Ergon Energy Corporation Limited

Submission on the *Connection Charge Guidelines: for Accessing the Electricity Distribution Network*

Issues and AER's Preliminary Positions Consultation Paper

Australian Energy Regulator

10 August 2011

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1. Introduction

Ergon Energy Corporation Limited (Ergon Energy), in its capacity as a Distribution Network Service Provider (DNSP) in Queensland, welcomes the opportunity to provide comment to the Australian Energy Regulator (AER) on its issues and preliminary positions outlined in the *Connection Charge Guidelines: for Accessing the Electricity Distribution Network* Consultation Paper (Consultation Paper).

Ergon Energy has structured this submission into the following sections:

- Section 2 details Ergon Energy's key issues and preferred position in response to the AER's Consultation Paper. In this section, Ergon Energy proposes four key conventions to guide the development of the Connection Charge Guideline (Guideline) in relation to shared network augmentation costs; and
- Section 3 outlines Ergon Energy's detailed responses, in tabular form, to the consultation questions posed by the AER.

Ergon Energy is available to discuss this submission or provide further detail regarding the issues raised, should the AER require.

2. Key Issues and Preferred Positions

This section discusses Ergon Energy's key issues and preferred positions in response to the AER's Consultation Paper. Ergon Energy believes these key issues require further development and consideration by the AER.

In summary, Ergon Energy considers the Guideline should:

- Take into account jurisdictional differences;
- Apply to all connections under Chapter 5A of the National Electricity Rules (the Rules), but only to the extent the assets are included in the Regulated Asset Base (RAB) and used to determine distribution use of system (DUoS) charges;
- Allow DNSPs to charge the actual costs and overheads incurred in performing works (i.e. not a market price or reasonable rate which is reflective of the market price due to market imperfections in regional Queensland);
- Allow shared network augmentation costs to be charged via a shared network cost (SNC) component of the cost-revenue-test instead of explicitly charging customers this cost in the incremental cost component. This should apply to customers who consume ≥ 100 MWh per annum of electricity; and
- Exclude or amend the requirement for a process whereby a DNSP must call a tender for works over $3,000 as this is administratively burdensome, costly and inefficient.

2.1 Jurisdictional Arrangements

Clause 5A.E.3(e) of the Rules requires the AER to have regard to historical and geographical differences between networks as well as jurisdictional differences related to regulatory control mechanisms, classification of services and other relevant matters. Accordingly, Ergon Energy believes the Guideline should be flexible enough to cater for any classification of services and form of price control. This should be achieved in such a manner that does not inadvertently impose or pre-empt a classification of services on a DNSP before the next Distribution Determination.

Further, Ergon Energy believes the Guideline should reflect jurisdictional arrangements in Queensland where developers are required to **fully fund all costs** associated with making an electricity supply available to the development (i.e. via a cash capital contribution or non-cash capital contribution). This includes internal and upstream costs associated with design, civil works, electrical reticulation works and tree clearing. This means the cost-revenue-test does not apply.

Queensland has adopted this approach for two reasons. Firstly, it is a condition of Local Government Authorities that developers provide and fund electrical infrastructure as part of the overall costs of developing and selling land. These costs are ultimately recouped in the sale price of the land. Secondly, this approach means DUoS payments received from all electricity customers are not used to support developers' costs and profits but are instead spent on the shared electricity distribution network, benefiting all customers. The Queensland Competition Authority, as approver of Ergon Energy's current Capital Contribution Policy, required the policy to reflect that developers are required to fully fund all costs. This approach is consistent with one of the purposes of the Guideline as it ensures connection charges limit cross-subsidisation of connection costs[1]. It should also be noted that while a developer can be a connection applicant under the Rules, they are not a retail customer. This means that while a developer can arrange a connection to the distribution network, they are not ultimately responsible for energy costs at the premises.

Therefore, Ergon Energy recommends that the Guideline should have a provision to allow DNSPs to implement this approach if applicable in their jurisdiction.

[1] Clause 5A.E.3(b)(3) of the Rules

2.2 Application of the Guideline

In its Consultation Paper, the AER states that DNSPs must charge new customers in accordance with the Guideline for basic and standard connection services only[2]. Ergon Energy does not support this statement and believes the Guideline should apply to all connections, including negotiated connection contracts, under Chapter 5A of the Rules. However, this application should be restricted by the extent that the assets are included in the RAB and used to determine DUoS charges.

