Agriculture Industries Energy Taskforce
Submission to ACCC discussion paper: Monitoring of Electricity supply in the National Electricity Market

Removing barriers to competitiveness for Australia's agriculture industries

December 2018

Contents

Executive Summary 3
General Comments 5
Terms of Reference 9
Response to Questions 10

This submission is provided on behalf of the Agriculture Industries Energy Taskforce: National Irrigators' Council (NIC), NSW Irrigators' Council (NSW IC), Cotton Australia, National Farmers' Federation (NFF), Bundaberg Regional Irrigators Group (BRIG), Central Irrigation Trust (CIT), CANEGROWERS, Winemakers' Federation of Australia (WFA), Queensland Farmers Federation (QFF), Pioneer Valley Water (Qld)

[redacted]

Executive Summary

The cost of electricity in Australia is putting at risk our agricultural industries' capacity to compete with the world as a provider of food and fibre. In a country with an abundance of renewable and non-renewable sources of energy and whose primary producers are among the world's most efficient, this is an untenable outcome.

Many of Australia's agricultural products (for both domestic and export consumption) use production processes that rely heavily on power, for example, irrigators who pump and pressurise water or producers who process, package or refrigerate products. Australia must have a comparative advantage for those producers - offering reasonably priced power from the grid. Instead, many producers are forced to consider off grid solutions (ie diesel) or face an uncompetitive environment and sometimes, forced out of production.

The agriculture sector has previously raised concerns regarding customers moving off grid, resulting in stranded network assets and leaving remaining grid consumers meeting the cost of high electricity prices (ie death spiral).

The Agriculture Industries Energy Taskforce (the Taskforce) has led a campaign to address the critical industry and market reform necessary to fix the broken regional electricity pricing system in Australia and to ensure that network supplied electricity is a secure and a cost-effective energy source for Australia's food and fibre producers.

Australia's agricultural industries play a significant role as economic drivers in local economies, providing flow on benefits to the national economy. Industries include cotton, rice, sugar, wine, almonds, horticulture and dairy. Energy use across the agriculture sector is variable, dependent upon the industry and the intensification of operations at various times. Energy is used for pumping irrigation water, pasteurisation, cool rooms, processing plants and moving products. Operations that require heating, cooling or irrigation have higher levels of electricity use. Some industries have stable electricity consumption year round, while in others there is seasonal variability.

The high cost of energy for the agriculture sector sits starkly against the backdrop of the excessive profits of regulated electricity and gas businesses.

Over recent years, the Taskforce has provided numerous submissions ***(Attachment A)*** to a range of Government initiated inquiries and AER pricing determinations. Yet despite this significant commitment and contribution highlighting the damage caused to Australia's increasingly efficient agriculture industries, high electricity prices have steadfastly remained, and in many cases increased over those years.

The focus has been on securing critical industry and market reform necessary to fix the broken regional electricity pricing system in Australia and to ensure that network supplied electricity is a cost-effective energy source for the sector.

We have strenuously advocated for an equitable system in the way Australia's electricity network companies calculate their network costs in submissions to the Australian Energy Regulator (AER) during the pricing determinations process. The Taskforce provided a submission to the AER as part of the examination of profitability measures for regulated gas and electricity network businesses in December 2017. ***(Attachment D)*** We recommended through that process that the AER adopt a performance measurement framework to enable an accurate assessment of the profitability of regulated electricity and gas businesses, comparable to that of other ASX entities and suggested that until that occurred, meaningful and systemic change would not be realised. We commend our submission and recommendations to the ACCC inquiry into retail electricity prices, July 2017. *(**Attachment B**)*

As part of the AER examination of profitability measures, the Taskforce supported the McGrath Nicol scoping study to identify financial performance measures used by some overseas regulators or electricity and gas network businesses, where commonly used financial performance measures that may be relevant when analysing the profitability of the regulated businesses were identified. Broadly, the Taskforce supported those measures that would allow the AER to:

- compare profit of the regulated business to the statutory profit earned by the owner of the regulated business;
- analyse the profits of a regulated business over time;
- compare the profit of a regulated business to the profit earned by other regulated businesses,
- compare the profit of a regulated business to businesses in other industries, including ASX listed companies.

Most recently, the Taskforce commissioned work by Sapere Research Group analysing the rate of return published by the AER. *(**Attachment C**).* The Sapere study found that as a group, networks are making super-normal profits because in the real world they are low risk and consequently have low financing costs, not because they are outperforming. The Taskforce objected to:

- an overinflated value of the Regulated Asset Base with no of optimisation of the asset base – something other sectors including gas have;
- pricing models that treat the industry as if it is high risk rather than a cosy monopoly;
- an industry that thinks that its desire to maximise return is more important than Australia's national interest.

Further detail is provided on the Sapere study on page 7.

Taskforce advocacy has been focused on securing fundamental changes within the NEM and energy related policies that ensure Australia returns to the lower quartile against international comparison with other high income OECD countries. We recommend specifically:

- A 30% reduction in the regulated electricity prices based on the 2014-15 financial year.
- A medium to long term price capped at 8 cents per kilowatt-hour for the electrons (R) and a similar ceiling of 8 cents per kilowatt-hour for the network (N).
- A rule change via the Australian Energy Market Commission (AEMC) to enable the AER to optimise an electricity network's regulated asset base (RAB) similar to the pre-2006 NEM rules that required the regulator to optimise the transmission and distribution network regulated asset base/s.
- A national food and fibre tariff model/s.
- Fundamental reform of the National Electricity Market (NEM) to address the lack of genuine competition, the operation of the contract bidding process and a market where consumers' interests are fairly represented.
- Stability and certainty in national energy policy to allow investment.

Introduction

The Agriculture Industries Energy Taskforce (the Taskforce) welcomes the opportunity to provide comments in response to the ACCC discussion paper regarding the monitoring of electricity supply in the National Electricity Market (NEM).

The Taskforce notes this next phase, or monitoring function, follows the inquiry conducted by the ACCC into Retail Electricity Pricing and the ACCC report titled *Restoring electricity affordability & Australia's competitive advantage,* published in July 2018. The Taskforce provided a submission to the ACCC inquiry into Retail Electricity Pricing in July 2017, and welcomed many of the report's 56 recommendations to address electricity affordability.

While much public focus has been on Government and Labor Opposition energy policies, including the National Energy Guarantee (NEG), meeting Australia's emissions targets and most recently the proposed divestiture laws, we have long sought a focus on the issues that sit outside those policy approaches, specifically the behaviour of the networks. The existing NEM provides ample opportunity to make changes within the current legislative and regulatory framework for Australia's energy markets, putting the spotlight on the actual profits made by the networks.

The ACCC inquiry represents a genuine attempt to address the inequities and the inconsistencies within the regulatory design of Australia's NEM, and the start of the process to reset the NEM which as the ACCC report suggests, has not worked well for consumers. We seek to highlight here the challenges faced by Australia's efficient productive agriculture sector due to the high cost of energy.

The failure of energy policy is compromising Australia's capacity to be a competitive global food producer and to put fresh food on the tables of Australian households. Producers have an opportunity to meet the demand of an ever-increasing global need for clean, green food and fibre, but instead face the risk of industry viability against the reality of high electricity costs. These cost pressures are imposing unrealistic barriers on the sector and driving down Australia's competitive edge.

There are approximately 85,681 farm businesses in Australia, 99 percent of which are Australian owned and operated. Each Australian farmer produces enough food to feed 600 people, 150 at home and 450 overseas. Australian farmers produce almost 93 percent of Australia's daily domestic food supply. [1] With population growth and rising personal income, the emerging middle class in Asia provides the major market for over 60 per cent of Australian agricultural exports.

Australia's farm exports earned the country $44.8 billion in 2016-17, up from $32.5 billion in 2010-11. The value of our farm exports, and indeed the future of Australian agriculture, depends largely on conditions in overseas markets, due to our high level of exports. [2]

Australian farmers export about 77% of what they grow and produce. As a sector that is highly exposed to trade, agriculture must remain competitive in the international market and consequently, reliable, affordable and sustainable electricity supply are a necessary pre-condition for the economic development of agriculture. It is also key to ensuring farmers remain profitable and can efficiently invest in agriculture.

[1] *National Farmers' Federation Farm Facts:* https://www.nff.org.au/farm-facts.html
[2] *National Farmers' Federation Farm Facts:* https://www.nff.org.au/farm-facts.html

Reform of Australia's water resources sector in recent years has resulted in greater competition for water resources. While water savings have been achieved on-farm through investment in infrastructure, the resulting higher use of energy has coincided with a dramatic increase in the cost of electricity. Analyses show that irrigators' and growers' electricity bills have increased in excess of 100% in most cases, and up to 300% for some over the period 2009-2014, mainly due to the rising cost of network charges imposed by the network companies.

Typically, regulated network charges and other costs represent around 50% to 56% of farmers' electricity bills; the actual electricity charges account for around 26%, although this is also changing rapidly. Network charges imposed by the electricity networks continue to have a highly distorting effect on the electricity market. Australian consumers are paying around twice as much for network charges as those in the United Kingdom are around 2.5 times as much as those in the United States.

We recognise the importance of gas supply and its potential role in the electricity grid with the shift away from coal supplied power and the efforts of the federal government to sure up gas supply are acknowledged. The Taskforce also supports the Vertigan Review recommendations around improvements in competition and access for existing pipeline infrastructure.

Under current market governance arrangements, existing loopholes are enabling price gouging by network businesses and preventing a fair and effective pricing structure for consumers.

The experience of Taskforce members to engage various responsible bodies within the NEM to highlight the challenges faced by the agriculture sector, has resulted in significant frustration and cynicism due to the complexity and bureaucracy of the electricity industry. This effort has demonstrated the entrenched culture of institutional and blame shifting with governance and regulation of the industry split between many bodies, where prescriptive rules and processes prevent any positive change. The myriad of regulation is increasingly divorced from reality and unaccountable, built on abstract theoretical ideas that are beyond the reality of the industry and its consumers.

The evidence of excessive industry profit and soaring prices supports our own observations that shareholders are benefiting at the expense of electricity consumers. The owners of the electricity generation, distribution and transmission assets have a dominant voice in driving the policies adopted by the regulatory bodies and take every opportunity to undermine the prospects for energy efficiency and distributed generation, both of which represent competitive threats to their business.

Sapere Research Group was engaged to provide necessary technical input in the development of Taskforce submission to the ACCC inquiry into retail electricity prices. This work confirmed that at every level of the electricity market *'costs, prices and profits across much of the sector, and at multiple points across the supply chain, exceed efficient costs, prices and profits'.*

The Sapere report showed that : *'despite being subject to price/revenue regulation, network costs, profits and prices also appear to be excessive.* And that: *There is evidence of substantial excess network capacity across many parts of the NEM. We have not been able to identify a corresponding reduction in the allowed cost of capital to accompany risk transfer associated with the move to the RAB roll-forward method for setting the RAB at the start of the following price period (replacing the previous method which included provision for asset optimisation). Consequently, it appears that network prices incorporate the double effect of excessive returns on an excessive asset base.'*

The additional work by Sapere Research Group (Oct 2018), commissioned by the Taskforce analysing the rate of return published by the AER, shows that energy networks had collectively earned economic or monopoly profits of $2.6 billion over four years.

Over this period the aggregate actual returns significantly exceed the $21.4 billion allowed or normal returns by more than $2.1 billion or 9.9 percent. Excluding Ausgrid, these economic or monopoly profits rise to more than $2.6 billion or 14.6 percent of normal returns of $18.1 billion.

The Taskforce has been consistently critical of the methodology used to allow network owners to *'exceed efficient costs, prices and* profits' as demonstrated by Sapere in Taskforce submission to the ACCC inquiry (July 2017).

The consideration of the rate of return guideline is fundamental. The rate of return methodology must be changed to ensure a reasonable rate of return to ensure that the 'gold plating' of assets is discontinued, and equity is re-established and delivered in the prices paid by consumers.

The key objective of Australia's energy policy must ensure that:

- Australia's international competitive position is guaranteed
- Equity for consumers is delivered
- Energy policy elements are not considered in isolation
- The entrenched behavioural and systemic problems in the National Electricity Market (NEM) are examined and addressed.

We have previously recommended the AER adopt a performance measurement framework to enable an accurate assessment of the profitability of regulated electricity and gas businesses, comparable to that of other ASX entities. Until that occurs, meaningful and systemic change will not be realised.

We have argued that the current regulatory framework is enabling regulated network businesses to build in unacceptable returns. The AER's lack of a performance measurement framework to understand the extent of the profitability of regulated electricity and gas businesses is enabling a continuation of gold plating.

The AER must move to a benchmarking model comparable to that of other entities. For example, the ACCC currently monitors and publishes information relating to prices, costs, profits and service quality of a range of sectors, including information on industry margins and the rate of return on assets. We support this further work to be undertaken by the ACCC as part of its monitoring role which will focus on data collection, the analysis it undertakes and expectations of market outcomes and participant behaviour against which it will view the monitoring results.

Overseas examples provide some insight into how regulators have the capacity to collect data which appropriately enables the calculation and reporting of profitability measures and to assess the financial performance of electricity and gas businesses compared to the expected returns under the framework applying in that jurisdiction.

In the UK for example, the monitoring of the financial performance of the electricity and gas transmission and distribution businesses through the collection of data, enables a calculation and report on the return on regulated equity and profit per customer. This enables a comparison with the cost of equity to determine whether businesses are outperforming or underperforming.

The New Zealand example provided in the AER discussion paper [3] is also useful. Distribution businesses regulated by the NZ Commerce Commission provide data on asset value and cash flow to enable the calculation of an internal rate of return (IRR). This is compared to expected returns on a nominal estimate of the weighted average costs of capital (WACC).

We know that the regulated asset base (RABs) of Australia's electricity networks have been artificially inflated and inefficiently grown to excessive levels. Over the past fifteen years, the networks' RABs have increased by around 400%. These growth rates now put Australian electricity networks' RAB levels significantly higher than their international counterparts; we know that the RAB per connection levels of Australia's distribution networks have been estimated at up to nine times the levels of networks in the United Kingdom.

In a submission provided to the 2014 Senate inquiry into the performance and management of electricity network companies, the Taskforce raised the issue of network companies misleading the AER in relation to their weighted average cost of capital (WACC). While these issues are complex, we view that regulatory design is the underlying reason for such failures. The determination of the WACC – an issue largely but not completely within the AER's discretion – is based on what the AER calculates to be the WACC of a 'benchmark efficient network service provider'. This calculation is by design, meant to be abstracted from the actual cost of capital of the regulated firms.

There are a range of factors across a failed market that are making Australia less competitive. The very comfortable arrangements for the owners of networks is an issue. It is crucial to Australia's future agricultural competitiveness that the base calculation of the return these owners are allowed to build into their pricing models is fundamentally reformed, to produce a reasonable rate of return to ensure the 'gold plating' of assets no longer continues.

The AER's wholesale market monitoring should be expanded and appropriately funded to include monitoring, analysing and reporting on the contract market. This should include analysing the data reported to the OTC repository (ACCC recommendation 6), ASX data and data gathered directly from generators and retailers (including through the use of compulsory information gathering powers).

The Taskforce supports ACCC report **recommendation 6:** *The NEL should be amended so as to require the reporting of all over-the-counter (OTC) trades to a repository administered by the AER. Reported OTC trades should then be disclosed publicly in a de-identified format that facilitates the dissemination of important market information without unintentionally revealing the parties involved. The requirement should be implemented to align with (or be eligible for) any OTC reporting requirements under the NEG. The AER, AEMC and AEMO should have access to the underlying contract information, including the identity of trading partners.*

The Taskforce also supports ACCC report **recommendation 42**: *The COAG Energy Council should adopt all the suggested increased penalties to all civil penalty provisions listed in the consultation paper as a matter of priority, but instead of increasing the amount to $1 million as proposed, increases should be to the same levels as parliament is currently considering for the ACL ($10 million, three times the benefit gained or 10 per cent of turnover). The civil penalties suggested for increase to the maximum level across the NEL, NER, NERL and NERR relate to provisions listed in the consultation paper, such as:*

- *information required for projected assessment of system adequacy*

[3] *AER discussion paper: Profitability measures for electricity and gas network businesses, November 2017*

- *limitations on generators' technical parameters—requirements only apply in certain circumstances*
- *key requirements that generators must meet, regardless of the circumstances of their plant*
- *the requirement to advise AEMO if a situation changes, and keep AEMO continuously informed*
- *obligations with respect to life support customers*
- *wrongful disconnection by a retailer or network service provider*
- *requirement to implement hardship policy*
- *explicit informed consent requirements for certain transactions*

It is not suggested that the task of fixing Australia's energy challenges is straight forward. Over a long period, we have provided numerous recommendations that would fit within the scope of the existing market, industry and policy structures. It is acknowledged that to seek more ambitious change would be challenging and would represent a broader commitment by all players – governments, industry, regulators, policy makers and consumers to undertake such wide reaching changes.

The sector however, will continue to advocate for outcomes that deliver equity for all consumers, restore Australia's competitive advantage and restore community confidence in a broken system. While there has been incremental change, this is not resulting in the system wide change necessary to deliver fair electricity prices. It is hoped that a focus on an analytical framework for monitoring, looking at a market failure framework, a legal framework and a distributional or equity framework will provide the appropriate backdrop for a comprehensive examination of market outcomes and participant behaviour.

Terms of reference

We note the matters to be monitored and taken into consideration under the terms of reference include but are not limited to:

i)	Electricity prices faced by customers in the NEM including both the level and spread of price offers, analysing how wholesale prices are influencing retail prices and whether any wholesale cost savings are being passed through to retail customers.
ii)	Wholesale market prices including the contributing factors to these such as input costs, bidding behaviour and any other relevant factors.
iii)	The profits made by electricity generators and retailers and the factors that have contributed to these.
iv)	Contract market liquidity, including assessing whether vertically integrated electricity supplies are restricting competition and new entry, and
v)	The effects of policy changes in the NEM, including those resulting from recommendations by the ACCC in its Retail Electricity Pricing inquiry report of July 2018.

Response to questions

The ACCC seeks views on:

1. The appropriate analytical framework/s for the ACCC's monitoring activities, including a. What frameworks are most relevant to the electricity market b. How the ACCC should incorporate these overarching frameworks into its monitoring activities.

Response: The Taskforce supports a transparent and strengthened analytical framework for monitoring the NEM against a set of expectations of market outcomes and participant behaviour, to prevent and manage poor behaviour by networks.

The three identified potential aspects of an analytical framework outlined in the discussion paper are supported, and appear to be most relevant to the inquiry's monitoring activities, that is:

- A market failure framework
- A legal framework
- A distributional or equity framework.

However, we do query why these functions have not previously been embedded as part of an analytical framework for monitoring, particularly the monitoring of legal and regulatory compliance.

As recommended in previous submissions, the AER must be afforded greater powers through the NEL *(ACCC, report recommendation 3)* to be enabled to address behaviour '*which has the effect of manipulating the proper functioning of the wholesale market, together with the necessary investigation powers and appropriate remedies'.*

In submissions to the AER on profitability measures, we recommended the AER adopt a performance measurement framework to enable an accurate assessment of the profitability of regulated electricity and gas businesses, comparable to that of other ASX entities. We included further detail on the suggested approach to undertake this work. *(Submission to the AER on profitability measures, Dec 2017) (**Attachment D**)*

With regard to how the ACCC should incorporate these overarching frameworks into its monitoring activities, the Taskforce has no specific further comment.

2. Current overlapping and inconsistent methodologies to market monitoring, and suggestions for preferred approaches.

Response: A critical question. We note that the approach suggested by the ACCC does not measure the performance of individual networks but electricity prices can differ significantly between networks within the state. In that regard, we support the observations made by the National Farmers' Federation (NFF) in their submission on this aspect: *'a breakdown of retail prices by energy networks themselves could be a useful way to examine competition (and potential competition issues) where a high spread indicates healthy competition and a low spread indicates otherwise. In regional areas, this could highlight that retailers make little effort in discounting, but may also highlight that other factors may be driving regional electricity prices.'*

3. Which retail price data collected and reported on in the REPI (ACCC Retail Price Inquiry) was insightful and should be produced on an ongoing basis as part of the monitoring function?
4. Is there retail price data not reported on in the REPI that would be useful to understanding how well the retail market is functioning?
5. Are there different approaches to the analysis of the REPI or other data that would be more useful than the analysis reported in REPI?

Response: The Taskforce notes and supports ACCC commentary regarding retail price monitoring, suggesting a consistent, NEM-wide approach to reporting on:

1. retail electricity prices
2. retail revenues, costs and profits, undertaken periodically, to help monitor the effectiveness of competition
3. wholesale market competitiveness, including reporting on new investment in generation capacity, ownership of capacity and output. This work should assist in monitoring the effectiveness of the NEG
4. analysis of the contract market, including analysing the data reported to the repository (as recommended in chapter 5 [4]) ASX data and data gathered directly from retailers and generators.

The Taskforce would support greater transparency, by way of a central repository, as suggested in the ACCC report, chapter 5.3.5: *electricity market participants being required to publish hedge contract information on a freely accessible website (https://www.electricitycontract.co.nz/) within five business days of entering into each contract. The website (would) record the contract type, quantity of electricity, price, region to which the contract relates, and a number of other statistics.*

Broadly the Taskforce supports ACCC **Recommendation 6:** *The NEL should be amended so as to require the reporting of all OTC trades to a repository administered by the AER. Reported OTC trades should then be disclosed publicly in a de-identified format that facilitates the dissemination of important market information without unintentionally revealing the parties involved. The requirement should be implemented to align with (or be eligible for) any OTC reporting requirements under the NEG.*

The AER, AEMC and AEMO should have access to the underlying contract information, including the identity of trading partners.

Also supported is **recommendation 40:** *Retail price monitoring should be streamlined, strengthened and appropriately funded to ensure greater transparency in the market, reduced costs, and allow governments to more effectively respond to emerging market issues. This should be done by:*

- *COAG Energy Council agreeing to streamline price monitoring and reporting to the AER and the AER receiving all the necessary powers to obtain information from retailers*
- *COAG Energy Council agreeing to extend price reporting for retail electricity services to small to medium business customers*
- *state governments agreeing to close their own price reporting and monitoring schemes in favour of an expanded and strengthened NEM-wide regime*

[4] *ACCC final report, Chapter 5.3.5: The need for greater transparency of the OTC market*

A NEM-wide price reporting and monitoring framework be implemented which includes a combination of price monitoring with full EBITDA data (including standardised costs to serve, attract and retain consumers, and margins), and consumer expenditure surveys. This reporting should be done on a regular basis and include customer expenditure data, based on representative customer surveys and retailer billing and offer data, and be reflective of demographic information.

6. The best way to measure the relationship between wholesale and retail prices over time, including:
    a. How wholesale prices affect retail prices and the ways in which this can be measures
    b. What types of monitoring or analysis would best reveal the relationship between wholesale and retail prices
7. What types of data are necessary to undertake this analysis.

Response: The Taskforce has no specific comment.

8. Analysis of the wholesale market that the ACCC could produce to complement the existing work of other agencies monitoring wholesale prices.

Response: The Taskforce has no specific comment in response to ACCC activity that might complement the existing work of other agencies monitoring wholesale prices. However, we draw on our comments previously provided regarding wholesale market liquidity *(ref Taskforce submission to ACCC inquiry into retail electricity prices)* ***(Attachment B).***

A key concern for any expanding retailer is the liquidity of forward hedge markets. Wholesale hedges reduce uncertainty over future wholesale purchase prices for retailers. Hedges may take a variety of forms, including swaps, options and caps.

The requirement to put in place a forward hedge portfolio arises in part due to the likelihood that customer acquisition costs will be capitalised and then recouped over a number of years. A three year amortisation period is not untypical. In this case, a retailer will need to hedge some portion of its forecast sales for three or more years into the future.

The requirement to hedge also arises because of the need to minimise the cost of credit guarantees. An expanding retailer is likely to need to procure a larger credit guarantee. This is because prudential settings scale with customer numbers and sales volumes.

Under AEMO prudential settings, the size of the credit guarantees required may be reduced by way of offsetting bilateral and other hedge arrangements registered with AEMO – known as reallocations.
In retailer interviews for the 2014 AEMC retail competition review, retailers noted that limited forward electricity wholesale market liquidity represented a barrier to expansion. One retailer interviewed expressed concern the duration was too short, the product mix was problematic and the minimum transaction level too high.[5]

A key challenge for a non-vertically integrated retailer is obtaining sufficient forward hedges (such as caps) to protect against extreme wholesale market price volatility for the entire duration of the period required to recoup the cost of customer acquisition (say three years), at a competitive price. Caps

[5] *See K Lowe and Farrier Swier Consulting, Op. Cit., page 35.*

may be available for part of this period, but not for the full period. If caps are not available for the latter half of the period, then the retailer is exposed to the risk that the cost of caps substantially increases relative to the cost assumed when offering three year pricing contracts.

This risk may be managed in part by changing retail prices, as is allowed under multi-year retail contracts. There is, however, a risk a price rise may result in customers switching away before amortisation of customer acquisition is complete.

A retailer's portfolio of forward hedges needs to be formed so that it matches the retailer's forecast aggregate demand profile for each half hourly trading interval for each wholesale market region (or fuel) it is retailing in. To the extent there are mismatches between the hedge portfolio and the actual consumption of its customers in any given trading period, the retailer is exposed to wholesale spot price risk.

In the NEM, this risk is greatest during spikes in wholesale prices. These price spikes are strongly correlated with demand spikes leading to generation congestion, as well as transmission congestion limiting transfers from other regions.[6] So during such an event, a retailer is likely to be both increasing its quantity of wholesale spot purchases and potentially being liable for substantially higher prices for each unit.

If a retailer has insufficient hedges in place, it will be exposed to spot prices. The outcome may be that actual wholesale purchase costs are substantially higher than assumed in the ITP for a given customer segment on which contracted retail prices were set.

In this case, the retailer would be selling energy for less than it cost to the retailer, and the retailer could make substantial financial losses on these sales. These losses may not be recoverable from customers and hence would need to be recovered from shareholder funds. The risk of such losses, and inability to hedge perfectly, is one of the reasons prudent retailers require a mark-up (margin) over their cost of sales and own costs.

This may be illustrated by reference to an extreme weather event. While the average wholesale price for NSW for the whole of 2017-17 was $81.22/MWh, the price may be 400 times this amount during price spikes. Price spikes are strongly correlated with high coincident system demand. Average small customer demand profiles are notable for being strongly associated with peak system demand and price spikes.

During an extreme heatwave in NSW and Queensland on 10 February 2017, wholesale prices went to $12, 221/MWh in Queensland and to $14,000/MWh in NSW.[7]

Price spikes and the more "peaky" demand profile of small customers mean that a mass market retailer's exposure to spot market prices is significantly leveraged. If a retailer acquires 10,000 new customers with an average annual demand of 6MWh, its annual liability for energy is in the order of $2,400,000 (volume times an historical average spot price of say $40/MWh) or $6,700 per day. However, as price spikes may contribute about a third of the average price, the retailer may be liable

[6] *See Implications of extreme weather for the Australian National Electricity Market: historical analysis and heatwave scenario by Sapere, dated August 2014.*
[7] *See page 5, Electricity spot prices above $5,000/MWh, New South Wales & Queensland, 19 February 2017, published by the AER on 5 May 2017.*

to $200,000-400,000 for these customers in a single afternoon. This could be sufficient to breach the AEMO Maximum Credit Limit.

If a retailer has acquired significant new customers over a period before a major price spike event, this could trigger a substantial increase in the retailer's prudential requirement with the AEMO. A similar outcome is also possible due to a steep increase in wholesale prices, as occurred in 2007/08 as a result of extended drought constraining generation output.

The Rules permit AEMO to change a participant's prudential settings at any time with one day's business notice. Any changes that result from the prudential settings require the retailer to increase its credit support by no later than 11am on the effective date. If the retailer fails to provide this increased support by the relevant time, this constitutes a default event.

The risk of being exposed to a default, together with limitations around the liquidity of forward hedge cover against price spikes, are likely to represent significant barriers to expansion for smaller retailers. This barrier could apply even to vertically integrated retailers with substantial generation, due to the likelihood of network congestion during the periods when exposure to spot prices is likely to be most significant.

Similar observations apply to gas, albeit gas market volatility is much lower than electricity. Integrated energy companies operating gas generation and with significant upstream gas investments may have a significant competitive advantage in sourcing competitive wholesale gas supplies. This is even more so, where companies are able to manage a portfolio of sales, with winter gas sold for heating and summer gas used for peaking generation. Such a portfolio would significantly reduce average upstream and transmission costs compared with a gas only retailer. This partly explains why there are no gas only retailers outside Tasmania.

A key advantage for major retailers with well-matched generation portfolios is they are less likely to be exposed to liquidity shortfalls. In effect, a vertically integrated internal retailer holds an option over the portion of future related party generation capacity that has not already been committed to external retailers.

This opens the opportunity for integrated generators to act strategically in considering how far into the future to offer forward wholesale contracts to external retailers. The incentive for acting strategically is limited if competition in retail markets is effective and retail margins are no more than as is required for retailers to recover their costs.

This may, however, change under conditions where retail markets are not effectively competitive and supra-normal margins are available. Under these conditions, it could be profit maximising for the related party generator to favour the internal retailer. Even if the internal retailer pays the same average hedge price as external retailers, the internal retailer could be advantaged in other ways, including by way of a long forward duration, or a load shape that more closely matches the relevant demand profile. Relatively small differentials in duration and/or half hourly profile may create a significant cost advantage for the internal retailer, once risk and uncertainty are taken into account.

9. Analysis of retailer and generator profitability. In the case of wholesale profitability, what analysis could the ACCC produce to complement existing work monitoring generators or retailers?

Response: The Taskforce offers no specific comment. Refer response to Question 8.

10. What methodology should the ACCC use in its approach to monitoring hedge contract markets? Are there specific metrics or pieces of information that are not currently reported that would be informative for market participants and policy makers? What types of data or information would be most valuable, and who should they be sought from?

Comment: In relation to specific methodology the ACCC might use in its approach to monitoring hedge contract markets, the Taskforce has no comment regarding specific methodology. However we commend our comments in Section 4.2.3 of the Taskforce submission to the ACCC inquiry at ***Attachment B.***

Broadly, agriculture users of electricity are forced to operate in a market environment that lacks genuine competition and appears dominated by generators and transmission and distribution infrastructure owners who aim to maximise returns. The absence of competition results in gaming on a spot market that is challenged with the transition to renewables. There is no equity in consumers being forced onto the spot market due to an inability to secure quotes from retailers for fixed term contracts.

In May 2017, the ACCC granted authorisation for a group of businesses, led by the South Australian Chamber of Mines and Energy (SACOME), to collectively bargain with retailers for electricity. The group including five of the original of 22 members, have signed up to the eight-year deal. The contract will begin in 2019. The ACCC authorised SACOME members to go to market to negotiate for a new electricity supplier.

Amendments to the Competition and Consumer Act (CCA) are providing for greater flexibility to the collective bargaining approval process for small business. We continue to support efforts by the ACCC to grant broader exemptions to groups wishing to collectively bargain for electricity.

