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3 August 2009

Australian Energy Market Commission
AEMC Submissions
PO Box A2449
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Dear Sir / Madam

Review of Energy Market Frameworks in light of Climate Change Policies – 2nd Interim Report

Ergon Energy Corporation Ltd (Ergon Energy) welcomes the opportunity provided by the Australian Energy Market Commission to comment on its Review of Energy Market Frameworks in light of Climate Change Policies – 2nd Interim Report

The attached submission represents Ergon Energy's response to the 2nd Interim Report.

If you have any questions or require any further information on the matters raised please do not hesitate to contact me on (07) 3228 7711.

Yours sincerely

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Ergon Energy Corporation Limited
Ergon Energy Queensland Pty Ltd

Review of Energy Market Frameworks in light of Climate Change Policies – 2nd Interim Report – Submission

Australian Energy Market Commission

3 August 2009

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Submission

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This submission, which is available for publication, is made by:

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1 Introduction

Ergon Energy welcomes the opportunity to provide comment to the Australian Energy Market Commission (AEMC) on its 2nd Interim Report - Review of Energy Market Frameworks in light of Climate Change Policies (2nd Interim Report).

This submission is provided by:

- Ergon Energy Corporation Ltd (EECL), in its capacity as a distribution network service provider (DNSP) in Queensland; and

- Ergon Energy Queensland Pty Ltd (EEQ), in its capacity as a non-competing retail entity in Queensland.

In this submission, EECL and EEQ are collectively referred to as 'Ergon Energy'.

Ergon Energy has structured this submission in two parts:

Part 1: Identifies Ergon Energy's key issues with the 2nd Interim Report; and

Part 2: Provides detailed comment on relevant issues under the chapter headings in the 2nd Interim Report.

Ergon Energy would be pleased to discuss this submission with the AEMC and to provide further information should the AEMC require.

2 Key Issues

The following is a summary of Ergon Energy's key responses to the 2nd Interim Report:

- The proposed model does not take into consideration the existing connection and capital contribution policies of DNSPs. The proposal to create a new process to deal with new renewable generation connections will duplicate current processes within DNSPs;

- There is a fundamental inadequacy in the G-TUOS Scheme proposed by the AEMC. The proposed design potentially sees customers within a National Energy Market region paying for both the congestion charge (through wholesale energy prices) and for the eventual removal of the constraint (through transmission charges);

- The emergence of large numbers of small intermittent generation sources should continue to be monitored by the AEMC in its role as Rule Maker. Should the market develop in such a way that large numbers of small un-scheduled generation connect to distribution networks, there will be a need to review the existing frameworks to ensure the continuation of effective and secure system operation; and

- Ergon Energy supports the AEMC's comments in relation to regulated retail pricing arrangements, in particular, that flexibility and cost pass-through will need to be continued features of these arrangements in an environment of CPRS, expanded RET and other initiatives which increase upstream costs for retailers.

3 Connecting Remote Generation

AEMC draft recommendations to the MCE:

- ***That a new framework be introduced to the National Electricity Rules (NER) for the efficient connection of remote generation to distribution and transmission networks where clusters of generators in the same locations are expected to seek connection over a period of time. This new type of network service, and adjustments to the regime for planning, charging and revenue recovery would allow for Network Extensions for Remote Generation (NERG).***
- ***That under the new framework customers would underwrite the cost of any additional capacity in excess of the requirements of the first connecting generators that is forecast to be efficient.***
- ***That if there is a significant risk that Network Service Providers (NSPs) will not develop NERGs, their provision should be made contestable.***

Questions: Will the recommended model adequately address the deficiencies in the existing framework? Does the recommended assessment process appropriately balance customer risk with potential customer benefits? Is there merit in allowing rival service providers to deliver network extensions for remote generation?

2a Will the recommended model adequately address the deficiencies in the existing framework? 2b Does the recommended assessment process appropriately balance customer risk with potential customer benefits?

Ergon Energy queries whether the deficiencies identified by the AEMC as inherent in the current "model" actually exist. Like all DNSPs, Ergon Energy receives numerous applications to connect from new developments off-grid and on-grid, including sub-divisions and new large customers. It, like all DNSPs, has existing connection and capital contribution policies to ensure network users are treated fairly and costs are determined and charged on an equitable basis with a view to likely future connections in the same area. Other jurisdictions have their own connection and capital contribution policies that are relevant to their area of supply.

