SP AusNet™
A member of Singapore Power Group

8 December 2011

John Pierce
Chairman
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Dear John,

Economic Regulation of Network Service Providers / Price and Revenue Regulation of Gas Services / Calculation of Return on Debt for Electricity Network Businesses Rule Change Proposals

SP AusNet welcomes the opportunity to make this submission in response to the AEMC's Consultation Paper on the following consolidated Rule Change Proposals:

- National Electricity Amendment (Economic regulation of network service providers) Rule 2011
- National Gas Amendment (Price and revenue regulation of gas services) Rule 2011
- Calculation of Return on Debt for Electricity Network Businesses Rule 2011

SP AusNet endorses the industry association submissions made by the Energy Networks Association (ENA) and Grid Australia.

SP AusNet's exposure to each of the industry specific arrangements gives it a distinctive perspective on the relative operations of the regime over the current regulatory review cycle – Chapter 6A of the National Electricity Rules applying to its transmission network, Chapter 6 applying to its electricity distribution network and the National Gas Rules applying to its gas distribution network. In that light, this submission provides views and perspectives in addition to those provided in the industry association submissions.

In particular, SP AusNet strongly questions whether there are fundamental problems with the effectively operating national regulatory regime in Victoria.

SP AusNet would also emphasise the important linkage between the Rules and the current Merits Review. This submission assumes the Merits Review is retained in scope and form. If either these were modified as a result of the review to be undertaken at MCE level during 2012, then the company's positions may change. The decision making of the AEMC should also be informed by this MCE review as appropriate solutions may change dramatically in light of changes to the National Electricity and Gas Laws in this area.

SPI Electricity Pty Ltd ABN 91 064 651 118
A subsidiary of SP Australia Networks (Distribution) Pty Ltd
Level 31, 2 Southbank Boulevard Southbank Victoria 3006 Australia Locked Bag 14051 Melbourne City Mail Centre Victoria 8001 Australia
Tel 61 3 9695 6000 Fax 61 3 9695 6666 www.sp-ausnet.com.au

If you have further questions regarding the information provided, please contact Alistair Parker, Director Regulation and Network Strategy on 03 9695 6090.

Yours Sincerely,

Charles Popple
General Manager Network Strategy and Development

1. Overview

The Rule change proponents have not provided sufficient persuasive evidence to justify the basic proposition that the current regulatory framework requires fundamental change. In particular, the AER provides little evidence for their underlying propositions. For example:

- The AER propose that the cost of capital setting process in gas and electricity distribution should be constrained and removed from an independent merits review process. However, the evidence shows that:
  - The flexibility has been used by both the AER and Network Service Providers (NSPs) to successfully deal with the ongoing or dissipating effects of the Global financial Crisis (GFC); and
  - Independent merits review has allowed gross errors of fact to be corrected.
- They raise concerns that the methodology for setting the Debt Risk Premium post the GFC leads to an inflated overall return. However, this ignores the ample evidence showing an equal but opposite problem created for equity returns post the GFC. Considered as a whole, no evidence is advanced that the overall return on capital is inflated.
- The AER raise concerns about incentives to overspend capital expenditure allowances but:
  - No evidence is provided that NSPs under the current regulatory framework are overspending their regulatory allowances. Interestingly, the evidence advanced by the AER for overspending occurred under the previous state based regimes; and
  - The AER has made no use of its existing explicit discretion to strengthen the capital expenditure incentive regime.
- The AER raise concerns that their ability to modify proposed expenditure allowances and the techniques that can be used is constrained. However, the evidence shows:
  - Expenditure cuts under the new regime have been at least as substantial as those under the previous state based regimes;
  - Decisions contain extensive use of techniques they claim they are unable use under the current Rules.

With respect to the five specific areas where the AER has proposed changes, the following high level observations on these issues are made:

- Many of the identified issues can be addressed in the existing framework without requiring changes to the rules and indeed the AER has not exercised some existing mechanisms;

- Many of the process issues are of the AER's making rather than inherent in the framework itself;

- Many of the legitimate but more minor issues can be fixed with relatively straightforward adjustments to the Rules without the need for wholesale change; and

- The return on capital issues have arisen as a result of an extremely rare but large exogenous shock from the global financial crises. This highlights the need for flexible arrangements that provide additional protections for long term investors.

These issues are addressed in detail in the following sections of this submission and the industry association submissions.

1.1. Structure of the submission

SP AusNet's response addresses the AEMC's questions outlined in its *Consultation Paper on the National Electricity Amendment (Economic regulation of network service providers) Rule 2011 and National Gas Amendment (Price and revenue regulation of gas services) Rule 2011* (AER Rule change proposal). Section 2 addresses the high level proposition underlying the comprehensive AER Rule change proposal – that the current regime as set out in the Chapters 6 and 6A requires fundamental change. Further sections then address the five specific areas where the AER has proposed changes:

- Determination of the WACC (Section 3);

- Debt risk premium (Section 4), this sections also addresses the Energy Users Rule Change Committee (EURCC) *Calculation of Return on Debt for Electricity Network Businesses Rule change proposal*;

- Capital expenditure incentives (Section 5);

- Operating and capital expenditure forecasts (Section 6); and

- Regulatory decision-making process (Section 7).

A conclusion is provided in Section 8.

2. The extent of the problems as characterised by the AER

SP AusNet does not agree with the basic premise of the AER rule change – that the current regime as set out in the Chapters 6 and 6A requires fundamental change:

- Firstly, major contributing factors to the price rises do not appear to be related to the current Rules nor are they solvable by changes to the current Rules; and

- Secondly, this is supported by the fact that the large network related price rises are observed to be limited to electricity and to NSW and Queensland.

These points are elaborated below.

2.1. Is the problem related to the Rules?

Three factors are acknowledged by industry, regulators and customers to be contributing considerable upward pressure on network prices in electricity:

- Aging assets;
- Demand growth; and
- Government imposts

The existence of these issues is not controversial (although the appropriate network response is debated during a review), as the AER states in its Rule change proposal:

> *"Recent increases in network charges have been driven in part by the need for increased investment to replace ageing assets and to meet increased peak demand, growing customer connections and higher reliability standards."*[1]

SP AusNet's experience of these factors is summarised below to illustrate that they are independent of the Rules and, therefore, cannot be mitigated by Rule changes.

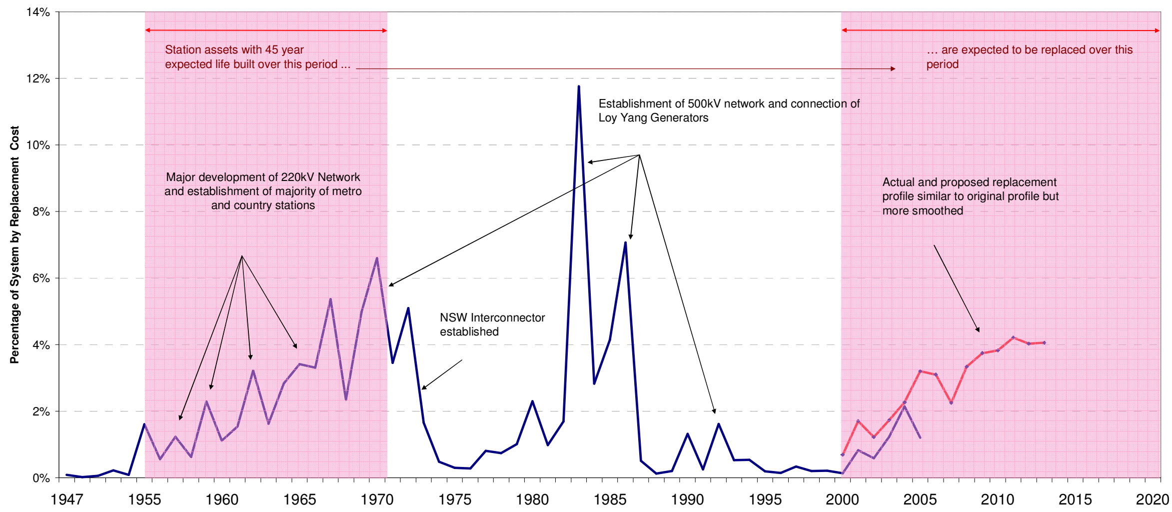
However, despite these universal pressures, there are differences observed between the jurisdictional network pricing outcomes. This leads to the obvious question of why the differences are being observed and are these related to the Rules? The answer to this question is addressed below.

2.1.1. Aging assets

The Australian electricity industry is universally faced with an asset replacement wave associated with the history of the network development, in particular, the major system development that took place between 1950 and 1970. For example, the figure below illustrates that the increases in replacement capital expenditure in SP AusNet's transmission network broadly mirror the pattern of network development from 50 years ago.

[1] AER, *Economic regulation of transmission and distribution network service providers*, September 2011, Part A and B, page 6.

Figure 1: Relationship between system development and replacement



Source: SP AusNet

2.1.2. Increasing demand

The northern, eastern and south eastern growth corridors of Melbourne are situated in SP AusNet's distribution area. As such, demand growth and customer connection growth associated with Victoria's population and economic growth impact heavily on SP AusNet's network. Compounding this, demand associated with new housing developments tends to be relatively peaky due to the high and increasing penetration of air conditioning (cooling). This leads to a peak demand on SP AusNet's distribution network that has been growing at the rate of 6.7% per year, considerably faster than energy consumption.

The increasing peakiness of network demand means costs are rising far more quickly than the number of customers or energy consumed, resulting in increasing average prices.

The long term solution is to provide appropriate price signals to customers to reduce the peak and, therefore, associated investment in the network. While SP AusNet has implemented dynamic demand price signalling for its industrial customers, it is subject to a Victorian Government moratorium on the introduction of time of use tariffs on residential and small commercial customers.

This issue, crucial to the long term moderation of network costs, is not addressed by the AER's proposed rule changes.

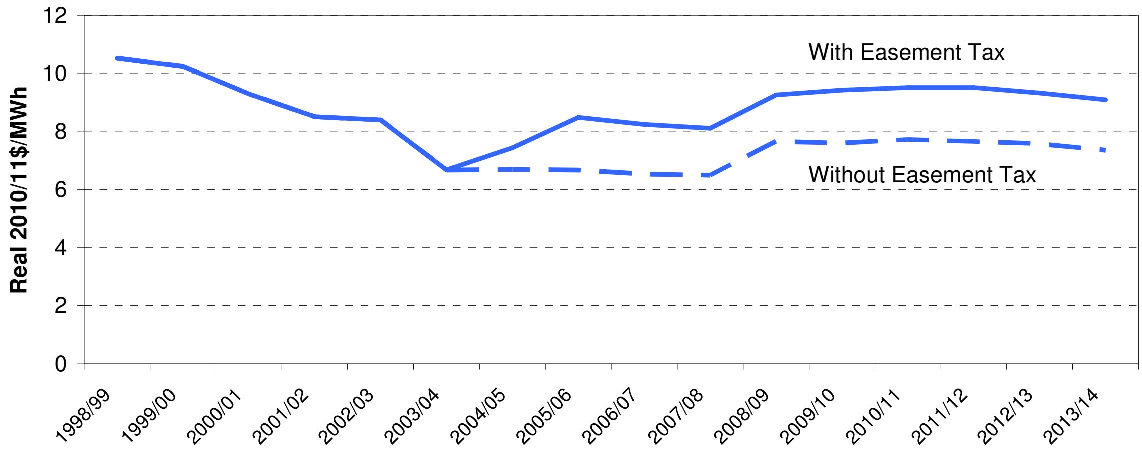
2.1.3. Government policies

The impact of Government policies is not transparent to customers. Government policies impose significant costs that appear as network costs on electricity bills and yet are not caused by the networks themselves. For example, in Victoria:

- SP AusNet's transmission costs have decreased by around 25% in real terms since privatisation, however, this has been swamped by the imposition of the $90 million easement land tax in 2004 (see figure below).

- The cross-subsidy by all electricity customers of PV solar cell installation under the Victorian Premium Feed-in Tariff Scheme, achieved through network charges, is forecast to increase SP AusNet distribution charges by $18 million in 2011.

Figure 2: SP AusNet – real regulated transmission revenue per MWh



Source: SP AusNet

2.2. Is the problem widespread?

Despite the universal nature of the issues highlighted above, which are present to varying degrees in each jurisdiction, materially different price outcomes have been historically observed and are projected to continue. For example, the AER commentary on the drivers for higher prices highlights this fact clearly (emphasis added).

> *"The increasing cost of electricity network services is expected to continue to affect overall electricity prices. The AEMC has noted that the increasing cost of distribution services alone are expected to contribute around 41 per cent of the total increase in electricity prices (at a national level) between 2009–10 and 2012–13. Transmission costs will contribute a further 8 per cent of the expected total increase.* ***With the exception of Victoria****, network charges will account for a significant proportion of expected price increases, with the effects particularly pronounced in NSW and Queensland."*[2]

The Victorian DNSPs commissioned analysis from Ernst and Young on the historic contribution of network charges to the total bill in NSW, Queensland and Victoria over the period 1996 to 2010.[3] The analysis contained in the report shows that network charges have not been a contributing factor to rising energy prices in Victoria. Attachment 1 to this submission contains analysis on this issue from a diverse range of sources. The Ernst and Young report is also attached to this submission.

Two key factors that are driving these different price outcomes can be highlighted:

[2] AER, *Economic regulation of transmission and distribution network service providers*, September 2011, Part A and B, page 6.
[3] Ernst and Young, *Victorian Electricity prices 1996-2010: the contribution of network costs*, 2011.

- Firstly, the existence of probabilistic planning standards in Victoria. This encourages the transparent incorporation of the Value of Customer Reliability into planning decisions while allowing businesses appropriate flexibility when assessing the cost/reliability trade offs; and

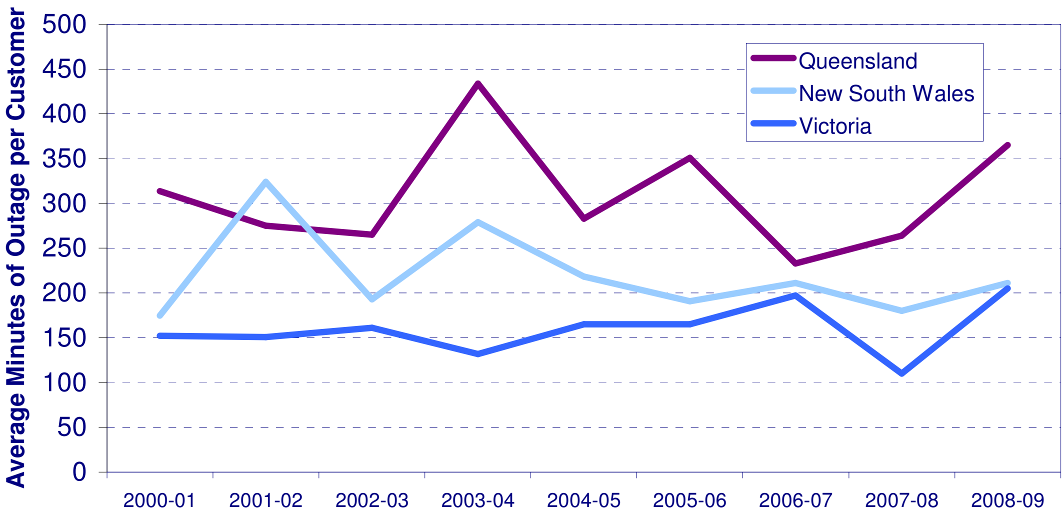
- Secondly, the private ownership of network businesses in Victoria which ensures the full force of incentives regimes put in place under the Rules are responded to effectively.

In combination these should allow the incentive regimes for efficiency and service standards implemented by the AER under the current Rules framework to be broadly effective. The evidence of lower costs and better reliability in Victoria strongly suggests this is the case. This was acknowledged by the AER in the most recent Victorian EDPR Final Decision:

> *"Overall, this trend analysis together with comparative benchmarking of Victorian DNSPs against DNSPs in other jurisdictions suggests that the Victorian DNSPs compare favourably from an efficiency perspective to those in other states. Thus the revealed costs of the Victorian DNSPs are a sound base for determining the starting point for evaluating the efficiency and prudency of their regulatory proposals.*
>
> *In addition, the Victorian DNSPs have maintained relatively high standards of service, in terms of reliability of supply compared to other jurisdictions."*[4]

Figure 3 below illustrates that balanced incentive regimes put in place under the Victorian Jurisdictional arrangements and largely retained and improved under the current national Rules have ensured reliability has not been sacrificed as costs have been driven down.

Figure 3: Network reliability



Source: AER State of the Energy Market Reports, Vic adjusted to be consistent with Qld and NSW (ie large exogenous events excluded – cyclones, large storms and bushfires)

[4] AER *Final Decision, Victorian DNSP Price Review 2011-15*, overview, page ii.

Again, the issue of jurisdictional reliability standards and ownership are not determined under the current rules or addressed by the proposed fundamental changes advanced by the AER.

3. Determination of the WACC

The AER proposal is that the three WACC frameworks should be converged to one based on the existing Chapter 6A Rules. This process does not allow the flexibility inherent in Chapter 6 of the NER and Gas Rules. The AER proposal claims that this convergence is desirable because:

- There is little justification for having different arrangements in electricity distribution, transmission and gas as there are no industry specific considerations;
- Under the Chapter 6 and Gas frameworks, DNSPs and gas pipelines, as well as the AER are in continual 'WACC review' mode, since there is scope to challenge parameter values at every price reset;
- The incentives for DNSPs to challenge AER determinations of WACC parameters has resulted in Tribunal reviews involving a "spurious" level of precision; and
- Where the AER has undertaken a thorough review and made a decision that reflects views of all stakeholders, it remains open for DNSPs to cherry-pick those components they consider unfavourable, detracting from AER's ability to consider the overall rate of return.