11. The value of the types of contract market measurements reported on in REPI, and which, if any of these measurements should be prioritised to be monitored on an ongoing basis.

Response: The Taskforce has no specific comment.

12. How an efficient electricity market can be expected to operate. 13. What specific measurements or thresholds of market outcomes or participant behaviour should be used in the ACCC's electricity market monitoring?

Response: Question 12 is a broad question, however we strongly support greater scrutiny of participant behaviour. We have consistently argued for an examination of the way network companies present information to the AER during the electricity reset determinations process. This is critical in being able to set appropriate regulatory allowances. The arrangement adopted in the National Electricity Market (NEM) known as the 'propose-respond' model sees network businesses submitting their business proposals and the regulator responding to the proposals. The regulator may wish to accept the proposals, though if proposals are rejected by the regulator, the onus is on the regulator to explain why.

This model was advocated by network businesses and adopted by the Australian Energy Market Commission (AEMC) and formalized in the National Electricity Rules. Prior to these rules, under the economic regulation performed by the ACCC (for transmission networks) and state regulators (for distribution networks), the regulators determined the information requirements and businesses responded to the regulator's requests. While the networks also submitted their intentions and proposals, there was no obligation on the regulators to respond to these proposals.

With the onus of proof on the regulator under the 'propose-respond' model, network businesses are afforded an unfair advantage. During the 2010 regulatory decision, demand growth was significantly over estimated by Queensland companies and recently acknowledged by them during the December 2014 forum where it was stated that they realised after proposals were submitted that the suggested demand would not expand as they had advised the AER it would.

While the AER has the capacity to ask questions and seek further information from network businesses, it does not set the agenda. We submit that a change of process is needed with the AER setting the agenda and the onus of proof being placed on network businesses to respond to the regulator's questions.

A further issue previously raised by the Taskforce was the need for a rule change around the five-minute settlement rule where pricing was set at every five minutes, yet financial settlement is made every thirty minutes. On 28 November 2017 the AEMC made a final rule to change the settlement period for the electricity spot price from 30 minutes to five minutes, starting in 2021. Five minute settlement provides a better price signal for investment in fast response technologies, such as batteries, new generation gas peaker plants and demand response.

14. What policy issues are likely to impact on the functioning of the electricity market and should therefore be a focus of monitoring by the ACCC?
15. What methodological approaches could be undertaken by the ACCC in monitoring the impact of particular policy developments?

Response: In response to question 14, we recommend a rule change via the Australian Energy Market Commission (AEMC) to enable the AER to optimise an electricity network's regulated asset base (RAB) similar to the pre-2006 NEM rules that required the regulator to optimise the transmission and distribution network regulated asset base/s.

As suggested earlier in this submission, we know that the regulated asset base (RABs) of Australia's electricity networks have been artificially inflated and inefficiently grown to excessive levels.

The WACC/RAB Inconsistency: The AER's methodology for determining the networks' 'return on capital' allowances does not appropriately consider the impacts of RAB indexation:

- The AER's methodology for estimating the required percentage returns (for both equity and debt) is based on the returns that investors require on their actual capital investments.
- However, the AER calculates its 'return on capital' allowances by multiplying those percentage returns to artificially inflated capital bases.

This inconsistent approach, together with the AER's incorrect gearing assumptions, is resulting in the AER providing 'return on capital' allowances well above the required levels – eg it is currently resulting in the AER providing 'return on equity' allowances to Powerlink, for example, of around four times the required level.

The Taskforce has suggested a comprehensive assessment of the economy-wide costs and benefits of revising the electricity network and transmission businesses' RABs to efficient levels, to deliver real cost reductions to consumers.

There have been countless studies into the drivers of recent electricity cost increases and most of these studies have concluded that the RAB and the Weighted Average Cost of Capital (WACC) have been a driving force behind these increases.

Given the current value of the electricity distribution and transmission businesses' RAB, electricity costs will remain high *unless* there is a fundamental shift in the way the RAB is set and calculated into the future (i.e. reduced to more sustainable levels).

A further issue and in response to question 14, a survey[8] prepared for Energy Consumers Australia (ECA) and conducted by the Institute for Sustainable Futures (UTS) which included NSW Irrigators' Council, Cotton Australia and Queensland Farmers' Federation, examined the benefits of regionally embedded generation. As expected, responses in the survey demonstrated the benefits of switching to more energy efficient equipment and on-farm renewable energy. However, findings also showed that grid connection process can be challenging for consumers, and irrigation farmers have experienced difficulty connecting renewable energy to the distribution network. This is a matter that warrants close monitoring by the ACCC.

16. The proposed reporting schedule and how it may affect your business.
17. Other similar reporting requirements your business is subject to, and the degree to which the ACCC's monitoring activities could align with those requirements (or information could be shared between agencies to minimise duplicative requests).
18. Whether particular measurements are likely to be more suitable for the March or September report, given the time of year those measurements are typically produced by your business, and the time required to finalise and collate that information.
19. Factors that may impact the proposed schedule of information requests and reports, such as other regulatory obligations at similar times.

Response: No further comment on 16-19.

20. For information that needs to be requested from market participants, whether any information can be effectively captured via voluntary requests.
21. Any relevant issues regarding the timing of reporting such as the value of certain information being available at certain times of year.

Response: As suggested in Taskforce submission to the ACCC inquiry into retail electricity pricing, the ACCC could exercise its information gathering powers to institute a regular scheme for monitoring of the efficiency of retail electricity markets that deliver:

[8] *Irrigators – the flow on benefits of regionally embedded generation: prepared for Energy Consumers Australia (ECA): Institute for Sustainable Futures (UTS): Nov 2018*

- *improved transparency for customers regarding electricity offers and pricing*, and
- *increased information about competition, pricing and other practices in the supply chain that may improve customer experiences in buying electricity services*.

Data requests for retailers: We provide some proposals on how the ACCC might most effectively exercise its information gathering powers for the purpose of independently assessing the efficient costs of retail supply in accordance with best practice retail price methodology.[9] With access to retailer customer and cost data that has not been available since the removal of economic price regulation in the major retail electricity markets, the ACCC has an opportunity to make substantial improvements to previous analyses of retailer profits and costs. [10] In particular, the ACCC has the opportunity to compare costs and prices and to distinguish between price diversity and price dispersion.

The data to be requested from retailers to support this analysis includes, for each network tariff and retail tariff, for each defined reporting period:

- total retail revenue
- total sales volume
- total customer numbers
- total billing days (assists normalise for entering/exiting customers)
- total network costs
- 'meta-data' identifying the network tariff and key characteristics (structure, rates), retail tariff(s) and key characteristics (structure, rates)

The acquired data is then applied to a number of simple calculations to derive: actual unit prices paid (inclusive and exclusive of the fixed component); average consumption per customer, and average cost per customer for each unit of analysis.

A significant feature of the form of this request is that it does not require any modification of retailers' existing customer information systems (CIS). The central function of retailer revenue systems is to link metering data for each NMI/customer to the relevant retail tariffs in order to calculate customer bills, and verify obligations under the corresponding network tariff. Indeed, for internal retailer reporting purposes, these revenue systems should be capable of reporting revenue and other key data for many methods of segmenting their customer bases. This will be done, for example, to monitor customer segments at risk of being bad debtors or for targeted marketing.

The ACCC has the choice whether to ask retailers for the corresponding data for other elements of the costs stack, for example wholesale, environment and market costs, or to adopt accepted methods of estimating these costs.

[9] *AEMC 2013, Advice on best practice retail price methodology, Final Report, 27 September 2013, Sydney*

[10] *Wood, T., Blowers, D., and Moran, G. (2017). Price shock: is the retail electricity market failing consumers?. Grattan Institute; Simon Orme, James Swansson, Quantification of excess costs in QCA draft electricity retail price determination for 2016-17, CANEGROWERS, 30 May 2016; St Vincent de Paul Society & Alviss Consulting, The National Energy Market – Still winging it, Observations from the Vinnies' Tariff-Tracking Project, St Vincent de Paul Society, Melbourne, September 2015; Carbon and Energy Markets, A critique of the Victorian retail electricity market. A report for the Brotherhood of St Laurence, June 2015; Carbon and Energy Markets, Australia's retail electricity markets: who is serving whom? A report prepared for GetUp!, August 2016; Essential Services Commission, Victoria, Electricity Retail Margins Discussion Paper. May 2013*

Attachment A

Agriculture Industries Energy Taskforce
List of submissions (2014-2018)

Over a four year period, the National Irrigators' Council (NIC) and the Agriculture Industries Energy Taskforce (the Taskforce) have provided submissions to following inquiries:

- The Treasurer's review of Competition Policy (Harper Review) (Nov 2014)
- Government Energy white paper (Nov 2014)
- Government response and recommendations to Harper Review (Nov 2015)
- Government review of Agricultural Competitiveness (White paper) (Dec 2014)
- Senate inquiry: performance and management of electricity network companies (Dec 2014)
- Government review of Governance Arrangements for Australian Energy Markets (April 2015)
- AER SA Power Networks Regulatory Proposal (2015-2020)(Jan 2015)
- AER Queensland electricity distribution regulatory proposals 2015-16 to 2019-20)(Jan 2015
- COAG Energy Council review of the Limited Merits Review regime (Oct 2016)
- Productivity Commission review of Regulation of Australian Agriculture (Feb 2016)
- Independent Review into the Future Security of the NEM (Finkel review)(March 2017)
- COAG Energy Council: consumer participation in revenue determinations (Nov 2017)
- AER discussion paper (Dec 2017): profitability measures for regulated gas and electricity network business
- House of Representatives inquiry into modernising Australia's electricity grid (May 2017)
- AER Review of the Rate of Return Guideline (Dec 2017)
- Further submission to AER position paper on Profitability measures for network businesses (May 2018)
- Three submissions to the COAG Energy Council on the various developments within the National Energy Guarantee (NEG)(2018)
- AER draft position paper on Profitability measures for network businesses (May 2018)
- AER on Regulated Australian Electricity Networks: analysis of rate of return data published by the AER (Oct 2018)
- ACCC discussion paper on monitoring (Dec 2018)

Attachment B

National Irrigators' Council, on behalf of the Agriculture Industries Energy Taskforce

ACCC 2017 inquiry into electricity prices

Sapere Research Group

July 2017

About Sapere Research Group Limited

Sapere Research Group is one of the largest expert consulting firms in Australasia and a leader in provision of independent economic, forensic accounting and public policy services. Sapere provides independent expert testimony, strategic advisory services, data analytics and other advice to Australasia's private sector corporate clients, major law firms, government agencies, and regulatory bodies.

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The views expressed in this document do not necessarily reflect the views of Energy Consumers Australia.

Contents

Executive summary v

1. Introduction 13

2. Agricultural producers as energy consumers 14

2.1 Characteristics of irrigators & agricultural energy users 14
2.2 Case studies 16
2.2.1 PV Water Mackay irrigation network 16
2.2.2 Cotton industry case study 17
2.2.3 Sugar industry case studies 18
2.2.4 West Corurgan Private Irrigation District 19
2.2.5 Australian dairy industry case study 20
2.2.6 Horticulture case studies 21
2.2.7 Australian wine industry case studies 22
2.2.8 Australian pork industry case study 22
2.2.9 Central Irrigation Trust case study 23
2.2.10 Almond orchard case study 24

3. Prices, costs and profits 25

3.1 Overview 25
3.2 Excess costs throughout the supply chain 26
3.2.1 Network costs 26
3.2.2 Are network price discounts passed through to consumers? 29
3.2.3 Wholesale costs and prices 29
3.2.4 Environmental related costs and prices 30
3.2.5 Other electricity costs and services 30
3.2.6 Regulation and market monitoring 31
3.2.7 Retail margins and risk exposures 31
3.2.8 Barriers to consumer participation and engagement 31
3.2.9 Impact of higher wholesale prices on retail margins 31
3.3 Price deregulation and monitoring 32
3.3.1 Removal of price regulation 32
3.3.2 Measuring retailer profits 35
3.3.3 Current retail market monitoring 37
3.3.4 ACCC role in rigorous monitoring of retail electricity market efficiency 40
3.4 Concluding remarks 42

4. Market structure and nature of competition 44

4.1 Introduction 44
4.2 Barriers to expansion by smaller retailers 44
4.2.1 Access to customers 45
4.2.2 Customer platforms 47
4.2.3 Wholesale market risk 50

4.2.4 Differential regulation 54
4.2.5 Access to capital markets 56
4.2.6 Combined effect of barriers to expansion 57
4.3 Incentives for larger retailers 58
4.3.1 Do major retailers have an incentive to expand? 58
4.3.2 Possible tacit coordination 59
4.3.3 Contrast with NSW post-privatisation 59
4.3.4 Implications of a 2014 merger Authorisation 60
4.4 Concluding remarks 61

5. Customers and their interaction with the market 62

5.1 Introduction 62
5.2 Retail market frictions 63
5.3 (Lack of) retail innovation 64
5.4 Demand response to excessive prices 66
5.5 Concluding remarks 67

Appendices

Appendix 1 About the authors 68

Tables

Table 1 Summary of spatial (zone substation) congestion 26

Table 2 Maximum demand as per centage of firm capacity 27

Figures

Figure 1 Retail unit retailer "residue" (c/kWh, converted to 2016 values) 33

Figure 2 Per centage retailer residues 34

Figure 3 Retail unit price path 35

Figure 4 Illustration of economies of scale 50

Figure 5 Illustration of possible barriers to small retailer expansion 57

Executive summary

Introduction

This report has been commissioned by the National Irrigators Council, on behalf of the Agriculture Industries Energy Taskforce[1], to support a submission to the ACCC inquiry into retail electricity supply and pricing. This project was part-funded by Energy Consumers Australia as part of its grants process for consumer advocacy projects and research projects for the benefit of consumers of electricity and natural gas. The views expressed in this document do not necessarily reflect the views of Energy Consumers Australia.

The report responds to the issues for comment in the ACCC's 31 May 2017 Issues Paper for the said inquiry. The focus of this report is interaction between the electricity retail market and primary producers purchasing electricity to power irrigation pumping equipment.

In Section 2, we set out the characteristics of irrigators and agricultural producers as electricity users. This includes a series of case studies on the impacts of rising power prices.

In Section 3, we set out evidence that electricity retail prices substantially exceed efficient costs. We note that excess costs, profits and prices exist not only the contestable parts of the supply chain; they also arise in parts of the supply chain that are subject to economic regulation.

In Sections 4 and 5, we set out characteristics of electricity markets, including various demand-side frictions, that interact to allow excess costs, profits and margins set out in Section 3 to arise in the first place. Each matter, when viewed individually, does not appear to represent a major issue; however in combination, they appear to be sufficient to explain the outcomes discussed in Section 2.

Agricultural producers

Australia has always been one of the world's most efficient agricultural producers, able to supply domestic demand for food and fibre at reasonable prices and to compete in export markets without distorting subsidies. 75 per cent of Australia's agricultural produce is exported, it is a trade exposed sector and that means production costs and prices are critical.

Electricity costs are a core input cost for much of Australia's agricultural product. This applies to product that is produced using irrigation, and product that requires packaging, processing or refrigeration. As the case studies cited in this report show, electricity costs are now making Australian irrigated products, in particular, less competitive.

1 Agriculture Industries Energy Taskforce members: National Irrigators Council, National Farmers Federation, NSW Irrigators Council, CANEGROWERS, Queensland Farmers' Federation, NSW Farmers, Bundaberg Regional Irrigators Group, Cotton Australia, Central Irrigation Trust, Winemakers Federation of Australia.

Historically, in most parts of Australia, irrigators were able to purchase electricity under specially designed, price regulated irrigator tariffs. The design of these tariffs recognised that irrigators may use significant volumes of electricity.

The design also recognised that irrigator demand profiles are relatively "flat" and do not correspond with system wide demand peaks and associated congestion in generation and network capacity underpinned by cooling loads, particularly during heatwaves, which drive wholesale and network costs in the retail cost stack.[2]

Where irrigation tariffs remain, they are being phased out and replaced with business tariffs. This transition is coming at the same time as general increase of electricity prices above inflation, affecting agricultural production and profitability.

Efficient, competitive markets would offer irrigators, and other agricultural users, tariffs with average electricity prices that are lower than average prices for typical small business and residential customers. This is because, compared with irrigators and primary producers, typical small business and residential customer demand profiles are more likely to coincide with cooling loads.

Efficient tariff structures (if not levels) appear to apply for very large irrigators and other agricultural producers, because there is a high level of transparency over both network costs and individual demand profiles (as interval metering is used). Most agricultural producers are, however, on standard business tariffs, without interval meters. These tariffs incorporate a substantial price loading for cooling profiles that for the most part do not reflect primary producer profiles.

The fundamental concern for irrigators (and others in the agricultural sector) is the substantial rise in electricity prices well above the rate of inflation. For irrigating businesses, where electrically pumped water is a primary input to agricultural production, the rise in cost of production means that:

- costs cannot be passed on to price sensitive consumers, without affecting demand and profitability,
- agricultural production is reduced and profitability squeezed, and
- in many cases agricultural producers search out alternative sources of power supply.

Higher electricity prices are leading to many farmers making behind the meter investments in electricity efficiency and generation. Case studies across agricultural sectors and jurisdictions are provided in Section 2.2. In summary, farmers are making substantial investments to minimise or avoid rising electricity prices.

Demand response to efficient retail electricity prices is beneficial. However, as shown in this report, current costs, profits and prices across the NEM supply chain are well above efficient prices.

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2 It is important to note that 'flat profiles' here means relative to annual demand profiles and maximum annual demand, that drive wholesale and network costs. This is different from daily demand profiles that reflect the rotation of the earth. This is explained in section 3 of a 2016 report by the present authors: *Errors in Australian Energy Regulator's Draft Decision on Ergon Energy's 2016 Tariff Structure Statement*. **https://tinyurl.com/ycgjmp6r**

Demand response to inefficient prices is not economically efficient or desirable. Investment in alternative generation as a result of inefficient prices, which is not available to agricultural producers, is not consistent with the National Electricity Objective; the long term interests of consumers of electricity with respect to price, quality, safety, reliability and security of supply. Such investment often has second round effects in the form of higher unit costs for monopoly services and reduced revenue for generation (contributing to reduced generation capacity). The result is that resource misallocation within the electricity sector is transmitted into other sectors of the economy.

Prices costs and profits

The substantial run up in retail prices is described in Figure 1 of the ACCC Issues Paper. There is ample evidence that typical electricity retail prices exceed efficient aggregate retail supply costs (the cost stack). By revealing the scale and source of these inefficiencies, the present ACCC inquiry can identify steps required toward addressing inefficiencies and excess profits across the NEM for all consumers, including irrigators.

Further substantial increases in prices and costs are already in train. These include the retail price increases effective from 1 July 2017 and the network price increases due to take place in NSW and the ACT from 1 July 2018.

There is no evidence that rising network and wholesale costs are leading to a substantial moderation in public retail prices offered by the major vertically and horizontally integrated retailers. However, there are indications that rising wholesale costs, and reduced liquidity, could further weaken the pockets of retail markets where competition is effective in constraining prices.

The causes of excess costs and prices include failures of:

- economic regulation to constrain costs and prices in the regulated parts of the supply chain – transmission and distribution; and
- regulatory monitoring of competitive markets to limit costs and prices in the competitive parts of the supply chain – wholesale and retail.

Excessive costs, profits and prices across the NEM are not consistent with the NEO and are suggest a major failure in the governance arrangements established under the Australian Energy Market Agreement, 30th June 2004.

Evidence is presented in Section 3 that costs, prices and profits across much of the sector, and at multiple points across the supply chain, exceed efficient costs, prices and profits. Despite being subject to price/revenue regulation, network costs, profits and prices also appear to be excessive.

There is evidence of substantial excess network capacity across many parts of the NEM. We have not been able to identify a corresponding reduction in the allowed cost of capital to accompany risk transfer associated with the move to the RAB roll-forward method for setting the RAB at the start of the following price period (replacing the previous method which included provision for asset optimisation). Consequently, it appears that network prices incorporate the double effect of excessive returns on an excessive asset base.

Current network prices incorporate substantial premiums to reflect increases in future network investment in response to new customer connections. Under the network pricing objective and associated principles, these costs should be recovered from connection charges, not from regulated network tariffs.

It is also likely that network connection costs and prices could be reduced if restrictions on competition in network connections services, outside NSW, were removed. Removal of these restrictions would also be beneficial in terms of minimising any network congestion arising from new connections.

The current limited merits review mechanism is expected to result in further increases in regulated network prices in NSW and the ACT, effective from 1 July 2019. Removal of limited merits review does not address the fundamental inefficiency with network prices due to the existence of excess capacity and most likely excess returns. These excess costs will continue to be permitted under the NER whatever changes are made to merits review.

Wholesale costs and prices have risen substantially over the last 18 months and are now clearly excessive relative to efficient generation costs. This reflects a complex set of factors including reluctance by the private sector to invest in new thermal generation due to ongoing uncertainty over carbon emissions abatement policies and lack of clarity over legal rights to emit carbon.

Reflecting ongoing policy uncertainty regarding future policy around pricing of carbon and obligations for low or zero emissions energy, in our view, environmental related costs and prices are higher than they should be. For example, over 2016 spot prices for Large Scale Renewable Energy Certificates were at or close to the post tax penalty cost of non-compliance with the Renewable Energy Target scheme, for extended periods. These prices have recently fallen, reflecting increased investment in renewable energy, but it is likely a significant premium remains.

Retail prices, now substantially exceed aggregate supply costs plus efficient and prudent retailer operating and other costs. This reflects the widespread presence of excessive retail margins.

On reviewing the most recent publicly available evidence, there is no reason to believe that the retailer margins of the major, vertically and horizontally integrated retailer margins have been adversely affected by higher wholesale prices. Smaller retailers, without physical hedges in the form of generation, are likely to be experiencing substantial pressure on their margins. This affects only a minority of retail customer accounts and further reduces competitive constraints on retail prices.

Price deregulation and monitoring

Safeguards to deter any exercise of market power – market monitoring – are not effective. In the absence of direct price regulation, energy retail market monitoring ('light touch' regulation) is intended to be a safeguard to deter any firms or groups of firms with market power from exercising such power, including by way of monopoly pricing. Monopoly pricing incorporates profits in excess of those required to compensate capital providers, including a margin for prudent risk.

When retail price caps were removed in the major NEM retail markets, no systematic market monitoring arrangements were put in place. This contrasts with other markets following removal of price regulation, where market monitoring arrangements are put in place and where suppliers have legal obligations to supply data and information (disclosure requirements). Well known examples include fuel price and airport monitoring undertaken by the ACCC.

Limited retail market monitoring is undertaken by the AEMC, AER and some State regulators including IPART and the Essential Services Commission Victoria. For the most part, these reports do not focus on the effectiveness of competition to constrain margins and discipline efficient prices. Some limited retail market monitoring is undertaken by jurisdictional regulators but this is hampered by unwillingness so far to exercise data gathering powers.

The AER undertakes substantial wholesale market monitoring and exercises its information gathering powers. However, the AER's retail market monitoring does not assess whether prices and margins are efficient and consistent with competition.

This most likely reflects the Australian Energy Market Agreement which suggests responsibility for retail market competition rests with the AEMC. While the AEMC has undertaken a series of reviews considering the effectiveness of retail competition, its conclusions are not evidence based.

The AEMC has undertaken a series of reviews on the effectiveness of retail competition. However, these do not test whether competition is effective. In its first national review of the effectiveness of retail competition, in 2014, the AEMC concluded that Victorian retail prices substantially exceeded prices in other markets, when normalised for differences observable in supply costs. While concluding that retail competition was effective, it did not entertain the possibility that retail prices incorporated excess cost recovery, reflecting the existence of market power on the part of retailers. In other words, its conclusion was not based on evidence.

Nevertheless, the AEMC's conclusion may have influenced a decision by the Australian Competition Tribunal to overturn a decision by the ACCC to reject AGL Energy's purchase of Macquarie Generation. This is because the Tribunal assumed retail margins were normal and hence there was no incentive for vertical foreclosure. The AEMC's conclusion on retail competition may also have influenced a later decision to reject proposals to constrain retailers from unilaterally changing prices during fixed term retail contracts.

There is an opportunity for the ACCC to exercise its information gathering powers to develop robust estimates of efficient aggregate electricity supply costs and thereby determine the extent actual prices exceed efficient prices. By exercising its data gathering powers, the ACCC may significantly reduce the uncertainties associated with estimating costs and profits, and offer a more robust set of conclusions regarding whether prices are consistent with the existence of workably competitive markets and effective economic regulation.

In turn, that transparency will enhance the ability for consumers, the intended beneficiaries of the NEM, to understand and test both supply and demand side practices in the market that may be obstacles to improved customer experiences in buying electricity services.

Market structure and nature of competition

Section 4 focuses on the supply side of retail electricity markets, and regulatory and market barriers to competitive energy markets being effective. It sets out a series of interconnecting hypotheses on how regulatory, market and other factors can have the combined effect of limiting the effectiveness of competition.

In combination, regulatory and market barriers have the effect that any smaller retailer seeking to expand is likely to face higher risks and costs than the major retailers with which it is competing. These barriers make it difficult for smaller retailers to reduce the aggregate market share of the larger retailers. As a result, smaller retailers may acquire customers based on offering lower prices compared with large retailers.

Collectively, however, smaller retailers seem unable to create a dynamic under which broad retail prices converge toward costs. A key barrier to expansion by smaller retailers is customer acquisition.

By contrast, statements by two of the three major retailers indicate their objective is to maximise their share of customer value, rather than increase market share. The fourth largest retailer, Snowy, has also expressed similar views. This raises the question whether the major retailers have strong incentives to expand and whether rivalry between major retailers is effective in constraining retail prices.

Customers and their interaction with the market

Effective markets require both demand and supply sides to be efficient and effective. Section 5 focuses on the demand side, and demand side frictions that contribute to and help explain why retail market outcomes do not appear to be consistent with workably effective competition.[3]

Retail market frictions principally take the form of high search costs for consumers (the Diamond Paradox). This means that competition is only effective in constraining prices in some smaller market segments. The key frictions are search costs and switching costs, with search costs generally agreed as being the most important. Search costs have significant impacts on market efficiency.

One example of this is the Diamond paradox.[4] This occurs when, despite there being multiple firms, they can charge monopoly prices. If there are material search costs, and consumers think that firms are all charging at the same level, consumers may not be bothered searching for better prices but simply choose a firm at random (or where default contracts are available, make no choice at all). The profit maximising response for firms is to charge a monopoly (significantly higher than efficient cost) price for these consumers.

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3 Workably effective competition is a far less demanding standard than perfect competition.

4 See a brief explanation here: http://economix.blogs.nytimes.com/2010/10/11/the-work-behind-the-nobel-prize/?_r=0

Potential outcomes

This report sets out a host of regulatory and market issues that inhibit workably effective competition in retail electricity markets across most of the NEM. These are for the most part set out in Sections 4 and 5. Viewed individually, each matter or issue may appear relatively innocuous. We would stress that the ACCC needs to view these issues collectively, noting that many are interactive and mutually-reinforcing. Key issues include:

- A small but significant set of remaining regulatory privileges for some but not all retailers
- High consumer search costs, in part due to complex tariffs and lack of consumer engagement
- Substantial barriers to expansion by smaller retailers
- Market structures including vertical and horizontal integration (a merger approval that appears to have been influenced by a view that retail margins are normal (and hence there is no incentive for vertical foreclosure)
- Weak incentives for rivalry among major, vertically integrated retailers and the potential for tacit collusion; and
- The absence of effective retail market monitoring to constrain any retailer market power.

By exercising its data gathering powers, the ACCC may significantly reduce the uncertainties associated with estimating costs and profits, and offer a more robust set of conclusions regarding whether prices are consistent with the existence of workably competitive markets and effective economic regulation. Being able to conclude that there are market and regulatory failures, the ACCC may then be able to test hypotheses on the origins of these failures and begin to identify remedies. It is suggested that the ACCC acquire data from retailers necessary to arrive at robust findings regarding:

1. Structural, competitive or behavioural issues in the industry;
2. Identification of any behaviour that raises concerns under the Competition and Consumer Act 2010;
3. Improved transparency regarding electricity offers and pricing;
4. Increased information about competition, pricing and other practices in the supply chain that may improve customer experiences in buying electricity services; and
    (a) For the reasons set out earlier, the ACCC Inquiry should also review the regulated components of the supply chain.

Depending on its findings, we would also suggest the ACCC could consider and make recommendations on options for establishing a framework for effective ongoing regulatory monitoring of electricity and gas retail markets. This reflects our observation there is no such monitoring at present. Precedents in the airports and petrol retail sector may be useful in this regard.

1. Introduction

This report has been commissioned by the National Irrigators Council, on behalf of the Agriculture Industries Energy Taskforce[5], to support a submission to the ACCC inquiry into retail electricity supply and pricing. This project was part-funded by Energy Consumers Australia as part of its grants process for consumer advocacy projects and research projects for the benefit of consumers of electricity and natural gas. The views expressed in this document do not necessarily reflect the views of Energy Consumers Australia.

The report responds to the issues for comment in the ACCC's 31 May 2017 Issues Paper for the said inquiry. The focus of this report is interaction between the electricity retail market and primary producers purchasing electricity to power irrigation pumping and other equipment. The report draws on previous work undertaken by the authors. Our relevant credentials are briefly summarised in Appendix 1.

The report commences in Section 2 with a description of the agricultural producers as a particular segment of consumers for whom energy is a key input in their productivity. This includes case studies of the price increases faced by agricultural producers and various responses, for a range of primary producers varying in scale, energy use, agricultural sectors and regions around Australia.

Following Section 2, the remainder of the report follows the structure of the ACCC's Issues Paper:

- Section 3 sets out evidence that costs, prices and profits across much of the sector, and at multiple points across the supply chain, exceed efficient costs, prices and profits. It includes a discussion on the impact of the removal of price regulation. It also evaluates the effectiveness of energy retail market monitoring by the relevant regulators in constraining pricing behaviour. We note that excess costs, profits and prices exist not only the contestable parts of the supply chain; they also arise in parts of the supply chain that are subject to economic regulation.
  Section 3 also includes a section proposing data the ACCC could request from retailers, in order to overcome data constraints to drawing robust conclusions regarding costs, prices and profitability across the sector.
- Section 4 sets out a series of interconnecting hypotheses on how regulatory, market and other factors can have the combined effect of limiting the effectiveness of competition. Each matter, when viewed individually, does not appear to represent a major issue; however in combination, they appear to be sufficient to explain the outcomes discussed in Section 3.
- Section 5 focuses on demand side frictions that contribute to and complete a possible explanation as to why retail market outcomes do not appear to be consistent with workably effective competition.

5 Agriculture Industries Energy Taskforce members: National Irrigators Council, National Farmers Federation, NSW Irrigators Council, CANEGROWERS, Queensland Farmers' Federation, NSW Farmers, Bundaberg Regional Irrigators Group, Cotton Australia, Central Irrigation Trust, Winemakers Federation of Australia.

