APVI Submission to the AER on the Issues Paper on Ergon's and Energex's Network's Regulatory Proposals December 2014

Summary of APVI Response

Both Energex and Ergon Energy, like all other network businesses in Australia, are facing a period of rapid change. Consumers are becoming more involved in their energy services and are increasingly choosing to manage their own supply and use, via onsite generation (mainly Photovoltaic systems (PV) and solar hot water (SHW)), smart appliances and energy management systems, operated via mobile phones or otherwise. Over the five years of this regulatory period, we can expect these trends to continue, with the likely introduction of other distributed energy systems and services, including onsite storage and electric vehicles, as well as significantly more energy efficient buildings and appliances.

Energex and Ergon can be commended for acknowledging these changes and for taking on board the findings of their customer surveys, which show that customers expect them to not only accept, but to facilitate their distributed energy choices. Energex and Ergon are also beginning to examine new technology options for their own operations. However, the efforts being put into these new areas, and into demand management opportunities, are very limited and are unlikely to keep up with the pace of change over the next five years.

A key reason for the approach taken by Energex and Ergon is the continued heavy reliance on the regulated asset base (RAB) as the key driver for allowed revenue. None of the other adjustments to this driver are sufficient to negate the strong incentive this provides for network businesses to continue to look for means of increasing their RAB. Hence, despite significant reductions in electricity use and demand peaks, changes to customer preferences and the availability of new technologies which could provide lower cost, lower risk and more reliable solutions to long grids, significant expenditure is planned to strengthen and increase the cost of these grids, and hence their RAB. This leaves customers with a legacy of sunk costs which they will have to pay for, whether or not they use them or want them. This approach locks Australia into old technology and old business models which will keep electricity prices high, erode the competitiveness of existing businesses and limit the opportunities for development of new technologies and new businesses. The Determination process could be enhanced by the need to consider scenarios progressively constraining RAB growth and their impact on network reliability.

It is clear that networks can no longer be viewed as a 'natural monopoly'. There are many options to network connection, to alternative supply and to demand management. Any capital expenditure on networks going forward should be open to third party competition, if customers are to get the most suitable energy services in the long term. The RIT-D provisions are a very tentative start, but do not cater for grid refurbishment or expenditure less than $5 million, and do not necessarily facilitate competition. The next 5 years will be crucial, given the age of Australia's grids and the rapid technology and climate changes underway. For Queensland, the next 12 months are likely to be particularly crucial, given the proposed long term leasing of Energex and Ergon to the private sector.

APVI comments on key issues

1. Is the DNSP capital expenditure proposal adequately justified?

APVI Comments

Revenue:

Over the 2010-15 Determination period, Energex has experienced under-recovery of revenues and so it is entitled to recover these revenues in the 2015-20 period. Over the 2010-15 Determination period, Ergon Energy appears to have experienced over-recovery of revenues. Under revenue cap regulation they should be required to pay back the over recovered revenues, however no mention is made of this in the AER Issues Paper.

Despite experiencing declining volumes, Ergon received significantly more revenue than allowed for in both 2013-14 and 2014-15. To do this they must have increased tariffs significantly for 2013-14 and then again in 2014-15, or decreased expenditure. The excess revenue in 2014-15 was even greater than in 2013-14. This indicates an inability to forecast electricity use even 1 year into the future. For Ergon, uncertain and changing deadlines for large mining related projects may be one reason for the discrepancy.

Energex's inability to forecast accurately extends to their projections for demand, energy, customers and required capital. Table 3.2 (below) of the Energex proposal demonstrates poor forecasting year after year. Importantly, the forecasting error is not random but is constantly biased in the same direction – forecasts are always greater than actual. Noting that these errors involved just a 12 month look ahead (often even less, given that plans were not published until end August) what gives the AER any confidence that their forecasts for the next Determination period, including those for required capex and opex, are likely to be credible? In particular, the current process places all the risk (i.e. cost) of incorrect forecasts onto the consumers, with the network business merely passing on costs whether or not the investments are sound.

