Energex Regulatory Proposal: July 2015 to June 2020

AGL submission to the Australian Energy Regulator

30 January 2015

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AGL

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1. Comments

AGL Energy Ltd (AGL) appreciates the opportunity to submit to the Australian Energy Regulator (AER) on Energex's Regulatory Proposal for the period 1 July 2015 to 30 June 2020.

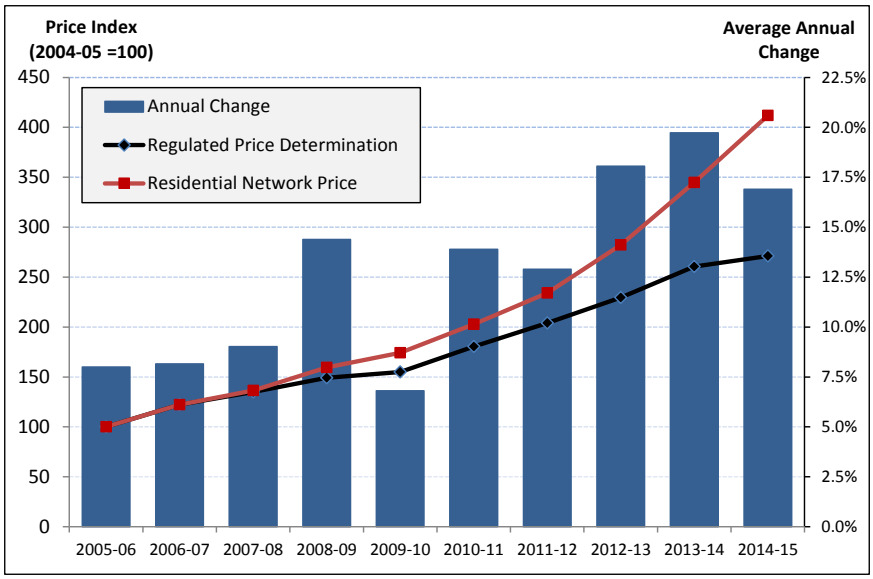
AGL is one of Australia's leading integrated energy companies and largest ASX listed owner, operator and developer of renewable energy generation in the country. Drawing on over 175 years of experience, AGL operates retail and merchant energy businesses, power generation assets and an upstream gas portfolio.

AGL has a diverse power generation portfolio including base, peaking and intermediate generation plants, spread across traditional thermal generation as well as renewable sources including hydro, wind, landfill gas and biomass. AGL also has one of Australia's largest retail energy and dual fuel customer bases including over 400,000 customers in south east Queensland.

AGL has chosen to participate in the current AER consultations for setting distribution network's future revenue requirements because of the significant increase in electricity network charges in recent years and an apparent assumption of distribution networks, as revealed through their regulatory proposals, that the current situation is efficient and sustainable.

Figure 1 highlights the annual increases in network prices for southeast Queensland domestic customers over the last 10 years as well as indices of network prices. Annual network price increases have exceeded 12.9 per cent in each of the last 5 years is readily apparent. What this means is that due to the regulated revenue allowed over that period, average network prices were regulated to increase by over 170 per cent. However, due to price change variations between tariff classes and falling energy consumption, actual network prices for residential customers in southeast Queensland have increased by more than 300 per cent.

Figure 1: Energex Network Price changes from 2005-06 to 2014-15



Source: AER, QCA determinations and actual network price change for NT8400.

To be clear, all network charges are passed through to customers in retail electricity prices so any increase (or reduction) in network charges has no direct commercial impact on retailers such as AGL.

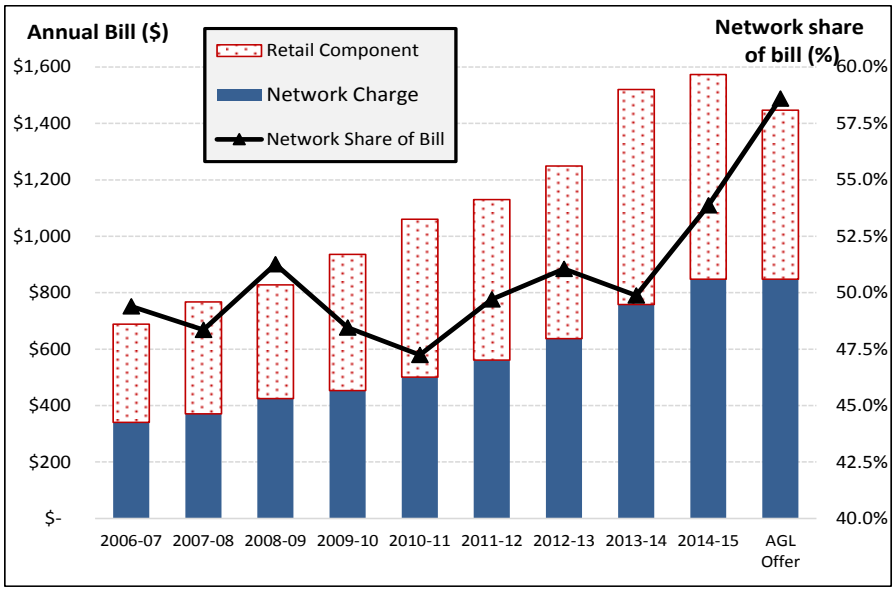
However, the consequence of the network price increases has been readily apparent both generally in the Australian electricity market and specifically in southeast Queensland and include:

- a general fall in the affordability of energy and increasing numbers of electricity customers on financial hardship programs; and
- large falls in energy consumption caused by the price response of domestic customers, the loss of industrial load as businesses in in energy intensive industries close and the accelerated take-up of replacement technologies such as solar PV.

This is a significant structural change for the electricity industry and needs be considered before networks make any further investment decisions that exacerbate the issue.

Network prices are now the single most important driver of retail electricity prices in southeast Queensland. Figure 2 shows the retail and network component of an average residential customer in the Energex region. The network (transmission and distribution) share of a competitive retail price has risen to 59 per cent in 2014-15. Importantly, network costs cannot be varied or discounted by retailers so any inefficiencies within network charges will completely overshadow the potential consumer benefits of a competitive retail energy market.

Figure 2: Queensland Residential Bill – network/ retail components



Source: Calculated for a domestic customer consuming 5 MWh pa on T11.

In this submission, AGL, as an active retailer in southeast Queensland, has chosen to focus on the Energex regulatory proposal. It is difficult for AGL to comment on Ergon Energy's regulatory proposal because its unique geographic and demographic circumstances make it difficult to compare to other distribution networks. However, many issues raised in this submission are applicable to both.

Furthermore, AGL does not have the resources to review the enormous amount of information supporting Energex's Regulatory Proposal so this submission predominantly

focusses on the revenue and price outcomes and whether they are reasonable from a customer, retailer and industry point of view.

In short, AGL finds the regulatory proposal of Energex to be less than adequate at addressing the impost that current network costs has on southeast Queensland customers.

AGL notes that Energex has proposed lower capital and operating expenditure in the next regulatory period but these reductions appear insufficient when you consider the :

- falling input costs of building infrastructure;
- less onerous network security and reliability standards that now apply;
- declining demand and consumption of electricity; and
- reducing network asset utilisation.

In fact, if the impact of the falling rate of return (which is outside Energex's control) is ignored, its regulatory proposal would again be seeking material network price increases. This cannot be supported given the current environment.

1.1. Transitional process

AGL understands that the delayed timetable for the AER consultation on the Queensland distribution networks means that network revenues and prices for 2015-16 will be based on the AER Draft Decision with "true-ups" to adjust for differences from the Final Decision in 2015-16. This is quite similar to the situation with the NSW transitional regulatory control period.

However, AGL has fundamental concerns because of the possibility of large variations between the AER's Draft Decision and Final Decision and consequently, the potential for significant network price instability in 2016-17. With commonly held expectations of network prices reductions, AGL as a retailer, does not wish to pass through a uniform price increase in 2016-17 due to a process failing.

