and Regulation 2005, Section 21.

5.3 Groundline vegetation management

Management of vegetation under and adjacent to network assets is carried out in order to establish and maintain safety clearances, maintenance access, and to provide hazard reduction to protect network and community assets, and reduce the likelihood of bushfires being initiated by network assets.

Techniques used consist of tree trimming, selective tree removal, application of pesticide, trittering, slashing, mowing and prescribed burns.

Left: Groundline management techniques employed, including removing dead and dangerous trees/limbs, plus using CCT, thus allowing for reduced clearances and increased line security.

5.3.1 Urban areas

Any vegetation within the established easement width, or in its absence, the nominal easement width (refer Table 5, section 5.2), that will reach a height greater than three (3) metres at maturity, shall be trimmed or removed from beneath overhead power lines with bare conductors.

Groundline management of vegetation around poles or lattice towers shall be carried out to the clearances shown below within the designated areas of Figures 10 and 11.

Consideration should be given to retaining vegetation of amenity value, but clearances must be achieved to prevent vegetation contacting the pole/tower, enabling the unhindered climbing of the pole/tower and ensuring that there is adequate clear space for a full excavation of the below ground area around the pole/tower.

Vegetation shall be removed from beneath overhead powerlines and substations where access for staff, vehicles and plant for essential maintenance activities is compromised and where, in a bushfire prone area, the level of combustible fuel, as identified by the RFS *Bushfire Risk Management Plan* (BFRMP), could result in damage to the Network assets.

Where these areas fall within protected areas, protected lands, protected trees and the like, these works shall be addressed in accordance with the relevant legislative requirements.

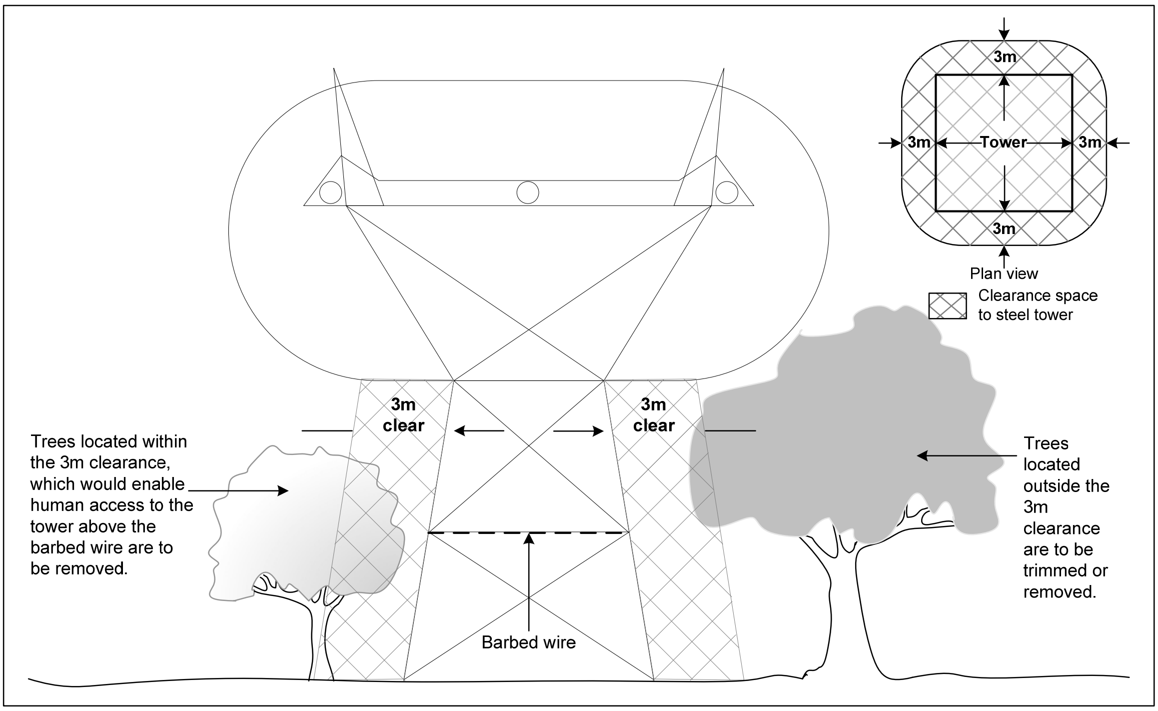
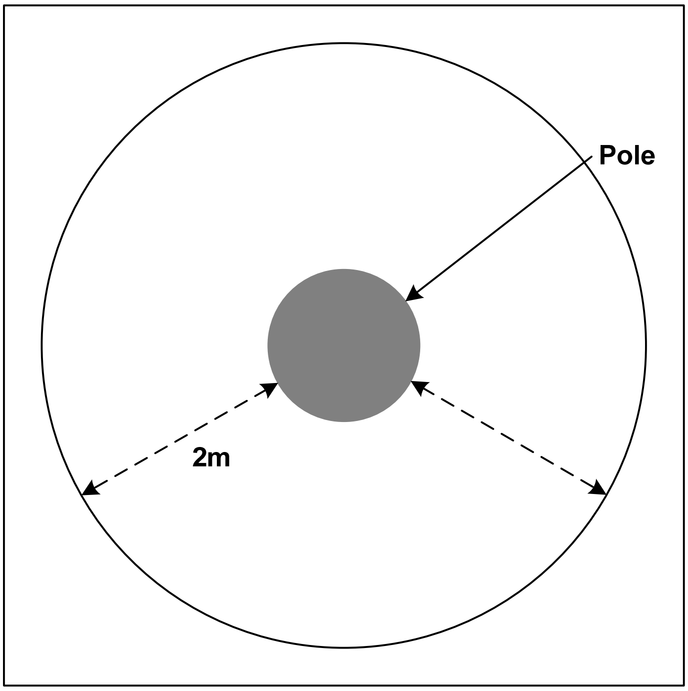


Figure 10: Clearance around steel towers



Note: A 5m clearing space shall be established and maintained around poles in non-urban bushfire prone areas.

Figure 11: Clearance around poles

5.3.2 Non-urban/bushfire prone areas

Any vegetation that will reach a height greater than three (3) metres at maturity shall be removed from beneath overhead powerlines with bare conductors. This groundline vegetation management shall extend out from each outside conductor of the overhead power line a distance equal to the minimum trimming clearance (refer Table 4, clause 5.1.7), or the width of the established easement/nominal easement (refer Table 5, section 5.2, covering the Network assets), whichever is the greater. Any extension of existing easements shall be subject to appropriate determinations.

Vegetation shall be removed from beneath overhead power lines and substations where access for staff, vehicle and plant for essential maintenance activities is compromised and where, in a bushfire prone area, the level of combustible fuel loads, as identified by the RFS *Bushfire Risk Management Plan* (BFRMP), could result in damage to the network assets.

Where the overhead power line traverses a deep gully or depression, removal of vegetation below the line shall only be required where the mature trees will come within the minimum safety clearance shown in Table 3, clause 5.1.6, with the conductors at their lowest point.

Groundline management of vegetation around poles or lattice towers shall be carried out to the clearances shown in clause 5.3.1, Figures 10 and11. Consideration should be given to retaining vegetation of amenity value, but clearances must be achieved to prevent vegetation contacting the pole/tower, enabling the unhindered climbing of the pole /tower, and ensuring that there is adequate clear space for a full excavation of the below ground area around the pole/tower.

Access track vegetation shall be maintained in accordance with the appropriate user's standards.

Where these areas fall within protected areas, protected lands, protected trees and the like, these works shall be addressed in accordance with the relevant legislative requirements.

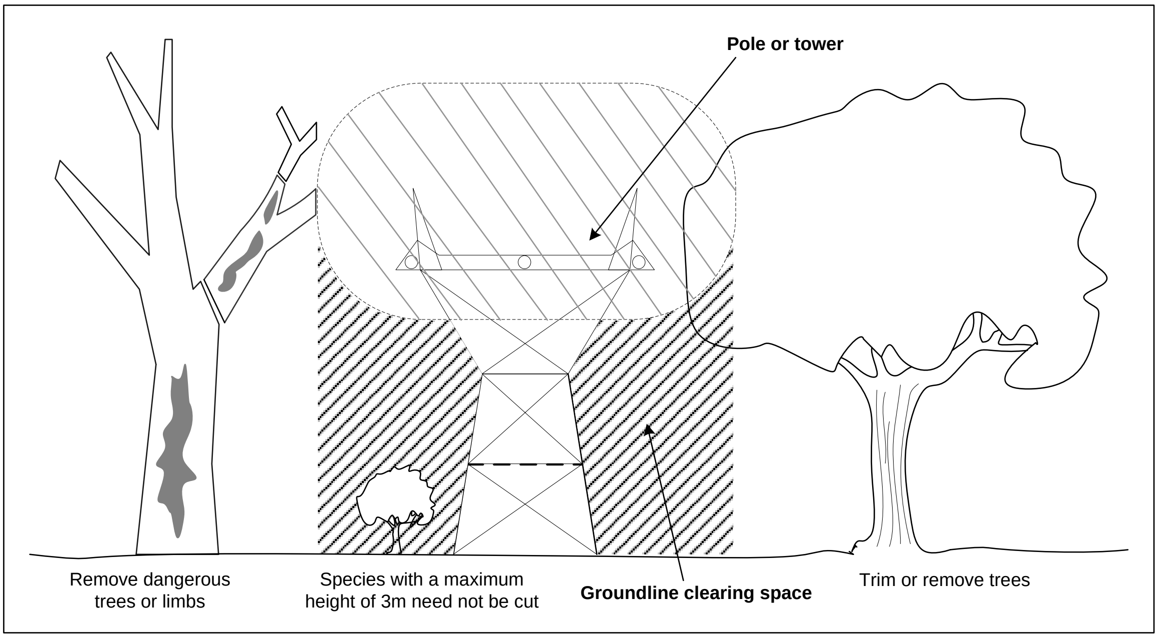


Figure 12: Ground line vegetation management around overhead power lines in non-urban/bushfire prone areas

5.3.3 Ground substations/switchyards (transmission and distribution)

Endeavour Energy is responsible for maintenance of all network assets that it owns (refer Company Policy 9.9.1).

Ground substations/switchyards include:

- Transmission substations.
- Zone substations.
- Switching stations.
- Regulators.
- Customer substations (with Endeavour Energy assets).
- Cottage distribution substations (land owned by Endeavour Energy).
- Padmount distribution substations (land owned by Endeavour Energy).

Where the above sites are on land owned by Endeavour Energy, ground and vegetation maintenance is carried out on an annual basis, as part of a contractual arrangement, to ensure sites are kept in a safe and tidy condition, and adequate access and safety clearances are provided to all electrical equipment.

Where network assets are located within easements or public land, Endeavour Energy shall trim or remove any vegetation on an annual basis that interferes with or prevents access to site or electrical apparatus.

General guidelines for ground type substations/switchyards are:

- No vegetation shall be permitted within the fenced equipment or blue metalled areas of a ground substation.
- Any vegetation that is within, or has the potential to come within, the safety clearances of the electrical equipment and power line landing spans shall be completely removed.
- Any vegetation within or surrounding the substation fences that has the potential to cause damage to network assets, or is deemed to jeopardise the security of the substation, or is potential risk to staff or public safety, shall be removed.

Vegetation management staff shall not enter the security fenced area of a ground substation unless they have been suitably trained and authorised by Endeavour Energy, or are accompanied by suitably trained and authorised Endeavour Energy employees.

Where possible, any vegetation above 300mm in height and within three (3) metres (both inside and outside of the security switchyard fence of a ground substation in an urban area), shall be completely removed for safety and security purposes.

Where possible, for ground substations in a non-urban area or a bushfire prone area, any vegetation within 10 metres of the outside of the boundary fence shall be completely removed for safety and security purposes, and adequate asset protection zones provided (subject to appropriate determinations - refer RFS bushfire guidelines). These clearances are shown in Figure 13 below.

Notwithstanding the above, development applications for new or upgraded substations require a fire risk management plan demonstrating maximum uncontrolled vegetation heights and fuel minimisation plans for approval. The types of vegetation proposed in these landscaping plans needs careful consideration so as not to compromise the safety, security or ongoing maintenance of the substation.

Alterations to existing landscaping may require formal consultation. All legislative requirements shall be complied with when removing any vegetation adjacent to substations.

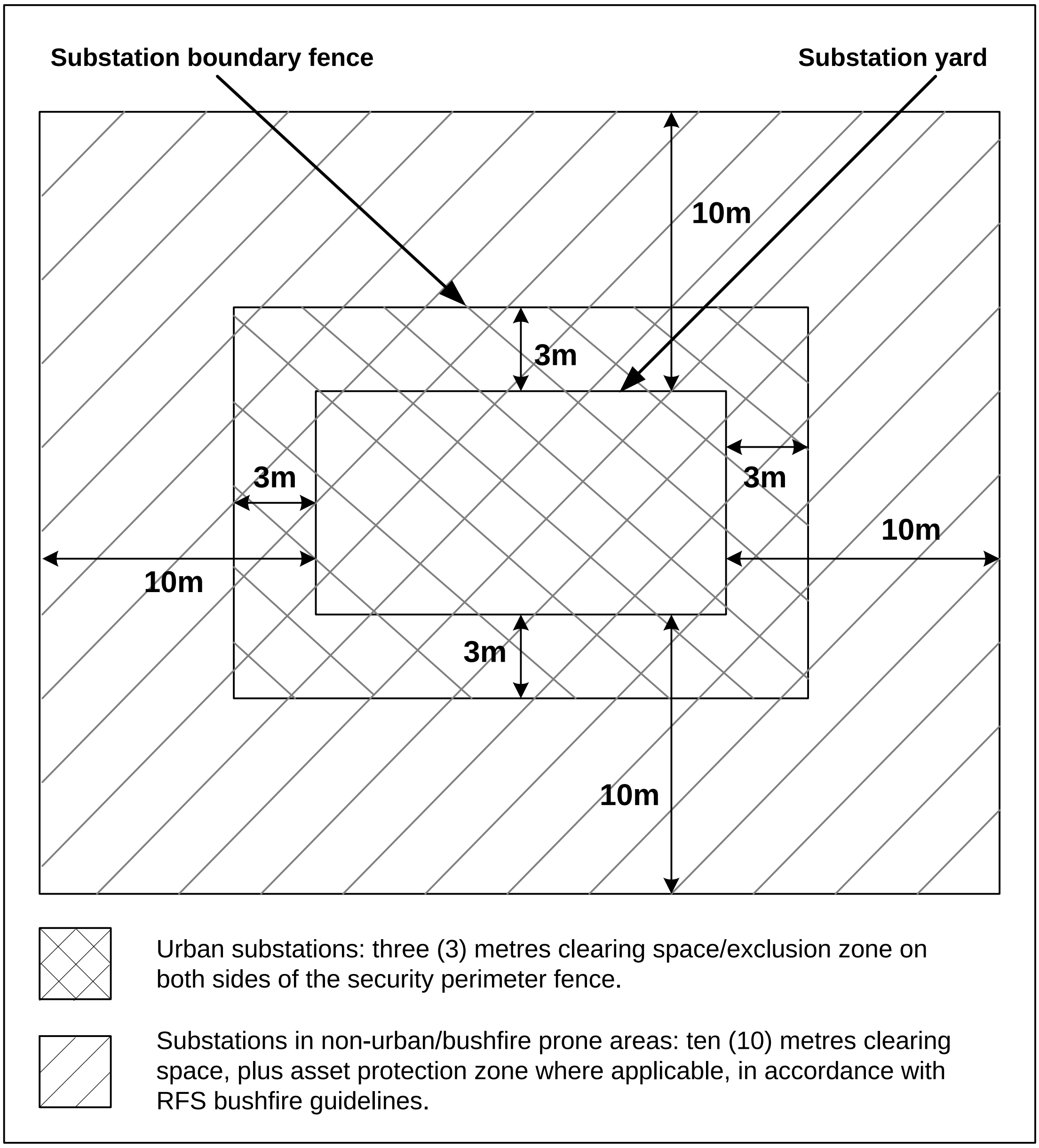


Figure 13: Clearing around ground substations

5.3.4 Hazard reduction around network assets

Hazard reduction programs aim to reduce the severity of a bushfire by reducing the amount of combustible fuel available to burn. This makes the bushfire easier to control and reduces the level of damage to network assets, such as powerlines and substations, as well as community and environmental assets.

Hazard reduction also reduces the likelihood of bushfires being initiated from network assets, and provides protection to firefighters and the network operator's staff during bushfires. Techniques to be employed are outlined in clause 5.3 and are usually addressed by the RFS legislative requirements, that is, hazard reduction (H/R) certificates and BFRM plans.

5.4 Water crossing signs

Water crossing signs require specific attention in order to ensure visibility by approaching vessels in accordance with NSW Maritime requirements.

The warning signs must be visible for two (2) metres in all directions; if two (2) metres is not achievable, the sign shall be listed as a defect in Ellipse for an increase in mounting height. The water crossing signs must be visible from anywhere on the waterway, within an arc of 45° either side of the crossing. Any vegetation between the warning sign and the waterway edge shall be cleared to ensure the warning signs meet the above requirements.

Note: This includes at least any one (1) warning sign being visible from a vessel in any position on the waterway/navigable channel from at least 100m from the crossing.

All such areas are generally classified as vulnerable land under the *Native Vegetation Act* 2003 and Regulation 2005. However, clearing of native vegetation to maintain safety clearances around electricity transmission and distribution lines does not require approval as long as works are carried out under or within 15m of an existing line, but this shall not include any mangroves, seagrasses or any other marine vegetation.

Noxious weeds and exotic species may also be removed to provide the necessary clearances.

All such works are environmentally sensitive and shall be carried out to a minimum extent, in accordance with State Protected Land (SPL) guidelines, and the affected Catchment Management Authority notified of the proposed works. All such works shall minimise impacts upon waterways and riverbank (riparian) zones.

Access to some water crossing signs within the Endeavour Energy franchise is available only from the waterway involved.

Left: Example of a clearly visible river crossing sign

5.5 Frequency of inspection

All network assets covered by this instruction shall be regularly inspected in accordance with the contract, and at least annually to ensure that the required vegetation clearances have been maintained.

Declared bushfire maps are to be inspected and cleared of bushfire defects no sooner than June and no later than September of each year. This includes transmission, distribution and private low voltage lines and services.

Arranging for the inspection of private high voltage lines is the responsibility of the Customer and Process Manager of System Operations.

5.6 Newly planted vegetation

In situations where newly planted vegetation around assets will present a future hazard, the person/organisation responsible for the planting shall be requested to remove or relocate the inappropriate vegetation. They shall be advised that if the offending vegetation is not relocated then subsequent trimming over the coming years will be detrimental to the shape and growth of the trees.

Left: Example of inappropriate tree planting

5.7 Vegetation clearing for new construction/augmentation works

All vegetation clearing around new network asset construction shall be carried out to the requirements of this standard and EMS 0004.

Before handover of these works to Endeavour Energy, the Vegetation Control Manager or nominated representative shall be notified and provided with copies of all relevant plans and documentation. The Vegetation Control Manager shall arrange for the inspection of these works and their inclusion in the contract, and the mark up of vegetation trimming maps or substation property scoping maps for inclusion in future maintenance cycles.

6.0 AUTHORITIES AND RESPONSIBILITIES

The **Chief Engineer** shall be responsible for approving this Standard.

The **Manager Network Engineering** shall be responsible for making recommendations to the Chief Engineer on this Standard.

The **Overhead & Underground Mains Manager** shall be responsible for:

- ensuring the content of this instruction is up to date;
- providing adequate direction for tree management requirements to safeguard the network; and,
- tracking the completion and taking necessary corrective actions to ensure that any remedial actions to restore minimum trimming clearances that have been temporarily reduced following submission of form FAE 3156 are completed within 12 months.

The **Vegetation Control Manager** shall be responsible for:

- Managing of the vegetation management program in accordance with this Standard.

- Authorising the contractor and the contractor's staff to work on the network in accordance with Company Policy 9.1.3 and to enter private property, as required, to perform vegetation management work.
- Providing training to the contractor.
- Advising the Overhead & Underground Mains Manager of any remedial actions to restore minimum trimming clearances which have been temporarily reduced following submission of form FAE 3156 that have not been completed within 12 months.
- Notifying the OLI/GLI section in writing within two (2) weeks where there is a vegetation defect associated with a service line or a private line that must be rectified by the customer in accordance with the maintenance responsibilities defined in MMI 0021.

Regional Managers shall be responsible for:

- Ensuring that the annual pre-summer bushfire inspections are carried out in defined bushfire prone areas for all transmission and distribution lines including private low voltage lines.
- Notifying the OLI/GLI section of the vegetation defects on private lines and service lines that must be rectified by the customer (in accordance with MMI 0021).
- Managing of the rectification of identified vegetation defects on all overhead lines, in accordance with the maintenance responsibilities defined in MMI 0021.
- Shall be responsible to ensure that all remedial actions are completed within 12 months to restore minimum trimming clearances which have been temporarily reduced following submission of form FAE 3156.
- Notifying the Vegetation Control Manager or nominated representative where new or augmented network asset construction involving vegetation clearing has taken place, and the provision of relevant plans and documentation as required.

The **OLI/GLI Manager** shall be responsible for:

- Notifying customers in writing within two (2) weeks of vegetation defects affecting privately owned lines or service lines on a customer's property.
- Managing the follow-up process to ensure that defects are rectified. Bushfire defects shall be cleared immediately within any current declared bushfire season or before the commencement of any subsequent bushfire season. All other defects that are not contained within bushfire maps shall be cleared within 12 months (refer to SMI 112, section 5.2 for defect priorities).

The **Vegetation Management Contractor** shall be responsible for:

- Ensuring that clearances between vegetation and Endeavour Energy's Network assets are maintained in accordance with this instruction and EMS 0004.
- Ensuring contract staff are provided with the relevant training.
- Ensuring that all work is carried out according to the Endeavour Energy Safety Rules.

The **Contractor Operations Manager, Network Connections Branch**, shall be responsible for:

- Notifying the Vegetation Control Manager or nominated representative where **new** network asset construction involving vegetation clearing has taken place, and the provision of relevant plans and documentation as required.

The **Regional Supervisor or Operations Manager** shall be responsible for arranging for the necessary training to all staff involved in vegetation management to be provided by the Manager Technical Training.

The **Manager Technical Training** shall be responsible for training of all Endeavour Energy and contracting staff involved in vegetation management to the requirements of this Standard.

The **Manager Strategic Asset Management** shall be responsible for the programming, reporting and corrective actions required in order to provide for the timely completion of all vegetation management within the Endeavour Energy Network.

The **Customer and Process Development Manager, System Operations** shall be responsible for ensuring that the annual pre-summer bushfire inspections are carried out in defined bushfire prone areas for high voltage customers.

7.0 DOCUMENT CONTROL

Documentation content coordinator:	Overhead & Underground Mains Manager
Documentation process coordinator:	Branch Process Coordinator

ISSC 3
GUIDELINE FOR MANAGING VEGETATION NEAR POWER LINES

Integrating Community, Safety and Environmental Values

December 2005

INDUSTRY SAFETY STEERING COMMITTEE (ISSC) GUIDELINES

In New South Wales, statutory safety requirements for electricity transmission, distribution and utilisation are contained in the Electricity Supply (General) Regulation 2001 and the Electricity Supply (Safety and Network Management) Regulation 2002. The Network Management Plans and other Safety Plans required under the latter regulation are prepared by the five NSW Network Operators. The regulation specifies the safety outcomes to be achieved. The means of achieving those outcomes are matters to be determined by each Network Operator.

The NSW electricity supply industry has traditionally published an extensive series of guideline documents. These set out the industry's view of minimum practices, which would enable an organisation, or individual, to fulfil the regulatory requirements.

Whilst compliance with the Plan is mandatory, organisations or individuals may choose to depart from the recommendations of the guides provided that the necessary duty of care is exercised and the regulatory requirements are fulfilled.

REVISION HISTORY

This Guideline was first published by the Department of Minerals and Energy as the "Guidelines for Tree Planting and Maintaining Safety Clearances Near Power Lines". The Electricity Council of New South Wales updated the Second Edition 1990 in February 1992: "Guide to Tree Planting and Maintaining Safety Clearances Near Power Lines - EC 3".

The Electricity Association of NSW (EA of NSW) published a revised guide ISSC3 on behalf of The Industry Safety Steering Committee (ISSC) in October 1996. A further review was conducted in 2001 under the auspices of the EA of NSW, but that review did not reach the publication stage.

In July 2002, the Minister for Energy reconstituted the ISSC following the 'winding up' of the EA of NSW, and the newly formed ISSC, under the secretariat and chairmanship of the Department of Energy, Utilities and Sustainability, conducted this latest revision.

DISCLAIMER

While due care has been exercised in the compilation of this Guideline, much of the content has been sourced externally to the ISSC and the Department of Energy, Utilities and Sustainability. Thus the Department of Energy, Utilities and Sustainability cannot accept responsibility for the content.

This Guideline is designed on the basis that it will be used in its entirety, and persons who use or observe parts of the publication without paying heed to the entirety of the publication do so at their own risk.

This Guideline has been prepared on the basis that the user will be appropriately trained, qualified, authorised and competent. This Guideline is not intended for use by untrained or unqualified persons, and anyone in that category using the guide does so at his/her own risk.

This Guideline does not purport to ensure compliance with all relevant statutes and regulations, such as occupational health and safety laws. Users must satisfy themselves as to the requirements of all relevant laws.

PREFACE

This Guideline was reviewed by a Working Group of the Industry Safety Steering Committee of New South Wales (ISSC), and has been prepared for the benefit of the Community, Network Operators, Service Providers, Local Councils and other Government agencies.

The Working Group included representatives from many stakeholders, including the NSW Network Operators, the Department of Energy, Utilities and Sustainability, Department of Local Government, WorkCover, the NSW Heritage Office, Local Government and Shires Associations of NSW, the Electrical Trades Union and Local Councils.

NSW Network Operators and the community recognise the value of trees in the landscape. Trees and vegetation therefore should be retained wherever appropriate. This guideline will provide options in the management of vegetation primarily aimed at the long-term harmonious co-existence of vegetation and overhead power lines.

The Network Operators have an ethical, business and statutory obligation to keep their electrical assets safe and operable. To meet these obligations, vegetation near electrical assets requires management in order to maintain the safe and reliable operation of the electricity network. A reliable and safe power supply underpins the economy of NSW and our community life.

It is recognized that the management of vegetation in the vicinity of power lines can be a sensitive and emotional issue with the community.

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OBJECTIVE

Safety and environmental management is of concern to, and the responsibility of, all members of society including individuals, community groups, special interest groups, private sector and public sector organisations. The management of vegetation near power lines is a critical environmental and safety issue for the community. The responsibility for vegetation management near power lines does not lie solely with the electricity industry and this is reinforced in the current NSW legislation that sets out the responsibilities of network operators, owners of private property and others for the management of trees near power lines.

This document seeks to provide guidance to network operators and the community generally in the safe and environmentally responsible management of vegetation near power lines by integrating community, safety and environmental values.

SCOPE

This guideline applies to any vegetation management work conducted near existing electricity assets. Community, safety and environmental values covered include:

- public and employee health and safety;
- the separation required between vegetation & electricity assets to ensure a safe environment;
- other relevant NSW and Federal codes, standards, legislation and regulations;
- the application of sound horticultural practices in vegetation management work;
- the protection of all assets, including trees, from unnecessary damage;
- the reduction of fire risk caused by contact of vegetation with electricity assets;
- the methods of restricting future planting of inappropriate vegetation and
- advice on development of tree management plans.

The requirements for the establishment of new overhead power lines are addressed in industry guide *"Guidelines for the Development of Electricity Systems Community and Environmental Considerations"* (ISSC22). The requirements regarding the maintenance of electricity easements are addressed in industry guide *"Guidelines for the Management of Electricity Easements"* (ISSC20).

In reviewing and further developing this guideline, the working group has considered the following:

- the current Australian standard for pruning amenity trees AS 4373-1996;
- practices in other States;
- other relevant NSW codes, standards and legislation;
- maximising the reliability of the electrical network;
- the principles of environmentally sustainable development and responsible environmental management;
- the 'essential service' function of the electricity network and the need to maximise its reliability;
- vegetation management requirements in relation to heritage areas and heritage listed, significant, protected and private trees and
- the need to enhance community awareness of the issues surrounding vegetation management and electricity assets.

APPLICATION

This guideline shall be read and applied in conjunction with any other codes, guides, standards and legislation relevant to NSW.

DICTIONARY

For the purpose of interpretation, the following definitions apply:

* Means consent or permission is usually required from the appropriate authority to prune/remove trees listed/protected under these provisions. Early contact should be made with the appropriate authority to clarify any necessary prior approvals and information required before proceeding with works.

Aerial Bundled Cable (ABC)	Two or more cores twisted together into a single bundled Cable assembly. Two types of aerial bundled cable are used: • Low Voltage Aerial Bundled Cable (LVABC) – means a cable which meets the requirements of *AS3560.* • High Voltage Aerial Bundled Cable (HVABC) – means a cable which meets the requirements *of AS3599 Part 1 or AS3599 Part 2*
Clearances	Refer to Clearing Space or Inspection Space.
Clearing Space (Minimum Safety Clearance)	Space surrounding the overhead power line conductors and other electrical equipment, which is to be maintained clear of any foliage. The extent of this space is dependent on the maximum sag, the voltage of the conductors, the regrowth characteristics of the trees, the period till the next planned inspection, and type of power lines.
Covered Conductor	A conductor around which is applied a specified thickness of insulating material. *AS3675* specifies two types of covered conductor: • CC where the nominal covering thickness is independent of working voltage. • CCT where the nominal covering thickness is dependent on the working voltage.
Customer Connection Service	Means any of the following services: a. The connection of any premises to an electricity distributor's distribution system, or b. An increase in the maximum capacity of any premises' existing connection to an electricity distributor's distribution system.
Electricity Asset	Any component of the electricity transmission or distribution network. Assets typically relevant to vegetation management are overhead lines, poles, towers, substations, access tracks, streetlights, warning signs, etc.
Electricity Distributor	This term also refers to and can be read to mean Energy Distributor.
Energy Distributor	A corporation constituted by the *Energy Services Corporation Act 1995* whose corporate name is listed *in Schedule 1 of the Act.* For the purposes of the guideline the term applies to Country Energy, EnergyAustralia, Integral Energy and TransGrid.
Environmental Factors	Those components of the environment that are to be considered concerning the impact of activities on the environment. The factors are prescribed in the *Environment Planning and Assessment Regulation 2000 Part 14 Division 1.*

Fire Hazard Area	An area where, in the opinion of the delegated officer of the electricity distributor in consultation with bush fire management committees established under *the Rural Fire Service Act 1997*, or representatives of the Rural Fire Service, and the local council, the combination of the normal build up of vegetation, excessive fuel levels and general weather conditions in the area would constitute a high probability of extending a fire ignition into a large fire or potential to increase the probability of damage to electricity assets from a fire.
* Heritage Listed Tree	Means any tree listed as having heritage value to the local area or to the state either individually as an item or as part of a group (e.g.: street trees, avenue, group) on any of a Local Government Authority's Local Environmental Plan or a Regional Environmental Plan (including exhibited draft versions) made under *the Environmental Planning & Assessment Act 1979*, on the State Heritage Register, or subject of an Interim Heritage Order or subject of an order made under *section 136 of the Heritage Act 1977*. Heritage listing of a property containing one or more trees deems that tree or trees to also be heritage listed or to have heritage value. Properties with trees may be listed individually as items or collectively as heritage conservation areas. Trees may be part of a larger place listed as a heritage item, area or heritage conservation area (for instance street trees within a conservation area, or an avenue of trees within a park or reserve).
Inspection Space	Space additional to the clearing space in which further clearing may be required where, in the opinion of the delegated officer of the electricity distributor, a part of a tree constitutes a serious hazard to bare or insulated aerial conductors or other electrical equipment under extreme storm or wind conditions.
Insulated Aerial Conductors	Aerial conductors which are continuously covered with fully rated insulation material of the appropriate grade of the voltage at which the overhead line is operated.
Local Councils	The councils constituted pursuant to *the Local Government Act 1993*.
Natural Tree	Tree(s) that have grown by natural seeding.
Network Operator	The holder of an Electricity Network Operators licence as provided for under NSW legislation. There are currently five NSW Network Operators: - EnergyAustralia, Integral Energy, Country Energy, TransGrid and RailCorp.
Non Urban	The areas outside urban areas.
Overhead Power Line	An aerial conductor together with towers, poles, insulators, hardware, cross arms, substations or other associated electrical equipment erected or in the course of erection for the purpose of supplying electricity.
Planted Tree	Tree(s) other than those that have grown by naturally seeding.
Private Overhead Line	Any electricity assets on private property beyond the "point of supply" of the network operator. These lines can be of any voltage, insulated or otherwise, and are the responsibility of the landowner/occupier.
Private Tree	Tree(s) on private property that are either natural or planted.

Protected Area	Means any area within a national park or nature reserve within the meaning of the *National Parks & Wildlife Service Act 1974,* or a. land that is reserved or zoned for environmental protection purposes under the *Environmental Planning & Assessment Act 1979*; or b. a public reserve within the meaning of *the Local Government Act 1993.*
Protected Land	a. land identified on a map a copy of which has been deposited in the office of a district soil conservationist in accordance with section 21B; or b. any land (not being land referred to in paragraph (a)) that is situated within, or within 20 metres of, the bed or bank of any river or lake which (with reference to the Water Act 1912) was listed in the Gazettes referred to in the Sixth schedule. but does not include: c. any State forest, national forest, timber reserve or flora reserve, within the meaning of the Forestry Act 1916; or d. any national park, historic site, nature reserve or state game reserve, within the meaning of the National Parks and Wildlife Act 1974.
* Protected Tree	Protected tree means a tree that is the subject of or within the area, as defined *in section 48 of the Electricity Supply Act 1995 (NSW)*; that is subject of an Interim Heritage Order, is listed on the State Heritage Register, is subject of an order in force under *section 136 of the Heritage Act 1977*; is subject of an *Interim Protection Order under the National Parks & Wildlife Service Act 1974*; is listed individually or as part of a place or area listed on a Local Government Authority's Local Environmental Plan or a Regional Environmental Plan made under the *Environmental Planning & Assessment Act 1979*; or a protection conferred by any similar law. It includes trees subject to a Local Government Authority Tree Protection Order (TPO). Size and age criteria differ between Local Government Authorities, and these should be checked in the first instance. It also means a tree within a protected area.
Pruning	All forms of pruning as defined by *AS4373-1996.*
Regrowth Allowance	The trimming of vegetation in addition to the minimum safety clearances detailed in Tables 1 and 2 dependant on environmental considerations and trimming cycles.

* Significant Tree	Significant tree means any tree classified by the National Trust of Australia (NSW) as significant, recognised by a Government Authority or by a recognised Community Group, or listed by a Local Government Authority on a Significant Tree Register (STR). Significant trees may be individually heritage listed, or form part of a larger place listed as a heritage item, area or heritage conservation area (for instance street trees within a conservation area). Significance is generally in relation to one or more of historic, aesthetic, scientific (e.g.: botanical, ecological or horticultural value) or social value. Heritage significance in NSW is defined in reference to the NSW State Heritage Register criteria, a copy of which is at Appendix A, along with other criteria.
Tree	Tree means a tree taller than 3 metres, or having a canopy of more than 3 metres in maximum diameter or having a trunk with a circumference at a height of 1 metre from the ground of more than 0.3metres. Trees can include shrubs and other plants for the purposes of the *Electricity Supply Act 1995 (NSW).*
Urban Area	A built-up area as designated by street lighting, or subdivision into small allotments or other areas agreed to by the Network Operator and the local council.
Vegetation	All plant life including, but not limited to *trees,* palms, vines, shrubs, and grasses such as bamboo but excluding lawns.
Water Crossing Sign	A notice located adjacent to bodies of water, warning of the presence of overhead or underground electricity powerlines crossing the body of water.

1. OVERVIEW OF RELEVANT LEGISLATION

1.1 General

Land use controls in Australia are principally governed by the laws of individual States and Territories. Particular federal laws also apply in all areas of the Commonwealth. The *Environment Protection and Biodiversity Conservation Act 1999* ***(Biodiversity Act)***, replaced five federal environment statutes. Approval will be required to take any action that will have, or is likely to have, a significant impact on areas and attributes for which the Commonwealth is responsible. These 'triggers' include actions affecting World Heritage properties, Ramsar wetlands, listed threatened species, listed migratory species and Commonwealth marine areas. Obligations and penalties differ substantially between jurisdictions. Where the corporation conducts business or carries out activities in several States or Territories, the statutory requirements of each must be complied with.

This section of the guideline is arranged in four parts. ***Each provides a different means of accessing information about the environmental laws that affect network operators***.

Part A provides access to the environmental legislative requirements through an activity table. The table allows cross-referencing of major activities undertaken by network operators, such as line maintenance, with specific environmental aspects of those activities and the applicable legislation.

Part B provides a broad overview describing the basic environmental performance and reporting obligations imposed on network operators under NSW and Commonwealth law. It is structured to provide a synopsis of the major environmental laws that affect network operators' activities under the following subject headings:

- waste management;
- land contamination;
- air pollution;
- water pollution;
- noise pollution; and
- hazardous substances.

Part C details the relevant legislative provisions and their implications for the network operators. The part contains the following information:

- the Act name and section;
- a summary of the obligation or offence imposed;
- identification of the appropriate regulatory authority;
- the relevance of the provision to the corporation;
- identification of the parties who may be liable in the event of a breach;
- the maximum penalties which may be imposed for failure to comply with the provision; and
- any defences that may be available to the corporation in the event of a breach of the provision.

Part D provides access to the Occupational Health & Safety legislative requirements through an activity table. The table allows cross-referencing of major activities undertaken by network operators with specific occupational health and safety obligations and the applicable legislation.

