



ERGON Energy Corporation Limited

Submission to the Queensland Competition Authority

on the following:

**Issues Paper – Electricity Distribution: Framework for
Regulation**

**Issues Paper – Electricity Distribution: Asset valuation,
Depreciation and Rate of Return**

February 2000

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Executive Summary

This document is the Ergon Energy submission to the Queensland Competition Authority (“the Authority”) in response to the Issues Papers titled:

- (a) *Electricity Distribution: Framework for Regulation*, and
- (b) *Electricity Distribution: Asset Valuation, Depreciation and Rate of Return*.

The significant points that Ergon Energy has developed and presented in this submission are summarised below:

- The regulatory framework should set the overall revenue targets. The outworking and delivery of those targets as structured network charges should be the responsibility of the Distributors. (Section 1.0)
- A hybrid type revenue cap approach based on the New South Wales model is recommended. Our proposed variance from the NSW model includes a network growth and development sensitivity deadband outside of which the Revenue Cap will be reviewed in line with a pre-agreed methodology. This approach provides revenue cap stability and consistency with a safety net in the event of unforeseen developments. (Section 1.1.3)
- Risk allocations in the competitive market have impacted Distributors operational processes and costs. Ergon Energy therefore seeks to have these market driven costs recognised as part of this review. (Section 1.1.3)
- Three sub-revenue caps should be developed, one for each of Ergon Energy's major regulated Distribution business components, namely electricity distribution and isolated generation services in:
 - (a) Urban and Coastal Areas;
 - (b) Rural and Remote Areas; and
 - (c) Isolated Generation Areas.The three business components have been selected to reflect the significantly different:
 - cost drivers,
 - customer expectations, and
 - government policies. (Section 1.2)
- In relation to the efficiency improvement regime a negotiated and coordinated approach is proposed. This will ensure a balanced regulatory contract outcome. (Section 2.2.1)
- The development of a set of cost pass-through principles, similar to those adopted in South Australia, is endorsed. (Section 3)
- A regulatory period of
 - (a) 3 years, or
 - (b) 5 years with a mid term review (subject to agreed triggers) is proposed. (Section 4)
- Ergon Energy supports the principle of a regulatory contract covering the regulatory period. Incentive sharing implementation should be managed over two 3 year periods, or a single 5 year period. (Section 5)

- The definition of prescribed distribution services should be progressed through an appropriate methodology, outside of but linked to the revenue and ring-fencing reviews. The methodology should include a separate public consultation process. (Section 6)
- The Depreciated Optimised Replacement Cost (DORC) asset valuation methodology is recommended as it best includes the valuation of monopoly assets under a market environment. (Section 7.0)
- Brownfields or incremental optimisation is proposed, consistent with the New South Wales approach. (Section 8.0)
- Service standards, safety, statutory requirements, supply security, system efficiency and planning horizons should all be taken into account during the optimisation stage of the DORC methodology. (Section 8.0)
- Capital Contributions should be treated as a once-off payment and be treated as part of the regulated revenue in the year the contributions are bought to account. (Section 9.0)
- Straight line depreciation over the physical life of the assets is supported. (Section 11.0)
- The WACC model is supported as the most appropriate methodology for determining the overall rate of return for distribution assets. (Section 12.0)
- The Capital Asset Pricing Model (CAPM) is supported as the most appropriate method for determining the cost of equity. (Section 12.5)
- The margin above the risk free rate is the proposed approach for determining the cost of debt. (Section 12.6)
- An industry benchmark capital structure should be used in the WACC model. (Section 12.8)
- The WACC should be expressed in pre-tax terms. (Section 12.9)
- The current statutory rate should be adopted as the appropriate tax rate. (Section 12.11)

In responding to the Issues papers, Ergon Energy recognises that there are a large number of outstanding issues related to the Distribution Regulation Review that are not fully addressed in this submission.

Ergon Energy will seek to work with the Authority, other regulators and stakeholders on these issues in appropriate forums in the future.

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Part A - Electricity Distribution: Framework for Regulation

1.0 Alternative Forms of Regulation

The Authority seeks comment on the benefits of alternative forms of revenue or price control in the context of electricity distribution, and the preferred method for the current review.

At present the Queensland Distributors are subject to a hybrid type revenue cap regulation methodology which includes a growth factor, an efficiency factor and a CPI indexation allowance. The growth factor is intended to reflect the underlying levels of network and customer growth during the regulatory period. This current regulatory approach is described in the “Transmission and Distribution Pricing Principles”¹

The options put forward by the Authority in their Issues Paper range from a fully prescribed revenue cap (set for all years in the regulatory period) through to an indexed price cap regime. There are also a set of intermediate options identified, known collectively as hybrid revenue cap arrangements. The remainder of this section includes a discussion of the various options and a recommendation by Ergon Energy on the most appropriate framework for Queensland at this time.

It is Ergon Energy's position that the regulatory framework should set the overall revenue targets. The outworking and delivery of those targets as structured network charges should be the responsibility of the Distributors. This approach will ensure that the Distributors can respond to the changing electricity market environment in a dynamic way.

1.1 Regulatory Price Control

This section discusses the range of regulatory price control options that are consistent with the National Electricity Code (NEC).

It is Ergon Energy's position that Electricity Distribution businesses have significant fixed costs including:

- (a) return on capital to shareholders,
- (b) depreciation to fund the replacement of ageing system and other assets, and
- (c) the operation and maintenance costs of a developed network to support the delivery of a safe and reliable supply of electricity to an existing customer base.

These costs will apply largely irrespective of short term fluctuations in the demand on the network. In this context, these fixed costs should be considered as the running costs of a “zero capacity network” which provides connection services to an existing and ongoing customer base. The regulatory price control option must address these committed distributors costs and in doing so seek to optimise and appropriately assign the revenue recovery risk.

Hybrid Revenue Cap arrangements are recommended by Ergon Energy in preference to specific price cap and fixed revenue cap type regulatory mechanisms.

¹ Queensland Government, Transmission and Distribution Pricing Principles, September 1999

This position is proposed on the basis of market maturity, economic signalling, the nature of the Distributors fixed running costs and the avoidance of inappropriate or perverse regulatory or operational incentives.

1.1.1 Price Cap Methodology

Any price cap regulation methodology would need to include a provision for the collection of the fixed running costs by the Distributor, or a test on the overall revenue amount. This provision would be necessary to ensure that the distributors were achieving adequate income streams to support the effective operation, maintenance, replacement and expansion of the network consistent with their obligations arising from the various licencing and charter arrangements.

Price Cap regulation would expose both customers and the Distributors to significant volume variance risk, particularly in regional Queensland where the customer mix delivers high correlation of energy throughput variances to climatic and economic conditions (both of which are difficult to forecast). A significant amount of the Ergon Energy electricity throughput is dedicated to major resource and industrial customers and this exposes Ergon Energy to significant revenue recovery risk, particularly that arising from the economic and business cycles of our customers.

Of significant concern to Ergon Energy is the current and ongoing development in the national electricity market and the impacts of that development on the regulated Network Businesses. Market changes during the regulatory period may render the prices established at the commencement of the period (P_0) either inadequate or unsustainable. This is particularly relevant in Queensland where the tranche 4 (full retail contestability threshold) customer network charges are still being developed and will not be available for publication until later in 2000. In addition, the capping of prices would preclude any refinement of the prices during the regulatory period, hence exposing Customers and/or Distributors to price shocks at the regulatory reset.

A hybrid revenue cap on the other hand would allow the Distributors to refine the prices during the regulatory period based on market developments, the introduction of new technologies and the uptake of demand side options. The hybrid revenue cap type regimes allow Distributors to develop and implement improved network pricing structures within the regulatory period, where the structural components encourage customers to improve network utilisation and operational efficiencies. It is also anticipated that the progression of “green” and environmental strategies could require changes to the network pricing strategies within the regulatory period covered by this review.