2. Agricultural producers as energy consumers

A fundamental concern for irrigators (and others in the agricultural sector) is the substantial rise in electricity prices well above the rate of inflation. For irrigating businesses, where electrically pumped water is a primary input to agricultural production, the rise in cost of production means that:

- costs cannot be passed on to price consumers without affecting demand and profitability,
- agricultural production is reduced and profitability squeezed, or
- in many cases, agricultural producers search out alternative sources of power supply.

2.1 Characteristics of irrigators & agricultural energy users

Electricity is a key input to the production of many of Australia's most important agricultural products for domestic consumption and for export. Australian consumers expect to have reasonably priced fresh food and locally produced fibre, and the Australian people and their Governments consistently highlight the potential for Australian agriculture to generate jobs and income through exports.

Electricity is a major input cost for agricultural producers. Electricity loads include pumping for irrigation, refrigeration and processing.

Irrigators are a diverse group of customers. They span a range of regions and different agricultural primary sectors, scale and types of irrigation and irrigation patterns (and corresponding energy use). Nevertheless some overall observations are possible.

Historically, in most parts of Australia, irrigators were able to purchase electricity under specially designed, price regulated irrigator tariffs. As retail electricity markets have been opened to competition, regulated irrigation tariffs have largely been replaced by business tariffs.

The design of regulated irrigator tariffs recognised that irrigators may use significant volumes of electricity. It also recognised that irrigator demand profiles are relatively flat.[6] While irrigation demands are typically higher during summer and sometimes during heatwaves, the available evidence suggests the consumption of electricity for irrigation purposes generally does not drive or correspond with maximum demand and associated congestion in

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6 It is important to note that 'flat profiles' here means relative to annual demand profiles that drive wholesale and network costs, and not daily profiles that merely reflect the rotation of the earth. This is explained in section 3 of a 2016 report by the present authors: *Errors in Australian Energy Regulator's Draft Decision on Ergon Energy's 2016 Tariff Structure Statement*. **https://tinyurl.com/ycgjmp6r**

generation and network capacity that drives wholesale price spikes.[7] As noted in the AEMO's 2017 Electricity Forecasting Insights:

> *Maximum operational demand (10% probability of exceedance, or POE10) is driven by cooling loads and occurs in summer in all regions except Tasmania… page 7*

The issue with cooling loads is that they drive spikes in demand and also network and wholesale market congestion. This in turn drives high costs and prices and represents a substantial portion of total electricity supply costs over a year.[8] By contrast, irrigation equipment does not use more electricity during extreme heatwaves.

This means that in markets providing efficient prices, irrigators should be paying average electricity prices that are lower than average prices for typical small business and residential customers. This is because, compared with irrigators, typical small business and residential customer demand profiles are more likely to coincide with cooling loads.

Agricultural producers do have some cooling loads, notably for temperature controlled food storage and freezing processes. For these applications, demand profiles are more akin to refrigeration. Load increases during extreme heatwaves. However, even during other times, refrigeration equipment may still be running. This contrasts with some air-conditioning when the equipment may only be operating during certain times. Consequently, the load factor for such refrigeration loads is better than that for air-conditioning loads.

The available customer switching data suggests that consumers outside cities – possibly including irrigators – may be less likely to switch retailers. Irrigators have attractive load profiles and significant volumes compared with other users. However in addition to increases to prices in general, irrigators may face higher prices through the mismatch of the load profile costs and tariff prices under business tariffs, and are not seeing competitive tariffs offered by the market to supply their demand. Excessive prices and demand response by agricultural producers

Up until the last decade, electricity demand was considered to be relatively inelastic – demand would not respond to increases or decreases in price. The substantial run up in retail prices as described in Figure 1 of the ACCC Issues Paper is, however, contributing to a substantial demand response by consumers in general. Coincident with the increase in prices across the NEM, aggregate demand has been decreasing.

The electricity sector represents a significant input for the production of Australian food and fibre. Energy costs are particularly significant for irrigated agriculture, which can see more than a third of overall cost of production taken by up by energy. It is also significant for many aspects of agriculture overall, with processing, packing and cooling all requiring energy usage.

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7 Note that in many areas, for small business customers, there is no widespread metering and hence there is limited information about irrigator profiles. However, where irrigator profiles have been analysed using demand interval data, this shows there is no increase in electricity demand during the limited periods of the year where maximum demand that drives a requirement for new capacity investment may be required.

8 See for example Section 3 of a 2014 report prepared by the present authors for the Australian Government entitled *Implications of extreme weather for the Australian National Electricity Market: historical analysis and 2019 extreme heatwave scenario*. https://tinyurl.com/y97glnor

Failing to respond to electricity price increases is not an option for agricultural producers – they cannot pass on costs to consumers, particularly for export markets. This can result in various combinations of reduced production or investments behind the meter to offset the impact of price rises, including increasing energy efficiency and use of alternative energy sources.

To the extent that prices significantly exceed efficient costs, the suppression of demand and investments in demand response to inefficient prices is neither economically efficient nor desirable. The result is that resource misallocation within the electricity sector is transmitted into other sectors of the economy. In the agricultural sector this is critical not just for the farming community, but also the downstream agricultural processing industries and irrigation infrastructure industries reliant on the productivity benefits of irrigation, as well as the regional businesses and community looking to those industries for their income.

2.2 Case studies

The case studies set out below reflect the responses to rapidly rising electricity costs by agricultural producers, particularly irrigators pumping water as an essential input to agricultural production. These examples reflect the common challenges of increasing electricity costs across jurisdictions and agricultural sectors. The case studies also present examples of actions farmers have taken to reduce energy costs that include[9]

- reducing demand for network provided electricity by reducing production
- reducing demand for network provided electricity through increasing energy efficiency;
- substituting demand for network provided electricity with distributed generation; and
- collaborating with other energy users to strengthen bargaining power in electricity markets.

2.2.1 PV Water Mackay irrigation network

PV Water is a not for profit entity operating an irrigation water supply network at Mackay supplying 250 customers for irrigation of sugar cane. The viability of these farmers supports the local sugar milling industry and the regional businesses and community.

The irrigation network combines five irrigation Schemes with 4 major pump stations, PV Water supplies a total irrigation water allocation 47,390 megalitres per annum. The irrigation supply supplements effective rainfall, and the network was established to aid with crop survival and increased productivity. The total project cost in 1993 dollars was $56.7 million by a joint venture between the Commonwealth and Queensland Governments, Mackay Sugar Limited and the irrigation network customers.

The network was designed to utilise off-peak electricity tariffs, not only to minimise electricity costs, but to maximise efficient use of both the electricity network infrastructure and the available water resource. Irrigation customers similarly operate their individual on-farm reticulation infrastructure during off-peak electricity tariff periods, maximising resource

[9] The case studies have been provided by members of the Agriculture Industries Energy Taskforce. For the purpose of this report, Sapere is interested in the scale and impact of electricity price increases. The views expressed in the case studies do not necessarily reflect the views of the present authors.

efficiency by avoiding higher evaporation rates and spray drift associated with application of irrigation water during hotter, generally more windy daylight hours. Once again, this also flattens the load profile for electricity network infrastructure.

Electricity comprises a significant component of production costs and as price-takers, many irrigators are choosing to gamble on rain falling rather than switch on electric irrigation pumps. Sugar cane is a robust crop and will not necessarily die under this strategy, but yield is dramatically reduced due to a lack of water reaching the crop in peak growing periods.

From commissioning of the irrigation network up to all PV Water electricity consumption was under Business tariff 22. Already between 2009 and 2013 in electricity costs increased 52 per cent. Sugarcane farmers are not indifferent to these increases, consequently water demand as decreased by nearly 20 per cent despite lower rainfall.

In 2012/13 the Queensland Competition Authority (QCA) restructured electricity tariffs on the path to 'cost reflective' pricing. On a transitional basis, PV Water was able to move to Irrigation Tariff 62 (T62) which maintained a clear differential between peak and off-peak tariffs. With total demand in excess of the 100MWh threshold, it is proposed that PV Water moves to Large Business Tariff 44 Demand Small (T44), with Time of Use Tariff 50 (T50) put forward as a possible alternative tariff option.

On top of historic prices increases, PV Waters modelling suggests moving to T50 will increase costs by 110 per cent while moving to T44 will increase costs by 145 per cent. There is no capacity to absorb such price increases.

PV Water has engaged engineering consultants SMEC to investigate existing energy and water use with a view to maximising efficiency. While efficiencies such as variable frequency drives and increasing existing water storage capacity have been identified, these will not reduce consumption below the T44 tariff threshold, so PV Water must investigate supplementary energy source, either diesel or solar, to reduce demand or going completely off grid.

At PV Water's most recent AGM, irrigators were asking the very troubling question "should we invest in on-farm infrastructure, or will the electricity component of water charges make using water unaffordable, and effectively close our scheme, further curtail our productivity, and threaten the local sugar industry?".

2.2.2 Cotton industry case study

Gunnedah farmer, Scott Morgan grows cotton, wheat and other grain on his 730 hectare Liverpool Plains property. His farm is dependent on bore water, requiring significant energy to lift. His 40kW mixed flow pump moves 30 ML per day in irrigation season.

Mr Morgan has installed 160 amorphous silicon solar panels to power his bore lift pump. He installed a travelling irrigator fed by a two-kilometre pipeline which has eliminated the need for two lift pumps and at the same time installed the solar array to power the remaining lift pump. The solar power cost was close to $60,000, but the combined efficiency of this system has shaved $18,000 off his power bill.

Mr Morgan reports the system is working well, noting the capacity for solar as a good technology to support agricultural production. A key challenge for irrigators is the seasonal nature of electricity demand where irrigators generally only pump high volumes of water three months of the year. While he is keen to go fully solar, viability of the system would depend on receiving income for generation capacity off season.

The price of solar panels has come down dramatically where a system to meet his energy needs would now cost around $20,000. For Scott Morgan this means that his payoff time is three times longer than otherwise. For other irrigators in the region, the threshold for switching is three times lower as prices are flagged to increase by up to 40 per cent.

2.2.3 Sugar industry case studies [10]

Kelvin Griffin is a cane farmer at Bargara, near Bundaberg, on Queensland's central coast. The high cost of electricity was a key factor in his decision to invest $100,000 in a solar system designed to power his farm's high-pressure irrigation pumps. To reduce their electricity costs, the family was irrigating off the head pressure on the SunWater system and using grid power sparingly on weekends or at night using cheaper tariffs. This approach however, was holding back their production and as electricity prices rose, production dropped by around 15% on the area which required high pressure irrigation.

In 2014, the family made the decision to move to solar powered high-pressure irrigation. The initial outlay was $20,000 to install concrete slab bases for the solar panels. The system was completed over an eighteen-month period, with some changes along the way driven by the need to find the right technology.

The Griffins are confident of significant savings and a boost in production of 10% to 20% over the system's 25-year life. Had the family remained with the electricity grid and the ever-increasing cost of power, they would have faced a power bill of around $35,000 to $50,000, more than double the bill he now pays. Mr Griffin says he would have preferred to spend the $100,000 on improving his farm layout and lifting over all cane production and productivity rather than investing it to generate electricity.

Also near Bundaberg, sugarcane grower Mr Allan Dingle uses electric powered pumps to water 110 hectares of his cane fields. The price of electricity to run those pumps has more than doubled over the past decade.

In 2007, the off-peak price of power on tariff 65 was 8.83c/kWh, the peak price was 16.04c/kWh and the service charge of just $10.32 a month. Now, on that same tariff the off-peak rate is 20.321c/kWh, the peak rate is 36.894c/kWh and the service charge is $23.73 a month. Mr Dingle asks, how is that justified?

Limited by the topography of his farm, Mr Dingle has installed soil moisture probes and taken other measures to improve his water use efficiency. He keeps a close eye on passing storms in making his irrigation decisions. Mr Dingle says I've had to lift my productivity, yet I'm seeing little evidence that Ergon is lifting its game.

Local irrigators' council representative and CANEGROWERS District Manager, Dale Hollis, is hearing about electricity price hikes right across the district. He says right now,

[10] Sources include: http://www.abc.net.au/news/2017-03-09/rural-businesses-turn-to-diesel-power-as-electricity-prices-soar/8339346

irrigators have two options: switch off the pumps and go back to dryland cropping, or go off the grid and look at alternatives.

While some farmers now find it economical to install solar panels, many growers require power to irrigate at night. Although battery prices are falling, currently battery storage is more expensive than conventional diesel generation. Some irrigators, like Bundaberg Sugar which produces 220,000 tonnes of raw sugar every year, are returning to diesel pumps.

Simon Doyle, in charge of farm operations at Bundaberg Sugar, says it's already 30 per cent cheaper for Bundaberg Sugar to pump water with diesel than electricity, and electricity prices set to rise even higher in the future, that number will become even greater.

While Mr Doyle considers electricity is "cleaner, more user-friendly and probably more reliable. But it is becoming cost prohibitive." As he turns to alternatives to manage costs, he is concerned that abandoning the grid altogether will hurt his neighbours by increasing their prices.

Dean Cayley operates a 150 hectare farm in the Bundaberg district, Queensland. Although its predominately a sugarcane farm, it also produces peanuts and some of the land is leased to sweet potato production.

Mr Cayley mainly uses his irrigation systems from September through to April. In 2016 responding to ever increasing electricity costs (his power bill for the year was more than $70,000), Mr Cayley invested more than $200,000 on a new lateral move and associated equipment and delivery upgrades just to stay in business. This has reduced his power costs by around 50 per cent and lifted production by 25 per cent. Without this investment, Mr Cayley says he may have reduced the area of cane production and switched to higher risk small crops and macadamia nut trees.

With rising prices, the payback period is shorter. But the upfront capital cost is large. World sugar prices have fallen sharply this year. Unsustainable electricity prices are forcing farmers to cut back on the irrigation or turn off their pumps, just to stay afloat. They're not getting the best out of their crops. Everyone loses. Our incomes are down. With farmers not earning, they're not spending. That hits local towns hard, jobs are lost. The viability of the local sugar mill is put at risk and everyone suffers.

In eight years Australia has gone from having among the cheapest electricity in the world to among the most expensive. We are being forced to make investments that would not otherwise be needed. As exporters, we can't pass the electricity price hikes on to our customers. Our competitiveness in the world sugar market is at stake. If the electricity price spiral is not stopped, we simply must find a way to regain control of our costs.

2.2.4 West Corurgan Private Irrigation District

The Southern NSW districts of Corowa, Urana and Berrigan produce sheep and beef, rice, vegetable, oilseeds and cereal cropping, yielding an approximate gross $90 million value annually.

West Corurgan Private Irrigation (WCPID) is based in Berrigan in Southern NSW. WCPID is a private Irrigation District providing irrigation water to approximately 300 properties covering an area of some 212,000 Hectares between the Murray river and the Billabong

Creek. West Corurgan lifts water 13 metres from the Murray via electric pumps and then into a gravity fed channel system.

Electricity cost for the pump station out of the river is one of the significant input costs for the business and as a component of costs passed on to customers.

For the 2016-17 financial year electricity costs for the single pump station was likely to be $284,000. West Corurgan will experience a 40% increase in that cost in the next year budgeting $398,000. A single year price increase of $114,000.

2.2.5 Australian dairy industry case study

Electricity (and gas) account for a significant proportion of costs of dairy production. Dairy farmers effectively pay twice for higher energy costs, in the dairy sheds and at the farm gate.

According to Dairy Australia the current cost of energy for dairy processors is about $160 million a year, set to rise by tens of millions of dollars as long term contracts are renegotiated. These costs are passed on back to dairy farmers through a lower farm gate milk price.

Electricity accounts for a significant proportion of a dairy farm's shed cost, which vary from $17,000 to $40,000 on average per year across Australia with a national 3 year rolling average $24,200 a year.[11].

In 2012 Dairy Australia, already responding to concerns about the rising cost of electricity, obtained grant funding from the Australian Department of Industry and Science to deliver the 'Smarter energy use on Australian dairy farms' project, aimed at helping dairy farmers use energy more efficiently.

The project enabled 1400 dairy farmers, or 21 per cent of the dairy industry, to access to personalised on-farm energy assessments, workshops and information resources. The assessments demonstrated while no two dairies are the same, milk cooling, milk harvesting and hot water production are the areas of highest energy use in the dairy shed.

Around two thirds of the farmers who have had energy efficiency assessments at the dairy are reaping the benefits of having identified areas for improvement, and are investing in changes. The assessment recommendations ranged from small changes to existing equipment that can be implemented immediately, to advice on new technology and long term investment options. Examples included

- Switching to cold water cleaning methods
- Solar water heating
- Installing heat recovery systems to use heat from milk refrigeration systems to heat water
- Pre-cooling water operating milk plate coolers
- Pre-cooling milk entering plate coolers
- Installing variable speed drives on vacuum/milk pumps.

11 ABARE National Farmer Survey, providing costs up to 2015/16

As a result of these energy efficiency investments, more than half of participating dairies identified significant energy savings that translated into cost savings of up to $2,000 per year, 40 per cent savings of $2,000–$10,000 and 5 per cent savings up to $29,000 annually.

While this project has been running since 2012 average dairy farm electricity costs have risen between 26 and 65 per cent across Australia, with increases averaging 48 per cent nationally. Dairy farmers now face paying up to 20 per cent more on their own power bills for dairy sheds.

2.2.6 Horticulture case studies

AE Cranwell & Sons – South Australia

The Cranwell Family run one of Australia's biggest Brussel Sprouts farms with properties at Langhorne Creek and Nairne in South Australia. The Cranwell's contract for electricity to supply their packing shed was up for renewal this year and the cost increased by 126% from around $50,000 pa to more than $113,000. The business now also invests in diesel and tractor driven generators, as back up for unreliability in the network, ensuring that key irrigation, packing, and cooling equipment can keep functioning in a blackout.

Despite being a major producer of Brussel Sprouts the Cranwell's are essentially price takers and like all vegetable growers they haven't seen a real increase in the price paid for their product for years. Increasing costs are making the business less competitive in the international markets as well, where once they exported to Korea and Japan now they find that their major competitors in that market from the US and Europe can offer cheaper product because of lower input costs.

Southern Qld Horticultural Business

One Southern Queensland vegetable grower producing beans for export, carrot, onions and pumpkin has seen electricity costs go from being a small part of input costs to being a major brake on competitiveness and profitability. The operation's major electricity costs come from irrigation and their packing shed.

The decision to ditch irrigation tariffs in Queensland has seen the cost of electricity for that aspect of the operation go from a price of 18c/kWh to 28c/kWh peak and off-peak 11c/kWh to 24c/kWh c off-peak. Coping with that for this business has meant a $1 million investment in new irrigation equipment - $1 million spent just to keep the power bill at the same dollar level.

The packing shed is a key part of the business and its demand for power sees its bill on its current contract standing at $675,000 this year. This year the electricity component of the bill will double adding $175,000 to the total bill. A 25% single year increase in the total bill.

This is a business that is generating jobs in South East Queensland, export is a key part of generating that activity with fresh beans heading overseas by airfreight several times a week in season. As businesses costs increase, the competitive position in the international market decreases, with potential flow on impacts for the regional whole community.

2.2.7 Australian wine industry case studies

A number of wine producers and grape growers have taken steps in recent year to mitigate the unsustainable cost of electricity. Many are considering the cost effectiveness of alternatives and moving off grid in an effort to regain control of their rising cost of production. A large number of wine businesses have invested heavily in solar systems as a result, with some utilising alternatives such as diesel generation in order to reduce reliance on Australia's energy grid.

In December 2016, Yalumba Family Vignerons in South Australia installed one of Australia's largest photovoltaic systems in a winery. The decision to install the 1.4MW system was taken against the backdrop of projected increased business energy costs of around 85% between 2015 and 2017. The system has the ability to deliver up to 20% of the businesses electricity needs and will help to alleviate this pressure. Installing the system required significant investment by Yalumba. The decision was taken as an alternative to cutting production costs through cutting jobs or passing these costs through to consumers through increased price of wine.

Redmud Green Energy based in the Riverland, South Australia is an initiative of Yates Electrical Services which offers land-owners the opportunity to re-purpose their properties for the construction and implementation of large scale Solar Farms. Utilising vacant land titles with a footprint of approximately 1.2 acres, Redmud Green Energy Solar Farms are designed solely to export generated energy into the grid, enabling energy to be sold on the National Electricity Market while simultaneously generating Large Generation Certificates.

Redmud Green Energy are focused on making the process and installation of these Solar Farms as seamless as possible by engaging farmers, primary producers and investors to work with us in offering a standardised turn-key Solar Farm solution. Redmud Green Energy notes the project's aim is to provide growth and prosperity in several key areas simultaneously by:

- the generation of maintenance and constructions jobs
- Providing supplementary income to land and property owners
- Strengthening the local economy
- Utilisation of current government incentives through STC and LGC creation
- Introduction of new innovative industry to the Riverland and surrounding regions.

The project enables money remaining within the local community, providing the economy the assets to improve infrastructure, and create a stronger and much more sustainable population. The quality of education of the need for a greener planet for the next generation of innovators will increase significantly, with our region being at the epicentre of contemporary thinking.

Redmud also aims to expose the Riverland and surrounding regions to the National Electricity Market, and enable generators the ability to trade their power generation, increase local revenue, and create a new industry for the Riverland.

2.2.8 Australian pork industry case study

Blantyre farms near Young, NSW, runs a 2,000 sow piggery, and at any point around 20,000 pigs on hand. As electricity charges were about 20 cents/kW, Blantyre farms turned to its pigs for power. Blantyre farms is first in the Australian pig industry to complete a commercial digestion system.

Methane from piggeries is released into the atmosphere from the anaerobic decomposition of pig manure in settling ponds. A methane digestion system captures this gas under a pond and burns the methane for power generation.

A methane digestion system has been installed at both the breeder site and the grower site on the farm. At each site a dam holds 50 days-worth of effluent, covered by a low density poly ethylene that captures the gas. The gas runs from the pond through a scrubber, which cleans the gas of impurities and then a chiller which removes condensation. The methane gas is a fuel source for a converted diesel engine, which is coupled to a generator. Generators are controlled by computer which can be accessed remotely. An auto alarm sends text messages signalling any problems with the generator.

For a further flexibility the separate digestion systems are connected by an underground pipe that maintains gas supply to the breeder site which uses the most power, but produces less gas.

Blantyre has three 80kWh generators that are set up for co-generation – that is the exhaust heat is used to provide hot water that is reticulated through weaner rooms and the farrowing house to provide heat to piglets. This efficiency replaces heating generated using electricity and LPG. Blantyre expects the project will have a 2-3 year payback period. A further advantage is the power that is sold to the grid at the rate of around 3.5 cents/kW – compared to the electricity purchase price of 20 cents/kW.

2.2.9 Central Irrigation Trust case study

Central Irrigation Trust (CIT) which is situated in Barmera, pumps water from the River Murray through large diameter pipeline systems to 1,600 growers who irrigate 14,000 hectares of horticultural crops in twelve Private Irrigation Districts in the Riverland Region of South Australia. CIT has an annual water allocation of nearly 120,000 Megalitres.

In seeking to be a leader in water management CIT water is supplied through fully automated pumping stations and pressurised pipeline systems. Their entire pumping infrastructure uses electricity as its source of energy.

CIT has seen significant and unsustainable increases in its electricity charges over the last seven years. Energy delivered to CIT increased in price by 82 per cent from 2010 to 2017 when the CPI increase for the same period has been less than 15 per cent. This includes network costs increasing over 60 per cent as well as the recent doubling of retail energy as gas generators have dominated pricing in South Australia since the closure of Northern Power Station in Port Augusta. No other input cost in their business has risen anywhere near these levels.

CIT actively seeks to reduce electricity costs, participating in the AER's SA Power Networks Regulatory Proposal 2015-2020 process and partnering with 27 large consumers in South Australia in an energy purchasing group. Together, the group's total load of 269 MW accounts for around 16 per cent of electricity demand in South Australia. It is hoped that the groups combined load increases the group's bargaining power in the retail supply of energy contracts in South Australia, in a market which is highly concentrated at times on the supply side.

While attempting to mitigate these cost impacts, nonetheless CIT has to raise its water prices to cover costs. The price increases for 2017-18 range from 47 to 66 per cent above 2016-17 prices for peak delivery and 24 to 43 per cent for off peak delivery.

2.2.10 Almond orchard case study

Omega almond orchards

Drew and Caren Martin run a dry land cereal and irrigated almond property. We currently irrigate 180ha with drip on a range of tree ages from 2 – 17 years. We pump water from the Murray River 3km away at a 60 meter head to a dam where we push water a further 1.7 km to the last blocks on the verge on the current low salinity zoning area. Our Five pumps all run on variable speed drives and are fully automated under the guidance of world's best scheduling. Even with the most efficient pumps, motors, PLC's and Drives, irrigation design, monitoring tools available we still manage to consume a colossal 1.5 GWh per year. Our latest power contract has increased 50% to 15.45 cents /kw peak, and 46% to 8.05 cents / kw off peak. This contract expires on the 30th of December and my broker informs me that the retail market is around 20 cents for peak.

Our scheduling crop factors are based on the results achieved though the Almond Board of Australia Irrigation Optimisation trial conducted by the famous Professor Raphael Assaf from Israel. Watering during the day is a key factor in achieving world's best yields per mega litre applied. Due to the exorbitant demand tariffs we pay to SAPN these gains have diminished if we pump between 12 noon and 9pm. To counter this we are considering installing a new filter, pump, motor and associated smarts in order to maintain capacity outside of these times. The flip side is we fall into a more costly demand tariff bracket due to the load increase only adding to the $160000p.a. network fees. In this calendar year we will pay $87340 more for electricity than we did last year (previous total cost $320,000).

Reliability has been an issue here for 12 years. We have power disruptions regularly particularly during summer where you can expect power flicks on a daily basis causing significant challenges for management. Over the last 5 years we have invested $200000 plus on equipment in an effort to curtail the effects on our production, these items were not budgeted for, however very timely in that we can currently afford it and with the situation in SA said only to worsen.

History tells me when you couple these new power costs with a commodity cycle downturn, the increase cost of water under the new SDL's it will not be sustainable for many business with high debt / equity ratios.

3. Prices, costs and profits

3.1 Overview

In addition to seeking feedback from interested parties, the ACCC will also seek information directly from electricity retailers on the costs that they incur in supplying customers throughout the course of the Inquiry. This may occur through methods including voluntary information requests, formal (compulsory) information requests and/or hearings. The information the ACCC may seek from retailers could include:

- *actual data on retail costs and profit margins, including costs associated with attracting and retaining customers*
- *information relating to the types of risks that retailers face in relation to the supply of electricity.*

There is ample evidence that actual electricity costs, profits and typical retail prices across the NEM substantially exceed economically efficient levels.

Excess costs and prices arise from failures of:

- economic regulation to constrain costs and prices in the regulated parts of the supply chain – transmission and distribution; and
- competition, regulatory design and oversight to limit costs, prices and profits in the competitive parts of the supply chain.

The National Electricity Objective (NEO) requires the NEM to operate in the long term interests of consumers of electricity with respect to price, quality, safety, reliability and security of supply. Excessive costs, profits and prices across the NEM are not consistent with the NEO and suggest a major failure in the governance arrangements established under the Australian Energy Market Agreement, 30th June 2004.

Electricity represents a substantial input cost for the production of Australian food and fibre. Energy costs are particularly significant for irrigated agriculture, which can see more than a third of overall cost of production taken by up by energy. It is also significant for many aspects of agriculture overall, with processing, packing and cooling all requiring energy usage.

Where electricity prices significantly exceed costs, demand is suppressed compared with what it would have been. This can result in various combinations of reduced production, and investment in and use of alternative energy sources. Whatever the response, the effect is to reduce the international competitiveness of agricultural industries.

The case studies set out in the previous section show that some agricultural producers have responded to prices and excess prices by making substantial investments in, and use of, energy efficiency and alternative energy systems and supplies, at least in part by-passing grid supplied power.

The decision to move from the grid to diesel generation being made by some of these producers would also appear to be at odds with the policy outcomes advocated by Government. Not all agricultural producers are in a position to be able to afford to make large investments that might allow them to by-pass the grid or significantly reduce their consumption. Those producers are often the producers left on the grid as others leave, they end up bearing higher unit prices for regulated network services, or lower levels of reliability following early retirement of generation due to falling demand.

While such responses could be efficient, they appear at least in part to be a response to excess costs, price and profits. This represents a significant misallocation of resources across the economy. Inefficiencies in NEM electricity markets appear to be leading to higher costs and a second round of economic distortions in the agricultural sector (and no doubt elsewhere).

3.2 Excess costs throughout the supply chain

This section summarises the basis for our view that aggregate retail supply costs (the cost stack) are not efficient.

3.2.1 Network costs

Network costs and prices are higher than they should be. This reflects a combination of substantial excess network capacity and regulated rates of return that are overly generous. In a report prepared for CANEGROWERS[12] and the NSW Public Interest Advocacy Centre[13], using data contained in Queensland and NSW network's Distribution Annual Planning Reports, we have assessed distribution congestion in the context of network pricing reform. There is spare capacity across almost all zone substations across both NSW/Queensland. This suggests there is no congestion in the parts of the network that supply irrigators in NSW and Queensland.

Table 1 below summarises spatial congestion at zone substations across NSW and Queensland. It highlights that across the five networks, there is congestion in just over 1 per cent of zone substations.

Table 1 Summary of spatial (zone substation) congestion

Zone sub-stations	Ausgrid	Endeavour	Essential	Energex	Ergon	Total
Total count	161	155	235	234	198	983
100% firm capacity and 0.2% hours/pa (demand)	0	0	1	1	9	11

12 See Evaluation of electricity distribution tariff structure proposals submitted by Ergon and Energex, a report prepared for CANEGROWERS, dated February 2017.

13 See *Evaluation of NSW 2016 revised electricity network tariff structure statements*, a report prepared for the NSW Public Interest Advocacy Centre, May 2017.

Zone sub-stations	Ausgrid	Endeavour	Essential	Energex	Ergon	Total
Congested substations	0.0%	0.0%	0.4%	0.4%	4.5%	1.1%

Source: Sapere analysis of Distribution Annual Planning Report and supporting data provided by NSPs

Table 2 below compares maximum firm capacity with planning forecast non-coincident maximum demand. It highlights substantial spare capacity across the networks for the foreseeable future.

Table 2 Maximum demand as per centage of firm capacity

MVA	Ausgrid	Endeavour	Essential	Energex	Ergon	Total
Maximum firm ZS capacity summer	8976	5737	3791	7229	2977	28710
Maximum forecast non-coincident demand summer	5604	3621	1736	4900	1678	17539
Maximum demand	5604.0	3621.0	1736.0	4900.0	1678.0	17539.0
Non-coincident spare capacity summer	3372	2116	2055	2329	1299	11171

In the limited areas where congestion exists, this is not due to rising demand from existing customers but rather new demand from new customers, typically in urban and industrial areas. The network pricing principles imply the cost of increasing capacity for new customers should be funded from connection charges, not from general network tariffs. In other words, inefficient cost recovery is placing further upward pressure on network prices.