For example, the dedicated asset component of a Large Customer Connection (LCC) is classed as an Alternative Control Service (ACS) for Ergon Energy. This means that it is treated as a Quoted Service and is regulated under a formula based price cap control mechanism. Ergon Energy does not believe it is appropriate to calculate the ACS price using the current formula and then deduct a revenue amount, based on DUoS, to determine the price. That is, the customer should pay the full ACS cost of the dedicated connection assets and the capital contribution component should only apply to any Standard Control Service (SCS), if applicable.

It should be noted that the AER, in its Final Decision on the Framework and Approach for Classification of Services and Control Mechanisms[3], stated that the design and construction of large customer connection assets should be classified as an ACS. This is because the AER considered that there are a sufficient number of alternative providers in the Queensland market and, if allowed to develop, this could lead to a competitive market for the design and construction of connection assets. As a result, LCC services are classified as an ACS. This means that the assets are not included in the RAB.

2.3 Market Price

Ergon Energy is generally supportive of the AER's design criteria used to develop the Guideline. However, we have a number of concerns in relation to design criteria two. This design criteria states:

> *"Where suitable alternative service providers for construction works are available, the DNSP's charge should be reflective of the market price; where no alternative service providers are available, DNSPs must charge at a reasonable rate, which is reflective of the market price"* [4].

Ergon Energy considers it is not appropriate for a DNSP to charge the market price, particularly in a non-contestable market. This is because it is unlikely that a DNSP's costs will be the same as market price where that market is imperfect. For example, at some points in time:

- Market price will be lower than a DNSP's cost. This is because alternative service providers do not have the same costs or responsibilities as a DNSP. Alternative service providers work on a project basis and do not incur costs associated with maintaining customer services or response requirements across Ergon Energy's distribution area. These costs include additional labour, equipment, materials and overheads (e.g. depots); or
- A DNSP's costs will be lower than market price. This occurs in regional or remote areas where alternative service providers do not exist (so travel costs needs to be included) or in times of a resource boom where scarce resources can charge accordingly.

Where Ergon Energy performs the work, it needs to be able to recover its actual costs. If we are unable to recover our costs associated with performing the work, then either:

- All other customers pay for a single customer's connection; or
- A single customer would pay more than they would otherwise be required to.

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[2] Refer to page 5 of the Consultation Paper

[3] AER (2008), *Final Decision, Framework and Approach Paper, Classification of Services and Control Mechanisms, Energex and Ergon Energy 2010–2015*, August 2008.

[4] Refer to page 7 of the Consultation Paper

This means that cross-subsidisation will occur. This contradicts design criteria three as well as two of the purposes of the Guideline – limiting cross-subsidisation and sending a user-pays signal.

We note that the AER has recently conducted a Distribution Determination for Ergon Energy and has determined that our procurement policies are efficient. Ergon Energy considers that this determination process should be sufficient enough for a DNSP to be able to pass through actual costs without the requirement to charge a market price determined by reference to an imperfect market.

In the event that design criteria two is retained, Ergon Energy also has concerns in relation to the second part of the design criteria. This is because it is unclear what a DNSP will charge if there are no pre-established contract prices available in certain areas. For example, Ergon Energy's distribution area covers many regional and remote areas where contractors or alternative service providers are not available.

2.4 Charging Shared Network Augmentation Costs

Ergon Energy does not support the AER's approach to charging customers for shared network augmentation costs. Ergon Energy considers the following four key conventions form an appropriate framework on which to develop the Guideline with regard to this issue:

1. Every customer is assumed to impose a cost on the shared network;
2. DNSPs should not explicitly charge customers for <u>actual</u> shared network augmentation costs;
3. Customers who consume < 100 MWh per annum of electricity (small customers) should not be charged a shared network augmentation cost; and
4. Customers who consume ≥ 100 MWh per annum of electricity (large customers) should have a charge in their cost-revenue-test, represented by the SNC component, which reduces future revenue by the amount needed to fund their contribution to the shared network.

Convention 1

Ergon Energy recognises that all customers connected to a distribution network impose a cost to the shared network. In line with the AER's current approach, Ergon Energy believes that the customer who triggers a shared network augmentation should not be the sole contributor to these costs. Therefore, all customers, in addition to meeting incremental costs, should contribute to the costs of the shared network.

Convention 2

Ergon Energy recognises the Guideline must describe the methods for calculating the augmentation component for the connection assets[5]. However, Ergon Energy does not support the AER's proposal to include a shared network augmentation cost (via a per unit rate charge) in the incremental cost component of the cost-revenue-test. Instead, we propose employing the SNC component currently used in our cost-revenue-test. Under the SNC calculation, the amount customers pay towards the shared network is defined as a percentage of the present value of the expected network charge payments (i.e. incremental revenue).