Finally, price capping arrangements can be seen to be at odds with economic efficiency, particularly as regards to the drivers on the Distributors to optimise their revenue streams. If price caps were adopted, Distributors would be inappropriately encouraged to increase system energy throughput at the expense of system utilisation and efficiency, all in order to maximise the income stream.

Hybrid revenue caps however can provide a clear and transparent incentive to the Distributors to minimise costs and maximise network utilisation to achieve the desired levels of profit. They can also facilitate an environment conducive to the development of demand side and embedded generation options.

1.1.2 Pure Revenue Cap Methodology

There are several options available to Regulators and Distributors in delivering revenue cap arrangements. Pure revenue caps for each year of the regulatory period can be determined at the regulatory reset based on the information and forecasts available at the time. Alternatively a hybrid regime can be developed where the first year cap is set and the following year caps are made relational to the first year through a roll forward and/or cost pass through regime. The advantage of the hybrid regime is that developments that occur during the regulatory period can be implemented immediately via the roll forward principles.

For the roll forward regime to be effective and workable any roll forward or indexation factor and supporting principles adopted must take into account the operating environment within which the revenue cap is to be applied. There must be a balance between the complexity of the roll forward or indexation formulae and principles, and the implementation and measurement of the independent input variables. Looking at the hybrid approaches adopted in other Jurisdictions (such as the United Kingdom), customer numbers and energy throughput (sales) have been flagged/adopted as the primary or main independent variables. It should be remembered, however that networks are built to support the maximum demand (peak load) and that energy throughput/sales is used as a proxy only for demand given that coincident system demand cannot currently be measured at the customer level.

Ergon Energy has concerns about the simplistic network expansion and growth correlation coefficients and proxies used by Regulators. It is our opinion that energy throughput and new customer connections alone do not sufficiently represent the underlying network growth/cost function in Queensland

Various Regulators have sought to establish roll forward and indexation factors which represent system and customer load development. Some of the resulting equations have included a diverse range of independent variable such as length of line, system losses, number of customers and energy throughput. However to date, all Regulators have sought to apply the roll forward or indexation factor to the total corporation/Distributor and have not taken account of the geographic and customer diversity. This has resulted in seemingly arbitrary decisions and sometimes ill fitting roll forward regimes. The roll forward/indexation factor development is critical to the effective deployment of the regulatory framework and must be given the appropriate level of attention.

1.1.3 Hybrid Revenue Cap Methodology

There are many and varied forms of hybrid revenue cap. The current Queensland regulated regime is a hybrid revenue cap form, which we would argue is not performing the intended purpose of :

- (a) providing clear operation cost reduction incentives, and
- (b) providing an appropriate allowance for system, demand and customer growth and development.

Ergon Energy has major concerns with the existing Queensland roll forward methodology and therefore seeks to revisit the appropriateness of this arrangement as part of this review.

Ergon Energy proposes an enhanced version of the New South Wales revenue cap regime. As a starting point for our explanation of the proposed regime we refer the

Authority to the IPART December 1999 document titled *“Regulation of New South Wales Electricity Distribution Networks: Determination and Rules Under the National Electricity Code”*². The IPART approach to apply to the New South Wales Distributors includes the following features:

- (a) 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 total referred to as the base revenue requirements);
- (b) The base revenue requirements for subsequent years is derived via a glide path of gains and losses using P_0 as the base year;
- (c) The CPI-X factor is used to achieve the desired revenue path only, as the efficiency gain targets (small x factor) are explicitly included in the Operating and Maintenance building block components;
- (d) The X Factor is applied in indexing revenue for each year after the base year, it is not an efficiency factor.
- (e) The two capital based building block components are indexed for each year of the regulatory period through the CPI-X process;
- (f) The resulting revenue caps will be tested against an assessment of the sustainable cash flows and profitability of the entity; and
- (g) A set of allowable cost pass through principles.

The revenue cap arrangements described above are dependent upon the determination of sophisticated forecasts based on expected network expansion, load growth, established service quality and reliability targets, efficiency improvements and new customer connections. Variations from these forecasts could leave the Distributors exposed to additional costs which would not be covered in the regulated income stream. Alternatively should network growth fail to reach expectations, customers should not be required to fund capital which has not been expended.

Regulators should also be cognisant of the developing market and the risks and liabilities that this market development introduces. The market has necessitated the management of more transparent planning, design and operational programs. This risk allocation has had a material impact on the overall risk profile of the businesses and directly impacted on Distributors operational processes and costs. Ergon Energy therefore seeks to have these additional market risk driven costs recognised as part of this review.

One significant advantage of the New South Wales approach is the minimal regulatory effort required to set the appropriate revenue cap for each successive year in the regulatory period.

In recognition of the dynamic nature of the national electricity market and the changing demands on Distributors as well as the possibility of network growth materially departing from the forecasts, Ergon Energy proposes the inclusion of a sensitivity threshold in the regulatory mechanism. This sensitivity threshold can be applied as a deadband around a set of parameters representative of the drivers of network growth and development. The purpose of the deadband is to trigger a revenue cap adjustment process in the event that the actual measured parameters fall outside of a band of allowable values established by the Regulator and the Distributor.

² IPART, Regulation of New South Wales Electricity Distribution Networks – Determination and Rules Under the National Electricity Code, December 1999

This deadband approach will provide the following benefits:

- (a) Annually indexed revenue caps over the entire regulatory period;
- (b) Low levels of regulatory maintenance,
- (c) Drivers for the Distributors to meet forecast targets, and
- (d) Ensure Customers and Distributors are not disadvantaged if there are material differences between the forecast and actual network growth.

Ergon Energy proposes that a hybrid revenue cap based on this deadband approach be explored and developed which includes the following key principles:

- (a) The development of operation and maintenance, depreciation, capital expenditure and capital base forecasts for each year of the regulatory period,
- (b) The development of realisable and specific operating and maintenance cost reduction targets which will be included in the operation and maintenance cost allowances for each year of the regulatory period (small x factor),
- (c) The determination of indexed revenue caps for each of the years in the regulatory period based on the building block components,
- (d) The application of any necessary revenue cap smoothing (to deliver the same NPV of regulated revenue over a set of smoothed cap changes) to limit price shock issues. (This effectively establishes a CPI-X indexation regime, however the actual efficiencies (small x factor) are implicit in the OPEX forecasts),
- (e) The determination of a set of deadband parameters within which the revenue cap will remain in line with the agreed CPI-X indexation regime,
- (f) Determine a revenue cap adjustment formulae to apply if the deadband parameters are triggered.

1.2 Application of Effective Revenue Management Arrangements

Taking into account the building block approach to revenue cap development, the nature of some network costs (fixed and variable) as well as the methodology for revenue cap setting, it may be appropriate to set a number of sub revenue caps. These sub revenue caps would apply to specific operational and/or geographic components of the business.

It is anticipated that Ergon Energy could operate under three such sub revenue caps, namely:

- (a) Urban and Coastal Areas,
- (b) Rural and Remote Areas, and
- (c) Isolated Generation Areas.

These sub revenue caps would reflect to the various operations of the Ergon Energy in our diverse geographic and operational environment as well as our customer's expectations.

Customers in the Ergon Energy urban and coastal areas enjoy a level of service and reliability exceeding that which we are financially and physically capable of delivering in the rural and remote areas at this time. We therefore believe that the two geographic groups of customers have different value expectations, namely:

1. Urban customers have expressed an expectation of price maintenance or reductions at a continued level of service, reliability and quality, while
2. Rural and remote customers are more concerned about improvements in the level of service and supply quality and reliability. This expectation is particularly relevant given the expansion of technological development and

uptake in rural and remote Queensland (e.g. facsimile, communications equipment; internet, etc.)