Ergon Energy is concerned that the proposed model does not take into consideration the policies already in place and in fact will be either duplicating or further complicating the current, efficient, processes, and suggests that the AEMC commence a process of understanding these policies and processes and incorporating them within the assessment of possible designs.

Ergon Energy notes that the proposed NERG model would only be implemented if the customer risk was minimal, that is, if the likelihood of further generator connections was high. In these cases, the capital expenditure would be considered prudent and efficient and DNSPs would size the network extension accordingly. This then negates the need for the model as proposed.

2c Is there merit in allowing rival service providers to deliver network extensions for remote generation?

Ergon Energy believes the provision of network extensions to a DNSP network by an alternative service provider for remote generation, is already sufficiently allowed for. In particular:

- The existing framework already allows for alternative service providers to deliver network extensions, provided that, if the assets are to be 'gifted' to the DNSP for ongoing ownership and maintenance, they are designed and constructed to the DNSP's standards; and

- The AER's decision in its Stage 1 Framework & Approach paper (to apply to Queensland DNSPs in the next regulatory control period (2010-15)) to classify the design and construction of large connection assets as alternative control service, was aimed at removing barriers to entry in the market, where they considered there was potential for competition to develop.

However, Ergon Energy notes if the proposed NERG model was implemented, the provision of network extensions by alternative (non-regulated) service providers becomes much more complex to manage from a revenue recovery perspective.

An alternative service provider has limited options for cost recovery, where they are required to build network connections to an 'efficient scale' to accommodate anticipated future connection. While the alternative service provider can collect a portion of its costs from the first connecting generator(s) (based on the share of assets used in the NERG by the generator(s)), the question remains, as to how the remainder of the costs are recovered by the alternative service provider.

While it may seem logical for the remaining costs to be transferred to the DNSP (for recovery from customers), Ergon Energy has noted the control mechanism to apply in the next regulatory control period (to apply from 2010) will limit Ergon Energy's ability to recover these costs from customers, meaning, the DNSP would be exposed to the remaining costs (and risks) of the NERG model. This is because in the NERG model, assets would be treated as contributed assets, which are excluded from the Regulatory Asset Base (RAB), and the costs for connection of the assets (collected via return on assets, and depreciation of assets) would not be able to be recovered through network tariffs under the revenue cap. Therefore, Ergon Energy would require some other method to recover such costs.

4 Efficient Utilisation and Provision of the Network

AEMC proposed recommendation to the MCE is that a transmission use of system charge be applied to all generators (G-TUOS). This charge would be:

- o ***Reflective of the forward looking long run incremental network costs at a particular location;***
- o ***Calculated as a fixed charge per kilowatt of generating capacity;***
- o ***Set on an annual basis;***
- o ***Revenue neutral in aggregate, implying positive and negative charges around an average charge of zero within each region.***

The AEMC is seeking stakeholder views on how generators should be grouped into zones and the most appropriate way to transition to the new arrangements. The AEMC is consulting on whether, in addition to a G-TUOS charge, a congestion pricing mechanism is required to manage short term congestion. The AEMC's current view is that, if warranted, the mechanism would be location-specific and time-limited. Key design features of such a mechanism would include:

- ***Geographic scope;***
- ***Duration;***
- ***Proportion of a generator's output exposed to the local nodal price;***
- ***Allocation of the supporting risk management instrument; and***
- ***Whether the mechanism applies to new generators only or all generators.***

Questions: Do you agree that we have accurately identified which elements of the existing framework are considered inadequate and therefore require change? Would the G-TUOS charging option design improve pricing signals to promote efficient location and retirement decisions in the most efficient way? Are there any design variations that may improve the signals? Given that G-TUOS is a preferred option, what additional value would a congestion pricing mechanism add? If such a mechanism is required, what design variations should be considered to improve signals to manage short term intra-regional congestion in the most efficient way?

Ergon Energy does not support the imposition of a G-TUOS Scheme as proposed by the AEMC. This is because the Scheme appears to involve transfers of money between generators based on congestion without reference to transmission activities to rectify the congestion.

At worst, the proposed design sees customers within a National Energy Market region paying for both the congestion charge (through wholesale energy prices) and for the eventual removal of the constraint (through transmission charges).