1.2 Part A: Network Activities and Environmental Obligations – Reference Table

This table may not cover all activities pertaining to vegetation management, however it would include:

- ***Line maintenance trimming;***
- ***Access track maintenance;***
- ***Easement/corridor cleaning;***
- ***Re-growth control; and***
- ***Emergency maintenance.***

Specific Management Issues	**Environmental Aspects**	**Relevant Legislation or Regulations**
Line Maintenance – Specific Vegetation Management Issues		
Vegetation Management (trees)	Controlling overgrowth of trees and other vegetation	♦ *Electricity Supply Act 1995* ♦ *Electricity Supply (General) Regulation 2001 Part 11* ♦ *Native Vegetation Conservation Act 1997* ♦ *Heritage Act 1977* ♦ *Rural Fires Act 1997* ♦ *Rural Fires Regulation 1997* ♦ *Environmental Planning and Assessment Act 1979* ♦ *SEPPs 14, 19, 26,44,46,56, 58C and 71* ♦ *World Heritage Properties Conservation Act 1984* ♦ *Environment Protection & Conservation of Biodiversity Act 1999*
Vegetation Management (use of herbicides)	Risk of escape during transportation, due diligence required in applying herbicide (*e.g.*, Tordon TCH, Access)	♦ *Protection of the Environment Operations Act 1997* ♦ *Environmentally Hazardous Chemicals Act 1985* ♦ *Scheduled Chemical Wastes Chemical Control Order 1994* ♦ *Occupational Health and Safety Act 2000* ♦ Occupational Health and Safety Regulation, 2001 ♦ *Pesticides Act 1999* ♦ *Dangerous Goods Act 1975 and Regulation 1999*
Vegetation Management (noxious weeds)	Managing noxious weed growth in areas containing electricity powerlines	♦ *Noxious Weeds Act 1993* ♦ *Noxious Weeds Regulation 1993*

Specific Management Issues	Environmental Aspects	Relevant Legislation or Regulations
Vegetation Management (endangered species)	Effect of physical clearing methods and herbicide use on endangered species / critical habitat	♦ *National Parks and Wildlife Act 1974* ♦ *National Parks and Wildlife (Land Management) Regulation 1995* ♦ *Threatened Species Conservation Act 1995* ♦ *Native Vegetation Conservation Act 1997*
Vegetation Management (soil)	Soil erosion arising from clearing of vegetation	♦ *Soil Conservation Act 1938* ♦ *EP&A Act 1979* ♦ *Heritage Act 1977 (relics / archaeology provisions)*

1.3 Part B: Major Environmental Laws

The main pollution control statute in New South Wales is the *Protection of the Environment Operations Act 1997* ***(Operations Act)***, which commenced on 1 July 1999. This Act replaced the *Environmental Offences and Penalties Act 1989,* the *Pollution Control Act 1970* and other specific legislation such as the *Clean Air Act 1961.*

The *Operations Act* contains the following key elements:

- an integrated licensing system, under which a single licence can cover emissions in multiple media from a site or activity;
- administrative enforcement through environment protection notices (clean up, prevention, prohibition and compliance cost notices);
- environment protection offences graded into three tiers and covering offences of air, water, noise, and land pollution;
- a duty to report any pollution incident which threatens material harm to the environment where the corporation occupies relevant land or employs relevant persons;
- directors and managers are made personally liable for offences committed by the corporation;
- provision for voluntary and mandatory environmental audits of the corporation to be conducted; and
- authority for appropriate officers to perform a range of actions, such as questioning persons, requiring information or records and entering and searching premises.

The *Operations Act* is supplemented by other regulatory instruments that address issues of relevance to network operators as follows:

1.3.1 Waste Management

The Environment Protection Authority ***(EPA)*** regulates the handling, transportation and disposal of wastes under the *Operations Act.*

Under s48 of the *Operations Act*, a person who is the occupier of any premises at which a scheduled activity is carried on must hold a licence that authorises that activity to be carried on at those premises. One of these activities is the generation or storage of hazardous, industrial or Group A wastes.

A licence is required under s49 of the *Operations Act* for activities listed in Schedule 1 that are not premises based (such as mobile waste processing). This category includes the use of mobile plant to recycle oil in transformers.

An environment protection licence as a *waste facility* is *not* required if hazardous, industrial or Group A waste is treated, processed or reprocessed by a mobile plant which is licensed.

The reporting and storage obligations under the *Protection of the Environment (Waste) Regulation 1996* (***Waste Reg***) apply only to non-licensed landfill sites, non-licensed waste activities or non-licensed waste transporting.

A *non-licensed waste activity* means an activity, carried on for business or other commercial purposes, that involves the generating or storage of hazardous waste, industrial waste, Group A waste but which is not licensed under the *Operations Act*.

The Appendix to Schedule 1 of the *Operations Act* describes various types of waste as being industrial, hazardous, Group A *etc*.

Additional licences are required for the storage and disposal of certain scheduled chemicals and chemical wastes under the *Environmentally Hazardous Chemicals Act 1985* ***(EHC Act)***.

The primary responsibility of the network operator is to classify the waste properly (irrespective of whether it is going to be disposed of or reprocessed), to use a licensed transporter and to ensure that the wastes are taken to suitable mobile waste processors or waste facilities. Liquids that cannot be lawfully discharged directly to sewer may be subject to licensing under the *Operations Act*. Legislation dealing with discharges to sewer include the *Sydney Water Act 1994*, *Hunter Water Act 1991*, s68 of the *Local Government Act 1993* and clause 55 of the *Protection of the Environment (General) Regulation 1998* and the *Local Government (Water Services) Regulation 1999*.

Vegetation management by products are recycled wherever possible and only treated as waste only after all other options have been considered.

The *Waste Avoidance and Resource Recovery Act 2001* provides for the most efficient use of resources, including the recovery of organic matter for processing and reuse. Local Governments are required to develop strategies for dealing with the recovery of organic matter, including vegetative matter from the pruning or removal of street trees and trees/shrubs from public land and private property. Waste facility operators are similarly required to provide receival facilities for organic material that is free from non-organic contamination. Further information on the recycling and reuse of organic material can be found from the websites www.compostaustralia.com , www.recycledorganics.com and www.bioenergyaustralia.org or the relevant local government.

1.3.2 Land Contamination

The *Contaminated Land Management Act 1997* ***(CLM Act)*** is the principal statute governing the use, occupation and ownership of contaminated land in New South Wales. Whilst the *Operations Act* deals generally with prevention of land contamination by pollution, the *CLM Act* regulates contaminated land after the actual contamination has taken place.

It is a major offence under the *Operations Act* to wilfully or negligently dispose of waste in a manner which harms or is likely to harm the environment. There are also prohibitions against transporting waste to a place that cannot lawfully be used as a waste facility, or permitting land to be used as a waste facility when it cannot lawfully be used for that purpose.

The *CLM Act* is primarily directed at instances where the EPA believes it needs to intervene due to the significant risk of harm to human health or to the environment from contaminated land. The EPA can order the investigation and remediation of a site. It regulates the management of contaminated land using the *National Guidelines for the Assessment and Management of Contaminated Sites* developed by the Australian and New Zealand Environment Conservation Council and the National Health and Medical Research Council.

The *CLM Act* also imposes a duty to report upon landowners and other persons whose activities have contaminated land. Responsibility for the contaminated land always remains with those persons responsible for contamination. Where, however, the polluter cannot be located, or is insolvent, the owner of the land or the *notional owner* will become responsible for remediation. In general terms, the notional owner is a person (not being the owner of the land or the Crown or a body representing the Crown) who is entitled to a freehold interest in the land.

State Environmental Planning Policy No. 55 - Remediation of Land prevents changes to land usage until the relevant consent authority has considered whether the land is contaminated and whether remediation is necessary in order to accommodate the proposed use. Remediation work must be performed in accordance with EPA standards and *Planning Guidelines for Contaminated Land.*

1.3.3 Air Pollution

The *Operations Act* incorporates provisions dealing with the general minimisation of air pollution, pollution by fires and motor vehicle emissions. In relation to network operators, the most relevant provisions of the *Operations Act* are the duties to maintain and operate plant, and to deal with any materials, in a proper and efficient manner so as to avoid causing air pollution.

1.3.4 Hazardous Substances

The *EHC Act* contains provisions to control the effect of chemicals and chemical wastes on the environment. It provides for the declaration of chemical wastes and the creation of Chemical Control Orders ***(CCOs)*** and declared chemical wastes.

There are CCOs for dioxin-contaminated wastes, aluminium smelter wastes, polychlorinated biphenyls ***(PCBs)***, organotin wastes and scheduled chemical wastes. Most CCOs require licences to be held by people engaging in prescribed activities with respect to the environmentally hazardous chemical. Prescribed activities are manufacturing, processing, keeping, distributing, conveying, using, selling or disposing of the chemical waste, or any act related to those activities. The keeping and transportation of dangerous goods is regulated by the *Dangerous Goods Act 1975* ***(DG Act)***, which requires licences and authorisations for dealing with dangerous goods of various classes. The *Road and Rail Transport (Dangerous Goods) Act 1997* ***(RRT(DG) Act)*** prescribes separate licensing obligations for the transport of dangerous goods by road or rail.

Pesticides are regulated specifically under the *Pesticides Act 1999*, which sets out various offences relating to the misuse of pesticides. The Occupational Health and Safety Regulation, 2001 contains provisions relating to hazardous substances. Chapter 6 of the Regulation sets out specific risk control measures for hazards arising from the manufacture, supply and use of hazardous substances. The need for employers to carry out health surveillance on employees exposed to hazardous substances and the need for employers and medical practitioners to retain records is also covered in this Chapter.

1.3.5 Water Pollution

The *Operations Act* prohibits any person from causing or permitting water pollution except in accordance with the regulations or a licence held by the person. Water pollution is defined very broadly to include anything that produces a change in the physical, chemical or biological condition of any waters. It is sufficient for a conviction that the substance was placed in a position from which it was likely to end up in the receiving waters.

1.3.6 Noise Pollution

This environmental aspect is also regulated by the *Operations Act*. Occupiers of premises are required to maintain plant in an efficient condition, operate plant properly and efficiently and to deal with materials in a proper and efficient manner so as not to cause noise emissions from the premises.

1.4 Part C: Relevant Legislative Provisions

1.4.1 Environmental Planning and Assessment Act 1979

The *Environment Planning and Assessment Act 1979* ***(EPA Act)*** provides the primary source of obligations with respect to development activity in NSW. Part 4 of the EPA Act applies where a State Environmental Planning Policy ***(SEPP)***, Regional Environmental Plan ***(REP)*** or a Local Environmental Plan ***(LEP)*** requires a consent to be obtained before carrying out a development. *Development* is defined to include: the use of land; subdivision of land; erection of a building; carrying out of a work and the demolition of a building.

Where development consent is not required for a proposal (relevant to vegetation), the proposal may still need to be assessed under Part 5 of the *EPA Act* and specifically with a project under Part 3A of the EPA Act. The network operator, as the *determining authority*, will be required to consider the potential environmental impacts of any activity proposed to be carried out by it or on its behalf. The network operator must decide in accordance with the test laid down in s112 whether the proposal "is likely to significantly affect the environment". Furthermore, the network operator must not carry out an activity in respect of land that is a critical habitat, or is likely to significantly affect threatened species, populations or ecological communities, or their habitats, unless a species impact statement ***(SIS)*** has been prepared under the *Threatened Species Conservation Act 1995.*

Where the proposal is decided to be significant an Environmental Assessment is required under the provisions of Part 3A of the EPA Act.

Most NSW Councils now have or are moving towards making Local Environmental Plans (LEPs) made under the EP&A Act. In addition Planning NSW has made Regional Environmental Plans (REPs) and State Environmental Planning Policies (SEPPs) under this Act. (See **Part B,** earlier for more). Heritage listed trees, plantings and areas have usually been identified by a local heritage study, then leading to their listing as local heritage items or areas on the LEP. Local Councils are responsible for the protection and management of local heritage items in NSW, under amendments to the *Heritage Act 1977* and *EP&A Act 1979.*

In addition, many NSW Councils have conducted specific tree surveys leading to Tree Protection Orders, covering all trees over a set size in the Local Government Area, or Significant Tree Registers, or protected tree listings on their LEP. Trees or vegetation may be listed singly, in groups, as part of areas such as parks or reserves, or as street plantings in residential or village conservation areas.

Electricity distributors planning pruning operations must consult with Local Councils to identify any heritage listed, protected or significant trees in that Local Government Area, before finalising pruning plans. Appropriate prior community consultation and Council consents may be required before pruning occurs.

Under 1999 and 2002 amendments to the *Heritage Act 1977* delegations of Heritage Council powers were made to Local Government, giving Councils powers to defer development and move to assess or protect potential or actual heritage items which may include trees or vegetation of local significance. All non-metropolitan Councils have delegations to place Interim Heritage Orders preventing works or harm to potentially significant trees or vegetation.

In many cases the current LEP listings do not reflect the full extent of significant trees or vegetation and it is thus important to consult Councils for the most up to date information on LEP listings and proposed listings.

In addition Councils should be asked about any Tree Protection Order or Significant Tree Register in existence, and what that means for proposed tree or vegetation pruning operations in that area. Any necessary prior consents must be obtained before proceeding to undertake pruning. In some cases exemptions from normal consents may be negotiated to expedite pruning in appropriate circumstances.

1.4.2 Vegetation Clearance

There are various regulatory instruments that deal with land clearing activities. The core legislative obligations are contained in the *Native Vegetation Act 2003* ***(NV Act)***. Under this statute, the network operator may be required to obtain a development consent before clearing native vegetation. There is a specific exemption for public utilities and emergency work, but this only operates in respect of land which has yet to become subject to a property vegetation management plan. Where the exemption remains available, it applies to clearing that is to a minimum extent for the maintenance of public utilities (*e.g.*, the provision of power lines and the transmission of electricity) or where native vegetation may reasonably be thought likely to be at risk of causing personal injury or damage to property.

Certain types of land and clearing are excluded from the operation of the *NV Act*, including:

- land zoned as 'residential', 'village', 'township', 'industrial' or 'business';
- land subject to *State Environmental Planning Policy No. 14 - Coastal Wetlands*

  (***SEPP 14***);
- land subject to *State Environmental Planning Policy No. 26 - Littoral Rainforests*

  (***SEPP 26***);
- clearing authorised by the *Rural Fires Act 1997*;
- clearing authorised by the *Noxious Weeds Act 1993.*

SEPP 14 restricts land clearing without consent on certain land designated as coastal wetland. Such development requires concurrence from the Director General of Department of Planning (NSW).

SEPP 19 Bushland in Urban Areas permits disturbance of urban bushland to occur without consent provided it is for the purpose of bushfire hazard reduction; or constructing, operating or maintaining lines for electricity or telecommunication purposes.

SEPP 26 also creates a more rigorous consent procedure where the subject land is designated as littoral rainforest. The Minister administering the *EP&A Act* must concur in granting consent and is required to consider any representation made by the Department of Planning as well as public interest factors.

Unless a licence has been obtained under the *National Parks and Wildlife Act 1974* ***(NPW Act)*** or the *Threatened Species Conservation Act 1995* ***(TSC Act)*** it is an offence under the *NPW Act* to harm any threatened species, population or ecological community. Additionally, the network operator must not, by act or omission, damage any critical habitat. There is also an offence under the *NPW Act* of harming protected fauna.

It is a defence in each of these provisions if the act or omission was essential for the carrying out of development under an *EPA Act* Part 4 development consent or an activity complying with *EPA Act* Part 5. There is provision in the *NPW Act* for the Minister administering the Act to grant an easement or right of way in relation to electricity transmission lines. The Department of Environment and Conservation (NPW Division) maintain two databases which should be consulted on threatened species, the NSW Atlas of NSW wildlife, and the Rare or Threatened Atlas of Plants.

In contrast to the above regulatory instruments, the *Noxious Weeds Act 1993* ***(NW Act)*** imposes a positive duty on the network operator to control noxious weeds on land occupied by it, to the extent necessary to prevent the weeds spreading to any adjoining land.

Other State Environment Planning Policies to consider in managing vegetation are:

- 44 Koala Habitat Protection;
- 56 Sydney Harbour Foreshores and Tributaries;
- 58C Protecting Sydney's Water Supply; and
- 71 Coastal Development.

1.4.3 The Threatened Species Conservation Act 1995

It is the Electricity Distributors responsibility to ensure activities are assessed to determine whether there is an impact on threatened species. This is particularly relevant for proposed developments or activities.

The Department of Environment and Conservation maintains two databases for threatened species:

- Atlas of NSW Wildlife
- ROTAP database

1.4.4 Electricity Supply Act 1995

Section 48 of this Act refers to "Interference with electricity works by trees". This section sets out a Network operator's rights and obligations to require the owner of a premises to trim or remove a tree on those premises which could interfere with that Network operator's electricity works.

Under emergency or failing action of the owner of the premises, the Network operator may carry out the tree trimming work itself.

Other than for trees on easements, or trees planted in a way, which would interfere with electricity works, the Network operator must meet reasonable costs. This is specified where notices have been served on owners of premises to remove or trim trees. Network operators can also carry out the work and recover the costs from owners of premises. Costs incurred by Network operators are recoverable through court jurisdictions. The requirement for the work to be carried out safely by qualified persons always applies.

1.4.5 National Electricity Network Safety Code

The National Codes NENS 01 and 04 in conjunction with the NSW Code of Practice for Electricity Transmission and Distribution Asset Management and HB C(b) 1-2003 'Guidelines for Design and Maintenance of Overhead Distribution and Transmission lines" provide information on safety clearances from overhead power lines. These guidelines state that trees should be kept away from overhead to achieve the following:

- Ensure public safety;
- Minimise the risk of fire caused by the contact between trees and overhead lines;

- Reduce the number of interruptions to supply caused by trees and
- Protect the distributor's assets from damage.

When determining the amount of clearance between trees and power lines consideration should be given to the following:

- Type of line ---- whether it is bare, covered or insulated overhead conductors;
- Conductor sag and swing;
- Tree movement, soundness and regrowth; and
- Overhang of branches.

1.4.6 Electricity Supply (Safety and Network Management) Regulation 2002

This regulation has been enacted to ensure Network Operators under the Electricity Supply Act develop and implement various plans in respect to the operation of adequate, safe and reliable transmission and distribution systems.

The regulation requires the following four (4) plans be lodged with the Director General and implemented by the Network Operator:

1 A network management plan, for the purpose of ensuring that transmission or distribution systems provide an adequate, reliable and safe supply of electricity of appropriate quality.

2 A customer installation safety plan, for the purpose of ensuring the provision of safe electrical installations and connections.

3 A public electrical safety awareness plan, for the purpose of providing a warning to the public of the hazards associated with electricity networks.

4 A bush fire risk management plan, for the purposes of ensuring public safety and for other related purposes (fire risk).

Clause 18 of the Regulation requires that "a person must not carry out work on or near a network operator's transmission or distribution system and a network operator must not allow a person to carry out work on or near its transmission or distribution system unless:

(a) The person is qualified, under the relevant requirements of the network operator's network management plan to carry out the work, and
(b) The work is carried out in accordance with the relevant requirements of that plan.

Generally, the network management plans require that persons are:

Trained – in accordance with Industry Guideline EA18 "Guide to the Training of Personnel Working on or near Electricity Works (October 1999).

Qualified – hold appropriate formal qualifications issued by a Registered Training Organisation (RTO) under the National Training framework.

Authorised - have been formally authorised in writing by the relevant network operator to work on or near its network, and received instruction in any local rules, procedures, precautions, hazards etc. Persons who work across various networks (e.g. Accredited Service Providers) will need to be authorised by each network operator.

Competent – employers have an obligation to ensure employees retain their skills in order to carry out their duties. This may include persons demonstrating their ability to carry out such tasks as Pole Top or EWP Rescue, Control Descent Device, Expired Air Resuscitation, Confined Spaces Rescue etc.

1.4.7 The Electricity Supply (General) Regulation 2001, Part 11

This regulation enables an Electricity distributor to develop a tree management plan in consultation with the relevant local authority and the community at large.

The regulation is seen as a way to ensure the management and protection of trees in accordance with the expectations of the community.

The relevant sections of this regulation are reproduced below:

Clause 102 Preservation of trees

1) A service provider must not remove any tree, or trim any tree in a way that substantially damages the tree, unless:

   a) It is of the opinion that it is necessary to do so to protect its powerlines or the safety of persons or property under or near its powerlines; and
   b) It has considered alternative methods and is of the opinion that none of those methods are feasible in the circumstances (including economically feasible); and
   c) The service provider is acting in accordance with a tree management plan.

2) Alternative methods include, but are not limited to, the use of aerial bundled cables, the controlled trimming of trees and the appropriate location or relocation of powerlines (including placing them underground).

Clause 103 Tree management plans

1) A service provider may establish a tree management plan for the trimming, or for the staged removal and replacement, of those species of trees that have a propensity to interfere with powerlines.

2) A tree management plan may contain (but need not be limited to) the following matters:
   a) Lists of suitable species of trees for planting under or near powerlines in different localities or situations;
   b) Plans for trimming or removing and replacing existing trees and for controlling future planting of suitable species of trees;
   c) Trimming or removing trees in; an emergency;
   d) Methods for trimming trees;
   e) The use of accredited contractors for trimming trees;
   f) The intended allocation of costs between the service provider and the relevant council or councils for the district in which the plan is to operate;
   g) The environmental factors to be considered in trimming trees; and
   h) The development of public education and publicity programs encouraging the selection of appropriate species of trees for planting under or near powerlines.

3) A tree management plan may make different provision with respect to public land, private land, urban land and rural land.

4) A tree management plan may be amended by a subsequent tree management plan.

Clause 104 Consultation with Councils and the public

A tree management plan is to be prepared in a way that gives an opportunity to comment on the proposed plan to the relevant council or councils for the district in which it is to operate, to the residents of the district and to local community groups.

1.4.8 Other Bodies Responsibilities and Requirements

In accordance with the provisions of the many pieces of legislation it is necessary to comply with the requirements of other bodies.

- **Rural Fires Service Act 1997**

Electricity distributors are represented on bush fire management committees, which have been established in local government areas outside Sydney and Newcastle. These committees are charged with preparing bush fire management plans that contain procedures for controlling fires and for managing fuel levels.
The committees are well placed to provide advice and the plans they prepare can provide statutory support for fuel management.

- **National Parks and Wildlife Act 1974**

Electricity distributors are required to comply with the provisions of the act particularly in regard to management issues of vegetation in land located in or administered by the Department of Environment and Conservation (DEC).

Particular attention needs to be given to Historic sites and items of European and Aboriginal archaeology.

A document called "Procedures for power line maintenance in lands administered by the National Parks and Wildlife Service of NSW' produced by the former 'Electricity Association of NSW' sets out the agreed practices between the parties in regard to the inspection and maintenance of powerlines.

The DEC (NPW) can be contacted on www.npws.nsw.gov.au

- **National Trust of Australia Act 1990 and Local Historical Societies**

To ascertain the location of important or significant trees, electricity distributors should also consult local or district historical societies, the National Trust of Australia (NSW) and local councils. The Trust will assist in the recognition and provision of advice on the handling of significant trees in any area and to give briefing and written material to any electricity distributor.

The National Trust can be contacted on www.nsw.nationaltrust.org.au

- **Sydney Water Catchment Management Act 1998**

Attention needs to be paid to areas that are deemed for the preservation of water supply in the special catchment areas.

Electricity distributors are required to make arrangements with Sydney Catchment Management Authority in regard to maintenance of powerlines and vegetation in the Special areas.

- **Trees and Plant Communities of Special Value**

Trees and plant communities of special value may be identified under any of the above statutes or instruments.

Special attention should be paid to botanically, ecologically or scientifically significant vegetation important or historically significant stands of trees, stands of special aesthetic significance, or rare and threatened plant species or ecological communities. Every endeavour should be made to ascertain where such important or significant trees are located.

In the first instance, electricity distributors should contact Local Council tree protection or heritage officers, the NSW National Trust, the State Heritage Inventory www.heritage.nsw.gov.au) and the DEC for information on rare or endangered, significant, protected or heritage listed trees or vegetation areas.

See definitions at the beginning of the document for definitions and more information regarding the terms tree, significant tree, protected tree, heritage listed tree and protected area.

Several options may be exercised when trimming or pruning is required of trees of special value and agreement may be reached in reducing the regrowth allowance. The options could include the replacement of trees or the relocation of the power lines albeit these options are more suitable for inclusion in a tree management plan.

- **The Heritage Act 1977**

The *Heritage Act 1977* provides that where a place is subject to an interim heritage order issued by the Heritage Council or is listed on the State Heritage Register, it is an offence to damage the place, carry out any development on the land or damage or destroy any vegetation on the land without the prior approval of the Heritage Council.

Such places can include private gardens, public parks or reserves, residential streetscapes or districts, stock routes and colonial roads lined with trees or vegetation, natural areas such as forests, wetlands and human modified landscapes such as farming land with scattered woodland cover.

The list of places on the State Heritage Register can be accessed on www.heritage.nsw.gov.au by searching by Local Government Area or address or place name. In addition the State Heritage Inventory, listing all heritage items with statutory protection (e.g.: LEP heritage items, Interim Heritage Orders or listed on the State Heritage Register) in NSW. Further information is available on the same website, or by contacting the NSW Heritage Office on telephone 02 9873 8500.

The Minister responsible for Heritage has the power to make Interim Heritage Orders and stop work orders to protect places under threat, or defer development to allow assessment and appropriate protection of places with recognised or potential heritage values.

Unless specific exemptions from normal approval have been granted by the Minister responsible for the *Heritage Act 1977* over such areas for activities such as tree pruning, electricity distributors require specific prior approval from the Heritage Council of NSW under section 60 of the Act. Section 60 forms can be downloaded off the NSW Heritage Office website on www.heritage.nsw.gov.au. Specific approval exemptions to allow appropriate regular pruning in specific places or circumstances can be negotiated and agreed with the Heritage Office. The Heritage Act also requires prior Heritage Council approval of excavation permits when excavating in areas of known or potential archaeological resources.

- **State Emergency and Rescue Management Act 1989**

The SERM Act requires local government authorities to prepare Local Disaster Plans based on emergency risk management assessments conducted in accordance with AS/NZS 4360:2004. These assessments include the response measures required and agencies responsible for mitigating foreseeable risks caused by either natural or technological causes or events. Emergency means an emergency due to an actual or imminent occurrence (such as fire, flood, storm, earthquake, explosion, terrorist act, accident, epidemic or warlike action), requiring a coordinated emergency response.

The emergency risk assessments and Local Disaster Plans are developed in consultation with local communities and stakeholders and are required to be agreed to by the Local Council and successively the District and State Emergency Management Committees, on which Network Service Providers are represented.

These assessments may warrant the removal of vegetation near power lines that poses an identifiable risk to the power supply infrastructure, for example due to a severe weather event, earthquake or related infrastructure failure.

- **Other Legislation**

Listed below are some of the major environmental or land management legislation Electricity distributors should have an understanding of:

- Rivers and Foreshores Improvement Act 1948
- Crown Land Act 1989
- Noxious Weeds Act 1993
- Fisheries Management Act 1994

1.5 Part D: Occupational Health and Safety Obligations

Activities of the Network Operators	Relevant Legislation, Regulations or Codes of Practice
General Occupational Health and Safety obligations	• Occupational Health and Safety Act 2000
Specific Occupational Health and Safety obligations	• Occupational Health and Safety Regulation 2001
Risk Management obligations, training, supervision, personal protective equipment, first aid facilities, amenities and emergency provisions	• Chapter 2 OHS Regulation • WorkCover Code of Practice – Risk Assessment
Workplace consultation	• Chapter 3 OHS Regulation • WorkCover Code of Practice - Consultation
Work premises and working environments	• Chapter 4 OHS Regulation, Note: This chapter deals with a number of activities relevant to network operators for tree management, fall prevention, electricity, heat &cold, noise and manual handling • WorkCover Code of Practice – Technical Guidance
Plant (Machinery, tools and equipment)	• Chapter 5 OHS Regulation • WorkCover Code of Practice – Risk Assessment • WorkCover Code of Practice – Technical Guidance
Hazardous substances, MSDS, labelling, health surveillance	• Chapter 6 OHS Regulation • WorkCover Codes of Practice – Hazardous Substances (3 Codes)
Hazardous processes	• Chapter 7 OHS Regulation • WorkCover Codes of Practice – Technical Guidance • WorkCover Code of Practice – Low voltage electrical work
Construction work	• Chapter 8 OHS Regulation • WorkCover Code of Practice – Technical Guidance
Certification of workers	• Chapter 9 OHS Regulation
Accident Notifications	• Chapter 12 OHS Regulation

Note 1: The above information must not be used as a substitute for the OHS Regulation or OHS Act. Employers should consult the full Act and Regulation to determine their OHS obligations and responsibilities.

Note 2: At the time of publication of this Guideline, WorkCover was developing the "Code of Practice-Work near Overhead Power Lines", which will replace the ISSC 26 "Interim Guide for Operating Cranes and Plant in Proximity to Overhead Power Lines". The new Code is expected to be gazetted in 2006.

2. SAFETY AND CLEARANCES BETWEEN VEGETATION AND POWERLINES

2.1 General

The clearing and pruning of vegetation should be carried out in a manner as to ensure the health and safety of all persons. Injuries (including electrical injuries) can be avoided if potential hazards are identified before work commences on a property or site. Before commencing work follow three basic steps,

- Identify all hazards;
- Assess the risks of the work; and
- Control any problems so it is safe to commence work.

Clause 64 of the Occupational Health and Safety Regulation 2001 requires that persons, their plant and tools must not come into close proximity with overhead power lines (except if the work is done in accordance with a written risk assessment and safe system of work and the requirements of the relevant network operator).

In addition to the above requirements all persons involved in tree trimming operations shall be appropriately supervised, trained, qualified, authorized and competent in the work to be performed.

In addition to the clearances to conductors discussed below, consideration must also be given to creating safe access to other electricity assets and within the power line corridors.

2.2 Tree Clearances for Conductors

The clearances stated in Table 1 "Minimum Safety Clearance Radius for Bare and Covered" and Table 2 "Minimum Safety Clearance Radius for ABC and Covered Conductors (Insulated)" are the clearances that should be achieved where possible. Negotiations with local Councils may be required where existing agreements are in place and the agreed clearances differ from those shown in the tables mentioned above.

2.3 Vegetation Management for Crane and Plant Operations (also refer to Industry Guide ISSC 26)

As required by the "Guide for Operating Cranes and Plant in Proximity to Overhead Power Lines" (ISSC26) the operator of the crane and the safety observer must have; and have documentary evidence of:

a) Following completion or recognition of the "Crane and Plant Electrical Safety Course", successfully undertaken a competency assessment in the "Crane and Plant Electrical Safety Course" at an interval no greater than twelve months from the previous assessment This is necessary to operate cranes and plant in the vicinity of live overhead power lines.

b) An Elevating Work Platform operator's **Certificate of Competency** issued under the Occupational Health and Safety Regulation 2001, or be a trainee undertaking on-the-job training under the direct supervision of a qualified operator.

c) Within the previous twelve months, demonstrated their ability to apply rescue procedure in the event of an accident associated with electrical apparatus and their ability to apply resuscitation procedure.

d) Having undertaken annual training in Network Operator's Safety Rules as required by the Electricity Supply (Safety and Network Management Plans) Regulation 2002;

e) Worksite Risk and Hazard Assessment.

f) Any Elevating Work Platforms and all tools must be insulated and tested every six months to the necessary voltage requirements in accordance with Industry Guideline EC14 "Guide to Electrical Workers Safety Equipment".

Note: At the time of publication of this Guideline, WorkCover was developing the "Code of Practice-Work near Overhead Power Lines", which will replace the ISSC 26 "Interim Guide for Operating Cranes and Plant in Proximity to Overhead Power Lines". The new Code is expected to be gazetted in 2006.

2.4 Additional Safety Requirements

a) All persons must be authorised by the Network Operator, including where appropriate, authorisation to accept Access Permits for trimming in the vicinity of high voltage conductors.

b) All safety clearances must be maintained in accordance with the Network Operator's and Industry requirements.

c) Tree trimmers will have completed as a minimum qualification "Tree Care for Electricity Workers" or its equivalent. Other courses may be developed and National Competencies may be set.

d) Where trees are being climbed, tree trimmers will be appropriately trained.

e) Where trees are being trimmed around live conductors, tree trimmers will be appropriately trained, qualified, authorised and competent.

f) Where traffic control measures are required, personnel will be appropriately trained to Roads and Traffic Authority requirements.

g) Where persons are using chain saws and other powered equipment, they shall be trained in their safe use.

h) All Personal protection equipment eg clothing, gloves etc will meet the requirements of "*Guide to Electrical Workers Safety Equipment*" (EC14) and the Network Operator's requirements.

2.5 Occupational Health and Safety Act (2000) and Regulations (2001)

In addition to the requirements outlined in Sections 1.5, 2.3 and 2.4 above, all general workplace safety measures required under the Occupational Health and Safety Act, 2000 and the Occupational Health and Safety Regulation, 2001 shall be complied with. These typically include the risk management provisions relating to hazard identification, risk assessment and risk control.

An employer must also consult with their employees to enable the employees to contribute to the making of decisions affecting their health, safety and welfare at work. Other provisions relating to plant safety, workplace amenities, first aid kits, accident notification, etc are also covered by the OHS Act and the OHS Regulation.

3. VEGETATION MANAGEMENT

3.1 General

Network operators have statutory obligations to maintain electrical assets in a safe and operable condition. However providers have in the past come under some criticism in their lack of flexibility in line clearing practices.

It is understood that there are particular difficulties in maintaining vegetation clear of powerlines in both densely populated, rural areas and in National Parks and open space reserves. Network operators are always considering ways to improve their environmental management practices.

Network Operators are aware that the electricity network is not the only use required of road reserves, parks and natural areas, however ensuring the safety of the public is of paramount importance in addition to maintaining a reliable electricity supply, however community expectations and aesthetic and environmental imperatives have a significant claim for consideration in this process.

It is important that all stakeholders consider open space values (tourism, recreation and amenity), the role of the land in terms of broader ecological sustainability as well as heritage considerations in maintaining and planting vegetation near powerlines.

Since 1977 there has been a marked growth in community concern and thus a rise in statutory heritage listings on LEPs and the State Heritage Register, Tree Protection Orders covering Local Government Areas and Significant Tree Registers. This parallels lobbying for and gazettal of increased areas of National Parks and other forms of nature protection reserves.

These listings have been for individual trees, groups of trees, avenues and street plantings, parks, reserves and natural areas. This reflects the increasing value the community is placing on remnants of the natural world and the cultural significance it places on human modified landscapes and plantings, of both native and exotic species.

The community is increasingly valuing the role and benefits of trees and vegetation in increasingly crowded and dense cities, sprawling suburbs and industrial lands, and their value in providing open space, recreation, tourism escapes, clean air and water.

Consideration would include but not be limited to, tree species present and their cultural requirements, tree age, local and regional ecological values and recognised and potential heritage values. They would also include consultation with Local Councils and relevant agencies to determine any significant, protected or heritage listed vegetation, necessary consents required. To effect appropriate management strategies, vegetation managers must be aware of planning instruments and policies at a local, regional and state and national level. These policies should be considered and acknowledged in the development of vegetation maintenance and tree planting programs or approvals. Such programs must contain a mechanism to monitor and review performance and hold service delivery accountable with regard to effective outcomes in these areas.

An important consideration for the implementation of a network management strategy is the issue of sustainability. Pruning that considers only line clearance without considering the broader, long term impacts on vegetation management has a very real potential for creating long term hazards in large numbers of street trees.

Trimming of vegetation at growth points and branch collars is to be conducted in accordance with the principles of Australian Standard AS 4373-1996.

Practical application will be given to the appearance of trees beneath overhead electricity lines having regard to the consideration that trees are often capable of maintaining heights greater than the lines themselves or the clearance envelope in Drawing 1 and Table 1.

Likewise inappropriate vegetation clearance can lead to altered species representation, local extinctions and detrimental physical effects such as weed invasion and soil erosion. All of these are legacies for other land managers.

Proper planning is essential in areas adjacent to powerlines. The planting of vegetation in the areas adjacent to powerlines must be carefully considered as large or fast growing species can lead to Network operators, Local Councils and other land managers committing additional resources in the future to ensure effective management.

In addition the areas within and surrounding electrical substations and equipment may require additional clearing / vegetation removal to create and or maintain Asset Protection Zones (refer RFS bushfire guidelines) in addition to the requirements for safety and security.

Water crossing signs require specific vegetation management attention in order to ensure visibility by approaching vessel in accordance with the Waterways Authority requirements.

3.2 Recognition of Land Types

There are essentially two locations that contain power lines. One is on public road reserve verges, the other location is on private properties.

For the purposes of this guideline these locations can be further categorised into the following;

- Urban
- Non-Urban
- Within Electricity Easements

In determining the most appropriate method of managing vegetation in a given location it is vital to be aware of the category of land type in which the vegetation exists. Different land use types may require different management strategies to successfully manage its vegetation, and delivering outcomes acceptable to the community. For example: a tree on an urban road reserve with no access difficulties may be managed differently to a tree on an urban property where access is very difficult. Management of vegetation within electricity easements is expanded in ISSC 20 "Guidelines for the Management of Electricity Easements".

3.3 Community Consultation

As outlined in the Scope of this guideline, the requirements for the establishment of new overhead power lines are addressed in industry guide *"Guidelines for the Development of Electricity Systems Community and Environmental Considerations"* (ISSC22). That guideline details the need for community consultation for the establishment of new power lines, particularly at the higher voltages. Larger projects may require a Review of Environmental Factors (REF) or an Environmental Impact Statement (EIS) that could involve formal engagement of community groups, publication of DRAFT documents for public comment, public advertisements and even open public forums and meetings.

In this guideline we are concerned with the maintenance of vegetation near the existing, built infrastructure. Consequently, community consultation in that context may generally involve:-

- Notification to customers, either generally (by way of public advertisement) or individually by card, letter or power bill, that vegetation work is about to commence in their area or street;
- Notification to an individual customer regarding a tree on their property that requires trimming;

- Notification to individual customers that a planned interruption to supply is required to carry out vegetation management work (usually 48 hours notice is given);
- Liaison with the local council that vegetation management work is about to commence in an area, particularly where a mutual obligation arrangement exists for the local council to chip or dispose of the trimmed material; and
- Liaison with the local council, community groups and other stakeholders when a new Vegetation Management Plan (see section 1.4.8), Vegetation Management Agreement (see section 3.6), or other local initiative is being negotiated between the local council and the local electricity distributor. This may involve invited public input, comment or meetings.

