SUBMISSION TO AUSTRALIAN ENERGY REGULATOR'S

PRELIMINARY POSITIONS FRAMEWORK AND APPROACH PAPER

6 March 2009

Table of Contents

1 Executive summary

CitiPower and Powercor Australia (the **businesses**) wish to raise a number of issues and propose a number of changes to the positions put forward by the Australian Energy Regulator (**AER**) in its *Preliminary Positions, Framework and Approach Paper, CitiPower, Powercor, Jemena, SP AusNet and United Energy, 2011-2015* (**Preliminary Framework and Approach Paper**).

The following summarises CitiPower's and Powercor Australia's views. These are described more fully in the body of the document.

1.1 Classification of services

The businesses consider the service activity *elective underground service where an existing overhead service exists* should be defined as a quoted service rather than a fee based service on the basis the nature of service does not lend itself to a fixed charge.

It is unclear from the Preliminary Framework and Approach Paper how the AER intends to classify new connections involving only the provision a service cable and meter as opposed to new connections involving broader augmentation. Currently these services are classified as fixed excluded charges, however it appears these services are to be classified by the AER as negotiated distribution services. The businesses believe these services are better classified as alternate control services due to predictable and consistent nature of the service involved.

1.2 Control mechanisms

CitiPower and Powercor Australia support a Weighted Average Price Cap (**WAPC**) form of price control proposed for standard control services. The businesses however also seek confirmation the AER intends to retain the L factor within the price control calculation.

CitiPower and Powercor Australia support in principle the AER's proposed individual price cap form of price control for alternative control services. However, the businesses are concerned that the AER's basis of control may not be effective and seek further clarification as to the AER's methodology for updating the control.

The AER has proposed that price caps for the individual prices of alternative control services will be established based on the requirements set out in the Essential Service Commission of Victoria's (**ESC**) *Guideline No.14, Electricity Industry – Provision of Services by Electricity Distributors* (**Guideline 14**). Whist the principles espoused in Guideline 14 are reasonable, their application in practice has been more contentious. The ESC has failed to provide any form of escalation (other than for the Goods and Services Tax) since 1996, resulting in both businesses failing to recover the full costs associated with the provision of a number of these services.

CitiPower and Powercor Australia propose that the basis of control for alternative control services should involve a top down assessment to establish the individual price caps for alternative control services in order for the AER to be assured that the charges reflect efficient costs, and the businesses are able to recover those efficient costs.

1.3 Service target performance incentive scheme

The Preliminary Framework and Approach Paper propose to apply the Service Target Performance Incentive Scheme (**STPIS**) outlined in the *STPIS Distribution Guideline* (**STPIS Guideline**).

Since the release of the Preliminary Framework and Approach Paper, the AER has released an amended STPIS. The AER has stated that any amendments to the STPIS Guideline will be finalised prior to May 2009. Submissions on the amended STPIS are due on March 2009.

CitiPower and Powercor Australia are currently considering the amended STPIS and will comment specifically on these amendments in response to the consultation process for the amended STPIS.

1.4 Efficiency benefit sharing scheme

The AER propose to apply the Efficiency Benefit Sharing Scheme (**EBSS**) outlined in *Electricity Distribution Network Service Providers Efficiency Benefits Sharing Scheme* (**EBSS Guideline**).

CitiPower and Powercor Australia accept the AER's proposed EBSS for the Victorian distributors.

1.5 Demand management incentive scheme

CitiPower and Powercor Australia have no issue with the AER implementing the Demand Management Incentive Scheme (**DMIS**) outlined in the *Proposed Demand Management Incentive Scheme CitiPower, Powercor, Jemena, SP AusNet and United Energy Regulatory Control Period commencing 1 January 2011* (**DMIS Guideline**). However, the businesses seek clarification over how the AER intends to factor in the foregone revenue into a price cap form of control.

1.6 Cost pass through

The Preliminary Framework and Approach Paper does not address pass through items.

CitiPower and Powercor Australia consider that clarity over events considered pass-through is essential for the businesses to be able to determine their future expenditure requirements. A clear understanding of these matters will assist not only distributors but also the AER.

CitiPower and Powercor Australia propose that the Final Framework and Approach Paper set out the AER's approach as to whether the following events will be deemed pass-through events:

- the financial failure of a retailer;
- a declared retailer of last resort event;
- a force majeure event;
- an emissions trading scheme event; and
- a transfer of non-pricing distribution functions event.