In response, SP AusNet endorses the industry submissions from the ENA and Grid Australia. These note, in particular, that:

- Standard approaches for setting the WACC failed during the GFC, and experience has shown that a 'safety valve' that permits departures from inputs or methods in a WACC Statement is essential to cope with such events;
- The AER's proposal to bring forward the review of the Statement could not address GFC type issues;
- If the proposed WACC Statement is binding, the problems experienced with setting the cost of debt during the GFC that the AER has sought to remedy with its Rule change would be likely to remain;
- The framework in Chapter 6 provides a mechanism to accommodate GFC type events; and
- It is incongruous that errors cannot be remedied for transmission businesses.

In addition, given the unique position of having a network regulated under each of the current WACC regimes, SP AusNet would make the following additional observations.

3.1. Experience under each regime

The transmission network had its WACC set under the original Chapter 6A Rules in its last revenue decision in February 2008. Therefore, SP AusNet was lucky to avoid the fall out from the onset of the GFC post the Lehman's collapse that caused the well documented and litigated problems in the NSW/Tasmania revenue reset processes. While an acceptable fix was found for that situation, the AER has subsequently closed that avenue for flexibility in the selection of the sample period in its current WACC Statement of regulatory Intent (SORI). This highlights that the rigid transmission WACC regime can result in a highly unfavourable outcome for a business, particularly for the allowed return on equity, while offering no remedy to the affected business from regulatory action (which is completely constrained). This regime potentially leaves a network with insufficient revenues to fund its operations and this situation cannot satisfy the NEO in the extreme circumstances exemplified by the GFC.

Therefore, SP AusNet does not consider the Chapter 6A WACC regime provides the necessary certainty for private investors in the Australian utility sector.

In contrast, SP AusNet has found the Gas and Chapter 6 Rules provide the necessary flexibility to debate and deal with financial events like the GFC. These experiences do not lead to an obvious preference between the two as both have advantages in certain situations. However, it should be observed that the Gas regime provides additional flexibility with respect to the framework used to measure equity returns as the particular form of the CAPM prescribed in the NER has problems with measuring the return on equity accurately under extreme financial conditions.

3.2. Use of the flexibility in the regime

The ability to depart from the existing SORI provides:

- An opportunity to correct clear errors of fact in the SORI;
- An invaluable source of flexibility for the regulator and businesses when facing 'black swan' events such as the global financial crisis.

The ability to correct errors of fact in a Decision should be an uncontroversial part of any well designed regulatory regime and is not commented upon further.

The flexibility inherent in the electricity distribution and gas rules has been utilised by both the AER and the industry to deal with GFC effects, illustrating the symmetrical and balanced nature of that flexibility. For example:

- The NSW Electricity DNSPs have successfully argued to change their sample period for setting their risk fee rate and Debt Risk Premium (DRP) away from periods heavily disrupted by the GFC; while
- The AER has recently lowered the value of the Market Risk Premium after alleging the GFC effects on the cost of equity have dissipated.

3.3. Continual reviews

Contrary to the impression given by the AER proposal, most contested WACC issues have been settled once and not been subjected to continual appeals. For example, the gamma has in effect been appealed once (in SA), settled and applied by the AER in subsequent Decisions and has not been the subject of continual appeals.[5]

The exception to this has been the DRP. The problems with continual appeals in this area have been caused by a combination of:

- Uncertainty as to how to interpret the current DRP Rule after the disruption of debt markets during the onset of the GFC;
- The AER not following the directions of previous Australian Competition Tribunal Decisions making in their own subsequent Decisions;
- The AER making simple but fundamental errors of fact, such as not annualising data in the 2010 Victorian Distribution Decision (conceded by the AER).

Importantly the Rules setting out the DRP methodology are not subject to the WACC process and, therefore, the problems encountered, self-inflicted or not, cannot be ascribed to the Chapter 6 WACC SORI setting framework.

4. Debt Risk Premium

The AER Rule proposal amends matters that may be the subject of a review of WACC parameters to include the debt risk premium while also providing for largely unfettered discretion with regards to setting the DRP methodology. The AER claims this is desirable to address the problem caused by the current Rules where:

- The AER must refer to a benchmark corporate bond rate that was problematic to measure during and after the GFC when the market for long-dated bonds was highly limited;
- The debate around an appropriate alternative proxy results in merits review processes focussing on technical arguments around the appropriate choice of data to satisfy the benchmark definition rather than how best to achieve outcomes that are in the long-term interests of consumers; and
- Results in setting the DRP at levels considerably above the networks' current actual cost of borrowing.

SP AusNet agrees with the AER, that the GFC has presented problems with regards to estimating the value of the DRP in light of the current definition in the Rules. However, it is important to observe that:

[5] The process for implementation can give the appearance of further material appeals. For example, the appeal in the Victorian Jurisdiction was initiated simply to access the yet to be determined SA appeal outcome, it was not seeking to re-litigate issues that had been previously appealed.

- The GFC has presented difficulties with many other WACC parameters and methodologies not least by materially supressing the estimation of the cost of equity; and

- The flexibility associated with the electricity distribution and gas WACC frameworks actually facilitates rather than compromises the achievement of the national electricity objectives in the face of unusual financial events.

Therefore, SP AusNet endorses the industry association submissions' proposed alternatives to solving the problems highlighted by the AER which provide for the desired level of flexibility to deal with GFC type events while also providing the long term certainty around returns that are crucial to attracting finance for long lived assets.

4.1. Cost of equity

Problems with measuring the DRP have received a very high profile in both the AER and EURCC proposals yet just as serious problems have been created on the cost of equity side of the return equation.

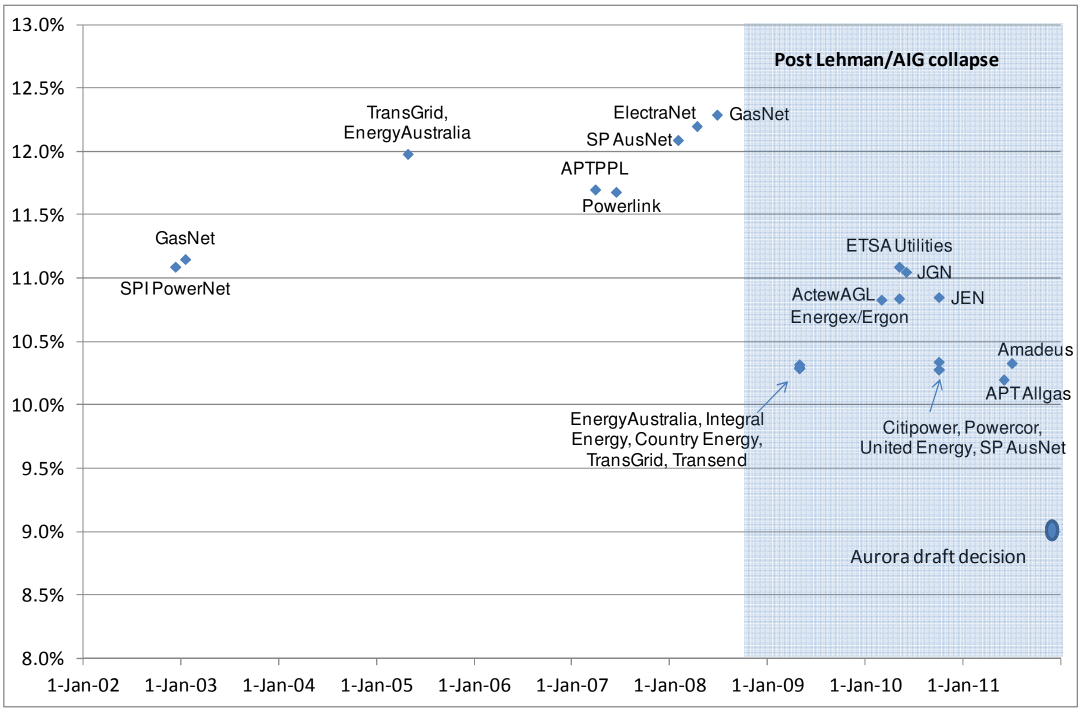
For example, the current cost of equity embedded in current regulatory decisions does not reflect the true cost of equity faced by private NSPs. This is because:

- An equity premium is set using a 100 year average (~6.0%) yet ex-ante measures of the short run MRP were in the twenties during the middle of the crisis and are still above 8%; and

- The risk free rate is suppressed from flight to quality effect caused by the ongoing issues in the Euro Area as investors demand Australian government bonds as an alternative to assets deemed as more risky (such as Greek debt).

Perversely, the AER's regulatory Decisions have been cutting the total return on equity allowed despite equity costs increasing post the GFC. The figure below shows the cost of equity embedded in regulatory Decisions before and after the onset of the GFC.

Figure 4: Cost of equity in ACCC/AER Decisions over time



Source: ACCC and AER Final and Draft Decisions (EA, Integral county Energy, TransGrid and Transend Decision overturned on appeal)

Therefore, it is highly unlikely that NSPs are being overcompensated when the effects of the GFC on the current WACC frameworks calculation of **both** the cost of debt and equity are looked at in combination. Neither the AER nor the EURCC have advanced any evidence that the overall return on assets is inflated.

4.2. EURCC Rule change proposal

SP AusNet welcomes the constructive contribution by the Energy Users Association of Australia on the issue of the DRP and hope this heralds a new era of sophisticated engagement by customer groups as envisaged by the framers of the current framework. In particular, they have provided extensive evidence and analysis on the problems the GFC has created in the existing regulatory regime in this area. This is in contrast to lack of evidence accompanying the AER Rule change proposal.

While SP AusNet has concerns with the detail of the rule change, the fundamental methodological change to a backward focused measurement of the DRP is worthy of serious consideration. However, SP AusNet would caution that such a change should not be advanced as a panacea to price rises as is implied by the EURCC. For example, while an immediate change to the methodology would lower the embedded DRP for SP AusNet's electricity distribution network (by replacing the spot rate DRP with a long term average), the same change would increase the embedded DRP in its transmission and gas distribution networks as their decisions currently have an embedded DRP that is below the current cost of debt.

With regards to concerns with the proposed EURCC approach, two important issues should be highlighted at this stage.

Firstly the rule change does not account for the actual debt raising practices of the private businesses, therefore, unless modified, it is unlikely to allow a reasonable opportunity for an NSP to recover efficient costs.

It is worth revisiting actual debt raising practices of Australian utilities at this point. It is impractical for an NSP to refinance their entire existing debt portfolio and raise new finance for future investment in the price review debt pricing window. Therefore, an NSP will maintain a portfolio of debt of varying maturity to minimise this refinancing risk. The majority of this debt is issued either as floating rate debt or fixed rate debt that is immediately swapped to floating rate at the longer maturity end. This is supported by the evidence in the EURCC Rule change proposal.

> *"Since 1998 Australian Utilities (as defined by Bloomberg) have issued 69 bonds with an average size of $204m, average term of 12 years and average coupon of 6%."*[6]

However, this mismatch between cost of debt of the debt portfolio and the cost of debt calculated in the price review debt pricing window exposes the NSP to interest rate and credit margin risk (also referred to as debt margin risk). The NSP manages this risk to an acceptable level by entering into fixed rate swaps at the time of the price review debt pricing window. This hedges the interest rate risk but leaves the NSP carrying the credit margin risk – this risk cannot be hedged. It is the credit margin risk, not the DRP or debt costs in their entirety, that has been difficult to measure post the GFC.

Therefore, at any point in time, the NSP's total cost of debt will be the sum of the risk free rate and the margin to swap as hedged at the time of the debt pricing window and the fixed credit margin being the ten year debt margin over swap established at the time of issuing the debt. It is the last component that is determined at the the time the debt is issued and cannot be varied subsequently.

The regulatory regime provides an allowance for the NSP's cost of debt of the risk free rate and the margin to swap as hedged at the time of the price review debt pricing window and the spot fixed credit margin at the time of the debt pricing window.

As such, it is the later cost alone (credit margin risk) that creates the potential mismatch between the price review allowance and the NSP's underlying costs of debt (not the total cost of debt).

The benchmark should be aligned with the debt raising practices of Australian utilities, therefore, SP AusNet considers that the credit margin should be the focus of any change to the DRP methodology rather than the total cost of debt.

Secondly, the EURCC analysis of the costs associated with the term to maturity of debt is in error. This arises because the supporting Cambridge Economic Policy Associates (CEPA) report[7] appears unaware of debt cost implications of confusing the remaining term

[6] EURCC, Proposal to change the NER in respect of the calculation of the return on debt, page 13.
[7] Cambridge Economic Policy Associates, *Rule Change Sub-committee of the EURCC Estimating the Debt Margin*, October 2011.

to maturity with the term to maturity at issue of debt portfolio. This confusion can be illustrated using a simple example.

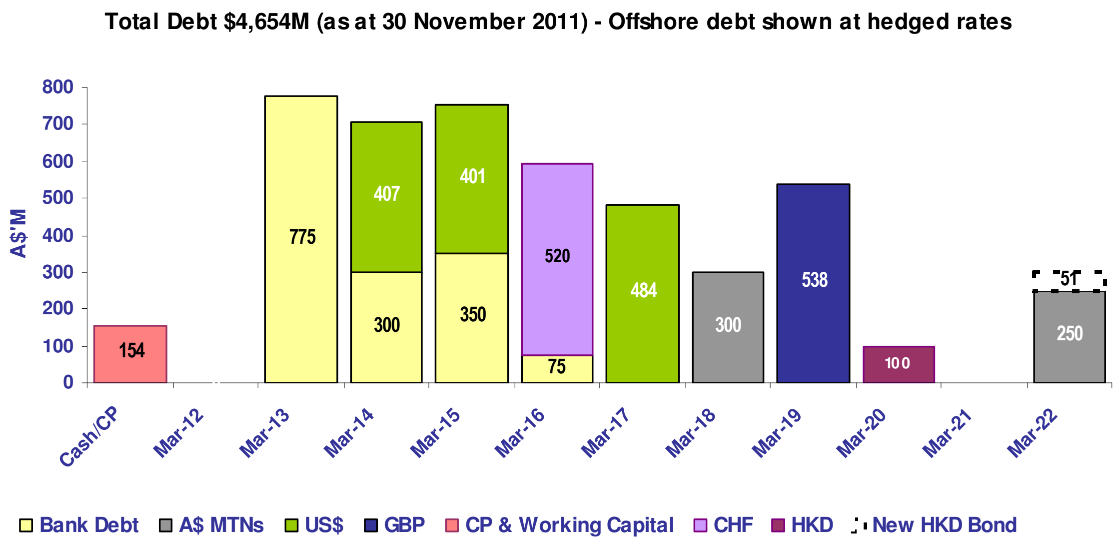
Assume a NSP refinances around 10 per cent of its debt annually (which is aligned with actual debt raising practice). To maintain this approach over time it must issue debt of ten year to maturity incurring the credit margin associated with issuing 10 year debt. However, at any point in time the average remaining term to maturity will be 5 years. The CEPA paper implies that as the NSP has an average remaining term to maturity of around five years they are incurring credit margins associated with issuing 5 year debt. This is clearly an error of fact.

The evidence presented in the CEPA paper actually supports this contention. For example, figure 4.2 in the paper shows the maturity profile of SP AusNet in early 2011.[8] SP AusNet provides the updated version of its maturity profile in the Figure below.

The EURCC rule change proposal, therefore, assumes incorrectly, an efficient NSP would refinance 20% of its debt portfolio a year incurring the DRP associated with 5 year debt. In fact, it is impractical for a NSP to turn over this proportion of its debt portfolio every year and maintain an investment grade credit rating because of the disproportionate and inefficient refinancing risk this would incur.

Again, the benchmark should be aligned with the debt raising practices of Australian utilities, therefore, SP AusNet considers that if a backwards looking approach was adopted the DRP should be based on 10 year average and assume 10 year debt is being issued.

Figure 5: Maturity profile for SP AusNet (November 2011)



Source: SP AusNet.

There are, nonetheless, several positives in the EURCC proposed rule, in particular:

[8] Ibid, page 16.

- Properly calculated (see above discussion), the backward looking approach allows a NSP a reasonable opportunity to recover the debt component of it efficient costs and manage its risk;
- It maintains the benchmark concept providing an incentive to private NSP to minimise their debt portfolio costs;
- It enshrines Australian corporate bonds as the benchmark;
- It retains flexibility and predictability in the face of changing market conditions; and
- The proposed calculation is transparent relative to the AER proposal.

Therefore, SP AusNet considers a preferable rule would have to combine the above principles in a methodology that calculated an average over the previous ten years, rather than five, and based on a credit margin for ten year debt not five.

Formulating such a Rule would be complicated and would require much more detailed input than included here.

5. Capital expenditure incentives

AER proposes to introduce a requirement that, to the extent total capital expenditure exceeds the total forecast capital expenditure, only 60 per cent of that expenditure is to be included in the RAB. To offset some of the risk from the introduction of this approach in distribution it is proposed that capital expenditure contingent project provisions and reopener provisions are introduced (aligning with the transmission framework). Finally, amounts of related party margins and capitalised overheads that are inconsistent with the manner in which any allowance for those amounts was determined in the AER's Decision are not to be included in the RAB. The AER claims the proposed changes address:

- Insufficiently strong incentives to ensure that only efficient investment occurs – particularly where the regulated cost of capital is higher than the actual cost of capital for the NSP; and
- Incentives created under the current RAB roll-forward mechanism for NSPs to incur more than efficient levels of capital expenditure in some circumstances, particularly in the latter stages of the control period (ie. there is no continuous incentive rate).

SP AusNet agrees with the AER that there are flaws in the current capital expenditure efficiency regime in electricity. However, it does not consider the proposed solution meets the National Electricity Objective, the Revenue and Pricing Principles in the National Electricity Law and the criteria the AER has to have regard to when setting an efficiency benefit sharing scheme under the existing Rules. This is addressed in detail in the industry association submissions.

In addition the following observations are made:

- The AER's solution does not fix the identified problems, in that it does not provide a continuous incentive across time or provide an equally strong incentive to reduce expenditure below the approved allowance even though these are equally valuable to customers.

- The AER's solution does not fix other identified problems in the regime such as, the strength of the incentive varying with asset life and allowing flexibility to balance the different incentives operating in the regime.

- The AER has had clear powers to introduce a redesigned, strengthened or brand new capital expenditure incentive regime under Chapter 6 of the NER and yet the existing tools to fix the deficiencies with the existing schemes lie unused.