Table 3.2 - Energex's actual and forecast demand, energy delivered and customer numbers

	2010-11	2011-12	2012-13	2013-14	2014-15
Demand- forecast (MW)	4,931	5,089	5,328	5,555	5,733
Demand - actual (MW)	4,875	4,881	4,590	4,372	4,356
Energy delivered - forecast (GWhs)	22,416	23,138	24,042	24,795	25,845
Energy delivered - actual (GWhs)	21,454	21,210	21,055	20,838	20,628
Customer numbers - forecast ('000s)	1,363	1,389	1,418	1,449	1,480
Customer numbers - actual ('000s)	1,316	1,334	1,347	1,364	1,381

Repex:

Energex and Ergon Energy have proposed increases of 66% and 10% to their repex requirements respectively. When replacement is required and demand peaks are projected to increase, the network size would be increased. Likewise, when demand peaks are projected to decrease for the foreseeable future, consideration should be given to decreasing the size of the network when assets are renewed or replaced. PV systems are getting cheaper and it is likely that within the next 5 years distributed batteries will be as common as PV systems are now, and will have spread into the commercial sector as well. This uptake will be accelerated by the types of cost-reflective tariffs currently being considered.

Forecasts of demand peaks should take this into account – note that the DNSPs significantly underspent on their capex for the 2010-15 period. This could significantly decrease the DNSPs' repex requirements.

Further, Energex and Ergon are in a good position to be able to examine the replacement of old assets with new service delivery models. There is an excellent opportunity to look to stand-alone power systems, mini and micro-grids, grid storage systems, demand management (DSM) and energy efficiency (EE) drives as options to rebuilding or strengthening existing grids. In cyclone and flood prone areas especially, where supplies can be cut for long periods during severe weather events, such alternatives to long grids may be significantly cheaper, more resilient and more flexible than undergrounding and other upgrades. Separately codifying assets enabling or associated with these new service models for the purpose of regulatory determinations would be a practical step to begin managing this change.

Augex:

Given that Energex experienced an annual decline in average peak demand over the period 2010-15, it is surprising that such a significant amount of augex was required in this period. Furthermore, despite Energex forecasting very small increases to average demand peaks over 2015-20 (which, as discussed above, may not occur), it is proposing further augex that is still about half what it was in the period 2010-15. This is in part responsible for Energex's RAB increasing by about 20% over 2015-20. Although there may be some areas where peak demand will increase, in most areas they will either remain steady or decrease. In these circumstances, how can such ongoing augex be justified?

Similarly, Ergon Energy also experienced an annual decline in peak demand over the period 2010-15, yet spent significant amounts on augex, and now wants to spend almost as much augex over the period 2015-20 (Ergon's RAB will increase by about 30% over 2015-20). Again, how can such ongoing augex be justified where historically demand peaks have declined and are forecast to increase only marginally?

The roll out of PV has reduced system peak by 335MW according to Energex[1] and also allowed uprating of substations by 457MW[2]. In reality many of the tens of thousands of distribution transformers within the network will also warrant up rating when this is finally analysed. Energex's increased ratings and peak reductions totalling 792MW (335MW + 475MW) would presumably be valued at hundreds of millions of dollars. Their 2012/13 NMP boasts the addition of 743MVA of substation capacity (Table 11 – 460 bulk s/s+ 283 zone s/s) under the C20 budget for the lion's share of the $523 million capital works transmission budget (Table 10). Are the DNSPs taking this substantial increase in capacity into consideration in their Regulatory Proposal? More importantly, are they factoring the future capacity increases and demand reductions to be provided by further PV rollout?

How much stock do the DNSP's hold in inventory, either in their own stores or held in manufacturer's facilities due to over expenditure during the present regulatory period? If stock levels have changed over the period, this should be taken into consideration when calculating repex and augex. In any case, some investigation may be warranted into the appropriate level of stock to be held, given the detailed planning required and the lead times for acquisition.

Appropriate incorporation of new technologies:

Ergon and Energex do not seem to be taking the full implications of new technology into consideration when producing new policy. For example, the joint "Standard for Small Scale Parallel Inverter Energy Systems up to 30kVA" only allows 2 – 5kVA inverters (Ergon) and 3 - 5kVA inverters (Energex) that may export into the grid to be connected without engineering assessment if they operate at 0.9 PF to import reactive power (Sn 5.2 & 5.3). This is a blunt tool that may require the

[1] Energex DAPR 2014 Vol 1, SN 5.1.2

[2] Energex DAPR 2014 Vol 1, SN 12.1.2

networks to spend additional funds to provide reactive compensation to meet their power factor obligations at their TNSP connection points. Given that Energex's 2012/13 Network Management Plan (later data not readily available) shows dozens of substations already failing to meet National Electricity Rules power factor obligations (Table 19), this would seem a substantial oversight.

