



**ENERGY USERS' ASSOCIATION OF AUSTRALIA  
and  
ENERGY ACTION GROUP**

**NEW SOUTH WALES  
2004 ELECTRICITY DISTRIBUTION REVIEW**

**SUBMISSION  
(AND COMMENTS ON  
IPART SECRETARIAT  
PRELIMINARY ANALYSIS REPORT)**

October 2003



PARETO



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## EXECUTIVE SUMMARY

The Independent Pricing and Regulatory Tribunal's (IPART) review of New South Wales (NSW) electricity distribution for the regulatory period beginning on 1<sup>st</sup> July 2004 is an important review that will set future distribution charges, impact service levels and otherwise provide regulatory incentives for the four NSW distribution network service providers (DNSPs). All energy users in NSW, whether small or large, will be required to pay the charges that result from this review and will have no choice but to do so.

IPART, therefore, has an important obligation to end-users to ensure that network charges and service levels are 'competitive' relative to other states and for NSW industries competing in world markets. Ensuring that the DNSPs continue to strive for efficiency gains and deliver these to consumers is one of the main ways to do this and the incentive-based regulatory regime applied by IPART is the main vehicle for achieving this outcome.

A number of the issues arising from our assessment of the DNSP proposals for the next regulatory period, IPART's Preliminary Analysis of these proposals and the Meritec final report are of concern to consumers. This is particularly the case in regard to the following:

- The four DNSPs have proposed substantial increases in Operating and Maintenance (OPEX) expenditure for the next regulatory period that total around \$3.8 billion, which is \$250 million/year (or around 37%) above levels allowed by IPART for the current regulatory period in its 1999 Determination.
- The three largest DNSPs (EA, IE and CE) have also proposed very substantial increases in Capital Expenditure (CAPEX), or new investment, for the next regulatory period that total around \$4.7 billion over the five-year period. This is more than double (140% more than) the total CAPEX allowed by IPART for the current regulatory period.

The DNSPs claim the increased expenditure in the current regulatory period, and the increases proposed for the next regulatory period, is needed because both maximum demand and energy consumption have increased far more than forecast in the lead-up to IPART's 1999 Determination. Despite the expressions of concern by the DNSPs about the undesirable outcomes arising from mis-forecasting, we note that none of the DNSP submissions provides detailed information on the forecasts adopted by IPART in 1999, or sufficient detail on actual demand and energy consumption for the current regulatory period. Nor have the DNSPs or IPART focussed attention on detailed analysis of actual and forecast demand patterns.

This is of significant concern because of the dramatic impact that the DNSP proposals have on driving up total costs, revenue and prices.

As a minimum, it seems reasonable that IPART subject all the DNSPs forecasts for demand, energy consumption, customer numbers, CAPEX and OPEX to independent and rigorous analysis on a directly comparable basis for the current and next regulatory period. To assist IPART in this endeavour, this submission focuses on an assessment of the DNSPs' forecasts using information provided in the DNSPs' proposals, the IPART Secretariat Preliminary Analysis report and the Meritec final report.

However, our analysis confirms that the DNSPs' proposals also contain a number of obvious data discrepancies that limit the ability of consumers to assess the validity of the DNSPs' growth and expenditure forecasts and associated analysis by Meritec. Nevertheless, the data discrepancies can only reinforce our assessment that the DNSPs are likely to have mis-forecast at least some key building block components and therefore that acceptance of their forecasts would produce an erroneous regulatory determination by IPART.

The impact on consumers of such an outcome would be significantly higher prices, no improvements in service and exposure to a regulatory outcome that was inconsistent with the incentive regulation IPART was set up to practice.

A matter that should be of considerable concern to NSW consumers is that (mis)-forecasting of demand/consumption/OPEX/CAPEX is a 'classic' demonstration of either poor management by regulated companies or 'strategic behaviour' (i.e. regulatory gaming) in a Price Cap regime such as that adopted by IPART for the next regulatory period. This form of 'strategic behaviour', the existence of which has been acknowledged by IPART, has also been referred to explicitly by all of the UK regulators and the Victorian ESC, and identified as a major negative feature of 'incentive' regulation.

In particular, mis-forecasting in a Price Cap regime allows distributors to raise prices to higher levels than are warranted at the start of a new regulatory period and then 'out-perform' the regulators' benchmarks and claim this as an 'efficiency gain', which it clearly is not.

The Weighted Average Price Cap (WAPC) price control approach adopted by IPART for the next regulatory period is very close to that adopted by the Office of the Regulator-General (ORG) in Victoria (now the Essential Services Commission (ESC)) in its 2001 electricity distribution price review. The similarity between these approaches allows useful observations to be made about possible outcomes for NSW consumers and the DNSPs. Our submission comments on these.

We acknowledge that adopting a WAPC price control approach can be of advantage to consumers providing it produces an outcome that reduces the financial risk to efficient, well-managed DNSPs and 'justifies' IPART making judgements in favour of an efficient cost of capital. This should reduce the single biggest cost component facing distributors and, therefore, result in lower overall costs to consumers without any reduction in service. However, experience in Victoria suggests that IPART has a key responsibility to oversee application of the WAPC and ensure that DNSPs do not use their monopoly position to exploit consumers.

As a minimum, IPART should ensure that DNSPs disclose full details of the way in which they establish regulated charges, including those for excluded services, and that retailers be obliged to present information on all regulated on each consumer's bills in the form of itemised total amounts for each billing period.

We also find that IPART's pricing principles, whilst useful, are in need of some refinement. In particular, they should be strengthened in the area of protecting consumers from the worst excesses of monopoly pricing (eg tariff setting rules, appeals to the regulator and meaningful penalties), should provide for more notice of impending price changes (60-90 days rather than 30), should provide for more consumer involvement in annual tariff setting and should be subject to some other changes to improve their transparency and information disclosure. We note the move towards a WAPC, which provides for even greater price freedom for DNSPs than presently exists, makes this even more important.

We note that IPART is considering the inclusion of several optional 'incentive' factors into the WAPC formula. In regard to the 'S-factor', or service incentive, it is our view that, although we support the use of service incentives (positive and negative) where appropriate, New South Wales (NSW) needs to substantially improve its monitoring and reporting of DNSP performance before it any moves are made to introduce this form of incentive. Presently, the measurement and reporting of service incentives in NSW leaves much to be desired. In addition, IPART should identify performance measures that deliver outcomes of direct benefit (and meaning) to consumers, ensure that the 'reward/penalty' incentives facing DNSPs are based on real economic value to consumers and ensure that affected consumers have a reasonable chance of receiving benefits from the service incentive scheme.

A key part of IPART's assessment of, and judgement on, the DNSPs' proposals is to determine whether the DNSPs forecasts for the next regulatory period are reasonable. A primary source of information for this task comes from observations of past performance. Accordingly, a key focus of this submission is on information about current performance of the DNSPs and information related to their forecasts of sales volumes (demand, consumption, etc) and their forecast CAPEX and OPEX costs.

Our assessment highlights significant problems with the DNSPs forecasts for the next regulatory period. Specifically:

- With the exception of Country Energy's winter demand forecast, the DNSPs are projecting lower rates of demand growth and energy consumption than either TransGrid or NEMMCO.
- IPART engaged Meritec to undertake an assessment of the DNSPs' proposals in relation to total costs and the forecasts behind these. Meritec's failure to critically analyse the DNSP forecasts and to support and justify its opinions/judgements with sufficient quantitative analysis and 'hard' evidence seems likely to allow 'strategic behaviour' to be exercised by the DNSPs and leaves IPART with insufficient information to support its key judgements on the:
  - adequacy and reasonableness of the DNSPs' sales volume forecasts;
  - links between sales volumes and costs;
  - efficiency of CAPEX and OPEX cost projections; and
  - fairness and reasonableness of the DNSP's pricing proposals.

Given the discrepancies in the Meritec report, we are unable to deduce just what dollar value IPART might adopt if Meritec's recommendations on CAPEX are accepted. However, our assessment makes clear that the DNSP's proposals are excessive by a large margin. In our view, IPART should use average CAPEX amounts adopted by the ORG for the last Victorian electricity price review to 'benchmark' the DNSPs. This suggests that CAPEX allowances for the next regulatory period, on average, should not exceed those for the current regulatory period. That is, rather than accepting the DNSPs' proposals to allow for \$4.7 billion in CAPEX, we suggest that IPART need allow no more than \$3.1 billion, with perhaps some allowance for the impact of inflation if CAPEX efficiency gains are expected.

Nor are we able to understand the logic of Meritec's recommendations on forecast OPEX. Comparisons made by Meritec to NZ *lines businesses* suggest the NSW DNSPs' OPEX costs are substantially higher than they should be. Yet Meritec inexplicably recommends that IPART adopt the DNSP proposals? We believe that Meritec's recommendation is not adequately supported by evidence.

We are not able to make any firm recommendations on OPEX levels with the limited information available. However, it seems reasonable to suggest that IPART should allow no more than an extension of actual OPEX amounts for the current regulatory period adjusted, on some sensible weighted basis, for key OPEX cost drivers such as increases in customer numbers, consumption and/or total line lengths. That is, rather than accepting the DNSPs' proposals to allow for \$3.8 billion in CAPEX, we suggest that IPART need allow no more than \$3.2 billion, with perhaps some allowance for the impact of growth in energy consumption of customer numbers if no OPEX efficiency improvement is expected. Indeed, there are indications that IPART should be set challenging targets to reduce OPEX costs.

These are matters that IPART must address as part of its determination process, both to ensure the forecasts on which its determination is based are robust and reasonable and to ensure that there is no excessive exercise of 'strategic behaviour' by the DNSPs.

A major concern is that the Meritec final report has not provided IPART with sufficient evidence to substantiate the opinion/judgement it expresses. NSW consumers expect the assessment and ‘testing’ of the notional revenue requirements to be based on an assumption that the DNSPs are prudent, well-managed and efficient businesses. This should result in an outcome where IPART sets the notional revenue requirements at a challenging, but achievable level free of ‘monopoly rent’ or any allowance for inefficient operation. Such an approach is entirely consistent with regulatory practices in the UK and is in accordance with a key principle and objective of the National Electricity Code. This outcome provides the fundamental incentive for the DNSPs to pursue efficiency gains into the future and ensures value is delivered to consumers.

Accordingly, we have recommended that IPART conduct its own rigorous quantitative analysis of all of the DNSPs forecasts, and particularly their CAPEX and OPEX proposals using a process that follows as closely as possible that adopted by OFGEM for its current review of UK electricity distribution charges. This involves the use a range of techniques for assessing efficiency and projecting future costs through:

- assessment of an efficient level of costs for each company in a base year for which actual data is available;
- changes in the efficient level of costs over time; and
- for those companies not already at the estimated efficient level in 2002/03, a roll forward of actual costs to “catch up” to the efficient level.

OFGEM acknowledges that a degree of pragmatism will need to be applied in the final assessment of projected costs. However, it also recognises that it is important to explain in a transparent way how efficiency and future costs have been assessed and how they have been used to derive the allowed level of revenue.

In regard to other key aspects of the review, including the IPART Secretariat Preliminary Analysis:

- We endorse the view that IPART should not approve any retrospective compensation for overspending in the current regulatory period. We agree with the Secretariat that this would be inconsistent with the intent of the National Electricity Code, and would substantially weaken incentives for the DNSPs to operate efficiently.
- We recommend that IPART reconsider the Secretariat’s proposals for Weighted Average Cost of Capital (WACC) by -
  - adopting the simpler “Vanilla”, post-tax form of Capital Asset Pricing Model (CAPM) used by the ESC, ACCC and QCA, which allows for more transparent explanation of regulatory judgements and more transparent treatment of tax costs;
  - bringing the estimated cost of debt into line with that adopted by the ACCC in its recent draft decision on the Transend revenue application (i.e. 3.93% real); and
  - following an approach similar to that adopted by all UK regulators with forward-looking estimates for values of all key parameters in the CAPM, with the value of those estimates based, primarily, on information obtained from independent financial market sources and not from sources linked to DNSPs.

This would produce WACC (“Vanilla”, real, post-tax) of no more than 5.0% and place the DNSPs at the efficiency frontier in Australia. The lower WACC is some 150-230 basis points below that supported by the IPART Secretariat and would save NSW electricity users some \$120 million per annum over the next regulatory period.

Finally, we urge IPART and the DNSPs to reconsider pricing proposals aimed at providing incentives for consumers to moderate temperature sensitive demand growth. Our analysis supports the view that continuing penetration of air-conditioning will be costly for NSW consumers. If the same trends continue through to 2010, demand above 30°C could grow by

as much as 2,000-2,500MW and extreme demand volatility could increase by a similar order. This will increase costs in the whole NSW electricity system. Our analysis also supports submissions made by EA and IE that residential consumers make a substantial contribution to temperature-sensitive extreme demand growth.

In keeping with the key pricing principles developed by IPART, we support moves towards cost-reflective tariffs, providing they directly target the consumers who create cost drivers for the DNSPs and directly benefit consumers who can respond to these drivers. However, we find that the current DNSP proposals for inclining block tariffs and seasonal block tariffs are very blunt instruments that will not deliver their intended objectives of achieving cost-reflective pricing and promoting demand management. Instead they will impose unreasonable charges on substantial numbers of 'low-cost' users.

We believe that pricing should be part of a suite of options that will assist consumers activate effective demand management (DM). We also believe that tariffs must be based on the principle of cost-reflectivity and also provide customers with genuine choices. This is important, not only for protecting the interests of consumers but also for maximising the effectiveness of the tariff changes in promoting more efficient patterns of consumption.

Therefore, it seems reasonable to expect that IPART will examine this issue in some detail. The DNSPs initiatives should be extended to include examination of the costs and benefits for roll-out of interval meters, accompanied by a suite of price and non-price demand management incentives including time of use (ToU) tariffs, interruptible tariffs and a comprehensive public education and information campaign. The DNSPs' programs need to be supported by appropriate changes and additions to IPART's regulatory framework, and means found to stimulate retailers to offer suitable products to consumers.

We therefore recommend that IPART, and the DNSPs, work closely with consumer groups to examine these options. If this process can demonstrate an overall benefit to NSW consumers, IPART and the DNSPs should publicly commit to workable targets for the further development of an easy-to-use load management infrastructure for small business and residential customers that is significantly more ambitious than commitments outlined in the DNSP submissions to IPART.

In particular, we draw IPART's attention to the findings from the EUAA Demand Side Response (DSR) Facility Trial conducted last summer. Several aspects of the Trial and its outcomes are directly relevant to the current price review process and to the (likely) content of the final SKM report. The most relevant are that:

- the Trial clearly identified opportunities for DM to deliver benefits in the network sector, but a lack of regulatory incentives operated to limit the willingness of distributors to respond to DSR options; and
- the end-users and the distributors who participated in the Trial both emphasised the importance of 'positive' commercial incentives to stimulate DM.

That is, the Trial demonstrated that both groups are able to identify opportunities for DM, but also that both expect to, at least, recover their costs. The end-users who participated in the Trial were large commercial and industrial consumers, who were willing to respond but only if it was commercially beneficial and they were sufficiently aware of the opportunities. Although not strictly part of the DSR Trial, we expect that some, possibly many, small consumers would be able and prepared to offer DM if the infrastructure (eg meters, ripple control devices, etc) existed to allow them to do so, they were sufficiently aware of the opportunities (or their retailers were) and 'positive' incentives ('carrots') were offered to them.

We urge IPART to consider these matters in framing its draft determination and would gladly assist the Tribunal in this area.

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## **1. INTRODUCTION**

The Energy Users' Group of Australia (EUAA) and the Energy Action Group (EAG) are pleased to have an opportunity to provide this submission to the Independent Pricing and Regulatory Tribunal's (IPART) review of New South Wales (NSW) electricity distribution for the regulatory period beginning on 1<sup>st</sup> July 2004. The submission comments on the proposals made by the four NSW distribution network service providers (DNSPs), as well as several other key documents including the IPART Secretariat's Preliminary Analysis report.

This is an important review that will set future distribution charges, impact service levels and otherwise provide regulatory incentives for the DNSPs. All energy users in NSW, whether small or large, will be required to pay the charges that result from this review and will have no choice but to do so.

The review also needs to be seen in the context of the significance that distribution charges have for energy users. They are a significant component of the delivered cost of energy to the vast majority of customers, on average comprising between one-third and two-thirds of their electricity charges and three-quarters of network charges. For some large consumers, who are EUAA members in NSW, they can be up to one-half of the bill. In addition, IPART's Determination will have an impact on the service levels that end-users receive from their DNSP for the next five years and have a major impact on consumption options for all consumers well beyond that.

This means that the IPART Determination will have an important impact on energy users in NSW for the foreseeable future. IPART, therefore, has an important obligation to end-users to ensure that network charges and service levels are competitive relative to other states and for NSW industries competing in world markets. Ensuring that the DNSPs continue to strive for efficiency gains and deliver these to consumers is one of the main planks of energy reform and the incentive-based regulatory regime applied by IPART is the main vehicle for achieving this outcome.

### **1.1. Preliminary Comment**

This submission has been prepared for the EUAA and EAG by Pareto Associates Pty Ltd (Pareto) and Marsden Jacob Associates (MJA). The submission builds on material provided to IPART in preliminary submissions made by the EUAA and EAG and is based on independent analysis of material provided to IPART by the DNSPs, IPART's consultants and other reports, publications and data in the public domain.

However, the views presented in the submission are those of the EUAA and EAG.

Every effort has been made to cover material of relevance and importance to large and small electricity consumers in NSW. But IPART should note, and make some allowance for the fact, that the analysis and scope covered in the submission are far from complete because:

- Material provided to IPART by the DNSPs contains some significant discrepancies that could not be resolved or explained within the time and resources available for preparation of the submission.
- The final report from Meritec, which should form a key role in informing IPART's analysis of, and judgement on, the DNSPs' proposals is, in our considered view, clearly inadequate for the purpose intended.
- IPART has decided not to release two key documents that directly relate to assessment of the DNSPs proposals prior to the deadline for submissions by end-users. These reports cover an independent assessment of the demand and

consumption forecasts prepared by the DNSPs<sup>1</sup> and the Final Report by SKM on *Reducing Regulatory Barriers to Demand Management*.

- Neither EUAA nor EAG can resource analysis of the all the issues that arise in regulators' reviews of monopoly network service providers.
- The NEM Advocacy Panel decided to fund only part of the application made by EUAA and EAG for funding assistance.

## 1.2. Key Concerns

As this submission makes clear, we have real concerns about negative impacts that the DNSPs' proposals would have on these outcomes, especially those of EnergyAustralia (EA), Integral Energy (IE) and Country Energy (CE).

A number of the issues arising from our assessment of the DNSP proposals for the next regulatory period, IPART's Preliminary Analysis of these proposals and the Meritec final report are of concern to consumers. This is particularly the case in regard to the following:

- The four DNSPs have proposed substantial increases in Operating and Maintenance (OPEX) expenditure for the next regulatory period that total around \$3.8 billion, which is \$250 million/year (or around 37%) above levels allowed by IPART for the current regulatory period in its 1999 Determination.
- The three largest DNSPs (EA, IE and CE) have also proposed very substantial increases in Capital Expenditure (CAPEX), or new investment, for the next regulatory period that total around \$4.7 billion over the five-year period. This is more than double (140% more than) the total CAPEX allowed by IPART for the current regulatory period.
- The DNSPs claim the increased expenditure in the current regulatory period, and the increases proposed for the next regulatory period is, and has been, needed because both maximum demand and energy consumption have increased more than forecast in the lead-up to IPART's 1999 Determination.

Despite the expressions of concern by the DNSPs about the undesirable outcomes arising from mis-forecasting, we note that:

- None of the DNSP submissions provides detailed information on the forecasts adopted by IPART in 1999, or sufficient detail on actual demand and energy consumption for the current regulatory period.
- None of the documents posted on the IPART Website related to the 1999 Determination contain any detailed information about the energy and demand forecasts on which that Determination was based.
- IPART's consultants (Worley-PWC) commented in their October 1998 report that none of the (then six) DNSPs had provided details of Load Forecast Models for assessment by the consultants.<sup>2</sup>

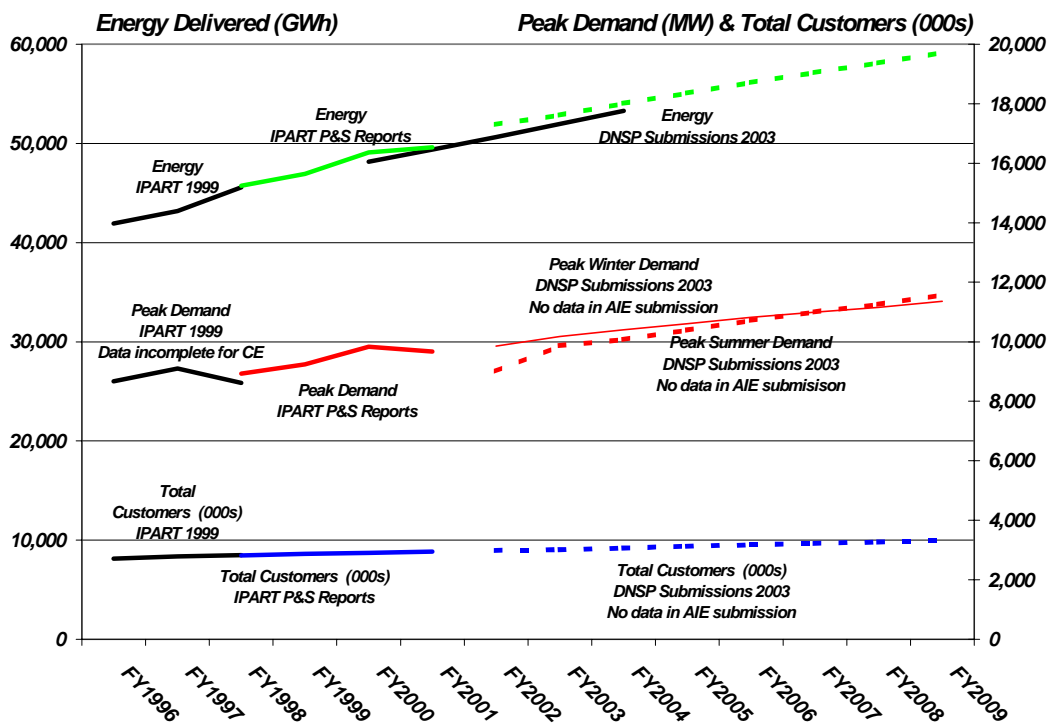
We have collated what information we could find from documents on the IPART Website, including the IPART Secretariat Preliminary Analysis report to produce Figure 1 below.<sup>3</sup>

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<sup>1</sup> Assessment of the demand and consumption forecasts is included in the scope of work for Meritec, but IPART has advised us that Meritec's role was limited to satisfying itself that the DNSP demand and consumption forecasts were adequate for Meritec to undertake its review of expenditure. We argue in the submission that this has seriously compromised the recommendations in Meritec's final report and seriously jeopardised any reliance that IPART may have been able to place on the Meritec report.

<sup>2</sup> Footnote 3, p4.1, *Report to the Independent Pricing and Regulatory Tribunal on Capital Expenditure Review in NSW Electricity Distribution - Final Report*, IPART Report RP10, Worley in association with PricewaterhouseCoopers, October 1998.

<sup>3</sup> DNSP forecast data is for Base Case, Median or Expected conditions.



**Figure 1: Comparison of actual and forecast demand, consumption and customer numbers for NSW DNSPs**

Source: DNSP submissions and IPART reports.

Note: Peak demand forecasts in IPART 1999 Determination incomplete for rural DNSPs. AIE provides little detail of demand or customer numbers for next regulatory period.

The information in Figure 1 shows that while customer numbers and energy consumption are growing, the rate of growth from FY1998 does not appear to be either extreme or substantially different to the period from FY1996. Similar plots for the individual DNSPs are included in Appendix A. These show:

- noticeably above the 1999 forecast growth in energy consumption for EA, an unexplained reduction in energy consumption for IE in FY2001 (in the IPART Price and Service report data), and reasonably close actual and forecast energy consumption for CE;
- significant difference between forecast and actual demand for IE and a noticeable ‘blip’ in maximum demand for EA in FY2001 (in the IPART Price and Service report data);
- an apparent ‘reduction’ in forecast energy consumption for in all three major DNSPs for the next regulatory period compared to current indicative trends; and
- apparently modest summer peak demand forecasts for EA and CE for the next regulatory period.

Despite the experiences and outcomes in the current regulatory period, neither the DNSPs nor IPART appears to have focussed attention on detailed analysis of actual and forecast demand patterns. This is of significant concern because of the dramatic impact that the DNSP proposals have on driving up total costs, revenue and prices.

Large increases in costs have a significant impact on prices to all consumers in NSW. Consumers have no choice but to pay whatever distribution prices the DNSPs set and need to be assured, through IPART’s Determination, that they will only be required to pay prices reflecting a balance in the needs of end-user and the DNSPs. That is, prices that would be

reasonable if electricity distribution services were provided in a competitive market. We do not believe that the DNSPs' proposals will achieve either objective. However, the proposals, if accepted by IPART, will impact adversely on the competitiveness of businesses in NSW as well as investment and jobs; and will also impact dramatically on small consumers.

*As a minimum, it seems reasonable that IPART subject all the DNSPs forecasts for demand, energy consumption, customer numbers, CAPEX and OPEX to independent and rigorous analysis on a directly comparable basis for the current and next regulatory period.<sup>4</sup>*

To assist IPART in this endeavour, this submission focuses on an assessment of the DNSPs forecasts of demand, energy consumption, CAPEX and OPEX using information provided in the DNSPs proposals, the IPART Secretariat Preliminary Analysis report and the Meritec final report.

### **1.3. Data discrepancies**

Our analysis confirms that the DNSPs' proposals also contain a number of obvious discrepancies that limit the ability of consumers to assess the proposals. For example:

- there are significant discrepancies in the expenditure figures in some of the DNSPs' submissions and the Spreadsheet models posted on the IPART Website -
  - EA appears to quote higher (>10%) OPEX figures in its submission compared to the Spreadsheet;
  - CE appears to quote higher (>10%) CAPEX figures in the Spreadsheet compared to the submission; and
  - It is not clear that EA is quoting its cost figures on exactly the same basis as other DNSPs because it sometimes includes costs associated with its transmission activities that are regulated by the ACCC and it sometimes includes costs for 'possible Excluded Services' with costs that will be included in revenues covered by the weighted average price cap.
- there are noticeable and unexplained differences between the consumption and maximum demand forecasts in the CE, EA and IE submissions and Spreadsheets;
- in addition, the DNSPs growth forecasts are noticeably at variance with the forecasts published by Transgrid and in the latest NEMMCO Statement of Opportunities for NSW. In each case, the DNSPs are forecasting significantly lower consumption and maximum demand for every year over the next regulatory period than the Transgrid and NEMMCO forecasts; and
- there is also an inconsistency between our analysis of extreme summer temperature demand (using NEMMCO and Bureau of Metrology half-hourly data) and the DNSP maximum demand forecasts.<sup>5</sup>

Of even more concern is that it is virtually impossible to correlate data in some of the DNSPs' submissions with values quoted in the Meritec<sup>6</sup> final report, or in the 1999 IPART Determination. For example Meritec says that the FY2000 value of forecast CAPEX for EA

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<sup>4</sup> As detailed later in this submission, the attempt by Meritec to present such information is inadequate.

<sup>5</sup> This does not necessarily mean that the DNSP forecasts are wrong, but given the difficulties claimed by the DNSPs due to 'forecasting errors' for the current regulatory period, it is reasonable for consumers to expect that the DNSPs would pay particular attention to explaining in detail how they derived their forecasts for the next regulatory period.

<sup>6</sup> In addition to the issues outlined above, it is noted that Meritec has used different bases for the Denominator and Numerator in estimating the percentage differences between forecast and actual CAPEX in the current regulatory period which is unconventional and confusing.

was \$110M (without *Excluded Services or Other*) or \$127M (Total). The relevant figure from the IPART Determination is \$148M, which is not consistent even after allowing for inflation.

It is of equal concern that actual values quoted by Meritec appear to bear little relation to the actuals reported by IPART in its *Annual Price and Service Reports*, or those reported by the DNSPs in their submissions. Again for example, IPART reports that EA spent CAPEX of \$158M in FY2000<sup>7</sup> and \$307M in FY2001.<sup>8</sup> EA says it spent \$256M and \$273M respectively<sup>9</sup> and Meritec says \$313M and 301M (Total) or \$190M and \$241M (without *Excluded Services and Other*).

Combined, the data discrepancies outlined above greatly limit the ability of consumer groups to assess the validity of the DNSPs' growth and expenditure forecasts and associated analysis by Meritec. Nevertheless, the data discrepancies can only reinforce our assessment (see section 3) that the DNSPs are likely to have mis-forecast at least some key building block components.

#### **1.4. *Mis-forecasting by the DNSPs - a case of regulatory gaming or technical inadequacy?***

The characteristic 'information asymmetry' in 'light-handed' regulatory regimes, such as those in place in NSW, means that nearly all of the forecast information used to set prices is supplied by the DNSPs.

A significant challenge created by this 'information asymmetry' and the profit maximising incentives in the regulatory regime is that regulated companies can use forecasts for 'strategic' purposes. As noted by IPART in connection with expenditure forecasts: "*Arguably there are incentives for over-estimating forward looking estimates of capital expenditure and operating expenditure.*"<sup>10</sup> Similarly in relation to energy consumption forecasts, IPART observes that under a price cap formula there is an "*incentive for DNSPs to understate their volume forecasts in order to earn greater revenue than would be required to recoup costs.*"<sup>11</sup>

These are two areas of major concern to end-users because DNSPs can exercise 'strategic behaviour' to maximise revenues and increases prices by:

- overstating CAPEX and OPEX forecasts; and
- understating volume forecasts.

Such outcomes would clearly not be in the interests of consumers, and can potentially act to discredit the regulator and the regulatory regime.<sup>12</sup>

On the other hand, the experiences in NSW in the current regulatory period also show that regulated companies can make incorrect forecasts of sales volumes and/or costs. This can

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<sup>7</sup> Table A.4.2, p30, IPART Jul 2001

<sup>8</sup> Table 6.6, p27, IPART Sep 2002

<sup>9</sup> Table 4, p(vi), EA Summary, Apr03

<sup>10</sup> IPART (2003) *Review of Capital Expenditure and Operating Expenditure of the NSW Distribution Network Service Providers*", Invitation to Tender p 2.