From a more limited analysis that does not estimate firm network capacity at zone substation level, there is reason to believe there may also be significant spare capacity in some parts of Victoria, South Australia and the ACT. Drawing on Regulatory Information Notice data provided by networks to the AER, in some networks, there appears to be significant excess capacity at a network wide level.

Excess network capacity has been attributed to unexpected changes in demand patterns. However, in broad terms this structural change was predictable and in fact was predicted in anticipation of carbon pricing and accompanying measures to encourage energy efficiency. Excess network capacity is more likely to be attributable to the fact that under the transition to the National Electricity Rules (NER) chapter 6 was amended to shift risk around demand and capacity from network companies to consumers. This was effected by moving from an optimised deprival value (ODV) method for setting the regulated asset base (RAB) to a roll-forward method.

Given the asset intensive nature of network businesses, the value attributed to the RAB is the principal influence on allowed costs, revenues and hence unit network prices. The RAB is the key determinant of two of the four major cost building blocks used to set allowed network revenues under the NER – regulatory depreciation (return of capital) and, along with the estimated weighted average cost of capital (WACC), the capital charge (return on capital).

Under an ODV approach, the value of the opening RAB is adjusted to remove any excess network capacity relative to forecast maximum demand (including adequate security margins for asset failures and losses, and using a 10 per cent probability of exceedance in any given year). This can either arise either as a result of changes in demand (demand risk) or due to inefficient capital expenditure (capex risk).

By contrast, under a RAB roll-forward approach, the opening RAB from the previous pricing determination is rolled forward to the end of the price control period to form the opening RAB value for the following period. There are adjustments for capital expenditure, depreciation, disposals and inflation (the last of which is then netted off to avoid over-compensating for inflation). There is, however, no optimisation for excess expenditure or excess capacity. There is no *ex post* review of the efficiency of capital expenditure.

We have not been able to identify a corresponding reduction in the allowed cost of capital to accompany risk transfer associated with the move to the RAB roll-forward method for setting the RAB at the start of the following price period. Consequently, it appears that network prices incorporate the double effect of excessive returns on an excessive asset base.

On 24 May 2017, the Federal Court of Australia handed down a decision that largely rejected an appeal by the AER to an earlier decision by the Australian Competition Tribunal requiring the AER to revise its final determinations with respect to NSW and ACT electricity and gas network prices for the period 2015-16 to 2018-19. This means the AER must now review the extent the Final Decision should be varied, in accordance with the National Electricity Law with regard to the:

- method for setting allowed operating expenditure
- return on debt; and
- estimated cost of corporate income tax .

This is expected to result in further increases in regulated network prices in NSW and the ACT, effective from 1 July 2019.

The COAG Energy Council is considering removal of the limited merits review mechanism that has to the requirement for the AER to revise its Final Decisions.[14] We do not wish to comment on these moves other than to note that removal of limited merits review does not address the fundamental inefficiency with network prices due to the existence of excess capacity and excess returns. Without reform of the regulatory framework, not merely the review mechanism, these excess costs will continue to be permitted under the NER whatever changes are made to merits review.

3.2.2 Are network price discounts passed through to consumers?

The AER has approved a first round of network tariff reforms across the NEM, further to the AEMC's Power of Choice Review. These new network tariffs typically incorporate discounts for various time-of-use and maximum demand tariffs, relative to traditional "flat" or two part tariffs. It is, however, unclear whether network pricing benefits are fully passed through to consumers. There does not appear to be any regulatory monitoring or inquiry on this issue.

3.2.3 Wholesale costs and prices

Wholesale costs and prices have risen substantially in recent times and are in our view higher than they should be. For example, the average actual wholesale prices experienced over 2016/17 for NSW was $81.22/MWh compared with $51.60/MWh the previous year. This reflects a complex set of factors including reluctance by the private sector to invest in new thermal generation due to ongoing uncertainty over carbon emissions abatement policies.

High upstream gas costs are a further factor. The ACCC is already familiar with many of these issues from its recent inquiry into upstream gas markets[15] and ongoing attention to gas markets.

It appears that domestic wholesale gas prices may now exceed export netback prices. While this has prompted a policy response in the form of a mechanism to divert supplies to domestic gas markets, the machinery to implement a policy response will not be in place until the start of 2018.

Following the withdrawal of significant coal plant, high gas prices are leading to a structural increase in wholesale electricity prices. Due to the wholesale market design, higher wholesale prices appear to be creating windfall gains for infra-marginal – coal – generators. Because all generators receive the marginal price for each price period/regional market, present average wholesale prices are likely to exceed actual generation costs, including an adequate margin for forward price risk. For example, in its half yearly report to 31 December 2017, AGL reported an increase in wholesale electricity EBITG of $58 million or 8.1 per cent. [16]

We acknowledge this state of affairs is relatively recent and follows the reduction in generation capacity, notably the closure of Hazelwood. Generator revenues, as recently as two years ago, were in many cases lower than total costs. For example, public reporting by

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14 The Australian government has announced this change, but if enacted through a change to the National Electricity Law, we understand it requires adoption by the full COAG Energy Council.

15 See http://www.abc.net.au/news/2016-04-22/gas-supplier-monopoly-pricing-hits-domestic-users/7350338

16 See Table 2.1.1 on page 12.

Macquarie Generation during the first year of the carbon price was very clear that it was unable to recover its carbon tax liability from its spot energy and forward contract revenues.

3.2.4 Environmental related costs and prices

Reflecting ongoing policy uncertainty regarding future policy around pricing of carbon and obligations for low or zero emissions energy, in our view, environmental related costs and prices are higher than they should be. For example, over 2016 spot prices for Large Scale Renewable Energy Certificates were at or close to the post tax penalty cost of non-compliance with the Renewable Energy Target scheme for extended periods. These prices have recently fallen, reflecting increased investment in renewable energy, but it is likely a significant premium remains.

The broader problem with environmental costs is that electricity emissions reduction costs are largely being met by consumers, rather than by a combination of consumers and investors. In competitive markets, innovation and transformation related costs are substantially funded by investors. In competitive markets, investors also face the risk of losses from assets that are replaced and retired early.

This is evident in the light passenger vehicle industry. Here, investors are funding development of scale production of electric vehicles. Manufacturers reliant on internal combustion engines have seen very large losses in their asset values. Consumers have not borne the cost of the asset write downs, and so far are not bearing the cost of scaling production of electric vehicles.

3.2.5 Other electricity costs and services

Other electricity costs are likely to be higher than they should be. For example, NSW is the only jurisdiction which allows competition in the supply of network connection services. These services apply to new or renovated premises. The market is significant in urban areas, reflecting the large volume of new construction activity in some areas.

In a project for COAG Energy Council in 2011[17], we concluded that, if the NSW approach were extended to other jurisdictions, there would be significant consumer benefits in the form of cost savings and improved services. These findings were not amenable to jurisdictions in the context of provisions for the mandated, monopoly deployment of smart meters both in Victoria and elsewhere (under the now repealed Smart Meters Act 2009.[18]

Regulation providing for monopoly deployment of smart meters has now been removed. However, regulatory frameworks that mean network new and modified network connections are effectively monopolies or have only limited contestability continue to apply across the NEM with the exception of NSW.

17 See Competitive provision of electricity and gas network connection services – report to the Network Policy Working Group [reporting to the Senior Committee of Officials to the Ministerial Council for Energy], dated April 2011.

18 See https://www.legislation.sa.gov.au/LZ/V/A/2009/NATIONAL%20ELECTRICITY%20(SOUTH%20AUSTRALIA)%20(SMART%20METERS)%20AMENDMENT%20ACT%202009_54/2009.54.UN.PDF

3.2.6 Regulation and market monitoring

Consumers are for the most part no longer protected by economic regulation.

3.2.7 Retail margins and risk exposures

Following the removal of economic or price regulation for most of the larger markets in the NEM, retail margins are substantially higher than they should be. Retail prices now substantially exceed aggregate supply costs, plus efficient and prudent retailer operating and other costs.

In dollar terms, retail margins have increased faster than electricity supply costs. This is because retailers typically set retail prices (margins) with reference to a mark-up on total supply costs – say five per cent.

As supply costs have more than doubled, the mark ups have tended to scale accordingly. Working capital and perhaps bad debtor costs are, however, the only retailer costs that scale in proportion to increases in electricity supply costs. These costs are relatively modest compared with other retailer costs. Rising mark ups relative to the costs these mark ups recover means that, if competition is not constraining price increases, retailers have the opportunity to make windfall gains as supply costs increase.

Previous regulator estimates of efficient retail margins assumed significant retailer exposure to wholesale market risk.[19] However, recent experience suggests that, at least for some retailers, such exposures may be limited, as increases in wholesale costs and risks can readily be passed on to consumers under the National Retail Energy Rules (NERR). The most recent available public reporting by major vertically integrated retailers suggests that structural increases in wholesale prices have not resulted in material reductions in actual retail margins.

On the other hand, a second tier retailer has publicly warned that, if wholesale prices remain elevated for a sustained period, then non-vertically integrated retailers may be required to exit retail markets.[20] This would result in a substantial reduction in competition and further reduce downward pressure on retail prices and margins (to the extent it exists).

3.2.8 Barriers to consumer participation and engagement

There are significant barriers to consumer empowerment and demand side participation. These are discussed in the following Section 5.

3.2.9 Impact of higher wholesale prices on retail margins

In our interactions with regulators and governments around electricity retail market outcomes, we have often been told that excess retail margins are short term and self-correcting. More recently, a view has been expressed that higher wholesale prices have reduced retailer margins.

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19 For example, in a series of pricing decisions, IPART included a volatility premium in its energy purchase cost allowance to reflect this exposure.

20 See AFR June 7 2017 *Does Powershop's deal herald the end of standalone power retailers?*

On reviewing the most recent publicly available evidence, there is no reason to believe that the retailer margins of the major, vertically and horizontally integrated retailer margins have been adversely affected by higher wholesale prices. We do accept, however, that margins for smaller retailers, without physical hedges in the form of generators, are likely to be experiencing substantial pressure on their margins. However, this affects only a minority of retail customer accounts.

Two of the three major energy retailers are publicly listed companies and provide extensive disclosure on financial performance. The most recently available public data is half year reporting for the period to 31 December 2016. While this data does not include the impact wholesale price spikes experienced during February 2017, and the full closure of the Hazelwood Power station at the end of March 2017, it does reflect the uplift in wholesale prices following the announcement of the closure of Hazelwood and after the system black event in South Australia in September 2017.

In its Interim Report for the six months ending 31 December 2016, AGL reports that its customer underlying EBIT is unchanged from the equivalent period to 31 December 2015 at $230m.[21] Similarly, its gross electricity margin was unchanged at $244m. This outcome reflected:

'Disciplined and effective price management across the Consumer Electricity portfolio was reflected in consumer price increases as a result of higher wholesale market prices. However, this was offset by a 7.8% decrease in customer sales volumes, higher wholesale electricity and LGC prices … combined with greater discounting within a highly competitive market. Total consumer average consumption per customer decreased by 7.4%, with average residential consumption declining by 5.3% per customer and small business average consumption declining 11.5%.'

Net operating costs decreased relative to the corresponding period in 2015. This was sufficient to offset declines in gross margins for gas.

In other words, rising wholesale electricity costs and failing volumes were largely offset by changes to retail prices. We would expect similar outcomes for Origin, EnergyAustralia and Snowy Hydro.

Wholesale prices have been elevated over the first half of 2017, and forward prices are also elevated. Substantial retail price rises have been implemented across many parts of the NEM, effective from 1 July 2017. This includes an out of cycle increase in Victoria (price changes typically relate to calendar rather than financial years). These price changes suggest retailer exposure to changing wholesale market conditions is relatively modest and certainly not sufficient to explain or justify very high retail margins.

3.3 Price deregulation and monitoring

3.3.1 Removal of price regulation

The ACCC's Issues Paper refers to the Grattan Institute's March 2017 report *'Price Shock; Is the retail electricity market failing consumers'*, by Tony Wood and David Blowers. Its key

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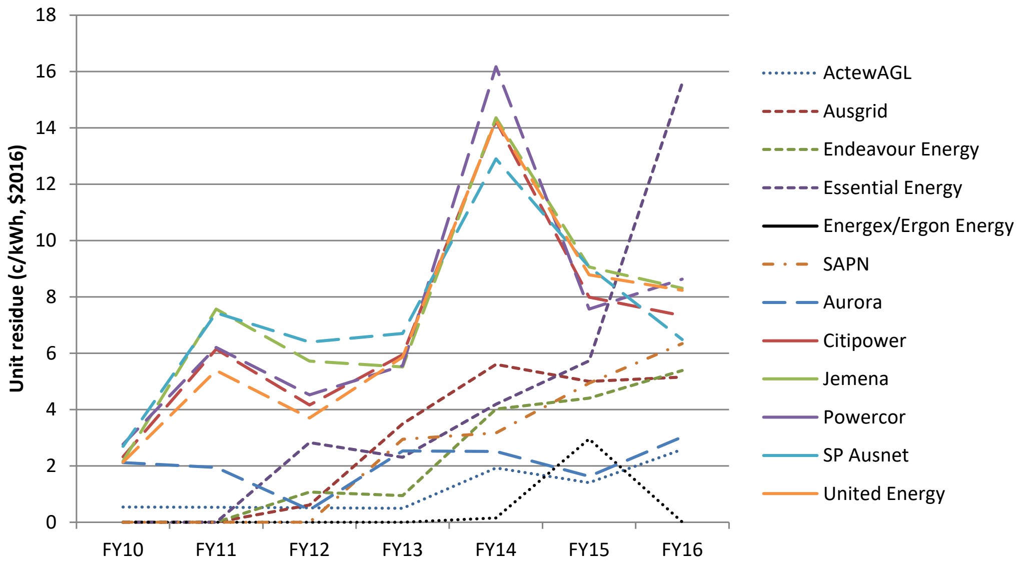
21 See Table 2.1.2 on page 12 and accompanying text from AGL's Interim Report.

conclusion is that the retail component of electricity bills in Victoria appears to be high relative to costs, to comparable retail electricity markets and to other retail activities. It notes that, while the estimates of profit margins are imperfect, the evidence they are high is compelling.

In a 2016 report for CANEGROWERS Quantification of excess costs in QCA draft electricity retail price determination for 2016-17,[22] which was part-funded by Energy Consumers Australia, Sapere modelled "residues" or excess margins across the NEM. This report refers to earlier work both by ourselves and a number of other observers strongly suggests retail electricity prices significantly exceed efficient costs for the majority of electricity retail consumers, and that this is persistent rather than merely transitory.[23]

Figure 1 below provides the results in c/kWh, converted to 2016 values. Key findings are that the excessive prices and profits have persisted for a number of years. It also shows that, with the removal of price regulation in NSW, excessive margins have begun to emerge in NSW, albeit at a lower rate than Victoria.

Figure 1 Retail unit retailer "residue" (c/kWh, converted to 2016 values)



Source: Sapere research and analysis

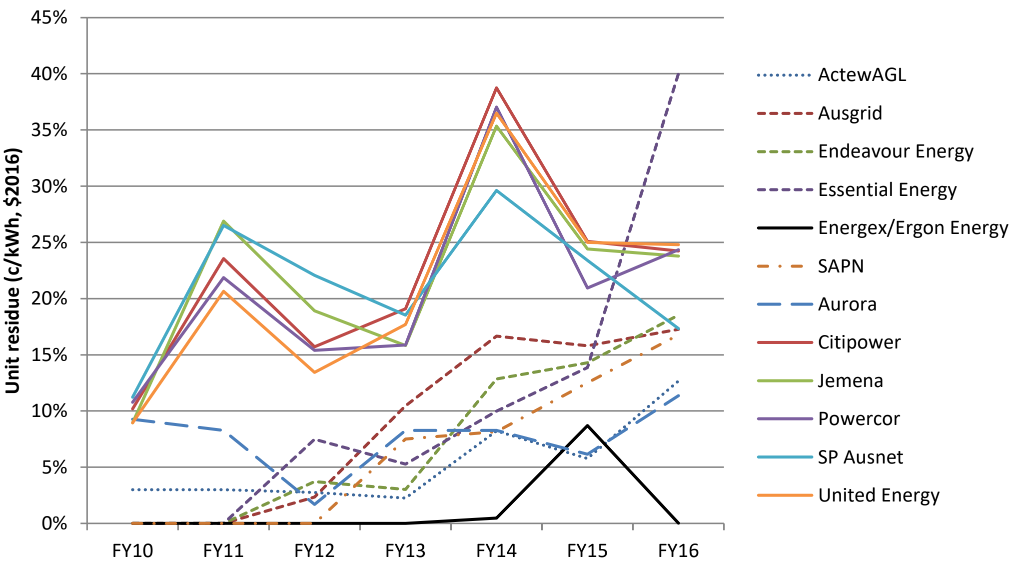
22 The report is available publicly at http://www.canegrowers.com.au/icms_docs/243259_Sapere_Research_Group_Quantification_of_excess_costs_in_QCA_draft_electricity_retail_price_determination_for_2016-17.pdf

23 See Simon Orme, James Swansson, Quantification of excess costs in QCA draft electricity retail price determination for 2016-17, CANEGROWERS, 30 May 2016; St Vincent de Paul Society & Alviss Consulting, The National Energy Market – Still winging it, Observations from the Vinnies' Tariff-Tracking Project, St Vincent de Paul Society, Melbourne, September 2015; Carbon and Energy Markets, A critique of the Victorian retail electricity market. A report for the Brotherhood of St Laurence, June 2015; Carbon and Energy Markets, Australia's retail electricity markets: who is serving whom? A report prepared for GetUp!, August 2016; Essential Services Commission, Victoria, Electricity Retail Margins Discussion Paper. May 2013

As most NSW primary producers are likely to be in Essential Energy's retail market, a significant concern for NSW irrigators and other agricultural producers is the substantial increase in the residue for Essential Energy's retail market.

Figure 2 below shows the same data expressed in terms of the per centage of the typical retail bill. It highlights the substantial residues in Victoria and the growing residues in other parts of the NEM.

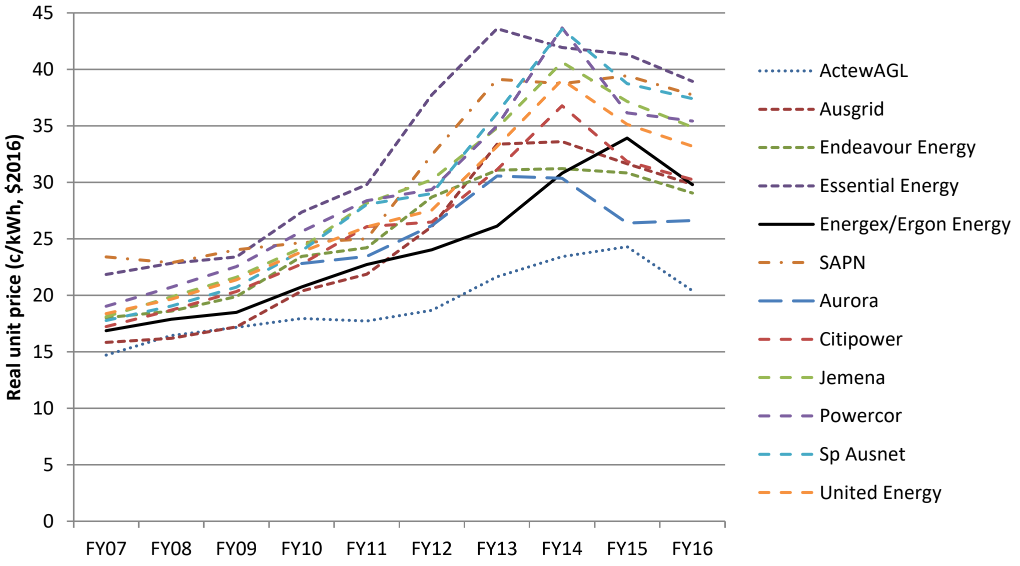
Figure 2 Per centage retailer residues



Source: Sapere research and analysis

Figure 3 below summarises changes to retail prices to early 2016. With a further round of price increases effective from 31 December 2016, we would expect that in many retail markets, retail prices could exceed the highs around 2014.

Figure 3 Retail unit price path



Source: Sapere research and analysis

This information is broadly consistent with Figure 1 in the ACCC's Issues Paper. A significant difference, however, especially from the perspective of primary producers, is that Figure 3 provides the price paths for retail markets correspond to network areas, rather than state averages in the Issues Paper chart.. Retail markets are aligned with network areas because both because they incorporate network tariffs and where wholesale market settlement continues to use accumulation rather than interval meters, there are deemed wholesale profiles (and hence prices) for small business and residential consumers in each network area.

3.3.2 Measuring retailer profits

In a series of projects including for the Victorian and Western Australian governments, we have analysed electricity cost stacks across the NEM by network area, seeking to identify the relationship between total efficient supply and retailer cost to serve, on the one hand, and prevailing retail prices, on the other. The analysis consistently shows that, for a substantial portion of published retail prices, both standing and market, the price exceeds efficient costs.

The basic methodology used in these margins analysis is tractable and is effectively the same methodology that has been applied by economic regulators in setting regulated retail prices. The methodology has also been endorsed by the AEMC in a 2013 report.[24]

The retailer residues estimated in the previous section are after allowing for costs associated with wholesale energy trading risk, including costs that cannot be offset by purchases of forward contracts. The residues are also after allowing for costs associated with retailer customer acquisition and retention and costs to serve.

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24 See 2013 AEMC report entitled *Advice on Best Practice Retail Price Regulation Methodology'*

We acknowledge there is some uncertainty in modelling efficient supply costs. Most notably, this includes uncertainty over the extent of wholesale trading exposures held by retailers, and the prudent and efficient cost of these exposures. It also includes issues such as the correct treatment of customer acquisition and retention costs, which is sometimes referred to as "headroom" for facilitating competition.

A further source of uncertainty arises due to lack of data on the number of customers on different types of retail contract. Combined with substantial dispersion in retail prices across what otherwise appears to be similar if not identical products, the absence of data on customer numbers per contract means that while it is possible to estimate retailer margins for individual tariffs, there is greater uncertainty over the size of excess margins for each retailer or for retailers overall. Nevertheless, drawing on available market share information some assessment of overall excess retail margins is achievable.

Price dispersion provides a useful cross check of the modelling of per tariff retailer margins. In previous work analysing a standard retail contract type, we have compared our estimates of excess margins with observed price dispersion for similar retail contract types. The lowest observed prices in the range have broadly corresponded to our estimate of efficient costs.

This highlights that the gap between prices and efficient costs is not uniform between retailers. The gap appears to be greatest for the larger, vertically and horizontally integrated retailers.

While there is uncertainty over the extent of the excess, the size of the excess exceeds the uncertainty around the estimates. In addition, it is possible that actual retail margins are higher than indicated in analysis such as Grattan Institute's report.

For example, there are significant cost efficiencies associated with dual fuel retailing. The nature of these efficiencies is set out in a 2011 Sapere report in the context of regulated price setting.[25] Although difficult to estimate, these cost efficiencies are likely to be significant. Absent downward pressure on retail prices and margins, dual fuel cost efficiencies increase retailers' effective net margins.

As a further example, it is also possible that retailer exposure to wholesale prices over the duration of fixed term contracts may be limited due to a practice whereby retailers are able to change prices at any point during the term of a fixed term contract, subject to some procedural requirements. The current National Energy Retail Rules (NERR) do not regulate how often or by how much retailers can change their prices.

In a 2015 decision, the AEMC declined to endorse a proposal from consumer groups to prohibit retailers from changing prices during energy contracts that have a defined term. The basis for the decision was that '*If retailers were unable to change their prices to pass on unmanageable changes in their costs when they occur, prices would have been likely to increase.*' This conclusion may be reasonable, if it were the case that retail margins were efficient and not excessive. Conversely, if some retailers are able to maintain monopoly pricing, this conclusion allows those retailers to sustain excessive prices and profits. The decision

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25 See for example the discussion in section 6.4 of a Sapere report to the Essential Services Commission 2011 Review of the South Australia gas standing contract retail operating cost and retail operating margin, dated April 2011 available at: http://www.escosa.sa.gov.au/ArticleDocuments/734/110406-2011_ReviewGasOperatingCosts-Saper.pdf.aspx?Embed=Y

appears to endorse behaviour whereby wholesale energy trading risk is transferred from retailers to consumers, but without a corresponding reduction in electricity retail margins.

Excess retailer margins are not limited to Victoria and South Australia. Following the removal of economic regulation in NSW, there are indications prices now exceed efficient costs for many NSW customers, especially those remaining on standing contracts. In addition, the excess retail margins across the NEM are now contributing to excessive regulated retail margins for regional Queensland under regulated tariffs set by the QCA.

In a 2016 decision, the QCA changed the methodology it used to set retailing costs for price setting purposes. In previous reviews, QCA sought to estimate efficient retailer operating costs. For its 2016 and 2017 reviews, the QCA adopted a new methodology that estimates benchmark total retailer cost (exclusive of prudential capital costs which are included in wholesale energy). This benchmark is based on the difference between retail electricity price observations from across the NEM for market and standing contracts, on the one hand, and estimated costs other than retailer costs, on the other. The difference is deemed to reflect retailer costs.

The resulting QCA estimates for retailer costs are excessive for two key reasons.

- The methodology does not provide a basis for estimating efficient retailer costs under conditions where a large portion of observed electricity prices incorporate substantial "residues", or excess margins, over and above efficient retail costs. It amounts to incorporating non-existent costs in notified prices.
- The methodology includes significant competition costs (customer acquisition and retention costs) that are in fact not incurred by Ergon Retail, where retail competition is not viable and does not occur for <100MWh customers under the Queensland Uniform Tariff Policy.

The apparent emergence of retailer "residues" or excess margins following the removal of price regulation breaches the National Energy Objective. The opacity of retailer margins and the failure of competition to constrain electricity pricing raises questions about the effectiveness of retail market monitoring.

3.3.3 Current retail market monitoring

Safeguards to deter any exercise of market power – market monitoring – may be less effective than they could be. In the absence of direct price regulation, energy retail market monitoring is intended to be a safeguard to deter any firms or groups of firms with market power from exercising such power, including by way of monopoly pricing. Monopoly pricing occurs where prices incorporate profits in excess of those required to compensate capital providers, including a margin for risk.

This may reflect the fact that, under the Australian Energy Market Agreement (AEMA) 2004, the AEMC was charged with assessing whether Victoria's retail markets are effectively competitive.[26] The AEMC undertook its first review of retail competition in Victoria's

[26] See clause 14.11 of the AEMA, as amended in 2009.

energy markets in 2007/08.[27] That review found that competition was effective and recommended the removal of retail price regulation.

When retail price caps were removed, no systematic market monitoring arrangements were put in place. This contrasts with other markets following removal of price regulation, where market monitoring arrangements are put in place and where suppliers have legal obligations to supply data and information (disclosure requirements). Well known examples include fuel price and airport monitoring undertaken by the ACCC. Recently the ACCC effectively secured real-time fuel price for consumers, opening access to the public (via data applications) to the price data base used to share price data by the fuel companies themselves.

While the AEMC has undertaken a series of reviews on the effectiveness of retail competition, the AEMC assumes but does not test whether competition is effective. In its first national review of the effectiveness of retail competition, in 2014, the AEMC concluded that Victorian retail prices substantially exceeded prices in other markets, when normalised for differences observable in supply costs. While concluding that retail competition was effective, it did not entertain the possibility that retail prices incorporated excess cost recovery, reflecting the existence of market power on the part of retailers. In other words, its conclusion was not based on evidence.

As pointed out by the Chairperson of the Victorian Essential Services Commission (ESCV), the AEMC findings are not evidence based.[28] The AEMC evaluates five criteria of 'effective competition' that reveal signs of competition, not proof of it. It appears consistently to discount evidence regarding the fifth test, related to retailer outcomes, specifically retailer margins.

Against this background, the 2015 decision to retain rules that allow retailers to change prices during energy contracts does not appear to be evidence based. The proposal to restrict retailers from changing prices within the term of retail contracts may not result in higher prices but rather lower retailer margins and/or a better service levels than otherwise.

In its 2016 retail competition review, the AEMC no longer seeks to quantify retailer margins, but emphasises the complexity of estimating these with certainty and dependence on assumptions.[29] It maintains this position while providing advice on best practice retail price methodology which includes advice on robust methods for estimating efficient and prudent retailer margins.[30] While noting the growing separation between standing and market offers, the AEMC does not view this as inefficient, even while acknowledging that market offers up to 30 per cent lower than standing offers are being funded at least in part, by those on standing offers, may be inefficient. The AEMC concludes, instead, on the uncertainty inherent in estimates of retail margins based on external observables.

27 See the AEMC's *'Review of the effectiveness of competition in the electricity and gas retail markets, Victoria'*, February 2008.

28 Dr Ron Ben-David, *If the retail energy market is competitive then is Lara Bingle a Russian cosmonaut?* Essential Services Commission, June 2015.

29 AEMC, 2016 Retail Competition Review, Final Report, 30 June 2016, Sydney.

30 AEMC 2013, Advice on best practice retail price methodology, Final Report, 27 September 2013, Sydney

This raises the issue of gathering relevant information from retailers and the corresponding information gathering powers.

The AER has extensive information gathering powers under the national energy laws to enable wholesale and retail market monitoring. It publishes weekly monitoring reports of wholesale market outcomes, as well as reports whenever there are significant price events or prices breach $5,000/MWh.[31] In 2008 the AER prosecuted a generator for an alleged breach of the national electricity rules regarding what it alleged was excessive wholesale pricing.[32] While Victoria remains outside the National Electricity Customer Framework (NECF), and associated NERR, the AER has no formal role in energy retail market monitoring for Victoria.[33]

The AER undertakes retail market monitoring but this does not refer to the effectiveness of retail competition. Some limited retail market monitoring is undertaken by jurisdictional regulators but this is hampered by an unwillingness to exercise data gathering powers.

The ESCV is responsible for the monitoring and surveillance of retail markets and compliance with retail licence conditions.[34] The ESCV is able to request and obtain such information from the retailers as it may from time to time require.[35] The ESCV publishes regular market surveillance reports. Regular reporting tends to focus on compliance with licence conditions and price trends, rather than whether retail markets are operating effectively.[36] The ESCV's monitoring of retail markets has significantly improved with the publication in November 2016 of the first annual Victorian Energy Market Report (VEMR).

Following deregulation of the NSW retail electricity market in 2014, IPART has similar responsibilities monitoring the performance and competitiveness of the electricity retail market for small customers, and has delivered two reports to date.[37] IPART does assess retail price trends and underlying costs, using methods similar to those previously used in their role as a price regulator. With regard to retail margins IPART incorporates the findings of the AEMC's retail competition review that retail margins are reasonable and are not inconsistent with a competitive market into its finding that competition in the electricity retail market is working well.

31 See for example http://www.aer.gov.au/node/451

32 Australian Energy Regulator v Stanwell Corporation Limited, Federal Court.

33 See http://www.aer.gov.au/retail-markets

34 Section 39A of the Electricity Industry Act 2000 and Section 47 of the Gas Industry Act 2001 require the ESCV to report to the Minister for Energy and Resources on published standing and market offers and other features of the competitive market.