With the average PV installation now about 3kVA, the policy will promote the universal adoption of a 0.9PF setting, regardless of network topology, despite the fact that reactive compensation only provides appreciable voltage improvement when the X/R ratio of the network source impedance is significant. Sinking reactive power on low X/R ratio networks with underground cables or aerial bundled conductor will produce little or no benefits. In many other cases, it may not be appropriate because of healthy voltage margins in the existing network. However, the reactive power being sunk by all these inverters will have to be sourced from somewhere; usually by generators operating inefficiently in an overexcited manner, or by additional capacitor banks on the network. To put this in context, if the 920MVA of existing SEQ inverters were generating at full output at 0.9PF, about 450 Mvars of additional reactive compensation would have to be provided by traditional generators or network capacitors at that time. Has this extra capital cost been included in the submissions and would it not be preferable to tailor the connection rules to relevant network conditions, thereby avoiding this unnecessary expense?

Incorporating peak demand reduction:

Although Energex acknowledges a 335MW reduction in system peak demand from PV, it claims that a "typical domestic substation with a significant quantity of residential solar PV systems does not affect peak demand". This contrasts with data provided by Ausgrid, which indicates that the amount of PV capacity available on different distribution network peaks varies from 11.8% to 48.5%.[3] The SA Power Networks regulatory proposal also shows significant peak load reduction due to PV.

Given the stated substantial reduction in system peak and the fact that it is local substation peaks that dictate capital investment, it would seem appropriate for the utilities to do a substation by substation analysis of the benefit gained from PV demand reduction and uprating of transformers. This will become particularly important as distributed batteries are taken up. Further, given the significant and increasing rollout of PV in commercial areas with typical daytime peaks, one would expect that commercial and industrial areas may be benefitting more substantially from demand reduction than otherwise indicated by the current assessment.

Resource companies:

Ergon Energy submitted that it expects to see increasing demand in its central Qld and southern Qld regions, in addition to coastal ports, driven by resource companies. It seems that these activities are being used to justify higher capex and therefore a higher RAB and therefore higher tariffs for all customers. This cross-subsidisation should not be necessary since new customers must pay for all new infrastructure and, if tariffs to cover on-going operation are properly cost-reflective, the new customers should also bear any extra costs required to cover the cost of that new infrastructure.

Tap setting of distribution transformers:

Energex states in its "Power Quality Strategic Plan 2015-20" that 83% of its distribution transformers are set on the incorrect tap, based on existing planning guidelines. If funds are being requested to address this, the DNSP should be asked how many of the transformers newly installed, upgraded, replaced, refurbished or otherwise connected to 11kV feeders that are affected by network topology changes in the current regulatory period are set on the incorrect tap. If a significant

[3] Calculated from Ausgrid. Effect of small solar Photovoltaic (PV) systems on network peak demand, Research Paper, *Ausgrid*, Oct 2011. From http://www.ausgrid.com.au/Common/About-us/Newsroom/Discussions/~/media/Files/About%20Us/Newsroom/Discussions/Solar%20PV%20Research%20Paper.ashx,

percentage, it would seem unreasonable for the regulator to allocate new funds to correct work that should already have been addressed in the current regulatory period.

Further, given that most transformers are tapped too high (about 76% for Energex) and noting that many utilities employ voltage conservation reduction to lower demand by reducing voltage, the DNSPs should be asked to advise how much additional energy has been unnecessarily consumed (and unnecessarily paid for) by customers because of this oversight. Further, has the reduction in energy (GWh) and peak demand (GW) arising from tap corrections been reflected in energy forecasts? A 0.7 to 1% reduction in energy is typically achieved for every 1% drop in voltage.[4] Given the 2.5% taps are used on standard transformers, the difference could be substantial.

Air conditioners:

Note that, although the uptake of air conditioners is forecast to increase, they will also become more efficient over time, both due to government programs such as MEPS and because of technological advances. Historically, the Energy Efficiency Ratio and the Coefficient of Performance of A/Cs in Australia have improved by about 5% annually, largely due to the uptake of inverter/variable speed motor systems.[5] It is not clear whether the demand forecasts take these improvements into account.