AGL would encourage the AER to :

- ensure the process for "true-up" is fully transparent in its Draft Decision including which cost elements are included or excluded; and
- consider whether allowances for 2015-16 should be set precisely according to the Draft Decision or whether a more conservative methodology is used to eliminate the risk of price instability (viz. the possibility of a subsequent sharp price increase) in 2016-17. Under a revenue cap, the networks will not be adversely affected by such a process.

1.2. Submission Structure

AGL's submission addresses Energex's regulatory proposal in the following sections:

- Section 2 discusses Energex's energy and demand forecasts;
- Sections 3 examines capital and labour productivity trends of the Queensland utility businesses;
- Sections 4 and 5 considers the capital and operating expenditure forecasts for the 2015-20 period and impact on the Regulated Asset Base;
- Section 6 makes some comments on the weighted average cost of capital;
- Section 7 highlights AGL's views on Metering Contestability; and
- Sections 8 and 9 comment on pricing of Standard and Alternate Services.

2. Energy and Maximum Demand Forecasts

As acknowledged by Energex, energy consumption has fallen significantly since 2009-10 along with similar reductions in peak demand.

Energex has been operating under a revenue cap framework with aggressive growth forecasts underpinning its current regulated revenue requirements. That this growth has not eventuated has caused significant and unexpected price impacts over the current period as highlighted in Figure 1. This issue and its implications for network pricing structures is discussed further in section 8.

The uncertainty surrounding these annual network price changes conflicts with a deregulated retail market and has had a profound negative impact on customers' confidence in the industry, businesses' investment decisions as well as retail product development (e.g. fixed price products). It is therefore important that the energy forecasts approved by the AER are conservative noting that network cost recovery over the long-term will be unaffected because of the revenue cap framework.

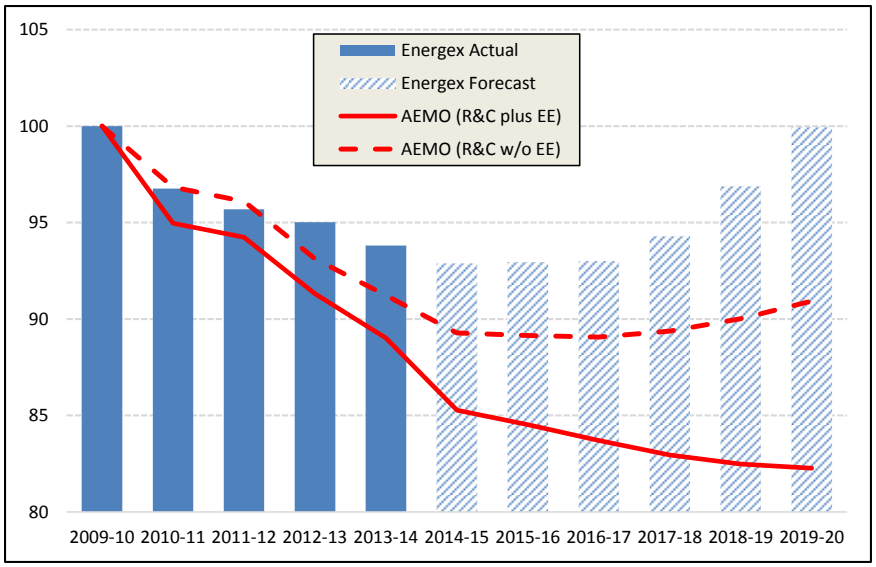
Maximum demand forecasts are also fundamental to the regulatory proposal to ensure that only essential capital expenditure is approved and further over-capitalisation of the Queensland networks can be avoided.

Energex has based its regulatory proposal on long term energy and maximum demand projections for the Energex region as provided by NIEIR. The following section compares these forecasts to the Australian Energy Market Operator's (AEMO) *National Electricity Forecasting Report 2014* (NEFR 2014).

2.1. Forecast Consumption

In Figure 3, we compare Energex's actual and forecast energy growth with AEMO's energy consumption and forecast for Queensland residential and commercial loads.

Figure 3: Energex Energy Forecast vs AEMO 2014



Source: Energex Regulatory Proposal, NEFR 2014

The index of Energex's actual consumption is consistent with an index of Queensland base residential and commercial loads in the NEFR 2014 (excluding Energy Efficiency). Both exclude the driver of increases in Queensland electricity consumption - the LNG projects - and are therefore comparable on an apple to apple basis

Energex is forecasting that annual energy consumption has bottomed out and that energy consumption will begin to grow from 2016-17 onwards. In comparison, the AEMO base residential and commercial forecast for Queensland (excluding Energy Efficiency) does not expect any positive growth until 2017-18.

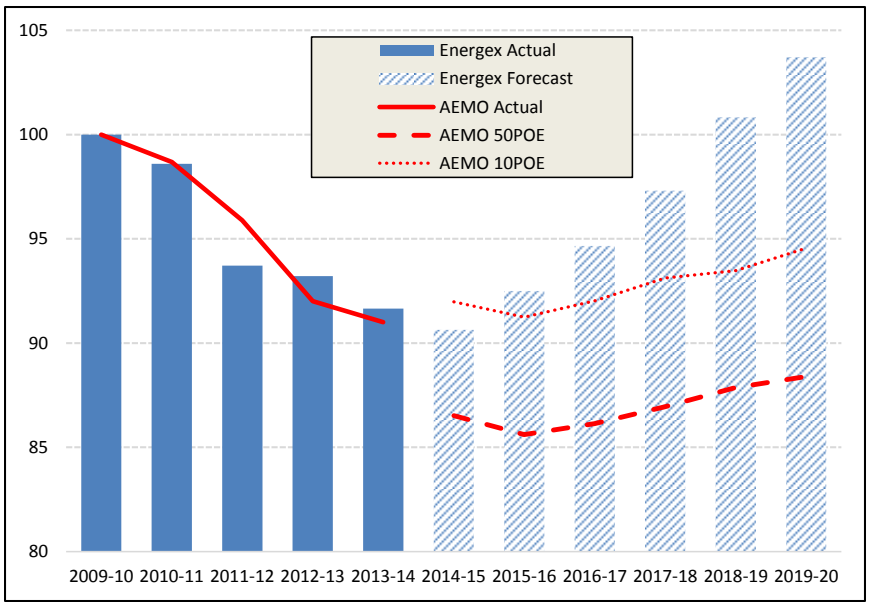
Furthermore, and important to consider, is that the Energex forecast displays a growth pattern similar to AEMO's residential and commercial forecast excluding Energy Efficiency savings.

Figure 3 highlights the large variation in forecast growth for the two scenarios. AGL consider the consumption growth rates for southeast Queensland are therefore optimistic compared with the NEFR 2014, especially if Energy Efficiency is taken into account over the period.

2.2. Forecast Maximum Demand

Figure 4 compares an index of Energex's actual and forecast growth in maximum demand (50% PoE) with an index of AEMO's recorded and forecast maximum demand for Queensland residential and commercial loads (2009-10 =100). Again, both exclude the significant LNG projects and are clearly aligned from 2009-10 to 2013-14.