2 Control mechanisms

The section addresses the form of price control as it relates to prescribed distribution services and alternate control services.

2.1 Control mechanism to apply for distribution services

The AER has proposed retaining a WAPC for standard control services. CitiPower and Powercor Australia support the retention of a WAPC form of control for standard control services.

CitiPower and Powercor Australia are also seeking clarification the AER intends to retain pass through of licence fees in the form of an L factor. The ESC included an L factor into the price control formula for prescribed distribution services. The ESC required the distributors provide documentation regarding the payment of the licence fees that they are passing through in the L-factor. The price control formula and the L factor formula are detailed on pages 467 and 468 of the *Electricity Distribution Price Review 2006-10.*

2.2 Control mechanism to apply for alternative control services

The AER has proposed to apply a price cap form of control for alternative control services.

CitiPower and Powercor Australia have no in principle objection to the AER's proposed form of control for alternative control services. However, the businesses require further clarification as to the AER's approach to the basis of control and how the AER intends to determine the individual price caps for these services. In particular, the businesses are concerned that the approach to assessing the basis of control may not allow the businesses to recover the costs of associated with providing alternative control services.

In the Preliminary Framework and Approach Paper, the AER have proposed that the basis of control for alternative control services will be established using a method akin to the current method set out by the ESC in the EDPR 2006-2010, which in turn currently requires the information set out in the Guideline 14.

Whilst the principles in Guideline 14 are reasonable, their application can be contentious. The AER notes in section 3.3.1.3 of the Preliminary Framework and Approach Paper that the EDPR 2006-2010 provides that distributors can apply for revisions to the charges at any time, but in practice no revisions have occurred since 1996 (except for the application of GST). The businesses have made a number of applications for revisions of alternative service charges over the past two regulatory periods. Separate applications were made for some or all charges in 2001, 2002, 2004 and 2006. In each of these cases the ESC dismissed the applications on the basis sufficient information was not available for it to make an assessment.

The failure to provide for any form of escalation has resulted in both businesses failing to recover the costs associated with the provision of excluded services. Even for public lighting, where the ESC has approved some increases to charges, the increases were not sufficient to allow the businesses to recover the efficient costs associated with providing those services. Tables 1 and 2 illustrate how CitiPower has not been recovering the costs it incurs in total for excluded services for 2006 and 2007 respectively. Tables 3 and 4 demonstrate similar trends for Powercor Australia.

Activity	Direct costs	Indirect costs	Revenue	Margin

	($'000)	($'000)	($'000)	($'000)
New connections	1,927	309	1,134	-1,102
Connections	2,169	189	2,214	-144
Underground services at request of third party	0	0	0	0
Metering – excluded services	1,198	387	317	-1,268
Public Lighting	3,752	633	2,337	-2,048
Other excluded services	2,176	412	1,966	-622
Total excluded services	**11,222**	**1,930**	**7,908**	**-5,244**

Source: CitiPower Regulatory Accounts for the year ended 31 December 2006 p. 29.
Note: Costs incurred in relation to the AMI project were allocated in 2006 to excluded services. A total of $410,000 was incurred in relation to the AMI project. 80 percent of this cost was allocated to Metering – Excluded Services and 20 percent to Connections – Excluded Services.

Table 1 CitiPower regulatory accounting statement excluded services 2006

Activity	Direct costs ($'000)	Indirect costs ($'000)	Revenue ($'000)	Margin ($'000)
New connections	1,981	422	1,025	-1,378
Connections	2,871	127	2,332	-666
Underground services at request of third party	0	0	0	0
Metering – excluded services	1,130	50	351	-829
Public Lighting	3,728	681	2,363	-2,046
Other excluded services	2,006	352	2,125	-585
Total excluded services	**11,717**	**1,631**	**8,196**	**-5,152**

Source: CitiPower Regulatory Accounts for the year ended 31 December 2007 p 29.
Note: Costs incurred due to AMI were allocated to prescribed services in 2007.