3.4 Factors Influencing Vegetation Management Options

Many factors will have an influence on the vegetation management option selected for any particular location. Land type is one influence and others may be:

- **Voltage of the Existing Power Lines**

Relevant when determining feasibility and costs associated with insulating the electrical network. Public risk or network reliability priorities may influence the proposed tree trimming works.

- **Tree Species**

Certain species are more likely to have a more aesthetic appearance after pruning. For example *Lophostemon confertus* (Brush Box) because of it's broad domed natural canopy. This is contrasted by other species such as Eucalyptus sp. which in general have a straight or erect type branching habit and therefore do not prune well.

- **Tree Health**

The tree's health should be one of the factors considered in the overall environmental assessment of the tree/s in determining the preferred vegetation management option.

- **Number of Trees**

May be a factor if removal and replacement is being considered. A street with many trees may provide a significant amenity and removal would have a significant impact on the area. This may be the situation even if the trees are in poor health. However, if a lone tree in poor health or a lone tree with an unsuitable branching habit (see above in Tree Species subheading), then consideration would be given to the removal and replacement of that tree.

- **Trimming Costs/Constraints**

A factor in considering possible environmental enhancement and removal/replacement.

- **Removal and Replacement / Tree Management Plan, Costs**

The costs should be carefully considered when assessing this vegetation management option, in comparison to retaining the trees and continuing to trim.

- **Good Corporate Citizenship**

An important factor when considering the ramifications of all options and processes of vegetation management.

- **Environmental Enhancement Program**

A selective program of environmental enhancement of the network (e.g. Use of insulated cables, undergrounding etc.).

- **Network Reliability**

Overall, one of the three key performance indicators for vegetation management. Consequently a strongly weighted factor to be considered when selecting the vegetation management option, particularly for voltages at or above 11kV.

- **Access**

Access to trees in certain locations such as urban backyards can prove very difficult. This combined with other influencing factors such as network reliability and safety will play a major part in selecting the correct management option.

- **Technical Feasibility**

Various technical options do exist such as the use of Aerial Bundled Cable (ABC), however not all situations make these options feasible. Correct assessment of the feasibility is essential, as other factors will influence this option, particularly costs.

Consideration of the various influencing factors (not all factors will be relevant in every situation) will assist in determining the most appropriate and realistic vegetation management option. It is important that this determination be justified against Section 2.1, and although the required factors for consideration in this section are not weighted, they nonetheless should be responsibly assessed to demonstrate the outcome determined.

3.5 Vegetation Management Options

Having considered the factors influencing a given situation, determination should then be given as to the most suitable vegetation management option to be taken. These options may include one or more of the following:

- **Trimming**

To be carried out in accordance with the practices outlined in this guideline and to maintain safety clearances.

- **Removal/Replacement**

To be carried out only after environmental assessment, consultation and a formal Tree Management Plan. Refer to the *Electricity Supply (General) Regulation 2001 Part 11* contained within the *Electricity Supply Act 1995.*

- **Slashing**

A limited option for distribution voltages and suitable for specific locations only. Commonly used for transmission line easements and acceptable within National Parks. Formal assessment will be required.

- **Climbing and Trimming**

This limited option works particularly well when managing large trees in situations where EPV access is not possible, or severely restricted. This option may also be useful in certain situations where live line trimming is not viable. It is also a cost-effective option where only a small number of trees need to be trimmed and in environmentally sensitive lands.

- **Close Approach Trimming near Live High Voltage Mains and Equipment**

Cost effective option, maintains supply and therefore helps reliability factor. Consequently a very good option where continuous supply is essential (e.g. near hospitals, commercial centres etc.).

- **Environmental Enhancement Works**

A program specifically set up to improve the aesthetic impact of the overhead power lines on the environment. Such a program is aimed to maximize the benefits to the general community, while demonstrating good corporate citizenship.

- **Undergrounding Overhead Power Lines**

A desirable solution but often financially unrealistic on a large scale. Selected locations may be cost effective after assessing all environmental factors.

- **Insulate Overhead Power Lines**

Aerial Bundled Cable (ABC), LV & HV - A good solution where large trees are retained below power lines. Allows a tree's canopy to develop under, around or over power lines, although the safety clearances must be maintained – refer Drawing 2 and Table 2.

Covered Conductor Thick (CCT), 11kV & 22kV - Similar to ABC and may reduce the trimming required. This Cable is designed for large trees growing adjacent to the power lines rather than directly under.

- **Re-Route Overhead Power Lines**

Could be considered after assessing all the environmental factors. Limited application as this option may create a new problem and effects along the alternate route.

- **Offset Crossarm Construction**

An option where room permits on roadside verge and where trees are planted offset from the power lines (may be combined with use of insulated cabling). May be particularly suited to column shaped trees such as pines, or palm trees.

- **Use of Taller Poles**

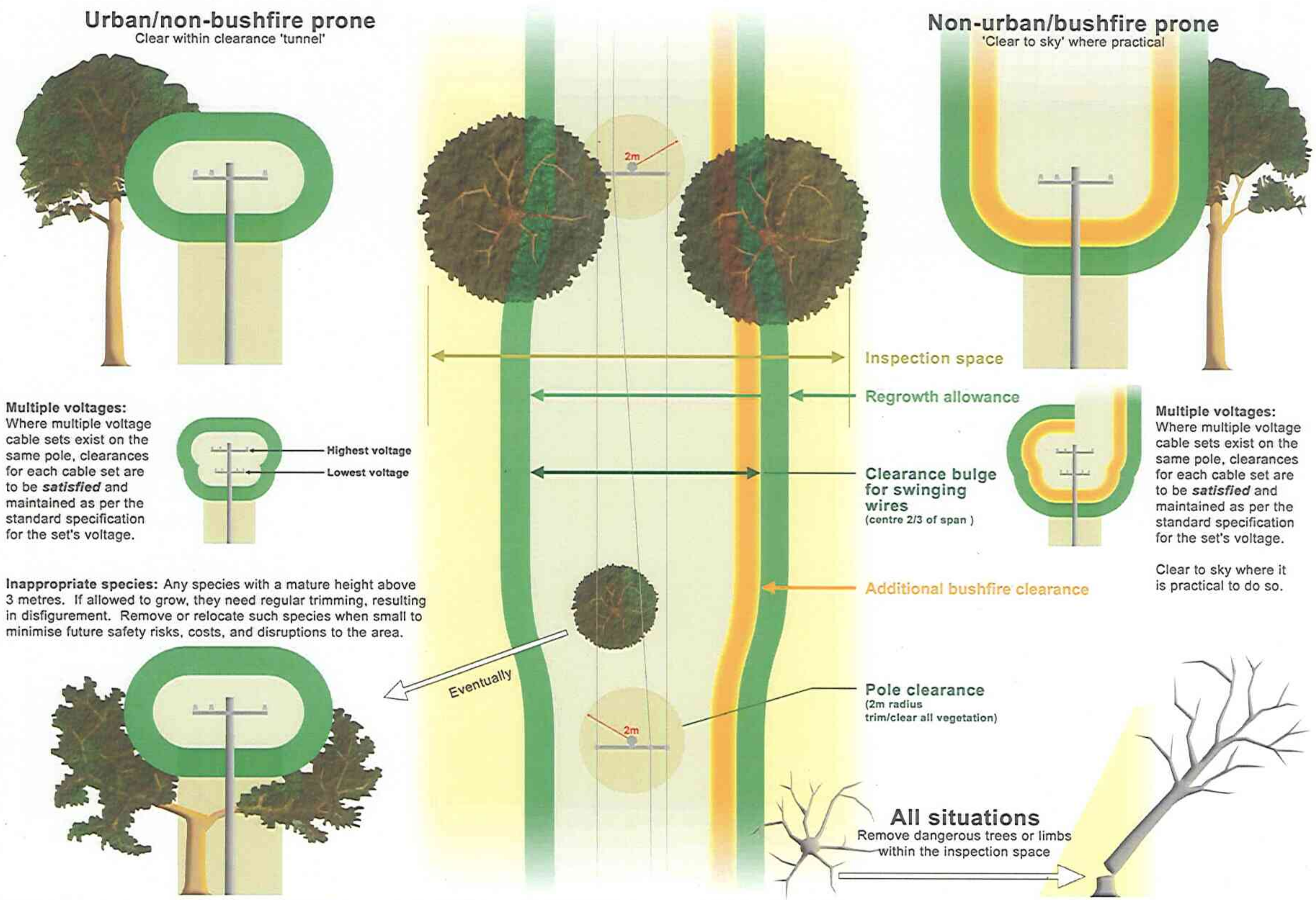
An option where tree health is good, trees will canopy below the wires, and tree numbers in a span are significant. However, insulation of the network may be the superior option.

3.6 Vegetation Management Agreements

Vegetation Management Agreements are another option to be considered which would put in place the protocol for managing vegetation in each of the local councils in the Network Operators' area. The key objectives would be negotiated between the two parties and may include such initiatives as tree removal arrangements, use of insulated cables or undergrounding where appropriate, preferred species selections for the streetscapes to achieve thematic, heritage or aesthetic outcomes, etc.

4. DRAWINGS and TABLES

4.1 Drawing 1: "Clearances for Bare Conductors and Covered Conductors"



4.2 Table 1: Minimum Safety Clearance Radius for Bare and Covered Conductors (CC)

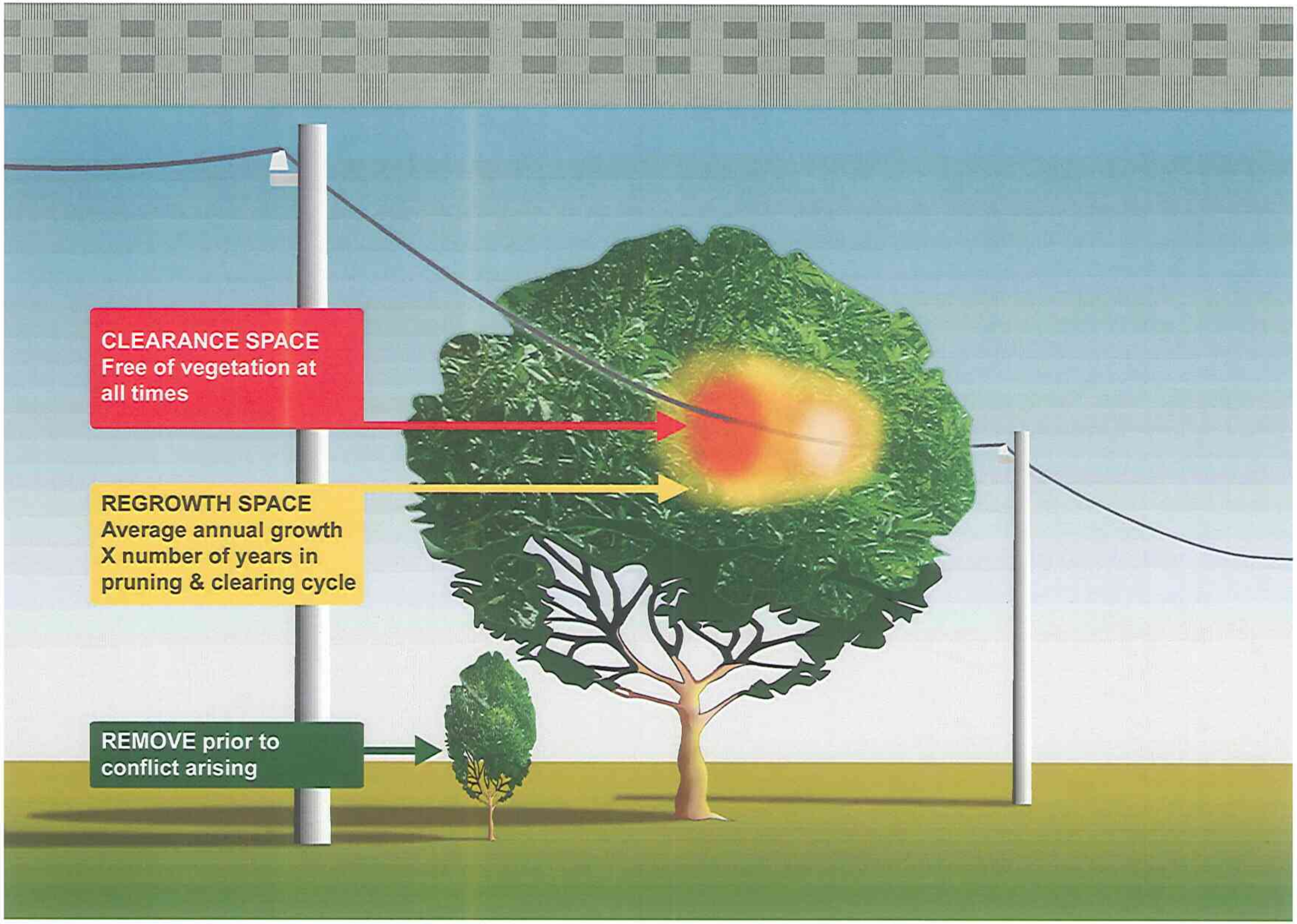
Cable Type & Operating Voltage	Distance along span				
	At Pole and 1/6th either side	Middle 2/3 of span less than 50m span	Middle 2/3 of span between 50m to 100m span	Middle 2/3 of span between 100m to 200m span	Middle 2/3 of span between 200m to 300m span[1]
Up to and including 1000V Bare LV and service lines	1.0m	1.0m	1.0m	2.5m	4.0m
Up to and including 1000V Covered LV and service lines	0.6m	0.6m	1.0m	2.5m	4.0m
Bare above 1000V up to and including 22kV	1.5m	1.5m	2.5m	3.5m	5.0m
Bare 33kV up to and including 66kV	2.0m	2.0m	3.0m	4.0m	6.0m
Bare 132kv	3.0m	3.0m	4.0m	5.0m	6.5m
11kV up to and including 22kV Unscreened CC	1.0m	1.5m	2.0m	2.5m	N/A

Note 1: For spans greater than 300m and clearances for voltages above 132kV to 500kV refer to specific construction types and design criteria or other specific requirements of the Network Service Provider. Also in specific circumstances the Network Service Provider may increase these minimum clearances due to other network constraints, e.g. High reliability requirements for Hospitals etc.

Note 2: Above table does not include any allowance for regrowth or additional clearances in Non-Urban/Bushfire prone areas.

See Drawing 1 for a diagram showing the application of this table.

4.3 Drawing 2: "Clearances for Aerial Bundled Cable and Covered (Insulated) Conductors"



4.4 Table 2: Minimum Safety Clearance radius for ABC and Covered Conductors (Insulated)

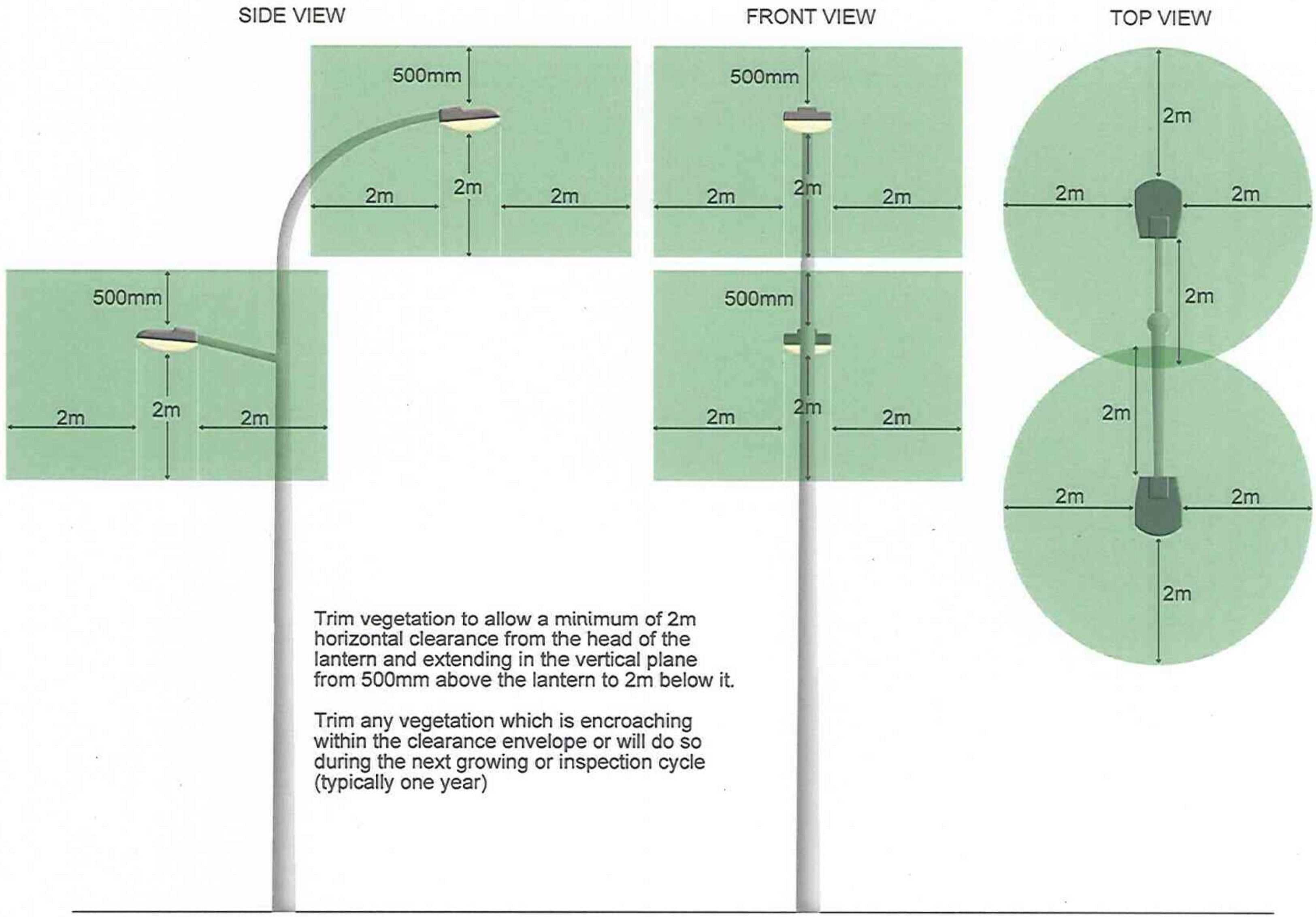
Cable Type & Operating Voltage	Distance along span		
	At Pole and 1/6th either side	Middle 2/3 of span less than 100m span	Middle 2/3 of span Greater than 100m
Less than 1000V LV ABC / Insulated XLPE Service lines	0.5m	0.5m	1.0m
11kV ABC / Screened CC or CCT	0.5m	0.5m	1.0m

Note 1: Above table does not include any allowance for regrowth or additional clearances in Non-Urban/Bushfire prone areas.

Note 2: Trim any twigs or branches thicker than your thumb (approximately 15mm diameter) which are in the aerial bundled conductor clearance tunnel, or which will encroach into the tunnel within the clearing cycle under still air conditions. The clearance tunnel should take into consideration variation in sag between support structures. (This requirement may not be applicable in Bushfire prone areas at the discretion of the Network Operator).

See Drawing 2 for a diagram showing the application of this table.

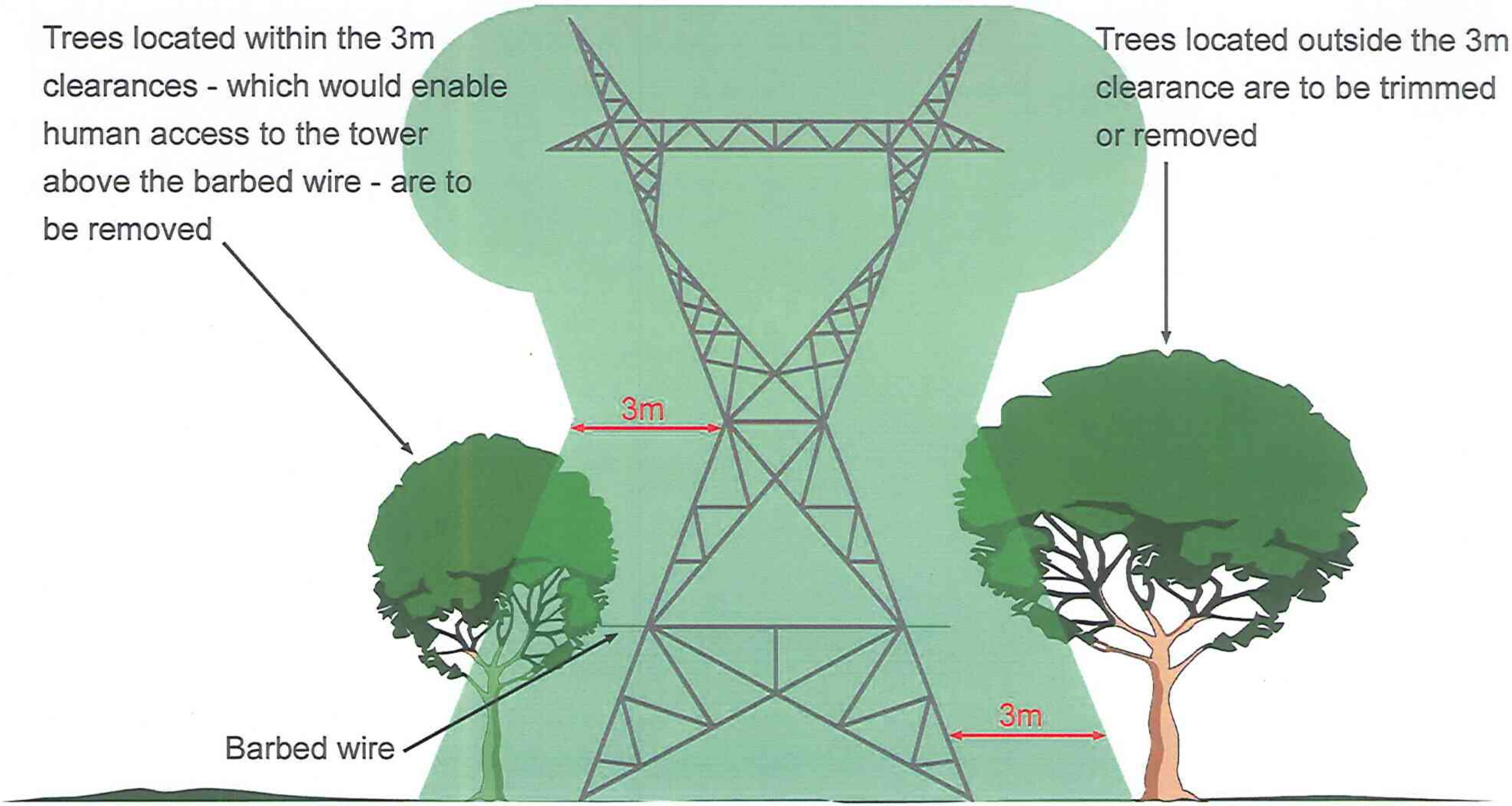
4.5 Drawing 3: "Clearances from Streetlights"



Trim vegetation to allow a minimum of 2m horizontal clearance from the head of the lantern and extending in the vertical plane from 500mm above the lantern to 2m below it.

Trim any vegetation which is encroaching within the clearance envelope or will do so during the next growing or inspection cycle (typically one year)

4.6 Drawing 4: "Clearances from Tower Structures"



4.7 Table 3: Minimum Safety Clearances from Poles & Tower Structures

Structure	Clearance
Poles	Clearances around all poles of all types and voltages is 2m radius, see Drawings 1,2 & 3.[1]
Tower Structures	3m radius around the tower or a 12m radius from the tower centre whichever is the greater. See Drawing 4 Tower plan.

Note 1: Consideration should be given to retaining vegetation of amenity value but clearances must be achieved to:

- **prevent vegetation contacting the pole;**
- **enable the unhindered climbing of ladders in safe locations; and**
- **ensure that there is adequate clear space for a full excavation and inspection of the below ground area around the pole.**

For clearances around Streetlighting lanterns see Drawing 3.

For clearances around Towers see Drawing 4.

4.8 Table 4. Regrowth allowances

Dependent on species and locality an allowance for growth must be assessed on a case by case basis. These columns indicate the estimated normal additional growth allowance that may be applied in the different vegetation circumstances - see Drawings 1 and 2.

This table gives the allowance for regrowth between inspection / maintenance cycles.

Location	Shrubs and mature trees	Typical native and introduced vegetation	Fast growing species in favourable environments and lopped vegetation
Urban areas where trimming cycles are short, typically annual	0.5m	1m	2m
Rural areas where trimming cycles are longer, typically 3 years.	1m	3m	6m

4.9 Additional clearances in Non-Urban / Bushfire Prone areas

Clearing vegetation above the conductors ("clear to sky"), in accordance with Drawing 1, should be implemented wherever possible in Non Urban / Bushfire prone areas. Consideration may be given to reduce this requirement where there is an occupied property within 25m of the lines.

At the discretion of the Network Service Provider an allowance of 0.5m may be added to the minimum safety clearances in Table 1 for bare conductors in Non Urban / Bushfire prone areas. This allowance is added to the minimum safety clearances before regrowth allowances are applied.

Other strategies such as specific maintenance or inspection cycles may be used instead of, or in conjunction with, the 0.5m suggested, based on the risk management profile of the network operator.

5. APPENDIX A: NSW Heritage Register Criteria

An item will be considered to be of State (or local) heritage significance if, in the opinion of the Heritage Council of NSW, it meets one or more of the criteria shown in the box below. While all criteria should be referred to during the assessment, only particularly complex items or places will be significant under all criteria. In many cases, items of environmental heritage will be significant under only one or two criteria.

In using these criteria it is important to assess the values first, then the context in which they are significant. Decide the appropriate context by considering similar items of local and State significance in each of these contexts. These criteria were gazetted following amendments to the *Heritage Act 1977* which came into force in April 1999. The Heritage Council determines the criteria for State significance and issues guidelines to assist in their application.

Criterion (a) -	an item is important in the course, or pattern, of NSW's cultural or natural history (or the cultural or natural history of the local area);.
Criterion (b) -	an item has strong or special association with the life or works of a person, or group of persons, of importance in NSW's cultural or natural history (or the cultural or natural history of the local area);
Criterion (c) -	an item is important in demonstrating aesthetic characteristics and/or a high degree of creative or technical achievement in NSW (or the local area);
Criterion (d) -	an item has strong or special association with a particular community or cultural group in NSW (or the local area) for social, cultural or spiritual reasons;
Criterion (e) -	an item has potential to yield information that will contribute to an understanding of NSW's cultural or natural history (or the cultural or natural history of the local area);
Criterion (f) -	an item possesses uncommon, rare or endangered aspects of NSW's cultural or natural history (or the cultural or natural history of the local area);
Criterion (g) -	an item is important in demonstrating the principal characteristics of a class of NSW's: • cultural or natural places; or • cultural or natural environments. (or a class of the local area's: • cultural or natural places; or • cultural or natural environments.) An item is not to be excluded from the Register on the ground that items with similar characteristics have already been listed on the Register

Different components of a place may make a different relative contribution to its heritage value. Loss of integrity or condition may diminish significance. In some cases it may be useful to specify the relative contribution of an item or its components.

Other criteria for significance for a tree or group of trees are any of:-

- It/they make/s an important contribution to the character or amenity of the local area;
- It/they is/are indigenous to the local area and its species is listed under the *Threatened Species Conservation Act 1995*; or
- It/they represent/s an important habitat for native fauna; or
- It/they is/are part of a wildlife corridor or a remnant area of native vegetation;
- It/they is/are important to the maintenance of biodiversity in the local environment; or
- It/they is/are a notable visual element to the landscape of a local area.

6. APPENDIX B: Additional Reading

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BOARD POLICY

SUPPLY MANAGEMENT	Document No:	12.0.1
	Amendment No:	0
	Approved By:	CHMN
	Approval Date:	7 / 3 / 2012
	Review Date:	7 / 3 / 2015

(Supersedes Board Policy (Supply Management) 12.0 am3)

12.0.1 PURCHASING

1.0 POLICY STATEMENT

The Company will purchase goods and services by obtaining the best value for money and, whenever reasonably possible, promoting open and effective competition. The Company will ensure that all procurement activity is conducted in accordance with the law and the Company's Code of Ethics, Statement of Business Ethics and will not support any individual who knowingly or recklessly breaches the law, including Occupational Health & Safety (OH&S) and environmental legislation. The Company will also seek to engage suppliers who align with its corporate values and meet high standards of capability, performance, quality, OH&S, risk and environmental management.

2.0 PURPOSE

To set down the principles for supply management, comprising of the procurement of goods and services and associated arrangements for the Company.

This policy covers purchasing arrangements for all goods and services sourced by the Company, including consultancy and advisory services. However, this policy does not extend to the following:

- the Company employment contracts;
- acquisition of real estate and subsequent licence or lease payments;
- sponsorship arrangements;
- payments to Local, State or Federal Government departments and statutory bodies;
- transfer of network assets;
- renewals of subscriptions to magazines, bulletins or newspapers;
- fees associated with membership of professional associations or industry accreditations;
- refunds of contributions for the demand management program;
- purchase of services from meter providers in respect of customers outside the Company's franchise area; and
- purchase of professional publications or subscriptions to professional companies.

3.0 REFERENCES

Board Policy 3.0 – Occupational Health and Safety
Company Policy (Supply Management) 12.4 – Probity in Procurement
Company Procedure (Supply Management) GSU 0001 – Purchasing
Company Procedure (Supply Management) GSU 0007 – Supplier Assessment Supply Quality Register
Code of Ethics
Statement of Business Ethics
Competition and Consumer Act 2010

4.0 DEFINITIONS

Executive Leadership Team
Includes Chief Financial Officer, Company Secretary, Deputy CEO Corporate, Deputy CEO Network, General Manager Health & Safety and General Manager Support Services.

Financial Delegate
The position nominated within Company Policy 1.1.1 – Sub-Delegations of Authority by the Chief Executive Officer to approve expenditure.

procurement
The end-to-end process associated with sourcing goods and services including, without limitation, planning, market research, sourcing, disposal, contract management, supplier relationship management, and benefits tracking. For the purposes of this procedure the term procurement is used interchangeably with the term purchasing.

review date
The review date displayed in the header of the document is the default date for review of a document. A document review may be required at any time where a need is identified due to changes in legislation, organisation changes, restructures, occurrence of an incident or changes in technology or work practice.

Tender Review Committee (TRC)
A committee convened to give comfort to the Chief Executive Officer and the Board that, with respect to a proposed procurement, the principles of probity have been addressed. The threshold level for purchases reviewed by the TRC is documented within the TRC Charter.

5.0 KEY REQUIREMENTS

Procurement arrangements will:

- Seek to minimise transaction costs, administrative costs, waste management costs, maintenance costs, inventory holding and any other consequential costs associated with a good or service.

- Support reliable supply of goods and services to employees with operational and governance responsibilities (right product, right time, right place).

- Promote open and effective competition whenever reasonably possible and ensure a robust and auditable process is in place to manage any exceptions.

- Deliver value for money to the Company. That is, offers accepted from suppliers for products and services will represent the best value for money having regard to the extent to which the offer satisfies the Company's requirements, the value of the offer and the benefits compared to whole of life costs.

- Reflect the Company's Code of Ethics and Statement of Business Ethics and be robust enough to withstand the scrutiny of independent third parties, such as Independent Commission Against Corruption, Parliament or the media. All arrangements will be transparent and at arm's length.

- Comply with Occupational Health & Safety and environmental management systems by enforcing appropriate diligence on products, services and service providers brought into the Company.

- Support delegated authorities set down by the Chief Executive Officer and the Board.

- Reflect the Company's commitment to compliance with the *Competition and Consumer Act 2010* and principles of open and effective competition.

- Will include appropriate documentation to ensure audit ability and enforceability of supply arrangements.

- Seek to consistently engage suppliers who align with the Company's corporate values and meet high standards of capability, performance, quality, OH&S, risk and environmental management.

6.0 ACTIONS TO ACHIEVE IMPLEMENTATION OF THIS POLICY

- Communicate the policy to all employees.

- The Company will establish and maintain supply management procedures based on the premise that best value for money is obtained through fair and open competition.

- Develop, communicate and implement procedures to support the policy.

- Audit the implementation of the procedures to ensure the integrity and compliance to the intent of this policy.

- Confirm compliance with risk assessment procedures including product testing, occupational health and safety, environment and the *Competition and Consumer Act* by involving the appropriate specialists.

7.0 AUTHORITIES AND RESPONSIBILITIES

Board has the authority and responsibility for approving this policy.

Chief Executive Officer has the authority and responsibility for ensuring compliance with this policy through the Executive Leadership Team members including the allocation of adequate resources to achieve compliance with this policy.

Executive Leadership Team has the authority and responsibility for:

- ensuring correct application of this policy; and
- appropriate use of sub delegation within their division.

Deputy CEO Corporate has the authority and responsibility for:

- the resourcing, deployment and enforcement of this policy;
- recommending changes to this policy;
- ensuring that procedures are developed with appropriate controls to support the intent of this policy;
- the ongoing monitoring of this policy;
- the administration of the Purchasing process; and

General Manager Strategic Procurement has the authority and responsibility for:

- recommending changes to this policy;
- ensuring that procedures are developed with appropriate controls to support the intent of this policy;
- monitoring this policy;
- the administration of the Strategic Procurement process; and
- enforcing this policy.

Tender Review Committee has the authority and responsibility for providing advice to the Chief Executive Officer in respect of tenders that exceed the limit designated in the Tender Review Committee Charter.

Employees have the responsibility for complying with this policy.

8.0 DOCUMENT CONTROL

Content Coordinator : General Manager Strategic Procurement

Distribution Coordinator : Business Process Coordinator, Company Secretariat

COMPANY POLICY

SUPPLY MANAGEMENT	Document No: 12.1 Amendment No: 3 Approved By: CEO Approval Date: 10/7/12 Review Date: 10/7/15

(Supersedes Board Policy (Supply Management) 12.1 am2)

12.1 PURCHASING

1.0 POLICY STATEMENT

The Company will purchase goods and services by obtaining the best value for money and, whenever reasonably possible, promoting open and effective competition. The Company will ensure that all procurement activity is conducted in accordance with the law and the Company's Code of Ethics, Statement of Business Ethics and will not support any individual who knowingly or recklessly breaches the law, including *Work Health and Safety Act 2011 (NSW)* and environmental legislation. The Company will also seek to engage suppliers who align with its corporate values and meet high standards of capability, performance, quality, work, health & safety, risk and environmental management.

2.0 PURPOSE

To set down the principles for supply management, comprising of the procurement of goods and services and associated arrangements for the Company.

This policy covers purchasing arrangements for all goods and services sourced by the Company, including consultancy and advisory services. However, this policy does not extend to the following:

- purchase of electricity for resale;
- the Company employment contracts;
- acquisition of real estate and subsequent licence or lease payments;
- sponsorship arrangements;
- payments to Local, State or Federal Government departments and statutory bodies;
- transfer of network assets;
- renewals of subscriptions to magazines, bulletins or newspapers;
- fees associated with membership of professional associations or industry accreditations;
- refunds of contributions for the demand management program;
- purchase of services from meter providers in respect of customers outside the Company's franchise area; and
- purchase of professional publications or subscriptions to professional companies.

3.0 REFERENCES

Board Policy 3.0 – Occupational Health and Safety
Company Policy (Supply Management) 12.4 – Probity in Procurement
Company Procedure (Supply Management) GSU 0001 – Purchasing
Company Procedure (Supply Management) GSU 0007 – Supplier Assessment Supply Quality Register

[Code of Ethics]
[Statement of Business Ethics]
Competition and Consumer Act 2010 (Cth)
Work Health and Safety Act 2011(NSW)

4.0 DEFINITIONS

Executive Leadership Team
Interim Chief Operating Officer, Company Secretary, Acting Executive General Manager Network, Executive General Manager Corporate Services & Chief Financial Officer, General Manager Health & Safety and General Manager Support Services.

Financial Delegate
The position nominated within Company Policy 1.1.1 – Sub-Delegations of Authority by the Chief Executive Officer to approve expenditure.

procurement
The end-to-end process associated with sourcing goods and services including, without limitation, planning, market research, sourcing, contract management, supplier relationship management, and benefits tracking. For the purposes of this procedure the term procurement is used interchangeably with the term purchasing.

review date
The review date displayed in the header of the document is the default date for review of a document. A document review may be required at any time where a need is identified due to changes in legislation, organisation changes, restructures, occurrence of an incident or changes in technology or work practice.

Tender Review Committee (TRC)
A committee convened by the Chief Executive Officer to review proposals to enter contracts valued at $500,000 or above.

5.0 KEY REQUIREMENTS

Procurement arrangements will:

- seek to minimise transaction costs, administrative costs, waste management costs, maintenance costs, inventory holding and any other consequential costs associated with a good or service.
- support reliable supply of goods and services to employees with operational and governance responsibilities (right product, right time, right place).
- promote open and effective competition whenever reasonably possible and ensure a robust and auditable process is in place to manage any exceptions.
- deliver value for money to the Company. That is, offers accepted from suppliers for products and services will represent the best value for money having regard to the extent to which the offer satisfies the Company's requirements, the value of the offer and the benefits compared to whole of life costs.
- reflect the Company's Code of Ethics and Statement of Business Ethics and be robust enough to withstand the scrutiny of independent third parties, such as Independent Commission Against Corruption, Parliament or the media. All arrangements will be transparent and at arm's length.

- comply with Work, Health & Safety Act 2011 and environmental management systems by enforcing appropriate diligence on products, services and service providers brought into the Company.

- support delegated authorities set down by the Chief Executive Officer and the Board.
- reflect the Company's commitment to compliance with the *Competition and Consumers Act 2010* and principles of open and effective competition.

- will include appropriate documentation to ensure audit ability and enforceability of supply arrangements.

- seek to consistently engage suppliers who align with the Company's corporate values and meet high standards of capability, performance, quality, work, health & safety, risk and environmental management.

6.0 ACTIONS TO ACHIEVE IMPLEMENTATION OF THIS POLICY

- Communicate the policy to all employees.

- The Company will establish and maintain supply management procedures based on the premise that best value for money is obtained through fair and open competition.

- Develop, communicate and implement procedures to support the policy.

- Audit the implementation of the procedures to ensure the integrity and compliance to the intent of this policy.