35 See Section 18 of the electricity retail licence and condition 19 of the gas retail licence condition and see also information specifications for Victorian energy retailers, ESCV, May 2013, available at http://www.esc.vic.gov.au/Energy/Review-of-Energy-Retail-Performance-Indicators/Energy-Retail-Performance-Indicators-2013-14

36 See for example the annual compliance reports – licensed retail energy businesses, available at: http://www.esc.vic.gov.au/energy/compliance/publications

37 See for example https://www.ipart.nsw.gov.au/Home/Industries/Energy/Reviews/Electricity/Retail-electricity-market-monitoring-2016?qDh=2

3.3.4 ACCC role in rigorous monitoring of retail electricity market efficiency

The Inquiry Issues Paper outlines a range of possible outcomes from the Inquiry. Beyond any behaviour raising concerns under the Competition and Consumer Act 2010, and the immediate term increased information about the retail electricity market, further action is passed to governments and industry.

There is, however, an opportunity for the ACCC to exercise its information gathering powers to institute a regular scheme for monitoring of the efficiency of retail electricity markets that deliver:

- *improved transparency for customers regarding electricity offers and pricing*, and
- *increased information about competition, pricing and other practices in the supply chain that may improve customer experiences in buying electricity services*.

Data requests for retailers

This section sets out some proposals on how the ACCC may most effectively exercise its information gathering powers for the purpose of independently assessing the efficient costs of retail supply in accordance with best practice retail price methodology.[38] With access to retailer customer and cost data that has not been available since the removal of economic price regulation in the major retail electricity markets, the ACCC has an opportunity to make substantial improvements to previous analyses of retailer profits and costs.[39] In particular, the ACCC has the opportunity to compare costs and prices and to distinguish between price diversity and price dispersion.

The data to be requested from retailers to support this analysis includes, for each network tariff and retail tariff, for each defined reporting period:

- total retail revenue
- total sales volume
- total customer numbers
- total billing days (assists normalise for entering/exiting customers)
- total network costs
- 'meta-data' identifying the network tariff and key characteristics (structure, rates), retail tariff(s) and key characteristics (structure, rates)

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38 AEMC 2013, Advice on best practice retail price methodology, Final Report, 27 September 2013, Sydney

39 Wood, T., Blowers, D., and Moran, G. (2017). Price shock: is the retail electricity market failing consumers?. Grattan Institute; Simon Orme, James Swansson, Quantification of excess costs in QCA draft electricity retail price determination for 2016-17, CANEGROWERS, 30 May 2016; St Vincent de Paul Society & Alviss Consulting, The National Energy Market – Still winging it, Observations from the Vinnies' Tariff-Tracking Project, St Vincent de Paul Society, Melbourne, September 2015; Carbon and Energy Markets, A critique of the Victorian retail electricity market. A report for the Brotherhood of St Laurence, June 2015; Carbon and Energy Markets, Australia's retail electricity markets: who is serving whom? A report prepared for GetUp!, August 2016; Essential Services Commission, Victoria, Electricity Retail Margins Discussion Paper. May 2013

The acquired data is then applied to a number of simple calculations to derive: actual unit prices paid (inclusive and exclusive of the fixed component); average consumption per customer, and average cost per customer for each unit of analysis.

A significant feature of the form of this request is that it does not require any modification of retailers' existing customer information systems (CIS). The central function of retailer revenue systems is to link metering data for each NMI/customer to the relevant retail tariffs in order to calculate customer bills, and verify obligations under the corresponding network tariff. Indeed, for internal retailer reporting purposes, these revenue systems should be capable of reporting revenue and other key data for many methods of segmenting their customer bases. This will be done, for example, to monitor customer segments at risk of being bad debtors or for targeted marketing.

The ACCC has the choice whether to ask retailers for the corresponding data for other elements of the costs stack, for example wholesale, environment and market costs, or to adopt accepted methods of estimating these costs.

As noted by Grattan Institute, the total wholesale costs are difficult to estimate, in part because these costs are related to the consumption behaviours of customer segments, and in part because 'gentailers' effectively 'purchase' their own generation so that it is difficult to allocate these costs. In the event the ACCC requests such data from retailers, there may be value in pursuing estimation methods to validate retailer data.

Together with wholesale energy costs, environmental costs, retailer cost to serve and customer acquisition and retention costs, this data provides the basis to assess the efficiency of retailer margins by customer categories and overall.

We acknowledge that each component of the cost stack provides a source of uncertainty, qualifying the conclusions of the cost stack methodology overall. However we also acknowledge that there are well established methods for quantifying the degree of each uncertainty, and hence the precision in determining any "residue" in excess of a best practice retail price methodology that accounts for expected retail costs and margins. It is by the application of these methods that we know that, for our own estimates, the size of the excess exceeds the statistical uncertainty around the estimates.

Collecting the proposed data would significantly reduce the uncertainty associated with two of the components of the cost stack – the retail price paid for electricity and the cost of network services. Rather than obtaining the inputs to retailer billing engines (tariff rates) and making assumptions about customer consumption and behaviour (e.g. regarding conditional discounts); information obtained on the outputs of those billing engines will correspond with what customers actually pay.

Importantly, prices could be normalised for differences in consumption volume between segments (and potentially for individual customers within segments). In analysing retailer costs for price setting purposes, determining the consumption volumes for each tariff is a central issue in the pricing decision. With falling average consumption volumes per customer observed in recent years, reference to actual consumption volume data would greatly improve the accuracy and value of retail market monitoring.

These outputs would enable comparisons of final offers, both between final offer types and within final offer types. This difference is important and relates to the distinction between price diversity and price dispersion.

Price diversity between final offer types is likely to be efficient as it reflects real differences in supply or (efficient) retailer cost to serve.[40] For example, dual fuel offers may reduce retailer costs (as well as customer costs), and time of use offers may reduce supply costs, including risk costs.

Price dispersion, on the other hand, refers to price differences between customers that are not attributable to difference in supply cost or retailer cost to serve. Price dispersion represents inefficiency and possible market frictions. Price dispersion (sometimes referred to as 'price discrimination'), if sustained, could be indicative of the exercise of market power and/or disengaged consumers.

Caution would be required in drawing any conclusions regarding price dispersion. This is because price dispersion could reflect differences in customer or demand characteristics that have not been addressed in the analysis. Apparent price dispersion may nevertheless useful in identifying areas of the market or market behaviour that may warrant further investigation.

3.4 Concluding remarks

This section reviews ample evidence that actual electricity costs, profits and typical retail prices across the NEM substantially exceed economically efficient levels. In the following Sections 4 and 5 this report sets out a host of regulatory and market issues that inhibit workably effective competition in retail electricity markets across most of the NEM. Viewed individually, each matter or issue may appear relatively innocuous. We would stress that the ACCC needs to view these issues collectively, noting that many are interactive and mutually-reinforcing.

By exercising its data gathering powers, the ACCC may significantly reduce the uncertainties associated with estimating costs and profits, and offer a more robust set of conclusions regarding whether prices are consistent with the existence of workably competitive markets and effective economic regulation. Being able to conclude that there are market and regulatory failures, the ACCC may then be able to test hypotheses on the origins of these failures and begin to identify remedies. It is suggested that the ACCC acquire data from retailers necessary to arrive at robust findings regarding:

1. Structural, competitive or behavioural issues in the industry;
2. Identification of any behaviour that raises concerns under the Competition and Consumer Act 2010;
3. Improved transparency regarding electricity offers and pricing;
4. Increased information about competition, pricing and other practices in the supply chain that may improve customer experiences in buying electricity services; and
    (a) For the reasons set out earlier, the ACCC Inquiry should also review the regulated components of the supply chain.

[40] For clarity, differences in supply costs arise from differences in demand characteristics (e.g. location, demand profile). Difference in retailer costs arise from difference in customer characteristics (e.g. credit risk, payment channel). Differences in supply cost for individual customers do not significantly vary between retailers.

Depending on its findings, we would also suggest the ACCC could consider and make recommendations on options for establishing a framework for effective ongoing regulatory monitoring of electricity and gas retail markets. This reflects our observation there is no such monitoring at present. Precedents in the airports and petrol retail sector may be useful in this regard.

4. Market structure and nature of competition

4.1 Introduction

The ACCC seeks feedback from all interested parties on:

5. The ways that electricity retailers currently compete.

6. The level of competition between electricity retailers in each NEM area and distribution area within each NEM area.

7. Any impediments to competition between electricity retailers.

The ACCC notes that questions 5 and 6 are targeted at all industry participants. Question 7 is targeted at existing electricity retailers and those that are interested in entering the retail electricity market.

This section sets out a series of interconnecting hypotheses on how regulatory, market and other factors can have the combined effect of limiting the effectiveness of competition. Effective markets require both demand and supply sides to be efficient and effective. The focus of this section is the supply side. Section five then turns to the demand side.

The remainder of Section 4 seeks to explain the outcomes discussed in section 3 regarding prices, profits and costs. While the focus is on electricity retail markets more generally, rather than the impact on agricultural producers, the evidence set out in section 3.3 above suggests that weaknesses in retail electricity markets may be greater in non-metropolitan areas, and hence are more likely to have adverse effects for agricultural producers. This is evident in the increase in estimated excess costs in the Essential Energy retail market, following the removal of price regulation in NSW, set out in section 3.3.

In a 2015 report prepared for the Victorian government entitled *Impact of market and regulatory arrangements on retail competition in Victoria's electricity and gas markets*, we considered whether regulatory and market barriers to competition may constrain competition for different consumer segments. Given there were at the time 24 active retailers in Victoria, including a number that had recently entered, the focus was on barriers to expansion by smaller retailers and incentives for rivalry for larger, vertically integrated retailers.

4.2 Barriers to expansion by smaller retailers

In combination, regulatory and market barriers have the effect that any smaller retailer seeking to expand is likely to face higher risks and costs than the major retailers with which it is competing. These barriers make it difficult for smaller retailers to capture market share from the larger retailers. As a result, smaller retailers may acquire customers based on offering lower prices compared with large retailers.

Collectively, smaller retailers seem unable to create a dynamic under which broad retail prices converge toward costs. This reflects an interconnecting series of market and regulatory barriers.

A key barrier to expansion by smaller retailers is customer acquisition. This reflects:

- persistence of government competition restrictions in the form of mandated requirements to offer standing or default retail contracts;
- existence of retail market frictions –or customer stickiness – associated with search costs;
- likely customer preference for dual fuel services, leading to a requirement to operate in gas and electricity markets;
- continuing information access privileges for 'first tier' retailers under retail market settlement arrangements;
- the possibility of win-backs and saves by incumbent retailers under the current switching rules;
- inability to access capital markets;
- the requirement to provide additional capital to remain within AEMO credit limits; and
- the risk of vertical foreclosure by integrated generator retailers.

4.2.1 Access to customers

To expand, a retailer must identify a segment of potential new retail customers to target for acquisition. This can be difficult if many customers are not active in the retail electricity market as they have not researched other offers or switched.

Disengaged customers

Where a large group of customers is disengaged or passive, expanding retailers would face higher average costs of acquisition, lower conversion rates and a poorer return on their investment in growing their market share. It is very challenging for expanding retailers to identify which customers are active, and therefore better prospects for acquisition, rather than passive and less likely to respond to sales campaigns.

Large retailers face a similar hurdle when acquiring, but as they already have the bulk of customers, and good information about these customers, they are in a better position to save or win these customers back. Incumbents sit on a good supply of existing and often passive customers who provide ready cash for acquisition or retention while entrants battle with few existing customers and challenges in acquiring new ones.

The level of switching is high in Victoria with the highest ever rates recorded in 2013−14 (31 per cent of electricity customers although inflated by between 3 and 5 per cent by the transfer of APG customers to AGL Energy in April and May 2014).[41] However, if there are a high number of disengaged or passive customers this high switching rate may also act as a disincentive to expanding retailers.

41 See page 129 of the 2014 *State of the energy market* report by the AER.

This is because the switching rate in the active segments is likely to be much higher. It is the active customers that expanding retailers are likely to acquire. Active customers may be switching more frequently – churning. This means that expanding retailers may be less likely to recover their costs of acquisition before these customers switch again. The active part of the market may be very competitive but the passive part may be almost static with standing contracts providing a form of regulated price discrimination.

Dual fuel

In Victoria 71 per cent of electricity customers also have mains gas accounts. Electricity and gas are substitutable for many applications, notably water and space heating and cooking.

In energy equivalent terms, for the majority of Victorian customers, gas is substantially lower cost than electricity. If wholesale gas prices rise in future, the current favourable differential may be reduced.[42]

Where customers have gas accounts alongside electricity, annual gas expenditure is lower than annual electricity expenditure. Accordingly, in economic terms, gas retail markets are subsidiary to electricity retail markets.[43] On the other hand, dual fuel customers purchase lower quantities of electricity. This is a key reason Victoria has lower average electricity consumption than other major NEM markets.

From a customer perspective, there are significant advantages in being able to purchase gas and electricity under a single contract. Customers avoid the inconvenience of dealing with two energy retailers and will typically receive dual fuel price discounts or other benefits. This is a key driver of convergence between gas and retail electricity markets, alongside supply side efficiencies.

There is no published whole of market data on the extent of the market that is dual fuel. However, partial information published by major retailers suggests the proportion may be substantial.

For example, AGL reports that it has 1.97m dual accounts across the NEM out of a total number of accounts of 3.7 m.[44] This indicates that 53 per cent of its accounts are dual fuel.

Similarly, Origin reports that in mid-2014 it had 1.2m dual fuel accounts out of 3.9m accounts. This indicates that 31 per cent of its accounts are dual fuel.[45]

A key advantage of duel fuel is that acquisition costs may be recovered over the combined value of the electricity and gas accounts belonging to a single customer. In effect, this substantially reduces acquisition costs per account.

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42 Note this conclusion may be less clear in other jurisdictions with lower average gas volumes per customer, resulting in significantly higher unit prices compared with Victoria. See for example http://www.ata.org.au/news/is-gas-a-good-energy-option-for-households, but also Table 5.5 on page 137 of the AER 2014 State of the Energy Market report.

43 See ACIL-Tasman report for ESCOSA, 2011, A review of the economic principles underpinning aspects of the draft price determination for the standing contract price of gas, available at: http://www.escosa.sa.gov.au/library/110630-ACILTasmanFinalReport-Public.pdf

44 See page 39 of AGL Energy FY17 Interim Results; Half year ended 31 December 2016, 9 February 2017.

45 See page 21 of Origin's Annual Report for 2014.

Win-backs and saves

Win-backs, to the extent they occur, may represent a significant barrier to expansion. A win-back arises where the incumbent retailer, on learning from MSATS that a customer intends to switch to a competitor, makes a counter-offer.

This may occur both during and after the mandatory cooling off period. This may involve price matching. Win-backs and saves could enable major retailers to discount from published rates, where customers have initiated or undertaken switching.

One effect of win-backs and saves could be to raise the average cost of customer acquisition significantly for any would be expanding retailers. This includes a higher risk of losing customers shortly after the cooling off period is completed, and where no termination charges were included in the relevant retail contract. In addition to unrecoverable customer acquisition costs, large scale win-backs could also adversely affect a retailer's wholesale trading position, and potentially result in un-recoverable wholesale costs.

Concerns over the potential competitive impacts of win-backs and saves led the New Zealand Electricity Authority to consider imposing restrictions on win-backs to support retail competition.[46] The outcome was an amendment to the New Zealand electricity rules (The Code) allowing energy traders to elect to have switch protection.

The authors are not aware of any similar regulatory scrutiny in Australia. Annual reporting by major Australian energy retailers highlights the success of retention programs, including discounting. They also highlight that retention is more significant than acquisition in terms of customer account numbers.

In a report to the AEMC as part of its 2014 retail competition review, it was noted that major and larger second tier retailers were engaging in more sophisticated retention strategies. This includes *'Contacting customers that have indicated they intend to switch (either directly or through a Business-to-Business (B2B) notification) and offering them a higher discount to stay ('save calls').'*[47] In its Final Report, the AEMC notes save calls are occurring but does not comment on their potential for adverse competition effects.[48]

4.2.2 Customer platforms

Customer service costs

The major retailers have invested heavily in scalable retail enterprise resource planning (ERP) platforms offering dual fuel capabilities. These systems provide an integrated platform encompassing most or all of the company's data bases and business processes, including the Customer Information System (CIS), billing and debtor management systems, and many others.

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46 See *Competition effects of saves and win-backs, decisions and reasons*, Electricity Authority (New Zealand), October 2014 available at: https://www.ea.govt.nz/development/work-programme/retail/winbacks-and-saves/development/decisions-and-reasons-published/

47 See K Lowe Consulting and Farrier Swier Consulting, *2014 Retail Competition Review: Retailer Interviews*, report for the AEMC, June 2014, page 61.

48 See AEMC, *2014 Retail Competition Review, Final Report*, page 36.

Notable ERP upgrade projects include:

- AGL's project Phoenix. This was a multi-year SAP rollout intended to replace multiple legacy retail platforms. AGL did not acquire any of the three NSW retailer platforms, and therefore did not need to consider any further structural changes to its retail platform.
- Origin's retail transformation project. This is an ongoing multi-year SAP rollout to replace multiple legacy retail platforms. This was complicated by Origin's purchase of an additional 1.6 million Integral and Country Energy customers in NSW.
- EnergyAustralia's C1 project. This includes the EnergyAustralia Integration Program designed to merge the SAP system operated by Ausgrid for 1.6 million NSW customers under a Transitional Services Agreement, with the Oracle system developed under the former TruEnergy.

A stand out feature of all three of these programs is they highlight the extensive project and financial risks around modernising and enlarging retail platforms. While two out of the three platforms use SAP, it appears these risks may be intrinsic to the nature of retail platforms in the NEM, rather than the particular enterprise resource planning (ERP) system being used.

Each ERP system needs to be custom designed for the NEM/NGM. This reflects the unique and highly complex institutional arrangements, alongside the need for retailers to exchange high volumes of data with multiple external databases, in real or near to real time.

A key aspect of two out of three of these platform projects is outsourcing. AGL has outsourced to Tata consulting services and IBM. Origin has outsourced to Wipro Technologies.

AGL informed its shareholders that Project Phoenix suffered extensive project completion delays and cost over-runs.[49] Project Phoenix has subsequently led to identification of costs that were previously unrecovered.[50] Subsequently, shareholder reporting suggests AGL has reduced some operating costs and provided greater flexibility in terms of its product design cycle and execution of sales campaigns.

Origin Enegy also informed its shareholders that its retail transformation project had incurred extensive delays and cost overruns.[51] This may also have included higher payments under its Transitional Services Agreements with Endeavour and Essential Energy. During cutover to the new system it is reported that 180,000 late energy bills were issued to customers in September 2012. As a direct result, bad and doubtful debt increased by $43m.[52] It is also likely that working capital costs would have been much higher due to an increase in average debtor days.

EnergyAustralia's C1 incurred extensive implementation problems including delayed billing, registration and credit management issues. This included 100,000 unbilled accounts over 20

49 See AGL Annual Reports and other information for investors over the period from around 2009 to 2013.

50 See http://www.theaustralian.com.au/business/latest/trouble-looms-as-agl-powers-on-project-phoenix/story-e6frg90f-1225764548847

51 See Origin Annual Reports for the 2013/14 and earlier periods.

52 See http://www.itnews.com.au/News/355572,origin-energy-lifts-itself-out-of-sap-doldrums.aspx

days.[53] This is likely to have resulted in higher bad debts and higher working capital costs. It may also have led to higher payments under its Transitional Service Agreement with Ausgrid.

Smaller retailers may seek to outsource aspects of their retail platform, use higher cost/less flexible legacy platforms, or use simpler but more labour intensive processes. It seems likely that smaller platforms are less efficient and possibly also less flexible. This a key driver for the major retail upgrade programs described above.

The recent round of platform upgrades were undertaken despite widespread industry experience around retail platform risks. Notable examples arose under previous retail platform upgrade programs associated with the introduction of retail competition, notably Integral Energy, and the formation of Country Energy from North Power, Advance and Great Southern Energy. In addition, Synergy experienced significant cost over runs and billing problems in its billing system.[54]

Single platform across the NEM

A notable feature of modern retail energy platforms is that, while some features may be jurisdiction specific, a single platform is used for all customers across the NEM for all the major retailing functions. Jurisdiction specific features may increase the overall cost of the platform.

Once in place, the platform cost is recovered from across the customer base. As a result, any differences in internal retailer costs between jurisdictions – leaving aside differences attributable to the level of consumer switching – are likely to be modest. This is also reflected in the fact that retailer financial reporting systems do not track internal retail costs depending on whether a customer is located in Victoria or elsewhere.[55]

In order for a retailer to expand it must own or have access to a scalable retail platform. These platforms integrate retail activities and enable retailers to serve customers including billing and debtor management.

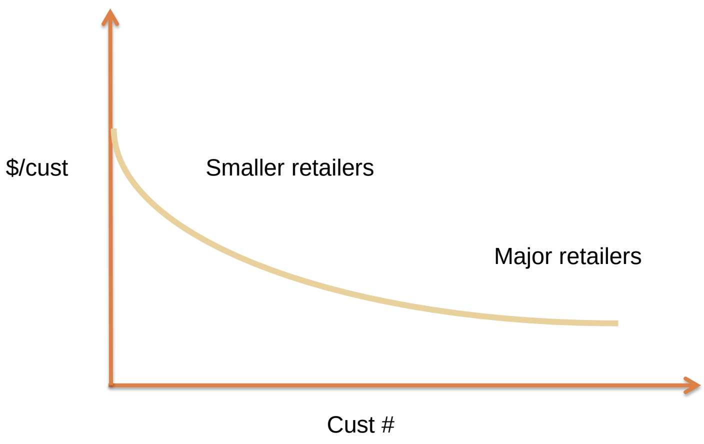
If the platform is scalable, then as the customer base expands, the unit cost to serve per customer should decrease. This reflects the high proportion of retail platforms that are fixed and do not vary in proportion to customer numbers. An objective of reducing per account costs, and thereby improving competitiveness, may form a key driver for a retailer's expansion program. The idea of economy of scale and a retailer cost curve is illustrated in Figure 4 below.

53 See page 62 of CLP Holdings 2013 Annual Report.

54 See for example: http://www.parliament.wa.gov.au/parliament/pquest.nsf/0/1e8e94f04798ab75c825765b001afe89?OpenDocument

55 See for example page 4 of *2011 Review of the South Australia gas standing contract retail operating cost and retail operating margin: Report to the Essential Services Commission of South Australia*, Sapere Resarch Group, available at http://www.escosa.sa.gov.au/library/110406-2011_ReviewGasOperatingCosts-SapereConsultantReport.pdf

Figure 4 Illustration of economies of scale



Source: Sapere

AGL reports that its core cost to serve per account, excluding customer acquisition and retention costs, is $52 per account.[56] This increase related to a bad debt from an acquisition that had been identified in the acquisition due diligence process.

4.2.3 Wholesale market risk

Management of wholesale market risk is an essential requirement for retailer expansion. In the first place this requires the estimation of a forward internal transfer price (ITP) (for either or both gas and electricity) for the purpose of setting retail prices for each product/retail supply market/customer segment, to apply for the sales and marketing campaign. The ITP is the wholesale price set between the group responsible for wholesale purchases and the group responsible for retail sales within an integrated retailer.

The ITP needs to be set so that it reflects prevailing wholesale market conditions, not prevailing retail market conditions. This is formalised by the existence of a middle office to provide an independent check of the formation of the ITP and its actual application.

During a sales campaign, a prudent retailer is likely to purchase some options or hedges. The forward contract portfolio would be modified over the course of the sales campaign in response to changing retail and wholesale market conditions. This is to avoid or minimise the risk of financial losses following a significant rise in wholesale prices compared with the assumptions on which the ITP was formed.

Falling wholesale electricity prices create opportunities for expansion by smaller retailers. This is because smaller retailers are less likely to be exposed to forward contracts that have been rendered 'out of the money', or to the costs of writing off or mothballing generation capacity.

[56] See AGL, Op. Cit. page 14.

In effect, smaller retailers hold relatively short duration forward positions. This is advantageous where prices are falling because the wholesale price reduction will flow through to a lower ITP than otherwise.

The major retailers, by contrast, hold relatively long duration trading positions, including via vertical integration with generation. This is disadvantageous when prices are falling because a retailer with a longer duration trading position will have a higher ITP than otherwise.

In theory, smaller retailers could offer potential customers with the major retailers lower retail prices while fully recovering their internal retailer, ITP and other supply cost components. Over a period of time, this could result in some reapportioning of aggregate market shares in favour or smaller retailers. Whether this is feasible in practice depends crucially on liquidity in forward contracts markets (or hedges).

Rising wholesale gas and electricity prices, on the other hand, represent a barrier to expansion by smaller retailers. This is because longer duration forward trading positions held by major retailers are likely to be set at much lower prices than prevailing wholesale prices.

As discussed earlier, any electricity only retailer can be expected to consider the feasibility of expanding into gas retailing, in order to offer dual fuel. However, current volatility in electricity and gas wholesale markets, with rising future prices, and limited liquidity, make such an expansion highly challenging.

Wholesale market liquidity

A key concern for any expanding retailer is the liquidity of forward hedge markets. Wholesale hedges reduce uncertainty over future wholesale purchase prices for retailers. Hedges may take a variety of forms, including swaps, options and caps.

The requirement to put in place a forward hedge portfolio arises in part due to the likelihood that customer acquisition costs will be capitalised and then recouped over a number of years. A three year amortisation period is not untypical. In this case, a retailer will need to hedge some portion of its forecast sales for three or more years into the future.

The requirement to hedge also arises because of the need to minimise the cost of credit guarantees. An expanding retailer is likely to need to procure a larger credit guarantee. This is because prudential settings scale with customer numbers and sales volumes.

Under AEMO prudential settings, the size of the credit guarantees required may be reduced by way of offsetting bilateral and other hedge arrangements registered with AEMO – known as reallocations.

In retailer interviews for the 2014 AEMC retail competition review, retailers noted that limited forward electricity wholesale market liquidity represented a barrier to expansion. One retailer interviewed expressed concern the duration was too short, the product mix was problematic and the minimum transaction level too high.[57]

A key challenge for a non-vertically integrated retailer is obtaining sufficient forward hedges (such as caps) to protect against extreme wholesale market price volatility for the entire

57 See K Lowe and Farrier Swier Consulting, Op. Cit., page 35.

duration of the period required to recoup the cost of customer acquisition (say three years), at a competitive price. Caps may be available for part of this period, but not for the full period. If caps are not available for the latter half of the period, then the retailer is exposed to the risk that the cost of caps substantially increases relative to the cost assumed when offering three year pricing contracts.

This risk may be managed in part by changing retail prices, as is allowed under multi-year retail contracts. There is, however, a risk a price rise may result in customers switching away before amortisation of customer acquisition is complete.

A retailer's portfolio of forward hedges needs to be formed so that it matches the retailer's forecast aggregate demand profile for each half hourly trading interval for each wholesale market region (or fuel) it is retailing in. To the extent there are mismatches between the hedge portfolio and the actual consumption of its customers in any given trading period, the retailer is exposed to wholesale spot price risk.

In the NEM, this risk is greatest during spikes in wholesale prices. These price spikes are strongly correlated with demand spikes leading to generation congestion, as well as transmission congestion limiting transfers from other regions.[58] So during such an event, a retailer is likely to be both increasing its quantity of wholesale spot purchases and potentially being liable for substantially higher prices for each unit.

If a retailer has insufficient hedges in place, it will be exposed to spot prices. The outcome may be that actual wholesale purchase costs are substantially higher than assumed in the ITP for a given customer segment on which contracted retail prices were set.

In this case, the retailer would be selling energy for less than it cost to the retailer, and the retailer could make substantial financial losses on these sales. These losses may not be recoverable from customers and hence would need to be recovered from shareholder funds. The risk of such losses, and inability to hedge perfectly, is one of the reasons prudent retailers require a mark-up (margin) over their cost of sales and own costs.

This may be illustrated by reference to an extreme weather event. While the average wholesale price for NSW for the whole of 2017-17 was $81.22/MWh, the price may be 400 times this amount during price spikes. Price spikes are strongly correlated with high coincident system demand. Average small customer demand profiles are notable for being strongly associated with peak system demand and price spikes.

During an extreme heatwave in NSW and Queensland on 10 February 2017, wholesale prices went to $12, 221/MWh in Queensland and to $14,000/MWh in NSW.[59]

Price spikes and the more "peaky" demand profile of small customers mean that a mass market retailer's exposure to spot market prices is significantly leveraged. If a retailer acquires 10,000 new customers with an average annual demand of 6MWh, its annual liability for energy is in the order of $2,400,000 (volume times an historical average spot price of say $40/MWh) or $6,700 per day. However, as price spikes may contribute about a third of the

58 See *Implications of extreme weather for the Australian National Electricity Market: historical analysis and heatwave scenario* by Sapere, dated August 2014.

59 See page 5, Electricity spot prices above $5,000/MWh, New South Wales & Queensland, 19 February 2017, published by the AER on 5 May 2017.

average price, the retailer may be liable to $200,000-400,000 for these customers in a single afternoon. This could be sufficient to breach the AEMO Maximum Credit Limit.

If a retailer has acquired significant new customers over a period before a major price spike event, this could trigger a substantial increase in the retailer's prudential requirement with the AEMO. A similar outcome is also possible due to a steep increase in wholesale prices, as occurred in 2007/08 as a result of extended drought constraining generation output.

The Rules permit AEMO to change a participant's prudential settings at any time with one day's business notice. Any changes that result from the prudential settings require the retailer to increase its credit support by no later than 11am on the effective date. If the retailer fails to provide this increased support by the relevant time, this constitutes a default event.

The risk of being exposed to a default, together with limitations around the liquidity of forward hedge cover against price spikes, are likely to represent significant barriers to expansion for smaller retailers. This barrier could apply even to vertically integrated retailers with substantial generation, due to the likelihood of network congestion during the periods when exposure to spot prices is likely to be most significant.

Similar observations apply to gas, albeit gas market volatility is much lower than electricity. Integrated energy companies operating gas generation and with significant upstream gas investments may have a significant competitive advantage in sourcing competitive wholesale gas supplies. This is even more so, where companies are able to manage a portfolio of sales, with winter gas sold for heating and summer gas used for peaking generation. Such a portfolio would significantly reduce average upstream and transmission costs compared with a gas only retailer. This partly explains why there are no gas only retailers outside Tasmania.

A key advantage for major retailers with well-matched generation portfolios is they are less likely to be exposed to liquidity shortfalls. In effect, a vertically integrated internal retailer holds an option over the portion of future related party generation capacity that has not already been committed to external retailers.

This opens the opportunity for integrated generators to act strategically in considering how far into the future to offer forward wholesale contracts to external retailers. The incentive for acting strategically is limited if competition in retail markets is effective and retail margins are no more than as is required for retailers to recover their costs.

This may, however, change under conditions where retail markets are not effectively competitive and supra-normal margins are available. Under these conditions, it could be profit maximising for the related party generator to favour the internal retailer. Even if the internal retailer pays the same average hedge price as external retailers, the internal retailer could be advantaged in other ways, including by way of a long forward duration, or a load shape that more closely matches the relevant demand profile. Relatively small differentials in duration and/or half hourly profile may create a significant cost advantage for the internal retailer, once risk and uncertainty are taken into account.