Figure 4: Energex Maximum Demand v AEMO 2014



Source: Energex Regulatory Proposal, NEFR 2014

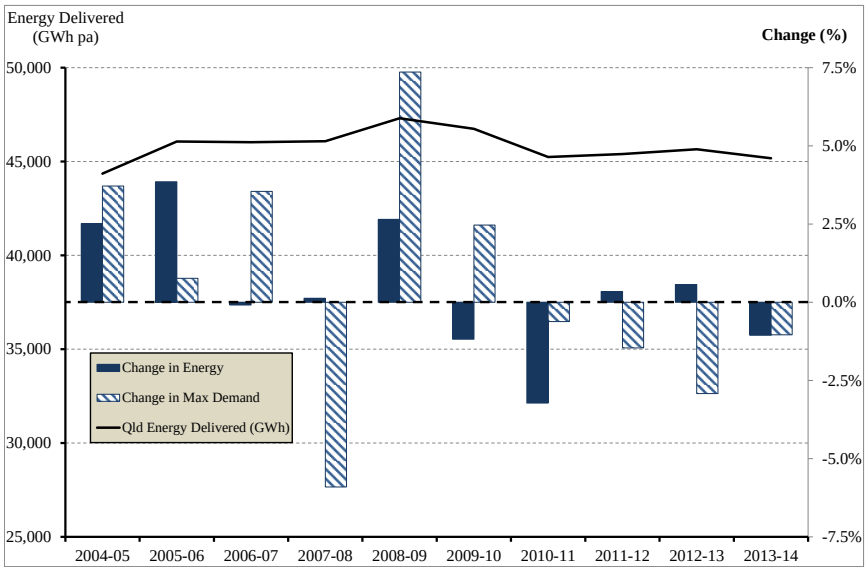
However, the Energex forecast predicts falling maximum demand to immediately return to growth from 2015-16 and forecasts significant growth over the regulatory period. In comparison, the AEMO (50PoE) forecast is for more moderate growth in maximum demand from 2016-17 onwards. The Energex demand forecast is more comparable with AEMO's 10PoE forecast.

Consequently, AGL believes the maximum demand forecasts are aggressive and should be closely reviewed before used to justify any capital expenditure.

3. Capital and Labour Productivity

Electricity consumption and demand growth have been contracting or flat in Queensland over the last 5 years and the annual changes shown in Figure 5 clearly highlight this. Total delivered energy in Queensland is also shown and in 2013-14, at around 45.2 TWh, it is actually still 4.5 per cent lower than in 2008-09.

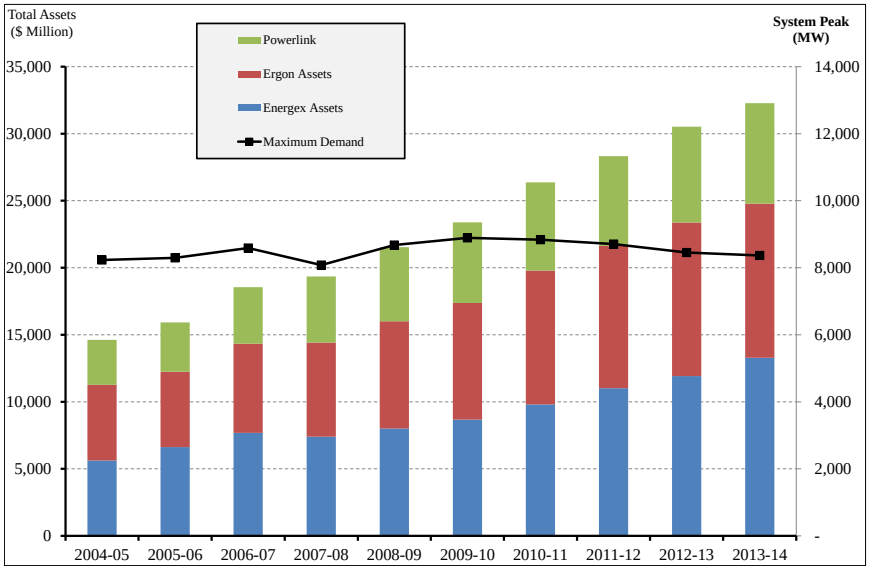
Figure 5: Queensland - Energy and Demand growth



Source: Annual reports

Large investment in Queensland network infrastructure over the last 10 years makes this a significant macroeconomic issue. In order to highlight why, AGL believes it is appropriate to examine some broad indices such as capital and labour productivity.

Figure 6: Queensland – Network Asset Base (Transmission and Distribution)



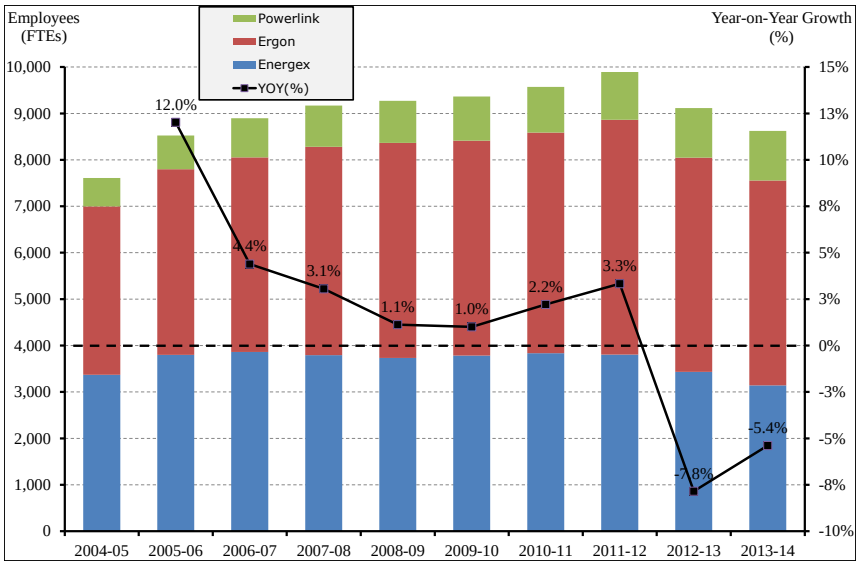
Source: DNSP Regulatory Information Notices

Figure 6 shows total network assets of the Queensland distribution and transmission network businesses have risen from $14 billion in 2004-05 to almost $33 billion in 2013-14 – an average investment of 13 per cent year-on-year.

The annual reports of these government owned network utilities also highlight the number of FTEs required to service and operate this network capital. Figure 7 shows the FTEs for each network business and in aggregate.

It shows a significant Year-on-Year increase in employees over most of the period although from 2012-13, there appear to have been marked reductions in labour. However, aggregate hours worked in 2013-14 is still 13 per cent higher than in 2004-05.

Figure 7: Queensland - FTEs



Source: Annual reports

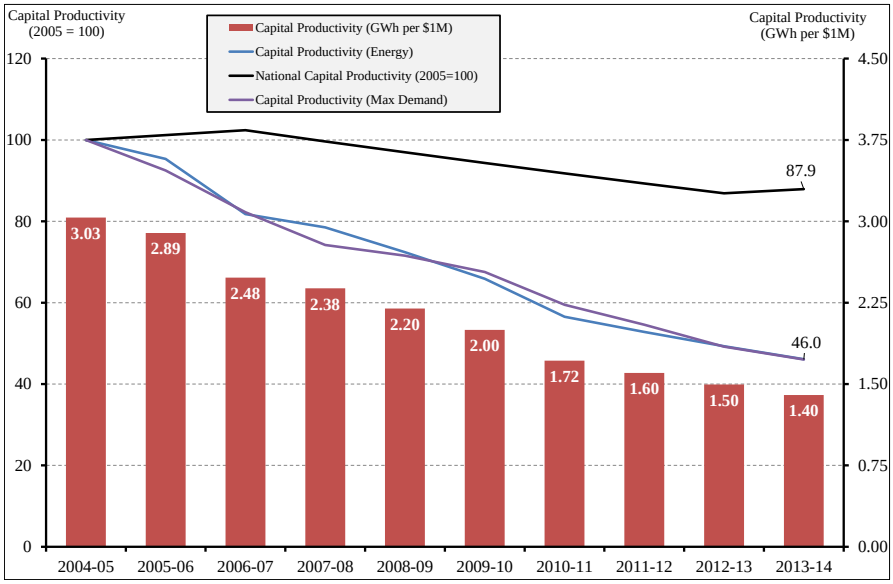
In order to examine capital productivity, Figure 8 measures energy throughput (GWh) per $1 million of capital deployed. In 2005, around 3 GWh of energy was delivered per $1m but by 2013-14 this has fallen to only 1.4 GWh. When converted into an index with the level of capital productivity in 2005 set as 100, capital productivity of the networks has fallen to just 46.0 by 2013-14.

At a national level, capital productivity is usually quite flat but as also shown in Figure 8, it has declined by 12 per cent since 2004-05. A fall in capital productivity is quite unusual at the macroeconomic level as one would not expect capital productivity to rise unless there is a technological break-though. As a result, capital productivity tends to be flat over time – i.e. when capital is deployed in an efficient manner and holding technology constant.