Nonetheless, SP AusNet strongly supports the application of incentive regimes, therefore, would welcome the extension of discretion under Chapter 6 to design capital expenditure efficiency schemes to Chapter 6A.

6. Operating and capital expenditure forecasts

AER proposes that they determine the total forecasts for operating and capital expenditure considered to meet the efficient costs that a prudent network service provider would require to meet the objectives in the Rules. This would include removing:

- The requirement to accept forecasts of operating and capital expenditure where the forecasts reasonably reflect the criteria in the Rules;

- The requirement to determine the substitute amount or value for forecast expenditure on the basis of the NSP's proposals and to only amend forecasts to the extent necessary for those forecasts to be approved under the Rules (distribution only).

The AER claims this is desirable to correct a regime that:

- Effectively allows NSPs to propose the highest possible forecast and leaves the evidentiary burden on the AER to prove forecast is not prudent and efficient;

- Limits the AER to amending a proposed forecast only to the extent necessary to make it fall within the reasonable range (distribution only);

- Requires that the AER must base any substitute on the original regulatory proposal (distribution only); and

- Restricts use of a range of techniques including top-down benchmarking.

In response, SP AusNet endorses the industry submissions from the ENA and Grid Australia. In particular, they noted:

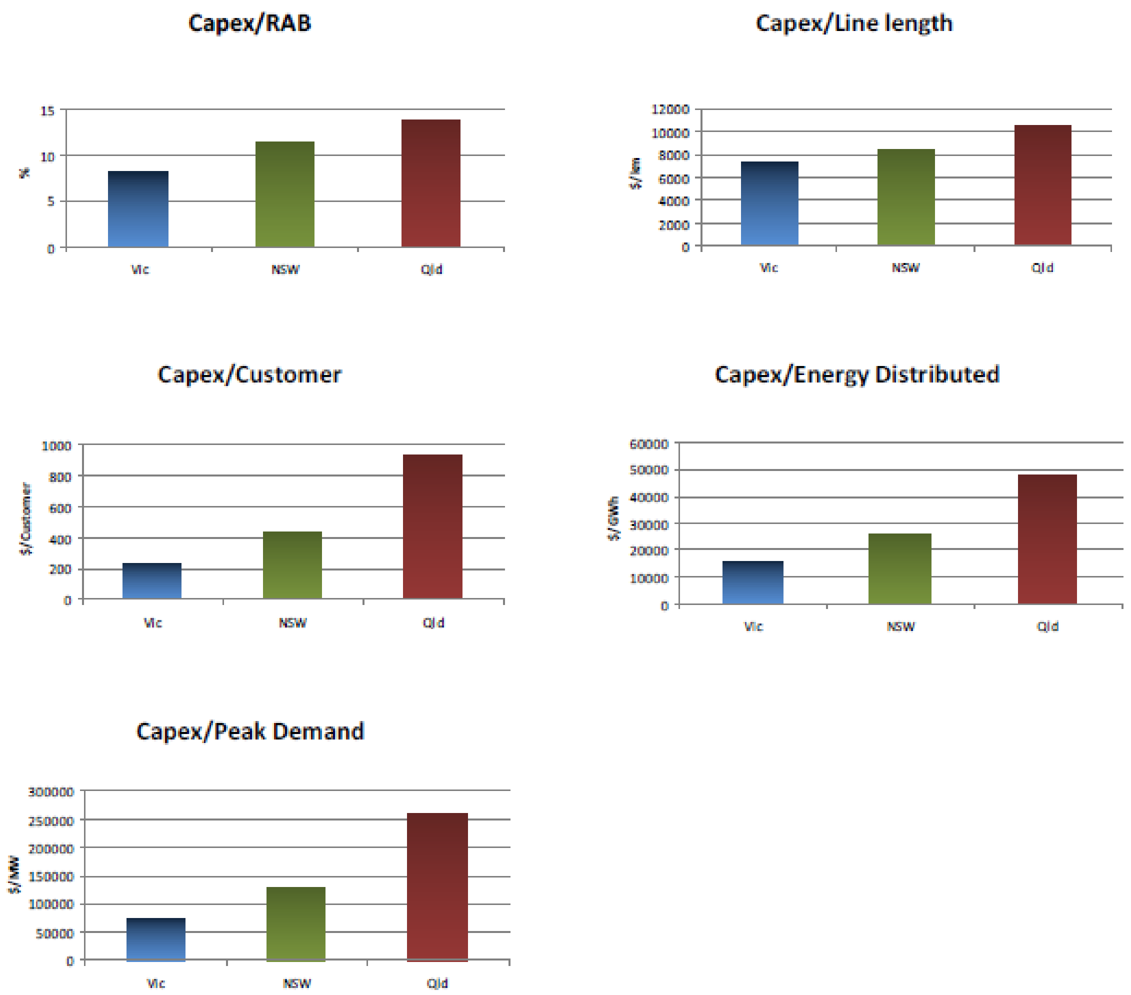
- The AER has not provided any evidence of a problem. The AER's decisions under the transmission or distribution Rules suggest:
    - That the AER has the power to undertake whatever assessment of forecasts it considers necessary and to undertake whatever modification is required to ensure compliance with the Rules;
    - There is no evidence that the AER has been constrained to revise forecasts only to the top of a range, nor a limitation on the scope to applying benchmarking or other analytical techniques;
    - There is no specific 'burden of proof' on either a network business or the AER, merely a practical hurdle for a network business to provide sufficient evidence in support of its expenditure forecast to satisfy the AER, and a requirement for the AER to provide evidence where it is not satisfied on the efficiency and prudency of the expenditure forecast;
- The AER's proposed Rule change will remove the requirement for the AER's decisions to be based on evidence;
- The combination of evidentiary and process factors may create ambiguity and that refinement would be beneficial; and
- It is appropriate that any undue restriction on proper benchmarking of expenditure forecasts should be removed.

However, SP AusNet would make the following additional observations.

6.1. Victorian regulatory outcomes

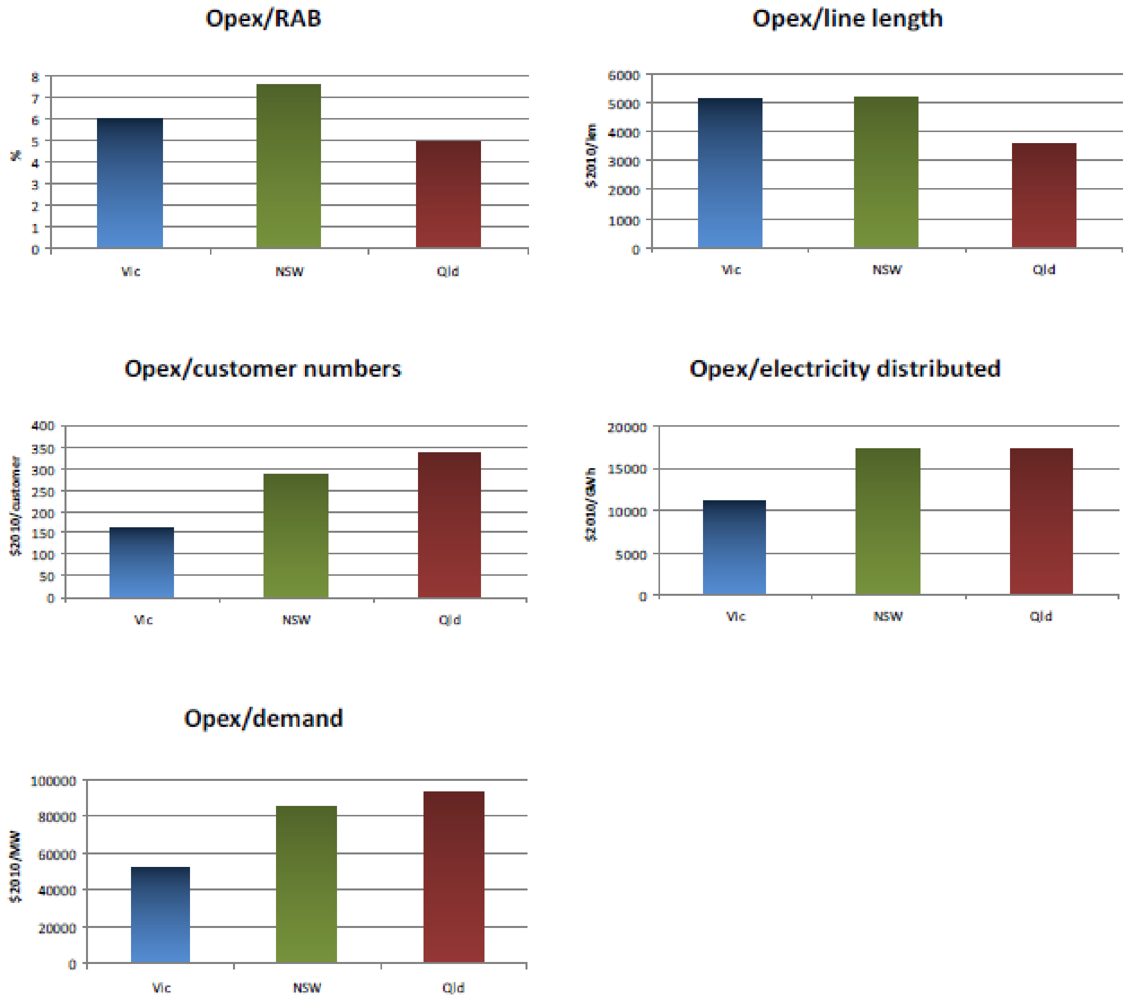
The AER has not made the case for any failure with respect to the Victorian jurisdiction which has delivered declining real prices and improved reliability for the last 15 years. In times of an undisputed need for increased expenditure to deal with aging assets and rising levels of peak demand and changing generation patterns associated with climate change; increases in operating and capital expenditure in Victoria have been limited by the AER to levels well below those seen in NSW and Queensland using the current framework. Benchmarking evidence generated by the AER during the recent electricity distribution price review illustrates this clearly (reproduced in Figure 6 and 7 below).

Figure 6: Historic Capex Analysis by State



Source: AER Final Decision, Victorian DNSP Price Review 2011-15, Appendix H, page 100.

Figure 7: Historic Opex Analysis by State



Source: AER Final Decision, Victorian DNSP Price Review 2011-15, Appendix H, page 110.

6.2. Restriction on the use of top down techniques

There is little evidentiary support for claims that the AER is restricted in its use of various techniques and approaches when assessing a regulatory proposal. For example, in SP AusNet's latest electricity distribution price review, multiple forms of analysis were used by the AER to set the regulatory capital expenditure allowances. Specifically:

- Use of a top down AER designed 'repex' model to set the regulatory allowance for replacement capital expenditure;
- The use in the Draft Decision of sampling and top down extrapolation to set the allowance for augmentation expenditure;

- Use of historical trends to set customer connection capital expenditure allowances;
- Use of detailed bottom up information for safety and bushfire related capital expenditure allowances; and
- Use of regulatory accounting information to set overhead capitalisation rates and remove related party margins.

These are not the Decisions of an unreasonably constrained regulator.

With regards to the AER dropping the initial high level approach to setting the augmentation capital expenditure allowance in its EDPR Final Decision, the AER implies it is somewhat restricted by Clause 6.12.3(f) of the Rules:

> *"… the AER considers that Nuttall Consulting's weighted average probability assessment requires further testing to be used as an appropriate methodology to determine a reasonable forecast of reinforcement capex within the requirements of the Rules.*
>
> *Based on its assessment of the Victorian DNSPs' revised regulatory proposals for reinforcement capex, the AER considers its estimate of $996.1 million is part of a total forecast capex that reasonably reflects the capex criteria. The AER also considers that this estimate reflects the minimum adjustment necessary to comply with clause 6.12.3(f) of the NER."*[9]

SP AusNet considers this is an argument of convenience. Rather, the DNSP's damning criticisms of the approach rendered it unusable.[10] This interpretation is born out by the fact that the AER retained its top down 'repex' model approach presumably because it felt its analysis was on stronger foundations (the 'repex' modelling was not appealed by the Victorian DNSPs). Interestingly, the AER did not claim it was restricted by clause 6.12.3(f) with respect to its use of the 'repex' model.

The industry association submissions proposes alternative rule changes to improve the current framework and put beyond doubt the AER's ability to apply various techniques when assessing a business's expenditure proposals.

7. Regulatory decision-making process.

The AER's major complaint in this area is that it constantly receives submissions from NSPs late in the process dealing with matters that should have formed part of the original or revised proposals. The AER also makes several more minor changes to process in the following areas:

- Introduction of an explicit provision providing that the AER may give such weight to confidential information as it considers appropriate;

[9] AER, *Final Decision, Victorian DNSP Price Review 2011-15*, page 425.
[10] These criticisms are contained in the SP AusNet *EDPR 2011-15 Revised Regulatory Proposal*, pages 101-6, available on the AER Website.

- NSPs claiming confidentiality over material that the AER does not consider to be genuinely confidential;
- Inefficiencies in framework and approach paper process;
- Limited ability to correct decisions for material errors;
- Inconsistency across electricity distribution and transmission and gas in timeframe allowed for conduct of WACC review; and
- Inability to extend the timeframe for particularly complex or difficult pass-through applications, contingent projects and capital expenditure reopeners.

In response, SP AusNet endorses the industry submissions from the ENA and Grid Australia. In particular, these note:

- It is important for effective regulatory decision making that the AER and third parties are provided with sufficient information to make its decisions;
- There are legitimate reasons for network businesses to provide information at times outside of the formal regulatory proposal or revised regulatory proposal
- Therefore, the AER proposal is overly prescriptive and restrictive and increases the risk of it having insufficient information and, therefore, regulatory error. This may ultimately lead to an otherwise avoidable use of the appeal mechanisms.
- The AER already has the discretion to ignore late submissions.

However, SP AusNet would make the following additional observations.

7.1. Major process changes – late submissions

The AER's proposal seems to ignore the obvious fact, that what ever the nature of the review process, the core document under review will always be the NSP's Proposal. As such, other submissions will almost always comment on or raise new issues and facts with respect to the Proposals or Revised Proposals.

In these circumstances, it seems uncontroversial that the NSP be allowed to address (with-in a reasonable timeframe) what is essentially new information in the process. In practice, this is almost always in the form of correcting any errors of fact contained in the submissions.

Furthermore, in SP AusNet's experience, late information is almost always in response to the businesses becoming aware of late changes to the AER approach on a matter that have not been previously raised. These matters are often being debated late in the process because they are controversial and material.

Overall, the perhaps unintended effect of the AER process changes would be to remove late decision making processes from scrutiny and deny businesses natural justice. Of most concern, the changes effectively allow the AER to make fundamental changes to their analyses, approaches and Decisions after their Draft Decision without consulting the businesses or providing them with an opportunity to respond.[11] Businesses may not be aware of the AER's Decision making processes until after the Final Decision is published.

For example, in the recent EDPR process the AER consulted on two material issues where they were changing the fundamental approach in ways that were not flagged in the Draft Decision (and therefore would not be addressed in the businesses' Revised Proposals) – the DRP methodology and close out of the jurisdictional service standards scheme. Changes under consideration were worth potentially hundreds of millions of dollars to the Victorian DNSPs. Importantly, the consultation allowed the businesses to make new arguments but did not unfairly constrain the AER – they fundamentally but successfully changed from the Draft Decision in these areas (the current Merits Appeal in Victoria on the DRP and Service standards scheme do not go to the changes made).

Yet the AER's proposed Rule changes remove the requirement to consult on such fundamental issues.

It should also be noted that the AER already appears to have discretion with regards to the weight to be given to information provided unreasonably late in the review process.

SP AusNet considers that any fair regulatory process must provide the business an opportunity to respond to new facts and analysis. Nonetheless, this must be done in a reasonable timeframe. Therefore, SP AusNet is happy to endorse the industry association changes that provide this clarity as to the AER's ability to reject new information without the wholesale changes to the review process.

7.2. Confidentiality

SP AusNet would highlight that the AER already appears to have discretion with regards to the weight to be given to information provided confidentially.

With regards to our own review processes, SP AusNet has always accommodated AER requests to present information in a form that can be released wherever possible. The company is unaware of any instance where SP AusNet has refused information being published where it has been requested by the AER (although it has made presentational changes where necessary – for instance, redaction to prevent the identification of customer information).

7.3. Other minor process improvements

The AER has identified several places where processes can be improved, for example, with respect to the framework and approach paper requirements and timeframes for complex pass through applications.

As such, SP AusNet endorses the industry associations' alternative proposed process rule changes which address these issues.

[11] For example, the removal of existing Clauses 6.5.6 (e) (3) and 6.5.7 (e) (3).

8. Conclusion

In the whole, the AER's Rule changes do not address the underlying causes of rising network costs such as aging assets and rising peak demand. Crucially, even where the key drivers of these price increases are limited to only some jurisdictions, such as ownership and reliability standards, these cannot be addressed through a normal rule change process having been reserved to jurisdictional control.

The AER's Rule changes can be described as generally increasing their own discretion to a significant extent. In the above discussions, SP AusNet has provided numerous instances of where:

- The AER has not used discretion it has under the current Rules (for example, with respect to capital expenditure efficiency regime);
- Instances where the AER has used discretion where it has said it has none (for example, techniques applied to expenditure setting); or
- Been responsible for the creation of the identified problem.

This raises the issue of AER resourcing and capability and the importance of increasing the involvement of sophisticated customer representation in the price review processes.

In particular, the current EURCC rule change illustrates what well resourced and constructive engagement by customers in the Rule change process looks like. SP AusNet would support changes to the existing framework that aids this form of sophisticated consumer representation in regulatory process whether through improved resourcing to groups capable of this sophistication or improved opportunities to interact in the existing framework.