RIT-D:

Although outside the scope of this Regulatory Proposal, it is worth mentioning that currently the RIT-D does not need to be applied where the project is related only to the refurbishment or replacement of existing assets. This is because on page 95 of the AEMC's 14 June 2012 draft decision, it states:

> "It is appropriate to exempt these projects from the scope of the RIT-D on the basis that the benefits to be gained from their assessment under the RIT-D would, in most cases, be unlikely to outweigh the costs, risks or regulatory burden on relevant NSPs from applying the RIT-D process."

Because rule 5.17.3(5) (NER) explicitly exempts refurbishment or replacement projects, the AER has no authority to request that the RIT-D application guidelines apply to this type of project. However, application of the 'greater than $5 million' rule should exclude projects where the costs outweigh the benefits – at least as well as it does for network augmentations. In such cases, if non-network alternatives are shown to have a greater net economic benefit over the projection period, the size/cost of the network could be reduced, which could result in absolute cost reductions. Exclusion of refurbishment or replacement projects from RIT-D also provides an incentive for augmentation projects to be misclassified in order to avoid the RIT-D requirements.

2. Is the DNSP operating expenditure proposal adequately justified?

APVI Comments

Opex efficiency:

On page 30 of the AER Issues Paper, the AER asks "If we were to make a revision to the opex forecasts to close the efficiency gap, a further issue to consider is how quickly this transition should take place. That is, who should bear the cost of the transition: consumers or shareholders". In a fully competitive market, which this regulation is trying to mimic, it would always be the shareholders who

---

[4] Warner, K. and Willoughby, R. (2013) Conservation Voltage Regulation: An Energy Efficiency Resource, IEEE Smart Grid, http://smartgrid.ieee.org/april-2013/842-conservation-voltage-regulation-an-energy-efficiency-resource.

[5] 'Evaluation of Energy Efficiency Policy Measures for Household Air Conditioners in Australia', by EnergyConsult for the Department of Climate Change and Energy Efficiency, Nov 2010 - http://www.energyrating.gov.au/program-publications/?viewPublicationID=2153.

bear the cost. Also note that networks are no longer a natural monopoly. They face direct competition from distributed generation and distributed storage. Trying to make consumers bear the cost of any efficiency transition will simply make the networks less competitive.

How is value for money in the capex and opex expenditure determined? There appears to be no metrics on the efficiency of this expenditure in terms of say, the cost per MVA in constructing new zone substations, the cost of replacing a 200kVA pole mounted transformer, cost per km of installing Moon conductors etc. Statements suggesting that overruns in expenditure have been mitigated in recent years (ie Table 3.3 below) do not prove that the expenditure has been either wise or efficient unless the benefit associated with that cost is demonstrated. How many of the capital projects involved budget overruns?

Table 3.3 - Energex's actual and forecast opex compared with allowance including and excluding one-off costs (direct and indirect)[1]

$m, nominal	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Opex allowance	323.4	329.1	345.6	363.1	365.6	1,726.8
Actual opex	334.4	370.7	404.9	379.3	367.8	1,857.2
Overspend	11.0	41.6	59.4	16.2	2.2	130.4
Percentage	3%	13%	17%	4%	1%	8%
Adjusted actual opex[2]	317.4	353.9	342.7	360.9	346.8	1,721.7
Adjusted overspend[3]	(6.0)	24.8	(2.8)	(2.2)	(18.8)	(5.1)
Adjusted percentage	(2%)	8%	(1%)	(1%)	(5%)	0%

Note:
1. Opex allowance, actual opex and adjusted actual opex are exclusive of FiT costs
2. 2010-11 has been adjusted by $17 million for the 2011 flood, 2011-12 has been adjusted by $16.8 million for the provision relating to faulty service lines, 2012-13 has been adjusted by $11.2 million for ex-tropical cyclone Oswald and 2012-13, 2013-14 and 2014-15 have been adjusted by $51 million, $18.4 million and $21 million respectively for restructuring costs
3. Negative value represents an underspend

3. Do you consider departures from the Regulated Rate of Return justified? Comment on the departures proposed by DNSP

APVI Comments.

Rate of return:

The AER has put considerable effort into providing a benchmarked rate of return for use by the Networks, including imputation credits relevant to the electricity sector, so there is no justification for Energex and Ergon choosing another method, because it provides higher revenue.