The capital productivity in the network businesses has fallen by 54 per cent in 9 years. This collapse in capital productivity should be taken as a signal to the AER that capital has not been allocated efficiently.

To be clear, this is not only a function of falling energy consumption. Maximum demand is a major driver of network capitalisation yet an index of capital productivity based on maximum demand rather than energy throughput produces the same results and is also shown in Figure 8.

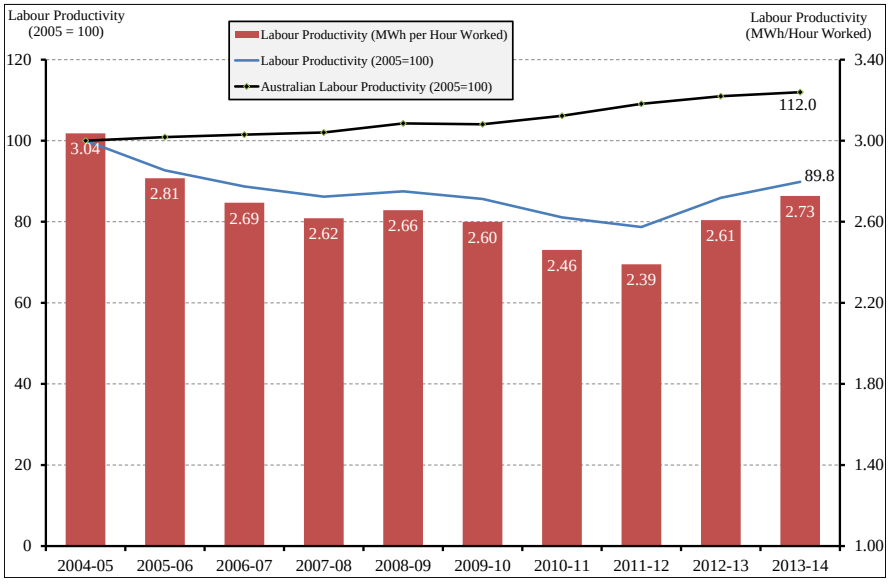
Figure 8: Capital productivity of Queensland Network



Source: Annual reports, ABS data

To examine labour productivity, Figure 9 measures energy throughput (MWh) per hour worked. This has been converted to an index with the level of labour productivity in 2005 set as 100 and compared with an index of Australian labour productivity.

Figure 9: Labour productivity of Queensland Network



Source: Annual reports, OECD data.

Average labour productivity in Australia has consistently improved over the period but labour productivity of the Queensland networks in aggregate has significantly and consistently declined from 2004-05 until 2011-12. It is pleasing to see that the labour productivity of the networks has increased markedly in 2012-13 and 2013-14 and that much of this improvement has been driven by Energex.

However, the networks' labour productivity remains 22 per cent below the Australian average so further efficiency gains should be expected.

Given this frame of reference and further projected declines in energy consumption and maximum demand, AGL does not believe the Energex Regulatory Proposals for the 2015-16 to 2019-20 period sufficiently addresses the issues of:

- poor utilisation of the regulated asset base;
- the need to avoid further capital investment; or
- inefficiency of capital and operating expenditures.

4. Capex and the Regulated Asset Base

Given falling energy consumption and reducing or flat maximum demand, the size of the Energex Regulated Asset Base (RAB) is a concern and a major impediment to correcting the high cost of delivered energy in southeast Queensland.

The Energex regulatory proposals still result in substantial increases in the real value of its RAB over the forecast period. This is not consistent with the state of the industry and it is unlikely a firm would make such investments on new long-lived assets without the certainty of the regulated framework.

AGL believes an efficient firm would focus on increasing utilisation of its current asset base by:

- limit capital augmentation to only cater for new connections;
- minimising its capital replacement program to slow non-essential asset replacement;
- delaying or deferring major capital works until the financial risks posed by decreasing network utilisation and technological replacement is reduced;
- driving efficiencies to lower the unit cost of capital expenditure; and
- reducing corporate and business overheads on any expenditure.

It appears that Energex have only addressed the first avenue for cost mitigation.

4.1. Regulated Asset Base

The issue of falling utilisation of distribution assets is a problem for all Australian electricity distribution networks but the problem is intensified in southeast Queensland because of the increased capital spending in previous years and consequent impact on the Energex RAB.

This is inarguable and is clearly demonstrated by comparing the RAB of Energex with its Victorian and NSW counterparts.

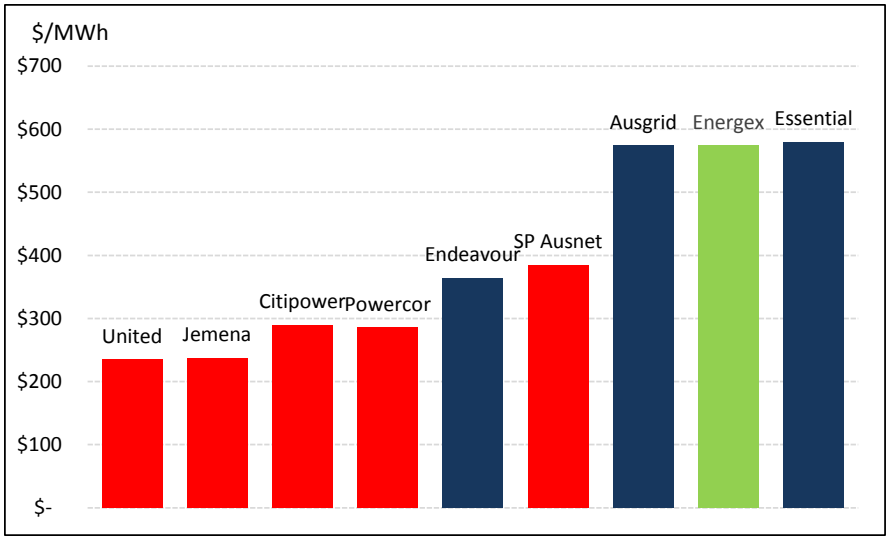
The RAB for Energex is projected to be over $13 billion in 2014-15 compared to a value of around $12 billion for the five Victorian networks in total. Figure 10 indicates the RABs of Australian distribution networks per MWh delivered with the Energex metric more than double that of the Victorian networks' average. Energex's RAB metric is on a par with the NSW distribution networks that have been shown to be over-capitalised in the recent AER Draft Decision.

Customers pay for the impact of the RAB so southeast Queensland customers are currently paying significantly higher network charges than Victorian customers for ostensibly the same service.

RAB values should remain relative stable in real terms over the long-term (i.e. RAB per MWh) but for Energex, the value of RAB per MWh has more than doubled in real terms over the last 10 years. This is partially explained by expectations of demand growth (which has not occurred) but in the current environment of falling growth and technological replacement, any arguments for continued asset capitalisation hold little weight.

The distributor's RAB is the outcome of its cumulative capital spending. While Energex has proposed lower capital expenditure in the 2015–20 period than in the 2010–15 period, its RAB is proposed to increase by around 21 per cent.

Figure 10: RAB/MWh, Energex and other DNSPs (2014-15)



Source: AER Victorian Determination, DNSP Regulatory Proposals.

The efficiency of past expenditure and the current RAB is not up for consultation but AGL believes the that Energex should be only putting forward essential capital investment in this regulatory period so that the real value of the RAB can be contained to its current levels. The proposed increase in replacement capital expenditure appears to be non-essential.

4.2. Capital Expenditure

AGL is not in a position to review the detail underlying Energex's capital expenditure forecasts nor the extensive supporting information. However, the following factors:

- declining energy consumption and no growth in electricity demand;
- the current RAB was built in order to satisfy higher energy usage and peak demand than is forecast to be achieved over the next period;
- the sector has rapidly declining capital productivity; and
- it is already outperforming higher reliability targets than will exist over the next period;

give little credence to capital expenditure proposals when they result in further real increases in the RAB.

