28 August 2009

Mike Buckley
General Manager
Network Regulation North Branch
Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601

by email: aerinquiry@aer.gov.au

Dear Mr Buckley,

QUEENSLAND ELECTRICITY DISTRIBUTORS REGULATORY PROPOSALS

Origin appreciates the opportunity to comment on the Queensland distributors' regulatory proposals for the period 2010/11–2014/15 (FY11-15).

Origin is the local electricity retailer in South East Queensland and provides retail services to many of Energex's small customers. Consequently, the regulation of distribution network services will have a direct impact on Origin. The concerns below relate primarily to the Energex network.

Origin's interests in relation to the regulatory proposals relate to:

- Peak demand and energy volumes;
- Capital expenditure;
- Operating expenditure;
- Pricing; and
- Contestability in metering charges.

1. Peak demand and energy volumes

Projections for peak demand and energy consumption are important drivers of expenditure for distribution businesses.

Energex has revised forecasts for growth in peak demand downwards in response to uncertainty about the impact of the global financial crisis, but has been unable as yet to make a comprehensive assessment of the impact of the financial crisis on energy volumes and peak demand, or any assessment of the impact of the Carbon Pollution Reduction Scheme (CPRS) on volumes.[1] (Energex maintains that the CPRS will have no impact on peak demand.) Origin looks forward to learning more about the impact of these factors on volumes and demand, given the comprehensive assessments Energex currently has

1 Energex Regulatory Proposal, p.149

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underway. These assessments should also include the impact of increases in regulated retail prices on peak demand and energy volumes.

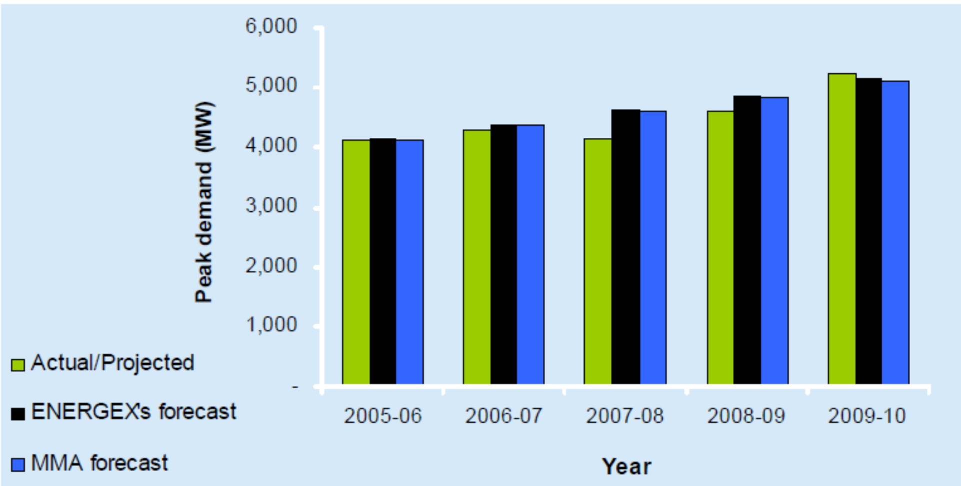
Peak demand – current performance and forecasts

Data provided on growth in peak demand in the current regulatory period could be more usefully presented. Energex provides three years of data on growth in peak demand in the section on current performance (Section 8).

If recent mild summers are the primary explanation for the limited growth in peak demand in FY06 to FY08, it would be helpful to provide data going back to before the period of atypical weather began in FY06. A longer data series would give a better picture of the accuracy of Energex's projections for demand growth over time.

The three years of data in Section 8 are provided Figure 8.1 (reproduced below). This is an unhelpful guide to trends. The table provides data on peak demand, by year, from FY06 to FY10. As marked in the key to the chart, the "Actual/Projected" category is a mixture of historical and projected data; with projections from Energex and McLennan Magasanik Associates (MMA) provided for comparison.

Figure 8.1 System peak demand



Source: Energex Regulatory Proposal, p.114.