The proposed sub revenue cap approach is a logical and potentially effective extension of the existing arrangements where Ergon Energy has a separate revenue cap for the isolated generation component of our regulated operation in Far North Queensland. It is proposed that this Generation Revenue Cap should be extended to include the other isolated generation areas in the Ergon Energy supply area.

The adoption of a sub revenue cap arrangement would allow for comparison of the urban network and revenue cap components with peer Distributors. The rural, remote and isolated networks revenue cap could include specific operation and maintenance cost allowances.

It is important to note that the development of the rural, remote and generation zones has been based on the outworking of a government social policy. This will need to be explicitly recognised in the development of the revenue requirements for Ergon Energy.

2.0 Incentive Regulation

The Authority seeks comment on whether CPI-X is considered the most suitable approach to incentive regulation and on the most appropriate method for determining the X Factor.

2.1 Incentive Regulation Economics

In appraising and evaluating alternative approaches to incentive regulation, it is desirable to establish clear evaluation/comparison criteria.

In the general view of economists there are two fundamental criteria for evaluating regulatory systems, namely:

- (a) economic efficiency; and
- (b) fairness and equity.

2.1.1 Economic Efficiency

In evaluating the economic efficiency of an incentive based regulatory regime, it is important to identify and recognise the major dimensions of the options. The three major dimensions of economic efficiency are:

- (a) productive efficiency;
- (b) allocative efficiency; and
- (c) regulatory cost.

Incentive regulation encourages productive efficiency to the extent that it signals the regulated business [the Distributor] to provide its services and meet the demands of its customers at minimum cost. In the short term a number of the Distributors' costs are fixed in the sense that any adjustments take time and short term adjustments are

costly (for example staff numbers, existing systems and processes). Therefore to meet short term signals, productive efficiency is dependent upon meeting the customer and regulatory expectations with a non-optimal cost mix of other resources and activities. In the longer term, the signals can be appropriately translated and applied assuming all business inputs are variable given sufficient implementation time. Therefore for productive efficiency gains to be developed and delivered a long term consistent signal is a mandatory requirement of the regulatory arrangements.

Allocative efficiency arises from incentive regulation when the Distributors are induced to meet customer demands where those demands have a value to customers which is equal to or greater than the cost of service provision. In the short run, the adjustment to network service rates that reflect changing market conditions is the main allocative efficiency challenge. In the longer run, however the mix of products and services becomes a more significant issue. It should be remembered that the allocative efficiency of a Distributor's operations does not hinge solely on the core or prescribed services offered to customers on a regulated basis. Distribution businesses can also enhance welfare (total benefit to the community) by providing products and services in more competitive markets. This competitive market involvement can spread the costs of the Distribution businesses across a greater range of products and services, resulting in lower costs being allocated to the monopoly business products and services. Incentive and regulatory regimes must recognise the ability of Distributors to identify and deliver on allocative efficiency improvements. Regulators must be cognisant of the limitations they themselves can apply through the application and enforcement of inappropriate ringfencing guidelines which limit the ability of Distributors to deliver allocative efficiency through market and product variance.

Regulation incurs costs, both in terms of the periodic regulatory review processes as well as the ongoing oversight and reporting functions. Whilst the benefits of regulation must exceed the costs in order for it to be effective, it is also important to seek the optimal regulatory balance. In developing incentive based regulatory regimes, Regulators must take into account the initial and ongoing costs for the regime and balance these against the envisaged (and realistically deliverable) benefits.

2.1.2 Fairness and Equity

Whilst Regulators and economic theorists have concentrated mainly on the economic efficiency of alternative regulatory and incentive based regimes, fairness and equity are also fundamental evaluation criteria. These criteria cover the manner in which the benefits arising from the regulatory regime are shared among the stakeholder groups, namely the Distributor and its Shareholders and the customers of the company.

Furthermore it is also important to determine the appropriate allocation of benefits to customer groups which may include domestic, industrial and commercial customers.

In the Queensland environment, due care must be paid to the rate at which incentives are applied and also to the disbursement of those benefits to the various stakeholders. It should be remembered that not all customers expect the same suite of benefits, however all have some expectation of improvements arising from the regulatory reforms.

At this stage, it is pertinent to reiterate our previous point about customer expectations, particularly in relation to the allocation of benefits. We believe that our

customers in the urban and rural areas have differing expectations of contestability and market deregulation. These expectations are:

- (a) Urban customers will expect lower costs at a continued level of service, reliability and quality, while
- (b) Rural and remote customers will expect improvements in the level of service and supply quality and reliability. This expectation is particularly relevant given the expansion of technological development and uptake rural and remote Queensland (e.g. facsimile, communications equipment; internet, etc.)

2.2 Incentive Regulation Options

World wide, there are three fundamental regulatory mechanisms, namely:

- (a) Rate and Revenue Indexing;
- (b) Earnings Sharing Mechanisms; and
- (c) Benchmarking Regulation.

Of these three fundamental mechanisms, only the Rate and Revenue Indexing group fulfils the requirements of the NEC. However this limitation should not preclude the adoption of some of the aspects of the other two regulatory mechanisms.

The Rate and Revenue Indexing group includes all three of the regulatory options proposed by the Authority in their Issues Paper, namely:

- (a) Price Cap Regulation;
- (b) Revenue Cap Regulation; and
- (c) Hybrid Revenue Cap Regulation.

As discussed previously in our submission, Ergon Energy supports the adoption of a hybrid revenue cap mechanism similar to the New South Wales approach where the operating cost efficiencies, (small x factor), are identified and included in the forecast operating and maintenance building block components.

2.2.1 Efficiency Modelling and X Factors

In developing the hybrid revenue cap arrangements for the current regulatory period, the Queensland Electricity Reform Unit engaged London Economics to complete a Data Envelope Analysis (DEA) of the Distributors' controllable operating costs. This DEA was completed as a "block box" approach with no direct co-ordination with the Distributors (other than the provision of data for inputs and outputs). This centralist regulatory approach resulted in disagreement over the results of the DEA and in the Distributors opinion, the realistic expectations of QERU. The Distributors queried the feasibility of meeting the QERU the targets, whilst maintaining and improving the service quality and reliability standards.

Taking into account the nature, diversity and extent of the distribution networks, as well as the need to service customers, the X factors (where this is the specific Queensland efficiency improvement target) applied to the overall revenue caps (range of 2.2% to 3.5%) resulted in target reductions of 6% to 13% of controllable operating costs on an annual basis. The use of the centralist "black box" derivation process and the lack of Distributor "ownership" of the efficiency gain targets have limited the delivered effectiveness of the Queensland type X Factors.

To ensure appropriate sign on and ownership of any efficiency improvement targets, Ergon Energy believes that the efficiency target determination should be a negotiated approach with targeted cost reduction strategies identified by an appropriate process and accepted by both parties. The agreed efficiencies would be included in the explicit OPEX projections used as part of the building block process for determining the regulatory revenues. This approach supports the Authorities proposal of a regulatory contract.

3.0 Cost Pass Through

The Authority seeks comment on the use of cost passthrough under an incentive regulation regime.

There are a range of costs which will impact Ergon Energy that are not, and can not be included in the foreseeable/immediate regulated operating cost allowance or capital expenditure forecasts.