<sup>11</sup> IPART (2003) *Determining Sales Volumes for the 2004 Electricity Network Review*, Discussion Paper DP 65, p 1.

<sup>12</sup> A notable example was the outcome from the 1994 UK electricity distribution review. Immediately following publication of the OFFER Director-General's decision, Trafalgar House launched a bid for Northern Electric that demonstrated 'the City' placed a much higher value on Northern's regulated revenue than OFFER had assumed. In a March 1995 Press Release, the Director-General said "... I ... consider it important that there is general confidence in the regulatory regime. I therefore need to look at these issues further." The issues included "... whether the price control proposals are sufficiently demanding on the RECs (distributors) and whether they represent an appropriate balance between the interests of customers and shareholders." The process of review initiated by the Director-General eventually led to a re-opening and re-determination of the price controls in September 1995.

create undesirable outcomes for consumers, particularly if the companies decide to ‘sacrifice’ asset condition, or service standards, in an effort to maintain levels of profitability demanded by shareholders.

A matter that should be of considerable concern to NSW consumers is that mis-forecasting of demand/consumption/OPEX/CAPEX is a ‘classic’ demonstration of either poor management by regulated companies or ‘strategic behaviour’ (i.e. regulatory gaming) in a Price Cap regime such as that adopted by IPART for the next regulatory period.

This form of ‘strategic behaviour’ has been referred to explicitly by all of the UK regulators and the Victorian ESC, and identified as a major negative feature of ‘incentive’ regulation. In particular, mis-forecasting in a Price Cap regime allows distributors to raise prices to higher levels than are warranted at the start of a new regulatory period and then ‘out-perform’ the regulators’ benchmarks and claim this as an ‘efficiency gain’, which it clearly is not.

As an illustration of this behaviour, we reproduce in Figure 2 below a diagram based on information in the UK regulator OFGEM’s 1999 decision on electricity distribution pricing. This shows that UK distributors have always forecast very much higher CAPEX requirements than allowed by the regulator and always achieved actual CAPEX commitments below the regulator’s forecasts. Virtually identical outcomes are observed in other UK industries and the Victorian electricity and gas distribution industries (for both CAPEX and OPEX), all of which are subject to regulated price cap regimes similar to that to be adopted by IPART in 2004.

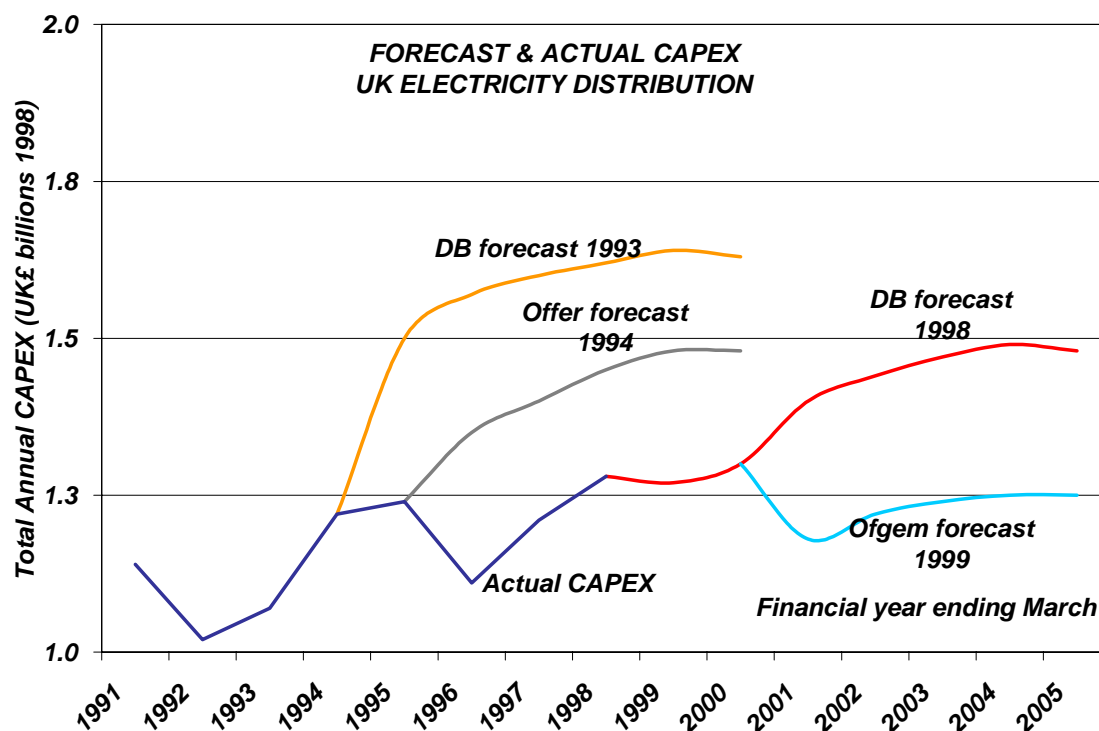


Figure 2: Forecast and actual CAPEX for UK electricity distributors

Source: OFFER and OFGEM Decisions and industry performance reports.

Evidence suggests that the NSW DNSPs’ forecasts for the current regulatory period were in error, which even they acknowledge in their submission and in public presentations. Bearing this in mind, IPART needs to adopt the Secretariat’s proposed position and disallow retrospective compensation for claimed over-expenditure in the current regulatory period. This prior experience means that IPART also needs to ensure that it does not succumb to further examples of ‘strategic behaviour’ in forecasts for the next regulatory period.

IPART also has an obligation to ensure it follows and sets ‘good regulatory practice’, in this determination. It is well known that regulators follow the precedents set by their peers and this potentially exposes customers in other jurisdictions to any precedents that IPART set here.

It would be unacceptable to NSW energy users to be left bearing the regulatory risks (and higher distribution charges) associated with the situation caused by poor DNSP forecasts. The owner of the NSW DNSPs (and management) should be made to accept responsibility for these serious errors and they should not be left to compound on energy users over the next regulatory period.

We also note that there has been public comment that the NSW Government has taken substantial dividends from the DNSPs in the past and that this seems to have placed additional pressures on the expenditure programs of the DNSPs. The Government clearly needs to avoid this type of behaviour in future and should not expect NSW energy users to now pay more in distribution charges as a result.

*If regulated companies ‘out-perform’ the benchmarks set by regulators (by keeping actual costs below forecast costs), they generate higher profit margins which they are permitted to retain for (at least) the current regulatory period.<sup>13</sup>*

*However, deliberate ‘over-forecasting’ of cost components and ‘under-forecasting’ of sales volume components is also a ‘classic’ tactic. If regulated companies can get a regulator to accept higher than efficient costs, or lower than expected sales volumes, the companies generate higher profits without having to ‘do the hard yards’ of striving for efficiency gains.*

*It is essential that regulators subject the companies’ proposals to rigorous, critical scrutiny and analysis. This not only ensures the efficiency incentive is retained, but it also provides the evidence to inform the judgements regulators have to make and ensures that the regulator is able to demonstrate that the long-term interests of consumers are being protected.*

### **1.5. Structure of this submission**

The IPART Secretariat Preliminary Analysis report deals with a number of key issues related to assessment of the DNSPs’ proposals, but leaves others to be addressed in further analysis. This will hopefully be undertaken as part of its Draft Determination.

This submission comments on issues raised in the IPART Preliminary Analysis report. It also includes comments related to review and analysis of the Meritec final report to IPART.

The structure of this submission matches as closely as practicable the structure and sequence of the IPART Secretariat Preliminary Analysis report. This is intended to assist IPART by making it as easy as possible to correlate our comments, suggestions and recommendations with the content of the Preliminary Analysis report.

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<sup>13</sup> The UK and Victorian regulators have generally implemented (so-called) ‘Efficiency Carry-over’ mechanisms that allow the regulated companies to retain ‘efficiency gains’ for (generally) at least the full duration of one regulatory period. This is intended to provide exactly the same ‘incentive’ to pursue ‘efficiency gains’ in each year of a regulatory period.

## **2. REGULATORY ARRANGEMENTS**

IPART has established that it will regulate network tariffs and other fees using:

- a weighted average price cap (WAPC) to set distribution charges;
- a pass through of transmission charges; and
- a separate process to set all miscellaneous service and monopoly service fees.

It will set the WAPC for distribution charges by:

- undertaking a building block analysis to determine a notional revenue requirement for each year of the regulatory period for each DNSP;
- testing these notional revenue requirements using financial analysis to ensure they allow the businesses to remain financially viable;
- taking the notional revenue requirements and, using throughput growth forecasts, converting them into price movements; and
- consider whether other factors should be included in the WAPC, such as a service quality incentive mechanism, a correction factor, demand management (DM) payments, other specified costs and a mechanism to deal with forecasting inaccuracies.

This approach is very close to that adopted by the Office of the Regulator-General (ORG) in Victoria (now the Essential Services Commission (ESC)) in its 2001 electricity distribution price review.

The close similarity between the approach adopted by ORG and that proposed by IPART allows useful observations to be made about possible outcomes for NSW consumers and the DNSPs. This submission comments on these where they are relevant.

IPART should also note that NSW consumers expect the assessment and ‘testing’ of the notional revenue requirements to be based on an assumption that the DNSPs are prudent, well-managed and efficient businesses. This should result in an outcome where IPART sets the notional revenue requirements at a challenging, but achievable level free of ‘monopoly rent’ or any allowance for inefficient operation. Such an approach is entirely consistent with regulatory practices in the UK and is in accordance with a key principle and objective of the National Electricity Code “*to regulate the non-competitive market for network services in a way which seeks the same outcomes as those achieved in competitive markets*”.<sup>14</sup> That is, the notional revenue requirements should be sufficient for a prudent, well-managed and efficient business to operate profitably, but no more. This outcome provides the fundamental incentive for the DNSPs to pursue efficiency gains into the future and ensures value is delivered to consumers.

A key part of IPART’s assessment of, and judgement on, the DNSPs’ proposals is to determine whether the DNSPs forecasts for the next regulatory period are reasonable. A primary source of information for this task comes from observations of past performance. Accordingly, a key focus of this submission is on information about current performance of the DNSPs and information related to their forecasts of sales volumes (demand, consumption, etc) and their forecast CAPEX and OPEX costs.

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<sup>14</sup> See clause 6.1.1(b)(3) of the National Electricity Code.

## **2.1. The Weighted Average Price Cap price control formula**

The WAPC distribution price control formula proposed by IPART is of the same form adopted by the ORG for in its September 2000 Final Decision on Victorian electricity distribution prices, except that ORG also added a *service adjustment* (or ‘S-factor’) linked to indicators for “*unplanned interruption frequency, unplanned interruption duration, planned minutes off supply*” for different categories of distribution customers, i.e. CBD customer, urban customer and rural customers. As noted above, IPART has left open the option of adding one or more subsidiary ‘service adjustment’ factors to its basic distribution price control formula.

### **2.1.1. Benefits of the WAPC**

The principal benefit (to NSW consumers) of adopting a WAPC price control is, essentially, that it gives distributors an incentive to link underlying costs with the prices of tariff components. The WAPC price control approach also provides a ‘self-compensating’ mechanism that automatically adjusts revenue to match costs if actual sales volumes of tariff components are different to those initially forecast at the start of the regulatory period, providing tariff component prices do, in fact, reflect the underlying cost. That is, the WAPC allows distributors to link prices to underlying costs and, thereby, minimise revenue risk should actual demand, consumption or customer numbers turn out to be different to forecasts.

The benefits for consumers from the WAPC arises by producing an outcome that reduces the financial risk to efficient, well-managed DNSPs and ‘justifies’ IPART making judgements in favour of an efficient cost of capital. This, in turn, reduces the single biggest cost component facing distributors and should, therefore, result in lower overall costs to consumers. The ‘self-compensating’ mechanism also reduces the likelihood of an outcome similar to that asserted by the NSW distributors under the ‘hybrid revenue cap’ (that has prevailed in NSW since 1996), following the acceptance by IPART in 1999 of what the DNSPs later claimed were ‘deficient’ demand and consumption forecasts.<sup>15</sup>

### **2.1.2. Disadvantages of the WAPC**

A disadvantage to NSW consumers of the WAPC (at least for consumer Classes subject to common tariffs) is that the incentive for distributors to structure tariff components so they reflect underlying costs will cause prices to rise for consumers who increase the DNSPs’ costs. This can be an issue for consumers if their consumption behaviour causes costs to rise rapidly, as appears to be the case for (at least) EA and IE due to the impact of rising AC use.<sup>16</sup>

We note that IPART proposes to continue using ‘side constraints’ to, amongst other things, reduce or control ‘price shock’ to consumers if DNSPs do decide to re-allocate costs between consumer classes. The use of ‘side constraints’ can, however, create issues that impact on consumers in the longer term. Brief comments relevant to the IPART Secretariat’s preliminary views on price movements and ‘side constraints’ are contained in Section 5.

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<sup>15</sup> Note that the ‘Hybrid Revenue Cap’ formula that applies currently includes ‘self-compensating’ mechanisms linked to energy sales and customer numbers. However, these adjustments were based on an assumption by IPART that its consultant’s advice of 1996, that incremental costs are linked to these two parameters in a 30:70 split, was valid, which may or may not be so. The current formula has no ‘self-compensating’ mechanism for mismatches between forecast and actual demand, which is likely to have been a problem for those DNSPs facing unexpectedly high (or unforecast) summer demand growth rates.

<sup>16</sup> The impact of rising AC penetration, particularly amongst Australian households is not confined to NSW (or Sydney). Temperature-sensitive extreme peak summer demand has a major impact on the whole electricity system in South Australia, and is also creating challenges in Victoria.

Another issue that should concern IPART and NSW consumers is that there are indications from Victoria that some distributors attempt to use the ‘flexibility’ available to them under the WAPC price cap to restructure rates for some tariffs so as to ‘extract’ more revenue from consumers, rather than minimise revenue risk to their business. The Box below contains some details.

*In the first year of the current Victorian regulatory period, United Energy introduced new rationally-designed, cost-reflective, hourly time-of-use (ToU) tariffs for all small consumers with interval meters<sup>17</sup> and then progressively ‘adjusted’ tariff rates to provide ‘incentives’ for existing consumers to switch to the new tariffs. The incentive in this case being a ‘negative’ one in the form of progressively increasing prices for the overwhelmingly vast majority of consumers who do not have interval meters.*

*But this is not the major loss to consumers. The major disadvantage occurs because not one retailer in Victoria offers a product that allows consumers to obtain whatever benefit there might be in switching to the new network tariff. Retailers claim this is primarily because the United ToU tariffs are too complex to ‘sell’ to consumers. Instead, the retailers absorb the difference in cost for interval-metered small consumers and ‘smear’ these costs amongst all the retailers’ customers regardless of their meter type.*

*This means that United is able to gain the benefit of rational, cost-reflective network tariffs, while individual consumers are denied access to any reciprocal benefit.*

*The net impact of this is limited change in the peak consumption habits of the customers concerned but increased revenue, which the distributor is entitled to retain as an ‘efficiency’ gain under the WAPC regulatory regime. However, there is in reality no increase in efficiency in the sense intended in economic regulation. Rather, this is a form of ‘gaming’ of the regime through ‘clever’ tariff restructuring, which appears economically efficient on the surface, but in reality is of dubious benefit.*

*There is also evidence that similar ‘revenue-raising’ tariff adjustments occur in other ‘standard meter’ tariffs offered by some Victorian DBs.*

*To date, the ESC has taken no action to address these issues, apart from convening a Pricing Issues Consultation Group similar to that established by IPART in January 2003.*

ORG also argued in its Final Decision that the incentive to link tariff prices with underlying cost meant that distributors would have ‘neutral’ incentives towards DM. But that is not demonstrated in practice in Victoria (see Box below).

*TXU has introduced a new grid-connected solar PV tariff for all small consumers with such installations (and compulsorily assigned all such consumers to the new tariff) with substantially increased fixed charges (up by ~195%) and less favourable energy rates than pre-existing tariffs.*

*As in NSW, Victorian distributors are required to publish planning documents that identify DM ‘opportunities’, but only show any real enthusiasm for DM if the proponent is prepared to assign a substantial proportion (typically 50%) of the avoided distribution cost to the distributor.<sup>18</sup>*

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<sup>17</sup> The Victorian distributors face relatively few restrictions in developing new or innovative tariffs, and discontinuing existing tariffs. They also have substantial freedom to determine what type of metering is installed on a new connection. Consumers have some limited protection through a right to choose from a range of tariffs offered by the distributors, but the tariffs on offer is frequently limited by the type of metering assigned by the distributor.

<sup>18</sup> It is worth noting that this is because ORG set a precedent when it decided that AGL Power Generation could only ‘claim’ 50% of the avoided distribution cost from AGL Distribution for the distribution-connected, embedded generator at Somerton (in

These are all issues for IPART and NSW consumers because ORG has also decided to take a ‘hands-off’ approach in the tariff approval process on the basis that the WAPC formula (and associated ‘tariff adjustment and rebalancing constraints’) contains ‘self-enforcing’ or ‘neutral’ incentives for distributors. ORG has limited its powers to intervene in that process only where the distributors are unable to demonstrate they comply with the tariff formula and ‘adjustment’ criteria. Consumers are supposed to be protected by side-constraints and through distributors publishing Annual Tariff Reports that explain their tariffs and indicate the cost impact on (the mythical) ‘average’ consumer, but even the ESC (and some distributors and retailers) have acknowledged this has not been very successful (see Box below).

*None of the Victorian distributors Annual Tariff Reports are of any practical use to consumers. A major reason for this is that ORG did not require the distributors to include in the Tariff Reports any information on the cost of Excluded Services, even though ORG also decided to ‘exclude’ meter reading charges that apply to all consumers (as well as some metering costs) from Prescribed Services (as IPART intends to do).*

*A second, and very important, reason why the distributors’ Tariff Reports are of no use to consumers is that no resources are committed to routinely analysing the information in the reports, which is presented in a form that cannot be directly related to the bills of any consumer.*

*This means that the Tariff Reports do not contain information on all the costs incurred by all consumers.*

*Even where Excluded Services Charges are only a small component of consumers’ bills, as is the case for virtually all commercial and industrial consumers, the Tariff Reports provide no useful information because:*

- they contain no details of cost allocation methodologies and outcomes;*
- there is no information which enables a consumer to determine how their tariff rates are established; and*
- the reports only show (indicative) annual cost outcomes based on ‘average’ consumers bills, which bear little relation to actual bills presented to consumers.*

Many of the key attributes of the ORG approach are also reflected in IPART’s proposals, which should be of concern to NSW consumers, particularly since IPART has put considerable effort into seeking input from stakeholders through its Pricing Issues Consultation Group.<sup>19</sup> We believe that IPART should look very closely at recent analysis and comment on outcomes of the ORG’s approach<sup>20</sup> and consider modifying its own proposals to more effectively achieve the goal of protecting consumer interests.

## **2.2. Other factors that could be included in the price control formula**

As noted above, IPART is considering several ‘incentive’ and ‘adjustment’ mechanisms that could be incorporated into the WAPC formula. These are briefly dealt with below.

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the North-Western suburbs of Melbourne). This may be one reason why none of the Victorian DBs has implemented any DM significant programs.

<sup>19</sup> IPART was the first regulator in Australia to establish a ‘pricing issues’ group and actively seek input from consumer representatives on pricing issues.

<sup>20</sup> See: *Customer Impacts of 2001 Electricity Distribution Price Review - Report to the Consumer Utility Advocacy Centre from Customer Energy Coalition*, Pareto Associates Pty Ltd, September 2003

### **2.2.1. Service quality incentive mechanism**

The IPART Secretariat notes that it has a preference for the introduction of an ‘S-factor’ in some form from July 2004, although there may be implementation issues that must be resolved prior to it being introduced. An ‘S-factor’ provides an indirect method of ‘rewarding’ or ‘punishing’ a distributor if it exceeds or falls below a nominated level of performance within a specified time frame.

Such a factor is included in the Victorian price control formula.<sup>21</sup> However, we note that the performance measures used in the Victorian ‘S-factor’ incentive have little meaning to most consumers. Average values of the relevant measures may improve because of the distributors’ response to the ‘S-factor’ incentive, but poorly-served consumers are still likely to be poorly served,<sup>22</sup> and all affected consumers still face the same forms of inconvenience.

It is also clear that the ‘S-factor’ incentive measures have no relationship whatsoever to overall ‘quality of supply’ that can dramatically affect large industrial and commercial consumers. The ‘S-factor’ incentive may reduce the frequency, duration and number of outages, but even short duration rare outages have costly impacts; and there is no direct incentive for distributors to improve voltage stability, harmonics, power factor, etc.

At first glance, there is some evidence that the ‘S-factor’ incentive (and guaranteed service payments) works for those Victorian distributors able to meet the specified criteria. As shown in Figure 3 below, Victorian distributors have generally been able to meet the performance targets proposed by them, and accepted by ORG, for Supply Reliability<sup>23</sup> from 2000. Similar outcomes can be observed for other performance measures related to the ‘S-factor’ incentive (Average Number of Interruptions per Customer (SAIFI), Average Interruption Duration (CAIDI) and Average Number of Momentary Interruptions per Customer (MAIFI)).

However, the most noticeable improvement in Reliability performance occurred prior to introduction of the ‘S-factor’ incentive in 2001. This was, most likely, in response to media attention on outages and the introduction of the twice-yearly public performance reporting instigated by ORG in 1997.

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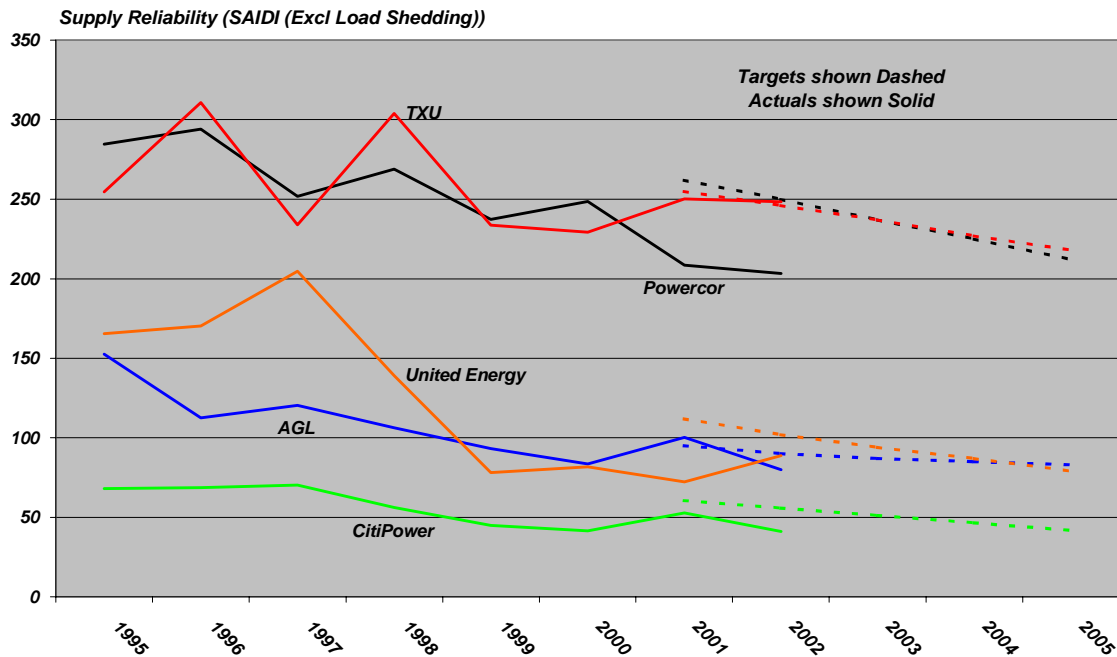
<sup>21</sup> The Victorian arrangements also include guaranteed payments to worst-served customers, which are factored into the distributors’ revenue requirements, but phased down over the regulatory period. While these payments provide some incentive for distributors to meet the specified service standards, the incentive is muted because:

- the cost of providing the payments is recovered from consumers through allowing an incremental “Building Block” component in the regulated revenue;
- the level of compensation paid to consumers is very modest compared to any actual loss they may incur (particularly if they are small, medium or large commercial and industrial consumers); and
- consumers must apply for payment of the compensation amount (which pre-supposes that consumers know they can do this and under what circumstances).

In addition, the overall ‘service incentive’ mechanism is deliberately muted because the total level of payment/penalty is designed so as not to create a significant revenue risk for the distributors (because, ORG argued, this helped ‘justify’ a lower cost of capital).

<sup>22</sup> The ESC public reporting system focuses attention on ‘Hot Spots’ by reporting performance measures for every major distribution network feeder and sub-station in considerable detail. But there is no formal obligation on the distributors to do anything about poorly-performing components of their network.

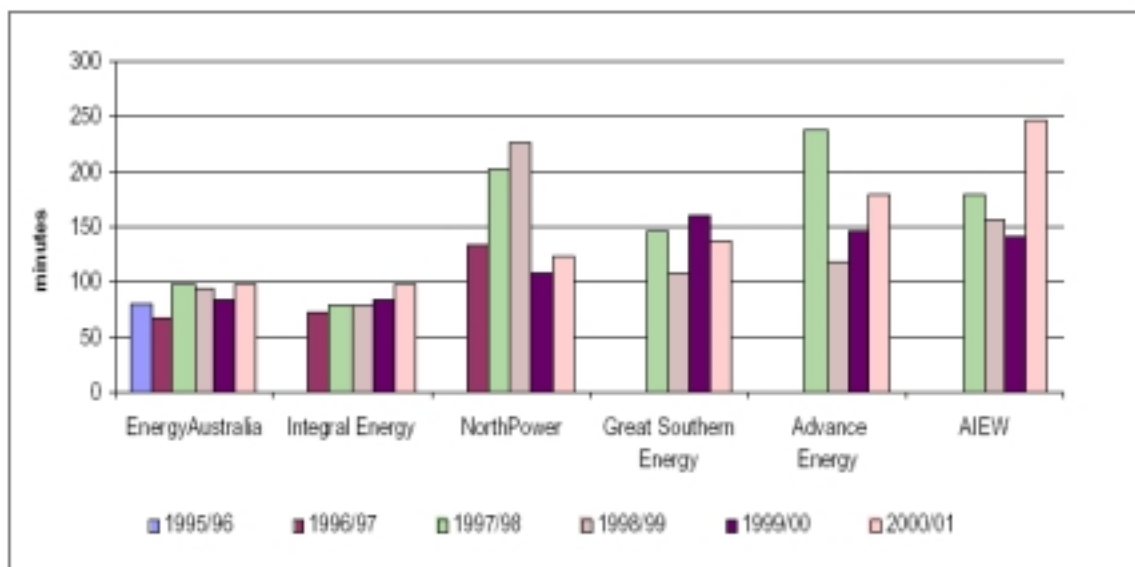
<sup>23</sup> System Average Interruption Duration Index (SAIDI), which is the total minutes, on average, that a customer could expect to be without electricity over a specific period of time. Total SAIDI comprises both planned and unplanned minutes-off-supply (but data shown excludes periods of Load Shedding during declared supply emergency in 2000). SAIDI is calculated as the sum of the duration of each customer interruption (in minutes), divided by the total number of connected customers averaged over the year. Note this is not exactly the same definition used by IPART and NSW DNSPs.



**Figure 3: Reliability performance for Victorian distributors**

Source: Table 9, p. 52 and Appendix B, Electricity Distribution Businesses – Comparative Performance Report for the Calendar Year 2002, Victorian ESC, August 2003.

By comparison, the performance of NSW distributors as illustrated in the Figure 4 below suggests Reliability is generally declining (i.e. getting worse) for most consumers, apart from those in Country Energy’s supply area.



**Figure 4: Reliability performance for NSW distributors**

Source: Figure A6.1, p. 37, Price and Service Report for 2000/01 - NSW Distribution Network Service Providers, IPART, September 2002.

Given the high costs proposed by some distributors to achieve reliability improvements,<sup>24</sup> NSW consumers might prefer to see the NSW public performance reporting improved so as

<sup>24</sup> EnergyAustralia estimates the additional CAPEX costs associated with enhanced service levels to be \$250M. Integral has

to put more 'pressure' on distributors through 'competition by comparison' or 'name and shame'. This would undoubtedly be a lower cost and less complex approach than using an 'S-factor' in the WAPC formula.

We are not opposed to the introduction of specific incentives that aim to improve service quality. Such schemes have the potential to add considerable value to consumers, if they are properly designed and implemented by focussing DNSPs on improving performance measures linked to outcomes that deliver real economic benefit. However, the existing NSW service standard performance measurement and reporting regime needs substantial and fundamental improvement before any financial incentive schemes are introduced.

IPART should use this as a timely opportunity to gain further movement towards service measurement that is consistent between NSW DNSPs and between NSW and other States. In our view there is a pressing need to align the DNSPs' reporting precisely with those of QCA, ESCoSA and ESCV. IPART must use this review to progress this matter and also to put maximum pressure on NSW distributors to 'lift their game' and beat their interstate counterparts.

Failure to do this will be a further indication of an urgent need to move towards a national regulation of distribution by the Australian Energy Regulator (AER) as quickly as possible.

*In our view, IPART should not move to introduce any form of financial service incentive scheme until it is able to ensure that:*

- *the definitions of all service performance indicators/measures are consistently and explicitly defined and accepted by all DNSPs and by consumer groups;*
- *such definitions are completely consistent with those adopted by other jurisdictional regulators (this extends the 'pressure' that can be applied to service providers through 'competition by comparison' or 'name and shame' reporting);*
- *the processes, systems and procedures of all DNSPs can be demonstrated to produce accurate, reliable and directly comparable performance data;*
- *mandatory process/system audits, subject to regulatory oversight, have been introduced for all DNSPs;*
- *independent assessment has been made of the cost-benefit for consumers of any proposed financial service incentive or consumer compensation scheme;*
- *the 'rewards/penalties' facing DNSPs are based on real economic values to consumers;*
- *consumers can be accurately and reliably informed of their obligations, rights and entitlements; and*
- *a cost-effective mechanism is introduced by all DNSPs that ensures affected consumers have a reasonable chance of receiving any benefits of the service incentive scheme.*

### **2.2.2. Cost pass through mechanisms**

The IPART Secretariat has suggested, as a preliminary view, that there is merit in implementing a cost pass through mechanism for uncontrollable costs at the 2004 review.

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estimated the extra CAPEX costs associated with the reduced risk scenario at \$317.1M, with extra OPEX costs of approximately \$8.5M. (see: p30, *Providing Incentives for Service Quality in NSW Electricity Distribution - An Issues Paper*, IPART May 2003).