The most significant elements of capital expenditure are generally network augmentation, asset replacement expenditure and new connections. This is certainly the case for Energex's proposal.

Over the next five years, Energex's reduced total capital expenditure is being driven by lower forecast expenditure on augmentation which is laudable. Lower peak demand and revised security and reliability standards support such an approach.

Furthermore, capital expenditure on growth or new connections has been limited to forecast customer connections. Although material, AGL readily supports the inclusion of efficient capital expenditure that is required to connect new customers or to establish additional capacity in areas of certain growth.

AGL would encourage the AER to confirm that:

- any augmentation of existing capacity is founded on realistic maximum demand forecasts as the network's forecast of peak demand appear aggressive; and
- the unit cost of new connections (including overheads) are efficient when compared to other networks.

In contrast to this moderation of capital expenditure for growth, Energex appear to have ignored the external factors on our industry when proposing replacement or renewal capital expenditure.

4.2.1. Asset renewal/ replacement

Energex have proposed submitted that maintaining levels of reliability, service levels improvements and age of network assets requires a substantial increase in replacement capital expenditure.

AGL queries the veracity of Energex's claims on the essential nature of this spending and agrees with the AER that replacement capital expenditure levels should remain relatively constant over time.

Under the regulatory framework, deferring of assets replacement simply by a year provides huge cost savings to customers over the long-term given the long-life of the assets. Furthermore, given the large investment in new and replacement assets over the last 10 year period, it is highly unlikely that any assets are in the high-risk, immediate replacement needed "bucket". If this is the case then AGL would question the efficiency of the recent large expenditure on network assets in southeast Queensland.

Consequently, AGL believes that:

- investment in asset replacement should be seeking to reach the long-term balance that aligns spending with straight line depreciation allowances; and
- the AER should review the asset replacement programs for efficiency and where possible, look to slow the capital replacement programs on a risk-adjusted basis. This would be in the long term interest of consumers and probably the long-term interests of the network given the long-life of the assets involved.

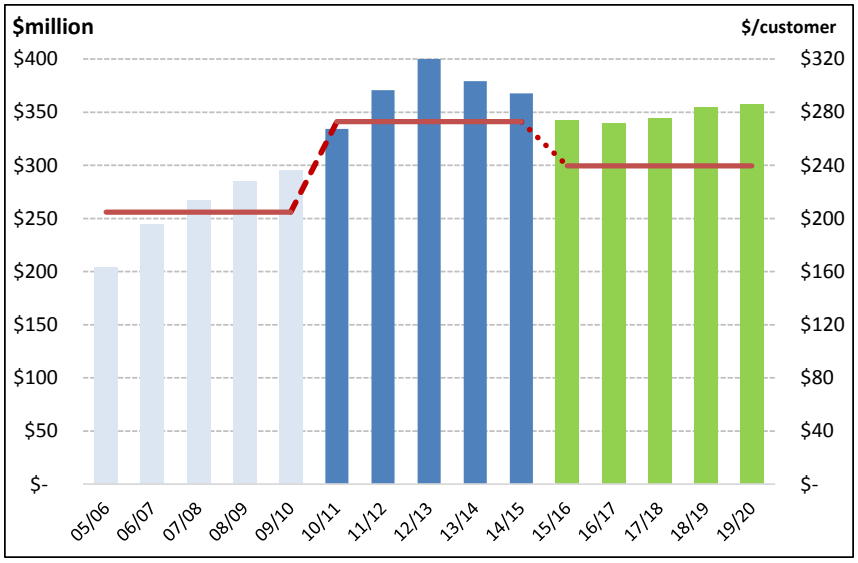
5. Operating Expenditure

As highlighted in section 3, the labour productivity of the Energex network has been increasing significantly over the last two years but has scope for further improvement to reach average Australian labour productivity.

In its regulatory proposal, Energex has forecast operating and maintenance expenditure levels at around 5 per cent lower than its actual operating and maintenance expenditure in the 2010–15 period. Energex has suggested the decrease is a result of efficiencies achieved in network management, contract management and overheads.

This is clearly positive step in comparison to the previous regulatory period. However, in our view it is still open to substantial efficiency and productivity improvements when compared with the business's headline efficiency in previous periods. Figure 11 provides a useful visual of its operating and maintenance allowances over time and the average cost in $/customer in each regulatory period. As indicated, Energex's proposal sees its average cost reduce to $240/customer per year. As substantial reduction but still 20 per cent higher than its earlier performance.

Figure 11: Energex Operating and Maintenance expenditure



Source: Energex Regulatory Information Notice and Regulatory Proposal.

Energex has indicated that key cost drivers for the proposed level of operating cost include:

- existing and new regulatory obligations and requirements;
- customer growth;
- a growing asset base with increases in line length, distribution transformers and installed capacity;
- the impact of solar PV on the LV network; and
- real growth in labour, contractor and materials costs.

However, AGL is not clear where Energex has accounted for the operational and maintenance efficiencies that should arise from its previous capital expenditure program, namely:

- lower asset ages – which would suggest less maintenance requirements;
- the reduction in network asset utilisation – which would lessen maintenance requirements; and
- the higher asset capitalisation in general with networks asserting that increased spending on assets leads to significantly lower operating and maintenance.

Furthermore, the comparison with current expenditure allowances does not adjust for the actual changes in cost drivers used in the previous period. A cursory examination of the forecast cost drivers used to derive the current regulatory determination (e.g. labour, exchange rates and material indices such as oil, aluminium, copper and steel) suggest that Energex's actual costs should have been considerably lower given these cost drivers were all considerably lower (or higher for exchange rate) than forecast.

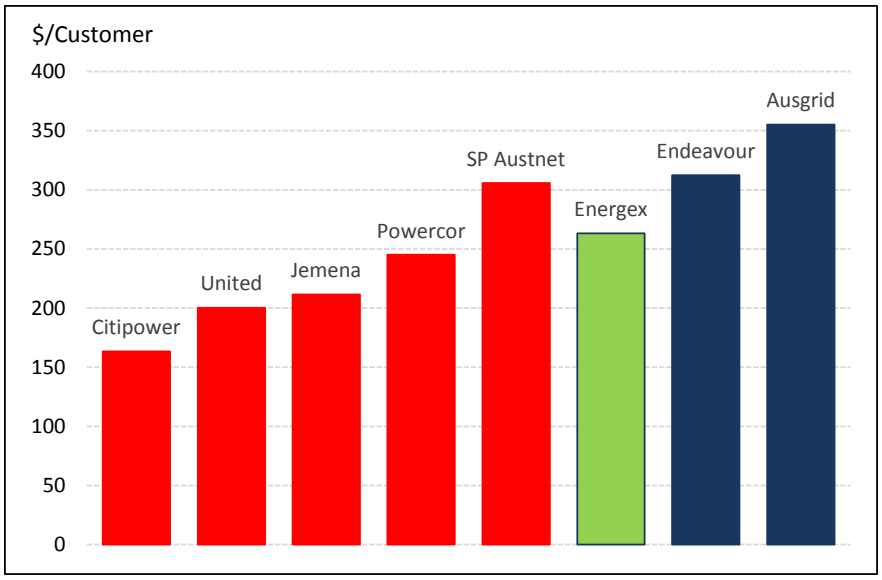
For these reasons, AGL supports the AER's use of benchmarking to review the networks cost proposals for efficiency and prudency. The AER's annual benchmarking report and methodology used in the recent draft determinations on the NSW/ACT electricity distributors is major step in this direction.

AGL does agree that benchmarking needs to take account of individual network's cost drivers where possible and would propose that spending on vegetation management is a cost component that will vary considerable with geographical and climatic factors.

In assessing the reasonableness of the Energex proposal, AGL has compared the operating and maintenance cost per customer a range of comparable networks in Figure 12.

It highlights that the operating cost for Victorian DNSPs ranging from $160 to $300 per customer, with a weighted average of $230 per customer per year. In comparison, the operating cost for relevant NSW networks range are over $300 per customer. Energex is shown to be a better performer than the NSW networks but still lags behind the performance of the non-rural Victorian networks.