On the page following Figure 8.1[2] Energex states that its peak demand data for FY09 and FY10 are temperature corrected projections. This should be clearly identified in Figure 8.1. Although the key to Figure 8.1 makes clear that the green bars in the chart move from historical data to projections at some point, it is not clear this occurs from FY09, nor is it clear that the last two years of "Actual/Projected" are temperature corrected projections. As a result, Figure 8.1 suggests that peak demand may have grown in last financial year (FY09), and that by the end of the current financial year (FY10) peak demand will probably have exceeded Energex's earlier forecasts. In reality, the outcome for peak demand in the FY09 is not yet available, while peak demand in FY10 is evidently still in the future.
The ambiguity in Figure 8.1 has important implications for any trend that might be drawn from the chart. Based on the three years of historical data provided, average growth in

[2] Regulatory Proposal Page 115

peak demand has been negligible. These three years may not be representative, but if so, data should be provided over a longer timeframe. Further detail could also helpfully be made public on the methodology for correcting for atypical weather. Weather corrected data on peak demand from FY02 to FY08 is provided in Figure 10.3, in the section on demand projections, but it would be useful to have *actual* peak demand for those years illustrated clearly (preferably with numerical data provided) in Section 8, *Current Performance*.

It would also be useful to provide a figure of *actual* peak demand for the year FY09, feasible.[3] Peak demand occurs in the summer, so presumably the peak for the Energex network in FY09 was reached in summer 08/09 - around four months prior to the submission of Energex's draft regulatory proposal. This would have allowed some time for the data analysis required to produce the figure. The inclusion of this data would also make Figure 8.1 more valuable.

Energy consumption – current performance and forecasts

Growth in energy consumption in recent years has been either negative or negligible. In explaining this trend Energex notes the impact of falling volumes in response to government directives relating to solar, gas and heat pump hot water and the resulting drop off in dedicated load.

More detail could be provided on Energex's analysis of this marked slowdown of growth in energy consumption. This analysis would better support Energex's projections for growth in energy consumption in the next regulatory period – these projections being for 0.5 percent growth in energy consumption in the first year, followed by increases of over 3.0 percent in all four remaining years of that period.

Even if weather patterns return to trend, the factors listed by Energex that have reduced growth in energy consumption in the current period will continue to have some impact in the next regulatory period, as will increases in retail prices. Further analysis of these competing factors should be provided.

2. Capital expenditure

Energex's proposed capital expenditure for the five years of the *next regulatory period* (FY2011-15) is $6.47 billion; or an average of $1.29 billion annually. Energex projected capex for the *current regulatory period* (FY06-FY10) is $4,016 million; or an average of $803 million annually. Average annual capex for the *prior regulatory period* (FY02-FY05) was $1,378 billion over four years, or $345 million annually on average.

The rate of growth in capex spending since FY02 has been rapid. Energex calculates that actual capital expenditure in the first three years of the current period has been on average 106 percent higher than in the prior regulatory period. Energex's proposed total capex in the next period would represent an increase of around 51 percent on total capital expenditure as projected for the current regulatory period.[4]

[3] In Table 8.6 on p.115, for example

[4] This is an estimate. Projected capex for the current period (FY06-FY10) is $4,016 million; proposed capex for next period (FY11-FY15) is $6,466 million. $6,466 million is in 2009/10 dollars (today's dollars), whereas the FY06-FY10 figures are in dollars of the day of each year. To adjust the FY11-15 data for inflation so it is more comparable to FY06-10 data: average annual inflation in Queensland in the period FY06-FY09 was 3.1%; taking two years as a mid point of that four year period gives a compound inflation figure of 6.3%. As a simple estimate then, $6,466 million would be closer to

While the rate of increase in capital expenditure proposed for FY11-15 is lower than the increase experienced in the current period over the prior period, it is still well above rates of growth in peak demand and customer numbers. Origin is not privy to all background material and evidence provided to the regulator and its consultants to substantiate the basis for this increase,[5] but would urge the regulator to apply detailed scrutiny when reviewing this material, in light of the quantum of the increases proposed.