Table 2 CitiPower regulatory accounting statement excluded services 2007

Activity	Direct costs ($'000)	Indirect costs ($'000)	Revenue ($'000)	Margin ($'000)
New connections	4,348	768	3,604	-1,512
Connections	2,564	359	2,436	-487
Underground services at request of third party	0	0	0	0
Metering – excluded services	561	1,027	187	-1,401
Public Lighting	4,666	696	4,606	-756
Other excluded services	7,751	652	8,818	-451
Total excluded services	**19,888**	**3,501**	**19,650**	**-3,739**

Source: Powercor Regulatory Accounts for the year ended 31 December 2006 p 31
Note: Costs incurred in relation to the AMI project were allocated in 2006 to excluded services. A total of $1,213,000 was incurred in relation to the AMI project. 80 percent of this cost was allocated to Metering – Excluded Services and 20 percent to Connections – Excluded Services.

Table 3 Powercor Australia regulatory accounting statement excluded services 2006

Activity	Direct costs ($'000)	Indirect costs ($'000)	Revenue ($'000)	Margin ($'000)
New connections	4,073	729	3,476	-606
Connections	3,222	112	2,699	-635
Underground services at request of third party	0	0	0	0
Metering – excluded services	262	9	194	-77
Public Lighting	5,746	743	4,744	-1,745
Other excluded services	8,127	402	8,934	405
Total excluded services	**21,431**	**1995**	**20,048**	**-3,378**

Source: Powercor Regulatory Accounts for the year ended 31 December 2007 (Inclusive of Related Party Margins) p.g 31.

Note: Costs incurred due to AMI were allocated to prescribed services in 2007.

Table 4 Powercor Australia Regulatory Accounting Statement Excluded Services 2007

The most robust and relatively simple way to ensure that price caps for alternative control services are set in a way that is reflective of efficient costs is to conduct a top down assessment based on the information presented in the Tables 1-4. A top down assessment would use the Audited Regulatory Accounts to establish an initial price cap for each alternative control service that could then be escalated for each year during the regulatory control period. The businesses would propose a price for each alternative control service and then undertake a top down assessment to verify that the revenue that will be raised by applying that price will not exceed the businesses' costs.

A top down assessment would not reconcile costs and revenues down to the individual charges (there are over 30 charges) but will do so down to the regulatory account classification of services, as outlined in Tables 1-4. Reconciling costs down to this classification of services will be sufficient to establish individual price caps for each alternative control service and verify that those price caps do not allow the businesses to recover more than their efficient costs of providing those services.

The advantages of a top down assessment include:

- for the purposes of setting the initial price caps, information is not required regarding the volume of services, only revenues and costs;
- the absence of cross subsidies between direct control services or unregulated activities (and between different categories of direct control services) is easily verifiable;
- the use of relatively consistent trends (at least over the current regulatory period);
- the approach is relatively simple; and
- the avoidance of cherry picking.

In deciding on a control mechanism for alternative control services, the AER must have regard to the possible effects of the control mechanisms on the administrative costs of the AER, distributors, users and potential users (see clause 6.2.5(d)(2) of the NER). A top down assessment will minimise the administrative costs of the AER, distributors, users and potential users.

The administrative costs of the AER and distributors for a top down assessment will be significantly lower than the costs of undertaking a process similar to Guideline 14. A

Guideline 14 process would require the DNSPs to provide, and the AER to review and assess, a large amount of detailed information in order to set the price cap for each individual service. The administrative costs of undertaking such a process for every individual alternative control service would be disproportionate to the benefits of such a process, especially given that many of these services generate relatively small amounts of revenue. A top down assessment would involve significantly lower administrative costs because most of the required information is already available in the Audited Regulatory Accounts.

Although clause 6.2.5(d)(3) of the NER requires the AER to have regard to the previous regulatory arrangements applicable to the relevant service, that is only one factor that is relevant to the AER's decision on the appropriate control mechanism. There is no presumption that the AER should adopt the control mechanism under the previous regulatory arrangements, and the businesses consider that the other relevant factors discussed above show that a departure from the previous regulatory arrangements is warranted in this instance.

2.3 Approaches to assessing charges for public lighting services

The AER has proposed to assess the efficient costs of the operation, repair, replacement and maintenance of public lighting assets under the price cap control mechanism through the use of a limited building block approach.

CitiPower and Powercor Australia are satisfied in principle with the AER's proposed form of control for public lighting services however believe clarification is required as to what constitutes a limited building block approach i.e. is it building blocks without an efficiency benefit sharing scheme carry over amount or is it something else?