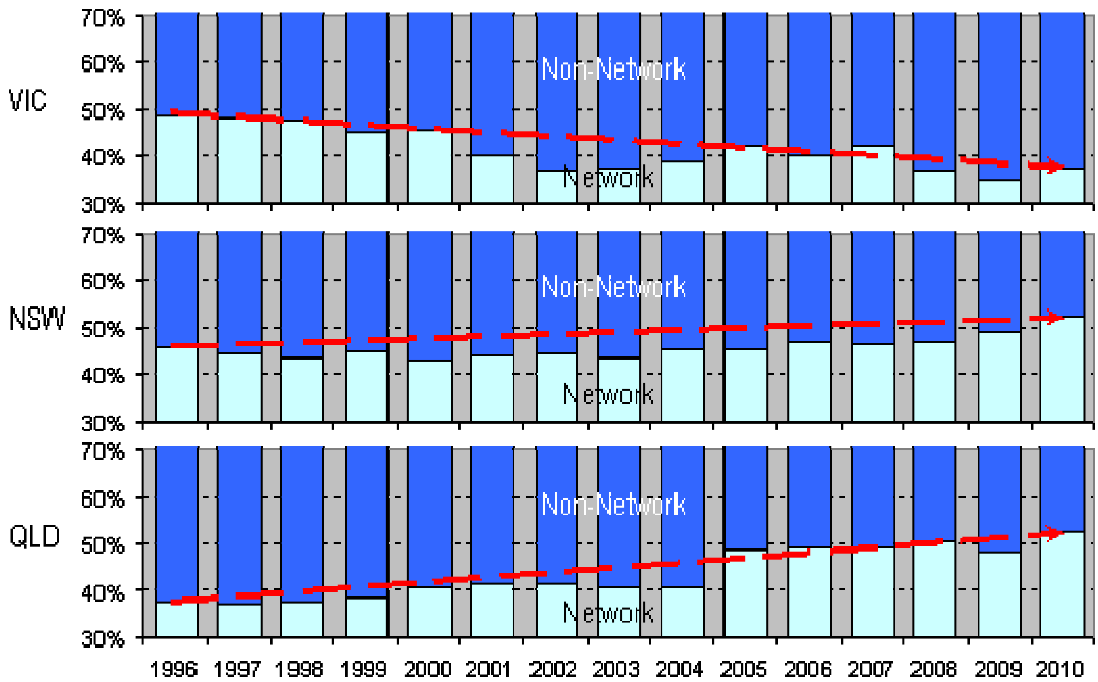
The industry association submission provides detailed alternative options for the issues raised by the AER's proposed Rule changes. SP AusNet fully supports the consideration of these options by the AEMC.

Attachment 1: Network cost trends in different jurisdictions

SP AusNet has commissioned analysis from Ernst and Young on the historic contribution of network charges to the total bill in NSW, Queensland and Victoria over the period 1996 to 2010. The Ernst and Young report is attached to this submission.[12] This analysis contained in the report shows that network charges have not been a contributing factor to rising energy prices in Victoria in stark contrast to NSW and Queensland.

The figure below illustrates that between 1996 and 2010 network charges have fallen from around 50% of an average customer bill to under 40%. In contrast, the proportion of network charges in NSW and Queensland have risen to over 50% over the same period of time.

Figure A1: Network share of Average Customer Bill ($/MWh)

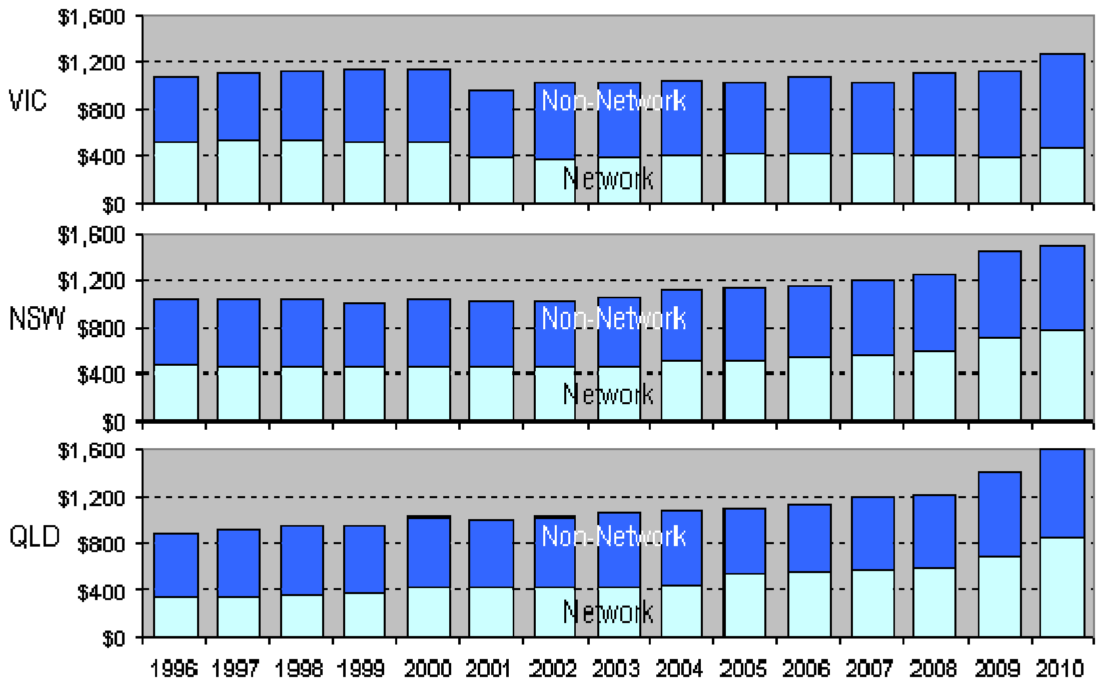


Source: Ernst and Young

Likewise, in terms of dollars per customer, network charges in Victoria have actually fallen in real terms over period 1996 to 2010 while charges have almost doubled in NSW and more than doubled in Queensland leaving customer bills substantially higher. This is illustrated in the figure below.

[12] Ernst and Young, *Victorian Electricity prices 1996-2010: the contribution of network costs*, 2011.

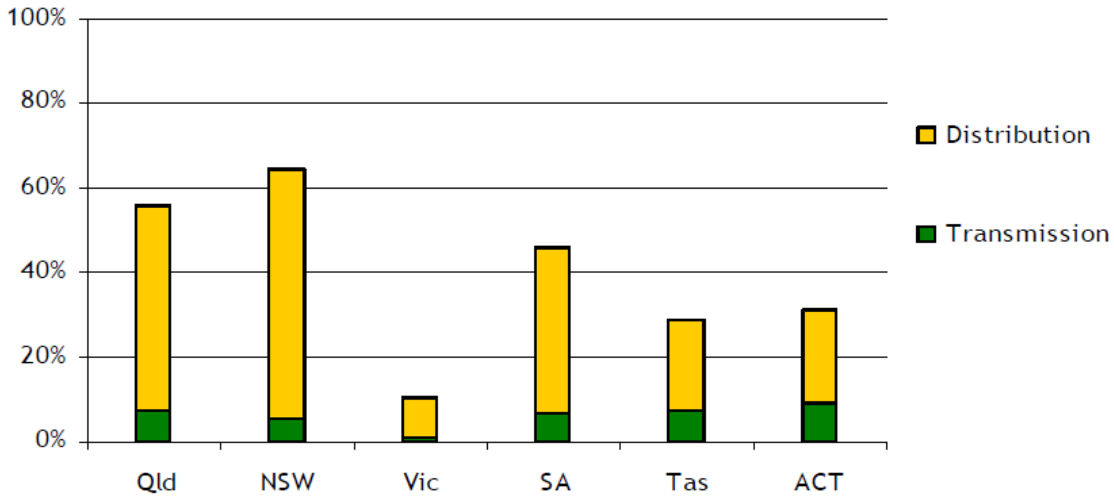
Figure A2: Average Bill ($/Customer)



Source: Ernst and Young

This historical analysis compliments and endorses previous AEMC analysis reproduced by the AER that projected forward three years from 2009-10 to 2012-13 that also showed that, in contrast to other jurisdictions, network price rises in Victoria were expected to be a small component of future price rises for residential customers. Figure 3 reproduces the key graph from that analysis.

Figure A3: The contribution of network charges to future possible residential electricity price increases



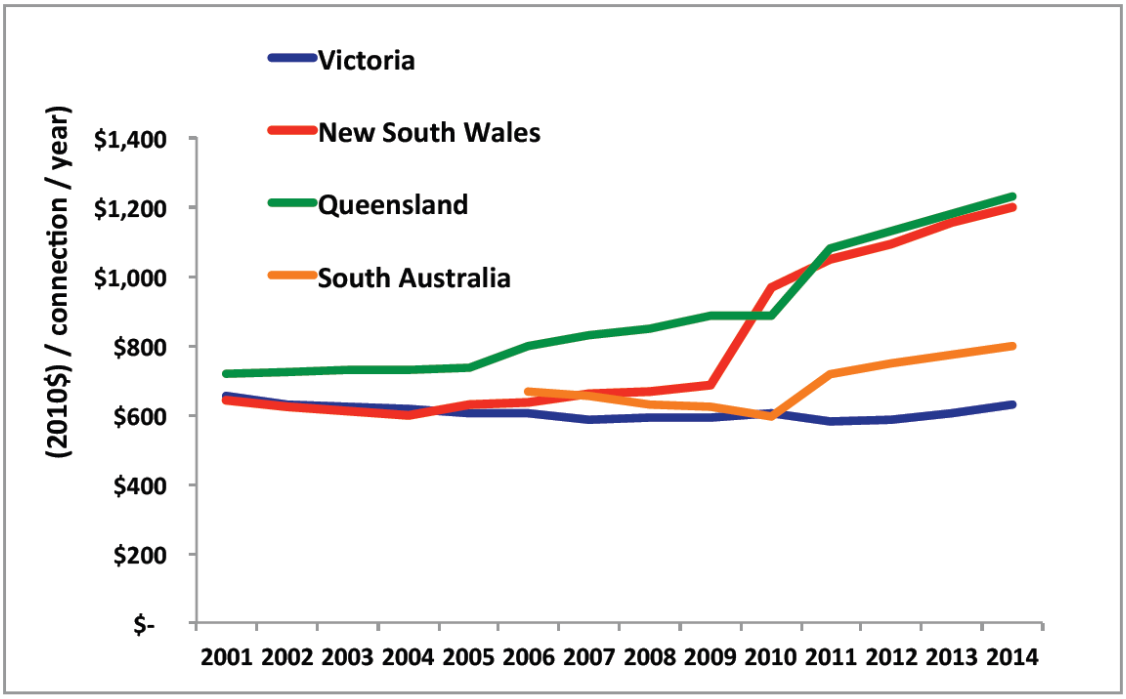
Source: AER Rule Change Proposal, Part A Overview and Context, page 6

These jurisdictional differences have also been highlighted in a paper commissioned by consumer groups from Carbon Economics, entitled *Australia's Rising Electricity Prices and Declining Productivity: the Contribution of its Electricity Distributors*. The extract and figure reproduced below summarises one of the key findings from that report with respect to cost per customer in the different jurisdictions.

> *"Revenues in the third regulatory period (from the end of the last decade) rose sharply in Queensland, New South Wales and South Australia but less so in Victoria. By the end of the third regulatory period in 2014/15, revenues per customer in New South Wales and Queensland will be twice those in Victoria."*[13]

[13] ESAA (Carbon Economics), *Australia's Rising Electricity Prices and Declining Productivity: the Contribution of its Electricity Distributors*, page 24.

Figure A4: Allowed revenue per connection



Source: ESAA, Australia's Rising Electricity Prices and Declining Productivity, page 25.

Victorian domestic electricity prices 1996-2010: The contribution of network costs

A report for the Victorian electricity network businesses

9 September 2011

Ernst & Young

Contents

This report was prepared at the joint request of CitiPower Pty, Jemena Electricity Networks (Vic) Ltd, Powercor Australia Ltd, SP AusNet and United Energy Ltd ('the Victorian electricity network businesses') solely for the purpose of undertaking an independent assessment of trends in Victorian electricity prices over the medium term. In carrying out our work and preparing this report, we have worked on the instructions of the Victorian electric network businesses only and we have not taken into account the interests of any parties other than the Victorian electricity network businesses. Ernst & Young does not extend any duty of care in respect of this report to anyone other than the Victorian electricity network businesses.

The services provided by Ernst & Young do not constitute an audit in accordance with generally accepted auditing standards, or a review, examination or other assurance engagement in accordance with auditing and assurance standards issued by the Australian Auditing and Assurance Standards Board. Accordingly, we do not provide an opinion or any other form of assurance under audit or assurance standards.

Except to the extent that we have agreed to perform the specified scope of work, we have not verified the accuracy, reliability or completeness of the information we accessed, or have been provided with by the five Victorian electricity network businesses, in preparing this report.

Liability limited by a scheme approved under Professional Standards Legislation.

1. Executive summary

Ernst & Young was engaged by the Victorian electricity network businesses to:

- Conduct an independent analysis of the trend in Victorian electricity prices over the medium term;
- Disaggregate the trend to examine the role of network costs in the changes in Victorian electricity prices; and
- To the extent possible, compare the results with those observed in other Australian jurisdictions.

This report provides the outcome of our work.

1.1 Approach

Analysing electricity prices over long periods of time presents a number of challenges due to changes in industry structure, ownership, information gathering processes and publication, the technology employed, the number and structure of tariffs over time, consumer behaviour and the tax system (e.g. the introduction of the Goods and Services Tax (GST) and the easement land tax paid by the Victorian transmission business).

The Australian Bureau of Statistics (ABS) produces an electricity price index (*ABS Consumer price index, catalogue no.6401.0 Table 13*) for each capital city[1] that commences in 1980 and shows the trend in electricity prices since that time. We have used that index in our analysis. The ABS does not however disaggregate the index into the components that make up the final retail electricity price.

To analyse the trend in Victorian electricity prices over the medium term, we have relied mostly on a bottom up approach as it uses the actual retail and network tariffs paid by customers. In particular, we have examined the historical trend of annual electricity costs for the typical domestic customer[2] from 1996 to 2010 (excluding GST)[3] and have disaggregated the trend down to the network and non-network components of retail electricity prices for each distributor. We have then averaged the results to provide State-wide results.[4]

Network costs (NUOS) have been disaggregated into distribution use of system costs (DUOS) and transmission use of system costs (TUOS). We have included the cost of the advanced metering infrastructure (AMI) or "smart meter" costs in the network component.[5]

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[1] While the ABS produces its electricity price index (which forms part of its Consumer Price Index) for each State and Territory capital city, the index is widely assumed to be representative for the whole State or Territory. In this instance, the ABS electricity price index for Melbourne is assumed to be broadly representative of domestic electricity prices in Victoria.
[2] The typical domestic customer is defined as a customer under a domestic single rate tariff with an average consumption profile throughout the period of analysis (i.e. consuming average consumption volumes in each year from 1996 to 2010. State-wide average consumption data sourced from the ESAA's annual Electricity Gas Australia publications). See Section 3 and Appendix A for more details.
[3] 1996 was the first year when prices charged by Victorian electricity network businesses were separately regulated following a broader industry restructure. There are thus significant limitations on data availability prior to this.
[4] The State-wide average is calculated as the average of the five distribution network businesses, weighted by volume or MWh distributed.
[5] Advanced metering infrastructure costs capture the costs reflected in the previous Victorian Government's decision to roll out 'smart meters' for all small users. In 2006-09, advanced metering charges for these businesses were subject to a separate pricing schedule approved and published by the ESC. From 2010, advanced metering charges for the Victorian electricity network businesses are determined by a separate regulatory decision by the AER. In practice, it includes some metering costs that would have been incurred absent the roll out.

Non-network costs refer to all costs involved in the supply of electricity other than distribution and transmission use of system charges (i.e. network costs) and includes costs such as wholesale energy costs and retail margins.

We have assumed the single rate tariff is representative of typical domestic electricity prices, as over 90 per cent of domestic electricity customers in Victoria pay this tariff.[6]

We have not analysed the cost of electricity in the business or non-domestic sectors because a similar analysis using the actual tariffs paid by these customers is not feasible for several reasons, including data limitations, the large number and complex structure of non-domestic tariffs and the prevalence of individually negotiated "non-standard" contracts.

Between 1996 and 2010, on average, domestic customers accounted for approximately 29 per cent of total demand in Victoria and around 88 per cent of customers by customer numbers.

All the data used in our analysis is publicly accessible. To validate our analysis, the Victorian electricity network businesses provided confidential data on customer numbers and average consumption by tariff type and SP AusNet provided data on costs associated with the easement land tax. However this data has not been used in our analysis or presented in our findings. All of the findings are able to be replicated using publicly accessible information.

We have further verified our results by, amongst other things, comparing the findings derived from the analysis described above:

- With the results of our disaggregation of the ABS electricity price index for Melbourne (the top down approach), which uses aggregated industry data rather than actual tariffs paid by customers; and

- With the annual price changes allowed by economic regulators in each year of the regulatory period in determinations made for the distributors' network businesses (i.e. P-noughts and X factors).[7]

We have also adopted the approach described above to disaggregate the change in annual electricity costs in NSW and Queensland.

1.2 Our results

Our analysis shows that:

- Electricity prices and typical bills for the typical domestic customer in Victoria have increased by 7 per cent in real terms from 1996 to 2010. However since 2007, domestic electricity prices have increased by 30 per cent in real terms. This followed a decrease in domestic electricity prices of 18 per cent in real terms between 1996 and 2007; and

- The increases in domestic electricity prices in Victoria cannot be explained by increases in network costs (i.e. the sum of distribution and transmission use of system charges).

Figure 1 illustrates what has happened to the relevant components of average Victorian electricity prices in real terms over the period 1996 to 2010. It separates retail prices into network costs and non-network costs (i.e. wholesale energy costs and retailers' costs), and network costs into distribution use of system costs and transmission use of system costs.