- Confirm compliance with risk assessment procedures including product testing, occupational health & safety, environment and the *Competition and Consumers Act 2010* by involving the appropriate specialists.

7.0 AUTHORITIES AND RESPONSIBILITIES

Chief Executive Officer has the authority and responsibility for approving this policy.

Executive Leadership Team has the authority for:

- ensuring correct application of this policy; and
- appropriate use of sub-delegation within their division.

Deputy CEO Corporate has the authority and responsibility for:

- resourcing, deployment and enforcement of this policy;
- recommending changes to this policy;
- ensuring that procedures are developed with appropriate controls to support the intent of this policy;
- the ongoing monitoring of this policy;
- the administration of the Purchasing process.

General Manager Strategic Procurement has the authority and responsibility for:

- recommending changes to this policy;
- ensuring that procedures are developed with appropriate controls to support the intent of this policy;
- monitoring this policy;
- the administration of the Strategic Procurement process; and
- enforcing this policy.

Tender Review Committee has the authority and responsibility for providing advice to the Chief Executive Officer in respect of tenders that exceed the limit designated in the Tender Review Committee Charter.

Employees have the responsibility for complying with this policy.

8.0 DOCUMENT CONTROL

Content Coordinator : General Manager Strategic Procurement

Distribution Coordinator : Business Process Coordinator, Company Secretariat

COMPANY POLICY

SUPPLY MANAGEMENT	Document No: 12.4 Amendment No: 1 Approved By: COO Approval Date: 03/07/2014 Review Date: 03/07/2017

12.4 PROBITY IN PROCUREMENT

1.0 POLICY STATEMENT

The Company is committed to the principles of probity in the course of procuring goods and services.

2.0 PURPOSE

To outline a framework for the implementation of the principles of probity within the procurement processes of the Company.

3.0 REFERENCES

Board Policy (Governance) 2.0 – Governance
Board Policy (Supply Management) 12.0.1 – Purchasing
Board Policy (Supply Management) 12.0.2 – Disposal
Company Policy (Leadership) 1.1.1 – Sub-delegations of Authority by the Chief Executive Officer
Company Policy (Governance) GRM 0016 – Charters of Senior Management Committees and Cross Divisional Committees
Company Policy (Supply Management) 12.1 – Purchasing
Company Procedure (Governance) GRM 0018 – Gifts, Benefits and Invitations
Company Procedure (Governance) GRM 0028 – Conflicts of Interest
Company Procedure (Supply Management) GSU 0001 – Purchasing
Company Procedure (Supply Management) GSU 0002 – Tendering
Company Form (Governance) FRM0007 – Recommendations of the TRC
Company Form (Governance) FRM0056 – Tender Review Committee Submission Paper – Proposal to Procure Goods and Services
Code of Conduct
Statement of Business Ethics

4.0 DEFINITIONS

conflicts of interest
A conflict of interest involves a conflict between the personal interest of an employee and the impartial exercise of an employee's duties. Such conflicts can be actual, potential or reasonably perceived.

Executive Leadership Group
Chief Executive Officer, Chief Operating Officers, Group Chief Financial Officer, Group Executive Network Strategy, Group Executive People & Services and Board Secretary.

Executive Leadership Team
Chief Operation Officer, General Manager Health, Safety & Environment, General Manager People & Services, Chief Engineer, General Manager Network Development, General Manager Network Operations, General Manager Finance & Compliance and General Manager Information Communications & Technology.

independent member
An employee who has no direct interest in the use of the goods or services being procured.

intermediate procurement threshold
The monetary value of the requirement above which the procurement is regarded as an "Intermediate Purchase" currently set at $30,000 or $60,000 for consultants and labour contractors.

offer
A bid or offer or quotation or tender or application as the context requires.

principles of probity
These are the values, standards, behaviours and duties described in this policy.

probity
Integrity, uprightness and honesty.

procedures
A comprehensive document instruction that demonstrates to employees how to implement a policy incorporating the necessary steps of a process allocating responsibilities required to be completed, so there is consistent delivery of outcomes.

project
Any Company undertaking such as an acquisition, construction of a building, a development application, a grant, a sponsorship, a privatisation, etc.

request document
A document that is issued by the Company to solicit an offer from suppliers.

review date
The review date displayed in the header of the document is the future date for review of a document. The default period is three years from the date of approval however a review may be mandated at any time where a need is identified due to changes in legislation, organisational changes, restructures, occurrence of an incident or changes in technology or work practice.

supplier
A party that is actually or potentially, seeking to enter into a transaction or contract with the Company. The term includes without limitation actual or potential tenderers, bidders, suppliers, joint venture partners, sponsors, contractors, development applicants and grant applicants.

5.0 KEY REQUIREMENTS

In order to demonstrate a commitment to the principles of probity in procurement the Company must articulate the principles of probity. This policy sets out a description of these principles however this is not an exhaustive list.

5.1 Impartiality and honesty

Suppliers must be treated impartially, honestly and consistently having regard to all information, advice, preferences and concessions. Where competitive offers are solicited, this includes, without limitation:

- systematic evaluation of all offers against explicit, predetermined evaluation criteria that are the same for each supplier and are not altered;

- avoidance of ambiguity in procurement documentation and, if discovered, should not be perpetuated to the advantage of one supplier;

- clarification of information received in an offer that is open to interpretation or is not clear, where this is material to identifying the successful supplier without allowing the supplier to revise or enhance its original offer;

- exclusion of late offers unless the relevant supplier either provides explicit and conclusive evidence of mishandling by the Company or demonstrates that they were unable to upload the offer document to the Company's electronic tendering portal due to factors outside their reasonable control and can provide evidence that they contacted or tried to contact the relevant Company representative in accordance with instructions set out in the request document; and

- consistent application of any extensions to the time period stipulated in request documents to all suppliers.

In the event that an ethical concern arises during the procurement process, the matter must be dealt with in accordance with the Code of Conduct.

5.2 Transparency and accountability

The financial delegate approving the procurement of goods and services for the Company is accountable for all procurement decisions and the efficient, effective and proper expenditure of public monies based on achieving value for money. All processes, evaluations and decisions must be transparent, free from bias and, where the value of the procurement exceeds the intermediate procurement threshold, fully documented in accordance with applicable policy and audit requirements. Where competitive offers are sought that are likely to be valued above the intermediate procurement threshold:

- effective documentation control and record keeping of evaluation deliberations and decisions against evaluation criteria must be maintained at all times. These records must provide sufficient information to enable audit and independent review functions to be carried out;

- competitive offers must be evaluated by people that possess or are reasonably likely of possessing the necessary skills and knowledge and independent members must be included on evaluation teams for higher value or complex procurements;

- unless specifically provided for in the request documents, negotiations with suppliers must not be used as an opportunity to trade off different supplier's prices against others in an attempt to seek lower prices;

- if any of the offers submitted is not accepted, the relevant supplier must be advised of the reasons;

- information on the supplier that is selected as a consequence of the procurement process must be made publicly available to the extent required by law; and

- suppliers must be advised if they have been unsuccessful and be debriefed regarding how their offer was rated against the evaluation criteria, upon request.

Departure from established procedures for procurement of goods and services must only be for sound, well-documented reasons. These reasons must be approved by the Chief Operating Officer (COO) or an Executive Leadership Team (ELT) member not directly involved in the process.

5.3 Security and Confidentiality

Generally, information received from suppliers other than promotional or other material that is reasonably likely of being in the public domain must be treated as commercial-in-confidence and should not be disclosed. Relevant actions include:

- consistent protocols in place for the receipt and management of supplier's confidential information;
- effective and secure storage of relevant documents or information that is commercially sensitive. This includes, without limitation information concerning the offer evaluation process; and
- awareness by all Company employees of the requirement not to disclose confidential or commercially sensitive information and to properly manage the information they receive as part of the procurement process.

5.4 No conflicts of interest

Any actual or perceived conflicts of interest must be identified, declared, appropriately managed, fully recorded and documented prior to undertaking any procurement or disposal. In particular, it is important that:

- no Company employee accepts, individually or on behalf of any other person, any article of monetary value or other benefit in exchange for any act or omission in the performance of that employee's procurement functions;
- full consideration is given to any likely conflicts of interest prior to the commencement of any procurement or, where relevant, offer evaluation process;
- in the event of a conflict of interest, individual employees must promptly and fully disclose that conflict in accordance with Company Procedure (Governance) GRM 0028 – Conflicts of Interest; and
- employee(s) follow the relevant protocols in the event that a gift or benefit is offered, as set out in Company Procedure (Governance) GRM 0018 – Gifts, Benefits and Invitations.

5.5 Competitiveness and Fairness

Procurements valued above the intermediate procurement threshold should, to the greatest extent reasonably possible, be undertaken on a competitive basis and:

- the selection of the procurement methodology and the formulation of evaluation criteria must have regard to the nature and market for the goods and services being sought;
- the selection of an offer solicitation method must take into account the level of risk and avoid creating unnecessary costs or delays for suppliers;
- the adoption of behaviours during the procurement process must be free from anti-competitive practices and not seek to benefit one supplier at the expense of another supplier; and
- a firm intention to proceed to contract and the basis of that contract must be apparent throughout the procurement process.

5.6 Value for Money

An open and competitive environment must be fostered in which suppliers can make attractive, innovative offers with the confidence that they will be assessed by the Company on their merits. Where the value of the procurement is less than the intermediate procurement threshold, every reasonable care must be taken to obtain offers that represent reasonable value for money in the absence of competition. Where competitive offers are solicited, it is important that:

- ‘value for money’ is assessed based on the combined outcomes of the assessments of the qualitative non price evaluation criteria and price. In assessing value for money, major factors to be considered include:
    - the quality of the goods or services offered ie, the extent to which they satisfy the specified requirements;
    - whole of life costs; and
    - risk ie, the capacity of the supplier to deliver the goods or services, as specified, on-time and on-budget. Where practical, the price impact of any risks identified in qualified offers or any pricing adjustment clauses sought by the supplier should be considered during the evaluation process;
- evaluation criteria are formulated that provide for both price and non-price elements of offers to be evaluated;
- evaluation criteria correspond, at least in part, to specifications set out in request documents. These specifications should include the performance standards and capabilities expected of a supplier, the benefits and expected outcome of the project;
- where suppliers are encouraged to offer alternative, better value for money offers, the conditions under which alternative offers will be considered is specified;
- the market is tested regularly to find out whether a good and/or service can be sourced more efficiently and effectively; and
- renewal of contracts is conducted on a competitive basis to the greatest extent reasonably possible.

5.7 Tender Review Committee

The role of the Tender Review Committee (TRC) as outlined in Company Procedure (Governance) GRM 0016 – Charters of Senior Management Committees and Cross Divisional Committees, is to review any proposal to procure goods and/or services from a supplier(s) in circumstances where either:

- an intention to enter into a contractual commitment with the supplier(s) and the estimated contractual commitment exceeds $500,000; or
- an intention to establish a panel of suppliers and the estimated expenditure on the panel exceeds $500,000.

The review is intended to give assurance to the Chief Operating Officer (COO), Chief Executive Officer (CEO) and the Board that, with respect to a proposed procurement, the principles of probity have been addressed.

The threshold level for purchases reviewed by the TRC is to consider competitive offers valued greater than $500,000. The threshold level is determined by the Manager Procurement & Logistics, following probity risk analysis of procurements, with approval by the Chief Executive Officer. The Chief Executive Officer can seek the advice of the TRC in respect of offers that were not subject to a competitive procurement process.

6.0 ACTIONS TO ACHIEVE IMPLEMENTATION OF THIS POLICY

- Commitment by the Chief Executive Officer, Chief Operating Officer and all ELT members to the principles set out in this policy.

- Communication by the Chief Executive Officer, Chief Operating Officer and all ELT members to all employee(s) about the importance of compliance with the law and the Company's standards.

- The allocation of sufficient resources to meet the Company's probity objectives.

- The implementation of processes in Procurement & Logistics that:

  - embed probity into operational procedures;
  - act on compliance failures;
  - educate, train and inform employees;
  - recognise and mitigate risk; and
  - report on performance.

- Procurement processes will be subject to regular review having regard to feedback from auditors or independent experts, where applicable.

7.0 AUTHORITIES AND RESPONSIBILITIES

Chief Operating Officer has the authority and responsibility for:

- approving this policy; and
- providing adequate resources for compliance with this policy.

Executive Leadership Team has the authority and responsibility for upholding the achieved policy objectives within their respective division or area of responsibility.

General Manager People & Services has the authority and responsibility for:

- resourcing and deployment of procurement activities in accordance with this policy; and
- recommending to the Chief Executive Officer annually, a dollar value above which proposals to enter into contracts or establish supplier panels, will be referred to the TRC for review.

Manager Procurement & Logistics has the authority and responsibility for upholding procurement procedures to comply with this policy.

Branch Managers have the authority and responsibility for carrying out the requirements of this policy when acting as a proponent of a proposal.

Commercial Manager – Procurement have the authority and responsibility for providing advice to the supplier in respect of this policy.

All employees have an obligation to comply with the company's Code of Conduct and where involved in procurement activities, be aware and practise the procurement probity principles.

8.0 DOCUMENT CONTROL

Content Coordinator : Manager Procurement & Logistics

Distribution Coordinator : GRC Process Coordinator

Company Procedure

PROCUREMENT & LOGISTICS	Document No	:	GSU 0001
	Amendment No	:	15
	Approved By	:	COO
	Approval Date	:	12/09/2014
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GSU 0001 PURCHASING

1.0 PURPOSE

To set out the process to be followed for procuring goods and services for the company. This procedure is to be read in conjunction with Company Policy 1.1.1 – Sub-delegations of Authority by the Chief Executive Officer and Company Policy 1.1.1B – Sub-delegations of Authority by the Chief Executive Officer for the Chief Operating Officer and Level 2 and Level 3 Group Positions.

THIS DOCUMENT IS A CONTROL FOR THE HEALTH AND SAFETY MANAGEMENT SYSTEM (H&SMS).

2.0 SCOPE

This procedure applies to the procurement or hire of goods and services by the company.

The procurement or hire of goods and services includes professional services and consultancy services along with materials, equipment and contracting services. Selection of suppliers and all procurement must be undertaken in accordance with the Code of Conduct and Statement of Business Ethics. Suppliers must comply with Work Health & Safety and Environmental Management Systems by enforcing appropriate diligence on products, services and service providers brought into the company and who align with our corporate values and meet high standards of capability, performance, quality, work health and safety, risk and environmental management.

All monetary amounts set out in this procedure exclude GST unless specifically stated otherwise.

This procedure does not apply to the following:

- procurement of inventory;
- company's employment contracts;
- acquisition of real estate and subsequent licence or lease payments;
- sponsorship arrangements;
- renewals of existing software licences;
- the maintenance or support of licensed software, where the supplier is either the licensor or holds exclusive rights to maintain or support those products or services in Australia;
- payments to Local, State or Federal Government departments and statutory bodies;
- payments to Australia Post for mailing services;
- payments to the company's provider of telecommunications services for carrier charges;
- transfer of network assets;
- renewals of subscriptions to magazines, bulletins or newspapers;
- fees associated with membership of professional associations or industry accreditations;
- refunds of contributions for the demand management program;
- procurement of Australian or other internationally recognised and referenced standards;
- procurement of services from meter providers in respect of customers outside the company's franchise area;

- procurement of professional publications or subscriptions to professional companies;
- utility expenses, eg gas or water;
- facility rent;
- freight/courier;
- salaries (outsourced Payroll);
- employee training;
- petty cash initiation;
- termination settlements;
- legal settlements;
- accounts receivable refunds;
- central billed Corporate Credit Card;
- travel costs;
- central billed fleet payments;
- central billed Petroleum Card;
- VAT/GST reclaim services;
- mobile phone charges and hardware (excluding handset); and
- donations.

3.0 REFERENCES

Internal:
Board Policy (Leadership) 1.1 – Delegation of Powers and Functions to the Chief Executive Officer
Company Policy (Leadership) 1.1.1 – Sub-delegations of Authority by the Chief Executive Officer
Company Policy (Leadership) 1.1.1B – Sub-delegations of Authority by the Chief Executive Officer for the Chief Operating Officer and Level 2 and Level 3 Group Positions
Company Policy (Procurement & Logistics) 12.1 – Purchasing
Company Policy (Procurement & Logistics) 12.4 – Probity in Procurement
Company Procedure (Governance) GRM 0003 – Risk Management
Company Procedure (Governance) GRM 0016 – Charters of Senior Management Committees and Cross Divisional Committees
Company Procedure (Governance) GRM 0018 – Gifts, Benefits and Invitations
Company Procedure (Governance) GRM 0022 –Tender Review Committee
Company Procedure (Governance) GRM 0028 – Conflicts of Interest
Company Procedure (Health & Safety) GSY 0068 – Contractor Management
Company Procedure (Health & Safety) GSY 0084 – Pre-Purchasing Risk Assessment
Company Procedure (Information & Records Management) GDM 0006 – Records Disposal
Company Procedure (Leadership) GLE 0006 – Exception/Compliance Reporting under the Sub-delegations of Authority
Company Procedure (Procurement & Logistics) GSU 0002 – Tendering
Company Procedure (Procurement & Logistics) GSU 0004 – Purchasing and Corporate Cards
Company Procedure (Procurement & Logistics) GSU 0007 – Supplier Assessment, Review and the Supplier Quality Register
Company Procedure (Procurement & Logistics) GSU 0016 – Contract Management
Company Workplace Instruction (Finance Management) WFC 0001 – Petty Cash
Company Workplace Instruction (Finance Management) WFC 0002 – Payment Vouchers
Company Workplace Instruction (Procurement & Logistics) WSU 0010 – Ellipse Requisition of Goods and Services
Company Form (Governance) FQY 0002 – Corrective Action Request
Company Form (Health & Safety) FSY 0151 – Pre-purchase Risk Assessment Form
Company Form (Procurement & Logistics) FSU 0001 – Request for New Vendor Evaluation for Entry into the SQR
Company Form (Procurement & Logistics) FSU 0002 – Supplier Evaluation Questionnaire
Company Form (Procurement & Logistics) FSU 0038 – Supplier Performance Evaluation

[Code of Conduct]
[Statement of Business Ethics]
Annexure A – Procurement – Roles and Responsibilities Matrix

External:
Competition and Consumer Act 2010 (Cth)
Electricity Supply Act 1995 (NSW)
Work Health and Safety Act 2011 (NSW)
AS Records classification handbook – HB5031 – 2011
General Retention and Disposal Authority: Administrative Records GA28
ISO 31000:2009 – Risk Management – Principles and Guidelines
NSW Premier's Dept Memo No. 2002-07
NSW Treasury Risk Management Toolkit for the NSW Public Sector (TPP12-03)

4.0 DEFINITIONS

Bid
Either a quotation or tender or offer as the context requires.

Catalogue
A database of regularly procured products with established specifications that are contained in inventory. The catalogue is maintained by the Procurement & Logistics Branch on Ellipse.

Commercial Manager (CM)
A manager from the Procurement & Logistics Branch responsible for providing users with expert advice in respect of procurement and managing, in collaboration with users of procurement services, the company's commercial relationship with suppliers within a defined portfolio.

***Competition and Consumer Act 2010 (Cth)* (CCA)**
The Competition and Consumer Act 2010 (*Cth*) (CCA) is a single, national Act concerning consumer protection and fair trading, which applies in the same way nationally and in each State and Territory.

For the first time, consumers have the same protections and expectations about business conduct wherever they are in Australia. Similarly, businesses have the same obligations and responsibilities wherever they operate in Australia.

Consequential costs
Additional goods or service related costs associated with transactions, administration, waste management, maintenance, inventory, etc.

Consultant
A person or company engaged under contract on a temporary basis to provide recommendations or high level specialist or professional advice to assist decision making by management. Generally it is the advisory nature of the work that differentiates a consultant from other contractors (refer to NSW Premier's Dept Memo No. 2002-07).

Contingency
Additional contract expenditure, established at contract inception but not accessible without approval from the appropriate financial delegate. Contingencies comprise of two parts:

- Risk Reserve – To cover contract risks which are identified at the time of the tender release but could not be accurately quantified or are not expected to eventuate. These Risk Reserves will identify specific items and have a dollar amount associated with them. Examples of this type of Risk Reserve would be foreign exchange or commodity price fluctuations and volume variations or un-anticipated scope such as different ground conditions to those suggested in the geotech report.

- Management Reserve – To cover unidentified or unforseen project risks. These are typically calculated as a percentage of the base contract amount.

Contract
A binding agreement between the company and a supplier established for a specific purpose or for a specific duration up to an amount approved by the relevant financial delegate.

Contractor
A person or company engaged to undertake a particular task as opposed to the provision of advice on those particular tasks, eg provision of training, provision of routine services, and program implementation in accordance with set specifications.

Document Control
Employees who work with printed copies of documents must check the BMS regularly to monitor version control. Documents are considered “uncontrolled if printed”, as indicated in the footer.

Ellipse
The company's integrated Enterprise Asset Management software supplied by Mincom Ltd.

Executive Leadership Team
Chief Operating Officer, General Manager Health, Safety & Environment, General Manager People & Services, Chief Engineer, General Manager Network Development, General Manager Network Operations, General Manager Finance & Compliance and General Manager Information, Communications & Technology.

Expression of Interest (EOI)
A response to a request for companies to register their interest in supplying a product or service and state their general capabilities.

Exception reporting
Reports that set out instances where users have not complied with certain provisions of this procedure that are managed in accordance with Company Procedure GLE 0006 – Exception/Compliance Reporting under the Sub-delegations of Authority.

External labour contract employees
Agencies or individuals who are not permanent employees but who are performing work on behalf of the company. These individuals are managed by internal employees as would be the case if they were permanent employees. This excludes contractors.

Field release order
A type of open or blanket Purchase Order (PO) in Ellipse with a particular supplier up to a dollar limit that is at least $10,000 and is often used where details of the goods or services are not known at the time of order creation or where multiple employees require goods and services from a supplier that is located at multiple locations. Invoices from suppliers that are engaged under field release orders must be approved by the relevant financial delegate. Payment of an invoice matched against a field release order will require financial delegate approval based on invoice value. The field release orders also allow for invoices to be costed to more than seven cost objects in Ellipse.

Financial delegate
The position nominated within Company Policy 1.1.1 – Sub-delegations of Authority by the Chief Executive Officer to approve expenditure and Company Policy 1.1.1B – Sub-delegations of Authority by the Chief Executive Officer for the Chief Operating Officer and Level 2 and Level 3 Group Positions.

Goods order
One of the two default purchase order types created in Ellipse to cover the procurement of goods including inventory, where the quantity and unit of issue are specified on the order up to a quantity and value approved by the financial delegate. Authorised Ellipse users are required to post receipts of goods in Ellipse.

The payment of invoices against a goods order are based on a three way match:

- PO exists;
- invoice value is equal to or less then PO; and
- receipt has been posted in Ellipse.

Cost can only be applied to a maximum of seven cost objects.

Intermediate procurement threshold
The monetary value of the requirement above which the procurement is regarded as an “Intermediate Procurement” currently set at $30,000 or $60,000 for consultants and labour contractors.

Probity
Probity is about making decisions with the right intentions, that is, in good faith. Probity involves maintaining fidelity to public sector values and duties such as selflessness, accountability, fairness and observing value for money. Probity implies values such as integrity, uprightness and honesty and, in doing so, minimises the risk of corrupt or dishonest conduct and mismanagement. Company Policy 12.4 – Probity in Procurement sets out the principles that must be followed during the procurement process.

Process manager
Either the level 3 or 4 manager responsible for sponsoring the request for tender or expression of interest or a Commercial Manager. Where the value of the requirement exceeds $500K the process manager must be the Commercial Manager. For all other requests for tender or expressions of interest the process manager must be the sponsoring level 3 or 4 manager.

Procurement
The end-to-end process associated with sourcing goods and services including, without limitation, planning, market research, sourcing, contract management, supplier relationship management, and benefits tracking. For the purposes of this procedure the term procurement is used interchangeably with the term purchasing.

Procurement & Logistics Officer
A member of the Procurement & Logistics Branch.

Procurement plan
Must be completed for all spend above $30,000. The procurement plan is to seek approval to move to the next step in the purchasing process and is not financial approval to actually acquire the goods or services. A procurement plan outlines the manner in which the market will be approached, the suppliers who will be included, an outline of the goods and services being sourced and the evaluation process and criteria. A procurement plan will be valid for a period no longer than six months between when it is approved and a tender being released to the market. If this period is exceeded the procurement plan will need to be resubmitted for approval based on changed market conditions.

Approval of a procurement plan is not the financial approval of the expense, it is the approval of the sourcing methodology.

Provisional sum
An amount of money that is set out in the contract to provide for known contract works that are not fully defined or scoped at the time of the tender release such that the contractor was unable to provide a fixed price submission for these works. Including provisional sums in request documents creates an environment in which tenderers can submit a total fixed price that minimises any risk premium and provides the company with greater certainty of total contract value.

Provisional sum values should identify specific items of undefined works and must be itemised within the tender submission and within the contract.

Purchase Order (PO)
A written contractual document prepared by the company to engage a supplier that sets out the goods and services required by the company and relevant pricing and delivery information.

Purchase requisition
An electronic form created in Ellipse to initiate the procurement of goods and services via a purchase order.

Purchasing card
A credit card provided by the company to authorised employees for procurements valued up to prescribed cardholder limits but not exceeding $20,000.

Quotation or quote
A proposal, offer or bid submitted to the company, generally in response to a formal request. In the context of this procedure a quote is differentiated from a tender by its value, ie offers valued less than the tender threshold are regarded as quotes.

Recordkeeping
Making and maintaining complete, accurate and reliable evidence of business transactions in the form of recorded information (Source: AS Records classification handbook – HB5031 – 2011).

Recordkeeping system
An information system which captures, manages and provides access to records through time. (AS/ISO 15489 1 – 2002 Records Management).

Request for Best and Final Offer (RFBAFO)
Request for short-listed tenderers' final offers.

Request for Expressions of Interest (RFEOI)
Request for expressions of interest where the company seeks to gauge the potential market for goods or services and/or help crystallise its requirements as a precursor to soliciting tenders or where the company seeks to establish a supplier panel.

Request for Proposal (RFP)
Request for response to a high level specification (where the company seek the suppliers to provide detail). A request to provide a solution.

Request for Quotation (RFQ)
A request for a response in the form of quotation for the supply of a product or service to a defined specification, generally used where the value of the requirement is less than the tender threshold.

Request for Tender (RFT)
Request for a structured and detailed response to a comprehensive statement of requirements.

Request documents
Means an RFT, RFP, RFQ, RFBAFO or RFEOI as the context requires.

Requirement
The goods or services that are required by the user, the value of which is based on the projected expenditure. In the case of goods or services for which there is a recurring need the estimated value of the requirement must be based on projected total expenditure for at least the financial year in which the supplier is being engaged.

Review date
The review date displayed in the header of the document is the future date for review of a document. The default period is three years from the date of approval however a review may be mandated at any time where a need is identified due to changes in legislation, organisational changes, restructures, occurrence of an incident or changes in technology or work practice.

Risk assessment
An assessment of occupational and environmental risks undertaken on a product or service in accordance with Company Procedure GSY 0084 – Pre-Purchasing Risk Assessment.

Service order
One of the two default purchase order types created in Ellipse for either specific goods and/or services or as an open or blanket order up to a dollar limit that is approved by the financial delegate, invoices can be costed to a maximum of seven cost objects per item and the requisitioner must acknowledge goods or services have been received before invoices can be paid.

SQR threshold
The dollar limit of expenditure on goods and services above which suppliers must be evaluated for eligibility for inclusion on the Supplier Quality Register (SQR), currently set at $30,000 per annum.

Supplier Quality Register (SQR)
An assessment record, maintained in Ellipse of the suppliers/contractors management systems and capability based on factual data.

Supplier panel
An approved list of pre-registered suppliers or contractors used to supply a defined set of goods or services for a defined period. All suppliers on a supplier panel have generally been engaged under the company's standard terms and conditions.

Tender
A proposal, bid, tender or offer submitted to the company, generally in response to a formal request. In the context of this procedure a tender is differentiated from a quotation by its value, ie offers valued more than the tender threshold are regarded as tenders.

Tender Review Committee (TRC)
A committee convened by the Chief Executive Officer or the Chief Operating Officer to review proposals to enter contracts valued at $500,000 or above.

Tender threshold
The monetary amount above which tenders must formally be sought in accordance with Company Procedure GSU 0002 – Tendering. The limit is $200,000 or $400,000 where a valid supplier panel is in place.

User
The end user of a good or service within the company.

User group
The representative group of key stakeholders for the particular product or service.

Value for money
The commercial attractiveness of a bid having regard to the extent to which it satisfies the company's requirements, evaluation criteria, the value of the bid, risk, and the whole of life costs.

5.0 ACTIONS

The Procurement & Logistics Branch is responsible for implementing the company's procurement policy and promoting the underlying procurement principles, namely:

- to promote open and effective competition; and
- to obtain best value for money.

Users must check the catalogue prior to initiating the procurement process and satisfy the requirement from inventory unless an emergency exists. This procedure must be followed where a requirement cannot be satisfied from inventory.

5.1 Procurement process responsibilities

Responsibility for performing parts of the procurement process is divided between the user and the Procurement & Logistics Branch depending on the value of the procurement. The following table sets out the division of these responsibilities based on the four procurement thresholds.

Procurement threshold	$ limits [3]	Preparing a procurement plan (Section 5.2)	Defining a requirement (Section 5.3)	Soliciting bids (Section 5.4)	Selecting a supplier (Section 5.5)	Engaging a supplier (Section 5.8)
Basic	< $3,000	Not required	User	User	User	User if cardholder or Procurement & Logistics Branch
Minor	>= 3,000 < 30,000 [1]	Not required	User	User	User	User if cardholder or Procurement & Logistics Branch
Intermediate	>= 30,000 [1]<$200,000	User	User – in writing	User	Approved Evaluation Team	Procurement & Logistics Branch
Advanced [2]	>=200,000	User	User – in writing	Procurement & Logistics Branch	Approved Evaluation Team	Procurement & Logistics Branch

1. The intermediate procurement threshold is $60,000 for Consultants.
2. The advanced procurement threshold is $200,000 and $400,000 for supplier panels.
3. Advanced procurements must be conducted in accordance with Company Procedure GSU 0002 – Tendering.
4. All amounts exclude GST.

5.2 Procurement plan

Where the value of procurement is likely to exceed the intermediate procurement threshold, users must complete Company Form FSU 0042 – Procurement Plan in consultation with a Commercial Manager (CM) before bids are solicited.

In the context of procurements that do not exceed the tender threshold, the purpose of the procurement plan is to determine that:

- the requirement cannot be satisfied from inventory;

- the value of the requirement is a reasonable estimate of the expenditure and, in the case of goods and services for which a recurring need exists, is based on projected total expenditure for at least the financial year in which the supplier is being engaged;

- where exceptional circumstances apply, the value of the requirement reflects the extent to which the engagement of the supplier represents an extension of a previous engagement having regard to the nature of the goods and services being procured;

- where exceptional circumstances apply and the supplier nominated in Section 2 of the procurement plan does not possess an SQR rating of 4.5 or greater, the procurement plan has been endorsed by the General Manager People & Services or Chief Operating Officer;

- the approach to the market is genuine and aimed at engaging a supplier;

- an approved budget exists for the procurement or where no budget exists the process manager has initiated action to secure budget approval (to the extent that this is possible);

- suppliers nominated as prospective bidders are capable of satisfying the requirement and reasonably likely to submit competitive offers and are not merely “straw men” included to give the impression of competition;

- bids must be solicited in the most effective manner, having regard to factors such as the nature of the market, or existence of supplier panels;

- competitive bids received for procurements valued above the intermediate procurement threshold will be evaluated in accordance with Section 5.5.1 of this procedure;

- successful bidders will be engaged using the most appropriate form of company agreement;

- timeframes for the bid solicitation process are realistic and achievable; and

- employees nominated to evaluate bids are capable, or reasonably likely to be capable, of evaluating bids based on their experience and skills.

5.2.1 Approval of procurement plans

CMs can approve procurement plans except where:

- selective tenders are being solicited;
- direct negotiation is the method of bid solicitation;
- tenders are solicited from fewer than all members of a supplier panel;
- a strategic alliance is being established; or
- exceptional circumstances exist.

With the exception of “exceptional circumstances”, “direct negotiation” or “strategic alliance” procurement plans, procurement plans meeting the foregoing criteria must be signed-off according to the value of the requirement as follows:

- Lead Portfolio Manager up to and including $100,000; and
- Manager Procurement & Logistics above $100,000.

"Exceptional Circumstances", "direct negotiation" and "strategic alliance" procurement plans must be signed-off according to the value of the requirement as follows:

- Lead Portfolio Manager up to and including $100,000;
- Manager Procurement & Logistics between $100,000 and up to and including $300,000;
- General Manager People & Services above $300,000 up to and including $500,000;
- Chief Operating Officer above $500,000 up to and including $1,000,000; and
- Chief Executive Officer above $1,000,000.

5.2.2 Variations to procurement plans

All variations to procurement plans with the exception of method of bid solicitation can be approved by the CM provided they comply with the once-removed principle, eg the CM cannot approve a change to the plan to appoint themselves to the Evaluation Team. Changes to method of bid solicitation must be approved by the officer who approved the plan.

5.3 Defining a requirement

Users have the responsibility for fully specifying the requirement and that planning is based on a reasonable estimate of the value of the requirement. Where the requirement is for goods or services for which there is a recurring need the estimated value must be based on projected total expenditure for <u>at least</u> the financial year in which the supplier is being engaged.

5.3.1 Basic and minor value procurements

Where the value of the requirement is less than the intermediate procurement threshold, the user should define the requirement in writing where the requirement is complex or ambiguous or where the level of risk associated with the engagement of the supplier is perceived to be high.

5.3.2 Procurements valued above the intermediate procurement threshold

Where the value of the requirement is equal to or greater than the intermediate procurement threshold or where it is necessary to engage a supplier via contract and the requirement can't be satisfied then the user must specify the requirement in writing having regard to at least the following criteria:

- scope of the goods and services to be provided including any deliverables;
- relevant technical specification or standards or drawings or manufacturer's part number; and
- service levels or performance measures or delivery milestones or required delivery date.

The requirement must be expressed in generic terms to maximise the competition and avoid any perception of bias, ie requirements should be specified rather than prescribed. Suppliers that respond to request documents must declare any conflicts of interest and sign the representation and warranty form set out in the RFQ.

5.3.3 Engaging contractors or consultants to define requirements or scope

Contractors or consultants may be engaged to prepare documentation that defines a requirement providing that:

- the contractor or consultant assigns all intellectual property rights in any documentation that is brought into existence by the contractor on behalf of the company to the company; and
- the requirement is not documented in a way that could be reasonably perceived to favour any supplier. To this end Australian or industry standards must be used where possible.

Contractors or consultants engaged in defining requirements (including the design phase of a project) and their affiliates are excluded from subsequently bidding to satisfy the requirement unless the Chief Operating Officer approves otherwise. Suppliers invited to bid to define requirements must be notified of this restriction in any request documents or discussions prior to their engagement so that they have the opportunity of declining to bid.

5.4 Soliciting bids

Where a requirement can be satisfied from an existing company contract then users must use the relevant contract in accordance with its terms. Where the requirement cannot reasonably be satisfied by an existing contract and the value is less than the tender threshold, the financial delegate must establish that quotes are solicited in accordance with Section 5.4.

5.4.1 Basic procurements

Where the value of the requirement is less than $3,000 responsibility for product or service selection rests with the user on the basis of a published price, price list or verbal quote. The relevant financial delegate or, where the user is a company credit cardholder, the user, must be satisfied that the price is commercially reasonable.

5.4.2 Minor procurements

Where the value of the requirement is equal to or greater than $3,000 and less than the intermediate procurement threshold, responsibility for product or service selection rests with the user or the Procurement & Logistics Officer who must obtain at least one written quote or extract from a published price list. The relevant financial delegate or, where the user is a company credit cardholder, user must be satisfied that the quote or price is commercially reasonable. The Procurement & Logistics Officer may select a product or service without further reference to the users, unless a user has requested consultation prior to procurement and has sound reasons for that request (for example, there are no standing arrangements and specialist judgement is required in selecting a new product). Where a supplier panel has been established, users must obtain a quote from a member of the supplier panel.

5.4.3 Intermediate procurements where supplier panel in place

Where the value of the requirement is between the intermediate procurement and tender thresholds and a supplier panel exists, the user must complete Company Form FSU 0042 – Procurement Plan before quotes are solicited/schedules of rates consulted. All members of a supplier panel must be invited to quote, at least three contractors must be invited to submit bids or published schedules of rates may be consulted. A subset of panel members may be invited to submit bids where the CM and procurement plan approval authority are satisfied that a case to restrict the solicitation of bids is made in the procurement plan.

Responsibility for selecting products and services rests with the user after obtaining as many bids as necessary in accordance with the relevant procurement plan. Users must follow the protocols set out in Sections 5.4.6 and 5.14 when soliciting bids.

5.4.4 Intermediate procurements where no supplier panel is in place

Where the value of the requirement is between the intermediate procurement and tender thresholds and no panel exists, the user is responsible for completing Company Form FSU 0042 – Procurement Plan before quotes are solicited/schedules of rates consulted unless exceptional circumstances are being invoked in which case a bid can be obtained directly from the supplier after the procurement plan has been executed. Responsibility for selecting products and services rests with the user after obtaining as many quotes as necessary in accordance with the relevant procurement plan. Users must follow the protocols set out in Sections 5.4.6 and 5.14 when soliciting bids.

5.4.5 Advanced procurements

Where the value of the requirement is equal to or greater than the tender threshold, tenders must be sought and evaluated in accordance with Company Procedure GSU 0002 – Tendering. Where the requirement exceeds the tender threshold, the provisions of Section 5.4.3 apply to the extent they relate to the engagement of a period contractor.

At least three contractors must be invited to submit bids or published schedules of rates may be consulted. A subset of panel members may be invited to submit bids where the CM and procurement plan approval authority are satisfied that a case to restrict the solicitation of bids is made in the procurement plan.