2.3.1 Operating expenditure

The current approach to developing operating, maintenance and repair prices for public lighting services is based on benchmark modelling. This approach has resulted in losses (see Tables 1-4) predominantly due to the lack of annual revision in the benchmark components and the setting of inappropriate benchmarks.

CitiPower and Powercor Australia consider the best approach to determine efficient costs is to conduct a top down assessment to set the initial price, that are then escalated each year during the regulatory control period. This approach is the same as the approach proposed above in relation to the other alternative control services, and the reasons for this approach are also the same as for those other services.

This approach of annual escalation is also consistent with the AER's *New South Wales Draft Decision* which provides that subsequent years' charges are to be calculated by multiplying the first year's schedule of charges by an appropriate escalation.[1]

2.3.2 Capital expenditure

The capital component of public lighting is made up entirely of replacement assets that the distribution business funds at the end of the public light's life.

[1] AER, *Draft Decision New South Wales Draft Distribution Determination 2009-10 to 2013-14*, November 2009, p.g. 339.

The AER has proposed to base its opening asset valuation for existing public lighting assets on the existing asset valuation, adjusted for additions, disposals and depreciation in the current regulatory control period.

CitiPower and Powercor Australia are satisfied in principle with this approach and propose to use a building block approach based on forecast capital expenditure. However, the businesses do require clarification from the AER over what 'efficiency adjustments for capital expenditure' will entail.

3 Classification of distribution services

CitiPower and Powercor Australia are generally satisfied with the AER's proposed classification of services for the Victorian distributors. However, the businesses consider the service activity, *elective underground service where an existing overhead service exists*, should be defined as a quoted service within the alternative control services classification. The AER proposes in the Preliminary Framework and Approach Paper to classify this service as a fee based alternative control service.

The Preliminary Framework and Approach Paper states that fee based services 'are generally homogenous in nature and scope and therefore their costs can be estimated with reasonable certainty'. That is not an accurate description of the *elective underground service where an existing overhead service exists.* The cost for this service can be very variable depending for example on the location of the site, the terrain and how deep the underground line needs to be located. A quoted service is a more preferable approach as a fee based charge does not accommodate the variability in costs.

CitiPower and Powercor Australia note the AER has referred to *emergency recoverable works* but not *non-emergency based recoverable works*. Non-emergency recoverable works should be separated and included as a quoted alternative control service or negotiated service.

It is also noted the Preliminary Framework and Approach classifies *connection and augmentation works for new connections* as a negotiated distribution service. While this classification is consistent in cases where augmentation of the network is required, it is not so for instances where only a service cable/meter are required. In the case of a service cable/meter only new connection, the customer is levied a fixed excluded service charge. The businesses would argue the services associated with a service cable/meter new connection are generally homogenous in nature and scope and therefore the costs can be estimated with reasonable certainty. On this basis the connection and augmentation works for new connections category should be separated with the service cable/meter new connection service being classified as an alternate control service.

4 Service target performance incentive scheme

In its Preliminary Framework and Approach Paper the AER proposes to apply the STPIS outlined in the AER's *Electricity Distribution Network Service Providers Service Target Performance Incentive Scheme* (**STPIS Guideline**).

Since the release of the Preliminary Framework and Approach Paper the AER has released an amended STPIS. The AER has stated that the amended STPIS will be finalised prior to the release of the Final Framework and Approach Paper in May 2009. Submissions are due on the amended STPIS in March 2009.

The amended STPIS involves a number of key changes to the scheme, including:

- *amended s-factor calculation*: The AER proposes to amend the method by which the S-factor is calculated. The S-factor calculation in the first version of the STPIS was determined on the basis of changes in performance from one year to the next. The AER has altered the S-factor equation so that the S-factor is determined on the basis of the difference between performance relative to the target.

- *amended cap on revenue at risk*: The AER also proposes to increase the amount of revenue at risk under the scheme from 3 percent to 5 percent.

- *amended major event day calculation*: The AER proposes to amend how it calculates the major event day threshold which applies to events excluded from the scheme.

- *amended value of customer reliability (**VCR**) values*: The AER proposes to update the VCR values to align these with the most recent VENCorp study. The VCR used to determine incentive rates is for the CBD segment, $95,700/MWh and for all other parameter segments $47,850/MWh.