Incentives for vertical foreclosure

A possible further set of barriers to expansion by smaller retailers may arise to the extent retail markets are not workably competitive. As noted in Section 3.2.7 above, if retail competition is not fully effective, and super normal retail profit margins are available, then vertically integrated retailers would have clear profit maximisation incentives to restrict liquidity in forward contracts, or otherwise favour the internal retailer. Such restrictions could be relatively subtle, for instance by limiting the forward duration to shorter time periods, or by offering generation profiles that leave external retailers exposed to wholesale price spikes.

There is no clear evidence that vertical foreclosure occurs in the NEM. No suggestion that there is vertical foreclosure is being made here. Vertical foreclosure could represent the misuse of market power, which is prohibited under Section 46(1) of the Competition and Consumer Act 2010 (Cwth.).

Nevertheless, Snowy's reluctance to participate in some retail market segments suggests that Snowy is not confident there is sufficient forward wholesale market liquidity in the NEM, even for relatively flat profiles. If so, it is even less likely there is sufficient liquidity for more challenging demand profiles, typical of smaller business and residential customer bases. The fact Snowy underpinned its expansion into NSW with a purchase of further peaking generation in the form of the Colongra gas power station lends further support to this view.

4.2.4 Differential regulation

There is just a small set of matters where retailers are treated differently depending on whether they are major, vertically and horizontally integrated retailers. Two of these are a legacy of the transition to markets with multiple retailers (standing contracts and the closely related Local Retailer role).

Standing contracts

By its very nature, the regulatory requirement for retailers to offer standing contracts represents a restriction on competition, in the sense used in the COAG Competition Principles Agreement.[60] Under the Agreement, competition restrictions should not be imposed (or continue to be imposed) unless it can be demonstrated that:

- the benefits of the restriction to the community as a whole outweigh the costs; and
- the objectives of the legislation can only be achieved by restricting competition.[61]

Standing contracts are inimical to competition to the extent they represent a barrier to expansion by retailers and exacerbate existing retail energy market frictions. While customers on default contracts are contestable, they are not engaging in the competitive retail market.

According to the AER, a quarter of Victorian customers remain on standing contracts, despite the market being contestable since 2002.[62] While some of these customers may now be served by retailers other than each Local Retailer, it seems likely a majority of customers may remain with each Local Retailer. This is because a retailer other than Local Retailers would gain customers on standing contracts only where three conditions are satisfied:

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60 See COAG *Competition Principles Agreement* – 11 April 1995 (As amended to 13 April 2007), available at https://www.coag.gov.au/node/52

61 See also the Victorian Guide to regulation, available at http://www.dtf.vic.gov.au/publications/victoria-economy-publications/victorian-guide-to-regulation

62 The ESCV estimate is less than half of this estimate.

- a new customer moves into a residence currently served by another retailer (the retailer is already the financially responsible market participant (FRMP)); and
- when a new customer requests a new connection from a retailer, the customer is able to identify and make a request to the existing FRMP, not the Local Retailer or one of the many other retailers available; and
- the customer requests the default retail contract rather than the – most likely lower priced including prompt payment discounts – market contract option.

Local retailer, FRMP distinction

The distinction between the Local Retailer and the FRMP in the Rules may favour Local Retailers, competitively. This risk arises from an information access asymmetry.

Rule 7.7 (a) of the NER governs entitlement to metering data and access to metering installations. Rule 7.7 (a) states that, among the *persons entitled to access energy data (metering data, NMI Standing Data, settlements ready data or data from metering register for a metering installation are*:

(1) *'Registered Participants with a financial interest in the metering installation or the energy measured by that metering installation;' and …*

(3) *financially responsible market participants* [retailer]…

Due to settlement by difference, each local retailer has a financial interest in the energy measured by a metering installation, since this affects their retail market settlement liability. Where a customer remains with the local retailer, Rule 7.7 (a)(1) serves no function.

This suggests the Rule is intended to apply where a customer is served by a second tier retailer. As a result, this aspect of the NER appears to give Local Retailers (and hence the three major retailers) privileged access to electricity consumption and standing data.

Second tier retailers are only able to obtain consumption and standing data from a given metering installation (or retail customer) if they are the current FRMP, or if they are a customer authorised representative (Rule 7.7 (a)(7(ii)), or potential future FRMP. By contrast, it appears that first tier retailers are able to obtain consumption and standing data for all customers in their supply area, whether they are the FRMP or a second tier retailer is the FRMP.

Privileged data access by Local Retailers within major retailers may reduce average customer acquisition costs for major retailers, compared with other retailers, with respect to the areas where major retailers are Local Retailers. This becomes more significant in markets, such as Victoria, which are settled using interval market data.

This advantage has been reduced but not eliminated by the AEMC's 2014 Rule change allowing other authorised parties to gain access to historical energy consumption data.[63] The remaining advantage is that the Local Retailer may not need to incur the cost of contacting a given customer and obtaining their explicit informed consent before accessing their historical consumption (and standing) data.

[63] AEMC, Final Rule determination, National Electricity Amendment (Customer access to information about their energy consumption); National Energy Retail Amendment (Customer access to information about their energy consumption) Rule 2014, 6 November 2014.

Prudential requirements

Prudential requirements have the effect of treating vertically integrated electricity retailers differently from non-vertically integrated retailers. This is because prudential settings are reduced to the extent a retailer has offsetting generation output for the given region and trading intervals. As a result, a vertically integrated retailer will face much reduced requirements in terms of credit guarantees (ignoring the much higher likelihood a vertically integrated retailer would meet the AEMO's credit criteria).

A similar outcome arises for vertically integrated gas retailer with a wholesale trading arm that is injecting gas at bulk injection points, and possibly also holds upstream interests in gas basins. In this case, it is because the calculation of prudential settings will be set in recognition of the extent of net liabilities and these will be reduced where related parties are injecting wholesale gas.

Retailer of last resort (ROLR)

Retailer of last resort arrangements are incorporated into retail licence conditions. Victoria's RoLR arrangements treat the three major retailers differently from smaller retailers. Under the present arrangements for Victoria, RoLR obligations were assigned to the three major retailers. Under the current market structure, this means that the three major retailers are RoLR.

In the event of a RoLR event, the three major retailers could incur significant costs, including a requirement to increase their wholesale prudential guarantees and possibly also their distribution credit support. In recognition of this, the AEMC undertook a review of RoLR arrangements under the NECF as part of broader inquiry into NEM financial market resilience.[64]

While a RoLR event would pose short term challenges even to major retailers, the possibility of these events also represents an option for expansion while avoiding direct customer acquisition costs. To the extent this is the case, it is possible that RoLR arrangements, overall, could be beneficial for major retailers.

The AER has expressed concern in a submission to the AER about effects on retail competition through changes to market structure if the RoLR scheme transferred a large retailer's customers to other large retailers.[65] The AER saw merit in exploring arrangements to support or supplant the RoLR processes in the event of a large retailer failure.

4.2.5 Access to capital markets

The competitive advantages of vertical integration in terms of access to lower financing costs are discussed in a recent report prepared by AGL.[66] This argues that, under conditions that occur in the NEM, pure play retailers and generators are unable to sustain investment grade credit metrics.

64 See http://www.aemc.gov.au/Markets-Reviews-Advice/NEM-financial-market-resilience

65 See page 25 of the AEMC *second interim report, NEM financial market resilience*, August 2014.

66 See *Merchant firm boundaries in energy-only markets: Who gets a credit rating – Pure Play vs. Vertical?* by Paul Simshauser, Yuan Tian and Patrick Whish-Wilson, August 2014.

The three major gentailers and the two government owned gentailers are all investment grade. The government owned gentailers are able to access capital markets indirectly and pay debt guarantee fees. It is also possible that subsidiaries of other large energy companies, such as Simply Energy may be able to access capital markets indirectly via their owner.

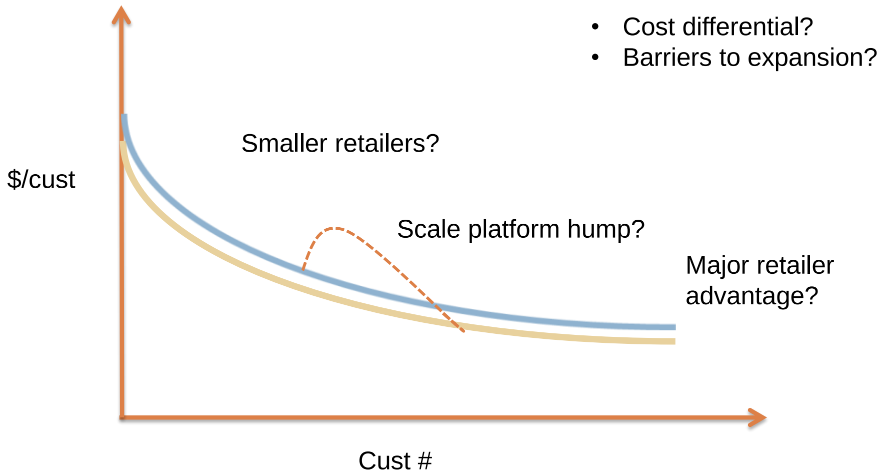
It is unclear how many smaller energy retailers in Victoria meet investment grade criteria. For such retailers, NEM prudential costs, and financing costs generally, are likely to be significantly higher than for investment grade firms, or their subsidiaries.

Recent Annual reports issued by Origin and AGL indicate the importance of maintaining investment grade rating. They also indicate the benefits; average debt financing costs for 2013-14 were below 5 per cent in nominal terms.[67]

4.2.6 Combined effect of barriers to expansion

The overall effect of NEM and NGM prudential settings, alongside gas and electricity network access arrangements is they appear to contribute toward a significant competitive advantage for major retailers. This is partly a product of the fact that major retailers are both vertically and horizontally integrated. Financing costs are also likely to be substantially higher for smaller retailers. In combination, these factors mean any smaller retailer seeking to expand is likely to face higher risks and costs than the major retailers with which it is competing. This overall conclusion is illustrated in Figure 5 below.

Figure 5 Illustration of possible barriers to small retailer expansion



The analysis of regulatory and market constraints on barriers to expansion suggests there may be a structural difference in the cost curves for major retailers and smaller retailers, indicated by the blue (smaller retailer) and brown (major retailer) lines. Not only is the blue curve higher than the brown curve, smaller retailers are situated to the left of the curve, while major retailers, especially Origin and AGL, are down at the far right or lowest part of the brown curve.

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67 2014 AGL and Origin Annual Reports, Op. Cit.

A further suggestion is the possible existence of a hurdle represented by the very high risk and cost of designing and implementing a scale retail platform. A separate but related set of hurdles also apply to expansion into generation, from retail electricity to retail gas, and from retail gas into upstream gas markets.

Even vertically integrated retailers such as Snowy (Lumo and Red Energy) and Hydro Tasmania (Momentum) may face significant wholesale market risks and challenges. In the first place, they arise from the risk of transmission congestion. If congestion occurs, then Snowy and Hydro Tasmania may face significant wholesale market risks.

As noted by the CEO of Snowy, Paul Broad: '*We don't want to get big and go broke*.'[68] In the same article it was noted that 'Snowy will not be chasing growth for the sake of it and does not expect to challenge the dominance of the big three suppliers…' The article indicated that Snowy considered that in '…*big base loads, we're not that competitive*…'. The article also noted that 'the pressure is on to prove the worth of the energy supplier's $834 million acquisition spree…. [Acquisitions] have almost tripled government owned Snowy's debt to about $1.2 billion. Its BBB+ rating is unchanged.'

4.3 Incentives for larger retailers

4.3.1 Do major retailers have an incentive to expand?

Statements by two of the three major retailers indicate their objective is to maximise their share of customer value, rather than increase market share. The fourth largest retailer, Snowy, has also expressed similar views.[69] It appears that AGL and Origin (and Snowy) are seeking to minimise acquisition while maximising retention.

This raises the question whether the major retailers have strong incentives to expand in Victoria. They may prefer instead to maintain market share. In this case, competition between the major retailers would be limited to retaining rather than gaining customers.

Retention is far lower cost than acquisition. But in addition, retention offers greater opportunities for incumbent retailers to segment customers and thereby limit the scope of retail price discounting. Instead of discounting from prevailing retail prices (via discounted published prices), to gain customers from rivals, discounting may be targeted to selected customers at risk of switching, or who may have initiated but not completed a switch.

Origin's shareholder presentation accompanying its 2014 Annual report emphasises *'margin management'*, *'reducing operational costs'* and *'limiting capital investment'* (in retail).[70] The report also refers to the *'success of retention programs reducing churn'*. Origin observes that 'the market has seen reduced churn driven by the withdrawal from door-to-door by Tier 1 retailers. In addition, Origin has focused on *'greater use of internal sales channels, lowering cost to serve*'.

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68 See *Pressure is on for Snowy* Hydro, Australian Financial Review, 11th February 2015

69 See section 4.2 above.

70 See 2014 *Full Year Results Announcement, Financial year ended 30 June 2014*, Grant King, Karen Moses, 21 August 2014.

Similarly, AGL's Annual Report emphasise that its objective is to *'grow retail margins and market share of customer value'*. In other words, AGL is seeking to maximise margins and its share of aggregate retail margins, not sales volume.

4.3.2 Possible tacit coordination

Without explicit coordination, where certain conditions apply, each retailer can independently arrive at a decision to set prices in such a way as to maximise its profits. Tacit coordination may arise under conditions where, if one major retailer decreases its price, in order to acquire customers from the other major retailers, it can expect other retailers to follow suit. This would decrease the profits of all major retailers and hence is not in their interest, individually or collectively.

As a result of anticipating pricing decisions by their major rivals, each retailer can maximise its individual profit by setting prices significantly above its costs. Under these conditions, retail prices reflect profits or margins significantly in excess of efficient profits/margins. Even though each participant is making independent decisions, the outcome may be the same or similar to the outcome that would occur if there were explicit coordination in pricing decisions.

The necessary pre-conditions for such outcomes include:

- Prices are transparent – retailers can readily compare their prices with those of their competitors;
- The firms are broadly symmetrical in terms of scale, footprint and capability; and
- There is sufficient spare capacity or other conditions that enable competing firms to respond, in the event one firm decides to break the tacit profit maximisation agreement.

All of these conditions appear to hold in the parts of Victoria's electricity markets where customers have opted to remain under standing contracts, or with major retailers at higher prices rather than with smaller retailers offering lower prices (normalising for supply and service quality). Prices are transparent, by regulation. All three major retailers are broadly symmetrical, including being Local Retailers in some retail supply areas. They all have readily scalable retail platforms and an ability to generate or procure additional wholesale supply (especially given excess generation capacity across the NEM).

In addition, incentives to avoid monopoly pricing behaviour may be reduced by the absence of regular and effective regulatory monitoring of retail markets, as discussed in Section 4.1.3 above. Moreover, no evidence from formal retail market monitoring contradicts the proposition that some retailers are engaging in monopoly pricing behaviour.

4.3.3 Contrast with NSW post-privatisation

The current situation in Victoria is unlike the situation that existed for a period in NSW following privatisation of the three NSW government owned retailers. In this case, there was an important asymmetry between the three major retailers.

The major retailer in gas markets was a second tier retailer in NSW electricity markets, whereas its competitors had become Local Retailers, by acquisition. In response, the major first tier gas retailer, AGL, undertook an active electricity customer acquisition strategy.

AGL's acquisition strategy resulted in a large transfer of customers from EnergyAustralia to AGL. In volume terms, customer switching in NSW substantially exceeded switching in Victoria.

For a period, this rivalry may have placed downward pressure on margins across most of NSW, especially under broader conditions of flat or falling demand, and excess generation capacity. This largely excluded the Essential Energy area, where retail competition is far more muted.

4.3.4 Implications of a 2014 merger Authorisation

Concerns over the possibility of vertical foreclosure by generators are part of the reason the ACCC has opposed two generation acquisitions by AGL. In 2014, the ACCC opposed AGL's purchase of Macquarie Generation.

In June 2014, the Australian Competition Tribunal overturned an earlier ACCC decision not to grant conditional authorisation to AGL's proposed purchase of Macquarie Generation.[71] This was subject to an obligation for AGL to offer a minimum quantity of forward hedge contracts to smaller retailers for a period of seven years.

The ACCC's principal concern about the Proposed Acquisition was that it would increase barriers to entry and expansion in the retail supply of electricity in NSW by:

1. significantly reducing liquidity in the supply of hedge contracts since AGL's retail load would be supported with a natural hedge; and
2. increasing AGL's ability and incentive to withhold competitively priced and customised hedge contracts to independent retailers.

The Tribunal found that:[72]

- It is clear that the market for the generation and supply of electricity is a national market.[73][74]
- The Tribunal has found that the relevant retail market for electricity is a NSW one.[75]

The Tribunal's finding that the market for generation and supply of electricity is a national market contradicts the suggestion made by the AEMC in its 2014 retail competition review that the explanation for higher observed retail margins in Victoria may be attributable to higher wholesale costs (see discussion in Section 4.1.3).

71 See http://www.accc.gov.au/media-release/accc-disappointed-by-tribunal-decision-authorising-agl-to-acquire-macquarie-generation

72 See http://www.judgments.fedcourt.gov.au/judgments/Judgments/tribunals/acompt/2014/2014acompt0001

73 Paragraph 280, Op. Cit.

74 Note that this is supported by analysis of forward contracts *for DPI* in *Sapere Research Group, Comparative analysis of household energy bills 2013.*

75 Paragraph 294, Op. Cit.

The Tribunal's finding focused on supply of hedge contracts and did not address whether vertically integrated generator retailers have an incentive to price competitively or use other means to seek to shut out smaller retailers through strategic pricing of hedge contracts.

In addition, the Tribunal considered that Victoria's retail markets were competitive.[76] This implies it considered there were no sustained supra-normal retail margins available.

This meant the profit incentive for vertical foreclosure may not have been fully addressed in the Tribunal's considerations. Accordingly, some parts of the findings around the risks of vertical integration for competition may be less relevant where a retail market is not effectively competitive, and there are supra-normal retail profits. As a result, the Tribunal's findings do not contradict the proposition that vertical foreclosure could occur and affect retail competition.

The Tribunal's conclusions also highlight a further problem with the absence of effective retail market competition. It may contribute to unfounded assumptions being made in merger decisions.

4.4 Concluding remarks

This section sets out evidence and considerations as to how, despite contestability of wholesale and retail electricity markets, actual costs, profits and margins are higher than efficient costs, profits and margins, as discussed in Section 3 above. On the supply side, key issues include barriers to expansion by smaller retailers and weak incentives for rivalry by larger retailers.

In combination, retail prices are constrained only in limited pockets where highly engaged consumers are able successfully to exert downward pressure on retail prices. From the available evidence, these pockets do not appear to overlap with agricultural producers. This suggests that agricultural producers are among the majority of smaller customers where actual power prices are well in excess of actual power prices. The extent to which there are downward pressures on retail prices appears to be strongly related to the nature of customer interaction with retail markets. This is discussed in the following section.

76 See for example paragraphs 344, 359 and 361, Op. Cit.

5. Customers and their interaction with the market

5.1 Introduction

This section focuses on demand side frictions that contribute to and complete a possible explanation as to why retail market outcomes do not appear to be consistent with workably effective competition. This includes a section on the limited evidence around irrigation customers and their interaction with competitive markets.

Along with the various supply side issues set out in the previous section, there are significant demand side issues that impede competition and together with supply side issues appear to result in pricing and other outcomes that are inconsistent with the existence of workably effective competition in Australia's deregulated electricity markets.

The ACCC is interested in exploring:

- *the extent to which customers are currently able to make informed choices about electricity, including the ability of customers to understand and compare electricity offers*
- *differences between and within different customer groups*
- *any impediments to informed decision making (such as low energy literacy)*
- *ways that customer decision making and outcomes could be improved*
- *how electricity usage data is, and can be, provided to and used by customers to enable them to better engage with the retail electricity market*
- *practices of retailers that affect customers' ability to participate in the market from confusing or misleading marketing to impediments to switch*
- *the ways that customer experience may impact on competitive outcomes.*

The ACCC seeks feedback from all interested parties on:

8. Any impediments that customers face in choosing a retail electricity service and any differences between customer types and NEM areas.

9. How customers' ability to make informed choices about electricity can be improved.

While this section of the paper focuses on household and small business customers, the ACCC welcomes views on issues that other customer types face. All interested parties are welcome to respond to these questions, however, they are targeted at customers and customer groups.

5.2 Retail market frictions

Retail market frictions principally take the form of high search costs for consumers (the Diamond Paradox). This means that competition is only effective in constraining prices in some smaller market segments. Market frictions such as search and switching costs, regulation and the interaction between these can exacerbate these market dynamics. The key frictions are search costs and switching costs, with search costs generally agreed as being the most important. Search costs have been shown to have significant impacts on market efficiency.

One example of this is the Diamond paradox.[77] This occurs when, despite there being multiple firms, they can charge monopoly prices. If there are material search costs, and consumers think that firms are all charging at the same level, consumers may not be bothered searching for better prices but simply choose a firm at random (or where default contracts are available, make no choice at all). The profit maximising response for firms is to charge a monopoly (significantly higher than efficient cost) price for these consumers.

It is also possible that regulation is playing a role. Customers remaining on standing contracts are less likely to switch retailers. They have had the option to enter the competitive part of the market in NSW, ACT and Victoria since 2002, and for more than a decade in both SA and Queensland but have chosen not to choose.

Standing or deemed contracts are a restriction on competition designed to assist in the transition to a competitive retail market but they have become a default option for disengaged or passive customers. In some jurisdictions, all retailers are obliged to offer standing offers. In other jurisdictions, Local Retailers are obliged to offer deemed contracts.

Passive consumers do not constrain firm pricing decisions to the same extent as active consumers. This reduction in price sensitivity by passive customers can translate into a lessening of the intensity of competition and, as a result, higher prices for consumers.

In the United Kingdom, a 2005 study of consumer choice gas and electricity retail markets found that most consumers were unlikely to switch their provider even though most knew they could switch.[78] This study concluded that search costs and perceptions of search and switching costs were important market frictions and that choice alone was not sufficient as consumers had to be prepared to exercise that choice if deregulation was to yield benefits. A subsequent 2010 study used a model of search costs to estimate a search cost distribution. It found that observed price patterns in the GB retail electricity market fitted with the view that search costs there were relatively high and the model supported that most consumers would not search or switch.[79]

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77 See a brief explanation here: http://economix.blogs.nytimes.com/2010/10/11/the-work-behind-the-nobel-prize/?_r=0

78 '*Consumer Choice and Competition Policy*': A study of UK energy markets, Giulietti, Monica., Waddams-Price, Catherine., Waterson, Michael., Economic Journal. Oct 2005, Vol. 115 Issue 506, p949-968. 20p

79 Estimation of Search Frictions in the British Electricity Market, Monica Giulietti, Michael Waterson and Matthijs R.Wildenbeest. Warwick University Research Papers, Number 940, 2010.

A report for the AEMC's 2014 retail competition review found that interest in looking for a better deal was relatively high, but many are simply disinterested.[80] Around 13 per cent of residential customers said they were currently looking for a better deal. However, 46 per cent were interested but not currently looking and 37 per cent were not interested. This implies that six out of ten customers were passive. When residential customers were asked about their likelihood of switching energy company or plan in the next 12 months 46 per cent were not interested[81] while 28 per cent were fairly interested[82].

This is comparable to the results found by Ofgem in its study of United Kingdom consumers in 2011[83] where a range of 10 per cent to 20 per cent were found to be active as they were likely to have switched provider or tariff within the last year either through their own searching or by contact with a sales agent.

Entrant retailers face a restricted pool of potentially interested consumers and acquisition costs are significantly higher. This may be exacerbated by standing offers which allow no engagement in the market. Overall, these market frictions reduce competitive pressure and consumer welfare.

Search costs also include complex retail tariffs and limited usefulness and complexity of price comparators. There appear to be ongoing difficulties with timely and efficient consumer access to energy consumption data.

Other barriers include a lack of transparency over the split between network and other costs in retail bills. In addition, it appears there remain significant barriers to customers obtaining their own energy consumption data. While reforms proposed in a 2012 report prepared by the present authors were adopted in part in the AEMC's 2015 Power of Choice decision[84], the Finkel Review suggests further improvements could be made.

Significant discounts relative to standing and market contracts are available for customers who are prepared to switch retailers. While some customer segments appear to be able to take advantage of these discounts, the available evidence suggests that most customer segments are not able to take advantage of discounts and end up paying higher prices than are otherwise available.

The available customer switching data suggests that consumers outside cities – possibly including irrigators – may be less likely to switch retailers.

5.3 (Lack of) retail innovation

Section 2.1 observed that, while a diverse group, agricultural producers pumping water as a key input to production possess general characteristics that have, historically, made it feasible to purchase electricity under specially designed, price regulated irrigator tariffs. The design of

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80 See a report prepared for the AEMC '*Consumer research for nationwide review of competition in energy retail markets; qualitative and quantitative research*', Newgate Research, June 2014.

81 A rating of 0 to 3 on the 10 point scale.

82 A rating of 4 to 6 on the 10 point scale.

83 Ofgem The Retail Market Review - Findings and initial proposals, 21 March 2011, Supplementary appendices, page 5

84 See

these tariffs recognised both that irrigators may use significant volumes of electricity, including schemes pooling farm demand, and that irrigator demand profiles are relatively flat.

As retail electricity markets have been opened to competition, regulated irrigation tariffs have largely been replaced by business tariffs. Irrigation tariffs remain in regional Queensland but are in the process of being phased out under regulated pricing decisions set by the Queensland Competition Authority.

As explained in section 2.1, irrigators and agricultural producers have attractive load profiles and significant volumes compared with other users. In addition, some irrigators and agricultural producers may have the ability and willingness to modify their demand during the very limited time periods when network and generation capacity is congested and retailer supply costs are correspondingly extremely high. [85]

In workably competitive markets, we could expect to see retailers develop products that are at least broadly comparable to the old regulated irrigator tariffs. Indeed, with the falling price of ICT, innovative tariff designs could be expected.

Under such tariff structures, irrigators could be rewarded for reducing consumption during extreme peak demand and price periods. Such tariffs would reduce retailer supply costs because they would:

- Transfer volume/price risk during brief periods of wholesale market congestion from retailers to irrigation consumers;
- Reduce retailer's wholesale market spot purchase and hedging costs; and
- Increase the potential benefits to retailers from switching customers to time of use or maximum demand related network tariffs with significant discounts in network prices.

However such tariffs are so far not forthcoming in contestable markets.

Energy Consumers Australia has recently agreed to fund the NIC Energy Task Force to undertake primary research into irrigator engagement in retail energy markets. Pending this work, there are indications that:

- NSW irrigators may be paying relatively high prices due to weaker retail competition in the Essential Energy retail market.
- All irrigators may be paying higher prices than may be available due to the search cost problem identified.
- Irrigators in Queensland are paying higher prices than otherwise, due to the QCA's over-estimation of retail costs.
- There is also evidence that electricity prices are higher than otherwise because they require irrigators to contribute to cross subsidies in favour of consumers with high cooling loads.

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[85] We strongly recommend the ACCC avoid falling into the common error of focusing on misleading daily demand profiles. Daily profiles reduce half hourly annual demand profile data to 48 daily or perhaps 192 seasonal profiles, but are of little value in understanding electricity supply costs or efficient pricing. This is explained in section 3 of a 2016 report by the present authors: *Errors in Australian Energy Regulator's Draft Decision on Ergon Energy's 2016 Tariff Structure Statement*.

5.4 Demand response to excessive prices

Up until the last decade, electricity demand was considered to be relatively inelastic – demand would not respond to increases or decreases in price. The substantial run up in retail prices as described in Figure 1 of the ACCC Issues Paper is, however, contributing to a substantial demand response. Coincident with the increase in prices across the NEM, aggregate demand has been decreasing.

According to the AEMO's 2017 Electricity Forecasting Insights report, this is expected to continue. Indeed, compared with its 2016 National Electricity Forecast Report, forecast demand for the next decade is now forecast to be lower.

Demand from the grid, however, is forecast to stay flat, as consumers increasingly control their own use and costs, reducing their demand for grid supply by:

- *Generating their own electricity behind the meter (through rooftop PV, cogeneration, and other small-scale generation technologies on their own premises).*
- *Using more energy-efficient appliances, buildings, and machinery.*
- *Changing their behaviour to reduce electricity use where possible.*

The case studies set out in Section 2 show that agricultural producers have responded to higher electricity prices by

- reducing demand for network provided electricity by reducing production
- reducing demand for network provided electricity through increasing energy efficiency;
- substituting demand for network provided electricity with distributed generation; and
- collaborating with other energy users to strengthen bargaining power in electricity markets.

Demand response to efficient prices is economically efficient and desirable. However, as established in the preceding sections, current costs, profits and prices across the NEM supply chain are well above efficient prices.

Demand response to inefficient prices is not economically efficient or desirable. The result is that resource misallocation within the electricity sector is transmitted into other sectors of the economy. As documented in the case studies in Appendix, resource misallocations are now arising in the food and fibre sector.

Of even greater concern is there are further substantial increases in prices and costs that are already in train. These include the retail price increases effective from 1 July 2017 and the network price increases due to take place in NSW and the ACT from 1 July 2018.

There is no evidence that rising network and wholesale costs are leading to a substantial moderation in public retail prices offered by the major vertically and horizontally integrated retailers. However, there are indications that rising wholesale costs, and reduced liquidity, could further weaken the pockets retail markets where competition is effective in constraining prices.

5.5 Concluding remarks

This section has set out how features of the demand side of electricity markets are contributing to and interacting with the supply side issues set out in Section 4. Together, supply and demand issues help to explain the inefficient pricing outcomes set out in Section 3 (excluding problems with network regulation discussed in Section 3.2.1).

The available data suggest that demand side issues are adversely affecting agricultural producers. Most notably, it appears that in regional NSW, for example, there is weaker competitive pressure constraining retail prices and margins.

Because of the network boundaries, NSW has the clearest distinction between regional and metropolitan retail electricity markets. The Ergon boundary is less useful because retail competition is not feasible due to the Queensland government's Uniform Tariff Policy. In other jurisdictions, network boundaries tend to overlap regional and metropolitan areas.

We would encourage the ACCC to exercise its information gathering powers, to the extent possible, to identify those parts of the market where competition is more or less successful in constraining retail prices. In particular, the ACCC could seek more detailed retailer data on the size and characteristics of customers who are currently accessing the most competitive (lowest) retail prices (or least competitive retail prices). Ideally, if this data were sorted by post code or similar geographical categories, it may be possible to draw robust conclusions on whether regional customer groups are perhaps more likely to be paying more for their electricity than comparable customers elsewhere (after accounting for likely higher distribution and electrical loss costs in regional areas).

Appendix 1 About the authors

Simon Orme is an economist who provides expert advice and management in complex, high-stakes issues in energy, infrastructure, utilities and public policy. He advises industry and government clients in infrastructure access regulation and pricing in the energy, water, and telecommunications sectors.