These suggested costs are very high compared with amounts allowed by ORG for Victorian distributors to achieve enhanced service standards in the 5-year period to 2006 (of \$5M in CAPEX and \$17.8M in OPEX over 5 years). (See: Tables E2 and E4, p243 and p244, *Electricity Distribution Price Determination 2001-05, Volume I Statement of Purpose and Reasons*, ORG, September 2000)

This would only apply to additional costs resulting from statutory changes impacting on the DNSPs' business. IPART's preferred mechanism would involve an application by the DNSP, to IPART, prior to an annual price change, for the costs to be passed through to customers. IPART would then conduct an independent review of the costs, passing through the efficient costs to customers if that was considered appropriate.

This proposal has merit if it is administered so as to reduce the 'sovereign risk' component of the DNSPs operations and assist IPART in delivering judgements on a lower cost of capital. However, such a proposal must not provide avenues for DNSPs to claim cost pass-through due to any act or omission for which they have any responsibility. To do so would eliminate the 'discipline' benefit of the primary efficiency incentive in the regulatory regime.

The proposal would, however, be more balanced if it included a reciprocal arrangement to pass-through cost reductions that result from statutory changes, although this would require IPART to take an active interest in this process because the DNSPs are very unlikely to identify circumstances where their costs would reduce.

### **2.2.3. Forecast risk hedging factor**

The IPART Secretariat also it is currently examining options for the introduction of a risk hedging factor. The Secretariat also notes the divergent and changing views of DNSPs on this issue, with EA and CE arguing, correctly in our view, that introduction of a 'forecast hedging factor' reduces the fundamental incentives of the CPI-X price cap mechanism.

IPART specifically referred to load forecasting as an area of business risk in its 1996 and 1999 Determinations. IPART also said in 1996 that:

*"(p)rices should allow distributors network operators to earn returns on new investments which reflect their relative levels of risk. It is recognised that the financial viability of distributors is largely protected by enabling them to recover all direct operating costs (adjusted for relative efficiency levels). The remaining risks revolve around the accuracy of load projections."<sup>25</sup>*

There are risks associated with demand and load (consumption) forecasting, but as several of the DNSPs have said, those risk are best managed by the DNSPs as they are the only parties with access to all the information and resources necessary for reasonable and robust forecasting. To the extent that DNSPs fail to prepare reasonable and robust forecasts or manage forecasting risk, they can be deemed inefficient and responsible for their own omissions. IPART should not protect DNSPs, or their shareholders, from inefficiency (or poor performance). Indeed, as noted above, a key principle and objective of regulators under the National Electricity Code is "to regulate the non-competitive market for network services in a way which seeks the same outcomes as those achieved in competitive markets". Firms in competitive markets have no option but to accept full responsibility for business risks associated with poor forecasting. Most Australian industry is fully exposed to this risk. There is no logical reason why regulated firms should be protected from the same risks.

As noted above, one of the primary benefits claimed for the WAPC form of price control is that it minimises forecasting risk so long as the distributors link tariff component prices to underlying costs. If DNSPs do this, the WAPC tends to 'self-compensate' the revenue stream for (minor) forecast errors. If sales volumes rise above forecasts, revenues linked to the underlying costs rise at a rate that compensates for increased costs. If sales volumes fall below forecast, costs fall at a rate that compensates for reduced revenue. If the DNSPs

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<sup>25</sup> p 6, Report 2.2, IPART, 1996

prepare reasonable and robust forecasts of sales volume and efficient costs, link the price of tariff components to underlying costs, and operate efficiently, they will have achieved ‘forecast risk management’ without the need for intervention or interference by IPART.

*The best way for IPART to foster a disciplined, efficient outcome is to satisfy itself that:*

- *the DNSPs’ forecasts of sales volumes and costs are reasonable, robust and efficient (and not based on ‘strategic manipulation’ of the WAPC, or poor forecasts);*
- *tariff component prices are linked to underlying costs; and*
- *the DNSPs have clear incentives to operate efficiently by ensuring that if they ‘get it wrong’ they (and their shareholders) bear the burden.*

### **2.3. Length of the regulatory period**

Based upon the evidence before it to date, the IPART Secretariat’s preliminary view is that the Tribunal adopt its preferred five-year regulatory period.

We concur generally with the view indicated by the Tribunal that five years would strike a balance between providing incentives for improving efficiency, reducing regulatory uncertainty and minimising the risk that changes in the industry affect the appropriateness of the regulatory regime.

Diverting attention onto more frequent regulation will distract DNSPs from focussing on how they can best provide services that consumers want and value. This (generally) means that consumers are most likely to be best served through regulators establishing an appropriate environment with the ‘right’ incentives for the distributors to operate effectively and efficiently in providing services that the consumers want and value.

### **2.4. Prescribed and excluded services**

The excluded distribution services proposed by IPART in the February 2003 Draft Decision are:

- Customer funded connections – design and construction of new connection assets and construction of customer-funded network augmentations;
- Customer-specific ancillary services – including inspection and maintenance of customer installations and connection assets (excluding separately defined monopoly services); asset relocation works; conversion to aerial bundled cable and other customer requested services;
- Metering services – meter supply, installation and maintenance, meter reading and data forwarding and other metering services (which are currently defined as provision of metering data, special meter reads, meter tests).
- Public lighting - construction and maintenance of public lighting assets.

Generally, regulators (and jurisdictional governments) ‘exclude’ recovery of the costs of providing a limited range of services from the WAPC revenue stream because the services are provided occasionally, to only a limited number of consumers and/or there is a belief that the services can be efficiently sourced in a competitive market. There is a stronger case for

this approach where the services are sought by a limited number of consumers and an effectively competitive market exists for providing the services, as may be the case for most instances of Customer funded connections, Customer-specific ancillary services and even Public lighting.

But there is little evidence that this applies to supply, installation and maintenance of meters to the vast majority of small consumers. Indeed, it is highly likely that competition in meter supply is wasteful and inefficient unless consumers are able to purchase, install and own their own meter, which they are not permitted to do. Certainly, the practice of changing meters with a change in retailer for large consumers would quite clearly be costly, wasteful and inefficient if extended to small consumers. In addition, it appears clear that cost reductions from economies of scale would be lost (or diminished) if undertaken by more than one entity. As discussed in the Box below there are some lessons from Victoria that relate to treatment of excluded services.

*A related problem that is evident in Victoria, where meter reading and supply of interval meters have been defined as Excluded Services, is that it is virtually impossible for consumers to determine what they pay for the combination of regulated WAPC charges and Excluded Services. The meter reading charge applies to all consumers, but distributors are not required to include information on Excluded Services charges in their Annual Tariff Reports and they do not identify which Excluded Services Charges apply to which tariff on their lists of Excluded Services Charges. Nor are retailers obliged to disclose any information on network or Excluded Services charges on consumers' bills.*

*If IPART persists with recovery of meter service costs as excluded service charges, then it should ensure that distributors and retailers are required to provide full and clear disclosure of the basis and magnitude of these costs in both public reports by the distributors and itemised on bills.*

### **3. BUILDING BLOCKS COMPONENTS**

The IPART Secretariat's Preliminary Analysis report presents key cost elements in the DNSPs' proposals with common assumptions covering:

- inflation (assumed at 2.5 per cent over the regulatory period);<sup>26</sup>
- interest rate on borrowings and investments (6.8 per cent over the regulatory period);
- dividend payout rate of 75 per cent;
- debt to equity ratio (60 per cent); and
- a common split between prescribed and excluded services;

then 'standardises' a summary of the proposals so as to provide a very brief comparison of (general) cost outcomes for consumers.

The IPART Secretariat also provides its views on key elements of the Revenue Building Block components, but was unable to make any comment on efficient CAPEX and OPEX because it had not received the Meritec final report.

We have, however, provided below a discussion of key aspects of the DNSPs' forecasts and of the subsequent analysis including:

- an assessment of consumption forecasts;
- a critical assessment of the growth forecast methods employed;
- a review of Meritec's assessment of growth forecasts;
- a discussion of CAPEX efficiency including deficiencies with the Meritec analysis and a suggested alternative approach; and
- a discussion of OPEX efficiency including deficiencies with the Meritec analysis.

In relation to the Meritec final report, our analysis shows that:

- the report is based on an 'opinion' that the demand and consumption forecasts provided by the DNSPs, which Meritec acknowledges are an essential input to assessment of the prudence and efficiency of expenditure, are reasonable for the purpose of (Meritec's) review of OPEX and CAPEX, even though our analysis raises concerns about the reasonableness and robustness of those same forecasts.<sup>27</sup>
- the report contains very little critical quantitative analysis of information provided by the DNSPs; indeed it appears that Meritec did not even subject the information provided by the DNSPs to the simplest validation processes;
- in virtually all areas that are critical to assessment of 'prudence' and 'efficiency', Meritec says, quite clearly, that its recommendations are based largely, or almost

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<sup>26</sup> An issue of concern for NSW consumers is that the IPART Secretariat says it has assumed an inflation rate of 2.5% over the regulatory period to 'standardise' presentation of the DNSPs' proposals, but shows a range of different inflation values (varying from 2.0% to 2.5%) in its summary presentation on comparisons of the Weighted Average Cost of Capital (WACC). A further concern is that the range of inflation values quoted by the IPART Secretariat in the WACC comparison is different to the values proposed by the DNSPs in their submissions to IPART. For example, AEI assumes 2.1% (not 2.5% - see p24 of AEI submission), CE assumes 1.9% (not 2.0% - see p6-18 of CE submission) and IE does not quote a value (see p151 of IE submission). Given the dominant part that the cost of capital plays in determining DNSPs' costs, it is essential that IPART provide a consistent and well-reasoned view on its inflation assumption. It is essential that IPART then apply the same inflation factor to all of the elements of the Building Block. The preferred method of estimating the value for inflation is to base this on the difference between nominal Bond rates and Index-linked Bond rates; rather than using an average value based on non-capital CPI data.

<sup>27</sup> IPART has advised that the DNSPs' demand and consumption forecasts are being subject to review by (another) independent consultant. However, this review will not be made public until the IPART Draft Determination is published in mid-December 2003.

entirely, on 'opinion' or 'judgement' which are normally the prerogative of regulators and should not be made by the regulator's consultant;

- the report contains cost data that is inconsistent with data contained in the DNSPs' own submissions and the IPART Secretariat Preliminary Analysis report, yet provides no explanation of this.

In view of these deficiencies, we believe that IPART should ignore the conclusions of the Meritec report. Instead, it should re-evaluate the DNSPs' CAPEX and OPEX forecasts drawing on well-established quantitative forecasting methods applied in other jurisdictions, notably by UK regulators.<sup>28</sup>

### **3.1. Growth Forecasts**

The DNSPs forecasts of sales volumes are a critical element in assessing the DNSPs overall proposals. In this section, we comment on our assessment of the DNSPs demand and consumption forecasts.

Unlike commercial businesses, where product prices are frequently adjusted up or down in response to changes in costs, sales volumes or other factors, regulated companies have their prices fixed in advance for periods of up to 5 years. Fixing prices over multi-year periods requires the regulator to forecast accurately a DNSP's costs and sales.

A DNSP's costs are built up from, among other things, forecasts of capital and operating expenditures, which are driven to varying degrees by growth in peak demand, energy consumption and the number of customers.<sup>29</sup> The resulting prices to end-users are then calculated taking into account the volume of sales and the number of customers. The three relevant growth forecast series:

- peak demand;
- sales volume; and
- customer numbers.

are therefore important elements of the price review process. It is essential therefore that IPART only makes its determination once it is confident about the reasonableness or otherwise of the growth forecasts provided by the DNSPs.

#### **3.1.1. Consumption Forecasts**

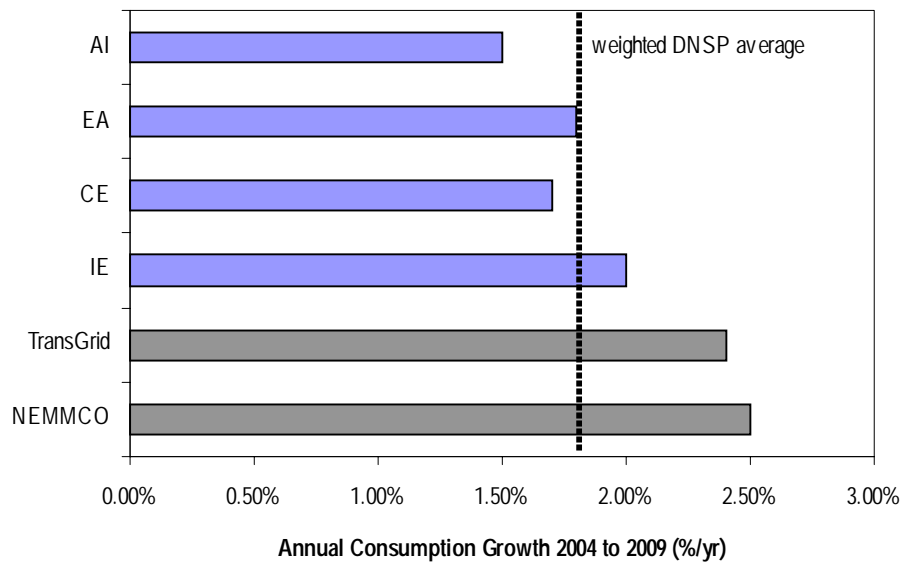
Figure 5 below sets out the DNSPs' electricity consumption growth forecasts (taken from their submissions), along with equivalent forecasts by NEMMCO and TransGrid. The TransGrid and NEMMCO forecasts are NSW totals for energy end-use and include industrial customers not supplied through the distribution network. However, as noted by IPART, the series are broadly comparable, particular when comparing growth trends.<sup>30</sup>

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<sup>28</sup> The approach implemented by OFGEM for the current review of UK electricity distribution charges is described in pp65-80, *Electricity Distribution Price Control Review - Initial Consultation*, Office Of Gas And Electricity Markets (OFGEM), July 2003

<sup>29</sup> There are many other factors that also drive costs for network companies, but many of these are beyond the control of the companies or cannot be changed efficiently. Geography, topography, weather, vegetation type and density, customer density and mix, asset types, asset age, consumption patterns are some of these.

<sup>30</sup> *Ibid*, p 11.



**Figure 5: Forecast Annual Consumption Growth 2004 to 2009**

Source: NDSP submissions, TransGrid, *New South Wales Annual Planning Report 2003*, NEMMCO, *2003 Statement of Opportunities*

The weighted average annual consumption growth of the DNSP forecasts is 1.8% compared to 2.4% and 2.5% for TransGrid and NEMMCO respectively. Thus, the DNSPs are all forecasting growth rates that are significantly lower than those projected by either TransGrid or NEMMCO. This outcome is of considerable concern to us, as trends in the NSW state level end-use consumption should mirror consumption trends at the weighted average network level.

The table below illustrates the consequences of forecast error in the consumption projections in terms of revenue generation from DUoS charges. In this simulation we have assumed IPART accepts the DNSPs submitted forecasts of 1.8% but actual growth aligns with the TransGrid projections of 2.4%. In addition, the average revenue is taken to be 3c/kWh and 2003 end user consumption is 52,927 GWh<sup>31</sup>.

**Table 1: Revenue Generation from DUoS Charges - Impact of Consumption Forecast Error**

	2003	2004	2005	2006	2007	2008	Total
Consumption - 1.8% growth (GWh)	52,927	53,879	54,849	55,837	56,842	57,865	
Consumption - 2.4% growth (GWh)	52,927	54,197	55,498	56,829	58,194	59,590	
Difference in Consumption (GWh)		317	648	993	1,352	1,725	5,035
<b>Revenue attributed to Difference in Consumption @3c/kWh (\$M)</b>		<b>9.5</b>	<b>19.5</b>	<b>29.8</b>	<b>40.6</b>	<b>51.8</b>	<b>151</b>

Source: Analysis for this submission

Thus, if IPART accepts the DNSP's forecasts but actual growth is as forecast by Transgrid then electricity consumption will be 5,035 GWh more than forecast. As a result, actual revenues will be higher than the amount determined by IPART by approximately \$150 million over five years. All NSW electricity consumers will pay for this additional cost. Arguably, there could also be a knock-on effect to NSW transmission and generation.

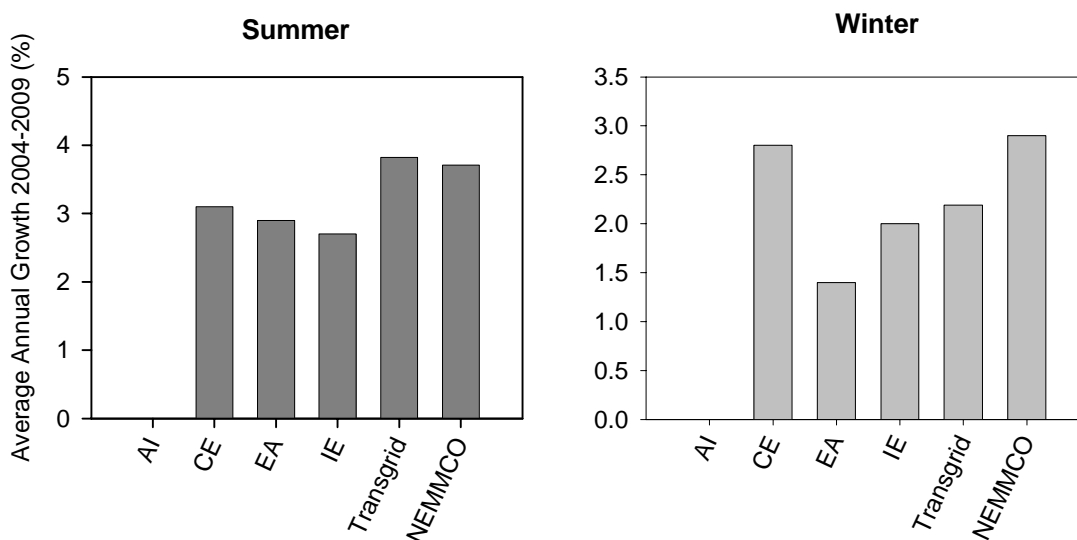
<sup>31</sup> From Transgrid (2003)

Because of the incentive for DNSPs to bias the consumption forecast in their favour and the significant cost consequences for users if the forecasts are erroneous, IPART needs to be vigilant in scrutinising the DNSPs growth numbers.

### 3.1.2. Demand Forecasts

Three of the DNSPs have projected consolidated demand growth in their networks using methodologies that are broadly comparable with demand projections used by TransGrid and NEMMCO. However, as with the consumption forecasts, the results are inconsistent.

Figure 5 illustrates the DNSP network demand growth forecasts and equivalent forecasts for the NSW undertaken by TransGrid and NEMMCO. Notably with the exception of CE's winter load forecast, the DNSPs are projecting lower rates of demand growth than either TransGrid or NEMMCO. This would appear to be an anomaly as, due to diversity in demand, state-wide growth as measured by TransGrid and NEMMCO is unlikely to be less than the individual DNSP projections. That is, we would have expected individual DNSPs maximum demand growth rates to be higher than the State-wide forecasts of Transgrid and NEMMCo. This is because there is a higher probability that localised extreme system peaks, that may not be coincident across the State, would occur within individual DNSP service territories.<sup>32</sup> This is so particularly for summer maximum demand.

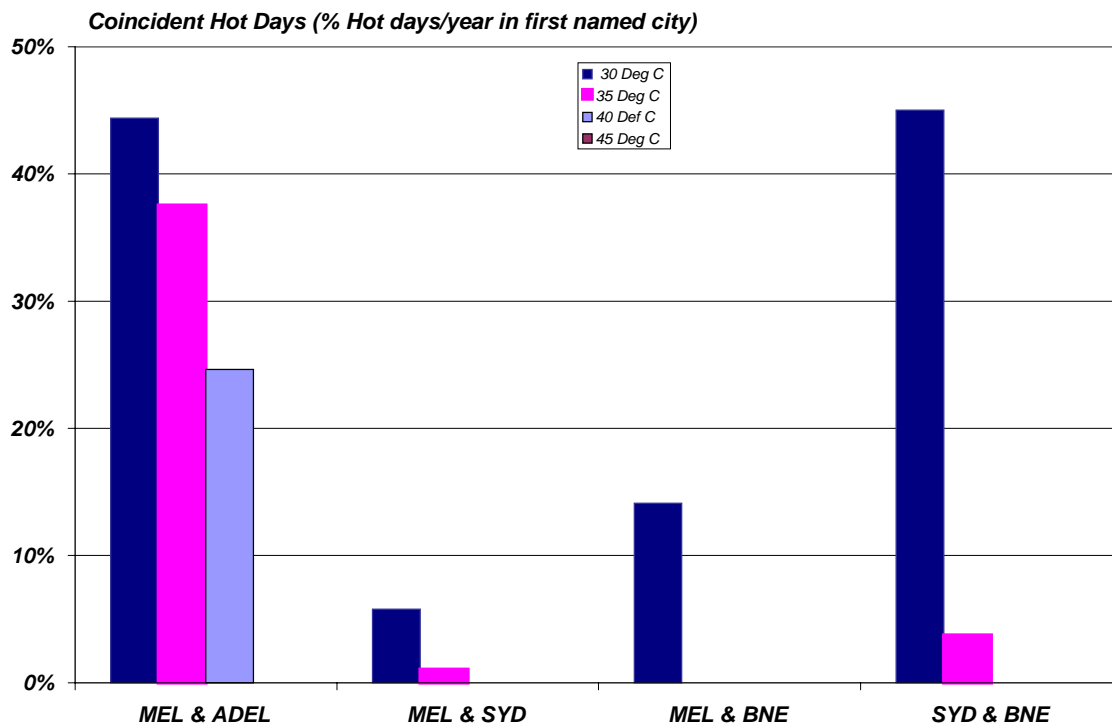


**Figure 6: Forecast Peak Demand Growth 2004 to 2009**

Source: NDSP submissions; TransGrid, *New South Wales Annual Planning Report 2003*; NEMMCO, 2003 *Statement of Opportunities*

For instance, as shown in Figure 7, it is far less likely for maximum temperatures to occur on the same day in both Adelaide and Melbourne, and even less likely for that to occur in Adelaide, Melbourne and Sydney. We would expect the same phenomenon to be observed across smaller geographic areas such as NSW, or even across single distribution areas. This suggests that temperature-dependent demand (such as for AC load) would also vary across NSW at any given time.

<sup>32</sup> Indeed, extreme peak demand in parts of a single DNSPs network would be expected to vary widely at any given time.



**Figure 7: Coincident hot days in Adelaide, Melbourne, Sydney and Brisbane 1885-2002**

We have also examined temperature-sensitive demand trends for NSW using half-hourly temperature data from the Bureau of Metrology's Sydney Observatory and NEMMCO's half-hourly data files. This enabled us to form a general view about the robustness of the DNSPs forecasts, and those of Transgrid and NEMMCO.<sup>33</sup> The results of this analysis are represented in the two sets of diagrams below.

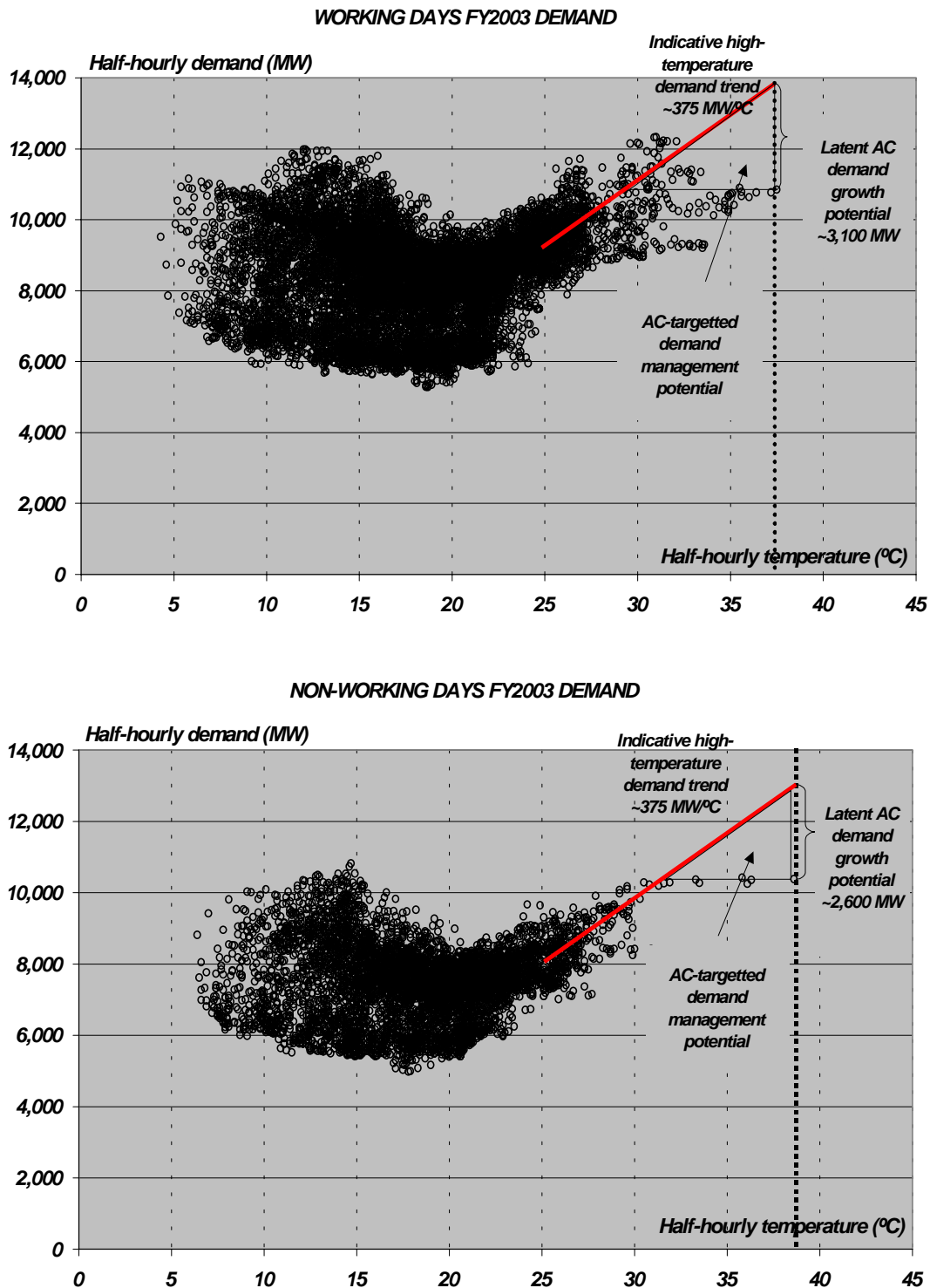
The first pair of diagrams (Figure 8) show scatters plot of half-hourly demand versus temperature for working days and non-working days in FY2003. This indicates that summer maximum demand now exceeds winter peak demand on working days (a situation that has been occurring since FY2001). Maximum summer demand on non-working days is only just beginning to match maximum winter demand, indicating that commercial air-conditioning load growth is still an influence on summer peak demand growth. However:

- the 'indicative high temperature demand trend is of the same order on working days and non-working days (at approximately 375MW/°C, or around 3.1%/°C), which confirms that Residential AC use is a substantial contributor to maximum summer demand; and
- demand 'flattens out' above (about) 30°C on both working days and non-working days, which demonstrates a 'latent AC demand growth potential' of around 2,500MW to 3,000MW in high-temperature extreme peak demand if AC penetration increases as projected by both EA and IE.

<sup>33</sup> It is not possible to form a definitive view on the validity or otherwise of demand forecasts using these data sources because:

- these are historical data files, not forecasts;
- there are likely to be differences in half-hourly temperature across NSW;
- the Sydney Observatory is on Sydney Harbour in a relatively mild temperature zone and temperature records may not be representative of NSW as a whole; and
- raw NEMMCO Regional Reference Price data files do not show imports/exports to and from the Snowy and Queensland Regions.

Each of these factors suggests there could be substantial potential benefit to NSW consumers in developing a DM program targeted at all AC users.

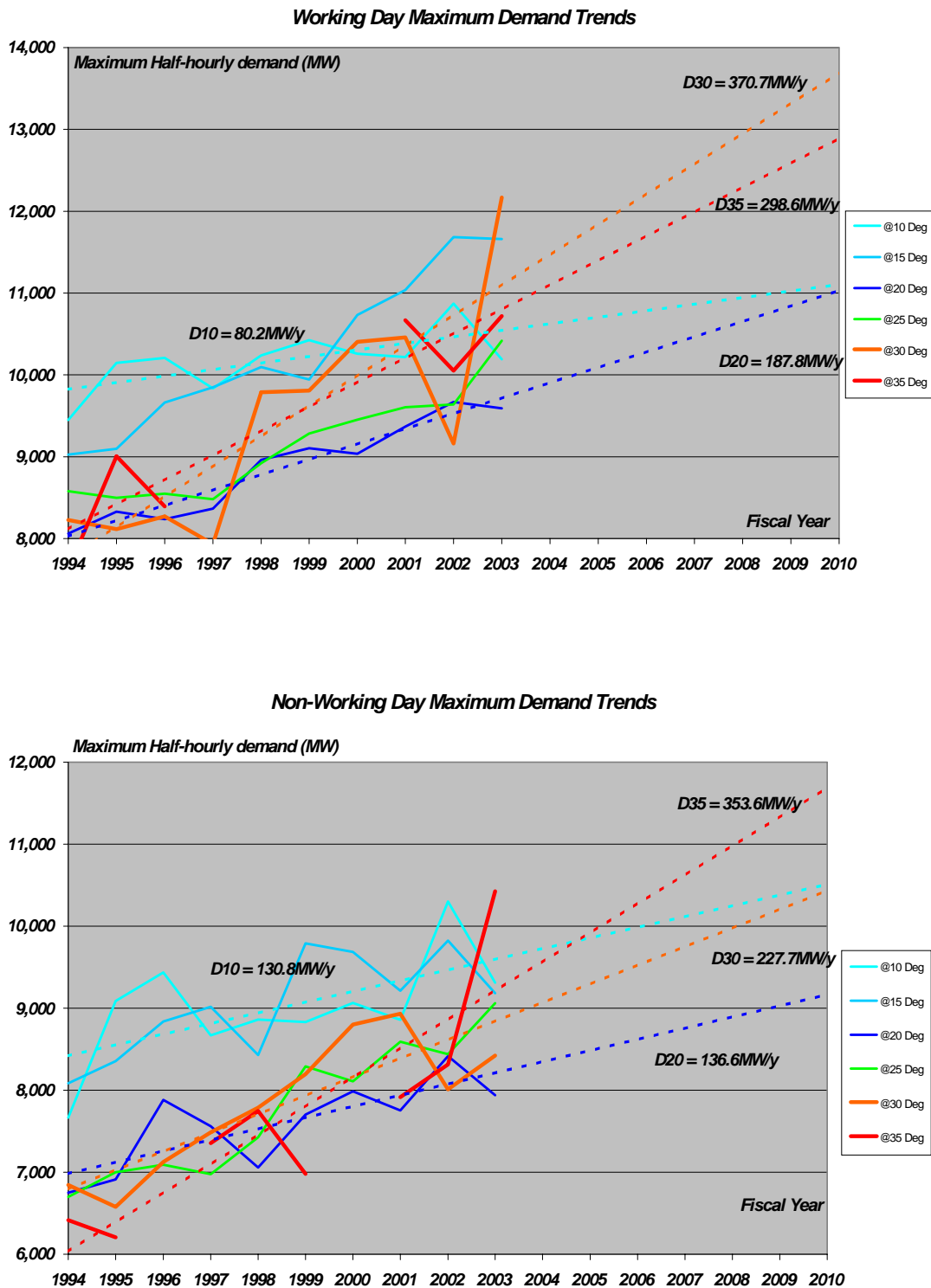


**Figure 8: NSW Daily Demand and Temperature Profile (Fiscal Year 2002-03)**

Source: NEMMCO and Bureau of Metrology half-hourly data files.