5.4.6 Mandatory inclusions in RFQ documentation for intermediate procurements

Where the value of the requirement is between the intermediate procurement and tender thresholds and the requirement is not being satisfied from a company contract or where it is necessary to engage suppliers under contract, quotations must be solicited in writing using Company Forms FSU0032 – Request for Quotation or Company Form FSU 0071 – Request For Quotation (RFQ) - Minor Value. The users must determine that the RFQ specifies, at a minimum:

- a closing date and time that is identical for all suppliers;
- a central quotation delivery address and company point of contact;
- a statement from suppliers certifying their compliance with the company's Statement of Business Ethics and declaring of any conflicts of interest;
- contractual terms and conditions that will govern the supply of goods or services; and
- a statement regarding the high level criteria against which quotes will be evaluated.

Users that regularly solicit bids should use the company's electronic tendering solution and should consult with an CM in this regard.

5.5 Selecting a supplier

The supplier selection process must be appropriate to the estimated level of expenditure, risk and the nature of the product and/or service and take into account, at a minimum, the following:

- supplier's demonstrated capability, eg resources, plant;

- supplier's ability to satisfy the requirement with goods or services which are fit for purpose;

- value for money proposition of the bid;

- minimal consequential costs;

- supplier's confirmation of their compliance with the Statement of Business Ethics and their declaration of any conflicts of interest. Where a supplier declares a conflict of interest, the Evaluation Team must take this into account during the evaluation process and must inform the financial delegate of their decision;

- compatibility of products offered with existing equipment;

- supplier's fit with the company's values;

- whole of life costs including the supplier's demonstrated ability to dispose of equipment rendered obsolete as a consequence of the procurement;

- supplier's ability to effectively manage work, health & safety and environmental risks;
- supplier's track record in supplying goods and services to the company captured on the SQR;
- supplier's SQR rating. Suppliers must have an SQR rating of at least 4.5 or a case for extenuating circumstances has been made, endorsed by the relevant Executive Leadership Team member sponsoring the procurement and approved by either the Manager Procurement & Logistics; and
- supplier's willingness to accept the terms and conditions under which they will be engaged.

5.5.1 Evaluation of competitive bids where the value exceeds the intermediate procurement threshold

Where competitive bids are obtained for procurements valued above the intermediate procurement threshold, they must be evaluated in accordance with the relevant procurement plan. The Evaluation Team must comprise at least three people who are capable or reasonably likely to be capable, of evaluating the bids based on their experience and skills, one of whom is an "independent" and either works outside the branch or region sponsoring the procurement and is not a Procurement & Logistics Officer. Where practicable, the independent should be at the same level in the company hierarchy as the majority of other members of the team. Where the CM or Evaluation Team form the view that there is only one or no employee that is capable, or reasonably likely to be capable, of evaluating the bids based on their experience and skills, a suitably qualified resource must be engaged from outside the company and included in the Evaluation Team. If a specialist contractor or consultant is required to act as an "independent" Chief Operating Officer approval must be obtained.

Where the value of expenditure with a supplier exceeds or is likely to exceed the SQR threshold, suppliers must be assessed for eligibility for inclusion in the SQR in accordance with Company Procedure GSU 0007 – Supplier Assessment Supplier Quality Register.

5.5.2 General rules

For RFT, RFP, RFBAFO or RFEOI please see Company Procedure GSU 0002 – Tendering for RFQ below the tender threshold the following practices need to be adopted.

5.6 Forms of submission

Quotes may be received via hard copy or electronically, that is, via the company's electronic tendering portal (tenderlink) or via email.

5.6.1 Enquiries and communication

The process manager must maintain that no supplier receives preferential treatment during the request for quote process. Requests for additional information between the company and the suppliers when in a competitive process must be consistent and each supplier should be given the same information. Information given to one must be given to all provided that the identity of bidders is not disclosed.

The process manager is responsible for maintaining an audit trail of all communications and quotes.

5.6.2 Amendments to request documents

Where it becomes necessary to amend request documents, the amendments must only be made by process manager and issued as an addendum to all suppliers. Each addendum should state clearly that it is meant to be incorporated in the request documents. All quotes should reflect the change.

Consideration may need to be given to extending the quote period when an addendum is issued. If the period is extended all suppliers are to be advised of the new closing time and date.

Where it is necessary to issue addenda to quote documentation after quotes have closed, consideration should be given to terminating the process and calling fresh quotes.

5.6.3 Clarification of tenders

In circumstances where a statement or information provided in a quote is open to interpretation or is not understood, clarification of the statement or information should be obtained from the supplier by the process manager. The clarification request must be framed in a manner that does not result in the supplier gaining advantage over other respondees, eg revising or expanding the offer.

Any discussion or contact with suppliers during the quote evaluation period must be performed in consultation with the process manager and have due regard to probity, in particular:

- the status (preferred, under consideration or rejected) of any quote must not be advised or implied to any supplier; and
- interaction with suppliers should be in writing. In circumstances where an issue is discussed verbally with the supplier, a record of the discussion must be documented.

5.6.4 Late tenders

Late tenders may only be considered where the integrity and competitiveness of the tendering process is not compromised.

Late tenders may be accepted by the Manager Procurement & Logistics only where tenders <u>have not been released</u> by the process manager to the Evaluation Team for evaluation <u>and</u> where:

- acceptance of the late tender provides the tenderer no material advantage or a benefit over other tenderers who have submitted on time; or

- the tender was not received on time due to mishandling by Procurement & Logistics Branch or other employees; or

- the tenderer was unable to upload the document to the Tenderlink portal due to factors outside the tenderer’s reasonable control that can be reasonably substantiated <u>and</u> that tenderer can provide evidence that they contacted or tried to contact the relevant RFT contact person in accordance with instructions set out in the request document; or

- the tender was an RFI or EOI where no formal pricing or agreement was being sort.

5.7 Approvals

The user is responsible for securing the approval of the appropriate financial delegate that is based on the total value or projected total value of the procurement before the supplier is engaged. Any projected contract or order values must represent a reasonable estimation of the company's total expenditure for the duration of any engagement and, where the engagement represents an extension of a discrete engagement, take into account any amounts previously approved.

In the case of requirements for goods and services of a recurring nature, the value of the approval being sought must represent the projected total spend for at least the financial year in which the supplier is being engaged.

5.8 Engaging a supplier

This section describes the methods by which suppliers of goods and/or services can be engaged:

- purchase order – placed by the Procurement & Logistics Branch and based on an approved Ellipse purchase requisition. Purchase orders are the subject of Section 5.10;

- petty cash – where the value of the requirement is less than $50, goods and services may be procured using petty cash providing the transaction is conducted in accordance with Company Workplace Instruction WFC 0001 – Petty Cash;

- corporate or purchasing card – approved cardholders may acquire goods and services in accordance with Company Procedure GSU 0004 – Purchasing and Corporate Cards;

- stationery ordering portal – approved Stationery ordering portal users are authorised to order stationery directly from stationery provider up to the limits set out in Company Policy 1.1.1 – Sub-delegations of Authority by the Chief Executive Officer; and

- payment voucher – used sparingly for emergency payments or payments subject to the constraints of Company Workplace Instruction WFC 0002 – Payment Vouchers.

5.9 Use of contracts

Certain types of procurements pose risks to the company and must be covered by an appropriate contract with specific terms and conditions regardless of value to mitigate against these risks. The following list contains examples of under what circumstances a contract should be established but is not exhaustive and users should consult with a CM or manager within Procurement & Logistics Branch to determine whether a contract should apply:

- civil construction where the value is $30,000 or more;
- provision of services by consultants;
- procurements that pose significant work, health & safety or environmental risks, eg oil, contractors operating on network assets;
- all procurements valued above the tender threshold;
- appointments of agents or third parties that interact with the company's customers; and
- any procurements involving confidential information or that pose a moderate or high level of commercial or reputational risk to the company.

Where a non-standard form of contract is used, the contract must be approved by the General Counsel.

5.10 Placing an order

A purchase order must be created to cover all procurements of goods and services that are within the scope of this procedure, with the exception of those made via petty cash, credit card or stationery ordering portal. Purchase orders are centrally managed and help determine that no goods or services are obtained without proper approvals and facilitate invoice processing. In order to initiate the purchase order process, users must firstly raise an Ellipse purchase requisition in accordance with Company Workplace Instruction WSU 0010 – Ellipse Requisition of Goods and Services. With the exception of stationery portal orders that are subject to prescribed constraints, only employees within the Procurement & Logistics Branch can issue purchase orders unless otherwise approved by the General Manager People & Services or Chief Operating Officer. When raising a purchase requisition for goods or services procured under a contract (including progress payments), the relevant contract number must be placed in the "contract number" field of the purchase requisition header. Upon receiving an authorised purchase requisition, the Purchasing Officer will select an appropriate supplier in accordance with Section 5.5 and forward a purchase order to them.

The only exceptions will be as follows:

- an emergency that generates an urgent need that cannot be immediately processed through Ellipse. In the case of emergencies prior approval should be obtained if possible. If prior approval is not possible, approval should be obtained as soon as possible after the emergency; and

- confidentiality requires an order to be placed by another group within the company (only with the prior approval of the General Manager People & Services or Chief Operating Officer.

In all cases, the purchase requisition must fully describe the goods and services citing the relevant specification, drawing or manufacturer's part number, delivery instructions, required delivery date and relevant contract number, where appropriate, for the procurement as these details will be carried over onto the purchase order. Where the intended procurement is not against an existing contract, the pricing basis for the procurement, eg quotation number and date must be included as part of the requisition item detail.

The current authorised risk assessment number and, where relevant procurement plan number that applies for the goods or services being procured must be included in the purchasing instructions section of the purchase requisition.

Financial delegates, prior to approving a purchase requisition, must confirm the following has been completed and documented:

- compliance with financial delegations – the value of the requisition (or, in the case of variations, the revised total value of the goods or services) is within their financial delegation and funds are available within their budget;

- bid solicitation – bids have been solicited in accordance with the relevant procurement plan where one applies;

- method of engagement – the supplier has been engaged in accordance with Section 5.8;

- SQR – the supplier is listed on the SQR with an SQR rating of 4.5 or above or where they do not possess such a rating develop a case for extenuating circumstances, endorsed by the Executive Leadership Team sponsoring the procurement and approved by either the General Manager People & Services or Chief Operating Officer;

- prohibited practices – the requisition does not violate Section 5.13;

- inventory items – check whether the requisition should have been satisfied from inventory prior to procuring from external sources;

- risk assessment – all risks associated with the relevant procurement have been considered and treated and that, at a minimum, a risk assessment has been completed or reviewed in accordance with Company Procedure GSY 0084 – Pre-Purchasing Risk Assessment and that all parties have been consulted and informed;

- restricted category – delegate approval is obtained in accordance with Section 5.14;

- procedural compliance – all relevant procedures have been adhered to; and

- contract validity – any contracts quoted are still current and within approved limits.

Prior to the placement of an order, Purchasing Officers must confirm that the above has been completed by the financial delegate and may request additional information such as copies of quotes or documentation from the financial delegate or user as reasonably required.

5.10.1 Amendment of a purchase order

In instances where the requirement changes and it is necessary to amend the purchase order (and potentially any contract), users are responsible for securing the written approval of the appropriate financial delegate based on the revised total value of the purchase order and forwarding a copy of such approval, clearly stating the purchase order number and amended total value, to the relevant Purchasing Officer or shared email box procurement@endeavourenergy.com.au. The Purchasing Officer will amend the purchase order in Ellipse and upload a copy of the approval to the Recordkeeping system.

5.10.2 Payment of a purchase order

The Accounts Payable Section will check that an approved purchase order is referenced on every invoice. Where a supplier cannot identify an approved purchase order, the company may decide to reject the invoice. Any instances of procurements having been made without an approved purchase order will be investigated and reported to the user's Executive Leadership Team member as part of standard exception reporting. Users will have to satisfy their Executive Leadership Team member that there was a legitimate reason to circumvent the company's procurement process.

5.10.3 Restrictions on the use of field release orders

Service orders and goods orders are the default order types and should be used wherever possible. Where it is necessary to cost expenditure to multiple work orders or account codes field release orders may be used providing that the order covers the procurement of goods and services for an entire region or branch and the minimum value of the order is $10,000 (excluding GST). The method used to determine the value of such field release orders must be consistent with the approach to estimate the value of the requirement set out in this procedure and must not be unreasonably inflated to reach this threshold. Requirements valued below $10,000 per annum that must be costed to more work orders or account codes that can be accommodated by goods and service orders must be satisfied using company credit cards in accordance with Company Procedure GSU 0004 – Purchasing and Corporate Cards.

5.11 Waiving the need to solicit competitive offers due to exceptional circumstances

The obligation on users to solicit competitive offers set out in this procedure will only be waived in any of the following exceptional circumstances:

- there is a bona fide need for a proprietary product to establish compatibility with existing equipment and there is a sole source of supply for the proprietary product;
- emergencies – there is a genuine business or operational urgency that seriously threatens employees, customers, assets or corporate reputation;
- there may be a material and otherwise unavoidable threat to the company's financial performance;
- there is a need for unique intellectual property or expertise that is available from only one supplier;
- confidentiality;
- where the introduction of a third party supplier may materially diminish the company's contractual rights with an existing contracted supplier; or
- where a case can be made to substantiate the restricted approach to the market observing that poor planning is not regarded as grounds for exceptional circumstances.

Requests to invoke exceptional circumstances provisions for procurement must be made on Company Form FSU 0042 – Procurement Plan. Users must justify why competitive offers should not be solicited to satisfy the requirement and one sentence justifications or checked boxes will not generally constitute an adequate explanation. Users must not seek quotes from suppliers until after the procurement plan has been executed.

Where the value of the requirement exceeds $500,000, the Chief Operating Officer or Chief Executive Officer may seek advice from the TRC as to whether the circumstances are exceptional.

All expenditure approvals must comply with the Financial Delegations as per Company Policy 1.1.1 – Sub-delegations of Authority by the Chief Executive Officer and Company Policy 1.1.1B – Sub-delegations of Authority by the Chief Executive Officer for the Chief Operating Officer and Level 2 and Level 3 Group Positions.

5.12 Risk assessments

Financial delegates are responsible for determining that all risks associated with the procurement of goods and services are assessed and a risk management plan is implemented where appropriate to mitigate any risks in accordance with Company Procedure GRM 0003 – Risk Management. Financial delegates must, at a minimum, carry out a risk assessment of the procurement is conducted in accordance with Company Procedure GSY 0084 – Pre-Purchasing Risk Assessment.

5.13 Prohibited actions and exception reporting

Users, their managers and financial delegates must maintain that the actions set out in this section do not occur. Breaches of this provision will be subject to exception reporting in accordance with Company Procedure GLE 0006 – Exception/Compliance Reporting under the Sub-delegations of Authority.

Users that breach this section must be counselled by their direct manager and reminded that repeated instances of non-compliance will lead to disciplinary action being taken against the user.

5.13.1 Requirement splitting

Employees will not intentionally split contracts, requisitions or invoices in order to circumvent expenditure delegations or the intent of this procedure. This provision extends to users that do not value the requirement in accordance with Section 5.3.

5.13.2 Creation of purchase requisitions/orders after the fact

Employees must not engage a supplier to provide goods or services until an authorised purchase order has been issued (except in bona fide emergencies). Purchase orders created after the date of the invoice will be subject to exception reporting.

5.13.3 Approval of invoices for goods and services covered by the scope of this procedure where no valid purchase order exists

Suppliers providing goods and services that are within the scope of this procedure must be engaged under a purchase order unless a bona fide emergency existed and any invoices for such goods and services that are not covered by a purchase order will be subject to exception reporting. Financial delegates must report to their Executive Leadership Team member why any suppliers subject to exception reporting were not engaged under purchase orders.

The Manager Procurement & Logistics must report any known breaches of Company Policy 1.1.1 – Sub-delegations of Authority by the Chief Executive Officer to the General Manager People & Services within 48 hours of becoming aware of such a breach. The General Manager People & Services must liaise with the relevant Executive Leadership Team member to manage the appropriate corrective action has been taken.

5.14 Restricted procurements

Users must obtain the approval of the appropriate financial delegate where the engagement of a supplier constitutes a specific function as defined in Company Policy 1.1.1 – Sub-delegations of Authority by the Chief Executive Officer.

5.15 Protocols governing interaction with suppliers

5.15.1 Communication and information sharing

Employees must oversee that the procurement process is equitable and that it is as transparent as possible having regard to commercially sensitive information:

During an RFQ process users must:

- not offer preferential treatment to suppliers;
- confirm that no supplier is disadvantaged or subject to prejudicial treatment;
- manage any potential, perceived or actual conflicts of interest in respect of their involvement in the procurement process in accordance with Company Procedure GRM 0028 – Conflicts of Interest;
- take reasonable steps to avoid direct communication or contact with suppliers that could give rise to perceived preferential treatment;
- reply to any questions from suppliers that are material to the RFQ in writing and provide questions and answers to all suppliers that are party to the RFQ process;
- provide all suppliers with identical information and an equal opportunity to compete; and
- where the value of the requirement exceeds the intermediate procurement threshold, manage any meetings, site visits, presentations or any direct supplier contacts and that they are coordinated with a Procurement & Logistics Officer.

5.15.2 Ethics and acceptance of gifts or benefits

Employees must comply with the Code of Conduct at all times and never place themselves in a situation where the impartiality of the supplier engagement process may be, or may be perceived to be, influenced by the provision of any gifts, inducements, samples or free of charge services. Under no circumstances can any employee involved in the procurement process act in a manner prejudicial to any supplier. The Code of Conduct provides guidance on acceptance of gifts as well as Company Procedure GRM 0018 – Gifts, Benefits and Invitations.

5.15.3 Probity and conflicts of interest

Procurement within the company must always be undertaken in an environment in which probity is paramount and all employees involved in the process must comply with the principles set out in Company Policy 12.4 – Probity in Procurement which includes managing perceived, potential and actual conflicts of interest in accordance with Company Procedure GRM 0028 – Conflicts of Interest.

5.16 Competitiveness and fairness

Procurement must always be undertaken in a manner that complies with the CCA. In particular employees must not:

- provide statements and representations which are misleading;
- provide opinions or make predictions without having a sound basis for doing so;
- impose conditions on a contractor that restricts or substantially lessens competition;
- impose unfair terms in standard form contracts;
- acquire or supply goods on the condition that goods or services are acquired from a third party; and
- engage in practices that aim to give a contractor an improper advantage over another.

In the course of monitoring the effectiveness of the company's preventative controls and mitigation controls over the risk of breaching the CCA, in respect its procurement activities, the PMO & Governance Manager will identify the relevant initiating causal factors that may lead to the risk of a material breach of the CCA.

If a risk of a material breach of the CCA is identified, the PMO & Governance Manager will, in conjunction with the Manager Group Governance Risk Compliance, facilitate the implementation of a treatment action plan.

If a need for knowledge enhancement in respect of the CCA is identified the PMO & Governance Manager will facilitate the presentation of awareness sessions regarding the CCA.

5.17 Records and audit trail

The Financial delegate is responsible for preserving an audit trail, which includes retaining all documents pertaining to the relevant procurement including without limitation: quotes; risk assessments, correspondence with suppliers, evaluation forms, financial analysis, reference checks, minutes of meetings, forms and approvals. Document retention periods are detailed in Company Procedure GDM 0006 – Records Disposal.

Where contracts are established with suppliers without the involvement of the Procurement & Logistics Branch, the user must provide a copy of the agreement to a Procurement & Logistics Officer who will scan into the Recordkeeping system and retain in a central repository.

5.18 Principles and guidelines

The PMO & Governance Manager will maintain and review as appropriate the Statement of Business Ethics and the CCA training required for the Procurement & Logistics Branch.

6.0 RECORDKEEPING

The table below identifies the types of records relating to the process, their storage location and retention period.

Type of Record	Storage Location	Retention Period*
Requisition	Ellipse	5 years after plan is superseded, then destroy – as determined by GA28 section 7.13.1

* Content Coordinator must liaise with the Records Manager to validate the retention period is compliant with the relevant disposal authority.

7.0 AUTHORITIES AND RESPONSIBILITIES

Chief Executive Officer has the authority and responsibility for:

- approving procurement plans as set out in Section 5.2.1; and
- approving financial delegations.

Chief Operating Officer has the authority and responsibility for:

- approving procurement plans as set out in Section 5.2.1;
- approving this procedure;
- providing resources; and
- deploying this procedure.

Executive Leadership Team has the authority and responsibility for overseeing correct application of this procedure and appropriate use of sub-delegation within their division.

General Manager People & Services is the Executive Leadership Team sponsor of this procedure and has the authority and responsibility for liaising with appropriate Executive Leadership Team member and/or general managers for resolving breaches of Company Policy 1.1.1 – Sub-delegations of Authority by the Chief Executive Officer.

Manager Procurement & Logistics has the authority and responsibility for:

- providing users with expert advice in respect of procurement and managing, in collaboration with users of procurement services, the company's commercial relationship with suppliers within a defined portfolio;

- administering this procedure and must report any known breaches of Company Policy 1.1.1 – Sub-delegations of Authority by the Chief Executive Officer;

- enforcing this procedure as part of its role in the company wide supply management;

- managing the contracts and procurement process set out in Company Procedure GSU 0002 – Tendering; and

- approving the engagement of suppliers rated below 4.5 on the SQR.

PMO & Governance Manager has the authority and responsibility for:

- reviewing the effectiveness of the company's preventative controls and mitigation controls over the risk of breaching the CCA;
- facilitating awareness sessions as required;
- maintaining and reviewing the Statement of Business Ethics and CCA training as required; and
- reviewing this procedure as and when required.

Purchasing Officer has the authority and responsibility for registering the risk assessments for products/services, selection of suppliers and the raising of purchase orders.

Commercial Manager has the responsibility and authority for:

- managing the company's commercial relationship with suppliers and act as the key company contact point for suppliers; and
- providing users with advice in respect of the procurement process, assist users manage communications, debriefs and meetings with suppliers, where appropriate.

For the purposes of this procedure the Lead Portfolio Manager or Inventory Material & Purchasing Manager or PMO & Governance Manager can perform the functions of the Commercial Manager.

Financial delegates have the authority and responsibility for managing all procurements that are authorised under their delegation and that they are compliant with all aspects of this procedure.

Tender Review Committee has the authority and responsibility for reviewing all procurements for compliance with this procedure in accordance with its charter.

Employees have the authority and responsibility for complying with this procedure.

8.0 DOCUMENT CONTROL

Content Coordinator : Manager Procurement & Logistics

Distribution Coordinator : GRC Process Coordinator

Annexure A – Procurement & Logistics Branch – Roles and Responsibilities Matrix

Responsible Accountable Consulted Informed (RACI)					
	Contract Owner	**Contract User [1]**	**Financial Delegate**	**Contract Sponsor [2]**	**GSU 0016 Procedure reference or other policy or procedure**
1.0 Establish sufficient budget exists					
Establish sufficient budget exists	I	I	A	R	5.3
Establish dedicated work orders created for projects		A			5.6
2.0 Define requirements					
Identify need		A		I	GSU 0001
Consult with Commercial Manager where assistance required or where procurement valued above intermediate procurement threshold	C	A			GSU 0001
Prepare procurement plan, where value greater than intermediate procurement threshold	C	A		I	GSU 0001
Define requirement in writing	C	A			GSU 0001
Develop service levels or performance measures if the contractor will be engaged under a written agreement	A	C			5.5.4
Develop work health and safety specification	I	A			GSY 0068
3.0A Solicitation and Evaluation of Offers (For Tenders Valued $200K to $500K)					
3.1A Solicit offers					
Prepare request document		I		A	GSU 0001 GSU 0002
Post request document on Tenderlink	Procurement & Logistics Branch	C			GSU 0001 GSU 0002

Responsible Accountable Consulted Informed (RACI)					
	Contract Owner	**Contract User** (1)	**Financial Delegate**	**Contract Sponsor** (2)	**GSU 0016 Procedure reference or other policy or procedure**
Coordinate site visits for bidders where required		C		A	GSU 0001 GSU 0002
Conduct briefing of prospective respondents to request document, if required		I		A	GSU 0001 GSU 0002
Manage Tenderlink forum	Procurement & Logistics Branch	C			GSU 0001 GSU 0002
Open electronic tender box	Procurement & Logistics Branch	I			GSU 0001 GSU 0002
Determine whether late offer acceptable	Procurement & Logistics Branch				GSU 0001 GSU 0002
Notify bidder that late offer rejected, if applicable	Procurement & Logistics Branch	I			GSU 0001 GSU 0002
Distribute offers to Evaluation Team	Procurement & Logistics Branch	I			GSU 0001 GSU 0002
3.2A Evaluate offers					
Develop evaluation templates for use by Evaluation Team		C		A	GSU 0001 GSU 0002
Brief Evaluation Team members		I		A	GSU 0001 GSU 0002
Ask Evaluation Team members to declare any conflicts of interest		C		A	GSU 0001 GSU 0002
Evaluate offers against approved evaluation criteria		I		A	GSU 0001 GSU 0002

Responsible Accountable Consulted Informed (RACI)					
	Contract Owner	**Contract User** [(1)]	**Financial Delegate**	**Contract Sponsor** [(2)]	**GSU 0016 Procedure reference or other policy or procedure**
Clarify offers with bidders, as required		C		A	GSU 0001 GSU 0002
Monitor that evaluation summary sheet signed by all team members		C		A	GSU 0001 GSU 0002
3.0B Solicitation & Evaluation of Offers (For Tenders Valued > $500K)					
3.1B Solicit offers					
Prepare request document	A	I			GSU 0001 GSU 0002
Post request document on Tenderlink	A	C			GSU 0001 GSU 0002
Coordinate site visits for bidders where required	A	C			GSU 0001 GSU 0002
Conduct briefing of prospective respondents to request document, if required	A	I			GSU 0001 GSU 0002
Manage Tenderlink forum	A	C			GSU 0001 GSU 0002
Open electronic tender box	A	I			GSU 0001 GSU 0002
Determine whether late offer acceptable	A				GSU 0001 GSU 0002
Notify bidder that late offer rejected, if applicable	A	I			GSU 0001 GSU 0002
Distribute offers to Evaluation Team	A	I			GSU 0001 GSU 0002

Responsible Accountable Consulted Informed (RACI)					
	Contract Owner	Contract User [1]	Financial Delegate	Contract Sponsor [2]	GSU 0016 Procedure reference or other policy or procedure
3.2B Evaluate offers					
Develop evaluation templates for use by Evaluation Team	A	C			GSU 0001 GSU 0002
Brief Evaluation Team members	A	I			GSU 0001 GSU 0002
Ask Evaluation Team members to declare any conflicts of interest	A	C			GSU 0001 GSU 0002
Evaluate offers against approved evaluation criteria	A	I			GSU 0001 GSU 0002
Clarify offers with bidders, as required	A	C			GSU 0001 GSU 0002
Manage post tender negotiations, where applicable for 2 phase tendering	A	C			GSU 0001 GSU 0002
Prepare minutes of meeting of negotiations for 2 phase tendering	A	C			GSU 0001 GSU 0002
Monitor that the evaluation summary sheet is signed by all team members	A	C			GSU 0001 GSU 0002
4.0 Secure financial delegate approval					
Prepare memo for delegate approval where value of procurement < TRC threshold		A		I	GSU 0001 GSU 0002
Prepare TRC paper where required	A	I		A	GSU 0001 GSU 0002
Distribute TRC paper/memo for delegate approval	A	I		C	GSU 0001 GSU 0002
Attend TRC meeting	A	I		R	GSU 0001 GSU 0002

Responsible Accountable Consulted Informed (RACI)					
	Contract Owner	**Contract User [1]**	**Financial Delegate**	**Contract Sponsor [2]**	**GSU 0016 Procedure reference or other policy or procedure**
Distribute TRC papers - post approval	A			I	GSU 0001 GSU 0002
Approve engagement of contractor		I	A		1.1.1
5.0 Develop contract					
Notify unsuccessful bidders of outcome of competitive bid process	A	I			GSU 0002
Prepare conditional letter of intent to successful bidder for non GC-21 contracts where value >= tender threshold	A				GSU 0002
Prepare letter of contract for GC-21 contracts where value >= tender threshold	A				GSU 0002
Create purchase requisition	R	A			GSU 0002
Approve purchase requisition			A		1.1.1
Convert purchase requisition to purchase order	A	I		I	GSU 0002
Draft relevant contract	Procurement & Logistics Branch	C		C	GSU 0002
Sign-off on draft contract	A	R		R	5.4
Send contract to contractor for signature	Procurement & Logistics Branch	I			5.4
Arrange for contract to be executed	Procurement & Logistics Branch	I		I	5.4

Responsible Accountable Consulted Informed (RACI)					
	Contract Owner	Contract User (1)	Financial Delegate	Contract Sponsor (2)	GSU 0016 Procedure reference or other policy or procedure
6.0 Administer contract (WHS-related)					
Develop Site Specific Safety Management Plan where construction works >$250k and the Company is the Principal Contractor		A		C	GSY 0068
Manage the contractor performs obligations set out in WHS Specification where one exists	I	A			GSY 0068
Induct contractor employees and sub-contractors to site where the company is Principal Contractor		A			GSY 0068
Monitor contractor performance to determine compliance with WHS legislation	I	R		A	GSY 0068
7.0 Administer contract (non WHS-related)					
Consult with internal stakeholders and contractor on contract implementation issues		R		A	5.4
Prepare contract implementation plan where contractor is tier 1 and contract is GC21	R	C		A	5.4
Prepare contract implementation plan where contractor is tier 1 and contract is non GC21	Procurement & Logistics Branch	C		A	5.4
Manage execution of plan, where one exists, to completion	R	C		A	5.4
Establish that contractors have received any Company-specific training and possess all necessary accreditations or authorisations to perform their obligations under the contract		R		A	5.5.1 GAM 0089
Establish dialogue with contractor and, where no implementation plan exists, set performance expectations		R		A	5.5.1
Determine that the site at which the contractor will provide the goods and/or services is available for use by the contractor, where applicable		R		A	5.5.1
Follow an approved process to request the contractor perform goods or services for common use contracts, eg book traffic management services		R		A	5.5.1

Responsible Accountable Consulted Informed (RACI)					
	Contract Owner	Contract User (1)	Financial Delegate	Contract Sponsor (2)	GSU 0016 Procedure reference or other policy or procedure
Instruct the contractor on a day-to-day basis and resolve routine contractor queries		R		A	5.5.1
Initiate action with a Procurement & Logistics Officer to expedite any delinquent purchase orders issued to the contractor		R		A	5.5.1
Validate and authorise any timesheets submitted by the contractor where applicable		R		A	5.5.1
Review and distribute reports provided by the contractor of a routine nature		R		A	5.5.1
Chair regular meets with the supplier as required by the relevant contract		R		A	5.5.1
Review, validate and, in the case of contract users that are financial delegates, approve invoices		R	A	C	5.5.1
Vary purchase orders to reflect any changes to the contract		R		A	5.5.1
Establish that the expenditure against the contract is captured against the correct work order or cost centre		R		A	5.5.1
Prepare routine correspondence to the contractor		R		A	5.5.1
Regularly meet with the contractor and oversee operational contractor performance		R		A	5.5.1
Provide contractors with regular forecasts of quantities required where the contract provides for such forecasts to be provided		R		A	5.5.1
8.0 Manage contract expenditure					
Oversee the contractor is paid in accordance with charges set out in the order or contract		R		A	5.5.3
Oversee the contractor is paid in accordance with security of payments legislation to the extent relevant		R		A	
Oversee payments to the contractor do not exceed the approved budget or contract value	R	C		A	5.5.3

Responsible Accountable Consulted Informed (RACI)					
	Contract Owner	**Contract User** (1)	**Financial Delegate**	**Contract Sponsor** (2)	**GSU 0016 Procedure reference or other policy or procedure**
9.0 Formally monitor contractor performance					
Receive performance related reports from tier 1 and tier 2 contractors		A		I	5.5.4
Review performance related reports for tier 1 and tier 2 contractors	A	C		I	5.5.4
Convene formal review of contractor's performance against contract for tier 1 and tier 2 suppliers	Procurement & Logistics Branch	C		C	5.5.4
Communicate with tier 1 or tier 2 contractor where service levels or performance measures or delivery dates are not being achieved	A	C			5.5.4
Liaise with tier 1 or tier 2 contractor to have service level credits or performance credits processed	A	I			5.5.4
Escalate serious issues of contractor non-performance to Commercial Manager using form Company Form FQY 0002 – Corrective Action Request		A		C	5.5.4
Meet with contractor to address serious issue of non-performance as pre-cursor to dispute management, alternative dispute resolution or litigation	A	C		R	5.5.4
Scan documentation in respect of serious contractor non-performance into the Recordkeeping system	A	I			5.5.4
Decide whether issue qualifies as major contractual dispute managed under "Manage Dispute" section	R	I		A	5.5.4
Prepare supplier evaluation Company Form FSU 0038 – Supplier Performance Evaluation at conclusion of contract		A			5.5.4
Revise contractor's SQR rating where necessary	A	C		I	GSU 0007

Responsible Accountable Consulted Informed (RACI)					
	Contract Owner	Contract User (1)	Financial Delegate	Contract Sponsor (2)	GSU 0016 Procedure reference or other policy or procedure
10.0 Vary contract or exercise options					
Consider any proposals received from contractors to vary contracts		A			5.6
Initiate action to vary specification for goods and/or services based on a revised need		A		C	5.6.1
Consider any changes to terms and conditions of contract	A	I		C	5.6.1
Prepare memo to secure approval for contract with tier 1 contractor to vary contract depending of nature of change	R	I		A	5.6.1
Prepare memo to secure approval for contract with tier 2 or tier 3 contractor to vary contract depending of nature of change	C	A			5.6.1
Consider contractor's performance and remaining contract value prior to seeking approval to exercise an option to extend (where available)		A			5.6.1
Seek Manager Procurement & Logistics approval to exercise option to extend contract duration	R			A	5.6.3
Create new purchase requisition or send email to mailbox "procurement" to vary purchase order		A			5.6.1
Create or vary purchase order	A	C			5.6.1
Provide Procurement & Logistics Branch with copy of financial delegate approval		A			5.6.1
Vary contract to reflect approved changes	A	I			5.6.1
Sign-off on any contract variations to the extent they relate to changes to the specification for goods and/or services	R	C		A	5.62
Arrange to have contract variations executed by both parties	A	I			5.62
Provide contract user and contract sponsor with copy of contract variation	A	I		I	5.62

Responsible Accountable Consulted Informed (RACI)					
	Contract Owner	**Contract User** (1)	**Financial Delegate**	**Contract Sponsor** (2)	**GSU 0016 Procedure reference or other policy or procedure**
Consult with contractor and company stakeholders so that they understand impact of any contract variations and establish that contractor possesses all necessary approvals and training to perform varied contract		A		C	5.62
11.0 Manage disputes or serious contractual issues					
Meet with contractor to review potential major contractual disputes	A	I		I	5.5.5
Participate in formal meeting with senior executives as first step to alternative dispute resolution	Procurement & Logistics Branch	I		C	5.5.5
Seek sign-off from Chief Executive Officer to invoke liquidated damages, escalate dispute to litigation, call on bank guarantee	Procurement & Logistics Branch	I		C	5.5.5
Call on bank guarantee	Procurement & Logistics Branch	I		C	5.5.5
Notify contractor of breach of contract	Procurement & Logistics Branch	I		I	5.5.5
Brief lawyers for mediation, arbitration or litigation with contractors	Procurement & Logistics Branch	I		C	5.5.5
Attend mediation, arbitration or litigation	Procurement & Logistics Branch	I		C	5.5.5
Draft deeds of settlement and/or release with contractor following litigation	Procurement & Logistics Branch	C		C	5.5.5

Responsible Accountable Consulted Informed (RACI)					
	Contract Owner	**Contract User (1)**	**Financial Delegate**	**Contract Sponsor (2)**	**GSU 0016 Procedure reference or other policy or procedure**
12.0 End contract					
Initiate action to begin procurement process to establish replacement contract for tier 1 contractor	C	I		A	
Initiate action to begin procurement process to establish replacement contract with tier 2 or 3 contractor	C			A	
Oversee that tier 1 contractor completes obligations, returns equipment, etc and performs any termination assistance for incoming contractor	A			C	
Oversee that tier 2 and 3 contractor completes obligations, returns equipment, etc and performs any termination assistance for incoming contractor		A			
Inform company stakeholders of contract completion and arrangements to transfer processes to business as usual	I	A		C	

(1) The contract owner is the employee for contracts valued below the tender threshold, the contract owner is the employee to whom the Contract User reports. For contracts valued at or above the tender threshold, the contract owner is a Procurement & Logistics Officer.

(2) The contract sponsor may elect to be accountable for functions performed by the Contract Manager where the contract is used throughout the company.

Key		
who is **Responsible** for the outcomes of the process	Responsible	R
who is **Accountable** for the outcomes of the process	Accountable	A
who is **Consulted** before the execution of the process	Consulted	C
who is **Informed** by the process	Informed	I

Company Procedure

PROCUREMENT & LOGISTICS	Document No	:	GSU 0002
	Amendment No	:	15
	Approved By	:	COO
	Approval Date	:	12/09/2014
	Review Date	:	12/09/2016

GSU 0002 TENDERING

1.0 PURPOSE

To set out the process to be followed in calling and evaluating tenders for the procurement of goods and/or services in accordance with Company Procedure GSU 0001 – Purchasing.

THIS DOCUMENT IS A CONTROL FOR THE HEALTH AND SAFETY MANAGEMENT SYSTEM (H&SMS).

2.0 SCOPE

This procedure applies to the procurement of goods and services by the company where the value of the procurement is greater than the tender threshold and there is no contract in place. All monetary amounts set out in this procedure exclude GST unless specifically stated otherwise.