Ergon Energy considers the SNC component should allow a DNSP enough flexibility to send some form of locational signal. That is, it could be segmented to reflect network differences in actual costs. For Ergon Energy, this percentage will vary between our three pricing zones due to the size of the shared network required to service all customers within each zone. Ergon Energy currently attributes 25 per cent of incremental revenue to the costs of the existing shared network in the East Zone, 80 per cent in the West Zone and 2 per cent in Mount Isa.

[5] Clause 5A.E.3(c)(5) of the Rules

Convention 3

This convention addresses the requirement under clause 5A.E.3(c)(4) of the Rules to establish principles for fixing a threshold below which a retail customer is exempt from paying for shared network augmentation costs. Ergon Energy believes that setting a threshold based on a customer's consumption is the best option as this will align with a range of existing legislative and regulatory structures governing a DNSP's participation in the national electricity market (e.g. network tariffs, consumer protection[6], and metering[7]). Ergon Energy considers that customers who consume less than 100 MWh per annum of electricity should not be charged a shared network augmentation cost. If a different and separate threshold is imposed, this will result in additional administrative costs for industry.

Convention 4

As above, this convention addresses the requirement under clause 5A.E.3(c)(4) of the Rules to establish principles for fixing a threshold below which a retail customer is exempt from paying for shared network augmentation costs. Ergon Energy believes that customers who consume 100 MWh or more per annum of electricity should contribute to the shared network via the SNC component of the cost-revenue-test.

2.5 Tender Process

Ergon Energy does not support the introduction of a mechanism whereby a DNSP must call a tender for connection works over $3,000. Ergon Energy's concerns in relation to the proposed tender process are detailed below.

- Ergon Energy believes that a threshold of $3,000 is too low. Ergon Energy currently deals with approximately 4,000 applications per year, with the majority of these valued at over $3,000. A more appropriate value should be considered if such a mechanism is introduced. A value lower than this may not attract interest from contractors (based on location and economic environment), potentially resulting in delays in our Customer Initiated Capital Works process. It will also be extremely administratively burdensome.

- The entire tender process will impose a level of administrative costs, such as overheads, and costs involved in developing a system to manage and oversee the tender process. These costs will need to be recovered from the customer through fees; otherwise the process may be open to over-exploitation, with customers viewing it as a no-cost service funded by the DNSP.

- In Ergon Energy's experience, a tender process takes in excess of 10 days as some contractors are unable to provide a quick turnaround with quotes. Difficulties may also arise in accessing pricing from contractors as contractors may not provide a quote for work they do not expect to receive. This will impact on our ability to make offers for basic and standard connection services within 10 business days of an application[8] and 65 business days for a negotiated connection service[9] as required under the Rules.

- The Queensland electricity sector continues to experience skills shortages which impact on the availability of skilled contractors to perform the required work, particularly in regional and remote areas. Additionally, the electricity sector must compete with other industries (such as mining) to engage these service providers.

- The vast geographical spread of Ergon Energy's distribution network (which includes small communities, regional and remote areas, and isolated areas) may pose an issue in engaging service providers to perform the required work. Travel distances to these areas impact on

[6] s5 of the *National Energy Retail Law* and s7 of the *National Energy Retail Regulations*
[7] Refer to the Australian Energy Market Operator's *Metrology Procedure: Part A National Electricity Market*
[8] Clause 5A.F.1 (a) of the Rules
[9] Clause 5A.F.4(a) of the Rules

transport costs and may deter skilled contractors from accepting work as it may not be deemed profitable.

- In times of skills shortages, requiring a DNSP to "either price its connection service at the market price, or engage independent service providers to provide the service to the customers"[10] will cause all customers to use Ergon Energy as the service provider, depleting our resources at a discounted rate. Ergon Energy is not a contracting business; rather its core business is to operate the distribution network.

While Ergon Energy does not support the inclusion of a mandated tender process, if a tender process is adopted, a better solution would be to provide customers with a list of contractors that are accredited to perform the work and have the customer itself source quotes. Ergon Energy currently employs this process for developers and it has proven to be successful. Under our current process, Ergon Energy issues a scope of works to a developer who in turn seeks prices from approved contractors to complete the work. Ergon Energy audits contractors' design and construction throughout the works and charges them the audit, testing and commissioning fees. Works are then gifted to Ergon Energy. Currently, work associated with auditing, testing and commissioning works for small customers are a Standard Control Service for Ergon Energy and a fee is not charged to the individual. As previously stated, the Guideline should not pre-empt a particular classification of services.

This option sends a clear user-pays signal without the administrative burden and costs involved in undertaking a DNSP-run tender process. Further, having a panel of accepted contractors that the customer can choose from still drives competition and would be a better reflection of market forces.