Note: The maximum temperature recorded at the Sydney Observatory was 45.3°C on Saturday 14 January 1939.

The second pair of diagrams in Figure 9 shows the trends in temperature-sensitive demand growth by fiscal year in 5°C increments for working and non-working days from FY1995.



**Figure 9: Growth in half-hourly Maximum Demand by Temperature**

Source: Analysis of NEMMCO and Bureau of Metrology half-hourly data files

The information in these diagrams illustrates:

- the volatility in demand trends at both low and high temperature;
- an apparently substantial increase in peak demand volatility at temperatures of 30°C or more since FY1998
- the relatively higher demand growth trends at 15°C on working days,<sup>34</sup> but not non-working days, which suggests industrial and commercial users contribute substantial to low-temperature demand growth;
- similar orders of demand growth at temperatures of 30°C or more, of 300-370MW/year on working days and 225-350MW/year on non-working days.<sup>35</sup>

The main conclusion from this analysis of half-hourly temperature and demand data is that it is highly likely that temperature-sensitive summer demand will increase as AC penetration continues in NSW. The data in Figure 9 suggests extreme peak demand growth rates of at least 3.3% to 3.5%/year are very likely to continue over the next few years for the whole of NSW. This is noticeably higher than the sub-3%/year rates suggested by EA and IE, the two DNSPs most likely to see the impact of increasing AC use. In addition, it is also reasonable to expect that the 'flattening off' of extreme peak demand above 30°C will become less noticeable, making extreme peak summer demand even more volatile and unpredictable.<sup>36</sup>

The implications of these characteristics for NSW consumers could be dramatic. If the same trends continue through to 2010, underlying demand above 30°C could grow by as much as 2,000-2,500MW and extreme volatility could increase by a similar order. This would lead to increased investment in distribution network assets, transmission assets and generation capacity and, at the same time, significantly reduce Load Factor for the whole electricity system in NSW.

We have not been able to make any estimate of the potential impact on consumers from mis-forecasting of demand growth. However, there is clear potential for this impact to fall most heavily on larger industrial and commercial consumers who face demand tariff components. If increasing extreme demand drives up costs for the DNSPs, the WAPC should reflect those costs in the demand component of tariffs. But this is unlikely to be equitable, efficient or effective (in moderating extreme demand growth) if the increasing costs are allocated to consumers who are not primarily responsible for the demand growth.

Our (preliminary) analysis above suggests that residential consumers (and to a lesser extent, small commercial/industrial consumers who operate on non-working days) make a substantial contribution to high temperature-sensitive extreme demand growth. This is supported in the submissions made by EA and IE (in particular). On that basis, it seems reasonable to expect that IPART examine this issue in some detail, particularly given the substantial potential for all NSW consumers to gain cost benefits from a price (and hopefully reward) based DM program targeting AC-users. We discuss issues related to this further in Section 4.

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<sup>34</sup> Although not shown on the diagram, the average demand growth rate at 15°C on working days has been approximately 310MW/year since 1994-5 (or 3.4% at FY1994-5). In the period since FY1998-9, the average growth rate has been 380MW/year (or 3.8% at FY1998-9).

<sup>35</sup> There has been dramatically increased volatility in high-temperature demand over the last two summers according to this data.

<sup>36</sup> This is what is observed in SA. Half-hourly temperature versus demand scatter plots for SA show no 'flattening out' at extreme high temperatures. This is a major factor contributing to the relatively poor Load Factor indicated for SA in Figure 17.

*In our view there is a need for IPART to reconcile the difference in growth rates between the DNSPs and those produced by NEMMCO and TranGrid independently as part of the price review. This is of particular relevance given the issues arising from poor forecasting performance in the current regulatory period.*

### 3.1.3. Review of DNSP Forecast Methods

Three of the four DNSPs have reported, to varying degrees, on the methods for producing growth forecasts. We have undertaken a review of the methods employed. The table below provides a summary of these methods and also a description of TransGrid’s approach to consumption forecasting.

**Table 2: Comparison of Consumption Forecasts Methods**

		EA	IE	CE	TransGrid
Residential Sector	Undertaken by	In-house	In-house	Consultants – (NIEIR)	As for non-residential
	Method	Appliance penetration projections	Appliance penetration projections	Information not provided.	
	Model parameters disclosed	Yes	No	No	
Non Residential Sector	Undertaken by	In-house	In-house	Consultants – (NIEIR)	In-house
	Method	Econometric model - GSP is the dependent variable	Econometric model - GSP and electricity prices are the dependent variables	Information not provided.	Econometric model - GSP, electricity prices, natural gas prices and interest rates are the dependent variables
	Model parameters disclosed	yes, GSP elasticity = 0.81	No	No	Yes. Elasticities are: GSP = 0.91, electricity price = -0.06, natural gas price = 0.06, interest rates = 0.05
Replication possible		No	No	No	Yes
Demographic and Economic Trends	Undertaken by	Consultants (NIEIR) but adjusted in-house	Consultants (NIEIR) but adjusted in-house	Consultants (NIEIR)	Consultants (NIEIR)
	Values disclosed	Yes. GSP growth = 2.6%	No	Yes. GSP growth = 2.1%	Yes. GSP growth = 3.0%

Source: DNSP submissions  
GSP = Gross State Product

Our general comments on the forecast methods are:

- **Inadequate disclosure of methods** - the DNSPs have broadly described the major steps in the forecast process but have not provided sufficient information to allow replication or validation of the results. Of particular concern is the lack of disclosure regarding the rationale for, and assumptions behind, the in-house adjustments to the NIEIR demographic and income forecasts.<sup>37</sup>

<sup>37</sup> For example see Integral Energy (2003) *2004 Electricity Network Review Submission to IPART*, 10 April 2003, p. 174. and EnergyAustralia (2003) *EnergyAustralia Global Electricity and Customer Number Forecasts 2002-2009*, April 2003, p. 21.

- **Inconsistent reporting** – a general theme in the submissions is the DNSPs claim to take into account a wide number of factors, for example greenhouse policy, gas prices etc, but in fact only use a subset of those factors in the forecast method.<sup>38</sup>
- **Use of old data** – where information on data sources has been disclosed, in several cases the data is old and possibly no longer relevant. For example 1985 data for appliance penetration rates used by EA.<sup>39</sup>
- **Exclusion of important causal/explanatory factors** – the reliability of forecasts can be enhanced by using knowledge of causal relationships and data on causal factors. While Transgrid used four causal drivers in their econometric models – income, gas prices, electricity price and interest rates,<sup>40</sup> EA only used one, income<sup>41</sup> and IE two, Gross State Product and electricity prices.<sup>42</sup>
- **No description of the decisions or outcomes that might be affected by the forecasts** – none of the DNSPs has attempted to relate consumption forecasts to pricing or revenue requirements. Network users have no way of assessing the impact of different forecast outcomes or the implications of forecast errors. This contravenes good practice in making forecasts.<sup>43</sup>
- **Reliance on a single source for economic trend data** – all DNSPs use the consultants NIEIR to prepare GSP and other macro variable forecasts. An over-reliance on one data source can lead to biased outcomes.<sup>44</sup> Given there are other alternative publicly available sources of forecasts for macroeconomic trends,<sup>45</sup> these should also be used to produce a combined macro-economic forecast.
- **No testing of forecasting methods** – it would be prudent and good practice<sup>46</sup> to back-test the forecasting methods by attempting to replicate (ex-post) the consumption outcomes in the current regulatory period. None of the DNSPs have tested their forecasting models in this way.
- None of the DB's has attempted to carry out any quantitative studies on the size and market penetration of AC in their territory.

Overall, our conclusion is that all of the DNSPs still need to make substantial improvements to the way in which they undertake sales volume forecasts. This is a matter that IPART must address as part of its determination process, both to ensure the forecasts on which its determination is based is robust and reasonable and to ensure that there is no excessive exercise of 'strategic behaviour' by the DNSPs.

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<sup>38</sup> For example compare forecasting equation outlined in EnergyAustralia (2003) op. cit. p. 20. with the information provided in EnergyAustralia (2003) op. cit. table 3.1 "Summary of Forecasting Methodologies – Treatment of Key Consumption Drivers" pp.10 – 11 and EnergyAustralia (2003) *Global Energy Consumption and Peak Demand Forecast Processes*, 10 January 2003, p. 5

<sup>39</sup> EnergyAustralia (2003) *EnergyAustralia Global Electricity and Customer Number Forecasts 2002-2009*, April 2003, p. 16

<sup>40</sup> Transgrid (2003) *New South Wales Annual Planning Report 2003*, p 122

<sup>41</sup> EnergyAustralia (2003) op. cit. p.20.

<sup>42</sup> Integral Energy (2003) op. cit. p. 174.

<sup>43</sup> See *Principles of Forecasting: A Handbook for Researchers and Practitioners*, J. S. Armstrong (ed.): Kluwer Academic Publishers, 2001

<sup>44</sup> See Ibid

<sup>45</sup> For example Access Economics, *Business Outlook* and Econtech, *Australian State and Industry Outlook*

<sup>46</sup> see *Principles of Forecasting: A Handbook for Researchers and Practitioners*, J. S. Armstrong (ed.): Kluwer Academic Publishers, 2001

### **3.2. Growth Forecasts: A Review of the Meritec Report**

In relation to the DNSPs growth forecasts for the period 2004 to 2009, the terms of reference for the “*Review of Capital Expenditure and Operating Expenditure of the NSW Distribution Network Service Providers*” requires the consultant (Meritec) to:

- *Identify the drivers of growth for each DNSP.*
- *Review each DNSP’s approach to forecasting growth.*
- *Comment on the reasonableness, or otherwise, of each DNSP’s growth forecasts in terms of customer numbers, energy sales, and maximum demand.*
- *Comment on the reasonableness of each DNSP’s low, medium and high growth scenarios and associated costs.*<sup>47</sup>

We have reviewed Meritec’s final report in terms of compliance with IPART’s terms of reference. Overall our view is that Meritec has not sufficiently addressed the terms of reference to provide a robust report. Specifically we note that:

- the analysis appears to solely relate to peak demand growth and not customer numbers and sales volumes (both critical areas for the IPART review);
- the drivers of growth have not been identified;
- the logical basis for assessing the appropriateness and validity of the forecasting methods is not described;
- the critique of forecasting methods is weak and appears to be mostly repetition of the method descriptions provided in the DNSP’s submissions;
- the criteria or method for judging the reasonableness of the forecasts is not identified, notwithstanding that this is important; and
- no factual basis is provided to support the conclusions reached by Meritec, which as a consequence, appear to be based largely on opinions and impressions.

Meritec’s approach contrasts poorly with the detailed analyses of distribution business growth forecasts undertaken for the Victorian and (to a lesser degree) Queensland distribution pricing reviews.<sup>48</sup>

In conclusion, Meritec’s report provides nothing that would allay our concerns that DNSPs have understated the potential for consumption and demand growth. This reinforces the concerns we express in later sections about the rigour of Meritec’s analysis of CAPEX and OPEX forecasts.

As a consequence, IPART is left with little of substance upon which to base its decisions in this important area.

### **3.3. Efficient capital, operating and maintenance expenditure**

The IPART Secretariat presents a summary of the DNSPs’ forecasts showing they propose to spend a total \$4.7 billion in capital expenditure and \$3.8 billion in operating expenditures

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<sup>47</sup> IPART 2003, p 9

<sup>48</sup> SKM (2000) *Report to the Office of the Regulator General on Electricity Demand Forecasting*, report by Sinclair Knight Merz for the Office of the Regulator General, May 2000 and GHD (2000), *Electricity Demand Forecasts*, report to Queensland Competition Authority.

over the 5 years to 30 June 2009.<sup>49</sup> A comparison with forecasts and actuals for the current regulatory period is summarised in Tables 3a and 3b below.

**Table 3a: DNSP CAPEX Forecasts and Actuals**

Total CAPEX (\$M nominal)			
DNSP	FY00-04		FY05-09
	Forecast IPART 1999	Actual/Estimate IPART 2003	Forecast DNSP
EA	\$863	\$1,452	\$2,093
IE	\$400	\$733	\$1,375
CE	\$702	\$897	\$1,240
AIE	\$17	\$19	\$15
Total CAPEX	\$1,981	\$3,101	\$4,723

**Table 3b: DNSP OPEX Forecasts and Actuals**

Total OPEX (\$M nominal)			
DNSP	FY00-04		FY05-09
	Forecast IPART 1999	Actual/Estimate IPART	Forecast DNSP
EA	\$1,070	\$1,340	\$1,509
IE	\$814	\$878	\$1,084
CE	\$832	\$952	\$1,138
AIE	\$36	\$44	\$50
Total OPEX	\$2,752	\$3,214	\$3,781

Information in the tables indicate that the DNSPs are proposing that IPART approve expenditure at a level that is some \$2.74 billion (or 138%) more for CAPEX and \$1.03 billion (37%) more for OPEX than was considered adequate for the current regulatory period in the 1999 Determination and some \$1.62 billion (or 52%) more for CAPEX and \$567 million (or 18%) more for OPEX than has been actually spent in the current regulatory period.<sup>50</sup>

As the IPART Secretariat notes, these are very substantial increases that would result in substantial additional costs to all NSW consumers, if approved.

However, we recognise that the DNSPs must have sufficient revenue to cover 'efficient' CAPEX and OPEX expenditures in the next regulatory period. If they do not, then it is highly likely that the supply capacity of the DNSPs' networks would be unable to provide adequate services to consumers.

The critical role for IPART in this review is to determine what level of CAPEX and OPEX expenditure is just sufficient for the DNSPs to achieve financially viable operations as efficient, well-managed businesses.

We have attempted to reconcile information in Tables 4.1 and 4.2 of the IPART Secretariat Preliminary Analysis report with our interpretation of information in the DNSP submissions, the spreadsheets posted on the IPART website, information in the IPART Price and Service Reports and the Meritec final report. In doing so, we note discrepancies between the DNSP submissions and spreadsheets posted on the IPART Website and each of the document sources referred to above.

<sup>49</sup> See tables 4.1 and 4.2 of the IPART Secretariat Preliminary Assessment report.

<sup>50</sup> Includes estimated expenditures for FY2004.

These discrepancies and deficiencies in Meritec's final report suggest that IPART will face a difficult task in assessing the DNSP proposals. In addition to the issues outlined in section 3 above, other matters of concern are:

- Neither the DNSPs, nor Meritec, comment on these discrepancies. Nor does the IPART Secretariat's Preliminary Analysis report. Indeed, Meritec expresses the opinion that the forecasts provided by the DNSPs are reasonable for purpose of its review of OPEX and CAPEX. Given the clear and obvious link between demand, consumption and the cost of supply, it was crucial for Meritec to base its assessment of OPEX and CAPEX on sound, robust and reasonable demand and consumption forecasts.
- IPART has decided not to release two key documents that directly relate to assessment of the DNSPs proposals prior to the deadline for submissions by end-users. These reports cover an independent assessment of the demand and consumption forecasts prepared by the DNSPs and the Final Report by SKM on *Reducing Regulatory Barriers to Demand Management*. Comments in this submission demonstrate why a rigorous and independent analysis of the DNSP demand and consumption forecasts is crucial to end-users. Independent analysis of demand and consumption forecasts is an integral part of any assessment of the prudence and efficiency of expenditure. Demand and consumption will impact directly on expenditure. Accordingly, in our view, IPART should have ensured that independent analysis of demand and consumption forecasts was completed before Meritec commenced its analysis of the DNSPs' capital and operating expenditure.
- Meritec's failure to critically analyse the DNSP forecasts and to support and justify its opinions/judgements with sufficient quantitative analysis and 'hard' evidence seems likely to allow 'strategic behaviour' to be exercised by the DNSPs and leaves IPART with insufficient information to support its key judgements on the -
  - adequacy and reasonableness of the DNSPs' sales volume forecasts;
  - links between sales volumes and costs;
  - efficiency of CAPEX and OPEX cost projections; and
  - fairness and reasonableness of the DNSP's pricing proposals.

Some of specific deficiencies in the Meritec final report are illustrated in the following sections.

### **3.3.1. Meritec's CAPEX efficiency assessment**

The diagram below illustrates the magnitude of overall difference between actual and forecast CAPEX costs provided to IPART by the DNSPs and by Meritec.<sup>51</sup> Similar diagrams for each of the DNSPs are included in Appendix B.

The diagrams in Appendix B show that the observed discrepancies in CAPEX data occur almost entirely in the data provided by EA and to a much lesser extent CE, with reasonably close correlations in CAPEX data provided by IE. Differences observed in CAPEX data provided by AIE are of a similar order to rounding errors in values quoted to the nearest million dollars in the IPART Secretariat Preliminary Analysis report.

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<sup>51</sup> The line annotated as 'IPART Preliminary Analysis' indicates cost stream data provided to IPART by the DNSPs. The line annotated 'Meritec Final Report' is based on data extracted from the tables in section 6 of the Meritec report

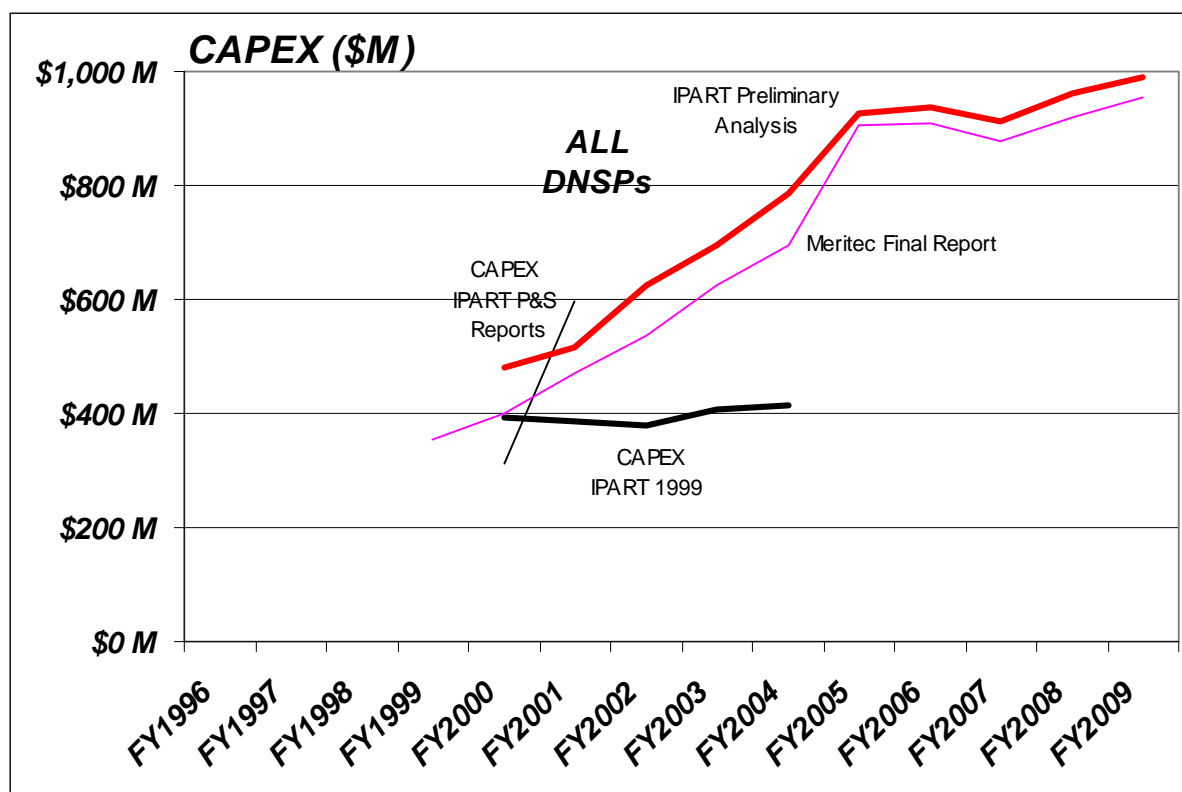


Figure 10: Comparison of CAPEX cost streams for all NSW distributors

Sources as marked.

It is important for IPART to note that there is no explanation in the Meritec final report for the differences between the IPART Secretariat interpretation of DNSP CAPEX data and Meritec's. What Meritec says, for example, is

*“EA was asked to enter its actual capex in the years FY1999-2003 under certain prescribed headings in the template together with its capex projections made at the time of the 1998 capex review. EA reported that assumptions had been made to align its historical expenditure with the requested reporting categories and that some inaccuracies may have resulted. We did not consider them likely to be material.”<sup>52</sup>*

Meritec appears to have made no attempt to reconcile the data provided by EA with the information in EA's submission.<sup>53</sup> Nor is there sufficient numerical or quantitative analysis of this data. A similar discrepancy in CAPEX data can be observed for CE, but not IE or AIE.

The reason why this is important to IPART (and consumers) is that the basis of Meritec's recommendation on the efficiency of CAPEX forecast for the next regulatory period (in the case of EA) is:

*We were, however, concerned about the magnitude of the capex programme as a whole. ... Also, it has been noted that both EA and its consultant, SKM, reported that the high level of expenditure proposed results partly from a*

<sup>52</sup> p43, Meritec final report.

<sup>53</sup> We note that Meritec says (about CAPEX forecast data) on p24 of its final report that “(s)ignificant changes were made to the figures in the table when errors and omissions in the DNSPs' templates were corrected following the presentation of our interim Draft Report. The main changes arose through the addition to IE's and EA's projections of estimates for possibly excluded services and through the separation of non-network expenditures from other renewal (end-of-life) expenditures.” But there is no mention of any attempt to reconcile the data with that provided to IPART.

*previous period of under-investment on the network ... These factors could justify a higher-than-expected level of capex but, on the other hand, the question arises as to how quickly any previous shortfall should be redressed. We took account, in this context, of the methodological reservations expressed in this section of the report.*

*For these and other reasons our opinion is that EA's total capex programme for FY 2004-2014 should be reduced for the purpose of the coming determination and we have recommended accordingly in Section 4 of the report.<sup>54</sup>*

Meritec's recommendations in section 4 being:

*Overall, capex in the range 4% to 4.5% of network replacement cost as proposed by EA and IE respectively (see Table 7) appeared high to us in the prevailing low-growth environment. ...*

*We concluded, and recommend to IPART for its consideration, that the overall capex programmes of EA and IE for FY the period 2004-2009 be reduced in IPART's modelling for the purpose of its determination to a level that we express as a percentage of current network replacement cost ... as follows:*

- (a) EA's growth capex projections would be accepted as put forward to us for review (they are equivalent to 1.6% of current network replacement cost as indicated in Table 7) but its projections of capex for other purposes would be reduced from the 2.4% indicated in Table 7 (balance of 4% less 1.6%) to 2.0% expressed as a percentage of current network replacement cost, giving a total percentage of 3.6%; and*
- (b) IE's growth capex projections would be accepted as put forward to us for review (they are equivalent to 1.7% of current network replacement cost as indicated in Table 7) but its projections of capex for other purposes would be reduced from the 2.8% indicated in Table 7 (balance of 4.5% less 1.7%) to 2.4% expressed as a percentage of current network replacement cost, giving a total percentage of 4.1%. The reduction proposed is equivalent to 10% and 9% for EA and IE respectively.*

*We did not consider adjustment of the capex projections of CE or AI necessary.<sup>55</sup>*

That is, Meritec has based its recommendation to IPART on CAPEX costs (in the case of EA and CE) that are different to those contained in the DNSPs' submissions to IPART. In the case of EA, Meritec has judged that CAPEX forecasts are too high, based on values less than provided to IPART by EA. In the case of CE, Meritec or judged that CAPEX forecasts are acceptable, based on values less than provided to IPART by CE.

### **3.3.2. The need for an alternative approach to assessing CAPEX efficiency**

Given the discrepancies in the Meritec report, we are unable to deduce just what CAPEX dollar value IPART might adopt if Meritec's recommendations are accepted. For EA, for example, should IPART:

- accept an average annual CAPEX figure of 3.8% of "approximately" \$10,927 million<sup>56</sup> - i.e. \$415.2 million/year; or

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<sup>54</sup> pp51-52, Meritec final report.

<sup>55</sup> p27, *Op Cit.*

- re-calculate a percentage figure based on the proportional difference between the total costs provided by EA to IPART and the total cost provided by EA to Meritec, which looks to be 3.8% times (\$2,418M/\$2,313.3M) times *approximately* \$10,927 million – i.e. \$434.0 million/year; or
- accept the average annual CAPEX figure provided by EA of \$483.6 million/year; or
- accept some other figure based on rigorous quantitative analysis that:
  - takes into account efficient actual costs using econometric benchmarking applied to a rational and reasonable asset management program; and
  - considers the possible impact of ‘strategic behaviour’ being exercised by EA.

We strongly recommend that IPART adopt the latter approach, which is based on the process followed by all the UK regulators. That is, we are recommending that IPART does not accept the information and assessments in the Meritec final report.

We also note that:

- preliminary benchmarking comparisons from the ‘efficiency’ analysis of Victorian distributors undertaken for ORG by PB Power in 2000 show very strong *prima facie* evidence that the CAPEX projections of the three main DNSPs are extremely high for the demand and consumption forecasts provided to IPART; and
- a brief commentary of the typical CAPEX patterns exhibited by many other regulated companies under Price Cap regimes, which generally show a tendency for regulated companies to increase CAPEX commitments at the end of each regulatory period and then cut CAPEX commitments substantially below forecasts at the beginning of the next regulatory period.<sup>57</sup>

### **3.3.3. A robust assessment of Capital Expenditure**

Most capital expenditure on distribution is planned, costed and committed within only a year or two ahead of the time when it will be undertaken.<sup>58</sup> Hence it is possible to accurately predict costs only about 2 years ahead. Often the cost of a project only becomes clear in the detailed design stage just prior to the commencement of construction. Therefore, beyond 2-years, cost projections increasingly rely on intentions and likelihoods rather than firm commitments and costing.

As firm costs are available for current projects only, a DNSP has considerable scope over the choice of parameters used to project expenditure forecasts. Discretionary choices include:

- the timing of the replacement and reinforcement expenditure;
- selection of the means of reinforcement or replacement; and

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<sup>56</sup> See Table 7, Meritec final report noting that Meritec does not quantify what level of accuracy is implied by use of the value c10,927 (\$m) in Table 7 – where the “c”, presumably, in an abbreviation for the Latin term *circa*.

<sup>57</sup> This is a logical outcome of the strong ‘incentive’ in fixed period, incentive regulatory regimes to derive commercial benefit by putting off CAPEX commitments as long as possible. This generally delivers a commercial benefit to regulated companies because revenue under a price cap regime is based on forecast quantities and costs. If the companies can cut actual costs below the forecasts they increase profit. For CAPEX, in particular, this is achieved by delaying expenditure as long as possible. However, the benefit decreases (or even disappears) if necessary CAPEX is not committed within the regulatory period. If the CAPEX is delayed too long, service standards will suffer or regulators will judge the CAPEX allowance to have been too high (or inefficient). In addition, regulators are inclined to take a ‘dim view’ of companies that do not provide appropriate services to their customers. UK regulators have even gone so far as to allocate ‘efficiency penalties’ to companies that (the regulator judges to have) provided ‘inefficient’ or inadequate service to consumers.

<sup>58</sup> Ralph Turvey, *Price Control of Electricity Distribution Networks*, Centre for the Study of Regulated Industries, Technical Paper, Feb 2003

- unit installation and operating costs.

Meritec has examined the issue of timing of expenditure and whether there is a justification for expenditure:

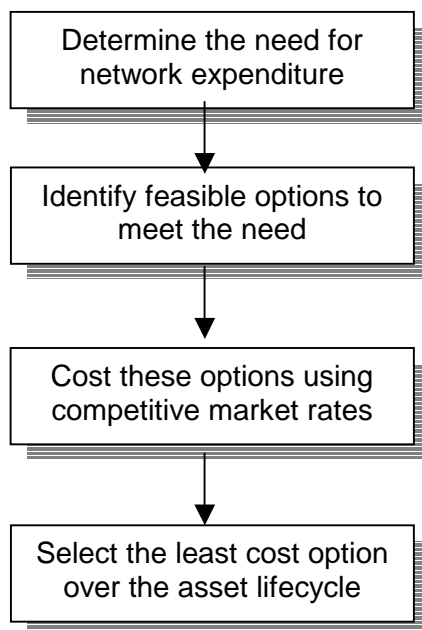
*The most important items as far as this review is concerned were the establishment of the need, the determination of optimal timing of the resulting works, and compliance with the DNSPs' licence conditions to investigate demand management alternatives in certain circumstances.<sup>59</sup>*

However, in a least-cost analysis selecting the optimal timing for an investment is only the first stage and there are two other important steps. The second is to ensure that the unit costs used in the analysis are based on competitive market rates. The third is to determine that the least-cost alternative has been selected (see Figure 11 below).

In terms of assessing the installed costs of new assets proposed in the DNSPs expenditure projections, Meritec asked the DNSPs to reveal if their unit cost estimates were in the accordance with Appendix C of the NSW Treasury's Guidelines. CE replied that their unit costs were based on the guidelines. However, both IE and EA advised that their costs were not, and that they had used their own 'in-house' cost estimates.<sup>60</sup> Despite this Meritec accepted EA and IE's unit cost values without further testing or validation of the numbers.