5 Regulated Retail Prices

AEMC are minded to recommend the following to the MCE:

By the time the CPRS commences all jurisdictions retaining retail price regulation should have developed an adjustment mechanism for energy and carbon related costs which:

- ***Can be invoked as frequently as six monthly subject to a cost change threshold;***
- ***Is symmetrical to allow adjustment for increasing or decreasing costs; and***
- ***Optimally can be initiated by retailers where costs are rising.***

The case for this additional flexibility is strongest if products enabling retailers to hedge carbon-inclusive energy cost risk do not emerge in the short to medium term. This is more likely in the initial years of the CPRS.

Questions: Do you agree that wholesale energy costs will be less certain, less able to be hedged and harder to forecast following the introduction of the CPRS? If jurisdictions and/or pricing regulators incorporate additional flexibility in pricing instruments, as set out in the recommended principles, does this sufficiently decrease the risks to retail competition and of retailer failure? Are existing regulatory approaches adequate to assess the cost to retailers of the expanded RET?

In relation to the first issue, Ergon Energy submits that:

- Until the precise nature of the CPRS is made clear, including what parties will be impacted and in what way, it will be impossible for retailers to adequately quantify the impacts of the CPRS on wholesale prices. All other things being equal, an additional charge on generators will lead to an increase in wholesale prices which will cause retail prices to rise – subject to the nature of retail price regulation in each jurisdiction. For Ergon Energy, which only offers electricity for sale to standard offer customers in Queensland for which prices are escalated in accordance with a Benchmark Retail Cost Index, the extent of pass-through of CPRS costs is a serious issue; and

- The ability to adequately hedge load is a function of the willingness of generators to enter into such contracts. Ergon Energy is not able to take a view on how difficult this may be under CPRS until more definitive information is available.

In relation to the second issue, Ergon Energy only offers electricity for sale to standard offer customers in Queensland for which prices are escalated in accordance with a Benchmark Retail Cost Index. The extent of pass-through of CPRS costs is therefore a serious issue and jurisdictional regulatory flexibility for these costs is fundamental.

In relation to the third issue, Ergon Energy notes that there is currently a review underway by the Queensland Government and the Queensland Competition Authority in relation to the current level and structures of retail tariffs. Ergon Energy is an active stakeholder to this review.

6 Generation Capacity in the Short Term

Our draft recommendation is that the reserve shortfall risk be addressed through a combination of:

- ***Facilitating more accurate reporting of demand side capability; and***
- ***Utilising the potential for distribution connection generation to help alleviate capacity shortfalls.***

We are also seeking stakeholders' views on the merits of a range of options in the form of short notice reserve contracting, load shedding management or longer term reserve procurement. At this stage, we are not taking a position on whether any of the options for more active reserve management should be pursued. We note that the AEMC Reliability Panel published an exposure draft package of changes to the Reliability and Emergency Reserve Trader (RERT) mechanism that seeks to increase its flexibility to operate at short notice. The Reliability Panel intends to submit a Rule change proposal and proposed Rule to the AEMC for implementation.

Questions: Is it the case that there can be commercial advantages in market participants not disclosing information about Demand Side Participation (DSP)? If so, what factors should we take into account in drawing out accurate information about the levels and firmness of DSP that market participants have contracted? Active load shedding management could mitigate the need for involuntary load shedding. Should we recommend this mechanism as part of our final advice to the MCE?

Ergon Energy is an active participant in assisting customers to engage in demand side participation. It has little evidence to support a view that customers are withholding information about participation.

Ergon Energy has no objections to the AEMC undertaking further investigations into active load shedding, where customers have explicitly agreed to participate. It does not, at this stage, support a recommendation in relation to this mechanism without further work being conducted.

7 Investment in Capacity to Meet Reliability Standards

The AEMC have concluded that energy market frameworks are robust in respect of delivering efficient levels and forms of capacity in the longer term in the NEM and that change to the framework is not required.

Questions:

Do you agree with our description and assessment of how the current framework operates, and our finding that the framework for the medium to long term is resilient to the stresses created by the CPRS and expanded RET?

Do you agree with our characterisation of the risks under existing frameworks, and how could they be managed or mitigated?