The businesses are currently considering the amended STPIS and will comment specifically on the key changes to the scheme during the consultation process for the proposed amended STPIS.

5 Efficiency benefit sharing scheme

The Preliminary Framework and Approach Paper propose to apply the EBSS outlined in the AER's *Electricity Distribution Network Service Providers Efficiency Benefit Sharing Scheme (June 2008)* (**EBSS Guideline**). CitiPower and Powercor Australia are satisfied with the AER implementing the EBSS outlined in the AER's *EBSS Guideline*, subject to the two comments below.

5.1 Base year

The *EBSS Guideline* provides for the EBSS to operate with forecast operating expenditure based on either the penultimate or antepenultimate regulatory years of the regulatory control period. The AER notes that regardless of whether the antepenultimate or penultimate year actual operating expenditure is used as the base year, the penultimate year actual operating expenditure is required to calculate carryover amounts.

CitiPower and Powercor Australia will be providing an operating expenditure forecast based on the penultimate year. The penultimate year must be adopted as the base year if the AER is using the penultimate year as the efficiency carry over. If the AER decides to use the antepenultimate year as the base year, it will potentially dilute the sharing ratio implicit in the EBSS. This is because maintenance of the sharing ratio is dependent on the same base year being used to establish operating costs for the next regulatory period and calculate the EBSS.

5.2 Adjustments for 'uncontrollable events'

The *EBSS Guideline* states that *'the forecast opex must be adjusted for the cost consequences of any differences between forecast and actual demand growth…. These adjustments must be made using the same relationship between growth and expenditure used in establishing the forecast opex.'*[2] The implications for 2006-10 EBSS are that:

- the AER will adjust the operating expenditure benchmarks using the methodology set out by the ESC; and
- there will be no consideration of other 'uncontrollable' adjustments.

The 2006-10 EDPR Final Decision sets out the ESC's views as to how future adjustments should be made to 2006-10 EBSS calculations to account for growth:

Growth adjustment = 0.431(log natural change in customer numbers) + 0.272*(log natural change in peak demand) + 0.296*(log natural change in consumption)*[3]

It was intended that the growth adjustment be applied to the base operating expenditure benchmarks and not to the approved step changes.

In terms of the EBSS for 2011-15, it is open to the businesses to propose an alternative adjustment mechanism that includes revised weightings or additional parameters.

CitiPower and Powercor Australia intend to submit these revisions or adjustments as part of their Regulatory Proposals.

---

[2] AER, *Electricity Distribution Network Service Providers Efficiency Benefit Sharing Scheme*, June 2008, pg. 6.

[3] ESC, *Electricity Distribution Price Review 2006-10, Final Decision Volume 1 Statement of Purpose and Reasons,* October 2005, p.g. 212.

6 Demand management incentive scheme

In the Preliminary Framework and Approach Paper the AER proposes to apply the DMIS outlined in the AER's *Proposed Demand Management Incentive Scheme CitiPower, Powercor, Jemena, SP AusNet and United Energy Regulatory Control Period Commencing 1 January 2011* (**Proposed DMIS Guideline**).

CitiPower and Powercor Australia have no issue with the AER implementing the DMIS outlined in the Proposed DMIS Guideline. However, the businesses seek clarification over how the AER intends to factor in the foregone revenue into a price cap form of control.

7 Cost pass through

The Preliminary Framework and Approach Paper did not address the issue of cost pass throughs.

The AER stated in the *Final Framework and Approach Paper, Application of Schemes Energex and Ergon Energy 2010-15 (Ergon and Energy Australia F&A paper)* that it was inappropriate to make an indication on additional (nominated) pass through events given that it is required to make its decision at the time of making its distribution determination.[4]

The NER does not impose any limitations on the AER indicating its likely approach to nominated pass through events in the *Final Framework & Approach Paper*. Clause 6.8.1(b)(5) of the NER gives the AER a broad power to set out in the *Final Framework and Approach Paper* the AER's likely approach to 'any other matter on which the AER thinks fit to give an indication of its likely approach'.