Regarding least-cost optimality, Meritec queried the DNSPs as to whether their procurement was optimal. On the basis of the DNSPs responses Meritec reached the conclusion that the DNSP approaches were acceptable but did not attempt to objectively test the data against the least-cost criteria.<sup>61</sup>

This reinforces our concerns about the adequacy of Meritec's approach to validating the CAPEX projections.



**Figure 11: Least Cost Analysis – Key Steps**

<sup>59</sup> Meritec (2003) p 9

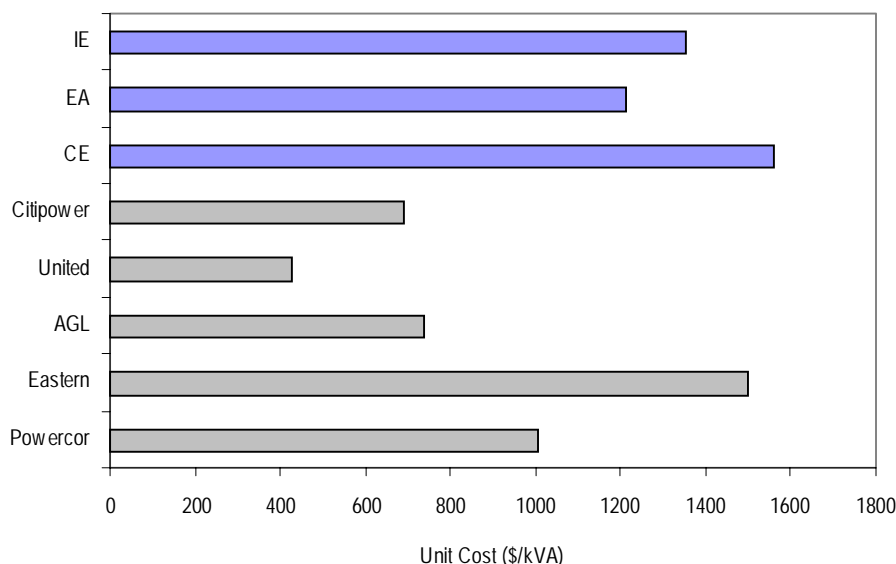
<sup>60</sup> Meritec (2003) - Section titled "Unit Installed Costs" p47, p65 p82.

<sup>61</sup> Meritec (2003) - Section titled "Optimality of Design and Construction Practices" p47, p65 p82.

The absence of any attempt to quantitatively assess the DNSPs costs is remarkable, as it is a relatively straightforward process to benchmark unit costs. For example, with the DNSPs load forecasts and demand related capital expenditure projections, it is possible to estimate the costs per kVA for network reinforcement assuming that the development of the system (in terms of capacity) follows the growth in system demand.<sup>62</sup>

The results of this calculation for each of the DNSPs are shown in Figure 12 below along with equivalent figures for Victorian distribution businesses compiled as part of 2001 electricity distribution price review, and adjusted to 2003 values. The average for the Victorian DBs is \$875/kVA versus \$1375/kVA for the NSW DNSPs (which is 63.6% higher). This simple comparison, alone, gives rise to concerns about the efficiency of the CAPEX proposed by the three largest DNSPs.

The above approach suggests that it would be reasonable for IPART to allow the three largest DNSPs to undertake a CAPEX program at average levels around 60% of that proposed.



**Figure 12: Total demand Related Capex per kVA of load growth**

Source: DNSP submissions and PB Power (2000), *Final Analysis of Distributors EDPR 2001 Submissions*, Report Prepared for the Office of the Regulator General Victoria, June 2000, Appendix E, p11

Given the potential for the DNSPs' forecasts to include an element of 'strategic behaviour', it is also reasonable to suggest that IPART assume CAPEX for the next regulatory period could be based on:

- the rate of actual CAPEX spend for the current period; or
- the rate of actual CAPEX spend for the current period adjusted for inflation, which would assume, in effect, that the DNSPs would achieve no CAPEX efficiency gain in the next period.

<sup>62</sup> The relevant formula for this calculation is:  $unit\ cost\ (\$/kVa) = demand\ capital\ expenditure\ 2004\ to\ 2009\ (\$) \div load\ growth\ 2004\ to\ 2009\ (kVa)$

The three values derived from these assumptions are compared to the DNSPs proposed CAPEX in the Table below. The above discussion suggests that each of the DNSPs should be allowed a CAPEX program of no more than that shown in the right hand column of the table below. This would reduce the total CAPEX allowance from approximately \$4.7 billion to no more than (approximately) \$3.4 billion over the next regulatory period and ensure the DNSPs were operating at a level of CAPEX efficiency similar to that of their Victorian counterparts.

In fact, there could well be good reasons for reducing it below this level if the DNSP are, for example, to be encouraged to continue pursuing efficiency gains, consistent with the objectives of regulation.

DNSP	Total CAPEX DNSP Proposal (\$M)	Suggested total CAPEX ranges FY05-09		
		VIC DB Equivalent CAPEX (\$M)	Actual CAPEX IPART PAR (\$M)	Actual CAPEX IPART PAR +10% (\$M)
EnergyAustralia	\$2,093	\$1,465	\$1,452	\$1,597
Integral Energy	\$1,375	\$960	\$733	\$806
Country Energy	\$1,240	\$870	\$897	\$987
Australian Inland Energy	\$15	\$20	\$20	\$20
<b>Total</b>	<b>\$4,723</b>	<b>\$3,315</b>	<b>\$3,101</b>	<b>\$3,411</b>

Note: Average annual CAPEX amounts rounded to nearest \$5M for EA, IE and CE and nearest \$1 for AIE. No greater accuracy is possible using amounts quoted in the IPART Secretariat Preliminary Assessment.

We would qualify the approach recommended above by stating that a higher CAPEX allowances could be judged by IPART to be appropriate if this can be supported by a DNSP through a detailed program of works. This would need to be based on specified activities to which the DNSP commits over the next regulatory period and which would be subject to an annual public progress reporting regime.

The latter approach is based on that adopted by OFGAS and Mergers and Monopoly Commission in the UK<sup>63</sup> and the Victorian ESC.<sup>64</sup>

However, a better approach (for NSW consumers overall) would be to initiate a ToU, price-based, demand response program targeting AC-users. This would enable NSW consumers to contribute to a more economically efficient outcome that reduced costs overall.

### 3.3.4. Meritec's OPEX efficiency assessment

Meritec's assessment of OPEX makes at least some attempts to compare measures of DNSPs' OPEX costs with a small selection of the two dozen or so NZ *lines businesses*. However, similar problems to those illustrated above with Meritec's CAPEX assessment remain, and the comments and conclusions from Meritec's comparison assessment seem to be inconsistent.

<sup>63</sup> Following Transco's, the UK gas distribution and transmission company, appeal against OFGAS' 1994 decision not to allow a very substantial increase in CAPEX for the period 1994-99.

<sup>64</sup> As a condition accompanying its allowance of a very substantial increase in CAPEX for Multinet in the 2002 gas distribution price review.

Figure 13 below illustrates the magnitude of difference overall between actual and forecast OPEX costs provided to IPART by the DNSPs and by Meritec.<sup>65</sup> Similar diagrams for each of the DNSPs are shown in Appendix C.

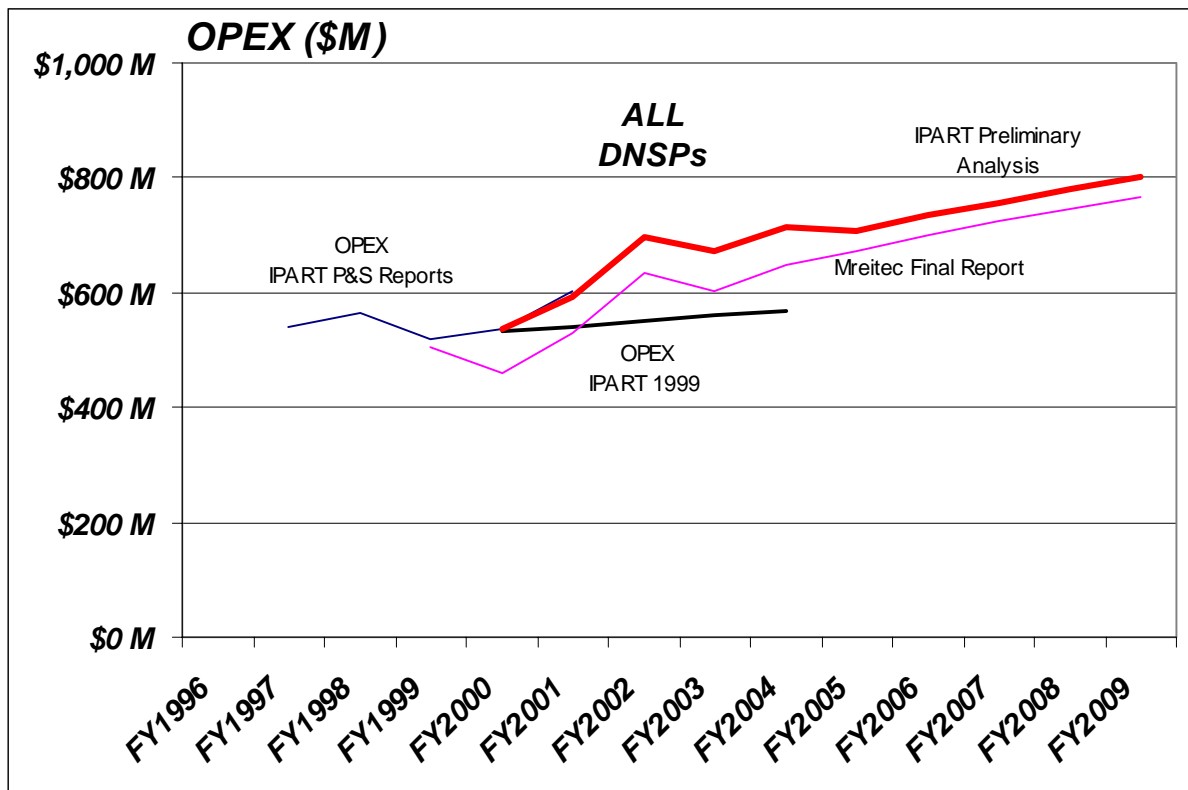


Figure 13: Comparison of OPEX cost streams for all NSW distributors

Sources as marked.

The diagrams in Appendix C show that the observed discrepancies occur mainly in the OPEX data provided by EA and to a much lesser extent IE, with reasonably close correlations in OPEX data provided by CE. Differences observed in OPEX data provided by AIE are significantly more than rounding errors for ‘actuals’ for the current regulatory period.

Again, it is important for IPART to note that there is no clear explanation in the Meritec final report for the differences between the IPART Secretariat interpretation of the DNSP data and Meritec’s. All Meritec says is:

*“To help determine the prudence of these expenditures we asked the DNSPs to break down their projected and actual opex under the headings shown in the table. Initially, the data received contained errors and inconsistencies as*

<sup>65</sup> As with the previous diagram, the line annotated as ‘IPART Preliminary Analysis’ indicate cost stream data provided to IPART by the DNSPs. This data has been taken directly from Table 4.2 of the IPART Secretariat Preliminary Analysis report, which is headed “DNSPs’ actual and projected forecast operating and maintenance expenditure (nominal \$ million)” and qualified by a footnote stating that “Data values for Integral Energy, Country Energy and Australian Inland are based upon updated data and revised IPART model.” The line annotated ‘Meritec Final Report’ is based on data extracted from the tables in section 6 of the Meritec report, with the data comprising:

- sub-totalled actuals and estimates for the period FY2000-03 for the OPEX category labelled ‘Total opex - Regulated services’ (presented by Meritec in Nominal dollar terms); and
- sub-totalled estimates of forecasts for the period FY2004-09 for the same OPEX category (presented by Meritec in 2003 dollar terms and converted to nominal dollar terms by application of CPI).

reported in our interim Draft Report but adjustments were made by the DNSPs to remove these completely as far as we are able to tell.

In some instances expenditures had obviously had to be re-categorised to fit historical or projected data into the reporting categories we requested. For example all DNSPs except EA reported their projections only under the heading 'other opex'. The assistance of the DNSPs in correcting errors and resolving inconsistencies put the analysis on a sound footing. We acknowledge their assistance during this period.

Based on the corrected figures reported in the table actual opex for all DNSPs was within 2% to 3% of their 1998 projections."<sup>66</sup>

That is, Meritec claims to have attempted to resolve data discrepancies but provides no explanation of why the total annual OPEX amounts are substantially different to those provided (by EA in particular) to IPART.

Figure 14 below illustrates the magnitude of the differences between the EA OPEX data referred to in the IPART Secretariat Preliminary Analysis report and the Meritec final report. This also shows that actual OPEX amounts for the current regulatory period in the IPART report is up to \$100 million higher than the \$214 million forecast for FY2002, clearly nowhere near "within 2% to 3% of their 1998 projections" as suggested by Meritec.<sup>67</sup>

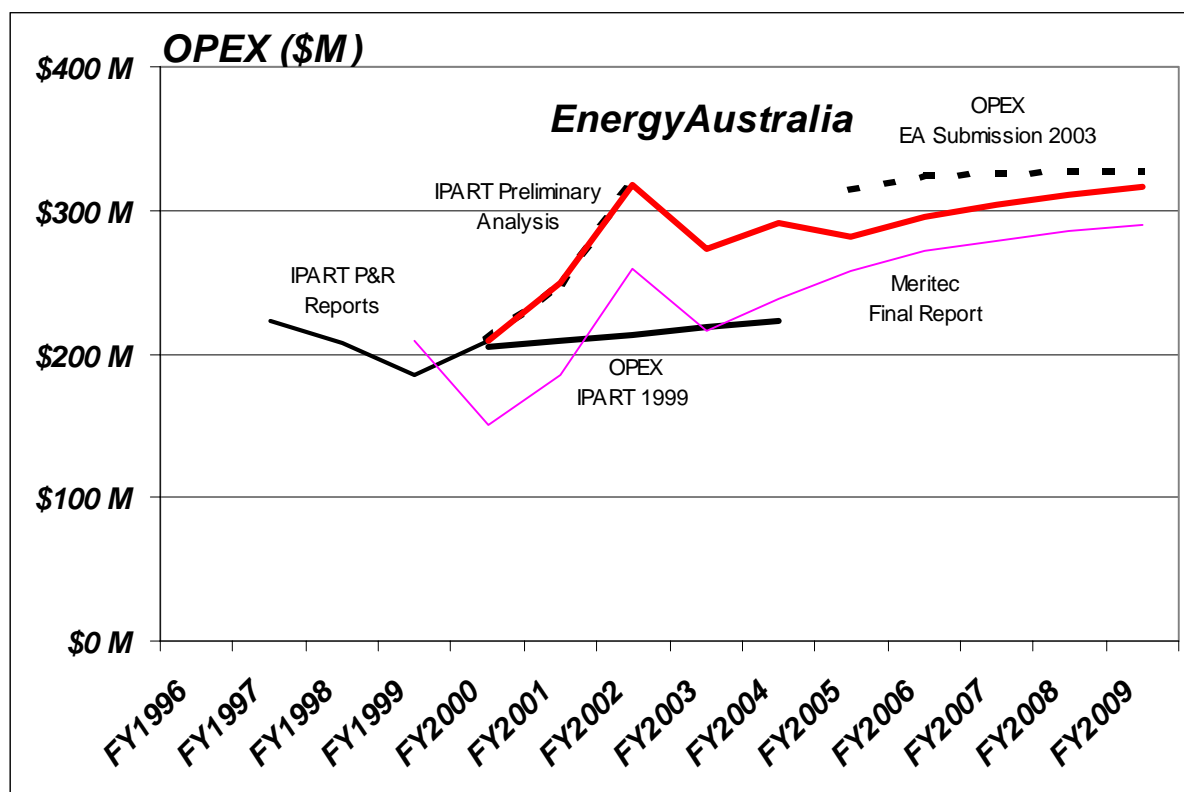


Figure 14: Comparison of OPEX cost streams for EnergyAustralia

Sources as marked.

<sup>66</sup> p29, Meritec final report.

<sup>67</sup> Figure 7 also illustrates the discrepancy between data provided to IPART by EA in its submission (shown OPEX EA Submission 2003) and, presumably, the Spreadsheet model used by IPART for its Preliminary Analysis. (See Table 12, p42, EA Submission. Amounts shown are \$2003, and are annotated with *includes Streetlighting and FRC*).

As far as Meritec's attempt at 'benchmarking analysis' goes, we draw IPART's attention to the following contradictory comments in Meritec's final report:

In regard to comments about 'total OPEX', Meritec said:

- *"AI had the highest opex as a percentage and EA the lowest, probably reflecting their relative economies of scale and other characteristics;"*<sup>68</sup>

Meritec's Table 10 shows EA with Total OPEX at 2.2% of "Average actual p.a. as pct of network replacement cost", CE at 2.5% and IE at 2.7% for the period FY99-03. If these figures were adjusted for the discrepancy in annual OPEX costs shown in Figure 14 above, EA would have OPEX costs at 2.8%, which is higher than both CE and IE.

In regard to comparisons with NZ lines businesses, Meritec said:

- *"EA's direct costs per unit of system length exceed the New Zealand maximum by 70% and IE's exceed it marginally but the rest of the NSW DNSPs are within the New Zealand range (AI's are significantly below); ...*
- *Total direct plus indirect costs per kWh sold are comparable but the minimum in NSW is 50% above the minimum in New Zealand;"*<sup>69</sup>

These are very substantial differences in indicated cost comparisons, yet there appears to be no adequate explanation that links these observations to the conclusions reached in Meritec's 'opinion' (repeated below).

Quantitative benchmarking is a challenging process because (amongst other factors) geography, supply area, customer mix, distance, asset age and technology impact on quantified comparisons. To have any useful meaning, measurement 'standardisation' is necessary, which Meritec has not provided even for the easiest parameter. For example, Footnote 16 of Meritec's final reports says (in relation to comments/statements referring to cost comparisons between the DNSPs and NZ lines businesses) "(t)he New Zealand data is presented in NZ dollars and the NSW data in Australian dollars. Adjustment for currency exchange rates was not considered appropriate".<sup>70</sup> The FOREX rate for the AU\$ has ranged between NZ\$1.31 and NZ\$1.07 over the current regulatory period. That is, Meritec appears to be making judgements on comparative efficiency that will cost NSW consumers hundreds of millions of dollars using parameters that based on substantially different currency values.

Even without 'standardisation' it is possible to make general observations. As Meritec notes in Table 12 of its report, the NZ lines businesses have very diverse characteristics. On this basis, it is reasonable to expect a wide range of unstandardised performance measure outcomes, but comparators with similar levels of efficiency would be expected to yield overlapping performance in at least some areas. Yet the DNSPs performance still falls outside the range indicated for the NZ lines businesses. A possible explanation for this is that the DNSPs are substantially less efficient than any of the NZ lines businesses.

We also note that Meritec says: "Care is needed in the interpretation of the figures, noting the differences between the DNSPs. However, the comparison does tend to support our own assessment based on experience that, although the NSW DNSPs have no doubt improved their operations over time, there are further efficiency gains to be achieved. ...."<sup>71</sup>

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<sup>68</sup> p32, Meritec final report.

<sup>69</sup> pp34-35, Meritec final report.

<sup>70</sup> See p35, Meritec final report.

<sup>71</sup> See note below Table 12.

Yet, in conclusion, Meritec says:

*Our opinion is as follows:*

- a) *We found no reason to conclude that opex during the period FY 1999-2003 was imprudent;*
- b) *We considered the FY 2003 opex figures as agreed with us and presented in the later sections of the report to be a reasonable and balanced starting level in all cases for the determination of future opex in accordance with the recommendations that follow;*
- c) *We saw no reason for opex movements in real terms from FY 2003 onwards to exceed a reasonable allowance for increase in scale of operation, given adequate capital investment;<sup>72</sup>*

and Meritec goes on to recommend that IPART consider:

*... the following actions in respect of projected opex for the period FY 2004-2009:*

- i) The implicit re-positioning of EA's opex not be agreed to;*
- ii) To give effect to (i) above EA's opex be adjusted to reflect an increase of no more than 10% in nominal terms from FY 2003 to FY 2009;*
- iii) Opex for the other DNSPs be accepted as projected;<sup>73</sup>*

That is, Meritec says that “*there are further efficiency gains to be achieved*”, but still forms an opinion that there “*was no reason to conclude that opex during the period FY 1999-2003 was imprudent*”; and “*no reason for opex movements in real terms from FY 2003 onwards to exceed a reasonable allowance for increase in scale of operation*” and then recommends that “*Opex for the other DNSPs (except EA) be accepted as projected.*”

The comments, conclusions and recommendations made by Meritec are very difficult to either understand or accept. If Meritec is right in saying that there are further efficiency gains to be achieved and the OPEX costs forecast for the next regulatory period are high in comparison with those incurred in the current regulatory period, then it is simply not credible to recommend to IPART that “*Opex ... be accepted as projected.*”

We believe that OPEX efficiency gains are possible for the DNSPs, given the comparison of the cost indicators with NZ *lines businesses*. This suggests that IPART should be reducing the DNSPs OPEX forecasts, not accepting them.

As with CAPEX, it is our view that IPART cannot place any weight on Meritec's assessment of OPEX efficiency and IPART should undertake its own rigorous analysis using techniques similar to those employed by all UK regulators.

We are not able to make any firm recommendations on OPEX levels based on the information available. However, it seems reasonable to suggest that IPART should allow no more than an extension of actual OPEX amounts for the current regulatory period adjusted, on some sensible weighted basis, for key OPEX cost drivers such as increases in customer numbers, consumption and/or total line lengths.

### **3.4. Regulatory Asset Base**

In its Preliminary submission to IPART, the EUAA noted that CE is seeking a very substantial increase in the 1998 Regulatory Asset Value (RAV), based on ‘advice’ from

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<sup>72</sup> p38, Meritec final report.

<sup>73</sup> p39, Meritec final report.

PricewaterhouseCoopers and NSW Treasury.<sup>74</sup> On the other hand, EA says in its submission:

*“EA has not included in its pricing proposal the impact of any ‘unrecognised’ assets, totalling \$440 million, that were not in the original 1998 RAB (Regulatory Asset Base) although we argue that, in principle, they should be included.”<sup>75</sup>*

The EUAA’s Preliminary submission also noted its opposition to any such changes in the RAB. There is no benefit to consumers or to economic efficiency in retrospectively ‘rewarding’ regulated businesses for sunk cost investments. The submission also noted its expectation of symmetry in treatment by any regulator accepting such a proposal. Hence, the regulator would need to determine that there are not asset values that, upon further review, should be excluded for the RAB or devalued.

We are pleased to note that the IPART Secretariat had proposed rejecting arguments put by the DNSPs to ‘adjust’ the starting RAB value. We concur with this view. It is generally consistent with decisions taken by all of the UK regulators not to change initial regulatory asset values. It is also consistent with circumstances in Victoria, where the Tariff Order explicitly specified the opening RAV and explicitly required that ORG use such values.

We also agree with reasons put forward by the IPART Secretariat in support of its position, viz:

- *revaluations of the asset base are inconsistent with the financial view (of the asset base), where the RAB is taken to represent the shareholders’ financial investment in the firm;*
- *it is questionable whether increases in the DORC valuation are sufficient to justify increases in the regulatory value of the firm;*
- *any allowance of the proposed adjustments would require a review of the 2002 DORC valuation studies to ensure that the DNSPs’ proposals represent a balanced view of the potential adjustments to the RAB;*
- *higher valuations can retard downstream competition as downstream firms endeavour to earn sufficient revenue to pass upstream to the regulated firm in order to cover the higher asset value; and*
- *there are unlikely to be any adverse impacts in terms of dynamic efficiency (incentives for investment) from not making adjustments to the RAB ... as long as the associated maintenance and replacement expenditure is recognised in future notional revenue requirements, the business will retain the incentive to undertake these maintenance and replacement activities.*

We strongly urge IPART to maintain this view

### **3.5. Return on Capital**

The approach adopted by Australian regulators to setting return on equity and Weighted Average Cost of Capital (WACC) is a critical issue for energy users (and for energy networks). It is one of the key issues in any review of energy network charges.

Return on capital (WACC x Asset Value) accounts for more than 50% of annual revenue requirement of the DNSPs and has a commensurate impact on distribution charges. Unfortunately, and inevitably, the importance of WACC to DNSPs’ revenue provides strong incentives for ambit claims and exercise of ‘strategic behaviour’ (i.e. gaming of the process,

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<sup>74</sup> See pp20-22, CE Summary submission.

<sup>75</sup> p (xv) of EA Summary submission.

setting of parameters and associated information) by the DNSPs. In the case of NSW DNSPs, a 10 basis point increase in WACC delivers \$80-100 million per year more revenue. This is a very powerful incentive to use every possible means to get regulators to set higher values than required to satisfy the 'reasonable expectations' of financial markets, which should be a key benchmark for regulators.

Regulators must balance the interests of utilities and consumers in setting WACC. It is also abundantly clear that consumer input into reviews such as this one has been inadequately resourced, especially compared to that of the DNSPs and that this creates an asymmetry in the information and argument provided to regulators. Therefore, regulators need to focus on overcoming this imbalance. The material presented below shows that, in the UK at least, regulators focus more on financial market expectations and impacts, preferring not to rely as much as Australian regulators do on the views of shareholders or utility owners.

This material shows a 'benchmarking' comparison of Return on Equity and WACC prepared by Pareto Associates. It builds on uses information presented initially to the ACCC on behalf of BHP-Billiton in relation to the last Victorian gas transmission application and to the Victorian ESC on behalf of the Customer Energy Coalition in relation to the last gas distribution access arrangements. For this review, the original Pareto data has been updated to show outcomes from all recent regulatory decisions in Australia, including the NSW DNSPs' proposals and the IPART Secretariat's preliminary view.

We urge the Tribunal to carefully consider it.

The approach taken is to use values of CAPM parameters selected by individual regulators to derive estimates of real, post tax Cost of Debt, Return on Equity (key WACC parameters) and the 'Vanilla' WACC (real, post-tax). This allows a (nearer) 'apples-for-apples' comparison of the outcomes from regulatory decisions than is possible by using numbers derived from different versions of CAPM (as has been done previously by both the ACCC and IPART), or by using nominal values that do not exclude the impact of inflation.

The results of this analysis show that Australian regulators have made judgements that are far more varied than those made by UK regulators administering similar incentive regulation regimes. The analysis also shows Australian regulators have endorsed outcomes that, unfortunately for end-users, ensure Australia's energy networks will be less 'efficient' (i.e. more costly to end-users) than in either the UK or US. This is not a desirable outcome for customers, especially those operating in competitive world markets.

We acknowledge that regulatory decisions that provide inadequate incentives for owners to invest would eventually harm Australia's economic interests, and those of end-users. But increases in the costs of regulated services due, for example, to excessive returns also play a direct role in diminishing the international competitiveness of Australian business.

Regulators must form robust views on these matters and minimise the degree of judgement. This is becoming more-and-more possible with the now substantial track record of regulatory decisions in Australia (and elsewhere). This makes it possible to refine the setting of WACC parameters and reduces the need for regulatory judgement (as well as regulatory risk). The main exception to this is regulatory judgement on the market risk premium, which is still subject to considerable debate. It also calls seriously into question the Productivity Commission position, in their report on National Access Regime that regulators should always err on the side of setting a higher WACC.

Our view is that this issue is best addressed through regulators undertaking careful analysis and making considered, well-informed and independent decisions focussed on outcomes that emphasise broad economic benefits. They should steer away from making decisions that protect the long-term interests of existing utility shareholders. IPART has a key role and responsibility here.

There is nothing in the decisions of any Australian regulator to explain why return on equity and WACC must be higher for Australian utilities than for utilities in the UK and US.<sup>76</sup>

The outcomes presented above may well be the result of overly-cautious regulation, or regulatory error, and there is a real possibility that regulators are contributing to a reduction in the competitiveness of the Australian economy, which the EUAA considers is a critical issue for Australia's energy using and world competitive industries.

The two diagrams below show a summary of the estimates for real, post-tax Return on Equity and 'Vanilla' WACC taken from a large number of UK, US and Australian regulatory decisions (and include the NSW DNSPs' the IPART Secretariat view presented in the Preliminary Analysis report. The key conclusions are:

- The NSW DNSPs are (in effect) claiming that financial markets judge the DNSPs to be much less efficient and more costly to finance than utilities in the UK or US – by at least 200 and 350 basis points respectively.
- Whilst the IPART Secretariat proposals are reasonable compared to recent regulatory decisions, the value for Return on Equity (and hence WACC) proposed is still substantially higher than judged efficient by UK regulators.
- Adopting similar values for Return on Equity to UK regulators would yield WACC values (real, post-tax "Vanilla") of just 4.5-5.0%, not the 6.5-6.8% proposed by the NSW DNSPs, a difference of between 130-230 basis points).
- The difference in outcomes between Australia and the UK will cost NSW consumers at least \$120 million/year more than would apply under the UK approach.

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<sup>76</sup> Material included in the CEC's submission to the last ESC's Gas Distribution Review shows that 'evidence' presented by NECG (rebutting a NERA report for the ACCC) purporting to show that the Australian economy is 'more costly' than the UK and US is misleading. Actual market data for Australia, the US and the UK referred to by NECG (and taken from *Expected returns and volatility in 135 countries*, C. Erb, C. Harvey, T. Viskanta, *Journal of Portfolio Management*, Spring 1996, pp. 46-58), shows expected returns for Australia (between 1979-1995) slightly below those for the US and UK. That is, the data suggests financial markets would expect the Australian economy to deliver slightly lower returns than the UK and US economies.