3.0 REFERENCES

Internal:
Board Policy (Procurement & Logistics) 12.0.1 – Purchasing
Board Policy (Procurement & Logistics) 12.0.2 – Disposal
Company Policy (Leadership) 1.1.1 – Sub-delegations of Authority by the Chief Executive Officer
Company Policy (Leadership) 1.1.1B – Sub-delegations of Authority by the Chief Executive Officer for the Chief Operating Officer and Level 2 and Level 3 Group Positions
Company Policy (Procurement & Logistics) 12.1 – Purchasing
Company Policy (Procurement & Logistics) 12.4 – Probity in Procurement
Company Procedure (Governance) GRM 0003 – Risk Management
Company Procedure (Governance) GRM 0016 – Charters of Senior Management Committees and Cross Divisional Committees
Company Procedure (Governance) GRM 0022 –Tender Review Committee
Company Procedure (Governance) GRM 0028 – Conflicts of Interest
Company Procedure (Health & Safety) GSY 0068 – Contractor Management
Company Procedure (Health & Safety) GSY 0084 – Pre-Purchasing Risk Assessment
Company Procedure (Procurement & Logistics) GSU 0001 – Purchasing
Company Procedure (Procurement & Logistics) GSU 0007 – Supplier Assessment, Review and the Supplier Quality Register
Branch Workplace Instruction (Procurement & Logistics) WLB 3005 – Best and Final Offer Negotiation
Company Form (Governance) FRM 0008 – TRC Checklist
Company Form (Governance) FRM 0056 – Tender Review Committee Submission Paper – Proposal to Procure Goods and Services
Company Form (Health & Safety) FSY 0151 – Pre-Purchasing Risk Assessment Worksheet for the Purchase of Goods/Services
Company Form (Procurement & Logistics) FSU 0002 – Supplier Evaluation Questionnaire
Company Form (Procurement & Logistics) FSU 0007 – Services Agreement

Company Form (Procurement & Logistics) FSU 0008 – Request for Best and Final Offer
Company Form (Procurement & Logistics) FSU 0018 – Request for Tender
Company Form (Procurement & Logistics) FSU 0020 – Request for Proposal
Company Form (Procurement & Logistics) FSU 0029 – Bid Evaluation Form
Company Form (Procurement & Logistics) FSU 0032 – Request for Quotation
Company Form (Procurement & Logistics) FSU 0033 – Request for Expressions of Interest
Company Form (Procurement & Logistics) FSU 0041 – Expression of Interest Evaluation Form
Company Form (Procurement & Logistics) FSU 0042 – Procurement Plan
Company Form (Procurement & Logistics) FSU 0043 – Contractor Services Agreement
Company Form (Procurement & Logistics) FSU 0044 – Tender Evaluation Template
Company Form (Procurement & Logistics) FSU 0046 – Master Agreement for Information Technology Goods and Services
Company Form (Procurement & Logistics) FSU 0047 – Services Schedule ICT (Short form)
Company Form (Procurement & Logistics) FSU 0048 – Services Schedule ICT (Systems Integration)
Company Form (Procurement & Logistics) FSU 0049 – Services Schedule ICT (Hardware)
Company Form (Procurement & Logistics) FSU 0050 – Services Schedule ICT (Commercial off the Shelf)
Company Form (Procurement & Logistics) FSU 0051 – Services Schedule ICT (Support)
Company Form (Procurement & Logistics) FSU 0063 – Request for Tender from Supplier Panel
Company Form (Procurement & Logistics) FSU 0064 – Tender Evaluation Plan
Company Form (Procurement & Logistics) FSU 0065 – NSW Government GC21 (Edition 1) General Conditions of Contract
Company Form (Procurement & Logistics) FSU 0066 – NSW Government General Conditions of Contract (Minor Works)
Company Form (Procurement & Logistics) FSU 0067 – Master Supply Agreement for the Supply of Goods and Services
Company Form (Procurement & Logistics) FSU 0068 – Supply Schedule (Supplier Panel)
Company Form (Procurement & Logistics) FSU 0069 – Supply Schedule (Specific Purpose or Period Contract)
Company Form (Procurement & Logistics) FSU 0070 – Consultancy Agreement
Company Form (Procurement & Logistics) FSU 0071 – Request for Quotation (RFQ) – Minor Value
Company Form (Procurement & Logistics) FSU 0090 – Unsuccessful Tenderer Feedback
Branch Form (Procurement & Logistics) FLB 3000 – Contract & Tendering Services Schedule of Submissions Received
Code of Conduct
Endeavour Energy Internet Site
Statement of Business Ethics
Annexure A – Contract Status Step
Annexure B – Procurement & Logistics Branch – Roles and Responsibilities Matrix

External:
Competition and Consumer Act 2010 (Cth)
Electricity Supply Act 1995 (NSW)
Government Information (Public Access) Act 2009 NSW – (GIPA)
AS Records classification handbook – HB5031 – 2011)
AS/ISO 15489 1 – 2002 Records Management
General Retention and Disposal Authority: Administrative Records GA28
ICAC Publication - *Probity and probity advising: Guidelines for managing public sector projects* (Guidelines for seeking assistance on major projects)
ICAC Publication – Direct Negotiations in procurements and disposals: dealing directly with proponents
ISO 31000:2009 – Risk Management – Principles and Guidelines
NSW Treasury Risk Management Toolkit for the NSW Public Sector (TPP12-03)

4.0 DEFINITIONS

Best and Final Offer (BAFO)
Has the meaning given in Sections 5.5.6.1 and 5.5.6.2.

Commercial Manager (CM)
A manager from the Procurement & Logistics Branch responsible for providing users with expert advice in respect of procurement and managing, in collaboration with users of procurement services, the company's commercial relationship with suppliers within a defined portfolio.

Contract
A binding agreement between the company and a supplier established for a specific purpose or for a specific duration up to an amount approved by the relevant financial delegate.

Contractor
The tenderer that is engaged by the company under contract as a consequence of the tendering process set out in this procedure.

Contingency
Additional contract expenditure, established at contract inception but not accessible without approval from the appropriate financial delegate. Contingencies comprise of two parts:

- Risk Reserve – To cover contract risks which are identified at the time of the tender release but could not be accurately quantified or are not expected to eventuate. These Risk Reserves will identify specific items and have a dollar amount associated with them. Examples of this type of Risk Reserve would be foreign exchange or commodity price fluctuations and volume variations or un-anticipated scope such as different ground conditions to those suggested in the geotech report.

- Management Reserve – To cover unidentified or unforseen project risks. These are typically calculated as a percentage of the base contract amount.

Document Control
Employees who work with printed copies of documents must check the BMS regularly to monitor version control. Documents are considered "uncontrolled if printed", as indicated in the footer.

Evaluation Teams
Meaning given in Section 5.6.3.

Executive Leadership Team
Chief Operating Officer, General Manager Health, Safety & Environment, General Manager People & Services, Chief Engineer, General Manager Network Development, General Manager Network Operations, General Manager Finance & Compliance and General Manager Information, Communications & Technology.

Expression of Interest (EOI)
A response to a request for companies to register their interest in supplying a product or service and state their general capabilities.

Financial delegate
The position nominated within Company Policy 1.1.1 – Sub-delegations of Authority by the Chief Executive Officer to approve expenditure and Company Policy 1.1.1B – Sub-delegations of Authority by the Chief Executive Officer for the Chief Operating Officer and Level 2 and Level 3 Group Positions.

***Government Information (Public Access) Act 2009 NSW* (*GIPA*)**
This Act supersedes *Freedom of Information Act 1982 (Cth).*

Independent evaluator
Meaning given in Section 5.6.3.

Intermediate procurement threshold
The monetary value of the requirement above which the procurement is regarded as an “intermediate procurement” currently set at $30,000 or $60,000 for consultants.

Level 3 managers
Includes general managers and regional managers.

Level 4 managers
Includes branch managers.

Negotiation
The process in which the company enters into discussions with a tenderer to reach agreement or mutual understanding between the parties in respect of a procurement. Negotiations are conducted for several reasons including, without limitation, to refine the requirement, eliminate qualifications to the tendered price, consider indicative offers, agree on terms and conditions or clarify a tender. Negotiations with tenderers that that are party to a two phased tendering or direct negotiation process must take place before formal offers are solicited. Negotiations must be led by a CM or manager from the Procurement & Logistics Branch, documented and, in the case of direct negotiations, conducted in accordance with Section 5.5.5.

Probity
Probity is about making decisions with the right intentions, that is, in good faith. Probity involves maintaining fidelity to public sector values and duties such as selflessness, accountability, fairness and observing value for money. Probity implies values such as integrity, uprightness and honesty and, in doing so, minimises the risk of corrupt or dishonest conduct and mismanagement. Company Policy 12.4 – Probity in Procurement sets out the principles that must be followed during the procurement process.

Probity adviser
A probity adviser is an independent third party who is engaged by the company to observe, review and, in the case of probity auditors, audit a complex procurement. The probity adviser usually provides an independent opinion on probity issues that may arise during the procurement process and confirms, in writing, whether the concluded process is consistent with the relevant probity plan, government regulations, guidelines, or general probity principles. Probity advisers must be engaged in accordance with guidelines set out in Section 5.3.

Process manager
Either the level 3 or 4 manager responsible for sponsoring the request for tender or expression of interest or a Commercial Manager. Where the value of the requirement exceeds $500K the process manager must be the Commercial Manager. For all other requests for tender or expressions of interest the process manager must be the sponsoring level 3 or 4 manager.

Procurement
The end-to-end process associated with sourcing goods and services including, without limitation, planning, market research, sourcing, contract management, supplier relationship management, and benefits tracking. For the purposes of this procedure the term procurement is used interchangeably with the term purchasing.

Procurement & Logistics Officer
A member of the Procurement & Logistics Branch.

Provisional sum
An amount of money that is set out in the contract to provide for known contract works that are not fully defined or scoped at the time of the tender release such that the contractor was unable to provide a fixed price submission for these works. Including provisional sums in request documents creates an environment in which tenderers can submit a total fixed price that minimises any risk premium and provides the company with greater certainty of total contract value.
Provisional sum values should identify specific items of undefined works and must be itemised within the tender submission and within the contract.

Recordkeeping
Making and maintaining complete, accurate and reliable evidence of business transactions in the form of recorded information (Source: AS Records classification handbook – HB5031 – 2011).

Recordkeeping system
An information system which captures, manages and provides access to records through time. (AS/ISO 15489 1 – 2002 Records Management).

Request for Best and Final Offer (RFBAFO)
Request for short-listed tenderers' final offers.

Request for Expressions of Interest (RFEOI)
Request for expressions of interest where the company seeks to gauge the potential market for goods or services and/or help crystallise its requirements as a precursor to soliciting tenders or where the company seeks to establish a supplier panel.

Request for Quotation (RFQ)
A request for a response in the form of quotation for the supply of a product or service to a defined specification, generally used where the value of the requirement is less than the tender threshold.

Request for Proposal (RFP)
Request for response to a high level specification (where the company seek the suppliers to provide detail). A request to provide a solution.

Request for Tender (RFT)
Request for a structured and detailed response to a comprehensive statement of requirements.

Request documents
Means an RFT, RFP, RFQ, RFBAFO or RFEOI as the context requires.

Requirement
The goods or services that are required by the user, the value of which is based on the projected expenditure. In the case of goods or services for which there is a recurring need the estimated value of the requirement must be based on projected total expenditure for <u>at least</u> the financial year in which the supplier is being engaged.

Review date
The review date displayed in the header of the document is the future date for review of a document. The default period is three years from the date of approval however a review may be mandated at any time where a need is identified due to changes in legislation, organisational changes, restructures, occurrence of an incident or changes in technology or work practice.

Specification
The document that sets out details of the requirement that is incorporated in both a request document and contract. The specification must either detail the technical characteristics of the requirement or the scope, milestones and deliverables of a project or state the desired outcomes from the procurement process. The specification <u>must</u> set out the performance measures, or

milestones, or volumes, or delivery dates and/ or standards (as appropriate) by which the contractor's performance will be monitored for the duration of the contract. Where the requirement involves the performance of services by a supplier at a company site of a non-trivial nature, eg delivery of goods or attendance at a meeting, the specification must be prepared in accordance with Company Procedure GSY 0068 – Contractor Management.

Strategic alliance
A strategic alliance is where the company enters into a long term (generally minimum three year) arrangement and has the meaning given in Section 5.5.7.

Supplier panel
Meaning given in Section 5.5.3.

Tender
A proposal, tender, offer bid or quotation which may have been submitted to the company in response to an approach to the market. For the purposes of this procedure, a tender is an EOI as the context requires.

Tenderer
A supplier who responds to a request document.

Tender evaluation plan
A tender evaluation plan is a document that sets out the detailed process, team composition, criteria and protocols that apply to a tender evaluation. Tender evaluation plans require financial/commercial aspects of a tender to be evaluated separately to the technical aspects and must be customised by the user to suit the request for tender.

Tender Review Committee (TRC)
A committee convened by the Chief Executive Officer or the Chief Operating Officer to review proposals to enter contracts valued at $500,000 or above.

Tender threshold
The monetary amount above which this procedure must be followed. The amount is currently $200,000 or $400,000 where a valid supplier panel exists.

User
The user of procurement services within the company. In the context of this procedure, the user is the employee responsible for driving the tender process in consultation with the Procurement & Logistics Branch.

User group
The representative group of key stakeholders for the particular product or service.

Value for money
The commercial attractiveness of a tender having regard to the extent to which the offer satisfies the company's requirements and/or evaluation criteria, the value of the offer, and the whole of life costs.

5.0 ACTIONS

Tenders to satisfy requirements valued above the tender threshold may be obtained using any of the following eight methods:

- tendering with EOI (described in Section 5.5.1);
- open (or public) tendering (described in Section 5.5.2);
- tendering from a supplier panel (described in Section 5.5.3);
- selective tendering (described in Section 5.5.4);

- direct negotiation (described in Section 5.5.5);
- two phase tendering, that is, RFP/RFT followed by best and final offer (Section 5.5.6);
- strategic alliance (described in Section 5.5.7); and
- exceptional circumstances (refer to Company Procedure GSU 0001 – Purchasing).

The end-to-end process is also summarised in Annexure A – Contract Status Step.

5.1 Planning and preparation

Every reasonable precaution must be taken so that tenders are only solicited where it is intended to award a contract at the conclusion of the tender process. To this end, the process manager must determine that the requirement is legitimate, the approach to market is aimed at establishing a contract and sufficient provision exists within budget.

5.2 Procurement plan

5.2.1 Purpose

Users are responsible for initiating the tendering process by completing Company Form FSU 0042 – Procurement Plan in consultation with a Commercial Manager (CM) for every requirement that is subject to this procedure. The purpose of the procurement plan is to determine:

- the requirement cannot be satisfied from inventory;

- the value of the requirement is a reasonable estimate of the expenditure and, in the case of goods and services for which a recurring need exists, is based on projected total expenditure for at least the financial year in which the supplier is being engaged;

- where exceptional circumstances apply, the value of the requirement reflects the extent to which the engagement of the supplier represents an extension of a previous engagement having regard to the nature of the goods and services being procured;

- where exceptional circumstances apply and the supplier nominated in Section 2 of the procurement plan does not possess an SQR rating of 4.5 or greater, the procurement plan must be endorsed by the General Manager People & Services or Chief Operating Officer;

- the approach to the market is genuine and aimed at establishing a contract, or where no budget exists action is underway to secure budget;

- an approved budget exists for the procurement or where no budget exists the process manager has initiated action to secure budget approval (to the extent that this is possible);

- approvals to procure the goods or services are made on the basis of a genuine pre-estimate of the likely cost of the engagement, taking into account any amounts previously approved;

- where appropriate, a probity auditor must be engaged;

- where appropriate, a tender evaluation plan must be developed and apply to the procurement;

- suppliers nominated in Section 2 of the procurement plan as prospective tenderers are capable of satisfying the requirement and reasonably likely to submit competitive offers to give the impression of competition;

- tenders will be solicited in the most effective manner, having regard to factors such as the nature of the market or the existence of supplier panels;

- tenders will be evaluated in accordance with this procedure;
- successful tenderers will be engaged using the most appropriate form of the company's agreement;
- timeframes for the tender process are realistic and achievable;
- employee's nominated to evaluate tenders are capable, or reasonably likely to be capable, of evaluating the tenders based on their experience and skills;
- where the value of the requirement is estimated to be $5m and above, whether the Manager Procurement & Logistics decides that a tender evaluation plan must be used by the Evaluation Team in accordance with Section 5.6.5;
- where appropriate, an independent financial evaluation of the tender must be conducted in accordance with Section 5.6.7; and
- an audit trail of the decision making process is preserved by users for all procurements over the intermediate procurement threshold.

5.2.2. Approval

CMs can approve procurement plans except where:

- selective tenders are being solicited;
- direct negotiation is the method of bid solicitation;
- tenders are solicited from fewer than all members of a supplier panel;
- a strategic alliance is being established; or
- exceptional circumstances exist.

With the exception of "exceptional circumstances", "direct negotiation" or "strategic alliance" procurement plans, procurement plans meeting the foregoing criteria must be signed-off according to the value of the requirement as follows:

- Lead Portfolio Manager up to and including $100,000; and
- Manager Procurement & Logistics above $100,000.

"Exceptional circumstances", "direct negotiation" and "strategic alliance" procurement plans must be signed-off according to the value of the requirement as follows:

- Lead Portfolio Manager up to and including $100,000;
- Manager Procurement & Logistics between $100,000 and up to and including $300,000;
- General Manager People & Services above $300,000 up to and including $500,000;
- Chief Operating Officer above $500,000 up to and including $1,000,000; and
- Chief Executive Officer above $1,000,000.

5.2.3 Variations to procurement plans

All variations to procurement plans with the exception of Method of Bid Solicitation can be approved by the CM provided they comply with the once-removed principle, eg the CM cannot approve a change to the plan to appoint themselves to the Evaluation Team. Changes to Method of Bid Solicitation must be approved by the officer who approved the plan.

5.3 Use of probity auditor or probity adviser

The CM must consider whether it is necessary to engage a probity adviser at the commencement of the tender process. A probity adviser should be engaged where any of the following circumstances exist, although the list is not exhaustive:

- the requirement is new and no similar requirement has been the subject of tender action previously and the value exceeds the Chief Executive Officer's financial delegation;
- the requirement is politically sensitive or high profile;
- the requirement is unusually complex and/or heavily reliant on innovation;
- the requirement is likely to have a significant social or environmental impact;
- the value of the requirement is significant;
- there was a previous request for tender that was terminated because the process was compromised in some way; or
- there needs to be extensive face-to-face consultation with tenderers to further develop the specification during the tender process and there are multiple suppliers involved.

Where it is necessary to engage a probity adviser after request documents have been released to the market, such engagement must be managed by the Group Head of Audit.

5.4 Preparation of request documents

5.4.1 Specifications and performance measures

The user is responsible for specifying both the requirement and relevant performance measures in writing in a specification. The Procurement & Logistics Officer must include the specification in one of the request documents, Company Form FSU 0008 – Request for Best and Final Offer, Company Form FSU 0018 – Request for Tender, Company Form FSU 0020 – Request for Proposal, Company Form FSU 0032 – Request for Quotation, Company Form FSU 0033 – Request for Expressions of Interest, Company Form FSU 0063 – Request for Tender from a Supplier Panel or Company Form FSU 0071 – Request for Quotation – Minor Value.

The user must develop the specification with regard to at least the following criteria;

- scope of the goods and services to be provided including any deliverables;

- relevant technical specification or standards or drawings or manufacturer's part number;

- service levels or performance measures, or delivery milestones, or volumes, or required delivery date(s) or other standards (as appropriate) against which the contractor's performance will be measured; and

- where the request document or form of agreement that accompanies the request document does not adequately address the commercial consequences of an engagement, the relevant information to mitigate any commercial risk must be included in the specification.

The requirement must be expressed in generic terms to maximise the competition, that is, requirements should be specified rather than prescribed. The complexity of the required product or service and the scale of the procurement should be taken into account when determining the extent to which a requirement should be specified.

5.4.2 Provisional sums and contingencies

Where the user expects that the value of any contract will vary because the contractor is likely to encounter conditions that could not have been reasonably discovered during the tender process, e.g. the provision of a section of building works that has not yet been designed, the user must, to the extent reasonably possible, seek expert advice to identify the type and value of provisional sums. Where-ever possible, the value of the provisional sums and the conditions under which they apply should be set out in the specification or request document and must be included in the contract. Where it is necessary to vary provisional sums during the tender process, all tenderers must be notified of such changes.

Where the user expects that the value of the contract will vary because of other factors including, without limitation, foreign exchange or commodity price fluctuations, unanticipated changes to the scope or project timeline, such variations can be managed using an approved contingency. Unlike provisional sums, contingency amounts are not disclosed in request documents or the contract. Where there is a contingency relating to foreign exchange variations, the process manager must consult with Treasury.

5.4.3 Approvals

The Lead Portfolio Manager must establish that the request documents incorporate the template of the most appropriate contract terms under which the successful tenderer will be engaged and obtain sign-off from the process manager on the request document that the Specification contains an accurate definition of the requirement and performance outcomes expected of the contractor. No sign-off from the process manager is required on the request document where BAFO's are being solicited. The Manager Procurement & Logistics must sign-off that the request documents have been prepared in accordance with this procedure.

5.5 Methods of soliciting tenders

5.5.1 Tenders with EOI

5.5.1.1 Purpose

EOIs may be solicited:

- to gauge the scale of an unknown market for goods and services;
- where there are a large number of suppliers in the market and a process is required to shortlist prospective tenderers that will be subsequently invited to tender;
- where information from the market is needed to help crystallise the requirement that will be subsequently be defined in request documents; and
- to establish supplier panels that are not based on schedules of rates (covered in Section 5.5.3).

Process managers must define their high level requirements in Company Form FSU 0033 – Request for Expressions of Interest Template. EOIs used to pre-qualify suppliers for a specific tender typically seek information in respect of suppliers' ownership, structure, financial performance and Health Safety & Environment (HSE) and quality management systems and generally do not seek pricing information. Where EOIs are solicited, the request for EOI must be advertised in accordance with Section 5.8.2.

5.5.1.2 Evaluation of expressions of interest

EOIs must be evaluated in accordance with Company Form FSU 0041 – Expressions of Interest Evaluation Form or evaluation criteria approved in writing by a CM. The composition of the team evaluating the EOI is subject to the same approval process that is described in Section 5.6 of this procedure and must be approved on Company Form FSU 0042 – Procurement Plan.

5.5.1.3 Approval of EOI shortlists

This Section only applies where EOIs are used to pre-qualify suppliers prior to releasing request documents. Where EOIs are used to establish a supplier panel, the provisions of Section 5.5.3 apply.

Following the evaluation of EOIs, the process manager must:

- prepare a memo that documents the results of the EOI evaluation process and recommends a short-list of EOI respondents that will be invited to tender;
- secure the endorsement of the relevant CM and sign-off on the short-list; and
- provide the original memo to the Lead Portfolio Manager who will retain it on file.

Where the Evaluation Team cannot reach unanimity on the composition of the short-list, dissenting views of the team member must be captured in the memo to the process manager. Where there is serious disagreement between Evaluation Team members, the Manager Procurement & Logistics will arbitrate and determine whether the evaluation process should be recommenced in its entirety. Disputes may be referred to the General Manager People & Services by either the Manager Procurement & Logistics or the process manager.

5.5.2 Open tendering

5.5.2.1 Purpose

Open (or public) tenders are solicited directly from the market by public advertisement. The main advantage of this approach is that competition is maximised.

5.5.2.2 Process

Open tenders must be solicited using approved request documents that are advertised in accordance with Section 5.8.2 and evaluated in accordance with Section 5.6.

5.5.3 Supplier panels

5.5.3.1 Purpose

Supplier panels of preferred suppliers streamline the process by which tenders are solicited and should be established for all recurring requirements.

5.5.3.2 Establishing a supplier panel

Supplier panels may be established in the following ways:

- an EOI or request for tender process;
- market research/investigation conducted in consultation with a Procurement & Logistics Officer; and
- selection of the companies that have tendered for comparable goods or services during the past 12 months in consultation with a Procurement & Logistics Officer.

Where a request document is issued to the market to establish the panel the provisions outlined in that document will cover the performance management of the panel including variations to the panel membership. Where no specific provisions are included in the request documents, Sections 5.5.3.5, 5.5.3.6, 5.5.3.7, 5.5.3.8 and 5.5.3.9 will apply.

Supplier panels can be used in one of two ways:

- tenders may be invited from members of the relevant supplier panel; and
- requirements can be allocated to panel members directly based on predetermined rules.

5.5.3.3 Tenders from supplier panel

Soliciting tenders directly from supplier panel members is intrinsically simple and quick and maximises competition among known market players. Tenders must be sought from all supplier panel members via RFP or RFT where a supplier panel member could reasonably satisfy the requirement. Tenders may be solicited from a sub-set of panel members where approval has been granted on the relevant procurement plan.

5.5.3.4 Awarding contracts to supplier panel members based on pre-determined rules

Contracts maybe awarded to supplier panel members based on a set of predetermined rules. These rules must be stated in the request document and contract or deed used to establish the supplier panel. Approval to award contracts in accordance with this Section 5.5.3.4 must be approved by the relevant financial delegate.

5.5.3.5 Variations to supplier panels

Supplier panels may be varied or dissolved, subject to terms of the contract, where changes to market conditions create a situation in which the supplier panel is not representative of the market or where it can clearly be demonstrated that the supplier panel no longer operates effectively, eg the contract with a supplier panel member is terminated due to unsatisfactory performance.

5.5.3.6 Variations to supplier panels with schedules of rates

Where less than 12 months have elapsed since EOIs or tenders closed, the original tender evaluation report can be used to determine the eligibility of tenderers for inclusion in the supplier panel. For example the tenderer originally ranked number four could be added to a supplier panel that originally comprised three suppliers, providing the tenderer is willing to honour their tendered prices. Probity considerations prevent the addition of suppliers to a supplier panel with schedules of rates where more than 12 months have elapsed since the date on which EOIs or tenders closed and consideration should be given to dissolving any ineffective supplier panels that fall into this category.

5.5.3.7 Variations to supplier panels without schedules of rates

Where more than 12 months remain of the initial duration of the supplier panel, the original tender evaluation report can be used to determine the eligibility of tenderers for inclusion in the supplier panel. Under this scenario, the tenderer that was ranked behind those originally appointed to the supplier panel could be approached to validate their original tender or EOI. Where less than 12 months remain of the initial duration of the supplier panel, consideration should be given to dissolving the supplier panel, subject to terms of the contracts and soliciting tenders afresh.

5.5.3.8 Dissolution of supplier panels

Consideration should be given to dissolving the supplier panel and calling fresh tenders or EOIs in instances where the market has changed significantly since tenders were originally called.

Dissolution of supplier panels is the preferable option where the contract provides for termination for convenience and there are less than 12 months remaining of the initial supplier panel duration.

5.5.3.9 Approvals

All supplier panels must be established in accordance with the Board or in accordance with the Company Policy 1.1.1 – Sub-delegations of Authority by the Chief Executive Officer and are endorsed/approved by the Chief Executive Officer. Panel members should always be engaged under a contract unless the simplicity of requirement does not necessitate the establishment of formal contracts.

The approval of the Chief Executive Officer is always required to dissolve supplier panels or to vary supplier panels where the panel establishment process did not set out a process to vary the panel.

5.5.4 Selective tendering

5.5.4.1 Purpose

Tenders may be solicited directly from a restricted set of suppliers that are not on a supplier panel where the process manager has satisfied a CM and relevant approval authority on Company Form FSU 0042 – Procurement Plan that there is a compelling business need to limit the approach to the market.

The following list provides guidance as to what circumstances may justify selective tendering but the list is not exhaustive:

- where an open approach to the market has recently been made and market conditions have not materially changed;
- where a market for the relevant goods and services has been properly researched and is reasonably known;
- where confidentiality or security considerations preclude open tendering; and
- where a supplier panel for the relevant goods and services has recently expired and market conditions have not materially changed.

The CM must satisfy themselves that all suppliers selected to participate are reasonably capable of satisfying the requirement and that restricting the approach to market will promote effective competition and yield the best value for money outcome.

5.5.4.2 Establishing a shortlist

The process manager must, in consultation with a CM, undertake a reasonable process to research the market and determine prospective suppliers. Suppliers on the SQR with a rating of 4.5 and above that could reasonably supply the goods and services should be included, where possible. Process managers are responsible for preserving an audit trail of any market research which has been conducted.

5.5.5 Direct negotiation

5.5.5.1 Purpose

Tenders may be solicited directly from suppliers via a transparent and strictly controlled negotiation process where negotiation with one or more suppliers will lead to the best commercial outcome possible, eg following a terminated tender process. The suppliers selected to participate may either be on a supplier panel or have been pre-qualified via an EOI or tender process or otherwise approved on Company Form FSU 0042 – Procurement Plan.

Wherever possible, more than one supplier must participate in the process.

5.5.5.2 Process

Once approval has been secured to conduct direct negotiations, the process manager must form a Negotiation Team, one member of which must be a Procurement & Logistics Officer. The Lead Portfolio Manager or CM is responsible for informing prospective bidders in writing of the way in which the process will be conducted. The CM is responsible for chairing meetings and managing the process of minutes of meetings and records of conversation, etc are maintained and forwarded to the Lead Portfolio Manager for retention on file. Direct negotiations must culminate in the submission of BAFOs by suppliers, the closing dates of which must be identical.

BAFOs must be solicited using Company Form FSU 0008 – Request for Best and Final Offer and direct negotiations must be conducted in accordance with Branch Procedure WLB 3005 – Best and Final Offer Negotiation and the principles set out in the ICAC publication Direct Negotiations in procurements and disposals dealing directly with proponents. Through the negotiation process feedback may be provided to suppliers, which can include, but is not limited to:

- technical areas;
- commercial areas; and
- pricing areas.

Pricing feedback must not be undertaken in manner that could be construed as “bid shopping”.

Pricing feedback can include the following:

- Feedback at the item, bundle or total solution level depending on the nature of the tender.

- Difference from that supplier’s offer to the best conforming offer must be provided as a range, ie 0-5%, 5-10%, 10-15% from best offer not as a specific amount, eg”8% higher than best offer”.

5.5.6 Two phase tendering – RFP/RFT followed by BAFO

5.5.6.1 Purpose

Tenders may be solicited in two phases, that is, RFP or RFT followed by BAFO, in instances where it is decided to negotiate with short-listed tenderers to obtain the best value for money outcome.

5.5.6.2 Process

Tenders are solicited using an appropriate request document which must notify prospective respondents that the process is in two phases and broadly set out the guidelines under which BAFOs will be sought and a timetable. Tenders are evaluated in accordance with this procedure and the Evaluation Team must sign-off on the short list of tenderers that are invited to submit a BAFO. Following the sign-off on the shortlist, there may be several rounds of negotiations with the short-listed tenderers (including the submission of indicative offers) culminating in a Request for Best and Final Offer (BAFO). The relevant CM is responsible for preserving the audit trail and forwarding such evidence to the Lead Portfolio Manager for retention on the relevant procurement file. The BAFOs must be solicited using Company Form FSU 0008 – Request for Best and Final Offer and all negotiations with tenderers must be conducted in accordance with the process described in Section 5.5.5.2.

5.5.7 Strategic alliances

5.5.7.1 Purpose

A strategic alliance applies where the company enters into a long term (generally minimum three year) agreement with a supplier to source specific goods and/or services within a procurement category or categories. The aim of a strategic alliance is for the company and supplier to collaborate on planning, cost reduction initiatives and potentially product development to realise quantifiable benefits for both parties in the long run. Where users seek to engage suppliers under a strategic alliance they must develop a draft business case in consultation with a CM that clearly sets out the projected scope of such an alliance, the projected value of the engagement and the target benefits which must be endorsed by the relevant Executive Leadership Team member and then approved by the Chief Operating Officer and Chief Executive Officer before negotiations commence.

5.5.7.2 Process

Strategic alliances must be established following either a competitive tendering or direct negotiation process. The company can only enter into strategic alliances where the financial delegate is satisfied that the final business case demonstrates such an alliance yields superior quantifiable benefits to more conventional tendering approaches, having regard to the effectiveness of a market for the goods and/or services. In this respect, users are accountable for tracking the realisation of projected benefits of strategic alliances set out in the relevant business case and reporting on progress to the relevant Executive Leadership Team member and Chief Operating Officer every six months. The Manager Procurement & Logistics must determine that the agreement with the strategic alliance contractor contains performance measures that mandate the realisation of any quantifiable benefits that rely on the contractor such as price reduction, product development gain sharing, profit sharing, reduced lead times or reduced total cost of ownership.

The provisions of Sections 5.2, 5.4, 5.6, 5.7, 5.8 and 5.10 of this procedure do not apply to strategic alliances.

5.6 Tender evaluation

5.6.1 Objective

The objective of the tender evaluation process is to determine the tender that best satisfies the Requirement and represents the best value for money proposition. The process manager is responsible for evaluating tenders in accordance with this procedure and the approved procurement plan.

5.6.2 Release of tenders

Following the registering of tenders, employees within the Procurement & Logistics Branch will scan all documents into the Recordkeeping system and securely store them. Request documents cannot be released to the user until such time they have signed the relevant checklist indicating receipt. The user after signing for the documents must securely store the request documents at all times and maintain the confidentiality of tenders, disclosing information to employees on a need-to-know basis.

5.6.3 Evaluation Teams

Evaluation Teams are set out in the approved procurement plan and must consist of:

- a minimum of two people who are capable, or reasonably likely to be capable, of evaluating the tenders based on their experience and skills;

- an independent evaluator who works in a separate branch or region to the user who is not a member of the Procurement & Logistics Branch. The independent evaluator must also be capable, or reasonably likely to be capable, of evaluating the bids based on their experience and skills and, where reasonably practicable, should be at the same level in the organisational hierarchy as the majority of other members of the team; and

- where the value of the requirement is likely to exceed $500k, a CM as the fourth member of the Evaluation Team.

Where the CM or Evaluation Team form the view that there is only one or no employee that is capable or reasonably likely to be capable, of evaluating the bids based on their experience and skills, a suitably qualified resource must be engaged from outside the company and included in the Evaluation Team. If a specialist contractor or consultant is required to act as an “independent” Chief Operating Officer approval must be obtained.

5.6.4 Tender evaluation criteria

Tenders must be evaluated using Company Form FSU 0029 – Bid Evaluation Form or Company Form FSU 0044 – Tender Evaluation for using the evaluation criteria which are approved on Company Form FSU 0042 – Procurement Plan. Where Company Form FSU 0029 – Bid Evaluation Form or Company Form FSU 0044 – Tender Evaluation is not used, the process manager is responsible for developing alternative criteria. Evaluation criteria and weightings must not unnecessarily exclude potential suppliers or restrict competition. The Procurement & Logistics Officer responsible for preparing the request documents must include the relevant approved evaluation criteria.

5.6.5 Evaluation protocols or plans

For procurements valued $5m and above, the Manager Procurement & Logistics must determine whether a tender evaluation plan should apply. For procurements valued less than $5m, the Lead Portfolio Manager may determine that the process manager must develop a tender evaluation plan in respect of the tender where they believe that the level of risk associated with the tender warrants such an approach. Where the process manager is required to prepare a tender evaluation plan they must complete Company Form FSU 0064 – Tender Evaluation Plan or equivalent and have the plan signed-off by the Manager Procurement & Logistics and sponsoring level 3 or 4 manager preferably before the tender closing date but always before tenders are released to the Evaluation Team by the Lead Portfolio Manager.

5.6.6 Tender evaluation process

Before commencing with the evaluation process, the Evaluation Team must agree upon the basis for which they will make their decision. While there are many different methods for doing so, the two main selection methods are:

- to rank tenderers based on an aggregate score that takes into account both qualitative criteria, eg service, quality, technical compliance, terms and conditions and quantitative criteria, eg pricing; or

- to qualify all tenderers that fully comply with the company’s minimum requirements, and to then select the lowest cost option from these qualified suppliers.

In both cases the evaluation criteria and weightings applied must be those as detailed in the relevant approved Company Form FSU 0042 – Procurement Plan.

During and after the evaluation process, the process manager is responsible for:

- liaising with a CM, where the process manager is not a CM;

- each member of the Evaluation Team understanding their obligations under this procedure and, where members of the Evaluation Team are unfamiliar with the process arrange for a Procurement & Logistics Officer to formally brief the team;

- driving the evaluation process;
- advising all members of the Evaluation Team to declare and manage any real or perceived conflicts of interest of Evaluation Team members in respect of the relevant tender process, in accordance with the Code of Conduct;
- tenderers signing forms of tender that warrant and represent that the tenderer complies with the Statement of Business Ethics, NSW Code for Procurement and are not conflicted or, where they are conflicted this is clearly raised to the attention of the financial delegate;
- adherence from all Evaluation Team members with the relevant tender evaluation protocol where applicable;
- where the process manager is a CM, advising the process manager to prepare a TRC paper using Company Form FRM 0056 – Tender Review Committee Paper, Company Form FSY 0151 – Pre-Purchasing Risk Assessment Worksheet for the Purchase of Goods/Services and Company Form FRM 0008 – TRC Checklist;
- securing sign off on forms by the sponsoring General Manager or level 3 manager and endorsement of the relevant Executive Leadership Team member of the TRC paper;
- arranging a TRC meeting;
- attending (and, where the process manager is a CM, accompanying the process manager) the TRC meeting and responding to any requests for information from TRC members;
- physically securing tender documentation;
- maintaining commercial confidentiality of tenders, ie it is at the CM's discretion on when the pricing aspects of tenders are shared with the Evaluation Team;
- complying with privacy legislation; and
- preserving an audit trail in accordance with Section 5.8.14, except in respect of direct negotiations where the CM bears this responsibility for all exchanges of correspondence with tenderers during the negotiation phase.

Tenders may be evaluated individually or collectively by the Evaluation Team. Where evaluations are conducted individually, final results must be agreed by the whole Evaluation Team.

Where unanimous recommendations cannot be reached by the Evaluation Team, dissenting team members' views must be noted as part of the final recommendation. Where there is serious disagreement between Evaluation Team members, the Manager Procurement & Logistics will arbitrate and determine whether the evaluation process should be recommenced in its entirety. Disputes may be referred to the General Manager People & Services by either the Manager Procurement & Logistics or the process manager.