James Swansson is a managing consultant in Melbourne who specialises in the development of evidenced-based solutions to complex problems, particularly through the design and application of analyses in data rich contexts. He has worked on a wide range of projects in Sapere's energy, transport and health practices, providing economic data analysis and modelling of complex data sets.

Simon is one of Australia's leading experts on energy retail competition. This was acknowledged by his selection by the WA Public Utilities Office (PUO) to lead a review of electricity retail costs, prices and margins across Australia for the WA Electricity Retail Market Review. In addition, Simon led a separate project for the WA PUO on the design of a legislative scheme for best practice energy retail regulation for WA. This project required consideration of the effectiveness of existing and previous regulation schemes, changes in retail energy markets relevant regulatory and economic theory and international developments.

Simon and James have undertaken several projects for the Energy Division of the Victorian government (through many machinery changes) assessing energy retail prices and margins. Most notably, in 2015 Simon led a report analysing regulatory and market barriers to effective competition in Victoria's retail energy markets. They have previously undertaken a series of projects measuring energy retail margins and prices in Victoria and other jurisdictions.

Simon has extensive experience around assessing wholesale energy trading risk, in the context of considering prudent and efficient retail margins. This included several projects for energy retailers on measuring and managing energy risk, and advising on energy risk in the context of regulated price setting both for regulators and regulated entities.

- Contributions to *Peer review of standard charges for airport access* (aeronautical charges) for Auckland International Airport (2017)
- *Errors in Australian Energy Regulator's Draft Decision on Ergon Energy's 2016 Tariff Structure Statement,* prepared for CANEGROWERS (2016)
- *Review of Queensland Competition Authority (QCA) Draft Decision on "R" component of Draft Determination, regulated Electricity Retail prices for 2016 – 2017*, dated March 2016, for CANEGROWERS, part-funded by Energy Consumers Australia
- *Design of a retail electricity and gas price regulation statutory scheme*, for Public Utilities Office, Department of Finance, Government of Western Australia (2015)
- Impact of market and regulatory arrangements on Victoria's electricity and gas markets, for Government of Victoria (DEDJTR) (2015)
- 2014 report prepared by the present authors for the Australian Government entitled *Implications of extreme weather for the Australian National Electricity Market: historical analysis and 2019 extreme heatwave scenario.*

- Workshops on retail price regulation for the Pakistan National Electricity Retailer (2015), for US AID (US government).
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Attachment C

Regulated Australian Electricity Networks - Analysis of rate of return data published by the Australian Energy Regulator

Report for the Agriculture Industries Energy Taskforce

[redacted]

October 2018

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About Sapere Research Group Limited

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Contents

Executive summary vii

1. Publication of returns data and review of rate of return Guideline 1

1.1 Introduction 1

1.2 What is the rate of return Guideline? 1

2. Analysis of actual versus allowed network returns 3

2.1 Actual network returns significantly exceed allowed network returns 3

2.2 In dollar terms, excess network returns are material and sustained 4

2.3 Our analysis under-states Economic Profits 5

2.4 The impact of excessive returns 6

3. Implications of returns data for 2018 ROR Guideline Review 7

3.1 Limitations of the AER's methodology 7

3.2 Evidence-corrected estimates of efficient WACC 8

4. Implications for content of 2018 ROR Guideline 10

4.1 Required changes to the Draft Guideline 10

4.2 Changes are required before elevation of ROR Guideline to binding instrument 10

4.3 Economic profits and excess network capacity 11

5. Data sources and technical notes 12

Tables

Table 1 Economic profits and losses 4

Table 2 Estimation of efficient WACC 8

Table 3 Actual Return on Assets excluding incentives 14

Table 4 AER allowed pre-tax real WACC 14

Table 5 Actual RoA excluding incentives relative to the WACC 15

Figures

Figure 1 Distribution of actual compared to allowed returns 3

Figure 2 Economic profits/losses for the period FY2014-17 4

Figure 3 Distribution of actual compared to corrected WACC 9

This draft has been prepared with limited resources and additional resources are being sought. Comments on this draft are welcome and may be incorporated into a future revised and amended draft.

Glossary

ACCC	Australian Competition and Consumer Commission
AER	Australian Energy Regulator
2013 ROR Guideline	The Guideline setting the allowed network, ROR against which the 2018 AER ROR data may be assessed
2018 ROR Guideline	The output from the AER's 2018 ROR Guideline Review process, currently in Draft form
Allowed ROR	WACC times Opening RAB plus adjustment for depreciation and capital expenditure per the PTRM
Binding instrument	The proposed changes to the NEL under which the ROR Guideline would become a binding instrument
CAP model	Capital asset pricing model – the broad type of theoretical model specified in the Draft 2018 ROR Guideline for setting the allowed ROR.
Closing RAB	The RAB value at the end of each FY – the denominator used for AER's reporting of the rate of return
EBIT	Earnings before interest and tax – the common numerator used for deriving allowed and actual percentage returns
Economic profit	The difference between actual returns and efficient returns, the latter incorporating a 'normal' profit that is sufficient but no more than sufficient to fund suppliers of capital inputs, including a margin for systematic risk. A business making normal profits will remain in the industry, and will only exit the industry if it is making losses in the long run. Depending on their source, economic profits are super-normal and reflect monopoly or other sources of pricing power.
FY	Financial year – varies between networks
Model error	Errors arising from the CAP model under-specifying real world complexity
NEL	National Electricity Law
NEO	The National Electricity Objective
NER	National Electricity Rules operating under the NEL
Opening RAB	The RAB value at the start of each FY and with an adjustment used by the PTRM as the denominator for setting the allowed rate of return
ODRC	A method for setting the Opening RAB, where excess capacity relative to maximum demand is optimised
Parameter estimation error	Errors arising from the fact the CAP model requires inputs that are not observable and therefore applies proxy parameters, likely to diverge from unobservable parameters

PTRM	Post tax revenue model used by the AER to derive the allowed rate of return using a combination of the CAP model and the Opening RAB plus adjustments
RAB	Regulated Asset Base
ROR data	Data published on the rate of return by the AER in September 2018
The ROR	EBIT divided by closing RAB (per the AER data)
The ROR objective	As stated in the Rules, implies that WACC times Opening RAB plus adjustment (per the PTRM) should more or less equal EBIT divided by Opening RAB plus adjustment.
WACC	Weighted average cost of capital

Executive summary

Introduction

The present report on Australian Energy Regulator (AER) network rate of return data has been commissioned by the Agriculture Industries Energy Taskforce (the Taskforce).[1] The Taskforce consists of 14 organisations spanning different parts of the agricultural sector across multiple jurisdictions.

The Taskforce represents a sector of the economy sensitive to electricity prices. This sensitivity is reflected in food and fibre prices domestically. It also influences the international competitiveness of these products and national revenues from food and fibre exports. Respondents to a survey undertaken for the Taskforce earlier this year reported an average annual electricity bill of $30,000 per annum.

Network prices represent around half of a typical retail bill. Networks are capital intensive businesses – by far the largest input cost is capital (depreciation and the rate of return). The rate of return (ROR) represents the largest part of the network component of retail bills. If actual returns exceed allowed returns, then retail prices would not reflect efficient network costs and bills will be less affordable.

Key findings

Our analysis of the AER's rate of return data strongly implies that the method used by the AER to determine the allowed rate of return, as specified in the Draft 2018 ROR Guideline, materially over-estimates the systematic risk exposure of the networks. As a result, the rate of return Objective (ROR Objective) in the National Electricity Rules (NER) is being breached. This is also a breach of the National Electricity Objective (NEO).

The ROR Guideline uses a theoretical model to estimate the risk exposure of the regulated firms, based on a very limited sample. The model does not refer to any data on actual returns.[2]

In September 2018, the AER published data on *the* (actual) 'return on assets' for the 18 electricity network entities[3] for the four financial years preceding 30 June 2017. These allow an empirical estimate of the economic profit within actual returns, compared with the allowed rate of return (the estimated weighted average cost of capital or WACC).[4]

Over this four year period the aggregate actual returns significantly exceed the $21.4 billion allowed or normal returns by more than $2.1 billion or 9.9 percent. Excluding Ausgrid these economic or monopoly profits rise to more than $2.6 billion or 14.6 percent of normal returns of $18.1 billion.

In standard economic theory economic profit is defined as the difference between total revenue and total economic cost, that is, the sum of explicit costs plus implicit costs including a 'normal' profit to compensate for systematic risk. Over a period of time, a business making normal profits will remain in the industry and will only exit the industry if it is making losses in the long run. If, over time, total revenues exceed total economic cost, then the business may be described as

[1] See https://agenergytaskforce.org.au/

[2] See the technical notes in Section 5

[3] Some entities such as Ausnet hold both regulated distribution and transmission networks.

[4] See the technical notes in Section 5

making super normal profits. Depending on the source of such profits, they may be described as monopoly profits.

The data published by the AER (included in this report in the technical notes) understates the variances between allowed and actual returns. The data is presented only in terms of percentages and actual EBIT dollar data is not provided. This minimises the perception of super-profits in two ways.

First, the aggregate variance in percentage terms is less than one per cent, which may seem immaterial. Only by reversing the calculation, using the regulated asset base (RAB) to obtain allowed and actual returns in dollar values, is the difference shown to be clearly material at more than $2.1 billion. As noted above, this is $2.1 billion above the allowed returns of $21.4 billion including normal profit.

Second, the AER has derived the percentage actual return on assets using the closing RAB. For consistency we have also used closing RAB in our reverse calculation. However, the allowed ROR in the AER's Post Tax Revenue Model (PTRM) is applied to the opening RAB adjusted for depreciation and capital expenditure – crudely an average of opening and closing RAB. Where RAB is increasing, this means a larger denominator applied in the calculation of actual ROA results in a smaller percentage number and smaller economic profit in percentage terms. As a result, the estimates calculated in this report under-state the actual economic profit.

Except under limited conditions (discussed below), economic profits are inefficient and unfair. They transfer wealth from consumers to networks and result in deadweight losses, reducing Gross Domestic Product and the international competitiveness of Australian exporters. Economic profits may also lead to investment by consumers in substitute assets and services at higher levels than otherwise, reducing the utilisation of network assets. As a result, economic profits reduce dynamic efficiency or economic efficiency over the long run.

The bill impact of the observed economic profits is material – perhaps adding 3 - 5 percent to the typical retail bill.[5] This means that, for a typical irrigator paying $30,000 p.a., the excess network component in retail prices could be in the region of $1,500 per annum and $6,000 over the four year period being reported.

The test of the Draft ROR Guideline is whether the proposed changes are sufficient to correct the errors observed under the 2013 Guideline. We recommend that the AER should undertake this analysis before a 2018 Guideline is finalised.

The Rate of Return Consumer Reference Group highlighted that the existing Guideline is an error reinforcing process, not an error correcting process, precisely because actual returns are not measured.[6] This may be contrasted with New Zealand's economic value regulation of monopolies including energy network companies, where economic profits earned in one year are returned to consumers in the following year so that on average consumers pay the economically efficient cost of the provision of regulated services. Under such regulation, more than $2.1 billion would have been returned to Australian electricity consumers.

The 2018 Guideline should require regular reporting of actual returns, consistent with, for example, the ACCC's regulation of airports[7]. The Guideline should also establish a mechanism for amending parameter inputs used under the Guideline methodology, to align with empirical data. In other words, the Guideline should establish the principle that empirical data is superior to the outputs from a

5 In part because the economic profit component in regulated network prices may also increase retailer mark ups on network prices.

6 Rate of Return Consumer Reference Group, Submission to the Australian Energy Regulator Rate of Return Guideline Review, May 2018 https://www.aer.gov.au/system/files/Consumer%20Reference%20Group%20submission.pdf

7 See https://www.accc.gov.au/media-release/airport-profits-continue-to-grow

theoretical model and the model inputs need to be modified where there is misalignment with empirical data.

Consideration could also be given to the development of a rule change proposal under which economic profits other than those attributable to shareholders (due to higher productivity or performance) would be returned to consumers in the following period. There is no inconsistency between this proposal and the concept of incentive regulation.[8] Nevertheless, some tests would need to be developed to distinguish between earned and unearned economic profits (similar to the framework used by the New Zealand Commerce Commission).

A breach of the ROR Objective is also a breach of the NEO, under the National Electricity Law (NEL). The ROR Objective is useful in that it directly addresses the issue of whether actual returns are consistent with the NEO.

There is, however, an active proposal before the COAG Energy Council to remove the ROR objective from the Rules, via a change to the NEL as part of the package to change the status of the ROR Guideline. This would have the effect of institutionalising the existing flawed methodology for setting the allowed rate of return until there is a review of the 2018 Guideline sometime in the mid-2020s.

There is a further source of economic profits in addition to the economic profits discussed above. The AER analysis assumes that RABs are efficient. Under the present NER, the RAB is rolled forward, whereas under the forerunner to the NER (the National Electricity Code), RABs were typically set using an Optimised Depreciated Replacement Cost (ODRC) method.

The 2018 ACCC Electricity Supply Prices Inquiry found that RABs for networks in NSW, ACT and Queensland networks (both distribution and transmission) should be optimised (reduced).[9] It is also possible RABs for private sector firms are also excessive but the ACCC did not broach the topic of optimising the RABs of private firms. On the ACCC's analysis, economic profits are substantially greater than measured in this report.

Any excess in current RABs are in part a product of historical economic profits creating strong incentives to over-invest in capacity ('gold plate'). The potential on-going presence of economic profits under the Draft 2018 ROR Guideline means incentives may remain for the entire network sector to over-invest in future network capacity. This is a concern given that, according to the AEMO's 2018 Integrated System Plan, replacement generation requires substantial investment in new regulated network capacity. Future over-investment in network capacity would increase the cost of early action to decarbonise the Australian economy (and therefore possibly delay this).

Economic profits flow to equity holders. Under full profitability reporting, it would be possible and desirable for the AER to estimate the actual return on equity (total returns minus actual debt servicing costs), alongside the return on assets. Data for debt servicing costs should be reliable and accessible.

A large and increasing proportion of equity in regulated networks is now held by parent entities outside Australia. This suggests that a significant portion of economic profits from electricity networks are leaving Australia.

8 The calculations here, for example, are based on actual returns after allowing for incentives.

9 See https://www.accc.gov.au/regulated-infrastructure/energy/electricity-supply-prices-inquiry

1. Publication of returns data and review of rate of return Guideline

1.1 Introduction

The Australian Energy Regulator (AER) is undertaking a review of the 2013 Rate of Return Guideline. The Guideline applies to a set of 33 Australian energy networks subject to price/revenue regulation by the AER.

Section 28V(1) of the National Electricity Law (NEL) states that:

> *the AER may prepare a report on the financial performance or operational performance of 1 or more network service providers in providing electricity services.*

NEL s. 28V(2)(a) specifies the content of a NSP performance report may:

> *(a) deal with the financial or operational performance of the NSP in relation to:*
>
> *(iii) the profitability and efficiency of NSPs in providing electricity network services.*

In September 2018, the AER published data on *the* 'return on assets', for the 18 electricity network entities,[10] for the year ending 30 June 2017, and the preceding three financial years, compared with the estimated weighted average cost of capital (WACC).[11]

The AER previously published some information on the profitability of network businesses:

- AER, Electricity Distributors 2011-13 Performance Report (June 2015)
- AER, Transmission Network Service Providers Electricity Performance Report 2010-11 (July 2013.

No recent rate of return data has so far been made available for gas networks. Aside from a brief technical report, there is no accompanying AER report analysing and commenting on variances between the *allowed* rate of return and *the* rate of return.

1.2 What is the rate of return Guideline?

The ROR Guideline forms a key component of revenue/price cap regulation. The purpose of revenue/price caps is to constrain energy networks, operating under the protection of statutory monopolies, from generating returns (profits) that *exceed* the returns necessary for capital funders (debt and equity) to finance network assets, including an adequate margin for risk. That is, earning economic or super-normal (monopoly) profits.

The Rate of Return Objective (ROR Objective) in the National Electricity Rules (NER) is:

The allowed rate of return objective is that the rate of return for a [regulated network] is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the [service provider] in respect of the provision of [regulated services].

The formulation with our emphasis highlights that the *allowed* rate of return is distinguishable from *the* (actual) rate of return. Variances between the two may exist and incentive regulation reflects the possibility such variances may be efficiency enhancing.

10 Some entities such as Ausnet hold regulated distribution and transmission networks.

11 Available at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/profitability-measures-for-electricity-and-gas-network-businesses.

Under workably efficient competition, or effective regulation, *the* ROR is proportional to systematic or non-diversifiable risk. This means that, for the typical regulated entity in the typical year, returns are sufficient, but no more than sufficient, to fund efficient interest costs and returns to equity holders. Under incentive regulation, this means that more efficient firms may be able to earn economic profits while less efficient firms may experience economic losses.

In a publication dated February 2018, the AER noted that:[12]

The AER does not currently have in place a performance measurement framework to provide a clear picture of the profitability of regulated electricity and gas businesses.

The centrepiece of the ROR Guideline is a methodology for determining, *ex ante*, the allowed rate of return. The data for *the* (actual) rate of return provide the empirical test of whether the theoretical method set out in the 2013 ROR Guideline is delivering outcomes consistent with the ROR Objective. It also provides the empirical test as to whether changes to the method proposed in the AER's Draft 2018 ROR Guideline Determination would reduce risks of outcomes inconsistent with the ROR Objective.

The Rate of Return Consumer Reference Group highlighted that the 2013 ROR Guideline is an error reinforcing process, not an error correcting process, precisely because actual returns are not measured.[13]

In June 2018, the COAG Energy Council agreed to amend the National Electricity Law (NEL) to implement a binding instrument relating to the calculation of the rate of return on capital used in economic regulatory decisions made by the AER.[14] This means that errors in the Final 2018 ROR Guideline would not be able to be remedied until a review of the 2018 ROR Guideline due no earlier than 5 years after the binding instrument takes effect.

The AER data on the profitability of electricity network businesses allows an empirical estimate of the economic profit within actual returns compared with the allowed rate of return (the estimated weighted average cost of capital or WACC). This provides a test of the current Guideline, and whether historical economic profits in one year have been corrected or sustained, and therefore whether the risk of excessive prices for consumers may be locked in by proposed changes to the Guideline and the National Electricity Law.

It is unclear why the AER has not been reporting outcomes relative to the ROR Objective, since the ROR objective was introduced in around 2013. Before the release last week, the most recent profitability reporting was published in 2015 and related to outcomes ending in 2013. This may have reflected past AER resource constraints.

The data on network returns was not available (at least to the public) until September 2018. It has not been considered, for example, in the public discourse of AER's Review of the Rate of Return Guideline. This contrasts with New Zealand, for example, where the regulator publishes data on returns compared with allowed returns on a regular basis, and employs that data in revenue regulation.[15]

13 Rate of Return Consumer Reference Group, Submission to the Australian Energy Regulator Rate of Return Guideline Review, May 2018 https://www.aer.gov.au/system/files/Consumer%20Reference%20Group%20submission.pdf

14 See http://www.coagenergycouncil.gov.au/publications/binding-rate-return-guideline-1

15 See https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance-and-data/profitability-of-electricity-distributors

2. Analysis of actual versus allowed network returns

2.1 Actual network returns significantly exceed allowed network returns

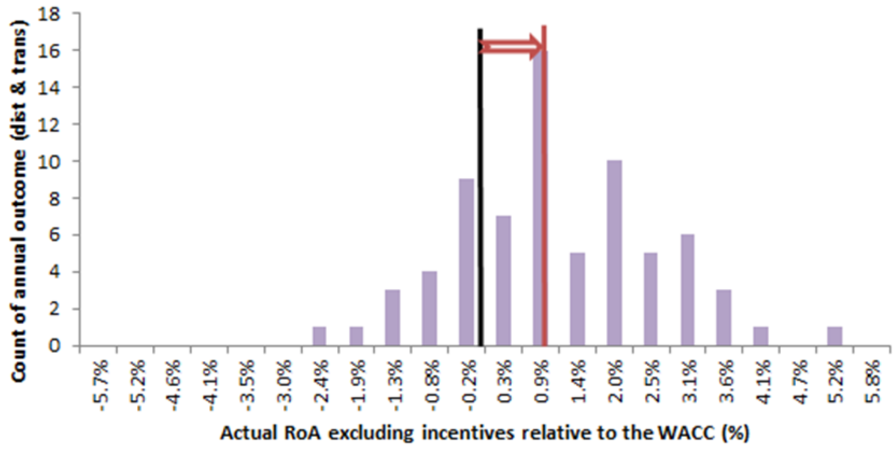
The AER's network returns data show that, over the four year period, actual network returns materially and consistently exceed allowed returns across the sector.[16]

This is illustrated in Figure 1 below that provides the frequency distribution of the difference between the actual and allowed returns in percentage terms, as published by the AER and reproduced in Table 5 in the technical notes below. Over a sample of 18 entities, some entities in some years would achieve positive economic profits while other entities in some years would achieve negative economic profits i.e. economic losses. If the ROR Objective were achieved, then for the average entity in the average year, the economic profit should be zero (i.e. there would be no material variance between the allowed and actual return). Graphically in Figure 1 the distribution of outcomes would be symmetrical about zero.

However, the actual data clearly illustrates this distribution is not symmetrical around zero economic profits. The average of actual returns (indicated by the red vertical line) is significantly higher than the average of allowed returns (zero on this axis, indicated by the black vertical line).

Across the 72 samples, if the ROR Objective were achieved, there would be no structural variance (positive or negative) between the allowed rate of return (black line) and the rate of return (red line). The observed variance represents structural economic profits. Except where economic profits are attributable to shareholders, they exceed returns commensurate with efficient financing costs, as required under the ROR Objective.

Figure 1 Distribution of actual compared to allowed returns



Source: Sapere visualisation of raw AER data.

While the percentage variance in Figure 1 may appear small, a variance on average of 0.82 per cent, this is nonetheless material and structural relative to the corresponding WACC values.

16 This is a visualisation of the AER data labelled 'Actual ROA ex incentives relative to the WACC', combining both distribution and transmission into a single data set.

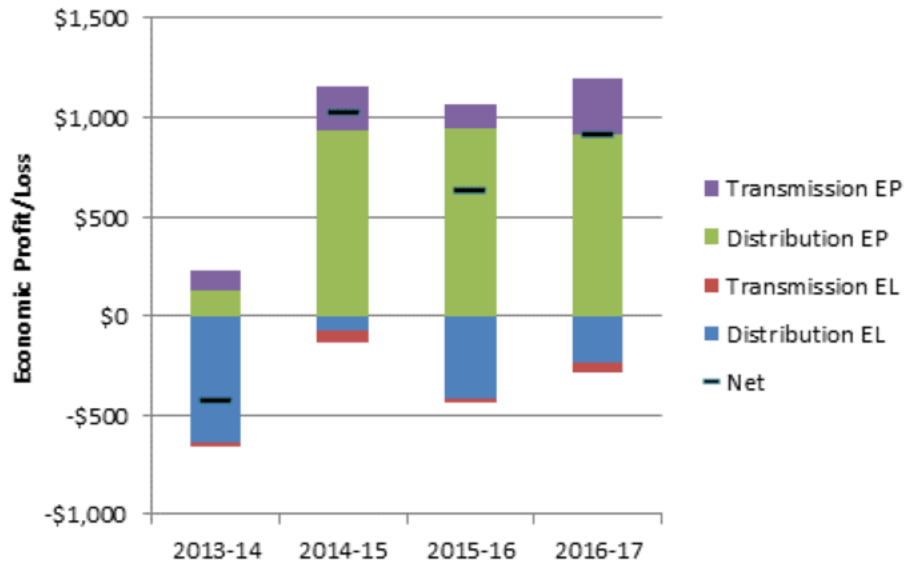
2.2 In dollar terms, excess network returns are material and sustained

The structural variance matters because the denominator in calculating these percentages is the aggregate Regulated Asset Base (RAB) of $91.8 billion dollars as at 30 June 2017. The rate of return percentages are derived by the AER from an estimation of Earnings Before Interest and Tax (EBIT) divided by the closing RAB. Using the same RAB denominator, differences between the allowed and actual EBIT in dollars terms may be calculated to yield the economic profits or losses for each of the 72 data points.

These are shown in Figure 2, aggregated into profits and losses for the distribution and transmission sectors. Consistent with Figure 1, it is evident that there are sustained and material economic profits in distribution and transmission well in excess of the economic losses. Moreover the economic losses over this period are significantly attributable to a single distribution company – Ausgrid.[17]

Table 1 below provides the economic profits for the overall sample. It shows the aggregate difference over four years is more than $2.1 billion. This includes a substantial economic loss from Ausgrid.

Figure 2 Economic profits/losses for the period FY2014-17



Source: Sapere calculation from AER profitability and RAB data.

Table 1 Economic profits and losses

Sector	*Allowed return*	*Actual return*	*Economic Profit*	*Ratio*
Transmission	$4,996	$5,565	$569	11.4%
Distribution	$16,424	$17,978	$1,554	9.5%

17 The AER is required to remake its decision on the electricity distribution determination that applies to Ausgrid, EvoEnergy, Endeavour and Essential for the 2014-19 regulatory control period, commencing 1 July 2014 to 30 June 2019 (the remittal). Allowed and actual returns for these networks are likely to increase, but the effect on actual returns is currently not in the public domain.

Sector	*Allowed return*	*Actual return*	*Economic Profit*	*Ratio*
Combined	$21,420	$23,543	$2,123	9.9%
ex Ausgrid	$18,071	$20,709	$2,638	14.6%

Actual returns significantly exceed allowed returns. The raw aggregate economic profit over allowed returns is more than 9.9 per cent.[18]

Excluding Ausgrid, the aggregate economic profit is more than $2.6 billion or 14.6 per cent. It is reasonable to exclude Ausgrid as its actual returns for the periods in question are likely to increase, retrospectively, due to the requirement for the AER to remake its final decision (the remittal).

The economic profit component in bills represents a payment for a service (bearing risk) that is not actually being rendered by the networks. This may be a contravention of the Australian Consumer Law.

Under the economic value regulation applied, for example, by the Commerce Commission of New Zealand, economic profits earned in one year are returned to consumers in the following year so that on average consumers pay the economically efficient cost of the provision of regulated services. Under such regulation more than $2.1 billion would have been returns to Australian electricity consumers.

The economic profit results are consistent with, and help explain, market data on the value attributed to networks in reported asset sales. The values typically imply multiples of 1.1 to 1.6 times RAB.[19] As the AER itself notes, these multiples consistently exceed the free cash-flows implied by the AER's post tax revenue model (PTRM).

2.3 Our analysis under-states Economic Profits

The preceding analysis demonstrates that substantial and sustained economic profits exist in the Australian electricity network sector, based on nothing more than the AER's reported data in percentage terms. All of the estimates above understate economic profits across the sector. The actual economic profits are 'more than' $2.1 billion.

This is because the AER data is limited to percentage returns, and neither EBIT data nor the 'allowed return' in dollar terms, are provided. The percentage returns are derived from EBIT divided by closing RABs. The WACC is a theoretical percentage derived formulaically. Allowed returns in dollar terms as defined in the PTRM represent WACC times Opening RABs, plus an adjustment for depreciation and capital expenditure.

Closing RABs are typically higher than opening RABs for most entities and in most years. This means the AER data ('Actual RoA excluding incentives relative to the WACC') is understating the variances between allowed and actual returns. In the analysis of dollar economic profits, we consistently applied the AER percentage ROR and WACC data to the closing RABs.

When we applied the same percentage data to the average of opening and closing RABs for each of the 72 samples, the resulting economic profits are significantly higher than indicated above. This approach is also inconsistent with the method used to derive the allowed rate of return in the PTRM, because it does not precisely replicate the adjustments made in the PTRM, but less so than using the closing RAB.

18 This excludes "earned" Economic Profits from incentives for exceeding performance benchmarks.

19 See Table 2, page 14 of the AER's *2018 RoR Guideline Review – Financial performance measures (Discussion Paper)*, February 2018.

2.4 The impact of excessive returns

Except under limited conditions (see discussion above on incentives for out-performance), economic profits are inefficient and unfair. They transfer wealth and result in deadweight losses, reducing Gross Domestic Product and the international competitiveness of Australian exporters. Economic profits may lead to consumers investing in substitute assets and services at higher levels than otherwise, reducing utilisation of network assets. As a result, economic profits reduce dynamic efficiency or economic efficiency over the long run.

The bill impact of the observed economic profits is material. Monopoly or economic network profits mean that, averaged across the NEM, retail bills are around three to five (3-5) per cent higher than they should be.[20] This means that, for a typical irrigator paying $30,000 p.a., the excess network component in retail prices could be in the region of $900-1,500 per annum and $3,600-6,000 over the four-year period (the actual amounts will vary by network).

A large and increasing proportion of equity in regulated networks is now held by parent entities outside Australia. This suggests that a significant portion of economic profits from electricity networks are leaving Australia.

[20] This reflects three assumptions that are broadly accurate but vary across different networks, wholesale price regions and retailer: a) the capital charge component (WACC*Opening RAB) represents around half the total network price and therefore a 14% increase in the capital charge results in a 7% increase in network prices and b) increases in network prices are fully passed through in retail prices and c) network prices represent 50% of retail prices. The excess network component is also likely to increase retailer mark ups.

3. Implications of returns data for 2018 ROR Guideline Review

Our analysis of the AER's rate of return data demonstrates that the method used by the AER to determine the allowed rate of return, as specified in the Draft 2018 ROR Guideline, over-estimates the systematic risk exposure of the networks. The ROR Guideline uses a theoretical model to estimate the risk exposure of the regulated firms. The model does not refer to any data on actual returns.

3.1 Limitations of the AER's methodology

The model set out in the ROR Guideline is a form of the Capital Asset Pricing (CAP) Model. The CAP model is technical and complex but the AER has so far never sought to verify or check the validity of its *theoretical* model for estimating returns against *empirical* data comparing actual and allowed returns.

The CAP model has two well-known limitations:

- Model error. The model is a representation or simplification of reality with limited explanatory power.
- Parameter estimation error. The model requires estimation of parameters for which there is either no data or only limited data, requiring use of proxy parameters.[21]

The CAP Model and the data used to derive the input parameters for the *ex ante* ROR are not useful or relevant to assessing the presence of actual economic profits. The CAP Model embeds the efficient markets theory and hence assumes that observed returns are efficient. On its own, the CAP Model cannot detect economic profits and it is therefore not fit for the purpose of assessing whether network returns incorporate structural economic profits.

A report by an AER appointed Independent Panel was required by the AER to address the following question:[22]

In the Panel's view, is the draft [ROR] guideline supported by sound reasoning based on the available information such that it is capable of promoting achievement of the national gas and electricity objectives?

The review Panel's report does not refer to the actual return data discussed above and it is therefore unknown whether this data was made available to the Panel. In any event, the Panel's report does not appear to consider applying any empirical testing of the theoretical method set out in the Draft 2018 ROR Guideline.

Similarly, the two 'evidence session's held by the AER earlier this year do not appear to have considered any empirical evidence on *the* rate of return under the 2018 Guideline.[23] It appears that no evidence that could contradict the AER's methodology was considered. In other words, the methodology was not tested against any evidence in the "evidence" sessions.