Ergon Energy considers that the current framework is resilient to the stresses created by CPRS and expanded RET. The existing framework provides signals to promote efficient levels of investment in transmission capacity, generation capacity and demand response, and can be expected to continue to operate in the long term interests of consumers, if those signals are appropriately maintained.

Ergon Energy notes that under CPRS and the expanded RET, the resultant increase in wind generation will lead to greater a need for fast response peaking generation. To ensure new entrant peaking plant enters the market it needs to be economically viable. This may require increases in the electricity spot market cap.

The AEMC should remain aware that an increase in the spot market cap may create risk exposure for electricity retailers and may potentially increase the price of caps in the interim, until more peaking plant becomes available. The AEMC should seek to encourage jurisdictional pricing regulators that any such changes in cost bases must be considered in the context of whether retailers are able to pass these costs on, within regulated retail tariff arrangements.

8 System Operation with Intermittent Generation

- ***Existing market frameworks do not need to be changed to maintain secure system operation in the context of large increases of intermittent generation.***
- ***In light of the importance of effective management of reactive power, we recommend that the network support and control services review commenced by NEMMCO be completed by the AEMO as soon as is practicable.***

Questions:

Is it necessary to create formalised centrally coordinated contracting arrangements for the provision of power system inertia? If so, what is the nature of the process by which those arrangements should be developed?

Is there adequate transparency in the process by which FCAS recruitment and interconnector capability is affected by the increasing penetration of intermittent generation?

Ergon Energy considers that the AEMC's finding that the existing market frameworks do not need to be changed to maintain secure system operation in the context of large increases of intermittent generation in respect of distribution networks may be premature. Ergon Energy considers that there continues to be a significant degree of uncertainty about how the market is likely to respond to the introduction of the CPRS and expanded RET.

Ergon Energy notes as a particular concern, the potential for the connection of large numbers of un-scheduled generators concentrated in certain parts of a distribution network to create significant network congestion, and congestion management issues. Under the current framework this would require a DNSP to augment the network for generation and require customers to pay for this augmentation, in circumstances where there may be little to no benefit to customers.

Ergon Energy considers that the development of the market in terms of large increases of intermittent generation should continue to be monitored. Should the market develop in such a way that large amounts of un-scheduled generation connects to distribution networks and creates congestion issues there will be a need to review the existing frameworks to ensure effective and secure system operation. Such a review should include consideration of the role of distribution network service providers in managing network congestion arising from generation and the appropriateness of existing thresholds for scheduling generation with the Australian Energy Market Operator.

9 Distribution Networks

There is likely to be a period of substantial change for distribution networks as a result of the CPRS and the expanded RET. Such change may impact on the costs of achieving service obligations for distribution businesses. We are minded to conclude that the framework is sufficiently robust to account for changes in expenditure and network operation imposed by the CPRS and expanded RET. There is a risk, however, that the response to change will not be efficient. Therefore, we are minded to recommend that further consideration be given to innovation funding for distribution businesses.

Questions:

Do you agree that the energy framework for distribution is able to manage the challenges imposed by the CPRS and expanded RET?

Is there merit in introducing formal, but temporary, arrangements to allow distribution businesses to recover the costs of accredited innovation projects?

Ergon Energy does not disagree that the current regulatory and legislative framework provides a sound basis for dealing with new exogenous shocks such as CPRS and the expanded RET. That notwithstanding, the AEMC is recommending serious and significant changes to the framework that, of themselves, could have subsequent impacts for market participants.

Ergon Energy supports careful and solution-oriented analysis of the existing framework, where the problems are carefully identified, options carefully weighted and stakeholder impacts taken into account. It cautions the AEMC from making wholesale changes to the framework that is in operation and which is inextricably linked to the operational arrangements of most participants.

Ergon Energy supports the introduction of formal arrangements to allow DNSPs to recover the costs of accredited innovation projects which enable them to respond efficiently to challenges imposed by the CPRS and expanded RET. Ergon Energy notes that the proposed arrangements could potentially operate to clarify that the existing framework specifically accommodates innovative programs and investments. With the respect to the timeframe for providing funding, the proposed arrangements should, at a minimum, clearly define the length of time that the particular investment is covered at the time of project approval.

Ergon Energy strongly supports the arrangements governing the funding being subject to further consultation with stakeholders.