All three of the revenue cap regime building block components contain unforeseen costs and expenses. Examples of some of these costs and expenses are:

(a) Operating Costs:

- Full Retail Contestability Implementation
- Regulatory Review and Oversight
- Additional Market and NEMMCO fees
- Externally imposed operational procedures changes that impact the Distributors work processes
- Any review of the minimum levels of prescribed service which results in a material change compared to the standards contemplated at the start of the regulatory period
- Any review of the minimum levels of service quality standards which results in a material change compared to the standards contemplated at the start of the regulatory period
- The introduction of a new tax, removal of an existing tax or a change in the way an existing tax is applied.
- Changes in the underlying business risk and the methods for mitigating that risk

(b) Capital Costs

- Systems and processes to support full Retail Contestability
- Network Augmentation to meet as yet undefined service quality standards

Ergon Energy proposes that a set of principles similar to those adopted in South Australia be developed. These principles will embody the circumstances under which cost pass through may occur and the methodology for progressing such a claim. Whilst not specifically listing those costs which are allowable pass throughs, the principles shall provide a framework by which costs and/or expenses will be recognised and if appropriate included in the revenue cap/regulated income.

4.0 Optimum Duration of the Regulatory Period

The Authority seeks comment on the optimum period for regulation for the first Regulatory period.

There are a number of factors which need to be considered when developing a regulatory regime which includes roll forward provisions.

Some of these factors are:

- (a) The regulation period must provide opportunity for the Distributors to meet and possibly exceed to the cost reduction targets and to derive some benefit from meeting those targets (incentives based on profit retention).
- (b) The current rate of National Electricity Market development limits the ability of Regulators and Distributors to look beyond the two to three year timeframe. Examples of market impacts on Distributors include the transmission and distribution pricing review, the review by NECA of the interaction between the energy and network services components of the market and the NECA review of distributor loss Factors, and
- (c) The effective signalling of the intentions and directions of the market, thus providing guidance and opportunity to enable Customers and Distributors to position themselves optimally to track and manage market developments. This tracking applies to both the flow through of efficiency gains as well as the funding of market developments and changes.

Taking into account the current maturity of the market and the regulatory environment, Ergon Energy proposes that the regulatory period be either:

- (a) 3 years, or
- (b) 5 years with a mid-term review

The mid-term review would be based on a set of agreed triggers which may include material market changes and the specification and regulation of Service Quality Standards.

5.0 Incentive Sharing

The Authority seeks comments on appropriate sharing mechanisms for incentive regulation, including mechanisms to share the benefits of reasonable efficiency gains achieved within the regulatory period, gains arising from 'out-performance' of the regulatory mechanism, and 'windfall gains'.

Ergon Energy supports the principle of a regulatory contract covering the regulatory period. Such a regulatory contract should provide incentives for Distributors to perform as they would in a market driven environment and deliver benefits to

customers as well as derive the benefits of increased profits that arise from performance excellence.

A glide path approach to the sharing of benefits and costs is preferable to material P_0 adjustments. P_0 adjustments provide undesirable and sometimes perverse incentives to defer until the commencement of a new regulatory period, the implementation of initiatives which will deliver efficiency improvements.

Ergon Energy strongly advocates a bilateral contract approach to the introduction of material revenue changes which include incentive sharing arrangements, and that such an approach should seek to manage the implementation over two three year regulatory periods or a single 5 year regulatory period.

6.0 Prescribed and Non-Prescribed Activities

The Authority seeks comments on:

- ***the appropriate methodology for determining prescribed distribution services and excluded distribution services; and***
- ***the services to be included as prescribed distribution services.***

Ergon Energy is of the view that excluded distribution services should be those activities where exposure to a competitive environment would provide social benefits including customer choice, price reductions and service improvement.

This “social benefit” definition should include all the benefits and factors arising from the deregulated option and their associated costs including:

- (a) market size and level of available competition,
- (b) allocative efficiency impacts on the existing service providers,
- (c) customers expectations, both in terms of service price and quality,
- (d) long term market development prospects, and
- (e) allocation of and responsibility for residual unprofitable activities.

Ergon Energy supports the progression of the definition of prescribed distribution services through an appropriate methodology. Taking into account the scope and impact of the definitions, the methodology by which this issue is progressed should include a separate public consultation process. The definition of prescribed and excluded distribution services however should remain linked to the current revenue and ring fencing reviews.

Some of the factors that the Authority should consider in drawing up the terms of reference for the prescribed distribution services review include:

- (a) obligations imposed on the Distributors by the Electricity Act and Regulations,
- (b) intent of the NEC in relation to excluded services and the impact on customer choice,
- (c) coordination of approach across jurisdictions to provide equity in application,
- (d) target benefits and performance measures to ensure overall social benefits,
- (e) possibility of and avoidance of costly inset disputes,
- (f) current options for customers and distributors

- (g) allocative efficiency impacts arising from reclassification of distribution services, and
- (h) residual activities retained by distributors in the oversight and management of excluded distribution services.

Part B - Electricity Distribution: Asset Valuation, Depreciation and Rate of Return

7.0 Asset valuation Methodology

The Authority seeks comment on which asset valuation method is the most appropriate for determining the value of the network assets of electricity distribution entities for the purposes of establishing prices for the use of the distribution system, given that there is a requirement to take into account:

- ***the COAG preference for deprival value; and***
- ***the existing regulatory arrangements for distribution entities, which currently apply DORC.***

It is understood by Ergon Energy that Section 6.10.3 (e) (5) (iii) of the NEC requires the jurisdictional regulator [QCA] have regard to a number of matters when determining asset values, including:

- (a) the agreement of the Council of Australian Government of 19 August 1998, that deprival value should be the preferred approach to valuing network assets;
- (b) any subsequent relevant decisions of the council of Australian Government; and
- (c) such other matters reasonably required to ensure consistency with the objectives specified in clause 6.10.2 of the NEC.

It is Ergon Energy's understanding that COAG's preference for deprival value was based upon "*Guidelines on Accounting Policy for Valuation of Assets of Government Trading Enterprises – using Current Valuation Methods*"³ which were released in October 1994. The guidelines were developed to encourage comparability as part of the COAG performance monitoring exercise, not for price determination. The purpose as stated in the guidelines was:

*"To ensure that the financial indicators used to assess the performance of GTE's are comparable it was recognised that a consistent approach to the current valuation of assets was required..... It [the guidelines] attempts to provide a framework for consistency in the valuation of non-current physical assets of GTE's involved in national performance monitoring so that relevant, reliable and comparable financial information is available for effective performance monitoring."*⁴

Ergon Energy proposes that as the guidelines were not developed for price determination purposes they do not directly consider the implications of using deprival values to establish prices for the use of electricity distribution systems. Neither did COAG anticipate the "circulatory problem" arising from the proposal to utilise deprival values when developing distribution use of system prices.

³ Steering Committee on National Performance Monitoring of Government Trading Enterprises, *Guidelines on Accounting Policy for Valuation of Assets of Government Trading Enterprises*, October 1994.

⁴ *ibid*, page iii

The QCA should therefore concentrate on clause 6.10.3(e)(5)(iii)(C) of the NEC and ensure consistency with the objectives specified in clause 6.10.2 of the NEC.

Consistent with other Jurisdictions, Ergon Energy supports the adoption of DORC as the asset valuation methodology. It is our position that the DORC methodology satisfies Clauses 6.10.2 (d), 6.10.2(g) and 6.10.2(f) of the NEC.

Taking into consideration the “circulatory problem” associated with deprival value, the adoption of the DORC methodology is also consistent with the Queensland Treasury, June 1997 “*Recording and Valuation of Non-Current Physical Assets*”⁵ document. It is Ergon Energy’s belief that the DORC methodology best emulates the valuation of assets under a market environment.

The following factors are considered to support this position.