2.6 Purpose of the Guideline

Ergon Energy believes our proposal, detailed in Sections 2.1 to 2.5 above, better reflects the purpose of the Guideline as outlined in the Rules[11]. That is, it will ensure connection charges:

- <u>Are reasonable, taking into account the efficient costs of providing the connection services;</u>

  As discussed above, Ergon Energy believes the SNC component of Ergon Energy's current cost-revenue-test can provide a locational signal by allowing a DNSP to segment their network to take account of network differences in actual costs due to historical and geographical reasons. This is in line with the AER's view that some locational signal is appropriate to take account of cost efficiency (charges reflective of actual cost) when charging for shared network augmentation[12].

  Further, Ergon Energy believes that the Distribution Determination process, which examines our procurement policies, should be sufficient in ensuring connection charges meet this requirement.

- <u>Provide, without undue administrative cost, a user-pays signal;</u>

  Ergon Energy does not dispute the use of a cost-revenue-test as the appropriate method to calculate capital contributions. Consequently, our proposed method continues to provide a user-pays signal to customers, whereby a customer will only be charged a capital contribution if the incremental cost component exceeds the incremental revenue that the connection will provide over its life.

  Additionally, the SNC component of our cost-revenue-test also provides a user-pays signal by acknowledging that new large customers should contribute to the costs of the shared network. Ergon Energy considers that using the SNC component in the cost-revenue-test is not as complex and administratively burdensome as the AER's current proposal (i.e. to include a shared network augmentation cost in the incremental cost calculation).

[10] Refer to page 19 of the Consultation Paper
[11] Clause 5A.E.3(b) of the Rules
[12] Refer to page 22 of the Consultation Paper

Also, our proposal sends a user-pays signal by allowing a DNSP to recover actual costs, rather than the market price. That is, a customer will pay for the actual costs incurred, not a market price that holds no relevance to them.

- Limit cross-subsidisation of connection costs between different classes of customers; and

  Ergon Energy considers using a SNC component in the cost-revenue-test limits cross-subsidisation because the costs to the shared network resulting from a new customer will not cause increases in network charges to existing customers. Allowing flexibility in the development of different segments will also ensure that shared network costs will not be levied on connections that would not normally require shared network augmentation for a given section of the network.

  Further, Ergon Energy believes using a customer consumption threshold of 100 MWh per annum will ensure that most retail customers will not pay for shared network augmentation, limiting the cross-subsidisation between different classes of customers.

  As noted above, allowing a DNSP to charge actual costs (instead of market price) will also limit cross subsidisation. It will ensure that all other customers do not pay for a single customer's connection or a single customer does not pay more than they would otherwise be required to.

  Ensuring that developers fully fund all costs associated with making an electricity supply available to the development also limits cross-subsidisation. That is, DUoS payments received from all other electricity customers will not be used to support developers' costs and profits.

- Are competitively neutral (for contestable connection services).

  Our proposal is that the Guideline applies to SCS only and does not impact on potentially contestable ACS services. If the Guideline were to apply to our LCC services, the cost would be lower than our competition and would not be competitively neutral.

  Moreover, the current proposal to charge a market price, or a reasonable rate reflective of market price, does not encourage competition in situations where a DNSP's actual costs are lower than market price.

3. Table of Detailed Comments

Question(s)	Ergon Energy Response
The AER seeks comments on the proposed definitions and those in appendix A for use in the connection guideline.	Queensland currently applies the definitions listed in Chapter 10 of the Rules. As such, Ergon Energy believes the Guideline should reflect these definitions, rather than those used in New South Wales. Ergon Energy does not support the AER's proposed definition for direct connection assets as it is not consistent with current practice and terminology in Queensland or the overarching National Energy Customer Framework legislation. The proposed definition states that direct connection assets "run from the connection point to the point of supply and where applicable also include the consumer mains". The problem with this is that, in almost all cases, Ergon Energy views the connection point as being the point at which our assets end and the customer's assets begin (for which we have no responsibility). Therefore, under the proposed definition, Ergon Energy would not have any direct connection assets and the assets, such as a service line and meter, would be considered an extension. This argument is supported by Section 5.3 of Schedule 2[13] of the new *National Energy Retail Rules* which states that a DNSP's "obligations extend up to the connection point[14] where energy is to be supplied to the premises (as defined by us) and not beyond". It is clear that the legislation envisages for a DNSP's responsibility to end at the connection point. Therefore, it is important that the AER's Guideline reflects this, by avoiding overlap and ambiguity in its definitions and interpretation. Ergon Energy suggests that a more appropriate definition for direct connection assets is "the premise's *connection* assets which run from the *network coupling point* to the *connection point*". The network coupling point, as defined by the Rules, is where a connection asset joins to the distribution network. For a connection service to a residential premises (e.g. a house), the network coupling point would be on the street where the line of mains connects to the service, and the connection point would be on the house where the service joins the consumer's mains.