5.6.7 Financial evaluation

Where a CM believes that a separate financial evaluation is required having regard to risks associated with procurement, Evaluation Team skills/availability and complexity of tenders, the relevant procurement plan must be endorsed accordingly. For tenders for which an independent financial evaluation is required, an appropriate member of Finance & Compliance Division must analyse the pricing offers from tenderers and provide a signed report to the Evaluation Team ranking tenders according to price. Tenders must be compared on a like-for-like basis or, where this is not possible, on the most equitable basis reasonably possible with any assumptions used in the analysis clearly identified in the report. Where the preferred tenderer is a new supplier that has not previously been rated on the SQR, the Evaluation Team must assess the supplier for eligibility to be added to the SQR in accordance with Company Procedure GSU 0007 – Supplier Assessment and the Supplier Quality Register. The Evaluation Team must take into consideration the financial evaluation in determining which tender provides the best value for money. Where the Evaluation Team recommends that a contract be awarded to the tenderer that has not submitted the lowest conforming tender, the case must be made to the financial delegate with any risks or additional costs quantified, where possible.

5.6.8 Evaluation of tenders where pricing affected by foreign exchange and commodity price variations

Where tenders contain pricing that is subject to foreign exchange or commodity price variations, the Evaluation Team must seek a report from the Treasury Manager that sets out the best strategy to manage the financial risk to the company.

5.6.9 Evaluation of compliance with the company's terms and conditions

Where tenderers seek to vary the company's standard terms and conditions, the Evaluation Team must seek advice from a Procurement & Logistics Officer who will prepare a table of changes sought and seek the sign-off of the Lead Portfolio Manager or General Counsel, one of whom must also provide a risk rating of the tenderer in respect of its compliance with terms and conditions, where this is an evaluation criterion. Where changes sought are of a material nature, the Lead Portfolio Manager may seek the advice of the General Counsel who may confirm that the tender is non-conforming on the basis of the extent of the changes sought.

5.6.10 Preparation of TRC and Board papers

Where the value of the procurement is $500k or greater, the CM is responsible for preparing the documentation required to secure approval from the financial delegate to award the contract, including TRC forms and checklists, where necessary. Where the value of the procurement is less than $500k, the user is responsible for preparing such documentation. For the purposes of seeking approval to award a contract, the contract value is the GST exclusive sum of the tendered price, including any provisional sums and contingency amounts for the planned contract duration including options. For supplier panels and contracts that do not oblige the company to procure nominated volumes of goods and services, the contract value comprises a genuine estimate of expenditure for the duration of the contract including options, provisional sums and contingency amounts.

5.7 Tender Review Committee (TRC)

5.7.1 TRC purpose and operation

The TRC considers recommendations to award contracts valued $500,000 and above in accordance with Company Procedure GRM 0022 – Tender Review Committee.

The TRC will either:

- recommend that a contract be awarded;
- reject the recommendation in its current form;
- request additional information prior to a decision; and
- recommend that a contract be awarded with specific conditions.

5.7.2 Post TRC actions

Following a meeting of the TRC, the relevant CM will:

- immediately notify the process manager or user of the decision of the TRC which may include a request for additional information;
- send all TRC-related documentation and notification to the successful tenderer(s) pursuant to Section 5.8.13 to the process manager at the earliest opportunity; and
- retain a copy of all TRC-related documentation on file.

The user is responsible for generating a purchase requisition in Ellipse for the approved value of the contract to facilitate prompt account settlement.

5.8 General rules

5.8.1 Forms of submission

Tenders may be received electronically, that is, via the company's electronic tendering portal, Tenderlink.

Tenderlink must be used to manage the tender submission process unless the Manager Procurement & Logistics is satisfied that a compelling case exists to use an alternative approach such as hard copies.

5.8.2 Tender closing date

It is essential that all tender documentation be endorsed with a closing date and time in the interests of probity and equity.

Tenders must remain open for at least two weeks, preferably four to enable suppliers to reasonably submit a tender. Tenders are to be submitted not later than the time and day indicated (the closing time of tenders), or as otherwise indicated in the tender documentation. Any tender received after this time and date shall be rejected or accepted at the discretion of the Manager Procurement & Logistics acting in accordance with Section 5.8.12.

Tenders submitted by electronic means will be considered as a formal submission (subject to data record of time of receipt).

5.8.3 Enquiries and communication

The process manager must maintain that no tenderer receives preferential treatment during the request for tender process. Requests for additional information between tenderers and the company must be controlled by a Procurement & Logistics Officer and any additional information provided that is material to the requirement or any responses to tenderers' requests for information that could reasonably affect their tender are made available to all tenderers in the interests of probity and equity. Tenderers must put all questions other than those of a trivial nature relating to process in writing and be advised in request documents that their questions and answers will be provided to all tenderers.

Subject to Section 5.5.5.2 – Process, the process manager is responsible for maintaining an audit trail of all communications with tenderers and forwarding copies to the CM at the conclusion of the request for tender process who will provide documentation of a material nature to the Lead Portfolio Manager for retention on file.

5.8.4 Presentations and site visits

A detailed presentation of technical issues and/or site visits associated with the request for tender may be arranged with tenderers providing that the presentation or visit is organised in consultation with a Procurement & Logistics Officer. Under no circumstances can pricing or other commercial issues be discussed during the course of the site visit or presentation with the exception of two-phase procurement or direct negotiations. The CM involvement in site visits presentations is dependent on the profile or value of the requirement.

Presentations and visits should be clearly identified in the request document if considered mandatory and should only be used to clarify items, explain information presented in the tender, assess cultural fit and assess competencies of individuals that tenderers propose will be associated with providing the services. Tenderers will be provided with written guidelines or agendas prepared by the process manager with Procurement & Logistics Branch input if required prior to the activity.

5.8.5 Post tender negotiations

If after a competitive tendering process none of the tenders are acceptable or conforming, negotiations may be conducted with the tenderer which is the closest to conforming to the tender requirements and provides best value for money. The decision to proceed with post tender negotiations must be approved by the Manager Procurement & Logistics.

Negotiations must be led by a CM and start with the tenderer which is the closest to the conforming tender and must be exhausted before negotiating with subsequent tenderers which if required will be approved by Manager Procurement & Logistics.

The purpose of the negotiations must be established and made clear and documented prior to the commencement of negotiations. Written records of all negotiations must be documented by the CM and provided to the Lead Portfolio Manager for retention on file.

The negotiation process should be open and accountable and post tender negotiations that unfairly seek to simplify or disclose tenderers' tenders to their competitors are prohibited.

5.8.6 Confidentiality

The security and confidentiality of all tenders must be maintained at all times and the Lead Portfolio Manager must keep hard copy tenders within the confines of the secure Procurement & Logistics workspace and electronic forms of tenders held in a file directory that is not accessible to members of the Evaluation Team before they are released to the Evaluation Team. The Evaluation Team leader is responsible for complying with this requirement after tenders are transferred to the Evaluation Team. Tenders must be treated as commercial-in-confidence and must not be disclosed to any party without a need to know. Tenders must also be afforded physical security – particularly out-of hours and must not be removed from the premises of the company without express approval from the Manager Procurement & Logistics.

5.8.7 Amendments to request documents

Where it becomes necessary to amend request documents, the amendments must only be made by a Procurement & Logistics Officer and issued as an addendum to all tenderers in sufficient time but never less than one working day earlier than the request closing date for all tenderers to properly and fully consider the addendum before the closing date. The addenda will be issued by the Lead Portfolio Manager or CM, as appropriate.

Each addendum should state clearly that it is meant to be incorporated in the request documents. Tenderers should confirm in their responses that allowance has been made for each addendum.

Consideration may need to be given to extending the tender period when an addendum is issued. If the tender period is extended all tenderers are to be advised of the new closing time and date.

Where it is necessary to issue addenda to tender documentation after tenders have closed, consideration should be given to terminating the tender process and calling fresh tenders. Where revised prices are sought, they must be managed in accordance with the tender receipt process set out in Sections 5.8.3 and 5.8.12, ie bids should be managed using the Tenderlink portal or tender box.

Records of all material communications between the company and tenderers must be retained on file by the Lead Portfolio Manager.

5.8.8 Clarification of tenders

In circumstances where a statement or information provided in a tender is open to interpretation or is not understood, clarification of the statement or information should be obtained from the tenderer by a Procurement & Logistics Officer. The clarification request must be framed in a manner that does not result in the tenderer gaining advantage over other tenderers, eg revising or expanding the offer.

Any discussion or contact with tenderers during the tender evaluation period must be performed in consultation with a CM or Lead Portfolio Manager and have due regard to probity, in particular:

- the status (preferred, under consideration or rejected) of any tender must not be advised or implied to any tenderer; and
- interaction with tenderers should be in writing. In circumstances where an issue is discussed verbally with the tenderer, a record of the discussion must be documented.

If the requirements alter substantially, consideration should be given to terminating the tender process and soliciting fresh tenders. Records of all communications between the company and the tenderers must be held by the Lead Portfolio Manager and may form part of the documents submitted for review by the TRC.

5.8.9 Alternative conforming tenders

The company can consider an alternative tender where the financial delegate is satisfied, on the balance of probabilities, that the alternative tender yields an outcome that offers the company a better value for money proposition. An alternative tender can only be considered conforming if it is accompanied by a strictly conforming tender. Before accepting alternative tenders, consideration should be given to whether the way in which the requirement was specified in the request documents was materially deficient in which case tenders should be sought afresh. Where tenders are called afresh under these circumstances, care must be taken not to re-define the requirements in such a way that may infringe the intellectual property rights of the tenderer that submitted the alternative tender.

Request documentation must state that alternative tenders may be considered subject to the requirements of this section.

5.8.10 Registration of tenders

All tenders must be registered at the earliest practicable opportunity after tenders are opened.
All tenders received will be recorded.

Tenders must be released to the Evaluation Team at the earliest practical opportunity following registration.

5.8.11 Late tenders

Late tenders may only be considered where the integrity and competitiveness of the tendering process is not compromised.

Late tenders may be accepted by the Manager Procurement & Logistics only where tenders have not been released by the Lead Portfolio Manager to the Evaluation Team for evaluation and where:

- acceptance of the late tender provides the tenderer no material advantage or a benefit over other tenderers who have submitted on time; or
- the tender was not received on time due to mishandling by Procurement & Logistics Branch or other employees; or
- the tenderer was unable to upload the document to the Tenderlink portal due to factors outside the tenderer's reasonable control that can be reasonably substantiated and that tenderer can provide evidence that they contacted or tried to contact the relevant RFT contact person in accordance with instructions set out in the request document ; or
- the tender was an RFI or EOI where no formal pricing or agreement was being requested.

5.8.12 Notification to tenderers and debriefings

The Lead Portfolio Manager will notify all tenderers in writing of the outcome of the tender process following approval by the relevant financial delegate. With the exception of the identity of the contractor, which can be made available on request, no information relating to the unsuccessful tenderers will be made available, unless otherwise specified in the request document, by agreement or required by law.

Debriefings will be available to unsuccessful tenderers on request and conducted by the CM or Procurement & Logistics Officer and member of the Evaluation Team where required. The debriefing should explain how their tenderer performed against the evaluation criteria, rather than against the contractors, with the objective of enhancing their future performance.

The *GIPA* means that within 60 days of a contract being executed all contracts over the value of $150,000 will be published on the company's internet site.

5.8.13 Records and audit trail

The process manager is responsible for preserving an audit trail, which includes retaining tender documentation, addenda to tenders, minutes of meetings and correspondence. Process managers must send all documentation which is material to the tender process to the Lead Portfolio Manager who will hold it in a central repository following presentation to the TRC.

5.8.14 Contract execution

Following approval from the financial delegate, the Lead Portfolio Manager will arrange contract execution, having regard to the form of agreement that accompanied the request document and any marked-up changes to that form of agreement by the tenderer which have been accepted.

Where there are material departures from the company's terms and conditions, the sign-off from the General Counsel or external law firm must be obtained by the Lead Portfolio Manager and retained on the relevant procurement file.

The process manager or is responsible for the ongoing contract management, administration and post contract evaluations in accordance with Company Procedure GSU 0016 – Contract Management.

5.8.15 Disputes

Tenderers have the right to expect that the tendering process is equitable and transparent within the limitations of commercial confidentiality. If tenderers have any concerns with the process, they can either pursue the grievance mechanism in accordance with the Statement of Business Ethics or document their concerns in writing to the Manager Procurement & Logistics who will determine what action to take in consultation with Manager Governance Risk & Compliance if necessary, which may include any of the following:

- participate in post tender debriefings with the tenderer;
- engage a third party to mediate and/or arbitrate any dispute;
- refer the matter to the Group Head of Audit for investigation; and
- escalate the issue to the Chief Executive Officer for consideration of potential actions.

In all instances, the Manager Procurement & Logistics will provide a written response to the tenderer notifying them of the outcome within a reasonable timeframe.

5.8.16 Register of contracts

The Lead Portfolio Manager must maintain a register of contracts (in accordance with the requirements of the *GIPA*) and supplier panels on the contracts and procurement database. The database will capture the following information:

- contractor(s);
- services/goods for which the contract applies;
- the nature of the contract, that is, supplier panel, project specific contract or period contract
- term or period for which the contract is valid;
- approved value of the contract, where applicable; and
- the date on which the contract was approved by the financial delegate.

5.9 Risk management

Financial delegates are responsible for assessing all risks associated with the procurement of goods and services and a risk management plan is implemented where appropriate to mitigate any risks in accordance with Company Procedure GRM 0003 – Risk Management. Financial delegates must, at a minimum, conduct a risk assessment of the procurement in accordance with Company Procedure GSY 0084 – Pre-Purchasing Risk Assessment and the relevant risk assessment number is referenced on the purchase requisition.

5.10 Terminating the tender process

Where it is necessary to terminate the tender process for whatever reason, eg the elapsed time, decision that tenders received do not constitute a representative slice of the market, the Manager Procurement & Logistics must approve such action in writing.

5.11 Varying the values of bank guarantee after the RFT closing date

Where the preferred tenderer, in their tender, seeks a variation to the value of a bank guarantee required in the request document, such a variation can be approved by the relevant financial delegate. Where the financial delegate has not expressly approved such a variation, the Manager Procurement & Logistics can vary bank guarantees by up to $50k and the General Manager People

& Services can approve changes up to $500k. All other changes must be referred back to the relevant financial delegate that approved the contract award.

5.12 Managing conflicts of interest

All employees involved in a tendering process, including the sponsoring General Manager, level 3 manager, financial delegate and members of Procurement & Logistics Branch must manage any actual or perceived conflicts of interest in accordance with Company Procedure GRM 0028 – Conflicts of Interest. Under no circumstances can employees who are responsible for making decisions in respect of a procurement exercise their authority where an actual or perceived conflict of interest exists unless a conflict of interested management plan has been approved by the relevant employee's manager.

6.0 RECORDKEEPING

The table below identifies the types of records relating to the process, their storage location and retention period.

Type of Record	Storage Location	Retention Period*
Tender documents	Ellipse, Recordkeeping system and Contract database	7 years after action completed, then destroy – as determined by GA28 section 21.0.4
Contracts	Ellipse, Recordkeeping system and Contract database	7 years after action completed, then destroy – as determined by GA28 section 21.0.4
Purchase orders	Ellipse, Recordkeeping system and Contract database	5 years after plan is superseded, then destroy – as determined by GA28 section 7.13.1

* Content Coordinator must liaise with the Records Manager to validate the retention period is compliant with the relevant disposal authority.

7.0 AUTHORITIES AND RESPONSIBILITIES

Chief Executive Officer has the authority and responsibility for:

- approving procurement plans as set out in Section 5.2.2; and
- approving financial delegations.

Chief Operating Officer has the authority and responsibility for:

- approving procurement plans as set out in Section 5.2.2;
- approving this procedure;
- approving relevant procurement plans and requests to enter into direct negotiations to establish a strategic alliance; and
- approving requests to dissolve supplier panels or to vary supplier panels where the panel establishment process did not set out a process to vary the panel.

Executive Leadership Team has the authority and responsibility for:

- overseeing correct application of this procedure; and
- maintaining appropriate use of sub-delegation within their division.

General Manager People & Services has the authority and responsibility for resourcing and deploying this procedure.

Manager Procurement & Logistics has the authority and responsibility for:

- accepting late tenders;
- resolving disputes; and
- approving changes to the default tender submission process.

Tender Review Committee has the authority and responsibility for providing advice to the Chief Operating Officer in respect of tenders that exceed $500k in accordance with TRC Charter.

Process managers have the authority and responsibility for:

- complying with this procedure;
- providing clear and precise specifications and service level requirements for the procurement of quality goods and/or services; and
- preserving an audit trail and providing all documents which are material to the tender and contract process to the Lead Portfolio Manager.

General Counsel has the authority and responsibility for providing advice on the relevant legal aspects of the tendering and contract administration sub-processes for the supply of goods and/or services.

Lead Portfolio Manager has the authority and responsibility for:

- managing and providing advice to the Commercial Managers; and
- determining if Company Form FSU 0064 – Tender Evaluation Plan should be used for tenders valued at <$5M.

Commercial Manager has the authority and responsibility for:

- providing advice to users in respect of procurements that are subject to this procedure including the preparation of procurement plans;
- assisting the process manager with the development of specifications and evaluation of tenders as required;
- facilitating opening and registration of tenders and EOIs;
- arranging the execution of contract documentation (as required);
- notifying all tenderers by formal documentation;
- registering contracts (in accordance with the requirements of the GIPA Act); and
- holding documents which are material to the tender and contract process;
- providing ongoing advice during the tender and EOIs process;
- completing Company Form FRM 0008 – TRC Checklist prior to TRC submission;
- driving any negotiation process; and

For the purposes of this procedure the Commercial Manager can perform the functions of the Lead Portfolio Manager where that officer is unavailable to approve procurement plans.

Employees that participate in a tendering process have the authority and responsibility for managing any real or perceived conflicts of interest in accordance with Company Procedure GRM 0028 – Conflicts of Interest.

8.0 DOCUMENT CONTROL

Content Coordinator : Manager Procurement & Logistics

Distribution Coordinator : GRC Process Coordinator

Annexure A – Contract Status Step

The below outlines the key steps in the tender process and indicative timing (where applicable)

Stage	Activity	Timing
Procurement plan	Draft procurement plan	1 working day
	Review and finalise procurement plan	1-4 working days
	Signatures	Up to 5 working days
Preparation of market engagement materials	Specification	As required
	Finalise tender documents (post receipt of specification)	Up to 5 working days
	Tender documents released to market	Must be with Procurement & Logistics Branch three days prior to planned request for tender release (Note: as a general rule, request documents are issued to market on Wednesdays and close on Wednesdays)
Recommendation	Evaluation and recommendation development	1-6 weeks (or longer as required)
	Draft Tender Review Committee (TRC) papers to Procurement & Logistics Branch for review	5 working days prior to required submission date
	Final TRC papers with signatures and full appendices	Must be submitted by 10am Thursday for the following Tuesday's TRC
TRC approvals process	TRC members to finalise minutes	5 business days
	Chief Executive Officer approval	5 business days
Contracts process	TRC/Board paperwork received in Procurement & Logistics Branch	As required
	Conditional Letter of Award sent to supplier (via fax or email)	2 business days after receipt of documents
	Scanned documentation shared with business owner and Commercial Manager	2 business days after receipt of documents
	Contract executed	45 calendar days after financial delegate sign-off

Annexure B – Procurement & Logistics Branch – Roles and Responsibilities Matrix

Responsible Accountable Consulted Informed (RACI)					
	Contract Owner	Contract User (1)	Financial Delegate	Contract Sponsor (2)	GSU 0016 Procedure reference or other policy or procedure
1.0 Establish sufficient budget exists					
Establish sufficient budget exists	I	I	A	R	5.3
Establish dedicated work orders created for projects		A			5.6
2.0 Define requirements					
Identify need		A		I	GSU 0001
Consult with Commercial Manager where assistance required or where procurement valued above intermediate procurement threshold	C	A			GSU 0001
Prepare procurement plan, where value greater than intermediate procurement threshold	C	A		I	GSU 0001
Define requirement in writing	C	A			GSU 0001
Develop service levels or performance measures if the contractor will be engaged under a written agreement	A	C			5.5.4
Develop work health and safety specification	I	A			GSY 0068
3.0A Solicitation and Evaluation of Offers (For Tenders Valued $200K to $500K)					
3.1A Solicit offers					
Prepare request document		I		A	GSU 0001 GSU 0002
Post request document on Tenderlink	Procurement & Logistics Branch	C			GSU 0001 GSU 0002
Coordinate site visits for bidders where required		C		A	GSU 0001 GSU 0002

Responsible Accountable Consulted Informed (RACI)					
	Contract Owner	Contract User (1)	Financial Delegate	Contract Sponsor (2)	GSU 0016 Procedure reference or other policy or procedure
Conduct briefing of prospective respondents to request document, if required		I		A	GSU 0001 GSU 0002
Manage Tenderlink forum	Procurement & Logistics Branch	C			GSU 0001 GSU 0002
Open electronic tender box	Procurement & Logistics Branch	I			GSU 0001 GSU 0002
Determine whether late offer acceptable	Procurement & Logistics Branch				GSU 0001 GSU 0002
Notify bidder that late offer rejected, if applicable	Procurement & Logistics Branch	I			GSU 0001 GSU 0002
Distribute offers to Evaluation Team	Procurement & Logistics Branch	I			GSU 0001 GSU 0002
3.2A Evaluate offers					
Develop evaluation templates for use by Evaluation Team		C		A	GSU 0001 GSU 0002
Brief Evaluation Team members		I		A	GSU 0001 GSU 0002
Ask Evaluation Team members to declare any conflicts of interest		C		A	GSU 0001 GSU 0002
Evaluate offers against approved evaluation criteria		I		A	GSU 0001 GSU 0002
Clarify offers with bidders, as required		C		A	GSU 0001 GSU 0002

Responsible Accountable Consulted Informed (RACI)					
	Contract Owner	**Contract User** (1)	**Financial Delegate**	**Contract Sponsor** (2)	**GSU 0016 Procedure reference or other policy or procedure**
Monitor that evaluation summary sheet signed by all team members		C		A	GSU 0001 GSU 0002
3.0B Solicitation & Evaluation of Offers (For Tenders Valued > $500K)					
3.1B Solicit offers					
Prepare request document	A	I			GSU 0001 GSU 0002
Post request document on Tenderlink	A	C			GSU 0001 GSU 0002
Coordinate site visits for bidders where required	A	C			GSU 0001 GSU 0002
Conduct briefing of prospective respondents to request document, if required	A	I			GSU 0001 GSU 0002
Manage Tenderlink forum	A	C			GSU 0001 GSU 0002
Open electronic tender box	A	I			GSU 0001 GSU 0002
Determine whether late offer acceptable	A				GSU 0001 GSU 0002
Notify bidder that late offer rejected, if applicable	A	I			GSU 0001 GSU 0002
Distribute offers to Evaluation Team	A	I			GSU 0001 GSU 0002
3.2B Evaluate offers					
Develop evaluation templates for use by Evaluation Team	A	C			GSU 0001 GSU 0002
Brief Evaluation Team members	A	I			GSU 0001 GSU 0002

Responsible Accountable Consulted Informed (RACI)					
	Contract Owner	Contract User [1]	Financial Delegate	Contract Sponsor [2]	GSU 0016 Procedure reference or other policy or procedure
Ask Evaluation Team members to declare any conflicts of interest	A	C			GSU 0001 GSU 0002
Evaluate offers against approved evaluation criteria	A	I			GSU 0001 GSU 0002
Clarify offers with bidders, as required	A	C			GSU 0001 GSU 0002
Manage post tender negotiations, where applicable for 2 phase tendering	A	C			GSU 0001 GSU 0002
Prepare minutes of meeting of negotiations for 2 phase tendering	A	C			GSU 0001 GSU 0002
Monitor that the evaluation summary sheet is signed by all team members	A	C			GSU 0001 GSU 0002
4.0 Secure financial delegate approval					
Prepare memo for delegate approval where value of procurement < TRC threshold		A		I	GSU 0001 GSU 0002
Prepare TRC paper where required	A	I		A	GSU 0001 GSU 0002
Distribute TRC paper/memo for delegate approval	A	I		C	GSU 0001 GSU 0002
Attend TRC meeting	A	I		R	GSU 0001 GSU 0002
Distribute TRC papers - post approval	A			I	GSU 0001 GSU 0002
Approve engagement of contractor		I	A		1.1.1

Responsible Accountable Consulted Informed (RACI)					
	Contract Owner	Contract User [1]	Financial Delegate	Contract Sponsor [2]	GSU 0016 Procedure reference or other policy or procedure
5.0 Develop contract					
Notify unsuccessful bidders of outcome of competitive bid process	A	I			GSU 0002
Prepare conditional letter of intent to successful bidder for non GC-21 contracts where value >= tender threshold	A				GSU 0002
Prepare letter of contract for GC-21 contracts where value >= tender threshold	A				GSU 0002
Create purchase requisition	R	A			GSU 0002
Approve purchase requisition			A		1.1.1
Convert purchase requisition to purchase order	A	I		I	GSU 0002
Draft relevant contract	Procurement & Logistics Branch	C		C	GSU 0002
Sign-off on draft contract	A	R		R	5.4
Send contract to contractor for signature	Procurement & Logistics Branch	I			5.4
Arrange for contract to be executed	Procurement & Logistics Branch	I		I	5.4
6.0 Administer contract (WHS-related)					
Develop Site Specific Safety Management Plan where construction works >$250k and the Company is the Principal Contractor		A		C	GSY 0068
Manage the contractor performs obligations set out in WHS specification where one exists	I	A			GSY 0068
Induct contractor employees and sub-contractors to site where the company is Principal Contractor		A			GSY 0068
Monitor contractor performance to determine compliance with WHS legislation	I	R		A	GSY 0068

Responsible Accountable Consulted Informed (RACI)					
	Contract Owner	**Contract User** (1)	**Financial Delegate**	**Contract Sponsor** (2)	**GSU 0016 Procedure reference or other policy or procedure**
7.0 Administer contract (non WHS-related)					
Consult with internal stakeholders and contractor on contract implementation issues		R		A	5.4
Prepare contract implementation plan where contractor is tier 1 and contract is GC21	R	C		A	5.4
Prepare contract implementation plan where contractor is tier 1 and contract is non GC21	Procurement & Logistics Branch	C		A	5.4
Manage execution of plan, where one exists, to completion	R	C		A	5.4
Establish that contractors have received any Company-specific training and possess all necessary accreditations or authorisations to perform their obligations under the contract		R		A	5.5.1 GAM 0089
Establish dialogue with contractor and, where no implementation plan exists, set performance expectations		R		A	5.5.1
Determine that the site at which the contractor will provide the goods and/or services is available for use by the contractor, where applicable		R		A	5.5.1
Follow an approved process to request the contractor perform goods or services for common use contracts, eg book traffic management services		R		A	5.5.1
Instruct the contractor on a day-to-day basis and resolve routine contractor queries		R		A	5.5.1
Initiate action with a Procurement & Logistics Officer to expedite any delinquent purchase orders issued to the contractor		R		A	5.5.1
Validate and authorise any timesheets submitted by the contractor where applicable		R		A	5.5.1
Review and distribute reports provided by the contractor of a routine nature		R		A	5.5.1
Chair regular meets with the supplier as required by the relevant contract		R		A	5.5.1

Responsible Accountable Consulted Informed (RACI)					
	Contract Owner	Contract User (1)	Financial Delegate	Contract Sponsor (2)	GSU 0016 Procedure reference or other policy or procedure
Review, validate and, in the case of contract users that are financial delegates, approve invoices		R	A	C	5.5.1
Vary purchase orders to reflect any changes to the contract		R		A	5.5.1
Establish that the expenditure against the contract is captured against the correct work order or cost centre		R		A	5.5.1
Prepare routine correspondence to the contractor		R		A	5.5.1
Regularly meet with the contractor and oversee operational contractor performance		R		A	5.5.1
Provide contractors with regular forecasts of quantities required where the contract provides for such forecasts to be provided		R		A	5.5.1
8.0 Manage contract expenditure					
Oversee the contractor is paid in accordance with charges set out in the order or contract		R		A	5.5.3
Oversee the contractor is paid in accordance with security of payments legislation to the extent relevant		R		A	
Oversee payments to the contractor do not exceed the approved budget or contract value	R	C		A	5.5.3
9.0 Formally monitor contractor performance					
Receive performance related reports from tier 1 and tier 2 contractors		A		I	5.5.4
Review performance related reports for tier 1 and tier 2 contractors	A	C		I	5.5.4
Convene formal review of contractor's performance against contract for tier 1 and tier 2 suppliers	Procurement & Logistics Branch	C		C	5.5.4
Communicate with tier 1 or tier 2 contractor where service levels or performance measures or delivery dates are not being achieved	A	C			5.5.4
Liaise with tier 1 or tier 2 contractor to have service level credits or performance credits processed	A	I			5.5.4

Responsible Accountable Consulted Informed (RACI)					
	Contract Owner	**Contract User** (1)	**Financial Delegate**	**Contract Sponsor** (2)	**GSU 0016 Procedure reference or other policy or procedure**
Escalate serious issues of contractor non-performance to Commercial Manager using form Company Form FQY 0002 – Corrective Action Request		A		C	5.5.4
Meet with contractor to address serious issue of non-performance as pre-cursor to dispute management, alternative dispute resolution or litigation	A	C		R	5.5.4
Scan documentation in respect of serious contractor non-performance into the Recordkeeping system	A	I			5.5.4
Decide whether issue qualifies as major contractual dispute managed under "Manage Dispute" section	R	I		A	5.5.4
Prepare supplier evaluation Company Form FSU 0038 – Supplier Performance Evaluation at conclusion of contract		A			5.5.4
Revise contractor's SQR rating where necessary	A	C		I	GSU 0007
10.0 Vary contract or exercise options					
Consider any proposals received from contractors to vary contracts		A			5.6
Initiate action to vary specification for goods and/or services based on a revised need		A		C	5.6.1
Consider any changes to terms and conditions of contract	A	I		C	5.6.1
Prepare memo to secure approval for contract with tier 1 contractor to vary contract depending of nature of change	R	I		A	5.6.1
Prepare memo to secure approval for contract with tier 2 or tier 3 contractor to vary contract depending of nature of change	C	A			5.6.1
Consider contractor's performance and remaining contract value prior to seeking approval to exercise an option to extend (where available)		A			5.6.1
Seek Manager Procurement & Logistics approval to exercise option to extend contract duration	R			A	5.6.3
Create new purchase requisition or send email to mailbox "procurement" to vary purchase order		A			5.6.1

Responsible Accountable Consulted Informed (RACI)					
	Contract Owner	**Contract User (1)**	**Financial Delegate**	**Contract Sponsor (2)**	**GSU 0016 Procedure reference or other policy or procedure**
Create or vary purchase order	A	C			5.6.1
Provide Procurement & Logistics Branch with copy of financial delegate approval		A			5.6.1
Vary contract to reflect approved changes	A	I			5.6.1
Sign-off on any contract variations to the extent they relate to changes to the specification for goods and/or services	R	C		A	5.62
Arrange to have contract variations executed by both parties	A	I			5.62
Provide contract user and contract sponsor with copy of contract variation	A	I		I	5.62
Consult with contractor and company stakeholders so that they understand impact of any contract variations and establish that contractor possesses all necessary approvals and training to perform varied contract		A		C	5.62
11.0 Manage disputes or serious contractual issues					
Meet with contractor to review potential major contractual disputes	A	I		I	5.5.5
Participate in formal meeting with senior executives as first step to alternative dispute resolution	Procurement & Logistics Branch	I		C	5.5.5
Seek sign-off from Chief Executive Officer to invoke liquidated damages, escalate dispute to litigation, call on bank guarantee	Procurement & Logistics Branch	I		C	5.5.5
Call on bank guarantee	Procurement & Logistics Branch	I		C	5.5.5
Notify contractor of breach of contract	Procurement & Logistics Branch	I		I	5.5.5
Brief lawyers for mediation, arbitration or litigation with contractors	Procurement & Logistics Branch	I		C	5.5.5

Responsible Accountable Consulted Informed (RACI)					
	Contract Owner	Contract User (1)	Financial Delegate	Contract Sponsor (2)	GSU 0016 Procedure reference or other policy or procedure
Attend mediation, arbitration or litigation	Procurement & Logistics Branch	I		C	5.5.5
Draft deeds of settlement and/or release with contractor following litigation	Procurement & Logistics Branch	C		C	5.5.5
12.0 End contract					
Initiate action to begin procurement process to establish replacement contract for tier 1 contractor	C	I		A	
Initiate action to begin procurement process to establish replacement contract with tier 2 or 3 contractor	C			A	
Oversee that tier 1 contractor completes obligations, returns equipment, etc and performs any termination assistance for incoming contractor	A			C	
Oversee that tier 2 and 3 contractor completes obligations, returns equipment, etc and performs any termination assistance for incoming contractor		A			
Inform company stakeholders of contract completion and arrangements to transfer processes to business as usual	I	A		C	

(1) The contract owner is the employee for contracts valued below the tender threshold, the contract owner is the employee to whom the Contract User reports. For contracts valued at or above the tender threshold, the contract owner is a Procurement & Logistics Officer.

(2) The contract sponsor may elect to be accountable for functions performed by the Contract Manager where the contract is used throughout the company.

Key		
who is **Responsible** for the outcomes of the process	Responsible	R
who is **Accountable** for the outcomes of the process	Accountable	A
who is **Consulted** before the execution of the process	Consulted	C
who is **Informed** by the process	Informed	I

COMPANY PROCEDURE

SUPPLY MANAGEMENT	Document No:	GSU 0016
	Amendment No:	8
	Approved By:	CEO
	Approval Date:	8/4/13
	Review Date:	8/4/15

GSU 0016 CONTRACT MANAGEMENT

1.0 PURPOSE

To ensure the Company sets out the way in which contractors are engaged and managed.

THIS DOCUMENT IS A CONTROL FOR THE HEALTH AND SAFETY MANAGEMENT SYSTEM (H&SMS).

2.0 SCOPE

This procedure applies to all engagements of contractors.

3.0 REFERENCES

Board Policy 12.0.1 – Purchasing
Board Policy 12.0.2 – Disposal
Company Policy (Leadership) 1.1.1 – Sub-delegations of Authority by the Chief Executive Officer
Company Policy (Supply Management) 12.1 – Purchasing
Company Policy (Supply Management) 12.4 – Probity in Procurement
Company Policy (Supply Management) 12.5 – Disposal
Company Procedure (Supply Management) GSU 0001 – Purchasing
Company Procedure (Supply Management) GSU 0002 – Tendering
Company Procedure (Supply Management) GSU 0005 – Risk Assessments for Purchasing
Company Procedure (Supply Management) GSU 0007 – Supplier Assessment and the Supplier Quality Register
Company Procedure (Process Management) GQY1140 – Corrective and Preventative Action System
Company Procedure (Governance) GRM 0022 – Tender Review Committee
Company Procedure (Health & Safety) GSY 0068 – Contractor Management
Company Procedure (Network Asset Management) GAM 0089 – Authorisations Governance and Management
Company Form (Health and Safety) FSY0081 – Work Health and Safety Management Plan (WHSMP)
Company Form (Supply Management) FSU0016 – Full Risk Assessment for Purchasing (OH&S and Environmental Risks)
Company Form (Supply Management) FSU0038 – Supplier Performance Evaluation Form
Company Form (Process Management) FQY0002 – Corrective Action Request
Annexure A – Procurement – Roles and Responsibilities Matrix
Work Health and Safety Act 2011(NSW)

4.0 DEFINITIONS

Corrective Action Request (CAR)
A form used to request corrective actions which may result from unsatisfactory supplier or product performance.

contract
A legally enforceable, written agreement between the Company and a supplier that sets out the terms and conditions under which goods and/or services will be provided. It is acknowledged that many contractors are engaged solely under a purchase order, ie, no written contract applies.

contractor
Any individual or body corporate that is engaged by the Company under a purchase order or contract to perform services of a non-trivial nature including suppliers that install or maintain equipment. Itinerant visitors or suppliers that are delivering goods to a Company site such as couriers are generally not contractors.

Contract Owner
An employee with management responsibility that is responsible for managing the commercial relationship including terms and conditions with the contractor. For contracts valued below the tender threshold, the Contract Owner is the employee to whom the Contract User reports. For contracts valued at or above the tender threshold, the Contract Owner is a Strategic Procurement Officer.

Contract Sponsor
The Level 3 or 4 Manager, as the case may be, that is identified on the relevant Procurement Plan that sponsored the procurement activity that led to the engagement of the contractor or Panel.

Contract User
The user of procurement services that is responsible for day-to-day use of the contract. For contracts that are used across the Company, every employee that is responsible for directing the activities of the contractor is a Contract User.

contract value
The amount of Company funds, approved by the relevant Financial Delegate that can be expended under the contract. The contract value may comprise a fixed price, contingency and provisional sums and/or an estimate of projected expenditure for the duration of the contract including contingency.

critical suppliers
Suppliers that provide the Company with essential goods and/or services that support critical processes that is fundamental to the operations of the organisation where there are no immediate alternative sources of supply for like or substitute goods and/or services. Critical suppliers may be identified during business impact analysis conducted as part of business continuity planning.

Executive Leadership Team
Chief Operating Officer, General Manager Health, Safety & Environment, General Manager People & Services, Chief Engineer, General Manager Network Development, General Manager Network Operations, General Manager Finance & Compliance and General Manager Information, Communications & Technology.

Financial Delegate
The position nominated within Company Policy 1.1.1 – Sub-delegations of Authority by the Chief Executive Officer to approve expenditure.

intermediate procurement threshold
The monetary value of the requirement above which the procurement is regarded as an "intermediate procurement" currently set at $30,000 or $60,000 for consultants and labour contractors.

Level 2 Managers
Includes Executive Leadership Team.

Level 3 Managers
Includes General Managers, Regional Managers and non-Network Branch Managers.

Level 4 Managers
Includes Branch Managers.

Level 5 Managers
Includes Section Managers and Project Managers/Operations Managers.

Principal Contractor
Has the meaning defined in the *Work Health and Safety Regulation 2011 (NSW)* – clause 293:

- a person conducting a business or undertaking that commissions a construction project is, the principal contractor for the project; and

- if the person referred to above, engages another person conducting a business or undertaking as principal contractor for the construction project and authorises the person to have management or control of the workplace and to discharge the duties of a principal contractor under this Chapter, the person so engaged is the principal contractor for the project.

probity
Probity is about making decisions with the right intentions, that is, in good faith. Probity involves maintaining fidelity to public sector values and duties such as selflessness, accountability, fairness and observing value for money. Probity implies values such as integrity, uprightness and honesty and, in doing so, minimises the risk of corrupt or dishonest conduct and mismanagement. Company Policy 12.4 – Probity in Procurement sets out the principles that must be followed during the procurement process.