- (a) Assets are revalued for inflation, technological change and optimised to remove imprudent or excessive investments;
- (b) DORC emulates a market environment where inappropriate investments are competed away and their value is reduced;
- (c) DORC replacement costs are based on benchmarked rates which include competitive market rates for materials and labour; and
- (d) DORC ensures that all assets are valued consistently, irrespective of their commissioning date, thus assuring allocative efficiency of capital investment.

8.0 Optimisation Rationale

The Authority seeks comment on whether an optimisation process is appropriate in establishing an appropriate asset value and, if so, the framework within which an optimisation process should be implemented and the elements that should be considered in the optimisation process, including:

- ***incremental versus greenfields approaches;***
- ***capacity optimisation;***
- ***impact of service standards; and***
- ***frequency of valuation/optimisation.***

8.1 Optimisation

The DORC methodology, which is supported by Ergon Energy, includes the following fundamental components:

- (a) Establishing the gross current replacement cost of the gross service potential embodied in the existing assets by reference to modern equivalent assets;
- (b) Adjusting or optimising the gross current replacement cost determined above for over-design, over-capacity and redundant assets;

⁵ Recording and Valuation of Non-Current Physical Assets in the Queensland Public Sector – June 1997

- (c) Depreciating this value to reflect the anticipated effective working life of the asset from new, the age of the asset and the estimate residual value at the end of the asset's working life.

Therefore optimisation is critical to the establishment of an appropriate asset value under the DORC methodology. The Queensland Treasury Document does not include specific advice on optimisation due to its generalised approach. The NSW Treasury Guidelines, however are more specific and does include a significant discussion on the subject of optimisation.

8.2 Incremental and Greenfields Approach

In relation to the incremental versus greenfields approach, NSW Treasury states:

“Incremental optimisation places a limiting constraint on the extent of optimisation. It denies a valuation based on optimal replacement of an entity's entire asset network. This latter approach is known as “greenfields optimisation”.

The incremental ODRC approach recognises that there is always some degree of suboptimality and allowance for growth in future demand, and it reflects the historical development of the existing business, the time lag in asset planning and construction, the very long lives of the assets, and the replacement of its components, in the normal course of business. As systems expand and change, a degree of suboptimality at any point of time is inevitable and is part of the total cost of output.”⁶

In ODRC/DORC valuations conducted in other jurisdictions, it has been generally accepted that the following constraints be adopted.

- The location of generating plants and Transmission Network Connection Points should be assumed to be fixed.
- The location of customers should not be varied.
- The existing boundaries of other network businesses should not be varied.
- Only existing easements, line and cable routes should be assumed.

It is our understanding that the issue of redesigning the complete network layout has not been considered appropriate for the valuation of infrastructure in other Jurisdictions.

Taking into account all of these factors, it is proposed by Ergon Energy that a brownfields or incremental optimisation process be adopted. It should be noted that the NSW Treasury has expressed its support for the brownfields approach to DORC in its submission to IPART, indicating that the NSW Treasury Guidelines are equivalent to a brownfields valuation.

8.3 Capacity Optimisation

Optimisation of system assets should be based on the reasonably expected level of use of the asset. This expected level of use is determined by reference to the required level of service potential or output consistent with both:

⁶ NSW Treasury, Policy Guidelines for Valuation of Network Assets of Electricity Network Businesses, December 1995

- (a) the reasonably foreseeable future demand/utilisation, and
- (b) the objective of minimising the whole of life costs.

The NSW Treasury Guidelines state that:

“The planning period assumed for future growth in power flows should be consistent with that used for business planning and Total Asset Management planning. These would typically be:

- *Up to 15 years for transmission and subtransmission networks except zone substation transformers;*
- *Up to 10 years for zone substation transformers; and*
- *5 years for distribution networks.”⁷*

This approach is consistent with the planning/capacity utilisation guidelines adopted by the then Queensland Distribution Corporations at the commencement of the current regulatory period. This longer term approach allows the Distribution Corporations to invest prudently, particularly for assets where the economies of scale or project lumpiness require a number of years for appropriate levels of utilisation to develop. It also provides for investments where the higher up front project cost is more economically efficient on a “whole of life” basis.

8.4 Impact on Service Standards

Ergon Energy supports the principle that service standards should be considered as constraints within which optimisation is to be effected. The difficulty in implementing this principle in the current environment is the lack of clear supply quality standards. Looking at the NSW Treasury Guidelines, it appears that a range of other issues should also be included in the optimisation consideration, namely:

- Safety requirements [choice of materials and type of construction];
- Acceptable voltage ranges [as defined in the NEC and the Queensland Electricity Regulation];
- The degree of supply security considered appropriate in different circumstances [urban, industrial, rural, etc]; and
- Efficiency issues such as electrical losses, less constructions, etc.

The policies and requirements of previous governments should also be recognised in the optimisation process so that networks developed to fulfil policy and legislative objectives are not optimised down on the basis of short term price path objectives.

A number of successive schemes and policies adopted by previous governments have resulted in the connection of many customers in rural and remote Queensland. Ergon Energy has an obligation to continue to provide distribution connection services to these customers in accordance with good electricity industry practice. Any move to reduce the value of assets in these areas will directly impact on our ability to replace the existing infrastructure and to connect new customers to the electricity network in those areas.

⁷ NSW Treasury, Policy Guidelines for Valuation of Network Assets of Electricity Network Businesses, December 1995

8.5 Frequency of Valuation/Optimisation

The adoption of the DORC methodology by definition implies periodic optimisation. This approach is considered appropriate by Ergon Energy.

As discussed in the previous sections, optimisation is intended to emulate the effect of market forces where imprudent or outdated investments are devalued by the market. For the DORC asset valuation to be implemented effectively, assets must be periodically optimised to take into consideration the known and prevailing market conditions. In some circumstances, successive optimisations will result in improvements to design and operating practices [eg utilisation of distribution transformers] or more appropriate recognition of the costs of service and reliability improvement.

The *Queensland Government Guidelines for the Recording and Valuation of Non-Current Physical Assets [June 1997]*⁸ states in relation to periodic revaluations that:

*“The Financial Management Standard requires that a comprehensive revaluation of non-current physical assets above the threshold be performed at five year intervals unless the nature of the assets dictate, or an event occurs that requires that revaluation of one or more classes of assets should be performed on a more frequent basis. Revaluations may be conducted on a rolling basis”*⁹

The NSW Treasury Guidelines also include a similar statement as regards frequency of revaluation.

It is anticipated that the frequency of revaluation will be made consistent with the regulatory review period. This approach has been adopted in other Jurisdictions [eg NSW] and provides the best link between the maximum allowable revenue and the prevailing and developing market conditions.

9.0 Contributed Assets

The Authority invites comment on the treatment of contributed assets in the context of the distribution pricing review, consistent with the provisions of the Code.

Under the current regulatory regime, Capital Contributions are treated as a once-off payment and are deducted from the Maximum Allowable Revenue to produce the Revenue Cap. This arrangement is summarised in the *“Transmission and Distribution Pricing Principles”* as follows:

“The NEC requires that network businesses do not impose capital related charges for assets contributed by customers. One of the difficulties in this requirement is that contributions often relate to many different assets and even part of some assets. It will be very difficult for network businesses to separately

⁸ Recording and Valuation of Non-Current Physical Assets in the Queensland Public Sector – June 1997

⁹ Recording and Valuation of Non-Current Physical Assets in the Queensland Public Sector – June 1997

identify and account for all contributed assets, particularly when revaluation of assets is required on a periodic basis.