CitiPower and Powercor Australia consider, as endorsed by the AER in the *Ergon and Energy Australia F&A paper,* that the framework and approach paper is a document targeted at providing information to the DNSPs on the AER's likely approach to certain matters so that they are able to prepare their regulatory proposals.[5] One of the matters that CitiPower and Powercor Australia are required to include in their Regulatory Proposals is a proposed pass-through clause with a proposal as to the events that should be defined as pass-through events.[6]

CitiPower and Powercor Australia consider that clarity over events considered pass-through is important for the businesses in order to manage its risk exposure over the next regulatory period. In determining its future expenditure requirements, the businesses will need to determine which risks can be managed through a pass through arrangements and which risks it will be required to manage within its expenditure allowance. A clear understanding of these matters will assist not only distributors but also the AER.

7.1 Pass through provisions

CitiPower and Powercor Australia propose that the following events should be nominated by the AER as pass-through events for the 2011-15 regulatory control period, in addition to those events defined in Chapter 10 of the NER:

- the financial failure of a retailer;
- a declared retailer of last resort event;
- a force majeure event;
- an emissions trading scheme event; and
- a transfer of non-pricing distribution functions event.

[4] AER, *Final Framework and Approach Paper Application of Schemes Energex and Ergon Energy 2010-15,* November 2008, p.g. 55.

[5] Ibid, p.g. 57.

[6] NER, clause 6.1.3(2)

CitiPower and Powercor Australia request the AER give consideration to the including the following events as cost pass throughs.

7.1.1 Financial failure of a retailer

The ESC allowed for the pass through of a financial failure of a retailer in the EDPR 2006-10. The pass through item was intended to cover the difference between the credit support provided by the retailer and the actual loss. At the time of the EDPR 2006-10 final determination, the retailer was required to meet certain creditworthiness standards. The standards were set out in default *Use of System Agreement* between the retailers and distributors. The minimum standard was either an investment grade rating or a bank or parent company guarantee for 3 months of distribution charges.

The credit support required by the retailer was substantially reduced by the ESC in its *Final Decision, Credit Support Arrangements*, *October 2006*. The retailer is now required to only provide credit support to a distributor when the amount of the retailer's average billed and unbilled Distribution Service Charges liability exceeds its Credit Allowance.[7]

In practice this means the retailers are now allowed to develop such a sizeable debt before a distributor is able to ask for credit support, that it is probable they would be under financial distress and as a consequence unable to provide credit support.

CitiPower and Powercor Australia consider that the low levels of credit support required to be provided by retailers means that a pass-through for the event of a financial failure of a retailer is crucial.

7.1.2 Retailer of last resort

The ESC allowed for the pass through of a declared retailer of last resort event in the EDPR 2006-10 decision.

If a retailer of last resort (**ROLR**) event is triggered, specified procedures are enacted including those for the transfer of customers of the failed retailer of last resort. In such an event, distributors may incur additional administrative costs in transferring customers from the failed retailer to the retailer of last resort due to the transfer of a significant number of customers over a short period of time. These costs include manually updating our internal databases and the MSATs system (which is a NEMMCO managed database that deals with customer transfer).

In light of these costs, which fall outside the distributors' control, the ESC allowed distributors to apply for a pass through for the incremental costs that arise from a 'declared' ROLR event, where these are material and cannot be recovered through another mechanism.[8]

CitiPower and Powercor Australia consider that the pass through of a declared retailer of last resort event that remains just as relevant for the 2011-15 regulatory control period.

---

[7] ESC, *Credit Support Arrangements, Final Decision*, October 2006

[8] ESC, *Electricity Distribution Price Review 2006-10, Final Decision Volume 1 Statement of Purpose and Reasons*, p.g. 488.

7.1.3 Force majeure

The AER accepted a 'force majeure' event as a nominated pass-through event for the New South Wales (**NSW**) distributors in the *NSW Draft Distribution Determination 2009-10 to 2013-14* (**NSW Draft Decision**). The AER defined a force majeure event as 'Any major fire, flood, earthquake, storm or other weather–related or natural disaster, act of God, riot, civil disorder, rebellion or other similar cause beyond the control of the DNSP (but excluding any insurable events – that is, those events for which external insurance or self insurance is feasible) that occurs during the next regulatory control period and materially changes the costs to the DNSP of providing direct control services.'[9]

A force majeure event is uncontrollable and often difficult to cover with insurance (either externally or through self insurance).