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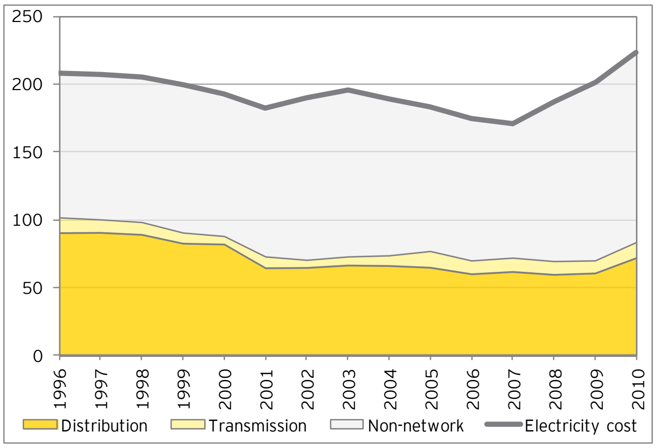
[6] Data made available to us suggests that 90% of domestic electricity customers in Victoria are under a single rate tariff based on data on domestic customer numbers by tariff type provided by the Victorian electricity network businesses.

[7] Determinations made under the Victorian Tariff Order 1995, and distribution determinations made by the ORG, ESC and AER. See Appendix B for details.

Figure 1 Victoria electricity costs by component 1996 to 2010 ($ per MWh, real 2010)



Source: Ernst & Young analysis

Figure 1 shows that network costs per megawatt-hour (MWh) in Victoria have fallen by 18 per cent in real terms between 1996 and 2010. On a per customer basis, network costs have decreased by 9 per cent in real terms. The difference reflects the increase in average consumption during this period.

Table 1 below shows the results numerically.

Table 1 Change in average annual Victorian electricity costs from 1996 to 2010 (real 2010)

	Percentage change		Dollar change	
	per MWh	per customer	per MWh	per customer
Final retail price	+7%	+19%	+$15	+$201
Network	-18%	-9%	-$18	-$46
Non-network	+31%	+45%	+$33	+$247

Source: Ernst & Young analysis

Disaggregating network costs between the distribution and transmission elements reveals annual distribution network costs between 1996 and 2010 have decreased to a greater extent than total network costs. Between 1996 and 2010:

- Distribution use of system costs have decreased by 20 per cent in real terms; and
- Transmission use of system costs have increased by 2 per cent in real terms, but have been driven higher by other factors and are quite volatile, for reasons described in Section 4.1.1.[8] For example, if the easement land tax was not paid by the transmission business in Victoria, transmission costs would also have fallen significantly, by as much as 18 per cent in real terms during this period.

In contrast, non-network costs increased by 31 per cent in real terms between 1996 and 2010.

In other words, for the typical domestic customer, annual network costs in Victoria have decreased in real terms between 1996 and 2010:

- On a per MWh distributed basis;
- On a per customer basis;
- Including AMI costs as a result of the previous Victorian Government's mandated roll out of AMI; and

[8] Figures may be affected by rounding.

- In excess of the benefits that may reasonably be expected from load growth (refer to Section 4.1.4).

Based on our analysis, none of the increases in electricity prices in Victoria over the 1996 to 2010 period can be attributed to network costs. Some of the increases in electricity costs from 2006 can be explained by the AMI roll out.

1.2.1 Consistency of results

We have validated our bottom up findings with the results from an analysis of the trend in Victorian domestic electricity prices achieved by disaggregating the ABS electricity price index for Melbourne[9] (i.e. the top down approach), which uses aggregated industry data rather than actual tariffs paid by customers. The top down approach produces similar outcomes in terms of the performance of network costs, but we have greater confidence in the results using our bottom up approach because they rely on actual tariffs rather than a price index.

We also compared our findings with the results produced by undertaking a similar analysis using a domestic two rate tariff. This comparison produced similar outcomes in terms of the trend in network costs.

Our findings on annual network charges are also consistent with the annual price changes allowed by economic regulators in each year of the regulatory period in determinations made for the distributors' network businesses (i.e. P-noughts and X factors).

The Victorian results in respect of network costs differ from the results of our analysis for New South Wales (NSW) and Queensland (refer to Section 5). In these States, network costs have been increasing in part due to the substantial capital investments that have been made, particularly in recent years. The different results between States may also reflect the different starting points in respect of each network's existing capital stock.

[9] Assumed to be representative of the general trend in electricity prices in Victoria – see footnote 1.

Glossary

Reference	Description
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
CPI	Consumer Price Index
CSO	Community Service Obligation
DUOS	Distribution Use of System
ESC	Essential Services Commission of Victoria
ESAA	Energy Supply Association of Australia
GST	Goods and Services Tax
IPART	Independent Pricing and Regulatory Tribunal
MCE	Ministerial Council on Energy
MWh	Megawatt-hour
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NMI	National Metering Identifier
NSW	New South Wales
NUOS	Network Use of System
ORG	Office of the Regulator-General, Victoria
QCA	Queensland Competition Authority
QLD	Queensland
TUOS	Transmission Use of System

2. Introduction

2.1 Scope of work

Ernst & Young Australia (Ernst & Young) was jointly engaged by CitiPower Pty, Jemena Electricity Networks (Vic) Ltd, Powercor Australia Ltd, SP AusNet and United Energy Distribution Pty Ltd (collectively referred to herein as "the Victorian electricity network businesses") to assess the trend in Victorian electricity prices and network costs. More specifically, Ernst & Young was engaged to:

- Investigate the options for analysing Victorian electricity prices over the medium term;
- Conduct an independent analysis of the trends in those electricity prices;
- Disaggregate those trends to examine the role of network costs in the changes in Victorian electricity prices; and
- Compare the results with those observed in other Australian jurisdictions to the extent possible.

Section 3 describes the approach undertaken to complete the work.

2.2 Outline of report

This report provides the output of our analysis. In particular:

- Section 3 describes our approach;
- Section 4 provides an overview of our key findings; and
- Section 5 provides an overview of our key findings in NSW and Queensland.

There are two appendices:

- Appendix A – Approach; providing additional details on our methodology, data sources and key assumptions; and
- Appendix B – Other results; providing an overview of other relevant findings.

3. Approach

We have analysed the historical trend of domestic retail electricity prices in Victoria for each year from 1996 to 2010 and have disaggregated the change in prices down to the network and non-network components (i.e. wholesale energy costs and retailers' costs) of retail electricity prices.

Network costs (NUOS) have been disaggregated into distribution use of system costs (DUOS) and transmission use of system costs (TUOS). We have included the cost of the advanced metering infrastructure (AMI) or "smart meters" in the network component.

This allowed us to determine the change in the proportion of the typical customer's annual electricity costs paid to network businesses through network charges, and the change in the proportion that is paid to other non-network entities (e.g. retailers, generators etc).

3.1 Methodology

Analysing electricity prices over long periods of time presents a number of challenges due to changes in industry structure, ownership, information gathering processes and publication, the technology employed, the number and structure of tariffs over time, consumer behaviour and the tax system (e.g. the introduction of the GST and the easement land tax paid by the Victorian transmission business).

For example, there have been numerous structural, regulatory and policy decisions that have significantly impacted the Victorian electricity industry between 1996 and 2010, including

- Privatisation of the five Victorian electricity distribution businesses in 1995-96;
- The introduction of the GST in July 2000[10] and the easement land tax in 2004;
- The implementation of Full Retail Contestability in 2002;
- The previous Victorian Government's decision to roll out AMI to all Victorian residents in 2006; and
- The removal of retail price regulation for small customers in 2007.

Furthermore, significant volumes of historical tariff and metering data are often unavailable, particularly where distribution businesses have merged or where data storage platforms have changed considerably.

To analyse the trend in Victorian electricity prices over the medium term we have relied principally on a bottom up approach as it uses the actual retail and network tariffs paid by customers. Using these tariffs, we have examined the historical trend of annual electricity costs for the typical domestic customer from 1996 to 2010 and have disaggregated the change in the trend down to the network and non-network components of retail electricity prices.[11]

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[10] All prices and costs exclude GST to the extent that all tariff data we have used in our analysis is exclusive of GST. We have not excluded the impact of the introduction of the GST in July 2000 on CPI / inflation data. However we expect that the impact on our final results is unlikely to be material.

[11] 1996 was the first year when prices charged by the Victorian electricity network businesses were separately regulated as part of a broader industry restructure. There are thus significant limitations on data availability prior to this.

As a result, we have assumed the domestic single rate tariff[12] is representative of typical domestic electricity prices, as over 90 per cent of domestic electricity consumers in Victoria pay this tariff.[13]

To undertake this assignment, we took the following broad approach:

- We obtained data on annual retail electricity tariffs in Victoria for domestic customers from the Victorian Government Gazette for each year from 1996 to 2010. Using these tariffs, we estimated the cost of electricity paid each year by a Victorian customer with an average consumption profile[14] under a domestic single rate tariff in this period; and
- We then determined the proportion of the annual electricity costs attributable to the network component, by undertaking the above analysis for the domestic single rate network tariff (i.e. the network tariff charged by the distribution businesses).

We completed this for each of the five Victorian network businesses in turn and then calculated a Victorian average, weighted by the megawatt-hours distributed by each business.

In NSW and Queensland, we were constrained by the unavailability of network tariff data prior to around 2001-02 due to additional data limitations of the type described above.

3.2 Qualifications

The period from 1996 to 2010 was used as the period of analysis as 1996 was the first year when prices charged by the Victorian electricity network businesses were separately regulated. Prior to this, there are significant limitations on the availability of data required to disaggregate electricity prices.

Our findings are first determined in terms of annual cost per customer. We then express the annual cost on a per unit of volume basis (i.e. MWh) by dividing the annual cost per customer by average consumption for that year.[15]

Unless otherwise stated, all findings express our estimates of the annual electricity costs paid by the typical domestic customer, i.e. a customer with an average consumption profile in each year from 1996 to 2010.

We have not analysed the cost of electricity in the non-domestic or business sectors for various reasons, including the limited availability of consistent data, large numbers of non-domestic tariffs, complexity of the non-domestic tariff structures and prevalence of non-standard contracts negotiated individually with the network business.

All the data we have used in our analysis is publicly accessible. To validate our analysis, the Victorian electricity network businesses provided confidential data on customer numbers and average consumption by tariff type and SP AusNet provided data on costs associated with the easement land tax. However this data has not been used in our analysis or presented in our findings. All of the findings are able to be replicated using publicly accessible information.

[12] A single rate tariff can also be referred to as a 'Domestic General' or 'Peak Anytime' tariff.
[13] Data made available to us suggests that 90% of domestic electricity customers in Victoria are under a single rate tariff based on data on domestic customer numbers by tariff type provided by the Victorian electricity network businesses. While this data is not publicly accessible, we have not used the data in our analysis.
[14] State-wide average consumption data for each year from 1996 to 2010 was sourced from the ESAA's annual Electricity Gas Australia publications.
[15] For example, if the annual cost per customer is $1,000 and consumption for the year is 5,000kWh or 5 MWh, the cost per MWh distributed is $200 per MWh.

3.3 Verification of results

We have only presented the findings from our bottom up analysis of the domestic single rate tariff. We adopted this approach because the single rate tariff is the price that most domestic customers actually pay for electricity.

However we also analysed and disaggregated the trend in electricity prices using other approaches to test the sensitivity and robustness of our findings under the single rate tariff. We have compared the findings derived from the analysis described above:

- With the results of our top down approach, which disaggregates the ABS electricity price index for Melbourne and uses aggregate industry data rather than actual tariffs paid by customers;
- With the annual price changes allowed by economic regulators in each year of the regulatory period in determinations made for the distributors' network businesses (i.e. P-noughts and X factors); and
- With the results derived from similar bottom up analysis described above using a domestic two rate tariff.

Both the bottom up analysis of the two rate tariff and the top down approach produce results which are consistent with the single rate tariff.

Appendix A describes our approach in more detail. Appendix B provides some additional results of our analysis.

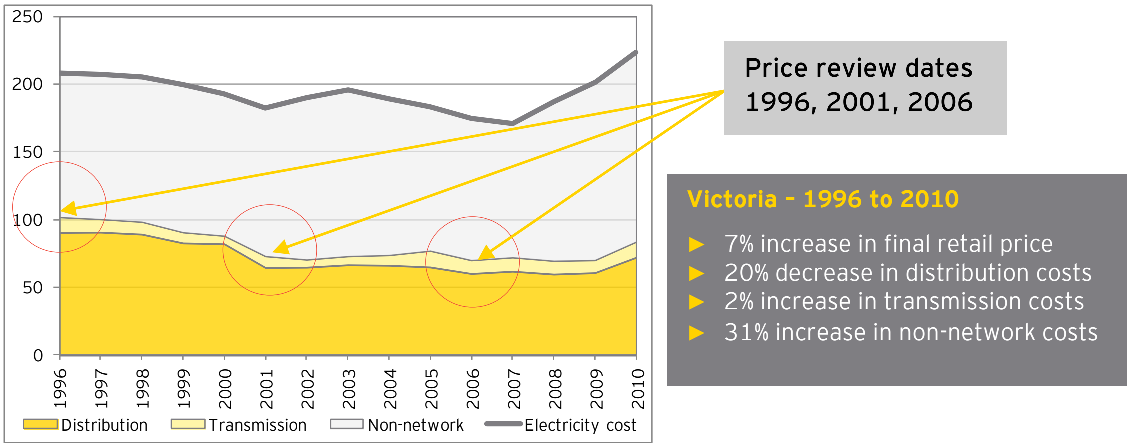
4. Key findings

4.1 Victoria

4.1.1 Costs per MWh

Our findings from the disaggregation of costs under the domestic single rate tariff in Figure 2 show the cost of electricity in real dollars per MWh paid by the typical customer increased by 7 per cent from 1996 to 2010. It also shows relevant price review dates and summarises the impact on the key components of electricity prices.

Figure 2 Victoria electricity costs by component 1996 to 2010 ($ per MWh, real 2010)



Source: Ernst & Young analysis

In other words, between 1996 and 2010:

- Network costs decreased by 18 per cent in real terms. Disaggregating network costs further shows that:
  - Distribution costs decreased by 20 per cent in real terms, including AMI costs; and
  - Transmission costs increased by 2 per cent in real terms, but have been driven higher by other factors, such as the easement land tax paid by the transmission business in Victoria.[16] If the easement land tax was not paid by the transmission business, transmission costs would have fallen significantly, by as much as 18 per cent in real terms between 1996 and 2010. As shown by Figure 2, transmission costs are also quite volatile for several other reasons also unrelated to the cost of providing transmission services.[17] Our results in respect of transmission costs should therefore be interpreted with particular caution.
- Non-network costs (i.e. wholesale energy and retailers' costs) increased by 31 per cent in real terms.

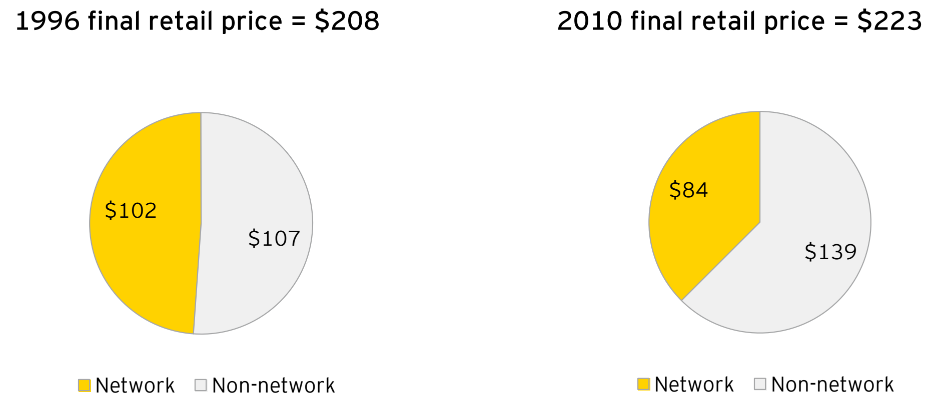
[16] In Victoria, TUOS charges also include an easement land tax from 2004 onwards, which is the land tax payable by on easements held by electricity transmission companies. This tax is fully passed through to the Government.
[17] 'Transmission' costs as measured capture some costs that are in practice unrelated to transmission services. These include various electricity market fees, including National Electricity Market (NEM) fees, and settlement residue costs and the costs of the associated auctions. In 2010, these costs were equivalent to about 34% of AEMO's TUOS income. See AEMO, Annual Report 2010, October 2010. NEM fees increased by over 10% between 2009 and 10, and we understand settlement residue costs can be volatile both in terms of both their quantity and incidence (i.e. which jurisdiction bears the costs). Appendix B also shows volatility by distributor.

In 2006, the previous Victorian Government rolled out AMI to all small Victorian electricity customers, which has implications for customers' costs. This can be seen in Figure 2 from the increase in distribution costs particularly from 2009.

In the absence of a roll out of advanced meter infrastructure, we believe the best estimate of network costs would mean the decrease in distribution network costs between 1996 and 2010 would be almost double the estimate of 20 per cent.

Figure 3 shows the breakdown of Victorian electricity costs between network and non-network costs in 1996 and 2010.

Figure 3 Composition of electricity costs in Victoria 1996 and 2010 ($ per MWh, real 2010)

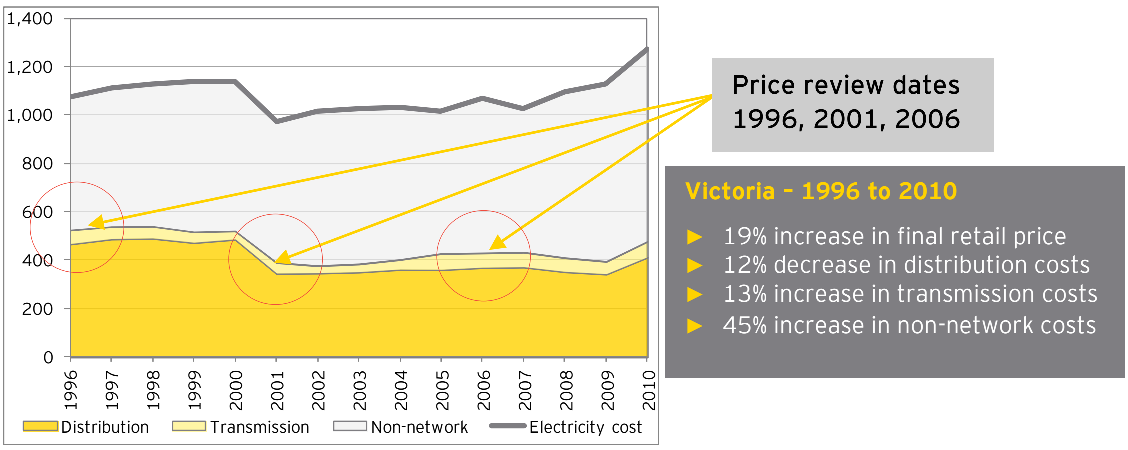


Note: Figures may be affected by rounding. Source: Ernst & Young analysis

4.1.2 Costs per customer

Analysing the breakdown of Victorian electricity costs on a per customer basis, as shown in Figure 4, produces broadly consistent results with our findings on a per MWh basis.