To fulfil the requirement of recognition while recognising the practical difficulty of identifying separate sets of assets in the future an alternative mechanism is used. This mechanism involves deducting an initial estimation of capital contributions to determine the revenue cap, which is then adjusted each year to account for the actual level of capital contributions in that year. This deduction is a once-off reduction in revenue that equates to the Net Present Value [NPV] of all future capital charges for the contributed assets. In this way the assets can be included in the asset base for rate of return and depreciation purposes while still recognising the contributions made in accordance with the NEC.¹⁰

Ergon Energy supports the retention of this methodology as it improves capital and operational efficiency by:

- (a) ensuring capital contributions for prudential coverage are minimised and that alternative prudential options are explored (which provides customer choice and a negotiated outcome);
- (b) a single set of regulated asset accounts are sufficient [ie no requirement to tag contributed assets]; and
- (c) a simplified revaluation process where all assets can be revalued without the need to identify contributed assets.

It should be noted that this method of capital contribution recognition applies only to the revenue cap determination process. The processes for recognising contributions in an accounting and taxation sense are a separate issue.

The current mechanism for adjusting revenue caps for capital contributions operates as follows:

- A multiple year regulated revenue cap is set with the initial year revenue being determined by including a rate of return on optimised assets plus depreciation plus efficient operating costs less net capital contributions for the year.
- By deducting the value of all capital contributions for the current year from the revenue cap a once-off recognition of capital contributions is made. This process is repeated each year where the expected receipts from capital contributions for the year are deducted from the revenue cap. The logic behind this is that the NPV of all future earnings from a contributed asset equals the current value of the asset. Therefore by deducting the actual value of the contribution from the revenue cap now, the future revenue that is achieved from the contributed assets is removed from the revenue base. In effect, the approach treats the capital contributions as an upfront reimbursement of future income.
- In this way average capital contributions are always recognised since future year revenues are linked to the initial year on a CPI-X basis. As part of the under and over-recovery provisions the impact of actual capital contributions

¹⁰ Queensland Government, Transmission and Distribution Pricing Principles, September 1999

received is recognised. This approach ensures that any error in the forecast level of capital contributions is corrected each year.

- In certain circumstances, the book asset value will not be increased by the total amount of the capital contribution. An example of this is where existing overhead is undergrounded. In this case, the amount of capital contribution that is recognised is the amount by which the asset value increases.
- Where a contribution is made for a standard customer class, that contribution has been made to provide access for that customer to average network prices. In effect the new customer is prepaying an access amount which is used to subsidise them in future to provide average network charges. Therefore the recognition should benefit all customers in that class who would otherwise be cross-subsidising the new customer. In a practical sense this means that the capital contributions attributed to standard customers should be deducted from the general revenue amount to benefit all standard customers. In the future it may be feasible to more specifically target the benefits [eg. to all 0-10 kV.A customers], however this is not feasible until distribution network prices are finalised for all customer classes.

10.0 Other Asset valuation Issues

The Authority seeks comment on any other issues which should be considered as part of the asset valuation process.

Ergon Energy does not seek to raise any additional issues at this time.

11.0 Asset Consumption and Depreciation

The Authority seeks comment on whether asset consumption should be recognised through a renewals annuity type approach, through depreciation charges, or through an approach that examines the difference in economic value of assets over a defined regulatory period.

Of the three different methods of asset consumption proposed by the Authority, Ergon Energy favours the straight line depreciation approach. The rationale behind this position is discussed below.

11.1 Renewals Annuity

The renewals annuity type approach is considered valid only where assets are treated as maintaining future cash flows into perpetuity. This implies a sophisticated asset management plan to determine the expenditure required to maintain the asset network over the period of the plan. The two major characteristics that a renewals annuity approach is generally considered valid for are:

- (a) The requirement that the asset system be renewable rather than replaceable, and

- (b) demand will warrant a continual extension of the asset system into the foreseeable future to maintain the assumption of an infinite asset life.

Ergon Energy does not support the renewals annuity approach for the following reasons:

- The asset management plan which will determine the expenditure needed to maintain the service potential of the network will, de facto, be a detailed asset listing containing the estimated useful lives of each part of the network. As such, Ergon Energy believes this simple calculation of straight line depreciation as the basis of determining the renewals annuity approach would result in there being no significant difference between the outcome under a renewals annuity approach or a depreciation approach.
- The renewals annuity approach is more suited to a system where different classes of assets are of similar age such as in the case of a new network system being implemented. The Ergon Energy network has evolved over many years and contains assets of many different ages with differing expected lives within each asset class. This will likely lead to a complex approach under the renewals annuity method.
- The asset characteristic assumption of an infinite asset life is not able to be supported in much of regional Queensland. Asset usage is subject to the vagaries of economic growth, commodity prices, and population trends. The risk of asset stranding and under-utilisation is increased given the dynamics of the Ergon Energy service area.

11.2 Competition Depreciation

The “difference in economic value approach” to depreciation (or so-called competition depreciation) which calculates depreciation only for the term of the regulatory period is not supported. This approach requires a valuation of assets at the beginning and end of the regulatory period, with depreciation being the net difference. The disadvantages of competition depreciation are as follows:

- The valuation of assets at both the beginning and end of the regulatory period should be equivalent of the change in market value of those assets. Given the monopolistic characteristics of the network there is no liquid market value for these assets. Market value can be determined by measuring a change in the economic value of the assets through this period. The calculation of the economic value requires inputs which are subject to variability and subjectivity.
- The concept of an economic value does not align with accounting and asset recognition standards. Generally Ergon Energy supports the alignment of accounting and regulatory standards and methodology.

If a depreciation approach is to be adopted, the Authority seeks comment on the expected life of the assets in the RAB.

11.3 Expected Asset Lives

Ergon Energy supports the adoption of the straight line depreciation approach and makes the following comments on assets lives within the regulated asset base:

- Asset lives for regulatory purposes should be aligned with asset lives for accounting purposes. The objective of the accounting standards for depreciation is to provide the best estimate of the useful life of the asset prior to its replacement. This is consistent with the objectives of the Regulator in determining the appropriate allowable depreciation.
- The allocation of asset lives across the various regulatory jurisdictions should not be inconsistent to the extent that there is alignment between accounting depreciation lives and regulatory depreciation asset lives.

Ergon Energy will supply a detailed list of asset categories and lives to the QCA under separate cover as part of the current asset revaluation process.

If a depreciation approach is to be adopted, the Authority seeks comment on the most appropriate method of recognising asset consumption for each asset class or group of assets (eg. straight line, units of production etc).

11.4 Recognition of Asset Consumption

Ergon Energy supports the continuation of depreciation allocation on a straight-line basis during the next regulatory period. The following factors have been taken into account in arriving at this recommendation:

- The administrative simplicity and transparency arising for the application of straight-line depreciation,
- The allocation of depreciation on a constant basis over the estimated useful life of the asset provides a good approximation of the reduction in the service potential of the asset and provides an acceptable allocation of the return of invested capital,
- By not requiring Distributors to keep separate records of depreciation for regulatory purposes by aligning both regulatory and accounting depreciation, regulatory compliance costs will be reduced. Ergon Energy currently utilises straight-line depreciation for accounting purposes,
- The option of accelerated depreciation has been investigated however this method which results in the depreciation in the early life of the assets being much greater than in the latter years of that assets life, is not considered appropriate for the types of assets utilised in electricity distribution networks. Accelerated

depreciation is typically used for assets where investment is to be encouraged by providing a higher return of capital in the early years of the investment. Alternatively, assets which provide a greater return in their early years and diminish in value rapidly, or assets which may have a high degree of technological redundancy, are most suited to accelerated depreciation method. Typically electricity distribution networks comprise of assets with a relatively low degree of technical redundancy and consistent returns over the life of that asset, and

- Potential for asset stranding in regional Queensland is significantly greater than that in major population centres. One method of managing the riskiness of the market stranding of assets (as opposed to the regulatory stranding of assets) is the allowance of accelerated depreciation to achieve a higher return of invested capital before the risk of market stranding increases with time. Ergon Energy has considered this risk and on balance still supports straight line depreciation as its preferred depreciation methodology.