In a general sense, Origin seeks more clarity on Energex's long term plans in relation to capital expenditure. Guidance is sought on when in the future Energex sees the trend of under-investment in its network is likely to have peaked, and when growth rates in capital expenditure will return closer to levels of growth in state product and peak demand.

Origin notes that Energex's Action Plan in response to the *Electricity Distribution for Service Delivery in the 21st Century* (EDSD) Review is a major driver of the proposed capital expenditure increase. Energex reports that some action items from its original EDSD action plan have been achieved, but not all;[6] further, that the N-1 security standard Energex is working towards has not yet been met; and that Energex contemplates that N-1 will not be met in the next regulatory period.[7]

It would be easier to assess Energex's proposed increases in capital expenditure if Energex could provide some detail on the trajectory for meeting the N-1 security standard and other EDSD objectives. This trajectory could show progress since the EDSD Review; the expected timeframe based on a capital expenditure levels closer to those approved for the current period, and then an indication of how the proposed increases in capital expenditure would work to bring this trajectory forward.

Information provided in tables 8.3, 8.4 and 8.5 on the capacity of bulk supply and zone substations and utilisation of different voltage feeders is welcome, but it would be more valuable to understand in a global sense what remains to fulfil the task of meeting N-1 standard and how far Energex has progressed in completing this task.

Energex observes that spending on EDSD and security is non-discretionary. This is true to the extent that Energex is required to meet its security objectives at some point in the future. However, given that the N-1 standard will not be met until some point after FY15, this implies that a number of trajectories towards N-1 are possible, each implying varying levels of associated risk and cost. Energex's proposed capital spend would be easier to assess if it could explain these trade offs more effectively.

Equally, it would be valuable to understand the breakdown between unit cost increases and increases in the number and quality of network assets to be acquired or created. Although the proposal does provide cost escalation factors for labour and material costs, the information could also be usefully summarised as the proportional contribution from unit cost increases, alongside the proportional contribution from increases in the number and quality of new assets. An understanding of the contribution of unit cost increases to the overall increase in capex would allow external parties to gauge to some degree the efficiency of the proposed spend in comparison to past years.

$6,082 million in dollars of the day. An increase from $4,016 million to $6,082 million represents an increase of around 51 percent.

5 In particular, confidential appendices 10.1 *ENERGEX Peak Demand and Energy Forecasts 2009-2015*, and 10.3 *System Maximum Demand and Forecasting Maximum Demand* by ACIL Tasman.

6 Energex Regulatory Proposal, p.55.

7 as per note 6.

3. Operating expenditure

Greater transparency on proposed increases in operational expenditure would be valuable. $1.83 billion is proposed for operating expenditure in the next period, up from $1.61 billion in the current regulatory period. Spending in the current regulatory period represents an 86 percent increase on average annual spending in the prior regulatory period (FY02 -FY05).[8] It is important that the efficiency of this spend be rigorously assessed.

Choice of base year

It is not apparent that FY08 is appropriate as a base year. Energex states in the proposal that:

The 2007-08 year represents expenditure that builds a foundation to enable ENERGEX to further increase its capability and progress toward EDSD compliance.

As shown in Figure 12.3 the steady build-up in expenditure in the early years of the current regulatory control period has been a precursor that places ENERGEX in a position to deliver a 2009-10 operating expenditure outcome that more closely aligns with the forecast operating expenditure included in this Regulatory Proposal.

The logic seems circular. If the current period is a 'precursor' to further dramatic spending increases – over and above the increase from the current period – then FY08 might be an appropriate base year. However, the current period should only be a precursor to further spending increases if Energex is making reasonable progress towards its goals. As outlined above in relation to capital expenditure, Origin would like more information on the trajectory Energex envisages for reaching these goals. Origin looks forward to more detail on these points.

Variation in relation to base year

Figure 12.4 (reproduced next page) is designed to show the variation between the base year (FY08), and the proposed average operating expenditure for the five years of the next regulatory period.