[13] Model terms and conditions for deemed standard connection contracts

[14] The deemed standard connection contract defines the connection point as "the point at which a distribution system connects to an energy installation or equipment that serves the premises of one or more customers".

	Ergon Energy also notes the drawings proposed in Figures 1.1 and 1.2 of Appendix A of the Consultation Paper are not an accurate reflection of current situations in Queensland.
The AER seeks comments on its design criteria for the connection charge guideline.	Ergon Energy is generally supportive of the AER's design criteria but has concerns in relation to DNSP charges being reflective of the market price. Please refer to detailed comments in Section 2.3 above.
The AER seeks comments on its preliminary position to apply a cost-revenue-test of the form CC = ICCS + ICSN – IR (n=X).	Ergon Energy notes that the AER's formula is expressed as CC = ICCS + ICSN – IR (n=X). Ergon Energy's current (and preferred) formula is expressed as: $CC = IC_{CS} – [IR_{(n=20)} – SNC_{(x\%)}]$ Where: CC = Capital Contribution IC_{CS} = Incremental Costs – Customer Specific portion of the Project Cost $IR_{(n=20)}$ = Incremental Revenue (present value of a 20 year revenue stream directly attributable to the new connection – calculated on the annual Network Price Book rates) $SNC_{(x\%)}$ = Shared Network Cost (an attribution of $IR_{(n=20)}$ to the costs of the existing shared network, with East Zone being 25 per cent, West Zone 80 per cent, and Mount Isa Zone 2 per cent). It should be noted that rearranging Ergon Energy's formula you get $CC = IC_{CS} + SNC_{(x\%)} - IR_{(n=20.}$ That is, at the high level the AER's proposed formula is very similar to that currently used by Ergon Energy. The difference is how the formula is explained to customers. For example, the AER's formula takes incremental costs plus shared network augmentation and then reduces the contribution by incremental revenue. However, Ergon Energy's formula takes incremental costs and reduces them by future revenue which is adjusted by the amount needed to fund the customer's contribution to the shared network. Ergon Energy believes its formula is easier to explain to customers. Ergon Energy's key concern is with the application of the formula and these concerns are discussed in Sections 2.1 and 2.4 above regarding our proposed changes to charging customers for shared network augmentation costs and the exclusion of developers from the cost-revenue-test. Given that at the principle level there is similarity between the formulas and the policy intent, Ergon Energy believes that the Guideline should provide flexibility for Ergon Energy's current formula and approach to be maintained. That is, changes to existing approaches should not be made where the costs incurred will outweigh the benefits from the

	changes.
The AER requests comments regarding whether DUoS is the appropriate measure of revenue to use in the cost-revenue-test.	Ergon Energy supports the use of DUoS as the appropriate measure of revenue in the cost-revenue-test. However, DUoS is only appropriate if the connection service is classed as a SCS (refer to comments in Section 2.2 above).
The AER requests comments on the appropriate assumptions regarding the connection period for new connections. The AER requests comments on how much flexibility DNSPs, or new business customers, should have to alter these default assumptions.	*Appropriate time period* Ergon Energy does not support the AER's proposed time periods for residential customers (30 years) and business customers (15 years). Currently, Ergon Energy applies a 20 year term which reasonably reflects the average life of network assets and the period of time before customers are expected to seek capacity enhancements. If 30 years is set for residential customers, Ergon Energy's contribution will increase and residential customers will pay less as the revenue recovery is over a longer period of time. On the other hand, if 15 years is set for business customers, Ergon Energy's contribution will decrease and business customers will pay more. Overall, the expected result is that Ergon Energy will fund more towards the connection of customers than what is currently the case. Further, setting different time periods between customer types may raise some equity concerns. That is, why should a business customer pay more than a residential customer for the same basic or standard connection service if the costs are both essentially the same? The incremental costs would be the same in the cost-revenue-test, but the DNSP would recover revenue from the business customer over a shorter time period. *Flexibility to alter default assumptions* Ergon Energy supports the notion that DNSPs should be given the flexibility to alter these default assumptions. This is particularly important in instances where individual customer circumstances are well outside the 'norm' (e.g. mines that have a five-year life cycle, constructions camps in small towns with a two-year life cycle etc.). However, if a different time period is requested by the business customer, Ergon Energy considers that such a request must be <u>reasonable</u> given the circumstances of the new connection. The Guideline should adequately address this issue.
The AER requests comments regarding whether the WACC is the appropriate discount rate to use in performing the net present value calculation. The AER requests comments regarding whether it is	Ergon Energy supports the use of the real post tax weighted average cost of capital (WACC) as the appropriate discount rate in the net present value calculation.