The Authority also seeks comment on any other issues which should be considered with respect to depreciation.

Ergon Energy does not seek to raise any additional issues at this time

12.0 WACC Model

The Authority seeks comment on the use of the WACC model to determine the overall rate of return for distribution entities.

12.1 Application of the WACC Model

Ergon Energy supports the use of the Weighted Average Cost of Capital (WACC) model to determine the overall rate of return for electricity distribution entities. The WACC model rightfully recognises that the stakeholders in a business comprise both shareholders and lenders while the overall return will reflect a weighted average cost of servicing the claims of the shareholders and the lenders on the company.

Schedule 6.1 of the National Electricity Code requires that the jurisdictional regulator must have regard for the prevailing cost of funds available in the market and with the riskiness involved in delivering the networks services. The code suggests that the most commonly used model for determining this weighted average cost from each applicable source of funds (equity and debt) is the WACC.

While it is acknowledged that the calculation of appropriate return on capital through the WACC model has its limitations, in particular with respect to the calculation of the return on equity, Ergon Energy supports the use of this model to determine the appropriate return of Queensland distribution entities.

The Authority seeks comment on the most appropriate method for estimating the cost of equity for distribution entities (eg. CAPM, DGM, PE ratio, APT).

12.2 Cost of Equity

The cost of equity can be calculated in a number of different ways. Ergon Energy supports the use of the Capital Asset Pricing Model (CAPM) as the most appropriate method in estimating the cost of equity. Issues which were considered in this process include:

- The Dividend Growth Model (DGM) is not applicable to the Government-Owned Queensland distribution entities. An essential part of DGM requires that DGM may only be applied to listed companies as the current market value of a company's shares are required in the calculation.
- The Price/Earnings (P/E) ratio which involves capitalising the estimated future maintainable earnings of the business at a P/E multiple appropriate to the risks and prospects of the business is not considered a valid model to utilise in estimating the cost of equity due to problems with calculation of various component parts of that ratio.
- The use of the Arbitrage Pricing Theory (APT) as a method for calculating the cost of equity is seen as less reliable than the CAPM due to its reliance on the subjective process of identifying macro-economic factors that affect the price of a company's equity, determining the risk premium for those factors, and estimating the sensitivity of the company's equity (usually shares) to each of those factors. Ergon Energy concurs with the generally held view that APT is less reliable than CAPM in practice due to the difficulty in determining the component parts of the model with any degree of accuracy.
- Ergon Energy acknowledges that measuring some of the component parts of the CAPM model for a Government-Owned, non-listed corporation may not be possible. Ergon Energy is also aware of the practical difficulties in determining a number of the individual component parameters of the CAPM which were discussed at the Public Forum on 3 July 1998, held by the ACCC and ORG.

The Authority seeks comment on, if CAPM is to be applied, the appropriate risk free rate (including the appropriate benchmark bond and whether there should be a point-in-time sample or some form of averaging).

12.3 Risk Free Rate

Ergon supports the use of the ten-year Australian Commonwealth Bond yield as a proxy for the risk-free rate of return. This accords with Clause 3.1 of Schedule 6.1 of the National Electricity Code which states:

“The risk-free rate is normally taken to be the yield to maturity on long term (10-year) Commonwealth Bonds, with the equity market risk premium also measured historically from such a benchmark.”

Ergon Energy does not support the use of a Commonwealth Bond yield which equates to a term equivalent to the regulatory reset period. Ergon Energy’s view is that the maturity of the bond should equate to average life of the assets, which generally exceeds ten years. Due to the lack of liquidity and depth in the market for longer-term bond yields, the ten-year Commonwealth Bond is viewed as the most appropriate proxy for the risk free rate.

Ergon Energy concurs with IPART and the ACCC on using an averaging method rather than relying on a single current “spot” rate. The use of a spot rate to calculate the risk free rate would subject that parameter to market volatility which may lead to significant price shocks to customers from one regulatory period to the next. Ergon Energy proposes a thirty-day moving average as the most appropriate benchmark for estimating the nominal risk-free rate.

The Authority seeks comment on, if CAPM is to be applied, the appropriate quantification of the market risk premium.

12.4 Market Risk Premium

The quantification of the market risk premium should be based on historical imperial studies and adjusted the market movements to provide a forward view as is required within the CAPM framework.

There have been a number of studies of the market risk premium based on historical data on the relative return performance of Australian equities and bonds on a long-term basis. One study¹¹ found that the market risk premium fluctuated between peaks in excess of 8% to levels as low as 1% with an average of 3.9% over the period 1928 to 1996. This is lower than research undertaken by Officer (as discussed by ORG, 27 March 1998) who suggested that the mean market risk premium was in the range of 6-6.5% for the period 1946 to 1991. In a report prepared for IPART by Baring Brothers Burrows, independent valuation experts have used market risk premia in the range of 5 to 7% (with a median of 6%) in independent expert reports valuing Australian business since 1992. Other recent independent expert reports including SG Hambrose valuation of Yandall Gold in February 1999 used 6.5%, while the National Electricity Code notes that the figure has averaged 6.6% in the period from 1952 to 1998 based on historical data.

Recent research suggests that market risk premium has exhibited a decline in trend in the most recent decade due to the decline in the inflation rate. While it may be argued that should a low inflation environment continue to be maintained in the Australian economy in future years, the equity risk premium will remain relatively low it should be noted that over longer periods the market risk premium is considered to be fairly stable. The historical empirical studies have included period of low inflation before and subsequent periods have seen the market risk premium rise toward the long-term arithmetic mean.

¹¹ Kortain, T (1988), Australian Sharemarket Valuation and the Equity Premium, Department of Finance, University of Sydney.

Ergon Energy supports an equity risk premium that reflects the long-term arithmetic mean based on historical empirical studies. The use of a longer-term rate will reduce the risk of price shocks to consumers should a lower rate be utilised than a subsequent period of higher inflation increases the market risk premium for the subsequent regulatory periods. Ergon Energy supports a market risk premium in the range of 6.5% to 7%.

The Authority seeks comment on, if CAPM is to be applied, the appropriate quantification of the equity beta.

12.5 Equity Beta

Ergon Energy agrees with the QCA that the appropriate equity beta for a Government-Owned Corporation is unable to be calculated. Ergon Energy makes the following comment with respect to estimating an appropriate equity beta for the company:

- There are no comparable listed companies which have a similar business profile to Ergon Energy.
- IPART has stated that
“It is difficult to justify an equity beta for the electricity network businesses in NSW of more than the market average (ie 1.0) given the predicability of their income and returns, negligible insolvency risk, and limited exposure to inflation risks. In addition, the demand for the electricity network services is relatively insensitive to changes in the overall market economy.
- Ergon Energy generally supports the IPART comments, however we believe a number of recent factors need to be taken into consideration which are expected to increase the volatility of future returns relative to the market as a whole.
- The risk of asset stranding is substantially greater in regional Queensland where reliance on a smaller number of large customers (primarily resource related) aligns the riskiness of the business more towards the resource dominated market average of 1.0. This risk also has roll on impacts through the regional centres around these resource industries.
- An equity beta comprises an asset beta plus an adjustment for the level of financial risk within the corporation. A comparative analysis can be made by comparing asset beta's and re-levering them to produce an estimated equity beta based on the assumed level of gearing in the organisation. As discussed earlier, Ergon Energy does not believe there are listed entities that have a similar asset base to itself thus the process of determining an appropriate asset beta and thenceforth an equity beta through this methodology is not deemed appropriate.
- While the Department of Mines and Energy, September 1999 determined that the equity beta for Transmission and Distribution entities in Queensland should be 0.8, Ergon Energy does not believe that the authors took into consideration all of the risks facing the business during the next regulatory reset period. Also it is our understanding that the beta developed by QERU was based on a diversified

portfolio of Shareholder investments, not on the basis of a specific Corporation. The market development risks, as outlined above, together with other business specific risks such as changes in greenhouse emissions legislation may increase the likelihood of stranding of assets, the likelihood of bypass of assets due to proposed new gas pipelines, the inability to meet operational cost efficiencies due to political considerations and the uncertainty attached to regulatory resets all contribute towards Ergon Energy having a volatility of price returned more closely aligned to that of the market as a whole rather than the safe, predictable perception on face value.