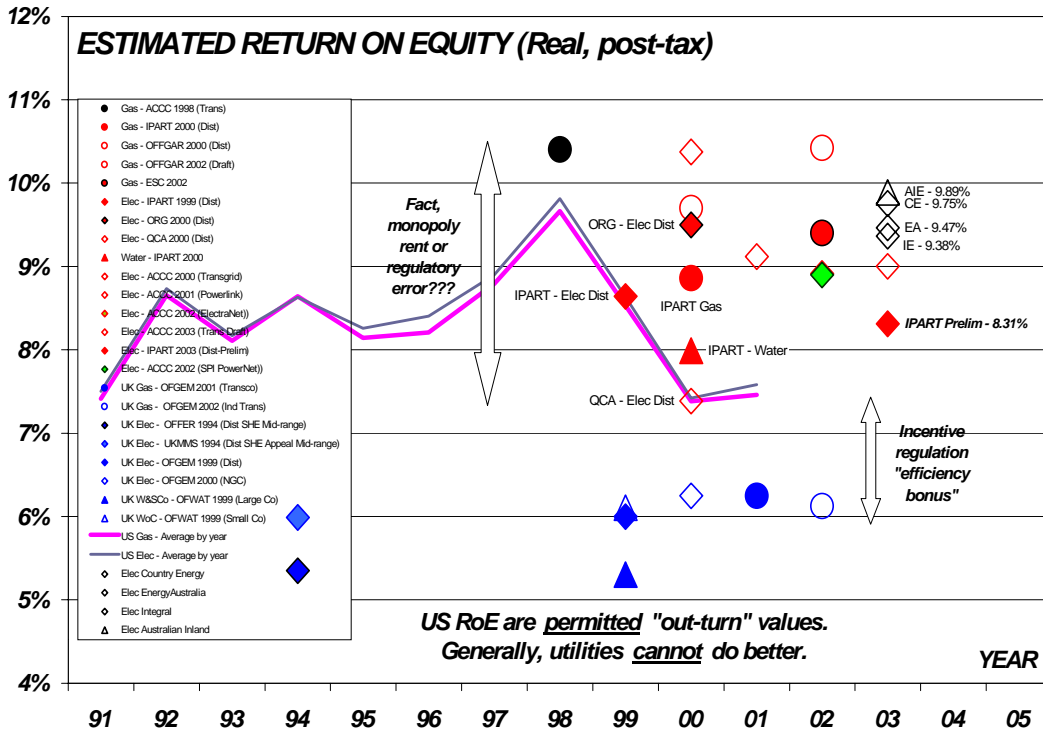


Figure 15: Estimated return on equity taken from regulatory decisions and DNSP submissions

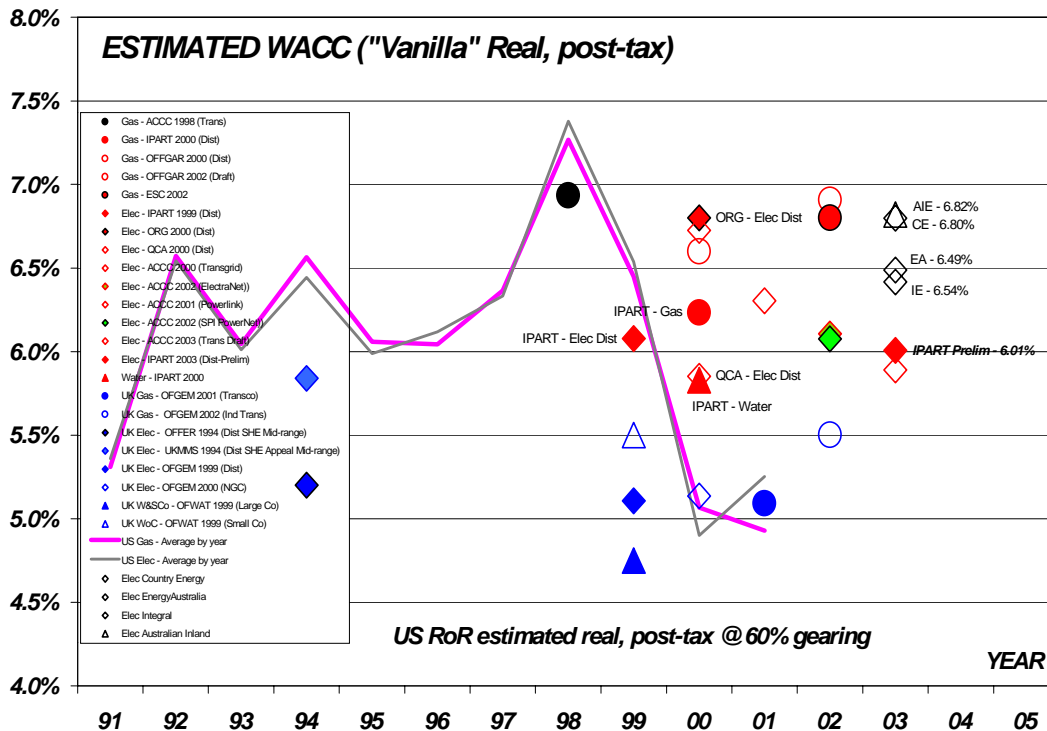


Figure 16: Estimated "Vanilla", post-tax WACC taken from regulatory decisions and DNPS submissions.

There are a number of other matters related to the Secretariat's approach to WACC that IPART should consider. These are:

- the value for the Cost of Debt adopted by the Secretariat, which we estimate is, 4.47%, is more than 50 basis points higher than judged 'efficient' by the ACCC in its on the recent draft Transend revenue determination; and
- IPART still appears to be 'wedded' to the more complex formulations of CAPM, when all other Australian regulators (or at least the ACCC and QCA) have followed the example set by ORG in its 2001 electricity distribution price review of using the simpler, and more easily understood "Vanilla", post-tax version of CAPM. This adds to regulatory inconsistency, as well as being less transparent.

### **3.6. Treatment of CAPEX and OPEX expenditure 'overspend' - Past Forecast Errors, Impacts on Costs and 'Claw-back'**

A major reason given by the DNSPs for their claim for significantly higher costs in both the current and next regulatory period is the 'unforeseen' increases in peak demand and underlying consumption of energy. This hinges critically on the robustness of the forecasts produced by the DNSPs at the time of the 1999 IPART Determination and IPART's ultimate view on these forecasts. The DNSPs have also criticised IPART for parring back their expenditure claims in the 1999 Determination. However, it is not sufficient to merely blame the regulator for this outcome, as the decision IPART took placed substantial weight on the DNSPs' own forecasts. In addition, Worley-PWC accepted the expenditure forecasts of the larger DNSPs and even increased expenditure above that proposed by three of the (then) rural distributors.

The NSW DNSPs have acknowledged in their submissions that they needed to improve their forecasting techniques. However, it is disturbing to see them use this as a basis for arguing that they should be permitted to retrospectively recover losses to their businesses and lost value in dividends to their shareholder, the NSW Government. This is clearly and starkly contrary to how incentive regulation is supposed to operate. It also clearly raises questions about what responsibility DNSPs should take for forecasting.

Our view is that the DNSPs cannot allocate responsibility to IPART for the forecast errors or to consumers for increasing their demand above levels the DNSPs had projected.<sup>77</sup> We endorse the view expressed by CE that distributors are in the best position to develop forecasts in consideration of local knowledge of growth trends, the capabilities of their respective networks, and the development of assets to meet future needs. Given the distributors are accountable for network planning, they must also have responsibility for demand forecasts. However, IPART also carries a responsibility to energy users to check the robustness of forecasts made by the DNSPs, as the forecasts are critical to the WAPC and, ultimately, distribution tariffs.

We believe the outcomes from the current regulatory period have all the signs of the DNSPs preparing badly constructed forecasts for the 1999 Determination. This raises the question of whether, and under what circumstances, IPART should protect the businesses from such serious errors, especially as end-users will be the ones who shoulder the costs. We consider this to be a very serious issue.

The DNSP submissions say that 'the shareholder' has had to forego dividends for the last few years as a result of these poor forecasts. However, as this is clearly due to a lack of DNSP forecasting error, such a loss should be borne by the businesses and the shareholder. That is what would happen in a competitive market place, which the regulatory regime

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<sup>77</sup> The DNSPs shareholder, the NSW Government, also carries some responsibility for this through its policy of containing price signals to consumers with the most volatile loads.

applied in NSW is meant to mimic. It is also consistent with incentive based regulation, where any efficiency gains (and losses) are borne by the regulated entity. We have no illusions whatsoever that either the shareholder, or the DNSPs, would consider for one moment handing back “excess profits” if the outcome had gone the other way.

IPART should not make a Determination that requires customers to pay for the DNSPs’ mistakes. It would be a major setback for incentive-based regulation in NSW if it did.

Accordingly, we are pleased to see that the IPART Secretariat is “*inclined to favour the ... approach (of allowing) no ex-post adjustment for foregone return on and of capital*”. Indeed, we very strongly recommended that IPART accept the logic set out by the Secretariat and explicitly and unequivocally reject claims by the DNSPs for ‘retrospective’ compensation for above-forecast expenditure.

We believe the arguments in favour of this approach are over-whelming for exactly the reasons the Secretariat presents. That is:

- disallowing retrospective compensation for over-spending is consistent with the incentive based regulatory framework that the Tribunal has adopted;
- allowing ex-post recovery of unexpected costs, is akin to rate of return regulation as has been applied in United States regulatory practice;
- rolling the undepreciated capital expenditure into the opening RAB with no adjustment for foregone rate of return prior to the start of 2004 regulatory period weakens incentives for seeking efficiency improvements;
- allowing ex-post recovery of unexpected costs would require DNSPs to hand back any allowed depreciation or rate of return on the difference between actual and allowed capital expenditure where actual expenditure is less than the allowed amount;
- an asymmetric approach that compensated DNSPs for over-spending but allowed them to keep the benefits of underspending would largely result in a 'one-way bet' for DNSPs and substantially reduce their profit risk;
- Clause 6.10.2(b) of the Code, which provides for, on a prospective basis, a sustainable commercial revenue stream which includes a fair and reasonable rate of return to DNSP owners on efficient investment, given efficient operating and maintenance of the network, is very much forward looking.
- Clause 6.10.2(b) makes no reference to positive incentives, which means DNSPs have no right to expect a guarantee of profit and the consequences of not making a profit act as a form of ‘negative’ incentive for DNSPs to operate efficiently; and
- customers bear the risk of paying too much in the face of lower than expected expenditure.

We also concur with the Secretariat’s preliminary view that the Tribunal should not allow ex-post recovery of operating expenditure in excess of that allowed for in the current determination. As with the arguments supporting rejection of ‘over-spent’ CAPEX, this reinforces the essential ‘efficiency incentive’ of the regulatory regime.

In addition, we draw IPART’s attention to precedents set in Victoria by ORG in response to:

- arguments put by Victorian distributors that they were entitled to retain ‘efficiency gains’ from the initial regulatory period not just for that period, but for a full five years;

- arguments that ORG had no power or right to ‘claw back’ what some argued were ‘excess’ profits in the initial regulatory period; and
- lengthy, detailed and ultimately fruitless arguments by TXU that it was entitled to request ORG to retrospectively re-set CAPEX allowances for the initial gas access arrangement period for Westar because TXU found its actual CAPEX commitments were substantially higher than allowed before Westar was privatised.<sup>78</sup>

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<sup>78</sup> The Victorian ESC website contains all the documentation associated with its assessment of this claim. Go to: Gas/Consultation Centre/Past Consultations “*February 2001: Barwon Heads - Application to Revise Access Arrangements*” on the ESC Website.

#### **4. PRICING AND TARIFF STRUCTURES**

Network charges constitute about 37 percent of the cost of delivered energy for the average residential customer in NSW<sup>79</sup> and can be 50 percent or higher for some customers. For large industrial customers, network charges are a lower proportion of total energy costs but are still very significant, both as a proportion of total energy costs and in dollar terms. Thus the level and structure of network tariffs are issues of key interest and concern to end-users. We are therefore keen to ensure that any restructuring of tariffs proposed by the DNSPs is consistent with IPART's pricing principles and with the objectives of economic regulation in the NEM, as well as ensuring that customers are not significantly disadvantaged.<sup>80</sup>

In keeping with these objectives, we strongly support moves towards cost-reflective tariffs, providing they directly target the consumers who create cost drivers for the DNSPs and directly benefit consumers who can respond to these drivers.

Accordingly, we are concerned that pricing initiatives proposed by the DNSPs, such as inclining block tariffs and seasonal block tariffs, are very blunt instruments that will not deliver their intended objectives of achieving cost-reflective pricing and promoting DM. Rather, there is a risk they will impose unreasonable charges on substantial numbers of 'low-cost' users.

In this section of the submission we examine some of the major pricing initiatives being proposed by the DNSPs. We discuss the impact of these pricing initiatives on energy users and (particularly) on demand and point out deficiencies in the proposed initiatives (section 4.2). We then provide some recommendations on preferred directions in relation to pricing and tariff structures (section 4.2.1).

##### **4.1. Cost reflective pricing and cost drivers**

Before discussing the DNSP's pricing initiatives, it is useful to review the principle of cost reflective pricing and comment on what we believe that this should mean in practice.

###### **4.1.1. The objective of cost reflective pricing**

IPART's *Pricing Principles and Methodologies for Prescribed Electricity Distribution Services* (PPM) of July 2001 was a positive move and one that we support. As discussed in section 4.2.1, whilst we believe that some of these principles need to be reviewed or strengthened they currently provide for some improvement in the framework for network prices, especially for promoting more economic use of the network and more efficient investment in network development, DM options and distributed generation.

The importance of cost reflective pricing is specifically recognised in principle 4, which states:

*Prices are to signal the economic costs of service provision, by:*

- (a) being subsidy free (i.e. between incremental costs and stand alone costs);*
- (b) having regard to the level of available service capacity; and*
- (c) signalling the impact of additional usage on future investment costs.<sup>81</sup>*

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<sup>79</sup> IPART (2002a), *Regulatory arrangements for the NSW Distribution Network Service Providers from 1 July 2004: Issues Paper*, IPART November 2002, p. 5.

<sup>80</sup> IPART (2002b), *Pricing Principles and Methodologies for Prescribed Electricity Distribution Services: Developed pursuant to clause 6.11 (e) of Part E, Chapter 6 of the Code*, IPART June 2002.

<sup>81</sup> *ibid*, p.21.

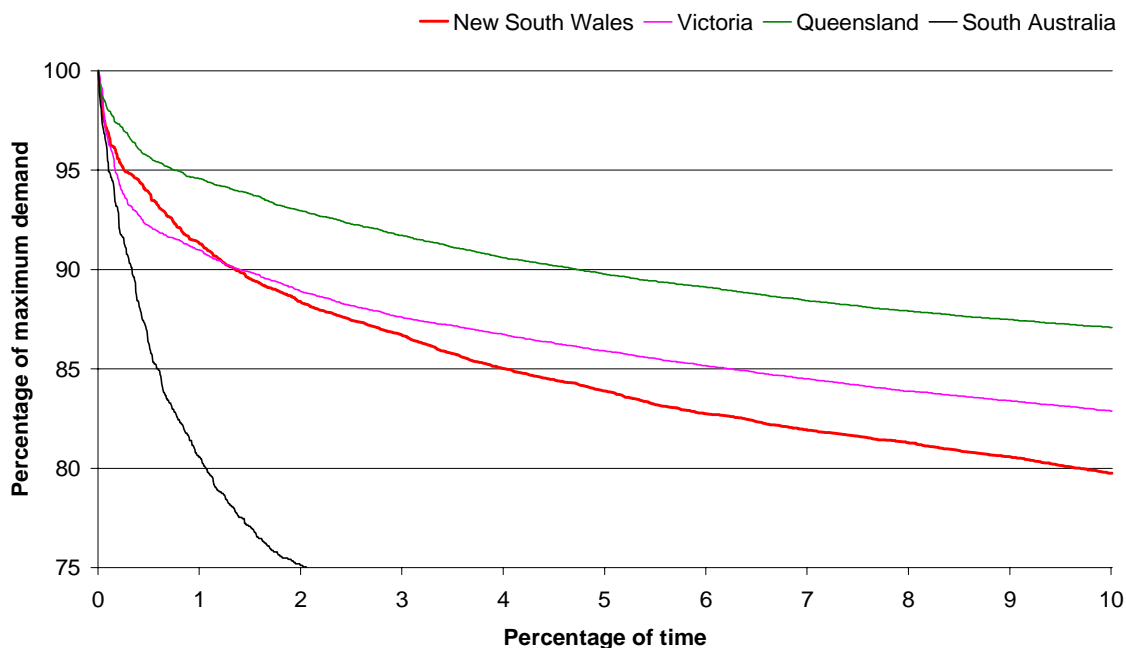
Tariffs that diverge significantly from costs are likely to lead to distortions in network use and a misallocation or over allocation of network investment, a point noted in IPART's *Issues Paper*.<sup>82</sup> A study undertaken for IPART's inquiry into demand management has also emphasised the importance of cost reflective network pricing, noting that this can have a critical influence on bringing forward the least-cost combination of demand and supply responses.<sup>83</sup>

#### 4.1.2. Key cost drivers

On the question of what are the major cost drivers on the network, we concur with the conclusion of both EA and IE that the biggest cost driver is increasing air-conditioning load, especially from residential and small commercial consumers. In its submission to IPART, EA notes that afternoon demand has become more prominent, particularly in summer, and that "increased use of air conditioning by small business and domestic customers has had a significant impact on the summer afternoon demand."<sup>84</sup>

IE's assessment is similar.<sup>85</sup> As a consequence, IE has concluded that "increased air conditioning load is the key problem driving uneconomic network capital."<sup>86</sup>

These conclusions are supported by available statewide evidence. Figure 17 below shows load duration curves for NSW and three other NEM Regions. It indicates that in NSW in 2002-03, 5 per cent of network capacity was used for less than 0.5 per cent of the year and 10 per cent of network capacity was used for only about 1.5 percent of the year.



**Figure 17: Top End Load Duration Curves NSW and Other States (2002-03)**

Source: NEMMCO half-hourly data files

<sup>82</sup> IPART (2002c), *Regulatory arrangements for the NSW Distribution Network Service Providers from 1 July 2004: Issues Paper*, IPART November 2002, p.29.

<sup>83</sup> East Cape Pty Ltd (2002), *Efficient Network Pricing and Demand Management*, report prepared for IPART, November 2002.

<sup>84</sup> EnergyAustralia (2003), *EnergyAustralia's Submission on the 2004 Distribution Determination to the Independent Pricing and Regulatory Tribunal*, 10 April 2003, p.77.

<sup>85</sup> IE engaged consultants to examine the economic impacts of air conditioning on its network. The consultants found that there has been a significant uptake of AC in recent years by residential customers, particularly in new housing in Western Sydney and that this is driving peak demand in summer which is now similar to winter peak demand.

<sup>86</sup> Integral Energy (2003), *2004 Electricity Review Submission to the Independent Regulatory and Pricing Tribunal*, 10 April 2003, p.195.

This situation can be attributed to demand becoming more volatile (or ‘peakier’), especially in summer.

If nothing is done to moderate this growth, the DNSPs will have to add at least 2000MW of capacity over the next five years and possibly as much again that would be required for relatively few hours per year because of increased extreme summer peak volatility. Otherwise, NSW consumers will face forced off-loading (i.e. ‘brownouts’ and ‘blackouts’) when Zone Substations become over-loaded on hot days. This impact will flow through to a need to increase, rarely used but costly, capacity in transmission and generation assets, and an increased, but very ‘peaky’, demand for gas (to fuel peak gas turbines, which are the most likely generation ‘solution’ to this challenge for NSW).

At present, consumers who are not contributing to the extreme summer peak, including industrial and commercial consumers with (relatively) high Load Factors and non-AC Residential and small business consumers, are bearing costs created by those that are. This cross subsidy has been estimated by consultants to IE at between \$80 million to \$110 million per annum for IE alone,<sup>87</sup> a cross subsidy that looks set to grow significantly.<sup>88</sup> Furthermore, the failure to address the key cost and demand driver will result in the need for costly and inefficient investment in the extreme peak capacity of the DNSPs’ networks, by up to 2500 MW by 2010, adding substantially to the average energy costs of end-users in the future.<sup>89</sup>

Nevertheless, unlike in South Australia for example, NSW DNSP’s still have a window of opportunity to address the summer residential air-conditioning load issue in ways that can delay the need to invest further in costly and under-utilized network capacity. As shown in Figure 17, SA already has a major challenge to contain electricity costs because of a relatively poor system load factor. With AC penetration continuing to grow,<sup>90</sup> there is a strong likelihood that NSW will face significant challenges in this area over the coming decade.

Yet the NSW Government appears to be relatively complacent on these matters. For example, the Hon Frank Sartor Minister for Energy and Utilities is on record as saying that NSW consumers will not face a loss of electricity supply because the DNSPs propose to spend in excess of \$4 billion on augmenting their networks. This entails a very costly and inefficient response to the problem. No doubt the Government’s stated position is being driven by the need to be seen to “have a solution” to the threatened blackouts reported in the media at the time, but their favoured response will increase customers’ bills significantly over time and will do nothing to change the behaviour of the causers. Naturally, greenhouse gas emissions will also increase.

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<sup>87</sup> *Op Cit*, p.193.

<sup>88</sup> Analysis of the situation in Victoria shows that the ‘AC cross-subsidy’ can be as high as \$200/year for small consumers on ‘average’ consumption, and could rise to \$1,000/year or more for AC-using Residential consumers with large capacity AC systems. Residential consumers on (near) average consumption appear to be paying ‘cross-subsidies’ of around \$200/year (or 25% of their annual bills) to subsidise AC-users. (See: *Smart Meters for Smart Competition? Will Current Proposals Hand Back Power to Consumers? Update 2003, A consumer-focussed comment on the Victorian Essential Services Commission Position Paper Installing Interval Meters for Electricity Customers - Costs and Benefits*, Report for the Energy Action Group, Pareto Associates Pty Ltd, March 2003)

<sup>89</sup> As noted elsewhere in this submission, the growth in extreme summer demand suggests NSW consumers are ‘investing’ around \$350-400 million/year in ACs. Data for the Victorian distributors presented in section 3.3.1 suggests this could require the DNSPs to ‘invest’ a similar amount, just to cope with demand for a (relatively) few hours per year.

<sup>90</sup> EnergyAustralia’s submission (p7) indicates that the number of residential customers with air conditioning increased from 29 per cent in 1997 to 43 per cent by 2002. It estimates that approximately 58 per cent of residential customers will have air conditioners by 2009. However, this seems to understate the potential for AC load growth.

For example, survey data on AC penetration published by BIS Sharpnel shows between 20-30% of NSW households have some form of ‘high-capacity’ refrigerative AC system, and another 20-25% having one or more window mounted systems. This would suggest there is substantial additional potential for increasing AC load as consumers choose to ‘upgrade’ to ‘higher-capacity’ refrigerative systems. (See: *Appendix B: Smart Meters for Smart Competition? - Will Current Proposals Hand Back Power to Consumers? - Update 2003, A consumer-focussed Comment on the Victorian Essential Services Commission Position Paper Installing Interval Meters for Electricity Customers - Costs and Benefits*, Report for the Energy Action Group, Pareto Associates Pty Ltd, March 2003).

Meanwhile the IPART report on Demand Management, commissioned by the Premier, remains without a Government response after more than 12 months. As outlined elsewhere in this submission, DM provides opportunities for a far more economic and energy efficient solution to some of these problems. The results of the DSR facility trial undertaken by the EUAA confirm that this is the case (see Section 6). The NSW Government response to the problem, to date has been disappointing and we urge them to adopt policies that provide for more effective solutions to these problems.

#### **4.2. Pricing initiatives Proposed by the DNSPs**

It is clear that the current pricing practices of the DNSPs, based principally upon customer class averaging, are not addressing growth in summer peak demand. The issue is whether the new pricing initiatives being advanced by them will address the cost drivers created by this growth more effectively and efficiently. As discussed in this section, in the main we are not convinced that they will. Pricing initiatives proposed by the DNSPs, notably inclining block tariffs, while ostensibly aimed at shifting or reducing demand, will at best only partially target the actual customers who are the cause of system peaks, and could increase costs to many who are not.

In general, we strongly support price and non-price demand management initiatives but believe that far more targeted initiatives than those proposed by the DNSPs need to be introduced. Unfortunately those targeted options, including a roll-out of interval meters and Time-of-Use tariffs, supported by options that provide consumers with genuine choice, such as interruptible tariffs and focussed customer information, appear to receive only limited attention in the DNSPs' submissions.

We recognise that the DNSPs cannot address these issues alone. Much depends on retailers developing products that also reflect the underlying cost of supply. But for IPART and the DNSPs to do nothing would amount to a lost opportunity to address an issue that has the potential to create long-term cost impacts for large numbers of consumers. We note that, in five years time, when the next IPART price review is due, many useful opportunities to deal with these matters economically will have been lost (and the costs of correcting past errors will have compounded substantially).

##### **4.2.1. Inclining block tariffs**

In their submissions both EA and IE have proposed the introduction of an inclining block structure for network tariffs applying to residential and small business consumers:

- EA has proposed a two-block structure, with the higher block charge starting at 7,000kWh annual consumption and a 25 percent differential between the first and second block tariffs.
- IE has also proposed a two block structure, but with the higher block charge starting at 3,500kWh annual consumption and with a 38 percent differential between the first and second block tariffs.

In assessing the merits of the inclining block tariff proposals, two issues need to be considered:

- the impact of the proposals on consumers, particularly in the context of current cross subsidies;
- the likely effectiveness of the proposed new tariffs in reducing consumption and demand, particularly summer peak demand.

We discuss these two issues briefly in turn.

### ***Impacts on consumers***

When considering the impact of inclining block tariffs on consumers, a key consideration is the extent to which the proposed new structures reduce cross subsidies both between customer classes and between groups within a class.

In relation to cross subsidies between customer classes, growing demand in the lowest voltage parts of the network (240/415V) will eventually require investment in higher voltage parts of the network. If the cost allocation processes of the DNSPs do not attribute the incremental cost of the higher voltage network assets to low-voltage consumers, then higher-voltage consumers (industrial and commercial consumers) will face higher costs through an almost totally opaque cross-subsidy process. In other words, higher-voltage customers, most of whom have a demand component in their tariff, may well be paying for the demand growth driven by residential air-conditioning load.<sup>91</sup> Of themselves, it is highly unlikely that the EA and IE inclining block tariff proposals will do anything to address cross-subsidies of this nature.<sup>92</sup>

A reduction in cross subsidies is contingent on there being a high correlation between customers with high consumption and high peak demand, a correlation that, due to the lack of available information, is uncertain. The IPART Secretariat highlights this uncertainty in the Issues Paper on inclining block tariffs produce. The issues paper notes that, under the proposed new structures higher consuming but less capacity-intensive customers could potentially be cross-subsidising other customers to a greater degree than with the current charge structure.<sup>93</sup>

*Clarity on the issue of cross-subsidies is highly relevant to small and large consumers, particularly if IPART followed initiatives adopted by ORG in its September 2000 electricity distribution price decision and take a more 'hands-off' approach to pricing/tariff approvals.*

*In Victoria, this 'hand-off' approach has allowed United Energy to develop a range of innovative ToU tariffs that apply to all small consumers, which have the effect of increasing the transparency of cross-subsidies that remain hidden in tariffs of other distributors, including those in NSW. However, United's tariffs, which comply with all of the tariff design, adjustment and rebalancing constraints in Victoria (that are similar in effect to the 'side constraints' proposed by IPART), can produce dramatically different cost outcomes for consumers using significant quantities of energy during summer.<sup>94</sup>*

Another important consideration when assessing inclining block tariffs is the impact of the proposed new structures on low income earners. On this issue, we note IPART's assessment that approximately 64,000 low-income households<sup>95</sup> will exceed the threshold energy consumption level at which higher energy prices apply under the EA proposal if such a tariff were applied uniformly<sup>96</sup>. *Prima facie*, this is a significant number of households.

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<sup>91</sup> This is exactly what has happened as a result of the introduction of a rational, cost-reflective, hourly time-of-use pricing structure by United Energy in Victoria. United's time-of-use tariffs all include Summer Demand components that (attempt to) reflect the cost to United of AC load. These tariffs are applied (by United) to all consumers with interval meters. Unfortunately for large consumers, they all have interval meters while the vast majority of small consumers, who create most of the AC demand volatility, do not have interval meters.

<sup>92</sup> Without access to the cost allocation methodologies of the DNSPs it is difficult to be certain about this.

<sup>93</sup> IPART (2003), *Inclining Block Tariffs for Electricity Network Services*, Secretariat Discussion Paper, June 2003, p.16.

<sup>94</sup> See *Smart Meters for Smart Competition? Will Current Proposals Hand Back Power to Consumers? Update 2003, A consumer-focussed comment on the Victorian Essential Services Commission Position Paper - Installing Interval Meters for Electricity Customers - Costs and Benefits*, Report for the Energy Action Group, Pareto Associates Pty Ltd, March 2003

<sup>95</sup> Defined as the 20 percent of households with lowest income.

<sup>96</sup> IPART (2003), op cit, p.17.

However, the significance of the impact of the EA and IE proposals on low-income households needs to be more fully assessed.<sup>97</sup>

A critical factor likely to influence the impact of the proposed tariffs on consumers, both low-income and other, relates to the issue of 'consumer choice'. In our view, providing price signals to low income households and other customer groups that reflect the real costs of their energy consumption is not, of itself, a concern, provided consumers are presented with options that enable them to respond to those price signals (or the Government acts to ensure they are not further disadvantaged economically).

These issues will be discussed further in later sections.

### **Effectiveness of proposed tariffs**

We acknowledge that the inclining block tariff proposals of EA and IE are, in principal, capable of modifying consumption patterns in a way that discourages the current significant growth in network peaks. No doubt this influenced the DNSPs advocating them to do so and we welcome their attempts to respond to an emerging problem with peak demand. However, the evidence suggests that they will be poorly placed to achieve this in practice.

*All Victorian distributors except AGL (Agility) have introduced network tariff structures that include inclining block tariffs as 'standard' and both United Energy and Powercor have 'optional' seasonal and/or hourly ToU tariffs. Each of the distributors claims that these 'new' tariff structures have been implemented to provide 'rudimentary' (or in the case of United, explicit) DM incentives targeted at AC-users.*

*But there is no compelling evidence that these 'negative' (i.e price-based) incentives have moderated extreme summer demand growth in Victoria, even though the average cost to Residential consumers, in particular, is substantially higher than proposed by the NSW DNSPs. We believe this is due, in part, to:*

- *the fact that consumers have no choices that are meaningful to them;*
- *'standard meter' tariffs still contain substantial 'cross-subsidies' in favour of AC users that mute the price signals the tariffs are supposed to deliver; and*
- *the ESC shows every indication of delaying the decision to approve widespread roll-out of interval meters as suggested by United Energy in 1999.*

The inclining block tariffs proposed by EA and IE are ostensibly aimed at improved cost reflectivity and equity in network tariffs by encouraging residential and small business customers to reduce consumption during the system peak periods. In theory this can be done through consumers:

- paying a higher overall price for energy which will encourage them to reduce their consumption; and/or
- seeking out tariff options that reward them directly for cutting peak period demand.