Project Manager/Operations Manager
The managers responsible for the maintenance of contracts and associated database for goods & services.

request document
A request for quotation, tender, proposal, best and final offer or expressions of interest as the context requires.

review date
The review date displayed in the header of the document is the future date for review of a document. The default period is three years from the date of approval however a review may be mandated at any time where a need is identified due to changes in legislation, organisational changes, restructures, occurrence of an incident or changes in technology or work practice.

Strategic Procurement Officer
A member of the Strategic Procurement Branch.

Supplier Quality Register (SQR)
Data captured in the Ellipse supplier master file recording the capability and performance of suppliers that have been subject to formal assessment in accordance with Company Procedure GSU 0007 – Supplier Assessment and the Supplier Quality Register and their consequent rating.

Tender Review Committee (TRC)
A committee with the objective to provide consequential evaluations of the tender process and documentation to provide recommendations to the Chief Executive Officer.

tender threshold
The monetary amount above which engagement processes are managed by the Strategic Procurement Branch. The amount is currently $200,000 or $400,000 where a valid supplier panel exists.

Tier 1 Contractors
Contractors with which the Company has spent $500,000 or more in the previous complete financial year or a contractor engaged under a contract in which the annual spend will exceed $500k per annum and critical suppliers which are actively managed by Strategic Category Managers as the nominated Contract Owner. Tier 1 Contractors are classified as such on the SQR.

Tier 2 Contractors
Contractors with which the Company has spent between $100,000 and $500,000 in the previous complete financial year or a contractor engaged under a contract in which the annual spend will be between $100,000 and $500,000 per annum which are less intensively managed by a Contract Manager or Strategic Category Manager as the nominated Contract Owner. Tier 2 Contractors are classified as such on the SQR.

Tier 3 Contractors
Contractors that are neither Tier 1 nor Tier 2 Contractors and in which the Contract Sponsor also becomes the Contract Owner. All contractors that are not listed on the SQR as being either Tier 1 or Tier 2 Contractors are Tier 3 Contractors.

Work Health and Safety (WH&S) Specification
A specification of the contractor’s work health and safety obligations as they relate to a specific engagement and defined in Company Procedure GSY 0068 – Contractor Management.

5.0 ACTIONS

5.1 Objective

The Company is committed to engage suppliers using outcome-based contracts that mitigate procurement risk to the greatest extent reasonably possible. Contractors must also be actively managed to ensure they achieve the standards of performance and/or delivery milestones that are set out in the relevant contract.

5.2 Roles and responsibilities

Annexure A is a matrix that sets out the roles and responsibilities of employees in respect of the contractor engagement and management process. The matrix does not contain an exhaustive set of functions performed by employees during a procurement cycle and is intended to clearly delineate accountabilities of Strategic Procurement Officers and other employees.

5.3 Engaging contractors

The Financial Delegate is responsible for ensuring that:

- contractors are engaged following an approved procurement process set out in Company Procedure GSU 0001 – Purchasing;
- sufficient budget exists to engage the contractor;
- a purchase order is issued to cover the engagement of the contractor;
- where the contract value exceeds the tender threshold or where the procurement plan necessitates that the contractor is engaged under a written form of agreement the contractor is engaged under one of the Company's standard forms of agreement. Where it is not possible to engage a contractor under one of the Company's standard forms of agreement, the Project Manager/Operations Manager must, in consultation with the General Counsel where appropriate, make every reasonable effort to negotiate terms and conditions with the contractor that closely mirror key provisions of the Company's standard forms of agreement and mitigate procurement risk to the greatest extent reasonably possible;
- where a contract has been established, the relevant contract contains clear standards by which the contractor's performance can be measured; and
- for any contractor engagements that have not been centrally managed by the Strategic Procurement branch, the Project Manager/Operations Manager is provided with all documents that are material to the contractor selection process, including without limitation, Financial Delegate approvals, minutes of meetings and Evaluation Team summary sheets.

5.4 Contract implementation planning

Effectively implementing contracts requires careful planning and consultation that takes into account the needs of contractor and the Company stakeholders. Formal implementation plans should be developed for all period contracts by the Contract Owner for all contracts awarded to Tier 1 contractors. Implementation plans should be developed in consultation with stakeholder representatives and must identify all necessary tasks and Company and contractor resources that will be responsible for performing the tasks.

5.5 Managing contractor performance

5.5.1 Administering the contract excluding WH&S

The Contract User is responsible for administering the day-to-day performance of the contractor which includes, without limitation:

- ensuring new purchase requisitions are created or purchase orders varied to reflect any changes to the contract;
- ensuring that a purchase requisition that is costed to the relevant work order or cost centre is created and subsequently converted into a purchase order by Strategic Procurement Branch;
- establishing a dialogue with the contractor at the earliest opportunity after the contract is executed and/or purchase order issued;
- briefing the contractor to ensure it understands the Company's performance expectations;

- ensuring expenditure against the contract is captured against the correct work order or cost centre;
- preparing routine correspondence to the contractor;
- regularly meeting with the contractor and overseeing operational contractor performance;
- ensuring the site at which the contractor will provide the goods and/or services is available for use by the contractor, where applicable;
- considering contractor requests for extensions of time and requests for contract variations;
- following an approved process to request the contractor perform goods or services, eg, booking traffic management services;
- instructing the contractor on a day-to-day basis and resolving routine contractor queries;
- providing contractors with regular forecasts of quantities required where the contract provides for such forecasts to be provided;
- initiating action with a Strategic Procurement Officer to expedite any delinquent purchase orders issued to the contractor;
- validating and authorising any timesheets submitted by the contractor where applicable;
- reviewing, validating and, in the case of Contract Users that are Financial Delegates, approving invoices;
- reviewing and distributing reports provided by the contractor of a routine nature;
- escalating issues and disputes to a Strategic Procurement Officer; and
- preparing documentation to seek sign-off on contract variations from the relevant Financial Delegate in accordance with this procedure.

The Contract User is responsible for providing managerial oversight of the contractor's performance which includes, without limitation:

- chairing regular formal meetings with the supplier as required by the relevant contract; and
- ensuring appropriate documented sign-off on contract variations from the relevant Financial Delegate in accordance with this procedure.

5.5.2 Work Health and Safety matters

The Health, Safety & Environment Division will conduct regular internal audits of Contractors using the audit tool constructed considering the requirements of the Site Safety Management Plan (Company Form FSY0081 – Work Health and Safety Management Plan (WHSMP). An audit report will be prepared and corrective actions identified during the audit will be documented. Copies of all audits will be sent to the Business & Process Manager. All significant corrective actions that cannot be implemented at the time of the audit will be:

- Recorded and monitored until evidence is provided that demonstrates that the corrective action has been completed.
- Follow up audits will be conducted.

Where the contractor is performing services at a Company site, the Contract User must comply with Company Procedure GSY 0068 – Contractor Management and ensure that the contractor performs the obligations that are set out in the relevant WH&S Specification, where applicable.

Where the contractor is performing construction-related works valued $250,000 and above and the Company has not advised the contractor in writing that it is the Principal Contractor, the Contract User must prepare Company Form FSY0081 – Work Health and Safety Management Plan (WHSMP) and ensure the contractor performs its obligations in accordance with the relevant plan.

5.5.3 Budget management

The Contract User is responsible for ensuring that the total funds expended in respect of a contract do not exceed the approved budget.

The Contract Owner is responsible for ensuring that the total funds expended against a contract do not exceed the approved contract value or budget.

5.5.4 Formal performance monitoring

The contractor must:

- provide goods or services in accordance with contracted standards of performance including, without limitation, technical specifications, drawings, service levels/performance measures, delivery dates, milestones, industry accreditations, standards or other metrics; and

- perform the obligations set out in the relevant contract, including without limitation those pertaining to compliance with relevant laws and codes of conduct, management of Company materials, confidential information and reporting.

The Contract Owner in consultation with the Contract User is responsible for incorporating measurable standards of contractor company performance into specifications. The Contract User is responsible for ensuring that the contractor complies with the operational requirements of this section and the Contract Owner for the commercial requirements of this section.

Contract Users must ensure that any reports provided by the contractor in respect of service level performance are also provided to the Contract Owner for the purposes of the periodic review of overall contractor performance.

It is also essential that formal performance review meetings be held with strategically important contractors to ensure that such contractors are meeting the contracted standards of performance. The following table sets out which employee is responsible for convening performance review meetings with contractors and the frequency with which such meetings must be held:

Contractor Type	Responsibility	Meeting Frequency
Tier 1	Contract Owner (Strategic Procurement Category Manager)	Once every six to twelve months
Tier 2	Contract Owner (Strategic Procurement Contract Manager)	Once every twelve months
Tier 3	Contract Owner (Business)	As reasonably required having regard to the nature of the goods and services being procured and level of risk

Depending on the matters planned for a discussion during a review meeting with a Tier 3 Contractor, it may be necessary for a Strategic Procurement Officer to attend.

The Contract Owner or Contract User, as the case may be, must document any instances where the contractor does not meet contractual standards or honour its contractual obligations and retain such documentation in the event a dispute arises. For more serious instances of non-conformance, the Contract Owner or Contract User, as the case may be, must prepare Company Form FQY0002 – Corrective Action Request in accordance with Company Procedure GQY 1140 – Corrective and Preventative Action System. The Strategic Category Manager is responsible for resolving any CARs that have been assigned to them in regards to contractor performance.

5.5.5 Issue and dispute resolution

The Contract User or Contract Owner (where that employee does not work in Strategic Procurement Branch) must escalate all issues that materially affect the contractor’s ability to perform its obligations under the contract and disputes to a Strategic Category Manager. The Strategic Category Manager will provide advice to the Contract User and consult with Strategic Procurement management and the General Counsel as necessary with a view to facilitating a resolution of the dispute. Where the contract provides that a senior manager from outside of the Strategic Procurement Branch is empowered to resolve a dispute, the advice of Strategic Procurement Branch must be sought and a Strategic Procurement Officer must, to the greatest extent practicable, participate in dispute resolution meetings, mediation, arbitration, expert hearings or legal proceedings.

Any formal notices to the contractor, with the exception of those alleging a breach or termination of contract must be approved by an Executive Leadership Team member or approved by the Manager Strategic Procurement.

The approval of an Executive Leadership Team member or the approval of the Manager Strategic Procurement must be sought to pursue alternative dispute resolution proceedings including, without limitation, binding or non-binding mediation or arbitration or expert determination. This does not include standard dispute resolution processes that are normally documented in the contract.

The approval of the Chief Executive Officer must be obtained in any instances where it is necessary to call on any security provided by the contractor, e.g. bank or parent guarantee <u>or</u> hold the contractor in material breach of the contract <u>or</u> terminate the agreement for cause <u>or</u> initiate litigation against the contractor.

5.6 Amending contracts

Changes to contracts may affect, without limitation:

- value, including payment milestones;
- scope;
- Specification of requirements;
- duration;
- performance standards or service levels, KPIs or delivery dates; and
- contractual terms and conditions.

5.6.1 Changes to contract duration, value, terms and conditions and material changes to scope where such changes cannot be accommodated with an approved provisional sum or contingency

The Contract Owner must ensure the written approval of the appropriate Financial Delegate is obtained, based on the revised total contract value including contingency and provisional sums, where the contract needs to be varied to take account of one or more of the following:

- change to contract duration;
- increase in contract value;
- an increase in the unit price of goods or services on contract that cannot be accommodated within the approved contract contingency based on the same projected quantities, ie, a change to a unit price that would increase the total contract value (including contingency) if the order quantities in the original request for tender and/or approval documentation applied must be managed in accordance with this Section 5.6.1;
- change to terms and conditions; and
- material change to the goods and services to be provided under the contract. In determining whether a change is material, consideration must be given to the way in which the Company's requirements were defined in the original request document and the extent to which the request document contemplated potential variations. Changes to part numbers of equipment supplied under contract as a consequence of the contractor's standard upgrade path would <u>not</u> generally be regarded as material. Significantly negotiating a reduction in the scope of a separable portion of construction works to accommodate an increase in a separate separable portion must be managed in accordance with this Section 5.6.1.

Where the approval of the Board is required or where the total contract value exceeds the TRC Threshold for the first time, the Chief Executive Officer may elect for the matter to be considered by the TRC in accordance with Company Procedure GRM 0022 – Tender Review Committee.
Where any variation in contract value can be accommodated within a contingency amount <u>specifically approved for such a purpose</u>, the Executive Leadership Team member of the division in which the Contract User works or employee to whom management of the contingency has been expressly delegated can approve the variation.

The Contract User must also:

- provide the relevant Strategic Procurement Officer with a copy of the Financial Delegate's sign-off so that a contract variation can be processed;
- confirm the suitability of any changes to scope and value in a contract variation; and
- either create a new purchase requisition to cover the new contract period or send an email to "Procurement" to vary the purchase order in accordance with the Financial Delegate's approval.

The Project Manager/Operations Manager must ensure the formal contract variation documentation:

- properly reflects the approved variation to contract duration, value, terms and conditions or scope of goods or services covered by contract;
- is signed-off as being correct by the Contract Owner prior to sending it to the contractor;

- is signed by the contractor before being signed by a delegate authorised to execute contracts under Company Policy 1.1.1 – Sub-delegations of Authority by the Chief Executive Officer;
- is copied to the Contract User and Contract Owner; and
- is scanned into eDOCS against the relevant contract number, where such a number applies.

5.6.2 Other changes to the contract including changes to contract duration and scope that can be accommodated within the contract value or an approved provisional sum or contingency

Changes to the contract not covered by Section 5.6.1, including, without limitation changes to:

- part numbers of equipment, or unit prices that can be accommodated within the approved contract value based on order quantities in the original request document and/or approval documentation; and

- contract duration and scope that can be accommodated within an approved provisional sum or contingency.

Can be approved by the Executive Leadership Team member of the division in which the Contract Owner works or project steering committee or Contract Owner or Contract Sponsor where the contract includes a provision to manage minor contract changes or where the Financial Delegate has approved such an arrangement.

The Project Manager/Operations Manager must ensure that the documents that have the effect of varying the contract are scanned into eDOCS quoting the relevant contract number or contract description, where no number applies.

5.6.3 Execution of contract option periods

Where a contract contains options to extend that contract and those options were included in the original approval from the relevant Financial Delegate, the Contract User must seek approval from the Manager Strategic Procurement to exercise the option. In seeking approval to exercise an option the Contract owner must demonstrate that the approved value of the contract will not be exceeded during the option period.

5.7 Purchase orders

The Contract User must ensure that:

- a purchase requisition for the goods and/or services being supplied under the contract is created at the earliest possible opportunity after contract execution;
- where it is necessary to issue a purchase order before a contract is executed, ensure that the engagement is covered by a pre-contract letter agreement or ensure that the purchase order clearly states that the terms and conditions of the contract will apply;

- new purchase requisitions are created or purchase orders are amended to reflect any approved material changes to contract scope, duration or value; and

- the relevant contract number is quoted in the priority code field of the purchase requisition to facilitate the tracking of expenditure against the contract.

5.8 Contract completion and supplier assessment

At the end of each contract, the Contract User must evaluate the contractor using Company Form FSU0038 – Supplier Performance Evaluation Form and forward it to the relevant Strategic Category Manager for assessment in accordance with Company Procedure GSU 0007 – Supplier Assessment and the Supplier Quality Register.

5.9 Supplier panels

While panels are subject to the provisions of Section 5.6, Company Procedure GSU 0002 – Tendering sets out unique arrangements in respect of supplier panel creation and variation.

5.10 Contract information

The Project Manager/Operations Manager is responsible for maintaining a database of contracts which have been established in accordance with Company Procedure GSU 0002 – Tendering that can be accessed by users of procurement services.

5.11 Audit trail

The Contract Owner or Contract User or Contract Sponsor, as relevant, must forward any documentation that is material to the contract in particular any documentation that may be relevant to a future dispute to the Project Manager/ Operations Manager. The Project Manager/ Operations Manager must ensure that an audit trail of all documents that are material to the contract or contractor selection process including, without limitation, TRC paperwork, contracts, contract variations, Financial Delegate approvals, and supplier assessments is preserved on eDOCS. Contract Owners or Contract Users are also responsible for scanning any documents relating to contractor engagements valued below the tender threshold and minor contract variations to eDOCS in accordance with Section 5.6 and preserving an audit trail of any documents in respect of contractor performance.

6.0 AUTHORITIES AND RESPONSIBILITIES

Chief Executive Officer has the authority and responsibility for approving this procedure.

Executive Leadership Team has the authority and responsibility for ensuring correct application of these procedures and appropriate use of sub-delegation within their division.

General Manager People & Services has the authority and responsibility for ensuring implementation and compliance monitoring of this procedure.

General Manager Health, Safety & Environment has the authority and responsibility for ensuring that appropriate resources are allocated to ensure the compliance to this procedure.

Manager Strategic Procurement has the authority and responsibility for the administration of this procedure.

Project Manager/Operations Manager has the authority and responsibility for:

- reviewing all contract variations where that variation cannot be accommodated within the approved provisional sum or contingency as documented in the contract;
- ensuring all purchase orders are issued and varied in accordance with the Company's procedures;
- arranging the execution of contract documentation and amendments;
- ensuring high risk and all contracts issued as a consequence of a request process are assigned a unique number for ease of tracking;

- ensuring all documents which are material to the tender and contract process are retained;
- ensuring the database of all contracts is maintained; and
- seeking legal advice on contract preparation and dispute resolution.

Auditors have the authority and responsibility for:

- conducting audits objectively and in an independent manner and providing a timely audit report;
- conducting audits in accordance with the requirements of the Code of Conduct for Auditors;
- ensuring that outstanding Audit Corrective Actions are recorded appropriately and monitored for completion within an appropriate timeframe; and
- conducting follow up audits.

Contract Owners have the authority and responsibility for performing the obligations set out in this procedure and the roles and responsibilities set out in Annexure A.

Contract Sponsors have the authority and responsibility for performing the roles and responsibilities set out in Annexure A.

Contract Users have the authority and responsibility for performing the obligations set out in this procedure and the roles and responsibilities set out in Annexure A.

Contract Managers have the authority and responsibility for:

- participating in formal reviews of contractor performance for Tier 2 contractors;
- preparing formal contract variation documentation;
- arranging the execution of contract documentation and amendments;
- registering contracts;
- holding all documents which are material to the tender and contract process;
- maintaining a database of all contracts which can be accessed by users of procurement services; and
- issuing contract revisions and amendments.

Strategic Category Managers have the authority and responsibility for:

- participating in formal reviews of contractor performance for Tier 1 contractors;
- initially managing any escalated instances of contractor performance;
- assessing supplier performance in consultation with contract users and sponsors; and
- performing the relevant functions set out in this procedure.

7.0 DOCUMENT CONTROL

Content Coordinator : Manager Strategic Procurement

Distribution Coordinator : Business Process Coordinator, Finance & Compliance

Annexure A – Procurement – Roles Responsibilities Matrix

Company Procedure GSU0016 RACI					
	Contract Owner	**Contract User** (1)	**Financial Delegate**	**Contract Sponsor** (2)	**GSU 0016 Procedure reference or other policy or procedure**
1.0 Ensure sufficient budget exists					
Ensure sufficient budget exists	I	I	A	R	5.3
Ensure dedicated work orders created for projects		A			5.6
2.0 Define requirements					
Identify need		A		I	GSU 0001
Consult with Strategic Category Manager where assistance required or where procurement valued above intermediate procurement threshold	C	A			GSU 0001
Prepare procurement plan, where value greater than intermediate procurement threshold	C	A		I	GSU 0001
Define requirement in writing	C	A			GSU0001
Develop service levels or performance measures if the contractor will be engaged under a written agreement	A	C			5.5.4
Develop H&S Specification	I	A			GSY0068
3.0A Solicitation & Evaluation of Offers (For Tenders Valued $200K to $500K)					
3.1A Solicit offers					
Prepare request document		I		A	GSU 0001 GSU 0002
Post request document on Tenderlink	Strategic Procurement	C			GSU 0001 GSU 0002
Coordinate site visits for bidders where required		C		A	GSU 0001 GSU 0002
Conduct briefing of prospective respondents to request document, if required		I		A	GSU 0001 GSU 0002

Company Procedure GSU0016 RACI					
	Contract Owner	Contract User [(1)]	Financial Delegate	Contract Sponsor [(2)]	GSU 0016 Procedure reference or other policy or procedure
Manage Tenderlink forum	Strategic Procurement	C			GSU 0001 GSU 0002
Open electronic tender box	Strategic Procurement	I			GSU 0001 GSU 0002
Determine whether late offer acceptable	Strategic Procurement				GSU 0001 GSU 0002
Notify bidder that late offer rejected, if applicable	Strategic Procurement	I			GSU 0001 GSU 0002
Distribute offers to Evaluation Team	Strategic Procurement	I			GSU 0001 GSU 0002
3.2A Evaluate offers					
Develop evaluation templates for use by Evaluation Team		C		A	GSU 0001 GSU 0002
Brief Evaluation Team members		I		A	GSU 0001 GSU 0002
Ask Evaluation Team members to declare any conflicts of interest		C		A	GSU 0001 GSU 0002
Evaluate offers against approved evaluation criteria		I		A	GSU 0001 GSU 0002
Clarify offers with bidders, as required		C		A	GSU 0001 GSU0002
Ensure evaluation summary sheet signed by all team members		C		A	GSU 0001 GSU 0002

Company Procedure GSU0016 RACI					
	Contract Owner	Contract User (1)	Financial Delegate	Contract Sponsor (2)	GSU 0016 Procedure reference or other policy or procedure
3.0B Solicitation & Evaluation of Offers (For Tenders Valued > $500K)					
3.1B Solicit offers					
Prepare request document	A	I			GSU 0001 GSU 0002
Post request document on Tenderlink	A	C			GSU 0001 GSU 0002
Coordinate site visits for bidders where required	A	C			GSU 0001 GSU 0002
Conduct briefing of prospective respondents to request document, if required	A	I			GSU 0001 GSU 0002
Manage Tenderlink forum	A	C			GSU 0001 GSU 0002
Open electronic tender box	A	I			GSU 0001 GSU 0002
Determine whether late offer acceptable	A				GSU 0001 GSU 0002
Notify bidder that late offer rejected, if applicable	A	I			GSU 0001 GSU 0002
Distribute offers to Evaluation Team	A	I			GSU 0001 GSU 0002
3.2B Evaluate offers					
Develop evaluation templates for use by Evaluation Team	A	C			GSU 0001 GSU 0002
Brief Evaluation Team members	A	I			GSU 0001 GSU 0002
Ask Evaluation Team members to declare any conflicts of interest	A	C			GSU 0001 GSU 0002

Company Procedure GSU0016 RACI					
	Contract Owner	**Contract User** [(1)]	**Financial Delegate**	**Contract Sponsor** [(2)]	**GSU 0016 Procedure reference or other policy or procedure**
Evaluate offers against approved evaluation criteria	A	I			GSU 0001 GSU 0002
Clarify offers with bidders, as required	A	C			GSU 0001 GSU 0002
Manage post tender negotiations, where applicable for 2 phase tendering	A	C			GSU 0001 GSU 0002
Prepare minutes of meeting of negotiations for 2 phase tendering	A	C			GSU 0001 GSU 0002
Ensure evaluation summary sheet signed by all team members	A	C			GSU 0001 GSU 0002
4.0 Secure financial delegate approval					
Prepare memo for delegate approval where value of procurement < TRC threshold		A		I	GSU 0001 GSU 0002
Prepare TRC paper where required	A	I		A	GSU 0001 GSU 0002
Distribute TRC paper/memo for delegate approval	A	I		C	GSU 0001 GSU 0002
Attend TRC meeting	A	I		R	GSU 0001 GSU 0002
Distribute TRC papers - post approval	A			I	GSU 0001 GSU 0002
Approve engagement of contractor		I	A		1.1.1
5.0 Develop contract					
Notify unsuccessful bidders of outcome of competitive bid process	A	I			GSU 0002

Company Procedure GSU0016 RACI					
	Contract Owner	Contract User [1]	Financial Delegate	Contract Sponsor [2]	GSU 0016 Procedure reference or other policy or procedure
Prepare conditional letter of intent to successful bidder for non GC-21 contracts where value >= tender threshold	A				GSU 0002
Prepare letter of contract for GC-21 contracts where value >= tender threshold	A				GSU 0002
Create purchase requisition	R	A			GSU 0002
Approve purchase requisition			A		1.1.1
Convert purchase requisition to purchase order	A	I		I	GSU 0002
Draft relevant contract	Strategic Procurement	C		C	GSU 0002
Sign-off on draft contract	A	R		R	5.4
Send contract to contractor for signature	Strategic Procurement	I			5.4
Arrange for contract to be executed	Strategic Procurement	I		I	5.4
6.0 Administer contract (WHS-related)					
Develop Site Specific Safety Management Plan where construction works >$250k and the Company is the Principal Contractor		A		C	GSY 0068
Ensure contractor performs obligations set out in WHS Specification where one exists	I	A			GSY 0068
Induct contractor employees and sub contractors to site where the Company is Principal Contractor		A			GSY 0068
Monitor contractor performance to ensure compliance with WHS legislation	I	R		A	GSY 0068
7.0 Administer contract (non WHS-related)					
Consult with internal stakeholders and contractor on contract implementation issues		R		A	5.4

Company Procedure GSU0016 RACI					
	Contract Owner	**Contract User** (1)	**Financial Delegate**	**Contract Sponsor** (2)	**GSU 0016 Procedure reference or other policy or procedure**
Prepare contract implementation plan where contractor is tier 1 and contract is GC21	R	C		A	5.4
Prepare contract implementation plan where contractor is tier 1 and contract is non GC21	Strategic Procurement	C		A	5.4
Manage execution of plan, where one exists, to completion	R	C		A	5.4
Ensure that contractors have received any Company-specific training and possess all necessary accreditations or authorisations to perform their obligations under the contract		R		A	5.5.1 GAM 0089
Establish dialogue with contractor and, where no implementation plan exists, set performance expectations		R		A	5.5.1
Ensure the site at which the contractor will provide the goods and/or services is available for use by the contractor, where applicable		R		A	5.5.1
Follow an approved process to request the contractor perform goods or services for common use contracts, e.g. book traffic management services		R		A	5.5.1
Instruct the contractor on a day-to-day basis and resolve routine contractor queries		R		A	5.5.1
Initiate action with a Strategic Procurement Officer to expedite any delinquent purchase orders issued to the contractor		R		A	5.5.1
Validate and authorise any timesheets submitted by the contractor where applicable		R		A	5.5.1
Review and distribute reports provided by the contractor of a routine nature		R		A	5.5.1
Chair regular meets with the supplier as required by the relevant contract		R		A	5.5.1
Review, validate and, in the case of Contract Users that are Financial Delegates, approve invoices		R	A	C	5.5.1
Ensure purchase orders are varied to reflect any changes to the contract		R		A	5.5.1
Ensure expenditure against the contract is captured against the correct work order or cost centre		R		A	5.5.1

Company Procedure GSU0016 RACI					
	Contract Owner	Contract User [1]	Financial Delegate	Contract Sponsor [2]	GSU 0016 Procedure reference or other policy or procedure
Prepare routine correspondence to the contractor		R		A	5.5.1
Regularly meet with the contractor and oversee operational contractor performance		R		A	5.5.1
Provide contractors with regular forecasts of quantities required where the contract provides for such forecasts to be provided		R		A	5.5.1
8.0 Manage contract expenditure					
Ensure the contractor is paid in accordance with charges set out in the order or contract		R		A	5.5.3
Ensure the contractor is paid in accordance with Security of Payments legislation to the extent relevant		R		A	
Ensure payments to the contractor do not exceed the approved budget or contract value	R	C		A	5.5.3
9.0 Formally monitor contractor performance					
Receive performance related reports from tier 1 and tier 2 contractors		A		I	5.5.4
Review performance related reports for tier 1 and tier 2 contractors	A	C		I	5.5.4
Convene formal review of contractor's performance against contract for tier 1 and tier 2 suppliers	Strategic Procurement	C		C	5.5.4
Communicate with tier 1 or tier 2 contractor where service levels or performance measures or delivery dates are not being achieved	A	C			5.5.4
Liaise with tier 1 or tier 2 contractor to have service level credits or performance credits processed	A	I			5.5.4
Escalate serious issues of contractor non-performance to Strategic Category Manager using form Company Form FQY0002 – Corrective Action Request		A		C	5.5.4
Meet with contractor to address serious issue of non performance as pre-cursor to dispute management, alternative dispute resolution or litigation	A	C		R	5.5.4

Company Procedure GSU0016 RACI					
	Contract Owner	**Contract User (1)**	**Financial Delegate**	**Contract Sponsor (2)**	**GSU 0016 Procedure reference or other policy or procedure**
Ensure documentation in respect of serious contractor non performance is scanned into eDOCS	A	I			5.5.4
Decide whether issue qualifies as major contractual dispute managed under "Manage Dispute" section	R	I		A	5.5.4
Prepare supplier evaluation form FSU0038 at conclusion of contract		A			5.5.4
Revise contractor's SQR rating where necessary	A	C		I	GSU 0007
10.0 Vary contract or exercise options					
Consider any proposals received from contractors to vary contracts		A			5.6
Initiate action to vary specification for goods and/or services based on a revised need		A		C	5.6.1
Consider any changes to terms and conditions of contract	A	I		C	5.6.1
Prepare memo to secure approval for contract with tier 1 contractor to vary contract depending of nature of change	R	I		A	5.6.1
Prepare memo to secure approval for contract with tier 2 or tier 3 contractor to vary contract depending of nature of change	C	A			5.6.1
Consider contractor's performance and remaining contract value prior to seeking approval to exercise an option to extend (where available)		A			5.6.1
Seek Manager Strategic Procurement's approval to exercise option to extend contract duration	R			A	5.6.3
Create new purchase requisition or send email to mailbox "procurement" to vary purchase order		A			5.6.1
Create or vary purchase order	A	C			5.6.1
Provide Strategic Procurement with copy of Financial Delegate approval		A			5.6.1
Vary contract to reflect approved changes	A	I			5.6.1
Sign-off on any contract variations to the extent they relate to changes to the specification for goods and/or services	R	C		A	5.62

Company Procedure GSU0016 RACI					
	Contract Owner	**Contract User (1)**	**Financial Delegate**	**Contract Sponsor (2)**	**GSU 0016 Procedure reference or other policy or procedure**
Arrange to have contract variations executed by both parties	A	I			5.62
Provide Contract User and Contract Sponsor with copy of contract variation	A	I		I	5.62
Ensure contractor and Company stakeholders understand impact of any contract variations and ensure contractor possesses all necessary approvals and training to perform varied contract		A		C	5.62
11.0 Manage disputes or serious contractual issues					
Meet with contractor to review potential major contractual disputes	A	I		I	5.5.5
Participate in formal meeting with senior executives as first step to alternative dispute resolution	Strategic Procurement	I		C	5.5.5
Seek sign-off from CEO to invoke liquidated damages, escalate dispute to litigation, call on bank guarantee	Strategic Procurement	I		C	5.5.5
Call on bank guarantee	Strategic Procurement	I		C	5.5.5
Notify contractor of breach of contract	Strategic Procurement	I		I	5.5.5
Brief lawyers for mediation, arbitration or litigation with contractors	Strategic Procurement	I		C	5.5.5
Attend mediation, arbitration or litigation	Strategic Procurement	I		C	5.5.5
Draft deeds of settlement and/or release with contractor following litigation	Strategic Procurement	C		C	5.5.5
12.0 End contract					
Initiate action to begin procurement process to establish replacement contract for tier 1 contractor	C	I		A	
Initiate action to begin procurement process to establish replacement contract with tier 2 or 3 contractor	C			A	

Company Procedure GSU0016 RACI					
	Contract Owner	**Contract User (1)**	**Financial Delegate**	**Contract Sponsor (2)**	**GSU 0016 Procedure reference or other policy or procedure**
Ensure tier 1 contractor completes obligations, returns equipment etc and performs any termination assistance for incoming contractor	A			C	
Ensure tier 2 and 3 contractor completes obligations, returns equipment etc and performs any termination assistance for incoming contractor		A			
Ensure Company stakeholders are kept informed of contract completion and arrangements to transfer processes to business as usual	I	A		C	

(1) The Contract Owner is the employee for contracts valued below the tender threshold, the Contract Owner is the employee to whom the Contract User reports. For contracts valued at or above the tender threshold, the Contract Owner is a Strategic Procurement Officer

(2) The Contract Sponsor may elect to be accountable for functions performed by the Contract Manager where the contract is used throughout the Company

Key		
who is **Responsible** for the outcomes of the process	Responsible	R
who is **Accountable** for the outcomes of the process	Accountable	A
who is **Consulted** before the execution of the process	Consulted	C
who is **Informed** by the process	Informed	I

Summary of activities involved in the maintenance of an air break switch (ABSMNT)

	Transmission/ zone substations and switching stations			Distribution	
Routine maintenance	Links	disconnectors	Air break switch	Links	Air break switch/ disconnector
1.0 IN-SERVICE INSPECTION					
Take photos of any defects found during inspection	X	X	X	X	X
General					
Inspect the equipment and note any defects.	X	X	X	X	X
Structure/steelwork					
Inspect unit for cracks and distortion.	X	X	X	X	X
Inspect for rust, corrosion or other defects.	X	X	X	X	X
Connections - fixed and flexible					
Inspect for discolouration, damage or other defects.	X	X	X	X	X
Contacts - main and earthing					
Inspect for discolouration, damage, burns or other defects.	X	X	X	X	X
Insulators					
Inspect for cracks, chips, burns or other defects – Defective insulators should be replaced as a phase set – if two (2) sets are defective replace all sets.	X	X	X	X	X
Arcing (flicker) horns					

	Transmission/ zone substations and switching stations			Distribution	
Routine maintenance	Links	disconnectors	Air break switch	Links	Air break switch/ disconnector
Inspect for discolouration or damage, burns or other defects.		X	X		X
Check alignment and correct operation.					X
Labels					
Ensure labels/signs are legible and correctly fitted.	X	X	X	X	X
Operating mechanism					
Check flexible earthing bond to moving handle is not damaged.		X	X		X
Check connecting-rod(s) for damage, decay, tracking and twisting.		X	X		X
Check pivot points move freely.					
Check handle for damage, sharp objects, rust.		X	X		X
Check down-rod for damage, decay, tracking and twisting.		X	X		X
Check down-rods supports for damage.		X	X		X
Ellipse data validation:					
Confirm the nameplate data that has been recorded in Ellipse.	X	X	X	X	X
Capture the nameplate data that has not been recorded or incorrectly entered in Ellipse and update accordingly.	X	X	X	X	X
2.0 MAJOR OVERHAUL					
2.1 As found checks					
Take photos of any defects found during overhaul	X	X	X	X	X
Measurements					
Record primary circuit resistance. The injected current during the measurement shall have a minimum of any convenient value between 50 A and the rated normal current	X	X	X		
Insulators					
Replace defective insulators with cracks, chips, flashovers, burns, or other defects as a phase set – if two (2) sets defective replace all sets.	X	X	X	X	X
Connections - fixed and flexible					
Inspect for discolouration, damage or other defects.	X	X	X	X	X
All terminations to be lugged, that is, *hammer lug*.					X
Contacts - main and earthing					
Rectify/replace discoloured, damaged or other defects.	X	X	X	X	X
Arcing (flicker) horns					
Rectify/replace discoloured, damage or other defects.		X	X		X
Ensure correct alignment and operation.		X	X		X
2.2 Overhaul					

	Transmission/ zone substations and switching stations			Distribution	
Routine maintenance	Links	disconnectors	Air break switch	Links	Air break switch/ disconnector
Insulators					
Clean with recommended solvent.	X	X	X		X
Contacts - main and earthing					
Clean with recommended solvent.	X	X	X		X
Dress if necessary.	X	X	X		X
Adjust spring tension if necessary.	X	X	X		X
Polish contact surfaces	X	X	X		X
Lubricate contact surfaces with recommended lubricant (indoor units only).	X	X	X		X
Connections					
Clean with recommended solvent.	X	X	X		X
Check tightness.	X	X	X		X
Modify all terminations to lug type, that is, *hammer lug*.				X	X
Hinges					
Adjust movement if necessary.	X	X	X		X
Clean with recommended solvent.	X	X	X		X
Arcing (flicker) horns - blades					
Clean with recommended solvent.		X	X		X
Ensure correct alignment and operation, dress/replace and adjust if necessary.		X	X		X
- springs					
Check condition and replace if necessary.		X	X		X
Operating mechanism					
Check tightness.		X	X		X
Adjust if necessary.		X	X		X
Lubricate with recommended lubricant.		X	X		X
Replace flexible earthing bond to moving handle if damaged.		X	X		X
Replace connecting-rod(s) if damaged, decayed, or if tracking and/or twisting.		X	X		X
Ensure pivot points move freely – lubricate as required.		X	X		X
Replace handle if damaged, rusted or other defect.		X	X		X
Replace down-rod if damaged, decayed, or if tracking and/or twisting.		X	X		X
Replace damaged down-rods supports and ensure correct alignment.		X	X		X
Check operation at least three (3) times, adjust as necessary.		X	X		X
Motor drive (where applicable)					
Check condition.		X			
Check motor protection automatic switch (MCB to protect motor)		X			

Routine maintenance	Transmission/ zone substations and switching stations: Links	disconnectors	Air break switch	Distribution: Links	Air break switch/ disconnector
Correct operation of interlocking device		X			
Clean with recommended solvent.		X			
Lubricate with recommended lubricant.		X			
Earthing connections					
Check condition - repair as required.	X	X	X		X
Check earth mat connections – repair as required.	X	X	X		
2.3 FINAL CHECKS					
Operation					
Check alignment and operation. Perform five (5) manual operations and check that the opening and closing movements are correct.	X	X	X	X	X
Measurements					
Record primary circuit resistance. The injected current during the measurement shall have a minimum of any convenient value between 50 A and the rated normal current	X	X	X		
Ellipse data validation:					
Confirm the nameplate data that has been recorded in Ellipse.	X	X	X	X	X
Capture the nameplate data that has not been recorded or incorrectly entered in Ellipse and update accordingly.	X	X	X	X	X