Further, the AER defines the return on equity as "the return shareholders of the business will require to attract new investment." However, the shareholder is the Queensland government, and the need for new investment is determined by service reliability requirements. Thus, the return on equity is actually just the rate of return desired by the Queensland government. Given that the return on equity makes up 40% of the required rate of return on the RAB, decreasing this could significantly decrease the revenue cap and hence the electricity bills of customers.

4. Metering

APVI Comments.

Metering replacement cost:

There are two separate issues here. 1) how well the DNSP calculates the residual cost of the old meters, and 2) how that cost should be recovered.

1) Exit fees for customers choosing new service providers is not justified. The transfer fees of $324 and $166 would appear to be higher than, or close to, the original meter cost, and definitely higher than its depreciated (and paid for) value. If any exit fee is to be contemplated, the following questions will need to be answered first:

- What was the cost of meters currently installed?
- Were these paid for up-front, via connection costs or otherwise?
- If not, over what period are their costs recouped?
- How often are they typically replaced?
- What is the average age of current meters?
- What is the cost of new 'smart ready' meters?

2) Presumably customers will also have to pay the cost and an installation fee for the new meter. Combined with an exit fees, this will serve to stymie the proposed new competitive market.

Attachment A: Background on the APVI

The APVI is an independent Institute comprising companies, government agencies, individuals, universities and research institutions with an interest in solar photovoltaic electricity. In addition to Australian activities, we provide the structure through which Australia participates in the International Energy Agency (IEA) PVPS (Photovoltaic Power Systems) and SHC (Solar Heating and Cooling) programmes, which in turn are made up of a number of activities concerning PV and solar system performance and implementation. Further information is available from www.apvi.org.au.

APVI Objective

The objective of the APVI is to support the increased development and use of PV via research, analysis and information.

APVI subscription provides:

Information

- Australian PV data and information
- Standards impacting on PV applications
- Up to date information on new PV developments around the world (research, product development, policy, marketing strategies) as well as issues arising
- Access to PV sites and PV data from around the world
- International experiences with strategies, standards, technologies and policies

Networking

- Opportunity to participate in Australian and international projects, with associated shared knowledge and understanding
- Access to Australian and international PV networks (PV industry, government, researchers) which can be invaluable in business, research or policy development or information exchange generally
- Opportunity to meet regularly and discuss specific issues which are of local, as well as international interest. This provides opportunities for joint work, reduces duplication of effort and keeps everyone up to date on current issues.

Marketing Australian Products and Expertise

- Opportunities for Australian input (and hence influence on) PV guidelines and standards development. This ensures both that Australian products are not excluded from international markets and that Australian product developers are aware of likely international guidelines.
- Using the information and networks detailed above to promote Australian products and expertise.
- Working with international network partners to further develop products and services.
- Using the network to enter into new markets and open new business opportunities in Australia.

The International Energy Agency Programmes

PV Power Systems (IEA PVPS)

- **Mission:** *To enhance the international collaborative efforts which facilitate the role of photovoltaic solar energy as a cornerstone in the transition to sustainable energy systems*
- **Focus** (26 countries, 5 associates)
  - PV technology development
  - Competitive PV markets
  - Environmentally & economically sustainable PV industry
  - Policy recommendations and strategies
  - Neutral and unbiased information

Australia currently participates in:

PVPS Task 1: Information Dissemination

PVPS Task 13: PV System Performance

PVPS Task 14: High Penetration PV in Electricity Grids.

Solar Heating & Cooling (IEA SHC)

- **Mission:** *International collaboration to fulfil the vision of solar thermal energy meeting 50% of low temperature heating and cooling demand by 2050*
- **Focus** (21 countries, 2 associates)
  - Components
  - Systems
  - Integration into energy system
  - Design and planning tools
  - Training and capacity building

Current Australian participation:

- SHC Task 51 – PV in Urban Environments
- SHC Task 48 – Quality Assurance Support Measures for Solar Cooling Systems
- SHC Task 47 – Solar renovation of non-residential buildings
- SHC Task 46 - Solar Resource Assessment and Forecasting
- SHC Task 43 - Solar Rating & Certification Procedures
- SHC Task 42 - Compact Thermal Energy Storage
- SHC Task 40 - Net Zero Energy Solar Buildings

For further information on the Australian PV Association visit: **www.apvi.org.au**

For further information on the IEA PVPS Programmes visit **www.iea-pvps.org and www.iea-shc.org**