In relation to the first point, we note evidence from Australian and overseas studies indicating that consumption of electricity is relatively unresponsive to price, especially in the short term

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<sup>97</sup> Note, *prima facie*, IE's proposal will negatively impact on a greater number of low income households than Energy EA's, given the 3,500kWh/year threshold at which the higher block charge commences with the IE proposal. However, IE claims that under its proposal, only customers consuming greater than 7,000kWh/year will pay more compared to the current situation. EA, on the other hand, claims that under its proposal only customers consuming greater than 8,600kWh/year will pay more compared to the current situation. More information is required though to assess both the overall and relative impacts of these proposals.

and particularly when the magnitude of the price change is relatively small.<sup>98</sup> For example, one recent Australian study estimates the long run price elasticity of demand ( $e_d$ ) for electricity in NSW to be in the range -0.22 to -0.52.<sup>99</sup> Overseas studies yielded substantially lower  $e_d$  rates, especially when the tariff increases were being applied during off-peak periods – as low as -0.06.<sup>100</sup>

Drawing on the NSW  $e_d$  data, the long term reduction in consumption in response to the increase in electricity prices arising from the EA and IE inclining block tariff proposals would be minor,<sup>101</sup> with no guarantee that the reduction in consumption would occur in peak periods. Indeed, it is likely that many 'low-cost' consumers, i.e. those who have relatively low demand during peak periods but have relatively high overall consumption and have little to do with the problem that needs to be addressed, will be negatively impacted by the proposed new tariffs.

It needs to be emphasised again that evidence from the DNSPs and other sources shows that the key cost driver of the NSW network is peak summer demand caused by residential and commercial air-conditioning. This driver is season dependent and more specifically, time-of-day dependent. The use of inclining block tariffs, which do not provide a direct signal to cut extreme peak demand, is a very blunt approach to the specific issue of summer peak demand, particularly given the relative unresponsiveness of consumption to (relatively small) changes in prices.

In relation to the second dot point above, the question is whether, in response to the inclining block tariffs, customers with high summer peak demand will seek out other tariff options that reward them directly for cutting peak period demand? This brings us to the issue of customer choice, raised earlier. One of the key deficiencies with the EA and IE pricing proposals is that the proposals are not accompanied by realistic options that will enable consumers to change their patterns and levels of demand. EA claims that its proposed inclining block tariff will "... create a strong incentive for large customers to migrate to more cost-reflective prices such as time of use."<sup>102</sup> Consumers can only migrate to more cost-reflective prices though, if they have both the capacity and necessary awareness (gained through accessible and timely information), to do so. In reality, neither the EA nor IE proposals offer this capacity and information.

For example, as part of its pricing initiatives EA proposes to roll out interval meters but only to consumers whose consumption exceeds 15,000kWh/year.<sup>103</sup> This leaves those who consume between 7,000kWh/year and 15,000kWh/year, and who are being targeted by the inclining block tariffs, with no opportunity to switch to ToU pricing. Similarly, although EA introduced an interruptible tariff in 2001, it is only available to customers with ToU meters.<sup>104</sup> IE has not given any indication that it intends to roll out ToU meters and although it has trialled interruptible tariffs, has not proposed a schedule for the introduction of these tariffs despite the apparent success of the trials.<sup>105</sup>

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<sup>98</sup> A further issue that has not yet been examined thoroughly in Australia or elsewhere is the 'challenge' for consumers to respond to price signals when their only choice they have is manual load control. We believe it is likely that consumers would be more willing to offer DM, and would suffer far less 'reaction fatigue' if they could access low-cost, remotely activated load control technologies. NSW, with its (admittedly aging) 'Ripple Control' powerline carrier technology has a 'head-start' on Victoria and other jurisdictions in this regard, but there is little signs of any enthusiasm to develop this technology further.

<sup>99</sup> NIEIR (2002), *The price elasticity of demand for electricity in NEM regions*, report prepared for NEMMCO, June, p.3.

<sup>100</sup> ESC (2002), *Installing interval meters for electricity customers – costs and benefits – position paper*, November, ESC, Victoria.

<sup>101</sup> By their own less estimates less than 10 percent, even for residential customers with high relative consumption (>12,000kWh/annum).

<sup>102</sup> EnergyAustralia (2003), op cit, p.78.

<sup>103</sup> ibid, p.77.

<sup>104</sup> ibid, p.79.

<sup>105</sup> Charles River Associates (2003), *Impact of Air Conditioning on Integral Energy's Network*, report to Integral Energy, May 2003.

A substantial time lag between consumption decisions and actually getting the bill further mitigates the possibility that the new tariffs will encourage a reduction in summer peak demand, as does the fact that the same tariff rates would apply during all parts of the day and over the year, not just when the network experiences its peaks.

Moreover, the fact that distribution charges make up only a part of overall electricity charges, albeit a significant proportion, means that the relative size of the signal will need to be greater to have any noticeable impact on consumption, even more so considering the relatively low  $e_d$ . The DNSP pricing proposals put to this review seem insufficient to have such an impact.

In summary then, there is little reason to expect that consumers with high summer peak demand will respond to the proposed inclining block tariffs, in the way proposed (i.e. that the tariffs will 'encourage' consumers to modify their consumption habits during network peaks). It is far more likely, in our view, that they will increase revenue for the DNSPs over-and-above what they would earn under the WAPC with the existing tariffs. The DNSPs would be able to keep this additional revenue, as it would be treated as an 'efficiency gain', despite the fact that it is clearly no such thing and more akin to a windfall or monopoly profit. IPART needs to undertake its role of balancing the interests of consumers with those of the DNSPs by ensuring that this does not happen.

#### **4.2.2. Seasonal tariffs**

EA and IE have both proposed the introduction of seasonal tariffs. Country Energy has also stated that it "*...may consider the introduction of seasonal signals during the forthcoming regulatory period*" but it provides little detail other than to indicate that the focus of any initiative would be on "*...reducing constraints within the network during the summer period.*"<sup>106</sup>

In commenting on the seasonal tariff proposals, a distinction has been drawn between the two proposals, which are quite different in structure and target consumer class.

##### ***Integral Energy seasonal tariff***

IE is proposing to introduce a summer energy tariff for all residential customers, charging a premium for all energy consumption during the peak summer period (December-February). The premium will be approximately 40 per cent higher than the existing uniform energy charge. At the same time, the non-summer energy charge will be reduced by approximately 11 per cent below the existing uniform energy charge. IE claims that the bill impact of the proposed summer tariff will be minimal for the roughly two thirds of consumers with summer use of 25 per cent or less of their annual consumption. For other consumers, the bill increase will range from 4 percent (for consumers 25-25 per cent of annual consumption in summer) up to about 25 percent (for high consumption customers with greater than 65 per cent of annual consumption during summer).<sup>107</sup> We are not in a position to verify these impacts one way or another.

At first glance, IE's summer tariff proposal might appear to be a more targeted approach than the inclining block tariff proposals previously discussed, since it is aimed at summer load. We also note that our own analysis of available (Victorian) interval meter data suggests that residential air-conditioning users generally have more than 25 percent consumption in summer. However, as noted by IE's own consultants "*peaks on the system ... are driven by*

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<sup>106</sup> Country Energy (2003), *Country Energy's Submission to the Independent Regulatory and Pricing Tribunal: 2004 Electricity Network Determination*, 10 April, p.10-6.

<sup>107</sup> Integral Energy (2003), op cit., pp.198-199.

*extremely hot days (and even more specifically, particular periods on hot days) rather than the whole seasonal temperature profile.*<sup>108</sup>

Thus, there is still no direct link between the seasonal tariff proposal of IE, which is essentially targeting overall summer consumption, and peak demand on hot days. Even though there is an indirect link between summer consumption and summer peak demand, this link is made very tenuous when (as in the case of IE's tariff proposal), "*the summer price is (very substantially) less than the marginal cost of the consumption on the peak days (in which case) over consumption may (or is likely to) still occur - (with) customers trad(ing) off the higher costs for that day for the amenity of the air conditioner.*"<sup>109</sup> In addition, this proposal also suffers from the same problems as inclining block tariffs in terms of not targeting the daily summer peaks, consumers not having enough information about the costs of their consumption until they get their bills (well after the 'event') and being diluted by the fact that distribution charges comprise only part of the total electricity bill.

In summary therefore, IE's summer tariff proposal seems unlikely to have much impact on the summer peak demand driven by residential and small commercial air conditioning load.

### **EnergyAustralia seasonal tariff**

EA is also proposing to introduce a summer peak surcharge for all ToU prices. The surcharge will apply principally to small and medium commercial customers but also to some (relatively) high consuming residential customers. From the limited information provided by EA, the surcharge seems to be aimed principally at residential and small commercial customers who have installed fixed wired (three phase) air conditioners. More information is required to determine how effectively the EA proposal will target the summer peak cost drivers.

However, it should be noted that three phase air conditioners represent only a small proportion of air conditioners now being installed by residential customers.

This suggests strongly that EA's proposal will be ineffective in moderating extreme summer demand growth. For example, one thousand consumers with 2kW, single phase air-conditioners and annual consumption of 4-5MWh/y will create exactly the same (or possibly more) cost pressures as 330 consumers with 6kW loads and annual energy consumption of 15MWh/y.

### **4.3. Recommended Directions**

As noted earlier, we are strongly supportive of moves towards cost-reflective tariffs, providing:

- the new tariffs directly target the consumers that are creating the cost drivers; and
- consumers are provided with options that enable them to respond to the price signals.

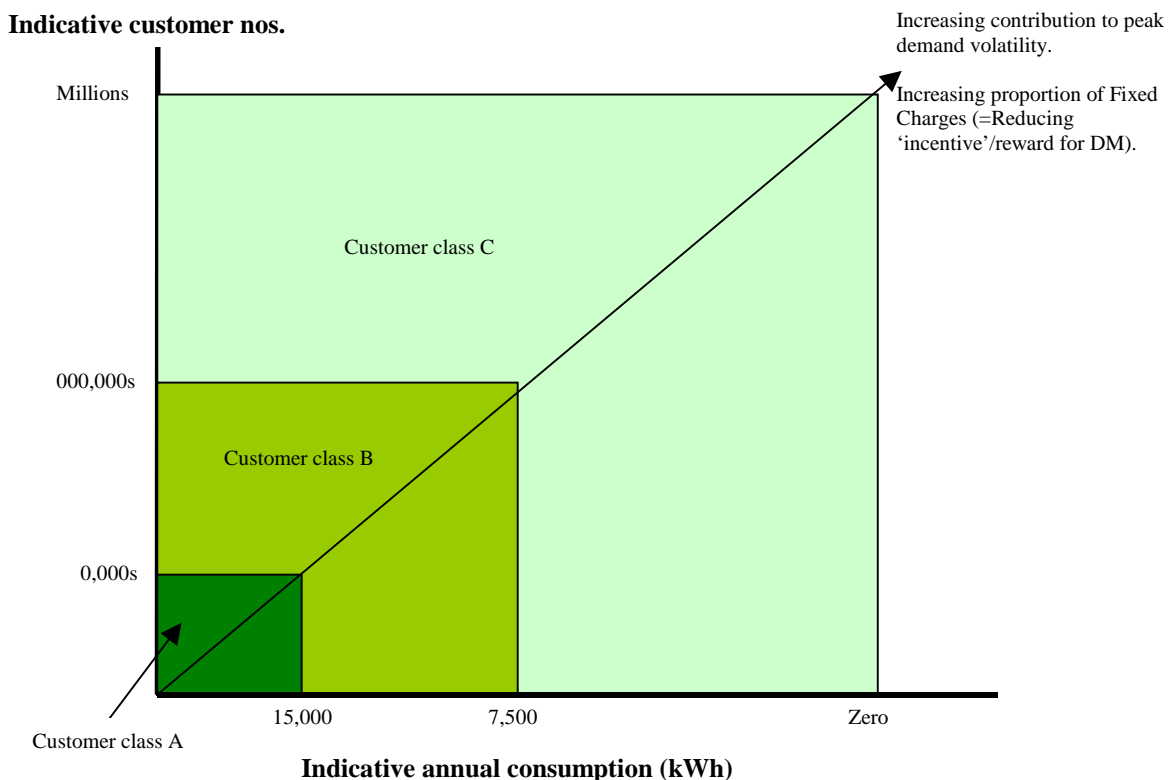
We believe that the proposals being advanced by the DNSPs, whilst having some merit, do not meet either of these critical objectives. Consequently, they will not provide an effective solution to the problem they claim to address. As illustrated in Figure 18, the initiatives being proposed by the DNSPs will, at best, provide limited negative and positive incentives to reduce summer peak demand for only a small group of residential customers whose annual electricity consumption is at the very high end of the consumption spectrum (customer class A). The vast majority of residential customers (customer classes B and C), a significant proportion of whom have air conditioners and are therefore contributing to summer peak

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<sup>108</sup> Charles River Associates (2003), op cit., p.34.

<sup>109</sup> ibid.

demand, will be provided with little or no incentives by the DNSPs to reduce their peak demand.



**Level of Incentives Provided by DNSPs’ Initiatives to Different Customer Classes**

Customer class	Negative incentive	Positive incentive
A	In Demand component	Limited
B	Limited	none
C	Indirect or none*	none

**\* Class C consumers with relatively low consumption are, in fact, financially discouraged from practicing demand management by the Fixed Charges (DNSP and retail) component of their bills.**

**Figure 18: Illustration of Limited Level of Incentives Provided by DNSP Pricing Proposals**

We therefore believe that DNSPS need to implement alternative initiatives that:

- provide consumers with incentives for changing their patterns of consumption and demand;
- provide them with opportunities to do so; and
- provide information as to why and how they can change their consumption and demand.

The DNSPs initiatives should include a program for the accelerated and expanded roll-out of interval meters, accompanied by a suite of price and non-price demand management incentives including time of use (ToU) tariffs, interruptible tariffs and a comprehensive public education and information campaign. The DNSPs’ programs need to be supported by appropriate changes and additions to IPART’s regulatory framework, and means found to stimulate retailers to offer suitable products to consumers.

### **4.3.1. DNSP initiatives**

#### ***Interval meters***

Interval meters (IM), which record the consumption of electricity each half hour, would allow DNSPs to develop tariffs in ways that more accurately reflect network cost drivers. Furthermore, IMs allow retailers to structure their tariffs in ways that reflect the costs of purchasing power in the wholesale market and encouraging their customers to better manage their electricity use. Overseas, there is increasing use of IMs, accompanied by ToU and other cost-reflective tariff structures, particularly in some states of the USA and some Western European countries such as Italy. Other jurisdictions in Australia, notably in Victoria, are also moving toward the wholesale installation of interval meters – in response to a 1999 initiative by one of the Victorian distributors. In SA, ESCoSA is currently undertaking a major study of interval metering and demand management in preparation for its review of ETSA' distribution prices in 2004.

As previously noted, the installation of interval meters for small business and residential customers is underway in NSW. EA states that it is currently undertaking a meter replacement program for about 24,000 customers and plans to install a further 82,000 meters during the next regulatory period<sup>110</sup> and CE has also been rolling-out IM for new connections, having already installed some 50,000.

Data provided to us from meter suppliers indicates that single and three-phase, direct connected interval meters are being produced and sold in substantial numbers, with approximately 280,000 interval meters having been installed in NSW and Victoria over the past three years. Information provided by meter suppliers also suggests that EA alone taking about 50,000/year of single-phase meters. If this rate of take-up continues then by 2010 around 300-400,000 interval meters will have been rolled-out to small consumers by EA alone. While this number is still only a small proportion of their total meters, it is considerably more than the DNSPs have publicly committed to installing.

We therefore recommend that IPART, and the DNSPs work closely with consumer groups to examine closely the costs and benefits of an expanded and accelerated program for the roll-out of interval meters. Such an examination should also include detailed analysis of the costs and benefits of extending the capability of the existing "Ripple Control" powerline carrier technology in NSW to provide low-cost, convenient, remotely-activated load management capability.<sup>111</sup> If this process can demonstrate an overall benefit to NSW consumers, IPART and the DNSPs should publicly commit to workable targets for the installation of interval meters for small business and residential customers that are significantly more ambitious than commitments outlined in the DNSP submissions to IPART.

#### **Tariffs**

We believe that tariffs must be based on the principle of cost-reflectivity and also provide customers with genuine choices. This is important, not only for protecting the interests of consumers but also for maximising the effectiveness of the tariff changes in promoting more efficient patterns of consumption.

Thus we support a 'carrots and sticks' approach to tariff structures. This means that ToU tariffs which need to follow the roll out of interval meters (as discussed above) should be accompanied by positive incentives to those consumers who respond to periods of extreme peak demand by shedding some of their network load. Neither IPART nor the DNSPs should

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<sup>110</sup> EnergyAustralia (2003), op cit., p.77.

<sup>111</sup> A similar recommendation has also been made to the Victorian ESC. See: *Smart Meters for Smart Competition? Will Current Proposals Hand Back Power to Consumers? Update 2003, A consumer-focussed comment on the Victorian Essential Services Commission Position Paper - Installing Interval Meters for Electricity Customers - Costs and Benefits*, Report for the Energy Action Group, Pareto Associates Pty Ltd, March 2003.

underestimate the importance to consumers of ‘positive’ incentives. The EUAA’s Demand Side Response Facility Trial showed conclusively that large consumers recognise the potential to benefit from providing ‘voluntary’ DM, but they will not do so unless this makes commercial sense.<sup>112</sup> We believe it is reasonable to expect that small consumers would be more inclined to offer DM in response to similarly focussed ‘positive’ incentives.

In particular, we believe that both IPART and the DNSPs should more actively pursue the introduction and marketing of interruptible tariffs that can provide a positive price-based incentive to allow load shedding in periods of extreme demand. NSW has a substantial advantage over Victoria and SA in this regard because of access to existing remotely activated, powerline carrier ‘Ripple Control’ technology. It is this technology that underpins EA’s ‘interruptible tariff’, and provides an opportunity for IPART and the DNSPs to develop a capability that could be offered to consumers willing to accept (with a ‘positive’ incentive) remotely activated management of temperature-sensitive loads during critical periods of maximum network loading. Given the strong indications that increasing AC penetration is likely to add substantial additional costs to NSW consumers, we believe this to be a relatively ‘low cost’ alternative to ‘inefficient’ expansion of the electricity supply system.

#### **4.3.2. Pricing Principles and the regulatory framework**

We believe that the current approach to tariff setting by IPART is too cursory in nature and too ‘light of touch’. Therefore, the pricing principles and associated rules should be strengthened as part of this review. In undertaking any changes to the regulatory framework however, we emphasise the need for IPART to ensure that pricing and associated rules are consistent and transparent.

In particular, we are concerned that the move towards a WAPC, similar to that applied by the ESC in Victoria, will bring similar tariff setting problems to those besting Victorian customers. In particular we urge IPART to ensure:

- that customers are entitled to some minimum protection from DNSP tariffs that involve the use of monopoly or inefficient pricing (this should be possible through a combination of relatively simple and unobtrusive pricing rules, the right to take complaints to the regulator and some meaningful sanction of any DNSP found to have breached these rules);
- that there is opportunity for involvement by customers in the tariff setting process; and
- that the DNSPs are required to notify customers of new tariffs sufficiently in advance to make this meaningful and noting that the present one month notice period has proved to be inadequate for many larger customers because it does not align well with their company budget cycle.

To support a move towards cost reflective pricing and information disclosure we recommend that IPART require DNSPs to provide full details of their cost allocation methodologies and processes, including details of the actual costs allocated to individual tariffs. This information should be in a form that is compatible with performance information contained in service standards reports. Furthermore, tariff information should be linked explicitly to ‘excluded services charges’ with total component cost amounts shown clearly on retailers’ bills. This would not only inform consumers about their costs, but place more competitive pressure on both retailers and DNSPs.

IPART should also actively explore the option of introducing a regulatory requirement on the DNSPs to install interval meters for all customers where this can be demonstrated to benefit

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<sup>112</sup> See: *A Demand Side Response Facility for the National Electricity Market. Trial Undertaken by Energy Users’ Association of Australia. Reporting Consultant’s Independent Assessment*, Pareto Associates Pty Ltd, June 2003 (Draft)

consumers. Interval meters are already a requirement on a new and replacement basis for customers above 160 MWh per year. The proposed regulatory requirement might initially apply to new customers only, to replacement of faulty meters or to larger residential customers. However, eventually the requirement may need to be extended to all residential customers.

The economic cost effectiveness of a regulatory requirement of this nature would need to be examined by IPART. EA claims that the unit cost of installing its proposed meter roll-out is about \$500 per meter.<sup>113</sup> This would obviously be prohibitive if an interval meter roll-out were to be extended to all customers at this unit cost. However, a study undertaken for the Victorian ESC suggests that \$500 represents an upper end estimate of the cost of interval meters (three-phase current-transformer connected, installed in small numbers). The ESC suggests the cost of interval meters (purchase and installation) is likely to be as low as \$105/meter for single phase non-off peak interval meters or \$164/meter for single phase off peak interval meters.<sup>114</sup> Incremental cost are substantially lower still when comparing the costs of interval meters with those of basic meters, and information provided to us by meter suppliers suggests costs would fall further in response to large-volume orders from DNSPs.

In supporting the roll-out of interval meters and the principle of ToU tariffs, we want to emphasise the importance of ensuring that any changes to tariffs are not used by the DNSPs as simply a means of increasing the amount of revenue that they can earn. We emphasise again that the incentive to take this approach will be stronger under the WAPC regime now being introduced by IPART.

Thus, it is essential that the current pricing principles relating to the protection from monopoly pricing be strengthened. Also in need of strengthening is the current requirement on DNSPs to post tariff changes with IPART, have them approved and then finalised, with 30 days minimum notice to customers before they come into force. While we support this requirement in principle, to increase protection for customers, we believe that the rule needs to be strengthened to provide for longer lead times for notification of price changes. EUAA members confirm that 30 days is an insufficient amount of time to plan for changes in budgets, especially as NSW distribution tariffs are adjusted at the end of the financial year, and suggest that 60-90 days notice is a more appropriate timeframe. In addition, much more information needs to be disclosed about cost allocation procedures, including the actual costs allocated to each tariff class (and tariff component), and the information disclosed subject to rigorous analysis by someone focussed clearly on consumers' interests.

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<sup>113</sup> *ibid.*

<sup>114</sup> ESC (2002), *op cit.*, pp.74-75.

## 5. LIMITS ON PRICE MOVEMENTS

The IPART Secretariat summarises the Tribunals position of ‘side constraints’ in the Preliminary Analysis report by saying:

*“The limits on price movements are an important element of the Tribunal’s current pricing philosophy, as they are the means by which the Tribunal ensures that residential customers do not see rapid price increases.”<sup>115</sup>*

That is, the impact of changing cost allocation can be mitigated in the short term by application of ‘side constraints’. However, short-term cost impact mitigation can also aggravate the cost impact in the longer term if consumer-induced cost increases are not effectively signalled in a timely manner.

*The use of ‘side constraints’ to minimise ‘rate shock’ is an issue that should concern IPART and NSW consumers because, as noted elsewhere in this submission, our analysis of temperature-sensitive summer demand suggest that residential air-conditioning (AC) load has been rising strongly for NSW as a whole since the mid-1990s, at rates higher than that forecast for the next regulatory period by the DNSPs.*

*The increasing temperature-sensitive AC demand from (mainly) small consumers (both Residential and Commercial) appears to have been adding around 350-400MW/year to extreme peak summer demand since at least FY1999. This suggests that NSW consumers are ‘investing’ around \$300-400 million/year in ACs. If this trend continues through to 2010, as suggested in the material provided to IPART by both EA and IE, the NSW electricity system will need another 2000-2500MW or more of additional capacity in 2009 and possibly as much capacity again to cope with increased demand volatility during short periods of extreme hot weather.*

*It could be that the DNSPs will need to invest at least \$300-400 million/year to cope with those few days every summer of extreme hot weather. If this was the case, consumers would face additional costs that increased by around \$45 million each year<sup>116</sup> to cope with demand than occurs for less than 100 hours.*

*By 2010, small Residential consumers could be facing cost increases of more than \$225 million/year just for the distribution component of their bills. Cost pressures of similar magnitude (or more) would occur in the combined generation and transmission sectors. In addition, the unpredictable nature of extreme, temperature-sensitive demand will increase price volatility and financial risk for retailers and this, combined with ETEF, will drive up retail energy costs for all consumers.*

*A realistic alternative to this scenario is implementation of a ToU, price-based, demand response program targeting AC-users. But, as discussed elsewhere in this submission, that will require far more ‘innovative proposals being developed and implemented by IPART.*

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<sup>115</sup> p41, IPART Secretariat Preliminary Analysis report.

<sup>116</sup> Assuming the new assets are fully depreciated over an effective life of around 30 years and WACC is set at the level indicated in the IPART Secretariat Preliminary Analysis report (at 8.3% Nominal using the post-tax “Vanilla” CAPM formulation.)

## **6. DEMAND MANAGEMENT INITIATIVES**

We welcome the increasing recognition, by both IPART and the DNSPs, of the role that demand management (DM) can play in helping to shave the peaks in the NSW distribution system. We also welcome the fact that EA proposes to undertake some DM initiatives during the next regulatory period and that IE has also foreshadowed its intention to make use of some DM initiatives. We also welcome the initiatives, which both these DNSPs have already undertaken on DM.

Nevertheless, much more needs to be, and can be, done in this area. IPART has an important role to play in ensuring that its pricing and regulatory regime plays a part during the next regulatory period.

To this end, we are disappointed that the recommendations on DM that IPART last year made to the Premier have not yet been acted upon.<sup>117</sup> In our view, this NSW Government hiatus has wasted time and made it more difficult (and costly) to deal with the issues in future. We would therefore urge the NSW Government to announce decisions on the IPART report on DM as a matter of urgency. The fact that the Premier asked for this report suggests that had some priority, making the non-response to date even more difficult to understand. We raised this matter in our earlier submission to this IPART review and note that there has been no response from the NSW Government to date. This apparent complacency about the IPART report to the Premier is difficult to comprehend.

Unfortunately, the DNSPs' limited proposals on DM are unlikely to have much concrete impact over the next regulatory period. The DNSPs themselves acknowledge this and have already said publicly that they will not have any offsetting impact on their expenditure. This is disappointing because one of the main impacts of DM on a distribution system is that it will defer the need for CAPEX, which shows all the hallmarks of being excessive in the next regulatory period based on the DNSP submissions.

We therefore believe that IPART should insist on a more meaningful approach to DM by the DNSPs so that there is an actual reduction in CAPEX. We would also consider supporting use of some of the offset in CAPEX to fund DM initiatives.

We are also disappointed that the DNSPs appear to be indicating support for DM (in principle) but refer to DM more in the context of 'additional costs' it would impose on their business rather than the benefits it could bestow.

The EUAA will be examining further and in more detail the DM issues surrounding the present review by IPART, particularly given the very promising indications that come out of our recent Demand Side Response Facility Trial mentioned in the previous section on tariffs/prices (about which we have previously briefed IPART).

In addition, we note that the three largest DNSPs all claim to support the need for additional demand management (DM) as a means of offsetting the need for future CAPEX. A number of DNSPs (eg EA and IE) have also made certain commitments aimed at activating some DM initiatives over the next regulatory period. We welcome these initiatives. However, we believe they can and should go much further, that the initiatives proposed are not as effective as they could be and we are disappointed that there is no expectation that the proposed initiatives will actually reduce peak demand growth over the next regulatory period or limit the need for CAPEX. We urge the DNSPs and IPART to more innovative in this important area (and IPART should be prepared to require them to do so, if necessary).

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<sup>117</sup> *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services, Final Report*, IPART, October 2002

We are concerned that IPART has not been able to release the final SKM report on *Reducing Regulatory Barriers to Demand Management*. In our view, DM could and can play a key role in NSW. Analysis earlier in this submission supports the view that continuing penetration of air-conditioning will be costly for NSW consumers. Our analysis also supports submissions made by EA and IE that residential consumers make a substantial contribution to temperature-sensitive extreme demand growth.

In keeping with the key pricing principles developed by IPART, we support moves towards cost-reflective tariffs, providing they directly target the consumers who create cost drivers for the DNSPs and directly benefit consumers who can respond to these drivers. However, the current DNSP proposals for inclining block tariffs and seasonal block tariffs are very blunt instruments that will not deliver their intended objectives of achieving cost-reflective pricing and promoting demand management, but instead will impose unreasonable charges on substantial numbers of 'low-cost' users.

We believe that pricing is a useful means of promoting economically efficient outcomes. But it should be part of a suite of options that will assist consumers activate DM. We believe that tariffs must be based on the principle of cost-reflectivity and also provide customers with genuine choices. This is important, not only for protecting the interests of consumers but also for maximising the effectiveness of the tariff changes in promoting more efficient patterns of consumption.

Therefore, it seems reasonable to expect that IPART will examine this issue in some detail. The DNSPs initiatives should be extended to include examination of the costs and benefits for roll-out of interval meters, accompanied by a suite of price and non-price DM incentives including ToU tariffs, interruptible tariffs that 'leverages' off existing capability using the 'Ripple Control' powerline carrier system in NSW, and a comprehensive public education and information campaign. The DNSPs' programs need to be supported by appropriate changes and additions to IPART's regulatory framework, and means found to stimulate retailers to offer suitable products to consumers.

We therefore recommend that IPART, and the DNSPs work closely with consumer groups to examine these options. If this can demonstrate an overall benefit to NSW consumers, IPART and the DNSPs should publicly commit to workable targets for the further development of the an easy-to-use load management infrastructure for small business and residential customers that is significantly more ambitious than commitments outlined in the DNSP submissions to IPART.

We believe it is still possible for IPART and the DNSPs to move to a more innovative approach to DM that does much more than rely on pricing initiatives that merely provide a 'stick', to consumers who cannot easily moderate consumption behaviour by manual means. Developing the capability of the existing the 'Ripple Control' powerline carrier system could extend an relatively simple and easy-to-use load management facility willing AC-users. This could be used to provide positive incentives (or 'carrots') that are more likely to influence consumer behaviour than a 'stick'.

In particular, we draw IPART's attention to the findings from the EUAA Demand Side Response (DSR) Facility Trial conducted last summer.<sup>118</sup> Several aspects of the Trial and its outcomes are directly relevant to the current price review process and to the (likely) content of the final SKM report.<sup>119</sup> The most relevant of these are that:

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<sup>118</sup> The final report on the Trial will be published shortly by the EUAA. Members of the IPART Secretariat were briefed on the outcome of this Trial earlier this year.