Figure 4 Victoria electricity costs by component 1996 to 2010 ($ per customer, real 2010)



Source: Ernst & Young analysis

Figure 4 shows that between 1996 and 2010:

- The cost of electricity in real dollars per customer paid by the typical customer increased by 19 per cent.
- Network costs decreased by 9 per cent in real terms;
    - Distribution costs decreased by 12 per cent in real terms; and

- Transmission costs increased in real terms by 13 per cent, but as noted above, they have been driven higher by other factors such as the easement land tax. In the absence of the easement land tax paid by the transmission business, transmission costs per customer would have fallen by an estimated 8 per cent in real terms between 1996 and 2010;[18]

- Non-network costs increased by 45 per cent in real terms.

The difference in the magnitude in the change in costs per customer compared with costs per MWh from 1996 to 2010 is explained by the increasing average consumption rates during this period.

4.1.3 Analysis of a typical annual bill in nominal terms

Our analysis of the typical annual bill shows that the annual cost of electricity in nominal terms, paid each year by the typical customer increased by 69 per cent from $752 to $1,273 between 1996 and 2010.

$752	$1,273	$521
The cost of the typical annual domestic electricity bill in Victoria in 1996	The cost of the typical annual domestic electricity bill in Victoria in 2010	Increase in the typical annual domestic electricity bill in Victoria from 1996 to 2010

Table 2 shows a breakdown of the typical Victorian domestic electricity bill in 1996 and 2010.

Table 2 Breakdown of a typical electricity bill in Victoria ($ per customer, nominal)

	1996	2010
Annual cost of bill ($, nominal)		
Network	$368	$477
Non-network	$385	$796
Final retail price	$752	$1,273
Proportion of final retail price (%)		
Network	49%	38%
Non-network	51%	62%

Note: Figures may be affected by rounding. Source: Ernst & Young analysis

Breaking down the bill increase between 1996 and 2010 of $521 in nominal terms, it is evident that:

- Network costs contributed 21 per cent ($110) of the increase in the average electricity bill; and

- Non-network costs contributed 79 per cent ($411) of the increase in the average electricity bill.[19]

4.1.4 Zero load growth for a typical customer

This scenario has been analysed to attempt to determine the impact that consumption growth, or load growth, has had on the cost of the network component each year for a typical domestic customer in Victoria.

[18] Refer to footnotes 16 and 17 for discussion of the volatility of transmission costs in Victoria.
[19] Figures may be affected by rounding.

We have focused our analysis on the network charges paid by a typical domestic customer as opposed to overall network costs because focussing on the latter is not possible without access to a network business's tariff model due to the complex nature of determining network charges.

Network businesses typically set tariffs based on two factors: the total amount of costs to recover through its network charges and the volume of electricity it distributes:

- Costs – if average consumption was fixed from 1996 to 2010, a network business would not necessarily have invested the same amount to expand or upgrade its network.[20] This would mean that it is likely that the network business would set a lower network charge than otherwise because the total amount of costs to recover would be lower.

- Volume – given price is broadly a function of costs and volume, if a network business distributes less electricity than expected (for example, if growth in average consumption is zero), it would most likely set a higher network charge to ensure it recovers its costs.

Typically for networks, it would be reasonable to expect increasing volumes to increase total costs but result in declining per unit costs.

Whether network charges would be higher or lower under a zero load growth scenario would depend on which of these two opposing impacts (lower costs to recover versus lower volumes from which to recover costs) is stronger. The results should therefore be interpreted with some caution.

Table 3 compares the distribution costs paid by a typical customer in 1996 and 2010 with the distribution costs the same customer would pay if his or her consumption remained at 1996 levels.

Table 3 Annual distribution costs of a typical customer in Victoria ($ per customer, real 2010)

	1996	2010	Change 1996-2010 ($)
Typical customer	$466	$412	-$54
Zero load growth	$466	$375	-$91

Source: Ernst & Young analysis

In terms of annual network costs, the typical customer in Victoria is better off by $54 between 1996 and 2010.

A typical customer whose consumption remained at 1996 levels would be a further $37 better off. This customer would be better off by $91 between 1996 and 2010.

The implication of this analysis is that performance improvements in the Victorian distribution network have likely played a significant role. Table 3 suggests Victorian domestic electricity customers have received benefits in addition to those benefits that one might reasonably expect to arise from increasing volumes (i.e. benefits from increasing total costs but declining per unit costs).

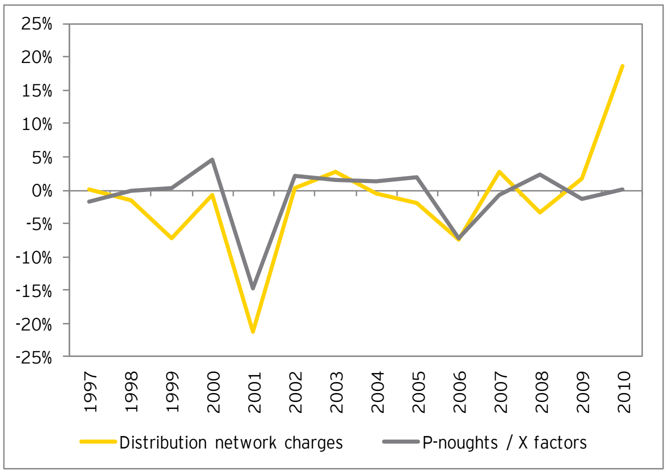
In other words, total network costs for Victorian domestic electricity customers have fallen despite increasing volumes.

4.1.5 Comparison with regulatory determinations

We have also cross-checked our findings by comparing the trend in network costs in Victoria between 1996 and 2010 with the P-noughts and X factors for the distributors' network businesses, allowed in regulatory determinations for this period. It is apparent from Figure 5 that there is a high degree of consistency between the two trend lines.

[20] The key relationship for cost is with the disaggregated growth in peak demand,

Figure 5 Victoria annual changes in electricity distribution network prices 1996 to 2010 (%)



Source: Ernst & Young analysis, AER, ESC, ORG

4.1.6 Victorian summary

Our analysis shows that for Victorian domestic electricity customers:

- Network costs have not been the driver of the increase in retail electricity prices for domestic customers between 1996 and 2010;
  - Distribution network costs have decreased by 20 per cent in real terms between 1996 and 2010, including AMI costs;
  - Transmission network costs have increased slightly by 2 per cent in real terms during this period, but are driven higher by other factors, such as the easement land tax paid by the transmission business in Victoria;
- In contrast, non-network costs (i.e. wholesale energy costs and retailers' costs) have increased by 31 per cent between 1996 and 2010.

These results are supported by the findings of all of the additional analysis we undertook, that is:

- Analysing the typical annual bill for the typical customer;
- Disaggregating electricity prices using the top down approach;
- Performing the equivalent analysis to disaggregate the domestic two rate tariff; and
- Comparing the findings on annual network charges against the P-noughts and X factors allowed in regulatory determinations made for the distributors' network businesses.

5. Other jurisdictions – New South Wales and Queensland

We have applied a similar approach to analyse the historical trend in domestic retail electricity costs and the disaggregation between the network and non-network components in NSW and Queensland.[21]

There were three key differences in our analysis of NSW and Queensland electricity prices:

► Prior to around 2001-02, we were constrained by the unavailability of network tariff data. To overcome this, we interpolated the network tariff data back to 1996 using the "P-noughts" and "X factors" allowed in each year of the regulatory period in determinations made by the economic regulator;

► Unlike in Victoria, the annual prices submitted to the regulator by NSW and Queensland distribution businesses do not disaggregate network prices into distribution (i.e. DUOS) and transmission (i.e. TUOS) prices. We were therefore unable to disaggregate network tariffs; and

► We adjusted for a distortion in Queensland retail electricity prices caused by the Uniform Tariff Policy. Refer to Section A.1.1 for more detail.

Our analysis shows that the increases in annual domestic electricity prices in NSW and Queensland paid by the typical customer between 1996-97 and 2010-11[22] are explained by increases in network costs.

Between 1996-97 and 2010-11, network costs paid by the typical customer in NSW and Queensland have increased in real terms by 65 per cent and 105 per cent respectively. Table 4 shows the results.

Table 4 Change in average annual electricity costs from 1996-97 to 2010-11 ($ per MWh, real 2010)

	Percentage change		Dollar change	
	New South Wales	Queensland	New South Wales	Queensland
Final retail price	+45%	+46%	+$67	+$65
Network	+65%	+105%	+$44	+$55
Non-network	+28%	+11%	+$22	+$10

Note: Figures may be affected by rounding. Source: Ernst & Young analysis

Several interested parties have cited the key drivers of increasing network costs (and hence electricity prices) in NSW and Queensland to include rising peak demand and the need to replace ageing and obsolete assets. These parties include AusGrid,[23] the Australian Energy Regulator (AER),[24] the Australian Industry Group[25] and the Reserve Bank of Australia.[26]

We present the following findings from our analysis of electricity prices in NSW and Queensland:

[21] We analysed NSW and Queensland as we believe they are the most relevant States to compare with Victoria.
[22] Electricity prices in NSW and Queensland were analysed on a financial year basis (as opposed to a calendar year basis as in Victoria) as it is consistent with the regulatory years over which electricity prices and regulated revenues are determined under the regulatory regime in NSW and Queensland.
[23] George Maltabarow, Managing Director of AusGrid, Appearance on Insight episode 'Power Play', 2 August 2011, transcript available at http://www.sbs.com.au/insight/episode/index/id/419/Power-Play#transcript
[24] AER, State of the energy market 2010, page 4
[25] Australian Industry Group, Energy shock: confronting higher prices, February 2011, page 21
[26] Reserve Bank of Australia, Developments in Utilities – Bulletin December Quarter 2010, available at http://www.rba.gov.au/publications/bulletin/2010/dec/2.html

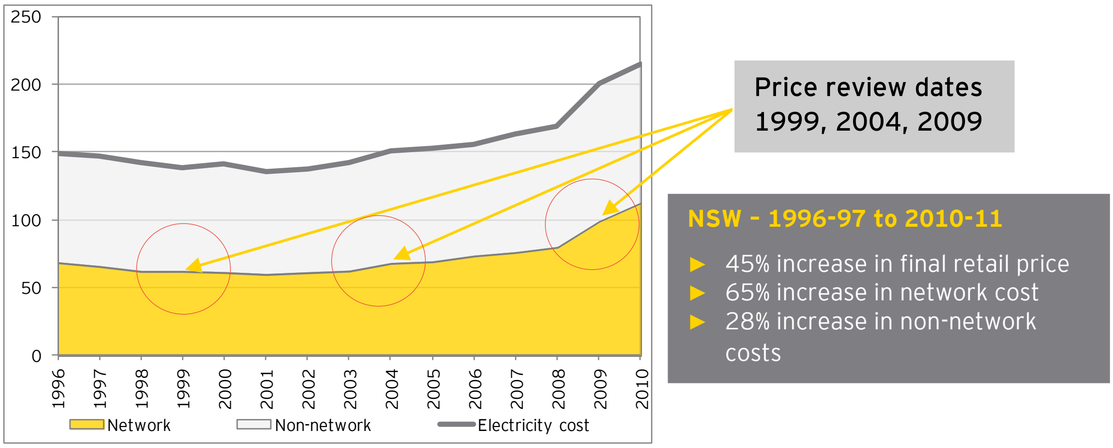
- Disaggregation of costs under the domestic single rate tariff on a per MWh basis;
- Typical annual bill;
- Comparing the change in network costs with price changes allowed in regulatory determinations; and
- Zero load growth for a typical customer (refer to Section B.3).

Our analysis shows that the change in annual network costs between 1996-97 and 2010-11 in NSW and Queensland are more significant than in Victoria.

5.1.1 Costs per MWh

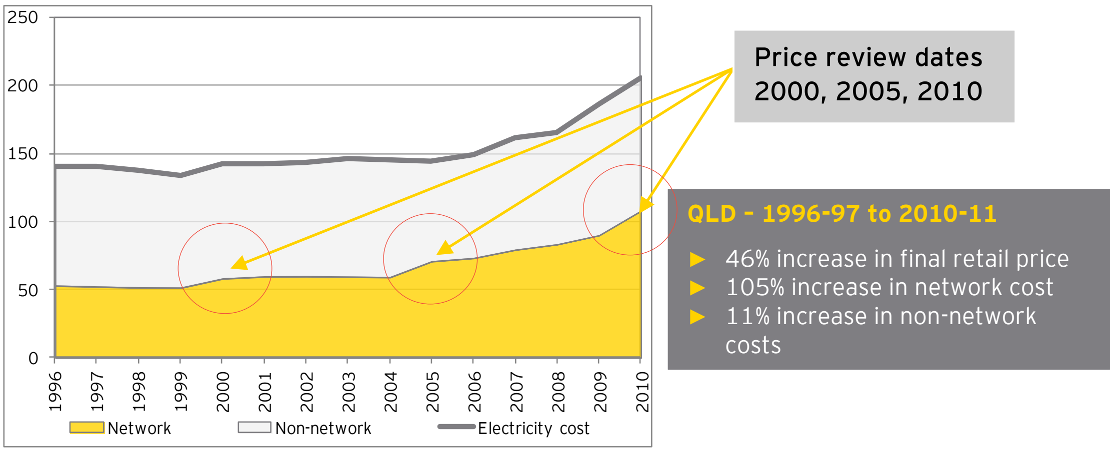
Figure 6 and Figure 7 show the disaggregation of costs under the domestic single rate tariff for NSW and Queensland. Costs are in real dollars per megawatt-hour (MWh) paid by the typical customer from 1996-97 to 2010-11. It also shows relevant price review dates and summarises the impact on the key components of electricity prices.

Figure 6 New South Wales electricity costs by component 1996-97 to 2010-11 ($ per MWh, real 2010)



Source: Ernst & Young analysis

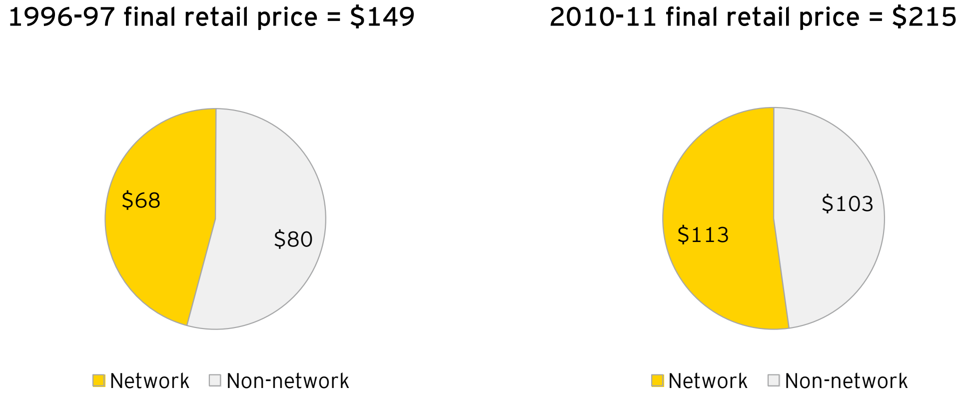
Figure 7 Queensland electricity costs by component 1996-97 to 2010-11 ($ per MWh, real 2010)



Source: Ernst & Young analysis

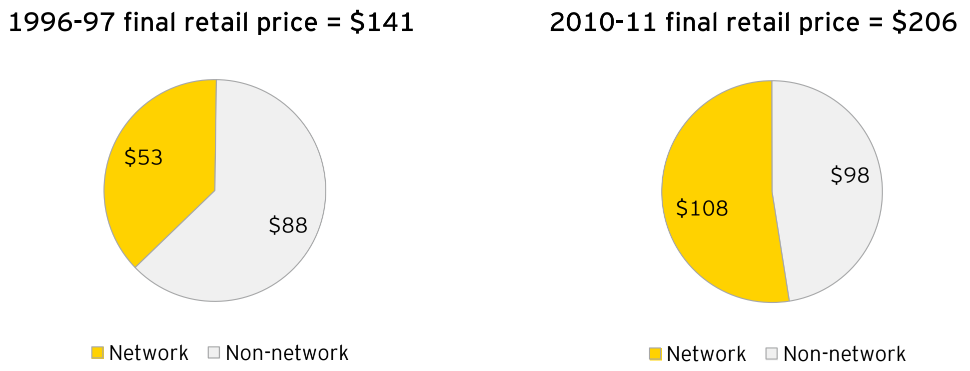
Figure 8 and Figure 9 show the breakdown of electricity costs between network and non-network costs in 1996-97 and 2010-11 for NSW and Queensland.

Figure 8 Composition of electricity costs in NSW 1996-97 and 2010-11 ($ per MWh, real 2010)



Note: Figures may be affected by rounding. Source: Ernst & Young analysis

Figure 9 Composition of electricity costs in Queensland 1996-97 and 2010-11 ($ per MWh, real 2010)



Note: Figures may be affected by rounding. Source: Ernst & Young analysis

5.1.2 Analysis of a typical average bill in nominal terms

For NSW, our analysis of the typical annual bill shows that the annual cost of electricity in nominal terms, paid each year by the typical customer[27] increased by 109 per cent from $720 to $1,503 between 1996-97 and 2010-11.