Energex notes that the "Other Operating Costs" category, which is the largest in the Figure 12.4, includes recoverable works. These will be an alternative control service, with a neutral cost impact on the broad customer base. Energex states that these services must be included in Chapter 12 to comply with a requirement in the pro-forma of the Regulatory Information Notice (RIN).[9] To the extent that these services need to be included in Figure 12.4, it would be useful to reproduce a version of Figure 12.4 that only includes expenditure on standard direct control services that will have an impact on costs for the customer base.

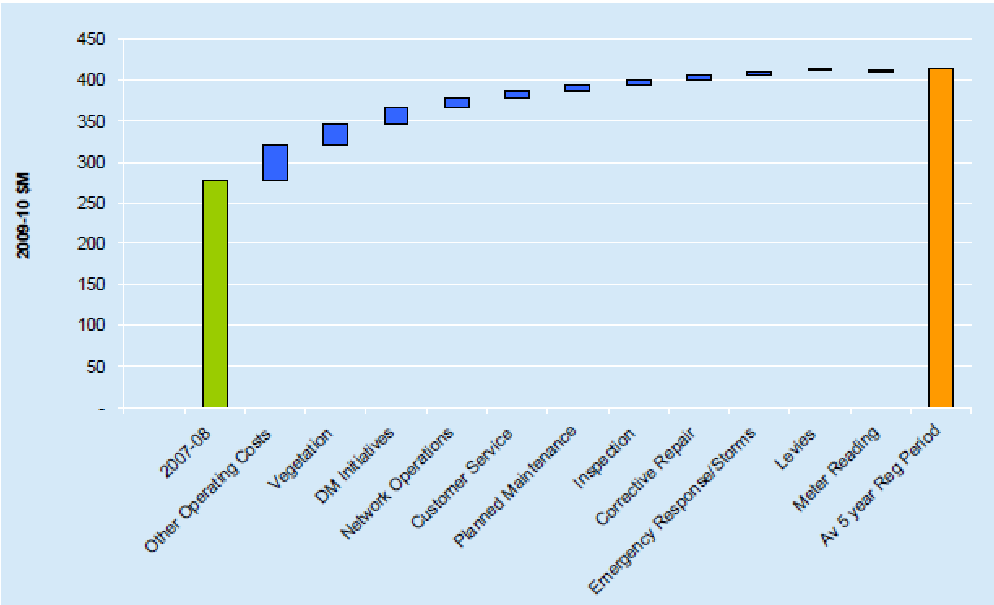
Vegetation management

Energex proposes spending $80 million annually (around $400 million over 5 years) on vegetation management over the next regulatory period (FY11-16). The average annual

[8] Regulatory Proposal, p.119
[9] Regulatory Proposal, p.183

spend approved for the current regulatory period (FY06-10) was $56 million, following from $33 million in the prior period (FY02-05).[10]

Figure 12.4 Variations in operating expenditure from 2007-08 to five year average 2009-10 to 2014-15*



** The five year average includes some alternative control services.*

The Queensland Competition Authority's (QCA) *Final Determination* covering the period FY06-FY10 noted the findings of the EDSD Review that Energex's focus on vegetation management had been inadequate; this being the justification for the increase in spending on vegetation in the current regulatory period. Energex should now make transparent the justification for the further increase to meet the same EDSD goals in the area of vegetation management. Energex notes that rainfall patterns returned to normal following the end of the drought in 2008 and as a result vegetation management work has intensified.[11]

Energex could provide guidance on whether projections of the work required in vegetation management has been substantially revised solely on the basis of the change in rainfall patterns, or whether goals related to vegetation management will be met more quickly than first planned as a result of the proposed increases in spending. Some indication of the extent to which the increase is driven by increases in unit prices would also be helpful. Comments provided below in relation to contracting are also relevant, in that Energex notes that vegetation management is undertaken by contractors.

Contractor costs

[10] These figures are all nominal. See Energex's submission to the *QCA 2005 Draft Determination*, p44.
[11] Regulatory proposal, p.183

Origin notes that Energex has revised its contracting strategy to improve its performance,[12] noting also that it considers that the "size of its current internal workforce is optimal for a business of this size."