<sup>119</sup> We have undertaken a preliminary review of the draft SKM report circulated by IPART in July 2003. However, we note that IPART advised that the final report had been delayed, in part, because SKM had been asked to extend the scope of work somewhat, and that this was likely to result in the final report having some different focus to the draft.

- the Trial clearly identified opportunities for DM to deliver benefits in the network sector;
- however, a lack of regulatory incentives operated to limit the willingness of distributors to respond to DSR options; and
- the end-users and the distributors who participated in the Trial both emphasised the importance of 'positive' commercial incentives to stimulate DM.

That is, the Trial demonstrated that both groups are able to identify opportunities for DM, but the both expect to, at least, recover their costs. The end-users who participated in the Trial were large commercial and industrial consumers, who were willing to respond but only if it was commercially beneficial and they were sufficiently aware of the opportunities. Although not strictly part of the DSR Trial, we expect that some, possibly many, small consumers would be able and prepared to offer DM if the infrastructure (eg meters, ripple control devices, etc) existed to allow them to do so, they were sufficiently aware of the opportunities (or their retailers were) and 'positive' incentives ('carrots') were offered to them.

At its meeting in August, the Ministerial Council on Energy (MCE) agreed to include DSR in its future work program (along with the Parer Report recommendations for a 'pay-as-bid' system for the demand-side) and it is expected that the results of the EUAA Trial will play a major part in the work of the MCE in this area.

We urge IPART to consider these matters in framing its draft determination and would gladly assist the Tribunal in this area.

**APPENDIX A: Comparison of actual forecast demand, consumption and customer numbers for the NSW DNSPs**

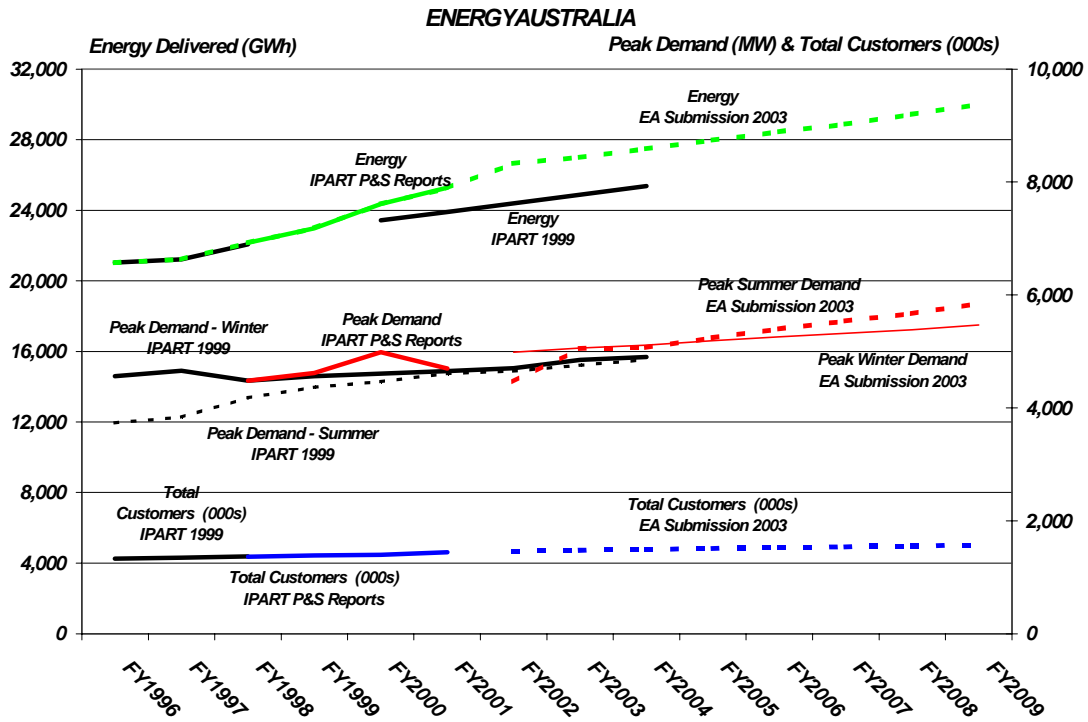


Figure 19: Comparison of actual and forecast demand, consumption and customer numbers for EnergyAustralia

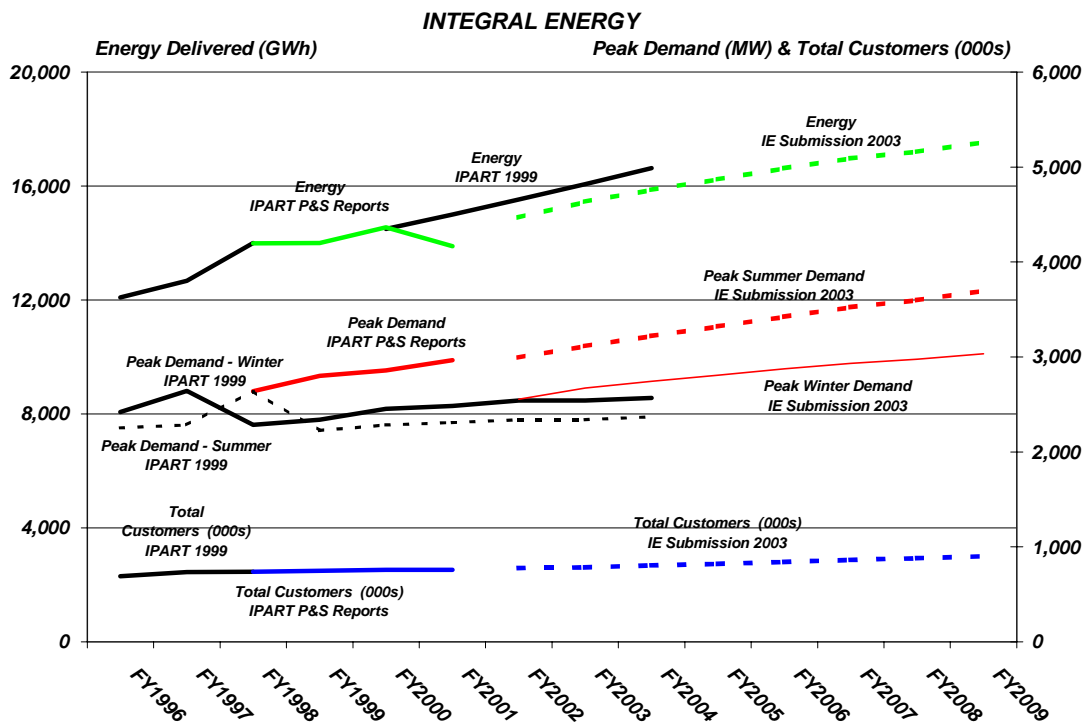
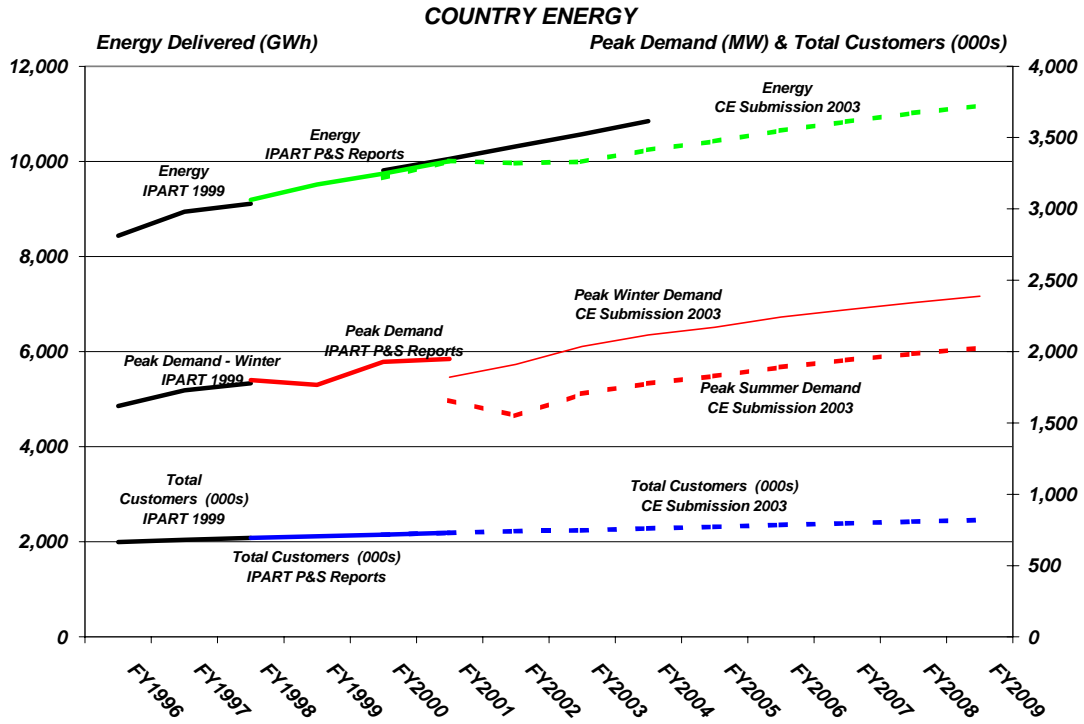


Figure 20: Comparison of actual and forecast demand, consumption and customer numbers for Integral Energy



**Figure 21: Comparison of actual and forecast demand, consumption and customer numbers for Country Energy**

Note: Demand forecasts incomplete for rural distributors in IPART's 1999 Determination.

**APPENDIX B: Comparison of CAPEX cost streams for the NSW DNSPs**

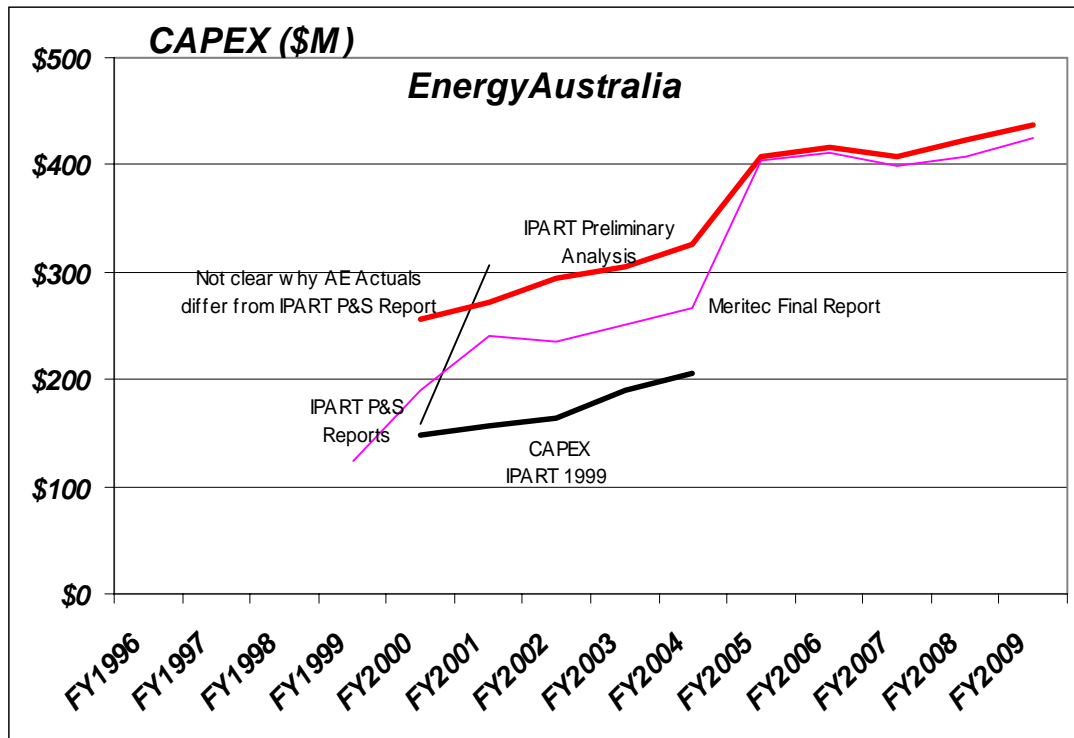


Figure 22: Comparison of CAPEX cost streams for EnergyAustralia

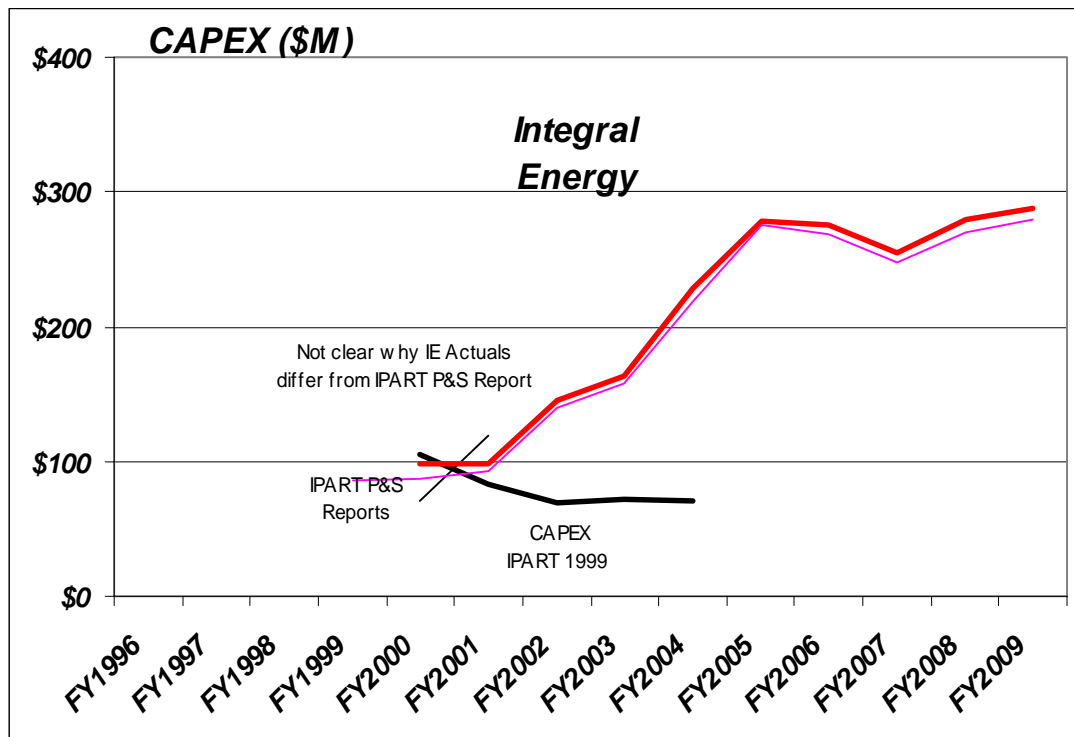


Figure 23: Comparison of CAPEX cost streams for Integral Energy

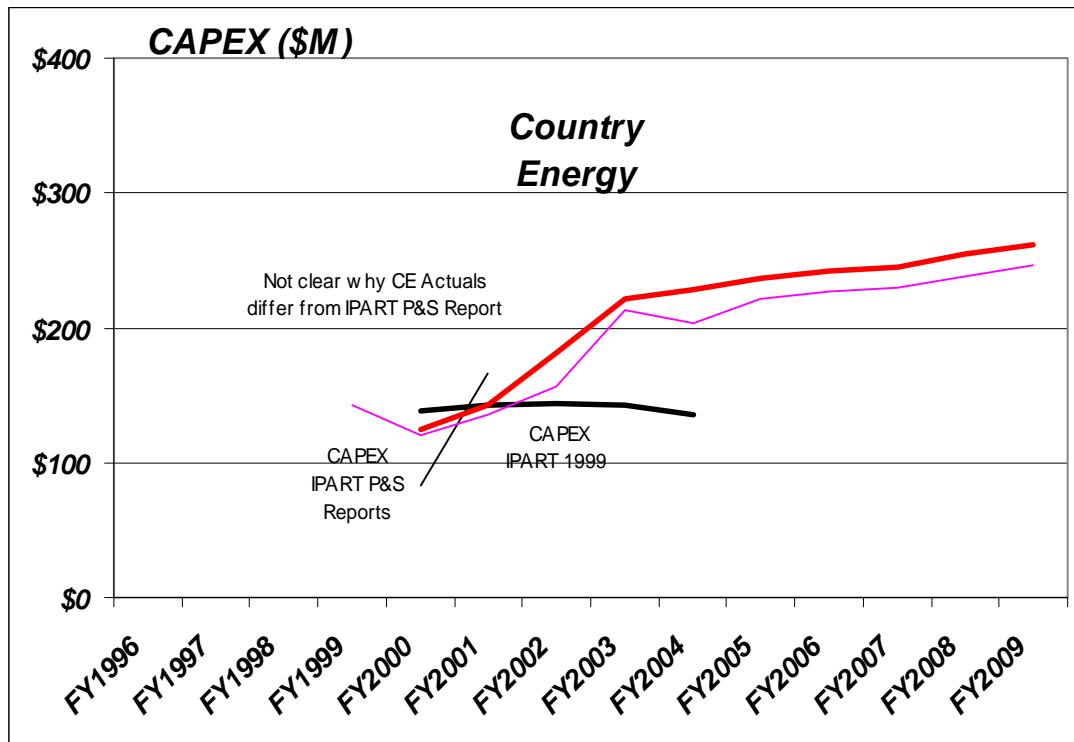


Figure 24: Comparison of CAPEX cost streams for Country Energy

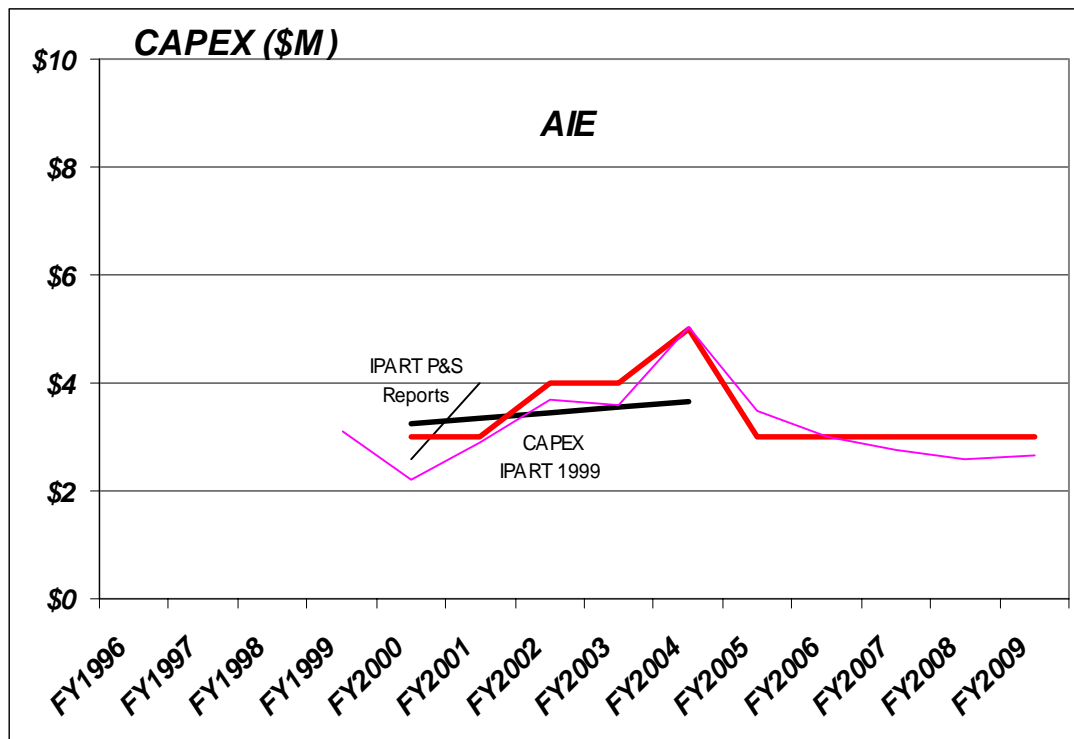


Figure 25: Comparison of CAPEX cost streams for Australian Inland Energy

**APPENDIX C: Comparison of OPEX cost streams for NSW DNSPs**

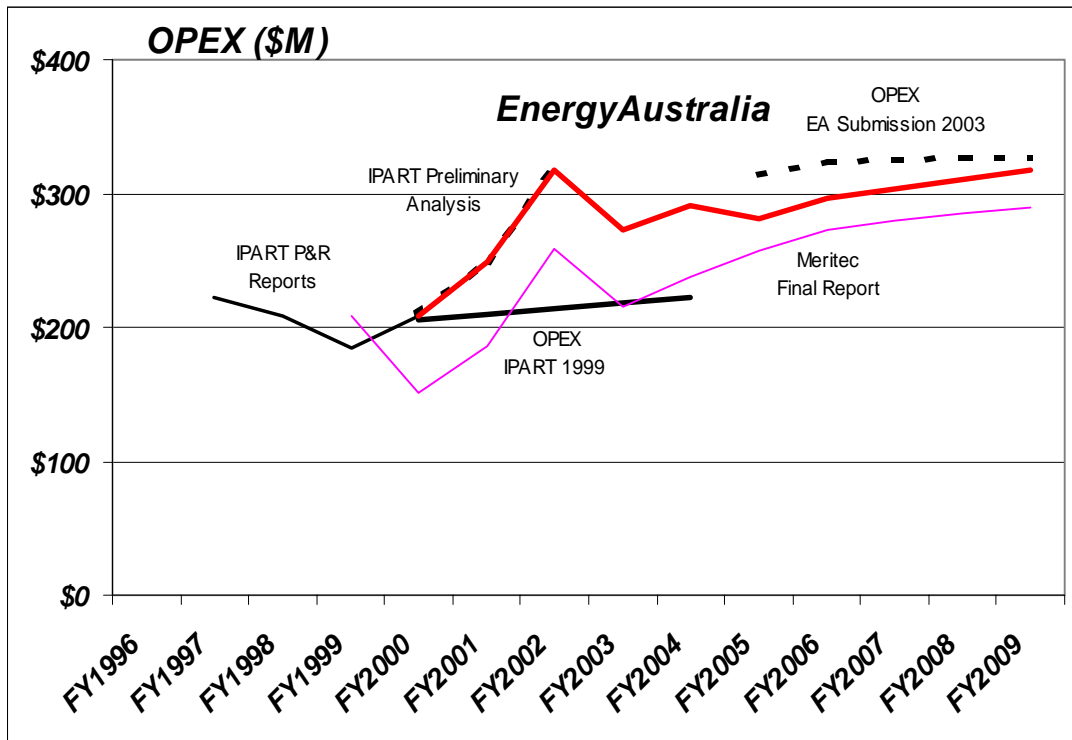


Figure 26: Comparison of OPEX cost streams for EnergyAustralia

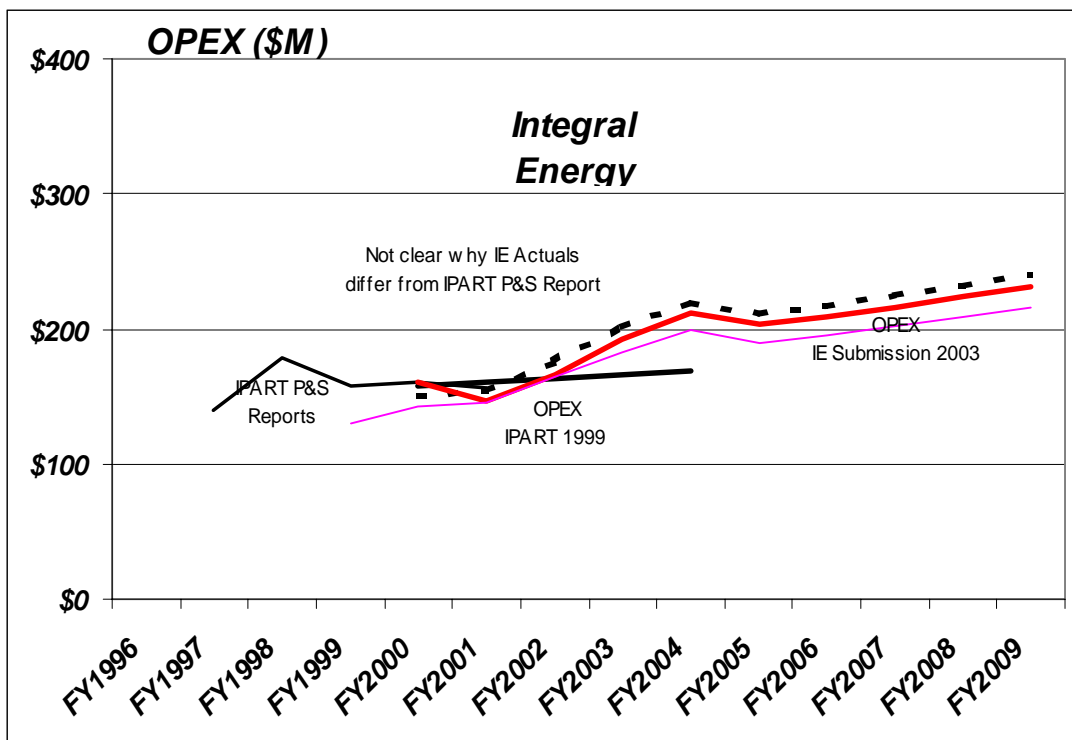


Figure 27: Comparison of OPEX cost streams for Integral Energy

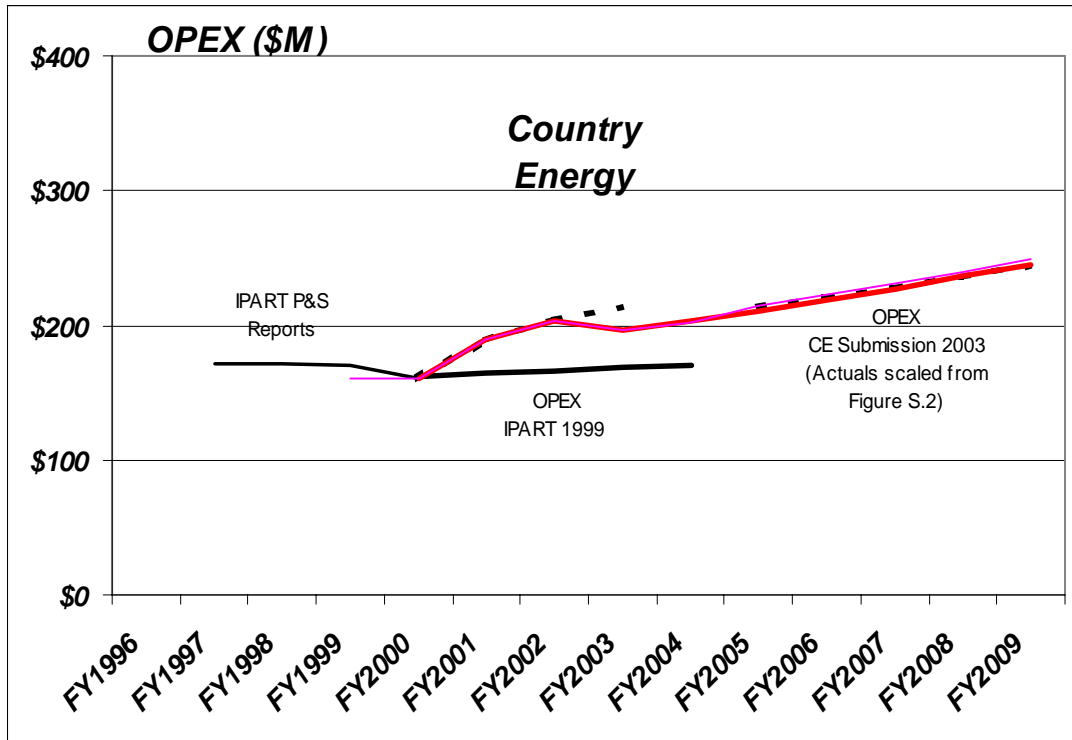


Figure 28: Comparison of OPEX cost streams for Country Energy

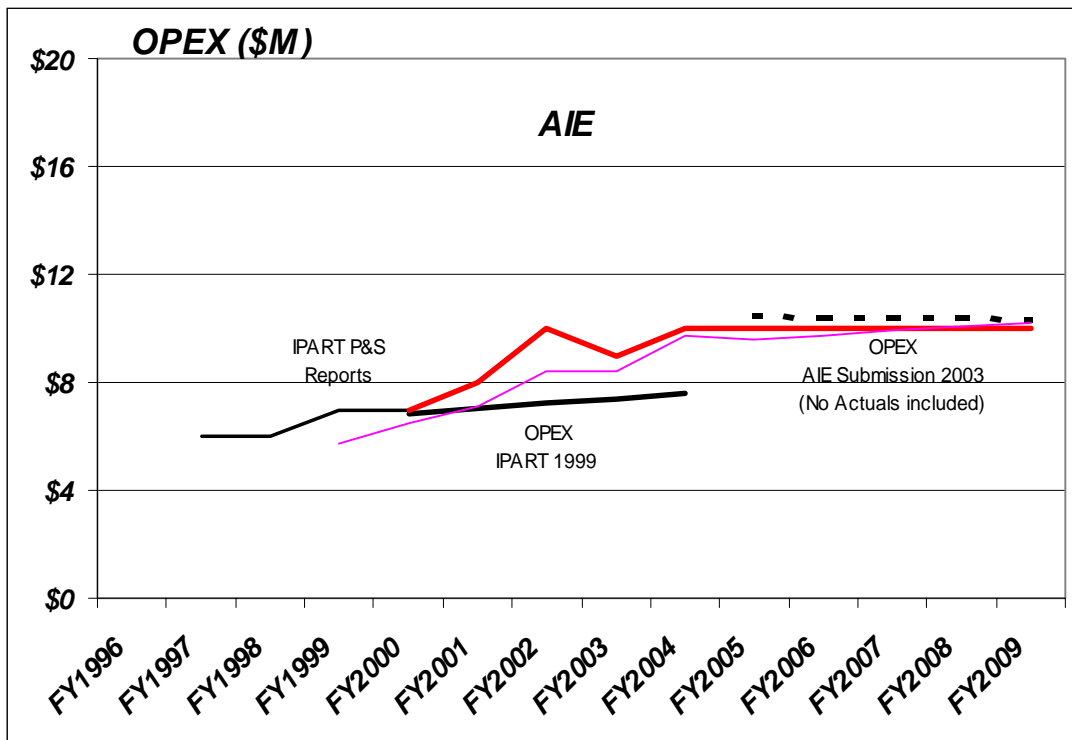


Figure 29: Comparison of OPEX cost streams for Australian Inland Energy