$720
The cost of the average annual domestic electricity bill in NSW in 1996-97

$1,503
The cost of the average annual domestic electricity bill in NSW in 2010-11

$783
Increase in the average annual electricity bill in NSW from 1996-97 to 2010-11

Table 5 Breakdown of a typical electricity bill in NSW ($ per customer, nominal)

	1996-97	2010-11
Annual cost of bill ($, nominal)		
Network	$331	$785
Non-network	$389	$718
Final retail price	$720	$1,503
Proportion of final retail price (%)		
Network	46%	52%
Non-network	54%	48%

Note: Figures may be affected by rounding. Source: Ernst & Young analysis

[27] Typical customer with an average consumption profile from 1996 to 2010

For Queensland, our analysis of the typical annual bill shows that the annual cost of electricity in nominal terms, paid each year by the typical customer[28] increased by 162 per cent from $615 to $1,608 between 1996-97 and 2010-11.

$615	$1,608	$993
The cost of the average annual domestic electricity bill in QLD in 1996-97	The cost of the average annual domestic electricity bill in QLD in 2010-11	Increase in the average annual electricity bill in QLD from 1996-97 to 2010-11

Table 6 Breakdown of a typical electricity bill in Queensland ($ per customer, nominal)

	1996-97	2010-11
Annual cost of bill ($, nominal)		
Network	$230	$844
Non-network	$385	$764
Final retail price	$615	$1,608
Proportion of final retail price (%)		
Network	37%	52%
Non-network	63%	48%

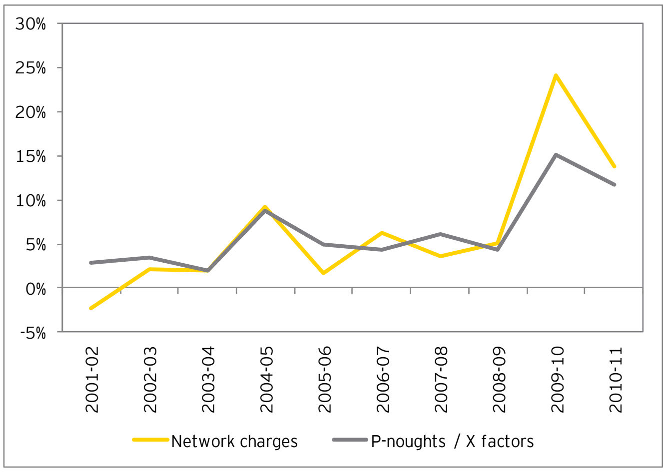
Note: Figures may be affected by rounding. Source: Ernst & Young analysis

5.1.3 Comparison with regulatory determinations

In NSW and Queensland, we performed the same cross-checks as in Victoria by comparing the trend in network costs with the annual price changes allowed by economic regulators in each year of the regulatory period in determinations made for the distributors' network businesses (i.e. P-noughts and X factors).[29]

These cross-checks for NSW and Queensland produced consistent results as the cross-checks for Victoria, suggesting reasonable consistency in the trend between network costs paid by a typical domestic customer and a distributor's P-noughts and X factors between 2001-02 and 2010-11.[30]

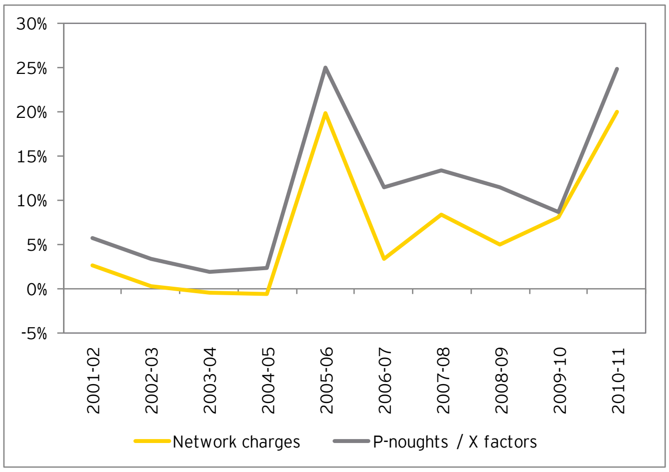
Figure 10 New South Wales annual changes in electricity network costs 2001-02 to 2010-11 (%)



Source: Ernst & Young analysis, AER, IPART

[28] Typical customer with an average consumption profile from 1996 to 2010
[29] Note that P-noughts and X factors for NSW and Queensland businesses are for distribution use of system prices only and do not include transmission use of system prices. These were sourced from distribution determinations made by the IPART, QCA and AER. See Appendix B for details.
[30] In NSW and Queensland, we have compared network charges and P-noughts / X factors from 2001-02 as were constrained by the unavailability of network tariff data in these States prior to this date.

Figure 11 Queensland annual changes in electricity network costs 2001-02 to 2010-11 (%)



Source: Ernst & Young analysis, AER, QCA

We have also undertaken an analysis of zero load growth scenarios in NSW and Queensland. These findings are presented in Appendix B.

Appendices to report

Appendix A: Approach

A.1. Methodology

The objective of our analysis is to:

- Determine the changes in domestic retail electricity prices in Victoria between 1996 and 2010; and

- Determine the changes in the components that make up the domestic retail electricity prices, having specific regard for the network component, the AMI (or advanced metering) component and the non-network component. The non-network component includes retailers' costs and wholesale energy charges and has been calculated as follows:

Non-network = Final retail price – Network – Advanced metering

We have undertaken two approaches to test the consistency and validity of our analysis: a bottom up and a top down approach. The bottom up approach involves disaggregating annual electricity costs based on actual tariffs and has been undertaken using the domestic single rate and domestic two rate tariffs. The top down approach involves disaggregating annual electricity costs based on the ABS's electricity price index.

These approaches, and our approach to replicating the analysis in NSW and Queensland, are described in more detail below.

A.1.1. Bottom up approach

This approach involves using the individual retail and network domestic single rate tariffs for each distribution business to estimate annual electricity costs based on average consumption profiles (i.e. a customer consuming the average level of domestic consumption in each year from 1996 to 2010). The annual electricity costs are then aggregated for the five distribution business to give a whole of Victoria annual electricity cost.

We have undertaken this analysis with both the domestic single rate tariff and the domestic two rate tariffs to test the sensitivity and robustness of our findings.

The steps involved in the bottom up approach for a customer in each distribution zone are set out below (using the single rate tariff analysis as an example):

1. Using the retailer's annual standing offer (i.e. default) domestic single rate tariff, determine the annual retail electricity cost for each year from 1996 to 2010 paid to the retailer by a domestic customer consuming the average amount of electricity each year. The average amount of electricity represents the average consumption of a customer in Victoria for each year.

2. Using the domestic single rate network tariff for the distribution zone, determine the annual network cost component for each year from 1996 to 2010 attributable to a domestic customer consuming the average amount of electricity each year.

3. For Victorian customers only, determine the annual costs paid by a domestic consumer for AMI for each year from 2006 to 2010. For domestic consumers under a domestic single rate tariff, the meter is assumed to be a single phase non off-peak meter that is read quarterly. These charges are currently prescribed by the AER and prior to 2010, by the Essential Services Commission of Victoria (ESC).

4. The non-network cost attributable to a customer consuming the average amount of electricity for each year is calculated as the difference between the annual retail electricity cost and the sum of the network and AMI costs.

5. Having determined the annual retail electricity costs paid by the average domestic consumer and the corresponding cost components in each distribution zone, State-wide annual electricity costs are calculated using a weighted average based on the volume of megawatt-hours of electricity distributed in each distribution zone.

New South Wales

In NSW, we were constrained by the unavailability of network tariff data before 2001-02 due to reasons such as the changing number and structure of tariffs over time, distribution businesses having merged, and significant changes in data storage platforms.

For these years, we consequently interpolated the network tariffs based on average annual price movements allowed by the regulator for the relevant year, using the approved P-nought and X factor adjustments. Refer to the Section on Key assumptions for more detail.

Queensland

As with NSW data, we were also constrained by the unavailability of network tariff data from network businesses in Queensland prior to around 2002. We consequently interpolated network tariffs for missing years based on approved P-nought and X factors adjustments or, where these were not available, changes in CPI.

In addition, our analysis in Queensland is complicated by the Uniform Tariff Policy, which ensures that all customers in Queensland pay no more than regulated prices available to customers in southeast Queensland. This means that the Queensland Government provides a Community Service Obligation (CSO) payment to subsidise the cost of electricity in regional Queensland.[31] The Queensland Government provided CSO payments of approximately $250 million to the electricity retailer in regional Queensland in 2009-10.[32]

This creates a distortion in the disaggregation of electricity costs in Queensland because retail electricity prices in regional Queensland are not fully reflective of the true network costs. The Uniform Tariff Policy requires a retailer in regional Queensland to set the same price for electricity as a retailer in southeast Queensland, despite the difference in network costs incurred in delivering electricity in these two areas.

This creates issues when it comes to disaggregating the change in domestic retail electricity prices in Queensland down to the network and non-network components, for example:

- The annual retail electricity costs produced by our analysis are lower than the fully cost-reflective prices;
- The network component is cost-reflective;
- As the non-network component of electricity prices is estimated as the difference between the retail price and the network component, the non-network component appears lower than it would be if retail prices were cost-reflective; and
- In practice, the distortion is corrected by the CSO payment which ensures that the incumbent retailer in regional Queensland recovers its network costs, while charging a retail price to its domestic customers which is lower than cost-reflective levels.

To correct this distortion, we have scaled down the network cost component in Queensland.

[31] http://www.ergon.com.au/your-home/accounts--and--billing/electricity-prices
[32] http://www.dme.qld.gov.au/zone_files/Electricity/ergon_energy's_role_in_a_competitive_queensland_electricity_market.pdf

Based on our other work in the electricity sector, we understand that the network component typically comprises between 45 per cent and 55 per cent of retail electricity costs in Queensland. This understanding is consistent with the findings of the QCA, which estimated that network costs account for 47% of the total cost of supplying electricity in 2009-10.[33]

We have thus normalised our estimate of the network cost component in Queensland, setting annual network costs to account for 50 per cent of the annual retail electricity price in 2010-11. We then extrapolated the normalised network cost in 2010-11 back to 1996-97 using the actual observed trend in network costs.

As a result, all charts on Queensland in this report reflects the trend in network costs over time, rather than the actual dollar value and the dollar values should be interpreted with some caution.

A.1.2. Zero load growth for typical customer scenario

This scenario has been analysed to attempt to determine the impact that consumption growth, or load growth, has had on the cost of the network component each year. To do this, we would have to determine what network charges would be if average consumption remained fixed from 1996 to 2010.

However without access to a network business's tariff model, this is not possible due to the complex nature of determining network charges.

Network businesses typically set tariffs based on two factors: the total amount of costs to recover through its network charges and the volume of electricity it distributes.

- Costs – if average consumption was fixed from 1996 to 2010, a network business would not necessarily have invested the same amount to expand or upgrade its network. This would mean that it is likely that the network business would set a lower network charge than otherwise because the total amount of costs to recover would be lower.
- Volume – given price is broadly a function of costs and volume, if a network business distributes less electricity than expected (for example, if growth in average consumption is zero), it would most likely set a higher network charge to ensure it recovers its costs.

Whether network charges would be higher or lower than otherwise would depend on which of these two opposing impacts (lower costs to recover versus lower volumes from which to recover costs) is stronger. This would require considering whether network investment in capital projects would have taken place based on the lower consumption profile which would be a complex process which we could not undertake with any certainty.

As a result, we have simplified the analysis to focus on the annual electricity costs paid by the typical customer from 1996 to 2010 if he or she fixed consumption at 1996 levels, holding all retail and network charges constant.

That is, this reflects the impact of load growth on one customer, rather than the impact on the annual cost of the network component of electricity.

The results should therefore be interpreted with some caution.

[33] Queensland Competition Authority, Final Decision on 2009-10 Benchmark Retail Cost Index, June 2009, page 5.

A.1.3. Top down approach

This approach relies on the ABS electricity price index to estimate average annual retail electricity costs for domestic customers, and only requires the aggregation of electricity costs from individual tariffs for one year.

The top down approach consists of the following steps:

1. Using the retailer's 2010 standing offer (i.e. default) domestic single rate tariff, determine the annual retail electricity cost paid to the retailer each year by a domestic customer consuming the average amount of electricity in 2010.

2. Extrapolate the annual retail electricity cost in 2010 back to 1996 in accordance with the ABS electricity price index to estimate average annual retail electricity costs for domestic customers consuming the average amount of electricity for each year from 1996 and 2009.

3. Estimate the annual network cost component attributable to customers consuming the average amount of electricity for each year from 1996 to 2010 by using the revenue per domestic customer as a proxy for the average annual price of electricity paid by a domestic customer. The revenue per domestic customer is the weighted average revenue per domestic customer based on the volume of megawatt-hours of electricity distributed in each distribution zone.

4. Annual costs for AMI are determined in an identical manner as under the bottom up approach.

5. The non-network cost attributable to a customer consuming the average amount of electricity for each year is calculated in an identical manner as under the bottom up approach.

We have elected to use the results of our down approach as a cross check on the results of our bottom up approach. We have done this for a number of reasons:

- The ABS electricity price index is a well-known and relied upon measure of retail electricity prices in Australia over time;

- There is a degree of uncertainty about how the ABS's price index is precisely calculated (e.g. which types of customers it applies to, does it include customers on market offers and default offers); and

- It is not as precise as the bottom up approach which involves using actual retail tariffs.

Nevertheless, we have undertaken a top down analysis to disaggregate annual electricity costs in Victoria, NSW and Queensland as a check of the robustness and sensitivity of our main findings.[34]

A.2. Data sources

All the data we have used in our analysis is publicly accessible. The Victorian electricity network businesses provided us with confidential data on consumption by tariff type to validate our analysis, but it has not been used in our analysis or presented in our findings. All of the findings are able to be replicated using publicly accessible information.

Table 7 shows the key data sources we used in our analysis.

[34] In all three States, the results of the top down analysis are consistent with our findings from the disaggregation of costs under the domestic single rate tariff.

Table 7 Data sources by State

	Victoria	New South Wales	Queensland
Retail standing offer tariff data	Victorian Government Gazette	Retail businesses (on request)	QLD Government Gazette
Network charge tariff data	Network businesses (on request)	Network businesses (on request)	Network businesses (on request)
Average consumption data (per customer)	ESAA	ESAA	ESAA
Per unit revenue indicators (e.g. revenue per customer, revenue per MWh)	AER / ESC annual performance reports	N/A[35]	N/A[36]
AMI costs	AER / ESC decisions	N/A	N/A
Electricity price index	ABS	ABS	ABS
Inflation data	ABS	ABS	ABS

Note: ABS = Australian Bureau of Statistics; AER = Australian Energy Regulator; ESAA = Energy Supply Association of Australia; ESC = Essential Services Commission of Victoria

A.3. Key assumptions

- Network charges refer to NUOS tariffs, which include both DUOS and TUOS tariffs.
- Unless otherwise stated, all prices and costs exclude GST to allow an appropriate comparison of prices and costs over time from 1996 to 2010.
- AMI costs only apply to Victoria in this report. AMI costs are generally not applicable in NSW and Queensland and have not been included in our analysis for these States as there is no Government-mandate for a small customer roll out of advanced meters at this stage.
- For simplicity, we assumed that the annual per unit metering service charges (for AMI) prescribed by the regulator[37] represents the average AMI costs paid by a domestic consumer each year.
    - In Victoria, the regulator prescribes metering service tariffs to cover meter provision and metering data services, which are either priced on a "per meter" or a "per NMI"[38] basis, depending on the distribution business.
    - Neither the number of meters nor the number of NMIs in the Victorian domestic sector is necessarily representative of the actual number of domestic customers in Victoria. This is because:
        - Domestic dwellings may have more than one meter for each NMI, such as domestic customers who have a dedicated hot water circuit meter in addition to an anytime energy meter. This customer would pay an annual metering service tariff either once (if they are charged per NMI) or twice (if they are charged per meter). For example, Powercor's metering service tariffs are charged per NMI, whereas SP AusNet's metering service tariffs are charged on a per meter basis; and

[35] The AER (and prior to 2008, IPART and the QCA) do not publish annual performance reports containing per unit revenue indicators for electricity distribution network businesses in NSW and Queensland for the 1996-2010 period.
[36] As above
[37] The AER assumed responsibility for the determination of metering services charges for the Victorian electricity network businesses from 2010. From 2006 to 2009, this was the responsibility of the ESC.
[38] A "NMI" is a National Metering Identifier is a unique reference number which defines a set of parameters and information about a particular meter point. The NMI system is implemented across the National Electricity Market.

- In some instances, domestic customers in multi-dwelling complexes (such as high rise apartments, social housing or student accommodation) may not have individual meters and hence would also not have individual NMIs. In these instances, a single NMI assigned to the entire complex.

- The process to obtain the data to aggregate information on an individual NMI and individual meter basis in each distribution zone in Victoria is complex and constrained by data availability. As a result, for simplicity, our analysis assumes that the metering service tariff (whether on a per NMI or per meter basis) prescribed by the regulator will be, on average across the State, broadly equivalent to the annual costs paid by the average domestic consumer.

- In this report, prices and consumption volumes are expressed on a calendar year basis in Victoria, and on a financial year basis in NSW and Queensland. This is consistent with the regulatory years (i.e. twelve-month periods) over which electricity prices and regulated revenues are determined under the regulatory regime in each of these States. Where data is expressed on a partial year basis, we have converted the data on a pro rata basis to calendar year (Victoria) or financial year (NSW and Queensland) terms.

- In some years, annual data on historical network tariffs were not available due to factors such as the merging of distribution businesses or significant changes in data storage platforms.[39] In these instances, we interpolated the tariffs based on average annual price movements allowed by the regulator for the relevant year, using the approved "P-nought" adjustments and "X factors"[40] and taking into account changes in CPI.[41] The P-noughts and X factors for each regulatory period are available from distribution determinations publicly available from the website of the relevant regulator.

- While we recognise that under a weighted average price cap form of price control, P-nought and X factor adjustments refer to the real percentage change allowed in the *weighted average* of a network business's entire suite of tariffs (rather than any individual tariff), and under a revenue cap these represent the real percentage change allowed in the annual revenue requirement, we consider that on balance, it is often likely to be a reasonable proxy for the percentage change in domestic tariffs. See Appendix B for detail of the P-noughts and X factors allowed by the regulator in previous determinations.