Origin would like more detail on the strategy, including whether there will be cost impacts flowing from the revised contractor strategy, given that forward labour escalation rates adopted by Energex indicate an equivalent increase in costs for both internal and external labour of 5.5 percent nominal per annum, as well as remuneration equivalency between internal and external labour.[13]

Benchmarking

In light of the increase proposed in operating expenditure, the benchmarking Energex relies on should be made more transparent than in section 12.10 of the Proposal. Energex reports that:

at the macro level SAHA concluded that ENERGEX is achieving operating expenditure performance similar to that of participating DNSPs that were similar in nature.

This is a limited and qualified conclusion to draw from the SAHA analysis – underlying the importance of the AER developing a standard framework for benchmarking, for distributors, allowing information to be collected on a 'like for like' basis, with transparent means for correcting for differences between distributors.

4. Pricing

As noted by Energex, prices will be determined based on the Annual Revenue Requirement (AAR), X factors, any pass through events during the *2010-15 regulatory control period*, and the annual pricing proposals submitted by Energex to the AER for approval each year of the regulatory control period in accordance with Clause 6.18.7 of the National Electricity Rules.[14]

Origin would observe that while Energex's forecasts for consumption volumes in both FY07 and FY08 were higher than actual energy delivered (Table 1, over), Energex has continued to generate revenues in excess of its AAR. This suggests that its pricing levels have been set too high. Origin would submit that, in light of this, careful scrutiny should be applied to proposed pricing.

Table 1. Energex network energy consumption, forecast and delivered, FY06-FY08, GWh[15]

Year	Forecast	Delivered
FY06	20,480	20,757
FY07	21,305	20,758
FY08	22,250	20,879

5. Metering charges

12 Energex Regulatory proposal, p.212
13 Energex Regulatory proposal, p.176-7
14 Energex Regulatory Proposal, p.273
15 Source: QCA 2005 Final Determination; QCA Energex Performance Reports, various years

Under arrangements as currently proposed for Queensland in the next regulatory period variable metering services will not be classified as alternative direct control services. Instead, metering services will be classified as standard direct control and ‘bundled’ in Distribution Use of System (DUOS) charges. In Origin’s view, this bundling creates a barrier to alternative metering providers who are looking to enter the small customer metering market. Metering services should be classified in a way that promotes choice and competition.

In the event that a customer wants to opt for a type 4 meter instead of a type 5 or 6 meter, this will normally involve the customer paying a third party meter provider for a type 4 meter. However, if all network charges relating to metering are bundled in the customer’s basic network charge, a customer continues to pay for metering services associated with the old meter. In this way, the cost of metering for customers opting for a type 4 include the costs associated with both old and new meters.

As long as customers opting for type 4 are subsidising the metering costs of others in this way, interval meters will reman relatively less attractive. Even as the costs of interval meters and accumulation meters converge, this double charging remains a considerable barrier to entry for alternative meter providers.

Origin concurs with the finding of the Australian Energy Regulator (AER) in this regard, made in relation to metering charges in South Australia, in the *Final Framework and Approach for ETSA Utilities*:

This barrier [to entry] *occurs as small customers opting for a meter from an alternative provider continue to pay ETSA Utilities for the provision of type 6 metering services (even though they are no longer receiving these services), and so effectively pay for their metering twice.*[16]

Origin also concurs with the AER’s finding that:

Separating these [metering] *charges would be more appropriate, as it would remove barriers to entry in metering service markets, leading to more cost reflective price outcomes.*[17]

Barriers to contestable metering impede a competitive process that would otherwise work to reduce the cost of meter provision.

As the use of interval meters becomes more widespread, more customers stand to benefit from efficient costing of metering services. Customers in other states who do not opt for interval meters, but who are assigned a meter under government mandate, will also benefit from greater contestability and more cost reflective pricing in Queensland.