Figure 12: Current operating expenditure/customer, by DNSP



Source: AER Victorian Determination 2009, DNSP Regulatory Proposals

5.1. Efficiency Benefits Sharing Scheme

The Efficiency Benefit Sharing Scheme (EBSS) is supposed to reward a network for any efficiency gains achieved during a regulatory control period while penalising them for efficiency losses.

The effectiveness of the EBSS in providing benefits to consumers is reliant on any efficiency gains exposed by the scheme being provided to consumers over the long-term. If this occurs correctly, then the benefits to consumers will eventually outweigh their short-term losses noting they continue to pay inflated costs to networks for the initial 6 year following the efficiency gains.

The difficulties facing the AER in identifying actual operating efficiencies are extensive and because of this, AGL supports the AER in removing efficiency benefit sharing schemes from the current regulatory framework.

5.2. Demand management

Energex has proposed a demand management program for the 2015–20 period in its regulatory proposal.

Demand management refers to any strategy to mitigate growth in consumption volumes or peak demand and in the current environment of reducing peak demand, it could be looked upon as redundant.

AGL does not believe this is the case and is supportive of the network encouraging demand management to provide efficient alternatives to network investments where there are net benefits to network users. These include incentives for consumers to change their demand patterns, operational efficiency programs, load control technologies, or alternative sources of supply.

Energex has proposed a suite of demand management initiatives, to reduce the need to increase network capacity. AGL would support network measures of demand management where they do not impact on any competitive markets. One such example has been Energex's power factor correction for consumers on demand (kVA) tariffs.

AGL develop energy efficiency projects to help our customers save money and achieve their sustainability and carbon reduction objectives and the Energex demand program, specifically the Power Factor Correction incentive, has been very beneficial to customer's business objectives these past 18 months. Over this time period, AGL has seen installed over 85 Power Factor Correction units in the Energex network. These installations were responsible for removing 12 MVA of peak demand and the customers have received (or are pending receipt of) over $550,000 of rebates in total. A typical installation generally sees 30 per cent of its cost covered by rebate.

Many of these customers were motivated to act on Power Correction specifically by the Energex rebates – not only to install power factor correction, but also to leverage the savings to achieve additional demand and energy savings at their site.

AGL believe that such customer focussed demand side programs represent the cheapest form of network augmentation to manage localised peak demand and should be supported. By improving customer project paybacks, demand management programs mobilise private sector capital and have amplified returns compared to straight conventional network upgrades.

6. Weighted Average Cost of Capital

Energex has proposed a lower rate of return on its assets than in the 2010–15 period when they received 9.72 per cent. Energex has proposed 7.75 per cent.

In its recent draft decision for electricity and gas network service providers across NSW, ACT and Tasmania, the AER applied it rate of return guideline after carefully considering a large amount of material submitted to it.

The AER guidelines were extensively consulted upon and AGL considers the final decision a compromise. While we would argue on different input assumptions, the headline result attempted to provide an equitable balance between the interests of consumers and investors with the AER determining conservative estimates at the top end of the calculated range for most parameters.

We note that Energex's rate of return proposal has departed from the guideline for some of the rate of return components including:

- estimating the equity beta as 0.91;
- the method for averaging the return on debt estimates; and
- benchmarking of credit rating.

AGL believes that the AER should enforce its rate of return guideline as good regulatory principle.

7. Alternate Services - Metering

AGL supports the direction of policy developments towards enhancing competition in metering, including the AEMC's Expanding Competition in Metering and Related Services Rule Change[1] (the Rule Change) consultation which proposes to:

> *"amend the National Electricity Rules (NER) and National Energy Retail Rules (NERR) to establish a competitive regime that would enable widespread investment in advanced metering technology. The objectives of these arrangements are to:*
>
> - *support the uptake of efficient demand side participation (DSP) products and energy services that promote consumer participation and choice; and*
> - *allow for the benefits of demand side participation to be captured across the supply chain."*

We firmly believe that meter provision and meter data services should be contestable in all circumstances, including new and replacement meters, and underpinned by a national framework based on national policy and rules. Competitive neutrality is a fundamental principle to ensuring smart metering and services are provided on a competitive basis. Any meter provision to a customer needs to be based on providing value to them, and must provide an incentive for the customer to engage with and support the services and benefits that smart meters enable.

AGL does not support a monopoly roll out of meters, which runs the risk of repeating the approach and results demonstrated in Victoria under the State Government's mandated smart meter rollout program.

AGL also believes that distribution businesses should be ring fenced, both structurally and financially, if they want to compete under contestable metering conditions and/or compete as a Meter Coordinator (MC) once the Rule Change takes effect. This approach will ensure that where DBs intend to compete for contestable meter or meter data provision services, they are not able to use regulated revenues for unregulated activities or allocate the costs of competitive metering provision to Standard Control Services. Competitive neutrality principles also dictate that any asset which is to operate in a competitive market and installed by DBs, should have the same risk profile as the assets with which it competes.

Under a contestable metering framework, the facilitation of a market led smart meter rollout will encourage competition and innovation in retail product design, and will result in enhanced customer service as meters record and report electricity more accurately.

This will in turn result in the elimination of estimated billing, simplify the process of moving house and reduce the need for onsite visits by field crews. Smart meters will also empower consumers through the regular provision of real-time information about household and business electricity usage, enabling customers to manage their consumption and therefore their costs. Further, it will also allow retailers to offer a broader range of products and services to consumers, meaning that consumers will have greater choice in the way they use electricity.

With this in mind, AGL broadly supports the AER's approach and rationale contained within their draft decision on the NSW distribution network proposals for 2014-19, particularly on exit fees.

We request the AER to take a consistent approach across all jurisdictions.

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[1] AEMC 2014, Expanding competition in metering and related services in the National Electricity Market, Consultation Paper executive summary

7.1. Provision of metering services

AGL believes that smart meters[2] should be viewed as an enabler of a suite of services that will deliver substantial benefits to customers. As is the case with other markets and technologies, full realisation of these benefits can only be provided through open market access and competition.

In reviewing the regulatory proposal for Energex for the regulatory control period 2015-20, AGL advises that it has several concerns. These are outlined below.

7.1.1. Policy and economic justification

In Queensland, the distribution networks currently operate under a State Government direction[3] which requires that all new and replacement meters must be 'interval meters' and be "*capable of being upgraded for use in a type 4 metering installation without the need to remove the meter*".

However, the State Government's 30 year electricity strategy released last year, makes clear that "*the Government supports a market led approach in which consumer needs drive the rollout of advanced meters and the resulting product innovation*" and that it has "*ruled out a mandated distributor led rollout of advanced meters*"[4]. .

The Queensland networks have been installing advanced meters without communication functionality in line with the State Government direction but have been operating and reading these as basic meters. As a result, Queensland customers have been paying for expensive type 4 communication-capable smart meters, but only receive the benefits of a type 6 meter.

The Energex proposal[5] indicates its intentions to continue this arrangement under an, in our view, aggressive new and replacement meter program. It appears that the increased frequency of meter replacements proposed by Energex are attempts to 'lock-in' customers on metering assets before the competition reforms can take place. This action will unfortunately create a barrier to smart meter uptake, as customers will face greater costs as discussed below.

For example, Energex has requested support from the Queensland Government to develop a number of transitional rules, including to maintain the derogation that requires networks to be exclusive providers of type 6 meters[6].

On this basis, AGL does not believe the Energex proposal has been developed in line with the overarching direction of the CEC's agreed national policy on electricity market reform or the Queensland Government's objective as outlined in their 30 year strategy.

There is a clear inconsistency in the approach to the roll out of smart meters which needs to be corrected. Under the competitive framework of the Rule Change, the Queensland Electricity Industry Code provides the networks with a methodology to increase their asset base while also serving as a barrier to entry for competitive providers. This does not align with the Queensland Government 30 year strategy and should be considered in the AER's revision of ring fencing guidelines.