- Where a network business formed after 1996, network prices and X factors for each year from 1996 to the year of the entity's formation have been estimated as the average of the prices and X factors of the preceding businesses, typically weighted by the value of the capital base. In this report, we have used this approach for Country Energy prior to its formation in 2001 and for Ergon Energy prior to its formation in 1999.

- Figures presented in this report may be affected by rounding.

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[39] The following tariff data was not available: CitiPower tariffs 1996-2000, Powercor tariffs 1996-1998, EnergyAustralia tariffs 1996-97 to 2001-02, Integral Energy tariffs 1996-97 to 2000-01, Country Energy tariffs 1996-97 to 2000-01, Energex tariffs 1996-97 to 2001-02 and Ergon Energy tariffs 1996-97 to 2002-03.

[40] A "P-nought adjustment" is the term given to the percentage increase or decrease in the weighted average of an electricity network business's annual tariffs allowed by the regulator in the first year of a regulatory period. "X factors" are the percentage increase or decrease allowed in all subsequent years of a regulatory period (from the second to the fifth year).

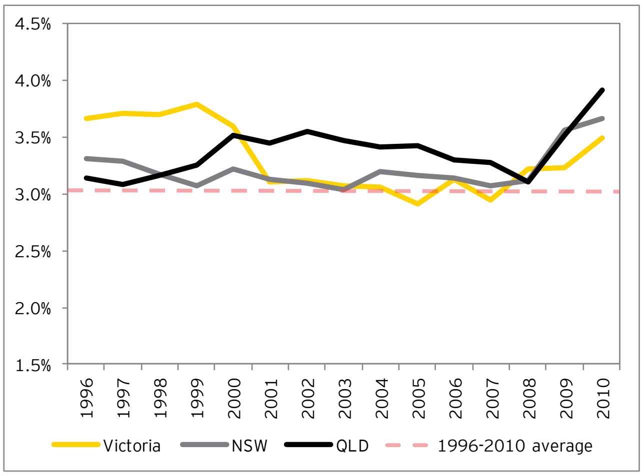
[41] Escalation of prices under *CPI–X* regulation, where a positive value for X indicates a real price decrease under the *CPI–X* formula.

Appendix B: Other results

B.1. Typical annual bill

Figure 12 shows the average annual electricity bill as a proportion of disposable income[42] in Victoria, NSW and Queensland from 1996 to 2010.

Figure 12 Average annual electricity bill as a proportion of disposable income 1996 to 2010 (nominal)



Note: Victorian results on calendar year basis (beginning 1 Jan), results for NSW / QLD on the year beginning 1 July.
Source: Ernst & Young analysis, ABS, ATO.

The proportion of disposable income spent by the typical domestic customer on electricity each year has increased in all three States in recent years. In Victoria, the proportion spent by typical domestic customers is somewhat lower than those in NSW and Queensland. In Victoria, it remains lower than it was in 1996.

However this only addresses the domestic customer with an average consumption profile. If this customer increased consumption by 10 per cent in 2010, the annual electricity bill would increase by:

- 4.3 per cent ($48) in Victoria;
- 8.7 per cent ($131) in NSW; and
- 8.0 per cent ($129) in Queensland.

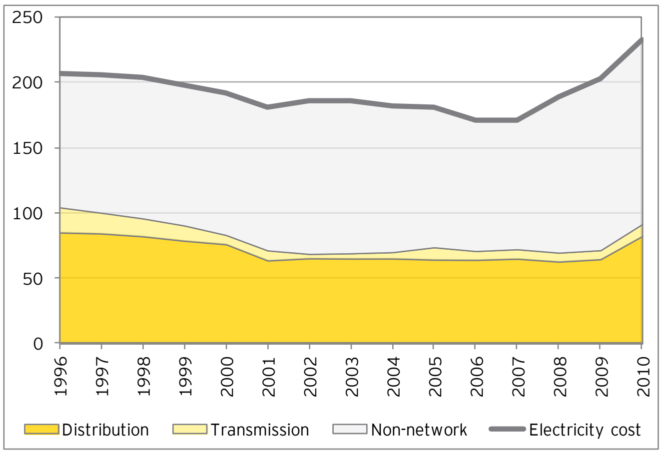
[42] Disposable income is calculated as income measured by the ABS average full time total earnings less tax payable in accordance with the ATO's individual income tax rates from 1996-97 to 2010-11.

B.2. Results by Victorian distributor

This section presents our findings of the disaggregation of electricity prices by distribution network business on a per MWh basis.

Jemena Electricity Networks (JEN)

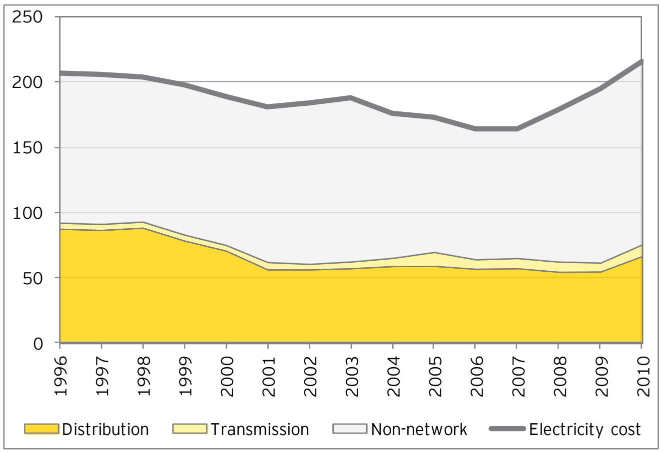
Figure 13 JEN electricity costs by component 1996 to 2010 ($ per MWh, real 2010)



Source: Ernst & Young analysis

CitiPower

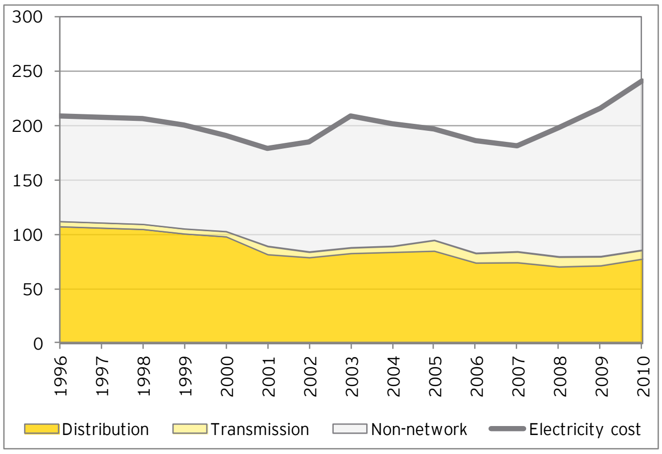
Figure 14 CitiPower electricity costs by component 1996 to 2010 ($ per MWh, real 2010)



Source: Ernst & Young analysis

Powercor

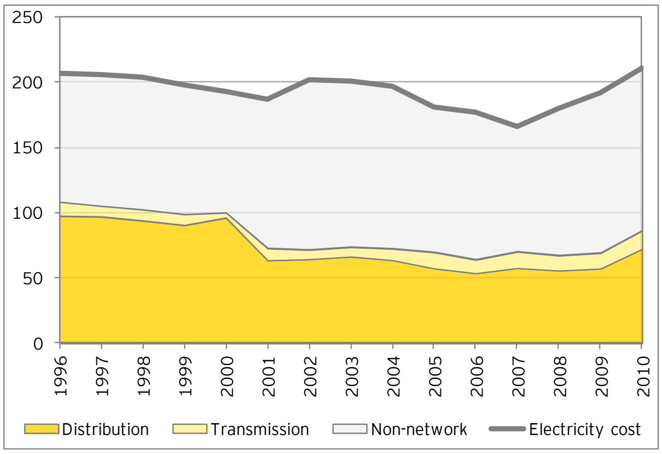
Figure 15 Powercor electricity costs by component 1996 to 2010 ($ per MWh, real 2010)



Source: Ernst & Young analysis

SP AusNet

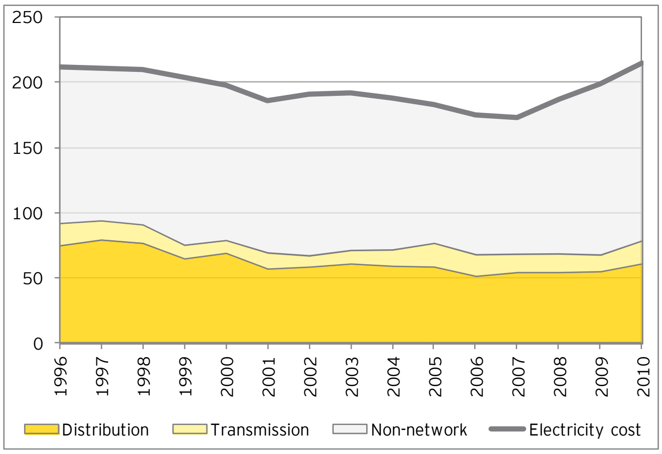
Figure 16 SP AusNet electricity costs by component 1996 to 2010 ($ per MWh, real 2010)



Source: Ernst & Young analysis

United Energy

Figure 17 United Energy electricity costs by component 1996 to 2010 ($ per MWh, real 2010)



Source: Ernst & Young analysis

The charts in Appendix B show that the volatility in TUOS appears to be exacerbated at the individual distributor level. This is likely to reflect the distributor's decisions in respect of tariff rebalancing between customer classes (i.e. any changes in who they recover these costs from), as our analysis is tariff-specific.

B.3. Zero load growth

This scenario has been analysed to attempt to determine the impact that consumption growth, or load growth, has had on the cost of the network component each year for the average domestic customer in NSW and Queensland. We have adopted a similar approach to our analysis of the zero load growth scenario in Victoria. Our findings are presented below.

Table 8 Annual distribution costs of a typical customer in NSW ($ per customer, real 2010)

	1996	2010	Change 1996-2010 ($)
Typical customer	$477	$785	+$308
Zero load growth	$477	$748	+$270

Note: Figures may be impacted by rounding. Source: Ernst & Young analysis

Table 9 Annual distribution costs of a typical customer in Queensland ($ per customer, real 2010)

	1996	2010	Change 1996-2010 ($)
Typical customer	$333	$844	+$511
Zero load growth	$333	$709	+$376

Note: Figures may be impacted by rounding. Source: Ernst & Young analysis

The results suggest that even holding consumption constant between 1996 and 2010, the annual network bill of typical domestic customers in NSW and Queensland still increases significantly.

An important point to note is that investment in the augmentation of a distribution network is driven by peak demand growth, not energy demand growth. It is therefore likely that growth in total energy demand may be flat or indeed falling, but if peak demand is growing then this will drive the need for investment in network capacity.

This point has been supported by stakeholders such as the Australian Energy Market Commission (AEMC)[43] and AusGrid.[44] In particular, the AEMC stated that peak demand has grown by 3.5 per cent per annum since 2005, compared to energy demand growth of 1.2 per cent per annum. Meanwhile according to Energex,[45] since 2001-02, peak demand growth has been approximately double the rate of growth in energy volumes.

The zero load growth analysis above (i.e. zero growth in energy demand) does not take into account changes in peak demand. As a result, the results should be interpreted with caution.

B.4. Regulatory decisions

The tables below show the P-noughts and X factors allowed by the regulator to the distribution network businesses in Victoria, NSW and Queensland from 1996 to 2010.

Table 10 Real allowed P-noughts and X factors by distributor in Victoria 1996 to 2015 (%)

<table>
<tr><th></th><th>JEN</th><th>CitiPower</th><th>Powercor</th><th>SP AusNet</th><th>United Energy</th><th>Regulatory Period</th></tr>
<tr><td>1996*</td><td>1.50</td><td>1.50</td><td>1.00</td><td>1.00</td><td>1.92</td><td rowspan="4">1996 to 2000: Victorian Tariff Order</td></tr>
<tr><td>1997*</td><td>1.50</td><td>1.50</td><td>1.00</td><td>1.00</td><td>1.92</td></tr>
<tr><td>1998*</td><td>1.50</td><td>1.50</td><td>1.00</td><td>1.00</td><td>1.92</td></tr>
<tr><td>1999*</td><td>1.50</td><td>1.50</td><td>1.00</td><td>1.00</td><td>1.92</td></tr>
</table>

[43] AEMC, Strategic Priorities for Energy Market Development Discussion Paper, 2011, page 4
[44] AusGrid, Response to the AEMC review of strategic priorities for Energy Market Development, May 2011, page 3
[45] Energex, Presentation to the Clean Energy Council Energy Efficiency Seminar, June 2009, slide 5, available online at: http://www.cleanenergycouncil.org.au/cec/mediaevents/Past-Events/EE-presentations/mainColumnParagraphs/0/text_files/file3/TERRY%20MCCONNELL.pdf

2000*	1.50	1.50	1.00	1.00	1.92	
2001*	17.10	12.40	19.60	21.80	12.90	2001 to 2005: ORG price review
2002*	1.00	1.00	1.00	1.00	1.00	
2003*	1.00	1.00	1.00	1.00	1.00	
2004*	1.00	1.00	1.00	1.00	1.00	
2005*	1.00	1.00	1.00	1.00	1.00	
2006*	3.80	8.70	17.30	9.30	14.70	2006 to 2010: ESC price review
2007*	2.50	2.50	2.50	2.50	2.50	
2008*	2.50	2.50	2.50	2.50	2.50	
2009*	2.50	2.50	2.50	2.50	2.50	
2010*	2.50	2.50	2.50	2.50	2.50	
2011	-4.99	6.41	-0.11	-9.99	-0.37	20111 to 2015: AER
2012	-3.00	-4.00	-3.00	-4.00	-1.00	
2013	-3.00	-4.00	-3.00	-4.00	-2.00	
2014	-3.00	-5.00	-3.50	-5.00	-6.00	
2015	-3.00	-5.00	-4.00	-5.00	-6.00	

* Note that from 1996 to 2010, P-nought and X factor adjustments were determined in distribution price reviews by the Victoria regulator or Government (i.e. the Victorian tariff order, the ORG and the ESC). From 2011 onwards, this responsibility was assumed by the AER. Positive values for X indicate a real price decrease and negative values for X indicate a real price increase.

Source: Victoria Electricity Supply Industry Tariff Order June 1995, Electricity Distribution Price Review 2001-05 (Office of the Regulator-General) and Electricity Distribution Price Review 2006-10 (ESC), Final Decision on Victorian Electricity Distribution Network Service Providers Distribution Determination 2011-15 (AER).

Table 11 Real allowed P-noughts and X factors by distributor in New South Wales 1995-96 to 2014-15 (%)

	AusGrid (EnergyAustralia)	Endeavour (Integral Energy)	Essential (Country Energy)	Regulatory period
1995-96*	3.50	3.50	1.45	1995-96 to 1998-99: IPART
1996-97*	3.50	3.50	1.45	
1997-98*	3.50	3.50	1.45	
1998-99*	3.50	3.50	1.45	
1999-00*	0.00	0.00	0.00	1999-00 to 2003-04: IPART
2000-01*	0.86	1.47	-2.26	
2001-02*	0.86	1.47	-2.26	
2002-03*	0.86	1.47	-2.26	
2003-04*	0.86	1.47	-2.26	
2004-05*	-7.00	-5.00	-7.00	2004-05 to 2008-09: IPART
2005-06*	-1.60	-1.50	-2.50	
2006-07*	-1.60	-1.50	-2.50	
2007-08*	-1.60	-1.50	-2.50	
2008-09*	-1.60	-1.50	-2.50	
2009-10*	-17.86	-12.58	-13.41	2009-10 to 2013-14: AER
2010-11	-12.00	-7.00	-13.31	
2011-12	-12.00	-7.00	-12.00	
2012-13	-12.00	-2.00	-12.00	
2013-14	-8.00	0.00	0.00	
2014-15	-	-	-	-

* Note that from 1995-96 to 2008-09, P-nought and X factor adjustments were determined in distribution price reviews by IPART. From 2009-10 onwards, this responsibility was assumed by the AER. X factors for 2014-15 are not known as this forms part of the next regulatory period (2014-15 to 2018-19). Positive values for X indicate a real price decrease and negative values for X indicate a real price increase.

Source: NSW electricity distribution price determinations March 1996, December 1999, 2004-05 to 2008-09 (IPART) Final Decision on NSW distribution determination 2009-10 to 2013-14 (AER).

Table 12 Real allowed P-noughts and X factors by distributor in Queensland 1995-96 to 2014-15 (%)

	Energex	Ergon	Regulatory period
1995-96*	No X factors available, prices extrapolated according to changes in CPI	No X factors available, prices extrapolated according to changes in CPI	1995-96 to 1999-00: QLD Government
1996-97*			
1997-98*			
1998-99*			
1999-00*			
2000-01*	-9.50	-18.80	2000-01 to 2004-05: QCA
2001-02*	0.50	-5.90	
2002-03*	0.50	-0.30	
2003-04*	0.50	-0.30	
2004-05*	0.50	-0.30	
2005-06*	-11.90	-30.80	2005-06 to 2009-10: QCA
2006-07*	-11.90	-5.70	
2007-08*	-11.90	-5.70	
2008-09*	-11.90	-5.70	
2009-10*	-5.50	-5.70	
2010-11	-18.20	-29.61	2010-11 to 2014-15: AER
2011-12	-7.90	-5.10	
2012-13	-7.90	-5.10	
2013-14	-7.90	-5.10	
2014-15	-7.90	-5.10	

* Note that from 2000-01 to 2009-10, P-nought and X factor adjustments were determined in distribution price reviews by the QCA. From 2010-11 onwards, this responsibility was assumed by the AER. Positive values for X indicate a real price decrease and negative values for X indicate a real price increase. Data on X factors for the 1995-96 to 1999-00 regulatory period could not be obtained and where necessary, network tariffs have been escalated in accordance with changes in CPI.
Source: Final Determination on Regulation of Electricity Distribution May 2001 and April 2005 (QCA), Final Decision on Queensland distribution determination 2010-11 to 2014-15 (AER).

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