CitiPower and Powercor Australia consider that a 'force majeure' event is an event that is applicable to all DNSPs. The AER considered for the NSW distributors that passing through the costs of a force majeure event meets the AER's assessment criteria and therefore it accepted a force majeure event as a nominated pass through event. It should accept the same for Victoria.

7.1.4 Emissions trading scheme

The AER rejected an 'emissions trading scheme event' for the NSW distributors in the NSW draft decision.

An emissions trading scheme is an event which results in the imposition of legal obligations on CitiPower and Powercor Australia arising from the introduction or operation of a carbon emissions trading scheme by the Commonwealth Government (**Commonwealth**) during the course of the regulatory control period and which:

- falls within no existing category of pass through event; and
- materially increases the costs of CitiPower and Powercor providing the direct control services.

The AER rejected the proposed 'emissions trading scheme event' in the NSW Draft Decision on the grounds that this event and several of the other proposed pass-through events 'are likely to be regulatory change events and therefore it considers that separate nominated events are unnecessary.'[10]

CitiPower and Powercor Australia request the AER to re-consider the issue of an 'emissions trading scheme event' and set out in the Final Framework and Approach Paper the AER's likely approach to whether it will nominate this event as an additional pass-through event for CitiPower and Powercor Australia.

CitiPower and Powercor Australia consider the event satisfies the AER's criteria set out in the NSW Draft Decision. CitiPower and Powercor also consider that it is unclear whether or not the event is captured by the 'regulatory change event' definition. As a result of the uncertainty regarding the application of that definition, the businesses are seeking certainty in

[9] AER, *NSW Draft Distribution Determination 2009-10 to 2013-14, 21* November 2008, p.g. 286-287.

[10] AER, *NSW Draft Distribution Determination 2009-10 to 2013-14, 21* November 2008, p.g. 281.

respect of this event by proposing it as an additional pass-through event for inclusion in the distribution determination.

The uncertainty regarding whether this event is covered by the definition of a 'regulatory change event' can be summarised as follows:

- the definition of 'regulatory change event' in Chapter 10 of the NER only covers a change in a 'regulatory obligation or requirement';
- the relevant part of the definition of a 'regulatory obligation or requirement' in the National Electricity Law only covers an obligation or requirement under 'an Act of a participating jurisdiction' or an instrument made under or for the purposes of such an Act';
- an 'emissions trading scheme event' will therefore only be covered as a regulatory change event if the emissions trading scheme is imposed by or under an Act of a participating jurisdiction;
- an 'emissions trading scheme event' relates to an obligation that is imposed by the Commonwealth and it is unclear whether the Commonwealth is a 'participating jurisdiction' for these purposes because:
  - the definition of 'participating jurisdiction' in the National Electricity Law provides that the Commonwealth is only a participating jurisdiction if 'there is in force, as part of the law of that jurisdiction, a law that corresponds to Part 2 of the *National Electricity (South Australia) Act 1996*' (the SA Act);
  - the *Energy Market Act 2004* of the Commonwealth (the Commonwealth Act) contains provisions that are substantively similar to the SA Act, but the Commonwealth Act only applies in certain parts of the Commonwealth and in certain circumstances; and
  - it is therefore unclear whether the Commonwealth Act meets the requirements of the 'participating jurisdiction' definition for these purposes.

If the Commonwealth is not a 'participating jurisdiction' for these purposes, then an emissions trading scheme event will not come within the definition of a 'regulatory change event' and will only be a pass-through event if it is nominated by the AER as an additional pass-through event.

CitiPower and Powercor Australia are happy to provide further information regarding these concerns about the interpretation of the relevant definitions if it would assist the AER.

This issue has similarities to the 'retail project event' that was accepted by the AER in the NSW Draft Decision.[11] The NSW 'retail project event' related to the possible privatisation of NSW electricity retail businesses. While that privatisation seems to be exactly the type of uncontrollable event that should be a regulatory change event, the AER accepted that privatisation was likely to occur as a result of an administrative decision of the NSW Government and that therefore it would not meet the requirements of the 'regulatory change event' definition.

[11] AER, *NSW Draft Distribution Determination 2009-10 to 2013-14, 21* November 2008, p.g. 280.