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[2] The Rule Change (page 6) defines a smart meter as:
"…an advanced metering technology that comprise the meter and a communications module. The communications software enables data to be retrieved from the meter remotely and enables other smart services……"
[3] Queensland Government: Electricity Industry Code; section 9.3.7
[4] Department of Energy and Water; PowerQ: a strategy for Queensland's electricity sector; page 37
[5] Energex Regulatory Proposal – Appendix 57: Metering Strategic Plan; page 13
[6] Energex Regulatory Proposal – Appendix 57: Metering Strategic Plan; page 12

AGL believes that the Energex approach which draws on regulated funding to undertake an activity in a contestable market would be both:

1. inconsistent with existing ring fencing guidelines; and

The existing Queensland electricity guideline[7] seeks to provide the following benefit:

> *"new players in the contestable elements of the market (particularly retailing) will be able to compete on a fair and equal basis, without fear of vertically integrated incumbents being able to gain a competitive advantage, thereby creating confidence in the integrity of the market."*

Although current arrangements are consistent with the guidelines, the meters installed under the Energex proposal would operate in a competitive market following the introduction of the Rule Change, and therefore would be incompatible. That is, they would compete with fully integrated smart meters (i.e. meters which include both metering and communications functionality) deployed by regulated providers, including retailers.

AER approval for the continued rollout of communications-disabled advanced meters would not allow competitors to compete on a fair and equal basis, and as such create a significant barrier to the market led approach and to overall competition in the metering provision and services market.

2. inefficient.

Continued rollout of interval meters without communications functionality will require:

- two site visits (one to install the meter, and a second to retrofit the communications module). Site visits are one of the most expensive capital line items, and duplicating it is grossly inefficient; and
- development or upgrade of expensive IT systems in order to manage asset deployment and ongoing functionality.

Any duplication of cost is ultimately borne by the customer.

Lastly, AGL recommends the AER consider new connections as a separate and distinct activity from the replacement of aged meters.

7.2. Meter replacement program

AGL note that a key characteristic of a market led approach is that where smart meters are installed on customer premises on an 'opt out' basis, no additional financial cost is imposed on the customer unless they request additional products and services. However, the increased rate at which Energex intend to implement their meter replacement programs suggests that customer meters may be replaced prior to meter end-of-life, especially in light of likely metering competition reforms.

For example, Energex forecasts that in 2015-16 they will install over 107,000 meters, with total installation of 546,528 meters across the regulatory control period.

We believe that AER approval of such a proposal will further delay and negate the benefits of smart metering to customers in Queensland.

The provision of accurate, useful information to Queensland customers will enable them to effectively and efficiently manage their electricity usage. Customers should have access to both consumption profiles and the applicable electricity prices throughout the day, to enable them to manage and/or shift their consumption in the most efficient way.

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[7] Queensland Competition Authority; Electricity Distribution Ring-Fencing Guidelines: Final Determination (September 2000); page 8

This can only be achieved through the installation of smart meters that are enabled with remote communications capability from the outset.

We therefore encourage the AER to send the right market signal by rejecting the Queensland proposal.

AGL recommends the following process for meter replacement programs under a competitive market:

- the distribution network, as the party who has exclusive visibility of asset age on their network:
    - identify sites that need replacement every 12 months;
    - notify the FRMP which NMIs require replacement; and
    - where requested, put in an offer to the FRMP for metering replacement.
- the FRMP either accept the offer or choose a competitive metering provider of choice - under the Rule Change, this is the responsibility of the Metering Coordinator (MC);
- Where its offer has been accepted, the network (acting as MC) will apply regulated funds available under its AER determination to:
    - provide the cheapest basic type 6 accumulation meter until the customer seeks smart meter services; or
    - engage a competitive provider through commercial arrangements to install a smart meter.

7.2.1. New connections

New connections are new homes and properties, of which the metering cost and installation is recovered directly from the customer/ developer/ builder. These costs currently vary by network and state but these meter charges (asset and installation) should be minimised in the metering regulated asset base under Alternative Control Services.

In addition, AGL believe that all new meters should be connected as smart meters in a contestable market rather than the under the current approach being implemented by Energex. This would provide new customers with the benefits of smart meters sooner, and avoid the additional cost facing customers with existing metering, including the cost of communications unit refit at a later date.

7.2.2. Cost recovery for stranded assets

Following the Rule Change, the process outlined above will ensure that retailers face a competitively neutral and efficient choice in deciding whether to use a network installed advanced meter without communications functionality, under non-exclusive market arrangements. In this situation, if the retailer appoints a competitive provider who replaces the current meter with its own meter then a network should not receive any further cost recovery.

To allow cost recovery in this situation would be inefficient because it:

- would result in consumers paying concurrently for two sets of capital cost – one for the new (competitive) meter, and one for the old meter, even though the latter was replaced; and
- would encourage inefficient asset investment decisions by networks.

However, AGL agrees with network cost recovery for existing meter assets, installed under the current exclusive arrangements, when they are replaced with smart meters post the introduction of competition. Cost recovery should be based on the depreciating asset value calculated by type of meter and directly recovered through the Standard Control Services.

7.2.3. Exit fees for churning customers

In 2013, the CEC (under the former Standing Committee on Energy and Resources) proposed a set of criteria to determine the appropriate amount of cost recovery based on the average depreciated value of the stock of the existing accumulation and manually read interval meters and that it may include administration fees.

AGL notes that under these principles, Energex have proposed to charge significant cost recovery fees (i.e. exit fees) of up to $324 for customers who choose to move to another metering provider under competitive market conditions. This charge, which also includes an administration fee, is excessive and is a barrier to an efficient market – since networks will gain some benefit from smart meters regardless of who installs the meter.

AGL does not support any upfront exit fees as it will impede a competitive market for installing smart meters and is a significant barrier to entry. AGL reaffirm the approach taken by the AER in their NSW draft decision and their Issues Paper: Queensland Electricity Distribution Regulatory Proposal 2015-20, which is consistent with our views that:

> *"….exit or transfer fees proposed by Energex and Ergon are likely to inhibit development of effective competition in the provision of metering services. This is because they will be a disincentive for consumers to switch to smart meters. In turn, the potential benefits of using smart meters will be less likely to emerge."*

Furthermore, in the interests of promoting competition neutrality, any other costs associated with metering services such as fixed or incremental operating costs and IT assets should be recovered through the Alternative Control Service or annual metering charge. These are costs of operating a metering business and should not be defrayed by making all customers pay through the Standard Control Service. AGL encourage the AER to explore this option.

7.3. Summary of position

AGL broadly supports the metering approach taken by the AER in its draft determination on the NSW networks. We recognise the Energex proposal was submitted prior to this determination but believe it would stifle competition in smart metering and deliver negative impacts to consumers.

As such, AGL encourages the AER to apply a similar metering approach to all network regulatory proposals. We acknowledge that some cost recovery for stranded assets installed prior to competitive reforms is necessary but believe the AER should reject Energex's proposal to:

- continue the substantive roll-out of interval meters without communications under a new and replacement program;
- recover costs of meter assets installed post Rule Change; and
- apply exit fees to customers who seek to take advantage of increased competition in metering services under the auspice of the Rule Change.

8. Network Pricing

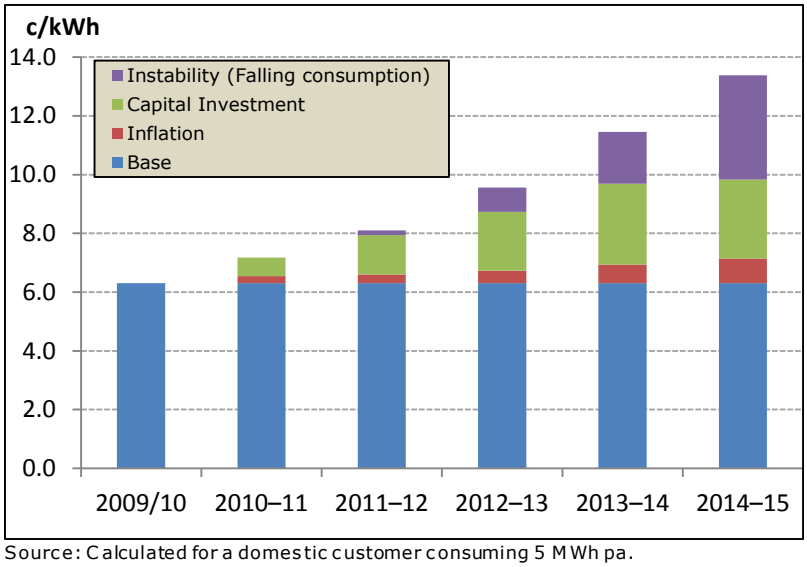
Energex's regulatory proposal contains indicative network pricing based on its draft annual revenue requirements. We have not commented on these price paths given they will obviously change significantly once the AER makes its draft decision.