In light of the above, Origin submits that the approach adopted by the AER in South Australia should be adopted in Queensland. The drivers for competition in metering services in the two jurisdictions are highly similar (if not identical), as is the regulatory framework in the National Electricity Rules (NER). The market in Queensland is larger, so increases in efficiency and competition will benefit a greater number of customers, with these gains more likely to have a positive influence in other states.

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[16] AER, *Final Framework and approach paper ETSA Utilities 2010-15*, November 2008, p.viii.

[17] op cit.

Ensuring an effective outcome will involve splitting metering costs in to fixed and variable components:

- ‘fixed’ standard small customer metering services (type 6 metering installations) as standard control services, and

- ‘variable’ standard small customer metering services (type 6 metering installations) as alternative control services.

The framework should clearly separate variable charges from bundled charges. While a distributor might in theory be able to separate out variable metering charges without a change in classification, the alternative direct control classification is the most appropriate means to guarantee choice in this area. Clause 6.2.2 of the NER determines the matters the AER must have regard to when classifying a direct control service as standard or alternative:

> *(1) the potential for development of competition in the relevant market and how the classification might influence that potential; and*
>
> *(2) the possible effects of the classification on administrative costs of the AER, the Distribution Network Service Provider and users or potential users; and*
>
> *(3) the regulatory approach (if any) applicable to the relevant service immediately before the commencement of the distribution determination for which the classification is made; and*
>
> *(4) the desirability of a consistent regulatory approach to similar services (both within and beyond the relevant jurisdiction); and*
>
> *(5) the extent the costs of providing the relevant service are directly attributable to the customer to whom the service is provided.*

In Origin’s view there is clearly significant potential for greater competition in the markets for meters and metering services. More evidence to support this proposition is provided in the following section. Equally, the way the services are classified will have a direct impact on the potential for competition, as outlined in previous section.

The classification is unlikely to involve a much greater burden for the AER than the alternative. The AER has assessed these costs in relation to South Australia and found they do not outweigh benefits to competition. Any upfront cost will be balanced against more cost reflective pricing in the long term.

Under previous arrangements in Queensland, all standard metering services were prescribed services. However, the contestable market for these services is expanding, as the cost of interval meters falls, so the future classification should reflect this.

Metering services are likely to be split in South Australia for the same regulatory period. Consistency would be enhanced by adopting a similar approach in both South Australia and Queensland.

Lastly, criteria (5) is best met by classifying alternative metering costs so that only customers receiving type 6 services pay for these services.

Evidence of a market for contestable metering services

Origin would contend that there is significant potential for contestable metering services in Queensland and South Australia. The market is in its infancy as the cost of interval meters has been high and regulatory arrangements have not been optimal.

A greater understanding of the market potential in these states is available from examining the market for contestable metering services in New Zealand.

In New Zealand, the adoption of interval meters by retailers and third-party providers has been driven by the commercial benefits that can accrue to customers. As the majority of meters in New Zealand are owned by retailers or third party providers, customers are not charged variable metering costs by their distributor.

In 2008, the Australian Energy Markets Commission (AEMC) commissioned an analysis of the market for contestable metering services in New Zealand. The study found that "customer demand, competitive pressure and the converging cost structure between AMI and conventional non-AMI meters were the primary drivers of competitive, retailer-led roll outs." At the time the study was completed in 2008, it was contemplated that the majority of New Zealand households would have AMI within three years. Announced and current deployment of meters included over 1 million meters in country of some 4 million people.

Furthermore, the study found that once meters were installed competition remained effective, with the installation of a particular meter not creating a barrier to competition among retailers. Meter providers faced strong incentives to make their platform workable for all retailers, since otherwise they risked stranding their asset. Payback frequently occurred over an extended period, meaning meter providers have an interest in keeping the meter in use for the full pay back period, strengthening the incentive for meter providers to develop arrangements with all retailers.

Origin maintains that contestability in metering services will guarantee better outcomes for customers in the longer term than models of monopoly provision.

If you have any queries relating to this proposal, please contact Steven Macmillan on (03) 8665 7155 in the fist instance.

Yours sincerely

B J Hughson

Bev Hughson
Manager Regulatory and Relationships