The proposed 'emissions trading scheme event' is similar in that it would be a 'regulatory change event' if the scheme was introduced by Victorian legislation, but it appears more likely that the scheme will be introduced by the Commonwealth and it is therefore unclear whether it will meet the 'regulatory change event' definition.

The legal mechanism by which the scheme is introduced clearly should not affect whether the costs associated with the scheme are a pass-through event. It would therefore greatly assist certainty and ensure that a sensible outcome is reached if the AER nominated an 'emissions trading scheme event' as an additional pass-through event.

7.1.5 Transfer of non-pricing distribution functions

CitiPower and Powercor Australia propose a pass-through for the 'transfer of non-pricing distribution functions event' as an additional pass-through event.

A 'transfer of non-pricing distribution functions event' is an event which results in the transfer of non-pricing distribution functions to a national framework, which:

- occurs during the regulatory control period;
- falls within no other category of pass through event; and
- materially increases the costs of CitiPower and Powercor providing the direct control services.

The AER rejected a 'functional change event' as a nominated pass-through event for the NSW distributors. CitiPower and Powercor Australia understand that the intended application of this 'functional change event' was similar to the scope of the proposed 'transfer of non-pricing distribution functions event', although the definition of the 'functional change event' was much broader than CitiPower and Powercor Australia's proposed definition.

Integral Energy's Regulatory Proposal stated that its 'functional change event' is intended to ensure that any changes in its obligations that occurs during the transfer of non-pricing distribution functions to the national framework and has a material effect on its costs of providing direct control services are treated as 'pass-through events'.[12]

The AER stated that it was concerned by the broad nature of the pass through events proposed by the NSW distributors.[13] CitiPower and Powercor Australia do not consider the transfer of non-pricing distribution functions to the national framework as a 'broad natured event' but a specific event and the costs incurred by that event are quantifiable.

CitiPower and Powercor Australia's proposed definition of the 'transfer of non-pricing distribution functions event' is much narrower and more specific than that proposed by New South Wales distributors. In particular, CitiPower and Powercor Australia's proposed definition only applies to a transfer of non-pricing distribution functions to a national framework. In contrast, Integral Energy's definition covered any event which imposes new obligations or changes the nature of the existing obligations on Integral Energy.

[12] Integral Energy, *Integral Energy's Regulatory Proposal to the Australian Energy Regulator 2009-2014*, 2 June 2008, p.g. 189

[13] AER, *NSW Draft Distribution Determination 2009-10 to 2013-14, 21* November 2008, p.g. 281.

CitiPower and Powercor Australia consider that the proposed definition of a 'transfer of non-pricing distribution functions event' satisfies the AER's criteria set out in the NSW Draft Decision:

- there is uncertainty as to whether the event is captured by the defined event definitions (this issue is discussed further below);
- the event is clearly identified in the proposed definition;
- the event is uncontrollable;
- the timing and cost impact of the event could not be reasonably forecast;
- the event is not already insured for;
- the event cannot be self-insured;
- the distributor is not the party who is in the best position to manage the risk, because it has no control over the risk; and
- pass-through would not undermine the incentive arrangements within the regulatory regime.

It is possible that the transfer of non-pricing distribution functions could be a 'regulatory change event'. However, whether a transfer of functions comes within the definition of a regulatory change event will depend on how the transfer is effected. The transfer will only be a 'regulatory change event' if it is a change in a regulatory obligation or requirement that is imposed by an Act of a participating jurisdiction, or is imposed under or pursuant to such an Act.

As with the NSW 'retail project event' and the proposed 'emissions trading scheme event', it is unclear whether the requirements of the 'regulatory change event' definition will be met. A transfer of functions is likely to be a regulatory change event if that transfer is effected by enacting or amending Victorian legislation. However, a transfer of functions may not be a regulatory change event if it is effected by other means, such as an administrative decision or Commonwealth legislation. It would therefore assist certainty if the AER nominated a 'transfer of non-pricing distribution functions' as an additional pass-through event.

There are many examples of the transfer of non-pricing distribution functions to the national framework. Currently, the Ministerial Energy Council (**MCE**) is assessing the transfer of non-pricing distribution functions to the national framework which will effect for example existing codes and guidelines such as the *Electricity Distribution Code* and the ESC's *Electricity Industry Guideline 14 Provision of Services by Electricity Distributors*.