AGL would note that Energex has been conducting extensive consultation on reforming network tariffs in southeast Queensland, including a Discussion Paper on *Residential and Small Business Tariff Strategy*. AGL greatly appreciates this consultation and notes the stated aim of introducing Demand Tariffs from 1 July 2016.

AGL believes this is essential to resolve the network tariff instability issue that has been a major driver of increasing the cost of electricity for southeast Queensland consumers.

Figure 13 summarises what has occurred in the last regulated period. From a base indicative network price in 2009-10, significant increases in residential network tariff were forecast to account for inflation and the extensive capital investment of Energex over the period (~60 per cent). However, with energy consumption falling under a revenue cap framework, residential network tariffs actually increased by over 110 per cent.

Figure 13: Instability of Energex Network Prices



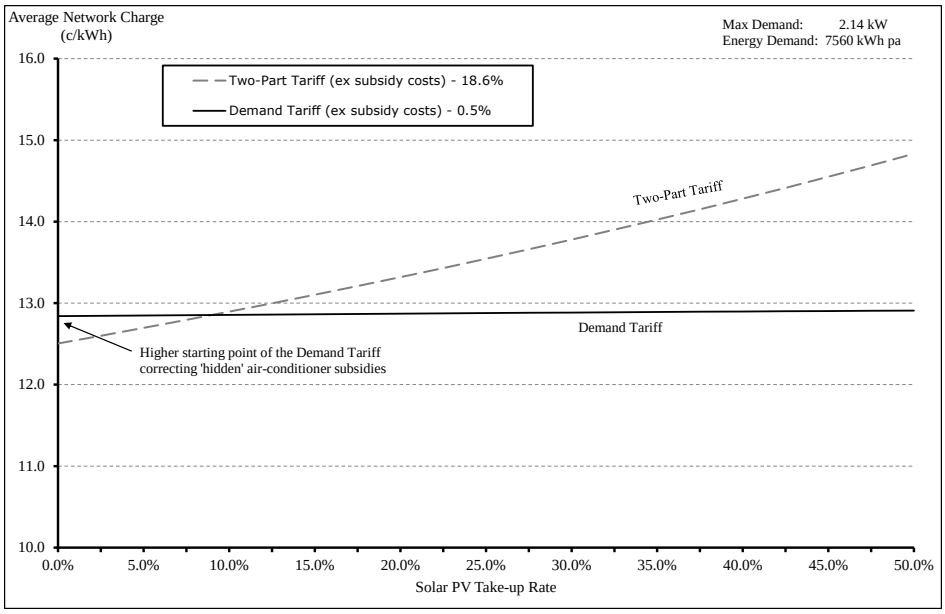
Source: Calculated for a domestic customer consuming 5 MWh pa.

The nature of the problem is therefore that the residential network tariff is a fixed/variable structural split of 20/80, dominated by the variable rate. This has historically managed in a high energy growth environment but under declining demand it has created a price spiral. That is, the associated network price increases induce further reductions in demand and non-trivial take-up of solar PV units which creates further compounding tariff increases. The variable rate tariff structure in southeast Queensland had become highly unstable and is driving inefficiencies not previously seen in the electricity industry – a situation that has changed quite literally within the last 3-4 years.

Consequently, AGL advocates moving to a demand based residential tariff as soon as possible with an appropriate transition mechanism. Not only would such a structure be more cost reflective for the distribution network but it would resolve the instability problem.

An analysis of tariff instability is presented in Figure 14 where the y-axis measures the overall average price under a 20/80 fixed/variable tariff (Two part) and under a demand tariff (20% fixed, 60% demand and 20% variable) given load is constant. The x-axis measures the corresponding Solar PV Take-up Rate of the entire 1.24 million residential customers in Southeast Queensland (based on a recent Working Paper undertaken by AGL on Network tariffs).

Figure 14: Tariff Stability with changing Solar PV Take-up Rates (0-50%)



Source: *Network tariffs: resolving rate instability and hidden subsidies*, AGL Working Paper No.45.

As could be expected, Figure 14 highlights that:

- the variable tariff (Two-Part Tariff) is the most volatile pricing system with network prices varying by around 43% depending on solar PV take-up rates between 0-50%; and
- the Demand Tariff is almost completely stable despite the variation in solar take-up.

AGL will be encouraging Energex to pursue demand tariff structures for all basic network tariffs and would expect the AER to facilitate such network tariff change.

9. Ancillary Service Fees

AGL is of the view that all proposed fees in the list of Ancillary Services need to be carefully reviewed and analysed by the AER to ensure that the fees charged to customers are fair and efficient.

The fees have raised some concerns with upcoming proposed changes in legislation. The National Energy Customer Framework (NECF) is due to be introduced on 1 July 2015 in Queensland. Of particular concern is the removal of Schedule 8 to the *Electricity Regulations 2006* which allowed the State Government to cap prices for certain services (see Table 1).

As a result there are many common services that Queensland consumers have not been required to pay for or paid a capped price on. If price caps are removed, this will increase energy costs for consumers dramatically in some cases. This is concerning, given there is insufficient explanation as to why these fees are set at the proposed levels and AGL considers further information is required to properly assess the fee level.

Table 1: Alternate Service fees

Service	Price Cap
Special Meter Reading	$33.50
Testing of a meter	$18.05
Inspection of a meter by a distribution entity	$18.05
Disconnection of supply	nil
Reconnection after disconnection	
Business hours	Nil or $45.35[8]
Reconnection is made outside of business hours	$109.10
Temporary connection of a supply of electricity by Energex during ordinary office hours	$409.60

Energex have also proposed increases to their meter maintenance fees - these increases being especially significant for CT meters that service large customers.

Table 2 highlights these fees with other state averages where applicable. AGL notes that the Energex proposed fees are significantly higher than other states as well as significant increases on Energex's current rates. Energex has not provided sufficient reasoning to justify these increased costs.

AGL understands that Energex is moving away from quoting services to fixed fees but there is no data to explain how these charges have been determined and whether they are cost reflective.

AGL considers that these fees should be thoroughly reviewed.

[8] Fee dependent on whether reconnection is a result of a disconnection under section 34 of Electricity Regulations 2006 or not.

Table 2: Meter Maintenance Fees

Category	Description	14/15 Rate	15/16 Rate	VIC Average Price	SA Price
Customer requested Meter Accuracy Testing of type 5-6 meter (physically test meter)	CT Metering	$16.41 (price cap)	$761.91 (+4543%)	$377.10	$121.82
	Not CT	$16.41 (price cap)	$365.4 (+2127%)	$297.12	$121.82
Customer requested Meter Inspection & Investigation (no physical meter test)	No fault in meter is found. CT Metering (business hours)	$98.03	$333.57 (+240%)		
Integrity verification as a result of a meter alteration. Meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment.	CT Metering (business hours)	$80.00	$793.15 (+891%)		$94.00
	Not CT (business hours)	$80.00	$128 (+60%)		$94.00
Customer requested meter reconfiguration - (Controlled Load)	CT Metering (business hours)	$81.27	$421.38 (+418%)		
	(Controlled Load) Not CT, business hours	$81.27	$91.53 (+13%)		
Customer requested meter reconfiguration - Change Time switch	CT Metering.	$81.27	$387.08 (+376%)		
	Not CT	$81.27	$122.49 (+51%)		