In view of the previous discussions, Ergon Energy supports an equity beta of 1.0.

The Authority seeks comment on the appropriate approach to determining the cost of debt for distribution entities (eg. average cost of existing debt, marginal rate, margin above the risk free rate or CAPM).

12.6 Cost of Debt

The cost of debt can be regarded as having two components, a risk-free component and a company specific risk premium. The risk-free rate can be derived by reference to Commonwealth long and short-term debt yields while the company specific risk premium is dependent upon the credit rating of the entity.

Ergon Energy supports the approach of determining a margin above the risk-free rate as the most appropriate approach to determining the cost of debt. In considering this approach, Ergon Energy has taken into account the following:

- The average cost of existing debt approach will require detailed analysis of each distribution entities borrowing costs on an actual basis. Such costs may not reflect the likely forward cost of debt during the regulatory reset period. During a period of rising interest rates the actual cost of debt calculation will likely underestimate the future costs through the regulatory period.
- The marginal rate approach to determining the cost of debt will also not provide consistency due to short-term variation in factors that may influence the marginal rate.
- A CAPM approach to debt determination involves the same basic formula that includes determining a debt beta. This determination is still somewhat subjective and thus this approach is not supported.

The most appropriate approach for determining the cost of debt is, in Ergon Energy 's opinion, the use of a margin above the risk-free rate. Ergon Energy proposes a debt margin of one hundred basis points (1.0%)

The Authority seeks comment on whether the cost of debt should be adjusted to reflect the impact of the benefit (if any) derived by distribution entities by virtue of the implicit government guarantee.

12.7 Cost of Debt Adjustment

Ergon Energy supports an adjustment to the cost of debt to reflect the implicit government guarantee by the nature of its shareholders.

In accordance with the Code of Practice for Government-Owned Corporations financial arrangements, a Competitive Neutrality Fee is already levied on Government-Owned Corporations as a proxy for all of the costs and benefits that arise through government ownership. The fee is applied as a margin based on the difference between Queensland's yield curve and the notional yield curve for each Government-Owned Corporation (based on its stand-alone credit rating). Ergon Energy is currently paying the competitive neutrality fee on a quarterly basis. The fee is based on the differential between a notional yield curve for Ergon Energy's shadow credit rating and the Queensland Government's "AAA" credit rating.

Ergon Energy should be assessed as paying a cost of debt equivalent to that of a comparatively rated Company.

The Authority seeks comment on whether the capital structure used in the WACC model should be the actual capital structure of the entity, or some industry benchmark (and if so what should this benchmark level be).

12.8 Capital Structure

Ergon Energy supports the use of a notional industry benchmark for determination of an appropriate gearing level. Ergon Energy's position has been influenced by:

- A gearing ratio is required as input into both the beta factor to be utilised in estimated cost of equity and within the WACC model.
- Gearing within a corporation can vary considerably over time as new investments are made and existing borrowings repaid, according to the availability of free cash flow of the organisation.
- The use of actual gearing may result in price shocks to customers from one regulatory period to another as the level of gearing changes through regulatory reset periods.

Ergon Energy views an appropriate benchmark level of gearing (debt to debt plus equity) to be 50%. Due to the commercial sensitivity of the derivation of the capital structure, Ergon Energy will provide any required information to the Authority on a Commercial-In-Confidence basis.

The Authority seeks comment on whether the WACC should be calculated based on pre-tax or post-tax cash flows.

12.9 Pre-Tax or Post-Tax WACC

Ergon Energy supports the use of a rate of return calculated on a pre-tax WACC. As the same result will derive on utilising either pre-tax or after tax rates of return Ergon Energy prefers the pre-tax approach for its simplicity and transparency.

While Ergon Energy accepts that the WACC model drawn from finance theory prefers calculation on an after-tax basis the level of complexity in determining the appropriate tax rate of the entity is far greater than warranted. Tax rates for a corporation will vary considerably dependant on a number of factors including the level of tax losses available, the availability of accelerated depreciation, and other allowable taxation adjustments. This does not accord with the concept of regulatory simplicity as it will necessarily involve determining the appropriate tax rate for each regulated entity.

The Authority seeks comment on the appropriate valuation of imputation credits (ie. gamma).

12.10 Valuation of Imputation Credits

Ergon Energy supports the view of the National Electricity Code with respect to the valuation of imputation credits at approximately 45 to 50 cents in the dollar. It is acknowledged that imputation credits for a Government-Owned Corporation which does not pay Federal Income Tax are equivalent to 100 cents in the dollar. However the principle of Competitive Neutrality requires that:

“As the ultimate owners of Government Business Enterprises, taxpayers would value their equity on exactly the same basis as they would value an investment in any other corporate tax paying entity. On this basis, it would be reasonable to assume the average franking credit value in the calculation of the Network owners pre-tax WACC.”

This assumption of a reduction in the value of franking credits from one hundred cents in the dollar to the range between forty-five and fifty cents in the dollar occurs by reason of Competitive Neutrality.

The Authority seeks comment on the appropriate tax rate to be applied to electricity distribution entities.

12.11 Appropriate Tax Rate

Ergon Energy's view is that the appropriate tax rate to be applied to electricity distribution entities should be the current statutory rate. In arriving at this conclusion, Ergon Energy has considered the following:

- There are two alternatives to applying an appropriate tax rate for distribution entities. These are either the statutory rate or an effective rate which adjusts the statutory rate for timing and permanent differences.
- Ergon Energy's view is that the calculation of an effective tax rate will likely contain considerable volatility through movements in factors making up the timing differences in tax payments.
- Any timing differences will be eliminated over a longer period, especially now that accelerated depreciation has been abolished.
- The adoption of a tax rate other than the statutory rate will necessarily involve either assessing the distribution entities together as a whole or the individual tax position of each entity. This may have an adverse impact upon individual corporations that may not be in a position to take advantage of taxation benefits.
- Ergon Energy concurs with IPART in that over the life of the electricity networks utilities generally move from a low to a full tax paying position and that it is for utilities to manage their own tax affairs.

Given the uncertainty associated with the review of Australia's taxation system, the Authority seeks comment on what events, if any, should trigger a review of the rate of return.

12.12 Rate of Return Triggers

Ergon Energy does not believe that it is necessary to review the rate of return determined at the beginning of a regulatory period during that period other than in exceptional circumstances. Ergon Energy's view (as commented under Section 4.0 above) is that for this first regulatory period either a three-year or five-year period with mid term review be adopted. The purpose of the mid term review or the shorter three-year term is to take account of any major changes in the market, the current level of maturity of the market, the possibility of other external influencing factors.

In the event of a material factor which may affect the distribution entity's business on a long-term basis, Ergon Energy anticipates discussing this directly with the Regulator.

The Authority also seeks comment on any other issues which should be considered in the context of the allowed rate of return.

13.0 Additional Rate of Return Issues

Ergon Energy notes that the Authority has not raised the issue of Nominal versus Real WACC's. We would suggest that the Authority should provide an opinion on this issue so that it can be considered at the same time as the pre and post tax options.