appropriate to use a pre-tax WACC, or a post tax WACC with a separate adjustment for taxation.	
The AER requests comments regarding the appropriate assumption of future price path to use in the cost-revenue-test.	While Ergon Energy currently uses a flat price path assumption in its calculations, we believe that trend prices in line with the Consumer Price Index (CPI) would be a more appropriate and defensible assumption of the future price path beyond the current regulatory control period given that real price paths will depend on real increases in the cost of inputs. This approach is more in line with commercial reality, and could be set and analysed each year.
The AER seeks comments on its preliminary view that an extension should be funded by the customer requiring the extension, subject to the cost-revenue-test. The AER seeks comments on its preliminary view that: • Subject to customer agreement, DNSPs should call tenders for connection works over $3000. • For works below this threshold, DNSPs should use pre-established period (standing) contract prices from qualified third party contractors as the basis for cost calculation.	*Funding extensions* Ergon Energy supports the AER's preliminary view that an extension should be funded by the customer requiring the extension, subject to the cost-revenue-test. *Tender process* As discussed in Section 2.5 above, Ergon Energy does not support the introduction of a mechanism whereby a DNSP must call a tender for connection works over $3,000. Please refer to Section 2.5 for specific comments.
The AER seeks comments on its preliminary view to charge for shared network augmentation on a per unit rate based on the calculation method outlined in the South Australia Guideline No.13.	As discussed in Section 2.4, Ergon Energy does not support the AER's approach to charging customers above the threshold for shared network augmentation costs using a unit rate based calculation. Ergon Energy suggests that customers who consume 100 MWh or more per annum will have an additional charge in the cost-revenue-test (via the SNC component) which reduces future revenue to fund their contribution to the shared network.
The AER seeks comments on its preliminary view to allow DNSPs to segment their network into areas where different shared network augmentation charge rates would apply.	Ergon Energy supports the AER's preliminary view to allow DNSPs to segment their network into areas where different shared network augmentation charge rates would apply. This is particularly relevant to Ergon Energy as certain areas of our network require greater capital investment due to their regional and remote nature. Currently Ergon Energy's regulated network is segmented into the East, West and Mount Isa pricing zones and the network charges for each reflect the relative cost to supply. For example, the West Zone is considered to have a relatively more expensive cost to supply compared to the East Zone and the network charges are therefore generally higher in the West Zone.

	Ergon Energy notes that any segmentation should, to the extent possible, be consistent with the DNSP's cost allocation and pricing methodologies which have been used to develop network tariffs. This will avoid any perverse outcomes.
The AER requests comments on: • What is the most appropriate manner to calculate the operation and maintenance costs imposed by a new customer? • Should the O&M cost be excluded from the incremental cost calculation; and instead the incremental revenue calculation be adjusted, based on the equivalent network tariff with the O&M component removed?	Ergon Energy does not support the inclusion of operating and maintenance (O&M) costs in the calculation of incremental cost to ensure that the O&M cost is netted-off from the cost-revenue-test. To do this would be administratively burdensome and require system development while providing little benefit to the customer. However, if adopted, Ergon Energy notes that the O&M costs could be calculated by separating O&M costs into asset classes and units, and then applying the average to the units comprising the connection. However, we have concerns on how achievable this option really is and whether it might promote cross-subsidisation (i.e. smaller customers paying for large customers in remote areas). If the AER adopts this position, Ergon Energy considers that adjusting the incremental revenue calculation is not ideal. O&M costs are not a separate tariff component and it would be difficult to separate this from the SAC standard rates approved by the AER. In this case, including the O&M cost in the incremental cost calculation is preferred.
The AER seeks comments on its preliminary view to set a fixed demand threshold rather than a threshold dependent on local capacity. The AER seeks comments on its preliminary view to set a threshold for most areas of networks on the greater of: • The level of customer demand in each DNSP's network that would result in approximately 10 per cent of new customers paying for specific shared network augmentation (based on existing customer demand information); or • 70 kVA (equivalent to 100 Ampere 3-phase low voltage supply). The AER seeks comments on its preliminary view to allow DNSPs to nominate less developed areas of the network	Ergon Energy does not support the adoption of a threshold based on fixed demand or local capacity. As detailed in Section 2.4 above, Ergon Energy considers that a threshold for shared network augmentation charges should be set at 100 MWh per annum for the general distribution network. For single-wire earth return (SWER) lines, Ergon Energy believes that it is appropriate for each DNSP to propose a suitable threshold/s in its connection policy based on technical considerations. For example, some of Ergon Energy's network has been constructed on the basis of 10 kVA per connection and not 25 kVA. If the AER adopts a fixed demand threshold, Ergon Energy supports the AER's preliminary view to allow DNSPs to nominate less developed areas of the network where a different threshold would be applied. Ergon Energy considers that it may be appropriate to use the same segmentation as the shared network augmentation charge to determine the different thresholds.

where a different threshold would be more appropriate. The AER seeks comments on its preliminary view that customers connected on SWER lines should pay for shared network augmentation on demand above 25kVA as the default level unless a different threshold is nominated by a DNSP and deemed appropriate by the AER.	Ergon Energy also notes that in developing a demand threshold, the Guideline should be formulated in such a way that prevents a single customer from artificially using multiple connection points (with lower demand) in order to remain below the stated shared network augmentation demand threshold.
The AER seeks comments on its preliminary view that it will be difficult to verify and enforce a customer's peak coincident demand and therefore the threshold should be a set based on peak demand.	As per Section 2.4 above, Ergon Energy prefers for this threshold to be set at 100 MWh per annum instead of using demand. That is, customers under 100 MWh per annum will not be charged for shared network augmentation. If the AER's proposal is adopted, Ergon Energy agrees with the AER's preliminary view that a threshold set based on peak demand is more appropriate than using a customer's peak coincident demand. Ergon Energy recognises that using a customer's peak coincident demand provides a greater opportunity to work with customers to shift their own peak demand time to reduce the coincidence of their demand with network peak demand in that area and hence lower the cost of augmentation. However, we believe that measuring peak coincident demand would be extremely difficult without significant investment in systems and processes. This is because Ergon Energy does not currently install meters that can measure coincident peak demand. To do so would be costly and impose ongoing administrative and compliance costs while only delivering a marginal benefit.
The AER seeks comments on its preliminary view that the approach outlined in ESCOSA's Guideline No. 13 is a fair and practicable approach for estimating peak demand that should be adopted.	Ergon Energy agrees the approach outlined in ESCOSA's Guideline No. 13 to estimate peak demand is reasonable. However, Ergon Energy believes determining a 'true-up' three years later is administratively burdensome, inefficient and costly for what will be, in all likelihood, a small rebate or even an additional charge to the customer. In particular, we have concerns that it will be difficult to determine an appropriate demand value given that the meters installed by Ergon Energy are an 'accumulation of usage' type and do not measure demand. In order to determine the actual demand, Ergon Energy will need to install a temporary interval meter at the premises, return a month later to read and remove the meter, calculate the demand and perform the adjustments in the system etc. However, as discussed above, Ergon Energy prefers for the threshold to be set at 100 MWh per annum instead of using demand.
The AER seeks comments on its preliminary view that a customer who is required to pay for shared network	As indicated in Section 2.4, Ergon Energy proposes to include an additional calculation in the cost-revenue-test (via the SNC component) which reduces future revenue for those

augmentation, would pay for shared network augmentation on the amount of their peak demand above the shared network augmentation threshold.	customers who are above the shared network augmentation threshold (i.e. greater than or equal to 100 MWh per annum) to fund their contribution to the shared network. If the peak demand approach is adopted, Ergon Energy agrees that a customer who is required to pay for shared network augmentation should pay for this on the amount of their peak demand above the shared network augmentation threshold.
The AER seeks comments on its proposal that embedded generators should fund specific network shared network augmentation to remove constraints on their outputs due to limits of the existing network.	Ergon Energy supports the AER's proposal that embedded generators (EGs) should fund their specific shared network augmentation as this sends a user-pays signal. Currently EGs are not charged any DUoS for the shared network but often cause upstream augmentation to enable their connection for which they make no payment. This proposal will ensure that EGs fund the cost of connecting their system to the network.
The AER seeks comments on: Should the AER place limits on the maximum amount of prepayment that a DNSP can charge the connecting customer? If so, should the AER specifically limit the amount of a prepayment to the actual upfront costs incurred by the DNSP, or should it set a maximum percentage?	Ergon Energy does not support the introduction of limits on the maximum amount of a prepayment that a DNSP can charge as this will unfairly place the risk on the DNSP instead of the customer. As an alternative, a DNSP should be allowed to determine the amount of a prepayment and seek agreement with the customer. This is because it might be in the DNSP's best interest from a commercial and credit risk perspective to request the full capital contribution amount as prepayment to ensure the customer is able to fully fund the connection. Further, for smaller connections, it might also be in the DNSP's best interest to receive full prepayment to limit administrative burden and costs involved. Ergon Energy currently applies a 40 per cent on acceptance and 60 per cent before construction policy to prepayments. This is a commercial decision to reduce the risk to the business. If a limit is set, Ergon Energy believes that continuing with our current policy is the most appropriate option.
The AER seeks comments on whether its connection guideline should have an option for DNSPs to implement security fee schemes.	Ergon Energy supports an option for DNSPs to implement security fee schemes as it is important to have penalties to recover unearned revenue when a connection agreement is terminated early. Ergon Energy currently applies this approach to large customers and we believe it would be appropriate to apply it to any customer with a high risk profile. Ergon Energy currently requests securities in the form of a bank guarantee. We believe that this practice should continue under the proposed security fee scheme. Bank guarantees do not attract interest, eliminating the administrative burden and complexity involved with redistribution that is inherent with cash deposits.

	Ergon Energy notes that the proposed security fee scheme relates to insuring the DNSP against the risk of failing to collect incremental revenue (DUoS). Ergon Energy supports this premise and believes that the proposed security fee scheme should not impede on current prudential requirements outlined in Part K of Chapter 6 of the Rules. This means the Guideline should not govern security arrangements between real estate developers and DNSPs where developers build assets and gift them to a DNSP. Ergon Energy has two such forms of security payable by developers – performance and retention securities[15]. These securities protect Ergon Energy in circumstances where a real estate developer: • fails to complete the work within an appropriate or agreed timeframe (performance security); or • completes the work to a standard which is not fit for purpose (retention security). The performance security is required to ensure that Ergon Energy does not carry the financial burden of undertaking the works (which would have been payable as a cash capital contribution or a non-cash capital contribution). It is payable if the developer requests a Certificate of Electrical Supply at any time prior to the completion of the electrical reticulation works. The retention security protects Ergon Energy by allowing us to cover the costs payable to fix an asset that is not fit for purpose (i.e. defective). Defects in electrical reticulation works cannot be covered by a warranty scheme since the assets cannot be returned nor can the installer return to fix any defect after the asset becomes part of the distribution system (since only suitably trained Ergon Energy employees or selected accredited contractors can perform works on an energised asset). Attempting to seek restitution from the real estate developer after the event is impractical as most development companies have a limited life and may not exist after the electrical installation is connected and a fault occurs.
The AER seeks comments on its proposed principles for a security fee scheme.	Ergon Energy supports the proposed security fee principles, subject to the Guideline specifying that interest is only payable when security is provided as a cash deposit and not other forms (e.g. a bank guarantee).
The AER seeks comments on its preliminary view that the	Ergon Energy supports the AER's preliminary position to allow DNSPs a high degree of

[15] Refer to Ergon Energy's Developers Handbook: Developer Design and Construct

assets subject to a rebate scheme should be depreciated over a 20 year return. The AER seeks comments on its preliminary view that a rebate scheme should have regard to the length of an extension and the capacity of the assets used by subsequent customers. The AER seeks comments on its preliminary view that a $500 refund threshold strikes an appropriate balance between a DNSPs' administrative costs and the materiality of a refund. The AER seeks comments on its preliminary view on customer payments when the network is built to a greater standard than a customer or group of customers would otherwise require, if the DNSP did not consider it more efficient to build the network to a greater standard based on forecast load growth. The AER seeks comments and alternative approaches to deal with the costs allocation issues where a DNSP provides a network extension on request of a single customer, to a standard greater than that customer requires due to the DNSP's network planning process.	flexibility in developing their own rebate scheme. This is particularly important given that many jurisdictions will already have some form of a rebate scheme in place. Ergon Energy notes that 20 years is an arbitrary figure which does not reflect the variance in asset lives across different asset types. However, Ergon Energy considers that it is not appropriate to base calculations on the actual depreciation of each asset as this is administratively burdensome and complex. As a result, Ergon Energy supports the AER's preliminary view that 20 years is appropriate. Ergon Energy believes that the AER should adopt a higher refund threshold than $500. This is due to the significant amount of administration work involved in administering the rebate scheme (e.g. calculating the rebate, invoicing, collecting the payment and paying the first customer). As per our key conventions in Section 2.4 above, Ergon Energy believes that customers should pay for the technical solution to connect them (i.e. extensions not shared network augmentation). However, if the DNSP, for its own purposes and not for technical reasons, builds to a standard greater than what is required by the customer, then the customer should only pay for their share.
The AER requests feedback on the completeness, consistency and adequacy of the proposed definitions. The AER seeks comment on whether stakeholders require clarification of any additional terms.	Please see comments above regarding consistency with the Rules and redefining direct connection assets.