There are three possible sources of the economic profits implied by the AER data:

- The entire sector is outperforming efficient benchmarks; or
- The AER' allowances for non-capital costs (maintenance and operating expenditure or OPEX) are well above actual costs; or

21 See for example *'Setting the WACC percentile for Vector's price-quality path'*, a report by Kieran Murray and Tony van Zijl, May 2014.

22 See page 59 Independent Panel Report, 7 September 2018.

23 See https://www.aer.gov.au/communication/aer-releases-discussion-papers-on-rate-of-return-guideline

- The AER's method for estimating risk includes risks that are not in fact being borne by capital providers.

Taking each point in turn:

- The entire sector has experienced falling productivity, due to excess capacity. It is highly unusual for a sector with falling productivity to generate large and widespread economic profits.
- Variances between actual and allowed OPEX affect economic profits, and explain the economic losses for Ausgrid (pre-remittal). These variances can be readily checked from actual, audited OPEX data available in Regulatory Information Notices.
- Actual payments paid by networks to debt holders (banks), relating to around 60 percent of the regulated asset base, are much lower than is being allowed by the AER under the CAP model. This would reflect a market outcome from the actual risk exposure for debt holders.

Our assessment of these points is that the AER's method for estimating risk (CAP model) includes allowances for risks that are not in fact being borne by capital providers. The methodology adopted under the 2013 ROR Guideline is over-compensating for risk.

3.2 Evidence-corrected estimates of efficient WACC

While it is complicated to calculate this over-compensation of the risk factor using the AER's WACC formula[24], Table 2 makes a first order estimate by assuming the average economic profit by sector and year in the reported data is reset to zero. The result is that in recent years the efficient WACC is likely to have been less than 4 and 5 percent respectively for distribution and transmission.

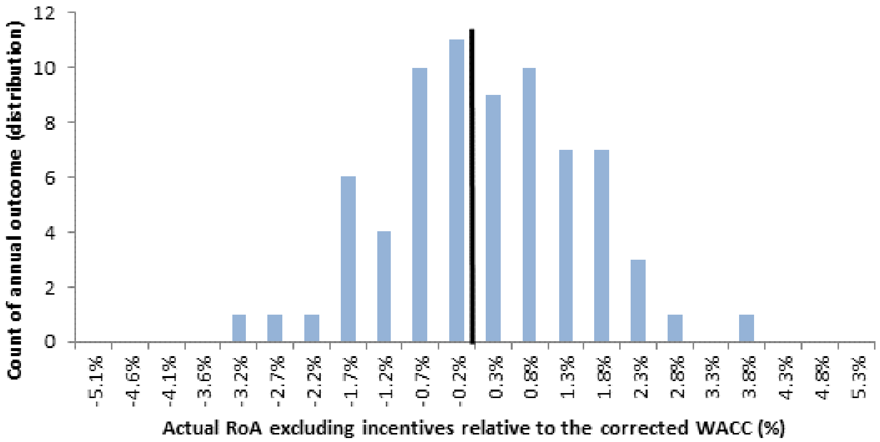
[24] One challenge is the discrepancy in the AER data between using the Closing RAB and the Opening plus adjusted RAB.

Table 2 Estimation of efficient WACC

	2013-14	2014-15	2015-16	2016-17	Average
Distribution					
Actual WACC	7.90%	6.95%	4.63%	4.60%	6.02%
Economic Profit	-0.58%	1.39%	1.22%	1.38%	0.85%
Efficient WACC	8.48%	5.56%	3.42%	3.22%	5.17%
Transmission					
Actual WACC	6.99%	5.25%	5.21%	5.19%	5.66%
Economic Profit	0.51%	1.06%	0.69%	0.72%	0.75%
Efficient WACC	6.48%	4.19%	4.52%	4.46%	4.91%

Figure 3 reproduces Figure 1 where the AER data in Table 5 has been corrected for each year by the estimates in Table 2. This distribution displays outcomes more consistent with the expected symmetrical distribution of economic profits and losses around an average value of zero.

Figure 3 Distribution of actual compared to corrected WACC



Source: Sapere visualisation of adjusted AER data.

4. Implications for content of 2018 ROR Guideline

The test of the Draft 2018 ROR Guideline is whether the proposed changes are sufficient to correct the material errors observed under the 2013 ROR Guideline. We recommend that the AER should undertake this analysis before a 2018 ROR Guideline is finalised.

The Rate of Return Consumer Reference Group highlighted that the existing Guideline is an error reinforcing process, not an error correcting process, precisely because actual returns are not measured.[25] This may be contrasted with New Zealand's economic value regulation of monopolies including energy network companies, where economic profits earned in one year are returned to consumers in the following year so that on average consumers pay the economically efficient cost of the provision of regulated services. Under this form of regulation, more than $2.1 billion would have been returned to Australian electricity consumers. This form of regulation nevertheless retains incentives for networks to outperform and to earn economic profits.

4.1 Required changes to the Draft Guideline

The Draft 2018 ROR Guideline should be amended to require regular reporting of actual returns. The Draft Guideline should also establish a mechanism for amending parameter inputs used under the Guideline methodology, using empirical data for actual outcomes. In other words, the Guideline should establish the principle that empirical data is superior to the outputs from a theoretical CAP model and CAP model inputs need to be modified where there is misalignment with empirical data.

Economic profits flow to equity holders. Under full profitability reporting, it would be possible and desirable for the AER to estimate the actual return on equity (total returns minus actual debt servicing costs), alongside the return on assets. Data for debt servicing costs should be reliable and accessible from the networks under modest enhancements to existing regulatory information notice requirements.[26]

Consideration could also be given to the development of a rule change proposal under which unearned economic profits would be returned to consumers in the following period. There is no inconsistency between this proposal and the concept of incentive regulation. Nevertheless, some tests would need to be developed to distinguish between earned and unearned economic profits (similar to the framework used by the New Zealand Commerce Commission).

4.2 Changes are required before elevation of ROR Guideline to binding instrument

A breach of the ROR Objective is also a breach of the National Electricity Objective (NEO) under the National Electricity Law (NEL). The ROR Objective is nevertheless useful in that it directly addresses the issue of whether actual returns are consistent with the NEO. There is, however, an active proposal

[25] Rate of Return Consumer Reference Group, Submission to the Australian Energy Regulator Rate of Return Guideline Review, May 2018 https://www.aer.gov.au/system/files/Consumer%20Reference%20Group%20submission.pdf

[26] The main challenge would be allocating debt (and hence debt servicing costs) but this challenge equally applies under the existing ROR Guideline.

before the COAG Energy Council to remove the ROR objective from the Rules, via a change to the NEL, as part of the package to change the status of the ROR Guideline. This would have the effect of institutionalising the existing flawed methodology for setting the allowed rate of return.

4.3 Economic profits and excess network capacity

There is a further source of economic profits in addition to the economic profits discussed above. The AER analysis assumes that RABs are efficient. Under the present NER, the RAB is rolled forward, whereas under the forerunner to the NER (the National Electricity Code), RABs were typically set using an Optimised Depreciated Replacement Cost (ODRC) method.

The 2018 ACCC Electricity Supply Prices Inquiry found that RABs for networks in NSW, ACT and Queensland networks (both distribution and transmission) should be economically optimised (reduced).[27] It is also possible RABs for private sector firms are also excessive but the ACCC did not broach the topic of optimising the RABs of private firms. As the dollar value of normal and economic profits scale with the value of RAB, the implication of the ACCC's analysis that the RABs could be lowered already is that the actual economic profits are substantially greater than measured in this report.

Any excess in current RABs are in part a product of historical economic profits creating strong incentives to over-invest in capacity ('gold plate'). The potential on-going presence of economic profits under the Draft 2018 ROR Guideline means incentives may remain for the entire network sector to over-invest in future network capacity. This is a concern given that, according to the AEMO's 2018 Integrated System Plan, replacement generation requires substantial investment in new regulated network capacity. Future over-investment in network capacity would increase the cost of early action to decarbonise the Australian economy (and therefore possibly delay this).

[27] See https://www.accc.gov.au/regulated-infrastructure/energy/electricity-supply-prices-inquiry

5. Data sources and technical notes

Relationships between percentage and dollar ex ante allowed ROR and ex-post actual ROR

1. For the allowed ROR under the Post-Tax Revenue Model (PTRM):

$$\text{allowed EBIT\$ (allowed return on capital)} = WACC\% \times opening\ RAB\$ + adjustment\ for\ depreciation\ and\ capital\ expenditure$$

or $allowed\ \%\ rate\ of\ return = Pre - tax\ WACC\%$

2. For the reported actual ROR, the AER has calculated:

$$actual\ \%\ rate\ of\ return\ as\ EBIT\% = {}^{EBIT\$}/_{closing\ RAB\$}$$

3. Whereas for comparability with allowed ROR above:

$$actual\ \%\ rate\ of\ return = EBIT\% = {}^{EBIT\$}/_{(opening\ RAB\$ + adjustment\ for\ \ deprec\ \&\ capex)}$$

As noted above, where RAB is increasing the EBIT% will be lower under 2 than 3.

The $EBITs under 1 and 3 are directly comparable – any divergence is "commensurable". The $EBITs under 2, on the one hand and 1 and 3, on the other are not comparable but we have been unable to measure the difference on the available information.

4. So for consistency with the AER reported ROR above we have calculated:

$$EBIT\$ = AER\ reported\ \%\ rate\ of\ return\ as\ EBIT\% \times closing\ RAB\$$$

Allowed pre-tax real weighted average cost of capital (WACC)[28]

The AER calculates the allowed pre-tax real weighted average cost of capital (WACC) as an estimate of efficient financing costs for a benchmark efficient entity providing regulated network services.

$$Pre - tax\ WACC\% = E(k^e)\frac{1}{(1-T_e)(1-\gamma)}(1-G) + E(k^d)G$$

Where

- $E(k^e)$ is the expected return on equity
- $E(k^d)$ is the expected return on debt
- G is the proportion of debt in total financing, otherwise referred to as the gearing ratio
- T_e is the effective tax rate
- γ is the value of imputation credits (gamma).

The pre-tax real WACCs have been sourced from the post-tax revenue model (PTRM) applying for the relevant regulatory years for each network service provider.

Reported ex ante allowed ROR and ex-post actual ROR

[28] AER, Return on Assets for electricity network businesses Explanatory not, 2018

The following tables reproduce the AER's reported data on ex ante allowed ROR and ex-post actual ROR and the resulting "Actual RoA excluding incentives relative to the WACC" that is analysed in Figure 1.

Table 3 Actual Return on Assets excluding incentives

Network	2013-14	2014-15	2015-16	2016-17
Ausgrid *	7.31%	5.52%	2.69%	3.21%
Ausnet (D)	6.46%	8.84%	3.93%	5.45%
Citipower	7.16%	8.37%	5.89%	5.97%
Endeavour *	8.07%	7.19%	5.02%	4.84%
Energex	5.39%	7.44%	7.59%	6.60%
Ergon	6.91%	8.37%	5.72%	6.69%
Essential *	9.01%	9.74%	3.38%	4.27%
Evo Energy (ActewAGL) *	5.18%	6.77%	7.37%	7.97%
Jemena	6.91%	8.42%	6.14%	7.76%
Powercor	7.97%	8.92%	7.12%	6.24%
SAPN	10.10%	11.12%	6.48%	5.20%
Tasnet (D)	6.96%	9.35%	9.98%	7.06%
United Energy	7.75%	8.43%	4.76%	6.54%
Ausnet (T)	9.45%	7.23%	6.34%	6.10%
ElectraNet	5.98%	5.83%	5.65%	5.53%
Powerlink	6.62%	5.37%	6.89%	9.06%
Tasnet (T)	7.63%	6.46%	6.07%	4.89%
Transgrid	7.81%	6.64%	4.57%	3.97%

Table 4 AER allowed pre-tax real WACC

Network	2013-14	2014-15	2015-16	2016-17
Ausgrid *	8.13%	4.73%	4.66%	4.66%
Ausnet (D)	7.80%	7.80%	4.51%	4.46%
Citipower	7.86%	7.86%	4.45%	4.39%
Endeavour *	8.15%	4.78%	4.72%	4.63%
Energex	8.02%	8.02%	3.97%	4.00%
Ergon	7.89%	7.89%	3.94%	3.97%
Essential *	8.07%	4.74%	4.68%	4.59%
Evo Energy (ActewAGL) *	6.91%	4.63%	4.53%	4.53%
Jemena	8.70%	8.70%	4.72%	4.66%
Powercor	7.76%	7.76%	4.35%	4.29%
SAPN	8.98%	8.98%	4.35%	4.36%
Tasnet (D)	6.55%	6.55%	6.55%	6.55%
United Energy	7.91%	7.91%	4.82%	4.76%
Ausnet (T)	7.66%	5.62%	5.62%	5.62%
ElectraNet	5.18%	5.18%	5.18%	5.18%
Powerlink	6.13%	6.13%	6.13%	6.13%
Tasnet (T)	7.93%	4.39%	4.29%	4.25%
Transgrid	8.04%	4.92%	4.83%	4.75%

Table 5 Actual RoA excluding incentives relative to the WACC

Network	2013-14	2014-15	2015-16	2016-17
Ausgrid *	-0.82%	0.79%	-1.97%	-1.45%
Ausnet (D)	-1.34%	1.04%	-0.58%	0.99%
Citipower	-0.70%	0.51%	1.44%	1.58%
Endeavour *	-0.08%	2.41%	0.30%	0.21%
Energex	-2.63%	-0.58%	3.62%	2.60%
Ergon	-0.98%	0.48%	1.78%	2.72%
Essential *	0.94%	5.00%	-1.30%	-0.32%
Evo Energy (ActewAGL) *	-1.73%	2.14%	2.84%	3.44%
Jemena	-1.79%	-0.28%	1.42%	3.10%
Powercor	0.21%	1.16%	2.77%	1.95%
SAPN	1.12%	2.14%	2.13%	0.84%
Tasnet (D)	0.41%	2.80%	3.43%	0.51%
United Energy	-0.16%	0.52%	-0.06%	1.78%
Ausnet (T)	1.79%	1.61%	0.72%	0.48%
ElectraNet	0.80%	0.65%	0.47%	0.35%
Powerlink	0.49%	-0.76%	0.76%	2.93%
Tasnet (T)	-0.30%	2.07%	1.78%	0.64%
Transgrid	-0.23%	1.72%	-0.26%	-0.78%

Attachment D

Agriculture Industries Energy Taskforce
AER Discussion paper
Profitability measures for regulated gas and electricity network business

Removing barriers to competitiveness for Australia's agriculture industries

December 2017

Contents

Executive Summary 3

Recommendations 4

Introduction 5

Response to questions 9

1. Do you agree with the preferred profitability measures? If not, what other measures do you consider should be reported by the AER and why? 9

2. Do you agree the five assessment criteria used by McGrathNicol to assess the profitability measures are appropriate? If not, what alternative criteria should be used? 10

3. Do you agree that the identified data is required to develop the preferred profitability measures? 11

4. If you consider other profitability measures should be reported, what data is required to support those measures? 17

5. Do you consider we should use the same measures and data for all regulated businesses, or should we adopt different measures for different sectors (electricity/gas) or different segments (distribution/transition) of the energy sector? 17

6. In addition to profitability measures, should we report other measures of financial performance? If so, how would these other measures contribute to the achievement of the NEO or NGO? 17

Other considerations 17

This submission is on behalf of the Agriculture Industries Energy Taskforce: National Irrigators' Council, NSW Irrigators' Council, NSW Farmers Assn, Cotton Australia, National Farmers' Federation, Bundaberg Regional Irrigators Group, Central Irrigation Trust (SA), CANEGROWERS, Dairy Connect, Queensland Farmers Federation, Australian Pork Limited, Pioneer Valley Water

[redacted]

Executive Summary

The cost of electricity in Australia is putting at risk our ability to compete with the world as a provider of food and fibre. For a country with an abundance of renewable and non-renewable sources of energy and whose primary producers are among the worlds' most efficient, this is an untenable situation.

Many of Australia's agricultural products (for both domestic and export consumption) use production processes that rely heavily on power, for example, irrigators who pump and pressurise water or producers who process, package or refrigerate products. Australia should have a comparative advantage for those producers - offering reasonably priced power from the grid. Instead, many food and fibre producers are forced to consider off grid solutions (ie diesel) or face being uncompetitive and sometimes, forced out of production. The result will be stranded network assets, leaving remaining grid consumers who are unable to move off grid, with unsustainable electricity prices (ie death spiral).

Australia's agricultural industries play a significant role as economic drivers in local economies and provide flow on benefits to the national economy. Industries include cotton, rice, sugar, wine, almond, horticulture and dairy. Energy is used for pumping irrigation water, pasteurisation, cool rooms, processing plants and moving products.

The high cost of energy for the agriculture sector sits starkly against the backdrop of the excessive profits of regulated electricity and gas businesses.

The Agricultural Industries Energy Taskforce (the Taskforce) has now made a number of submissions to various inquiries, in some, we have engaged expert advice, and on each occasion we have highlighted that – while not the only factor – network costs are a major contributor to making Australian agriculture less competitive and less viable.

The Taskforce has been, consistently, critical of the methodology used to allow network owners to, as our consultants, Sapere Research Group, said in our ACCC submission, "exceed efficient costs, prices and profits".

This consideration of the rate of return guidelines is fundamental. The rate of return methodology must be fundamentally changed to ensure a reasonable rate of return commensurate with the secure monopoly position network owners find themselves in and to ensure that we no longer see 'gold plating' of assets.

At its core energy policy in Australia must have as a key objective Australia's competitive position and equity for electricity consumers. We need to ensure that we don't look at elements in isolation, there are entrenched behavioural and systemic problems in the National Electricity Market (NEM) that must be addressed.

We would like to see the AER adopt a performance measurement framework to enable an accurate assessment of the profitability of regulated electricity and gas businesses, comparable to that of other ASX entities, until then meaningful and systemic change will not be realised.

Recommendations

The Taskforce concludes that:

1. The AER should adopt a performance measurement framework to enable an accurate assessment of the profitability of regulated electricity and gas businesses, comparable to that of other ASX entities.
2. The AER be allowed to compare the actual profitability of the regulated entity to:
    a. The allowed return on equity from its regulatory determination,
    b. Actual profit of other regulated entities, and
    c. Actual profit of other businesses operating in the Australian economy.
3. The AER should have access to the following suite of data:
    - Return on Assets
        - Earnings before interest and tax (EBIT)
        - Regulated asset base (RAB)
    - Return on Equity
        - Net profit after tax (NPAT)
        - Total equity
    - Economic profit
        - Earnings before interest and tax (EBIT)
        - Pre-tax weighted average cost of capital (WACC)
        - Total assets
    - Operating profit per customer
        - Earnings before interest and tax (EBIT)
        - Customer numbers
4. The calculation of the weighted average cost of capital (WACC) for transmission and distribution businesses must be based on the evidence of the real borrowing costs and operating conditions of businesses.
5. A comprehensive assessment of the economy-wide costs and benefits of revising the electricity network and transmission businesses' regulated asset base (RAB) to efficient levels is necessary.
6. To calculate the return on assets, return on equity or economic profit measures, the AER should include a balance sheet in its annual data collection from electricity businesses.
7. Additional financial performance measures (as suggested in the McGrathNicol scoping study), including liquidity ratios, financing ratios and activity ratios may be helpful in assessing financial performance and to enable comparison across organisations of different size and across other industries.
8. A review of tariff networks is necessary, to examine and ensure that irrigators and other businesses in non-congested parts of the network are not forced to meet the costs of network investments made to overcome congestion in other parts of the network. *(Refer to Sapere research at footnote 11)*
9. This current examination of profitability measures for regulated gas and electricity network business, provides an opportunity for the AER to move to a ''propose-respond' model, where the AER sets the agenda in relation to preferred measures, data required and issues relating to financial performance.

The Taskforce recommends the following further reforms:

10. The Competition Principles Agreement should not apply to state government monopoly electricity networks. The application of this agreement to electricity networks is obviously contrary to the legitimate commercial and economic purpose of this agreement for government

owned businesses that provide services in competitive markets. No longer subsuming the network monopolies under this agreement will mean that the economic regulation of the government owned monopolies will recognise the state government's ownership, and regulatory allowances for the cost of capital will be established accordingly.

This will bring the regulation of government owned networks back into line with the long-established practice in Australia (which prevailed until the Competition Principles Agreement) and will mean that the economic control of government owned network monopolies in Australia will be consistent with the approaches adopted in the economic regulation of government owned networks in other countries including the United States, Germany, Austria and Scandinavian countries.

11. Government owned network monopolies must be economically regulated by the state governments that own them. This is the long-established tradition in Australia until the reforms that led to economic regulation initially by state government regulators and subsequently by the AER. The outcomes delivered by these ostensibly independent regulators have, as we have shown, been highly unsatisfactory. Political accountability for the prices charged by state government distributors must rest with the governments that receive their profits and taxes.
12. The excessive asset valuation must be addressed through write-down of the networks' assets. The AER's current examination of profitability measures for regulated gas and electricity network business may offer some solutions as part of this endeavour.
13. The AEMC should NOT have any role in the economic regulation of networks. The bifurcation of economic regulation between the AER and AEMC is a unique model internationally.
14. The form of regulation (specifically periodic price/revenue controls as opposed to other forms of regulatory control) should be reviewed.

Introduction

It is unacceptable that in an energy rich country like Australia, weak energy policy is compromising Australia's capacity to be a competitive global food producer and to put fresh food on the tables of Australian households.

The Agricultural Industries Energy Taskforce (the Taskforce) has frequently pointed to the impacts of Australia's high electricity prices on our highly efficient agricultural sector. Australian producers have an opportunity to meet the demand of an ever-increasing global need for clean, green food and fibre, but instead face the risk of industry viability against the reality of high electricity costs. These cost pressures are imposing unsustainable barriers on the agricultural sector and driving down Australia's competitive edge.

Australia's 135,000 farmers produce enough food to feed 80 million people, providing 93 per cent of the domestic food supply, and support an export market valued at more than AU$41 billion per annum (over 13 per cent of export revenue)[1]. With population growth and rising personal income, the emerging middle class in Asia provides the major market for over 60 per cent of Australian agricultural exports.

More than 75% of Australian agriculture produce is exported. As a sector that is highly exposed to trade, agriculture must remain competitive in the international market and consequently, reliable, affordable and sustainable electricity supply are a necessary pre-condition for the economic development of agriculture. It is also key to ensuring farmers remain profitable and can efficiently invest in agriculture.

[1] *Australian Bureau of Agricultural and Resource Economics and Sciences. (2014). Agricultural Commodity Statistics.*

Reform of Australia's water resources sector in recent years has resulted in greater competition for water resources. While water savings have been achieved on-farm through investment in infrastructure, the resulting higher use of energy has coincided with a dramatic increase in the cost of electricity. Analyses show that irrigators' and growers' electricity bills have increased in excess of 100% in most cases, and up to 300% for some over the period 2009-2014, mainly due to the rising cost of network charges imposed by the network companies.

Typically, regulated network charges and other costs represent around 50% to 56% of farmers' electricity bills; the actual electricity charges account for around 26%, although this is also changing rapidly. Network charges imposed by the electricity networks continue to have a highly distorting effect on the electricity market. Australian consumers are paying around twice as much for network charges as those in the United Kingdom are around 2.5 times as much as those in the United States.

We recognise the importance of gas supply and its potential role in the electricity grid as we move away from coal supplied power and we acknowledge the steps the Federal Government has taken to sure up domestic gas supply. The Taskforce also supports the Vertigan Review recommendations around improvements in competition and access for existing pipeline infrastructure.

Irrigated agriculture users of electricity are forced to operate in a market environment that lacks genuine competition and appears dominated by generators and transmission and distribution infrastructure owners who aim to maximise returns. The absence of competition results in gaming on a spot market that is struggling to cope with the transition to renewables. It is unacceptable that consumers are forced onto the spot market due to an inability to secure quotes from retailers for fixed term contracts.

The Australian Competition and Consumer Commission (ACCC) is working to address some of these issues. The ACCC preliminary report[2] tabled in September 2017, following their review into retail electricity supply and pricing, provides a further important step towards systemic change. In May 2017, the ACCC granted authorisation to a group of 28 organisations led by the South Australian Chamber of Mines and Energy (SACOME) to collectively bargain with retailers for electricity. The SACOME group makes up approximately 15 per cent of South Australia's electricity demand.

Recent amendments to the Competition and Consumer Act (CCA) provide for greater flexibility to the collective bargaining approval process for small business.

Under current market governance arrangements, existing loopholes are enabling price gouging by network businesses and preventing a fair and effective pricing structure for consumers.

Efforts by Taskforce members to engage various responsible bodies to highlight the challenges faced by the agriculture sector, has resulted in significant frustration and cynicism due to the complexity and bureaucracy of the electricity industry. We have witnessed the entrenched culture of institutional and blame shifting with governance and regulation of the industry split between many bodies, where prescriptive rules and processes prevent any positive change. The myriad of regulation is increasingly divorced from reality and is unaccountable, built on abstract theoretical ideas that are beyond the reality of the industry and its consumers.

The evidence of excessive industry profit and soaring prices supports our own observations that shareholders are benefiting at the expense of electricity consumers. It would appear that the owners of

[2] *ACCC Retail Electricity Pricing inquiry: Preliminary Report, 27 Sept 2017*

the electricity generation, distribution and transmission assets have a dominant voice in driving the policies adopted by the regulatory bodies and take every opportunity to undermine the prospects for energy efficiency and distributed generation, both of which represent competitive threats to their business.

In making a submission to the ACCC retail electricity price inquiry recently, the Taskforce engaged Sapere Research Group to provide expert advice. Sapere's work confirmed that at every level of the electricity market "costs, prices and profits across much of the sector, and at multiple points across the supply chain, exceed efficient costs, prices and profits".

The Sapere report goes on to show that "despite being subject to price/revenue regulation, network costs, profits and prices also appear to be excessive.

"There is evidence of substantial excess network capacity across many parts of the NEM. We have not been able to identify a corresponding reduction in the allowed cost of capital to accompany risk transfer associated with the move to the RAB roll-forward method for setting the RAB at the start of the following price period (replacing the previous method which included provision for asset optimisation). Consequently, it appears that network prices incorporate the double effect of excessive returns on an excessive asset base."

The Taskforce has long argued that the current regulatory framework is enabling regulated network businesses to build in unacceptable returns. The AER's lack of a performance measurement framework to understand the extent of the profitability of regulated electricity and gas businesses has clearly enabled gold plating resulting in unsustainable price increases to consumers.

There is a critical need for the AER to move to a benchmarking model comparable to that of other entities. For example, the Australian Competition and Consumer Commission (ACCC) monitors and publishes information relating to prices, costs, profits and service quality of a range of sectors, including information on industry margins and the rate of return on assets.

Overseas examples also provide good insight into how regulators have the capacity to collect data which appropriately enables the calculation and reporting of profitability measures and to assess the financial performance of electricity and gas businesses compared to the expected returns under the framework applying in that jurisdiction.

In the UK for example, the monitoring of the financial performance of the electricity and gas transmission and distribution businesses through the collection of data, enables a calculation and report on the return on regulated equity and profit per customer. This enables a comparison with the cost of equity to determine whether businesses are outperforming or underperforming.

The New Zealand example provided in the AER discussion paper is also useful. Distribution businesses regulated by the NZ Commerce Commission provide data on asset value and cash flow to enable the calculation of an internal rate of return (IRR). This is compared to expected returns on a nominal estimate of the weighted average costs of capital (WACC).

We know that the regulated asset base (RABs) of Australia's electricity networks have been artificially inflated and inefficiently grown to excessive levels. Over the past fifteen years, the networks' RABs have increased by around 400%. These growth rates now put Australian electricity networks' RAB levels significantly higher than their international counterparts; we know that the RAB per connection levels of Australia's distribution networks are now up to nine times the levels of networks in the United Kingdom.

In a submission provided to the 2014 Senate inquiry into the performance and management of electricity network companies, the Taskforce raised the issue of network companies misleading the AER in relation to their weighted average cost of capital (WACC). The issues are complex and regulatory design is the underlying reason for such failures. The determination of the WACC – an issue largely but not completely within the AER's discretion – is based on what the AER calculates to be the WACC of a 'benchmark efficient network service provider'. This calculation is by design, meant to be abstracted from the actual cost of capital of the regulated firms.

There are range of factors across a failed market that are making Australia less competitive. The very comfortable arrangements for the owners of networks are one of the keys. It is crucial to Australia's future agricultural competitiveness that the base calculation of the return these owners are allowed to build into their pricing models is fundamentally reformed to produce a reasonable rate of return commensurate with the secure monopoly position network owners find themselves in and to ensure that we no longer see 'gold plating' of assets.

Response to questions

1. Do you agree with the preferred profitability measures? If not, what other measures do you consider should be reported by the AER and why?

We note McGrathNicol's scoping study to identify financial performance measures used by some overseas regulators or electricity and gas network businesses, where they have identified commonly used financial performance measures that may be relevant when analysing the profitability of the regulated businesses. Broadly, we support these measures which would allow the AER to:

- compare profit of the regulated business to the statutory profit earned by the owner of the regulated business;
- analyse the profits of a regulated business over time;
- compare the profit of a regulated business to the profit earned by other regulated businesses;
- compare the profit of a regulated business to businesses in other industries, including ASX listed companies.

We also note McGrathNicol's observation that further analysis of results could then be undertaken to identify individual elements that may be driving material differences, and unusual results that vary significantly from benchmarks.

We draw on the Consumer Challenge Panel (CCP) submission[3] to the AER draft 2018-22 revenue decision regarding Powerlink revenue proposal (Dec 2016). The submission provided an analysis of the actual returns being realised by two Queensland networks (Powerlink Queensland and Energex) over the past fifteen years, and compared those returns with the returns being realised by businesses in other sectors of the economy.

The CCCP analysis compared the returns that Powerlink's owner (Queensland government) has realised from its equity investment in the Queensland networks with the returns it would have received had it invested the same funds in blue-chip ASX 50 companies in other sectors of the Australian economy. This is the first time that such an analysis has been performed on the Australian electricity networks' actual profitability.

During the 2012-17 determination period, Powerlink achieved extraordinary profitability levels, achieving annual return on equity levels of up to 75%, compared to the AER's assumed 9.4%. Powerlink achieved these major gains from over-forecasting its capex needs and was rewarded with around $300 million in 'windfall gains', due to its revenue allowances, including return on capex that it did not incur. Stakeholder criticisms of the AER's 2013-17 allowances have been proven correct (eg Powerlink's actual demand was 40% lower than its forecast demand during the period).

Powerlink's over-investments continued to result in increasing levels of excess capacity and major declines in asset utilisation levels. Powerlink's operational efficiency continued to decline significantly over the period. Powerlink continued to receive very high bonuses from the AER's Service Target Performance incentive Scheme achieving annual bonuses of over $20 million.

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[3] *Consumer Challenge Panel submission to the AER draft 2018-22 revenue decision. Powerlink revised 2018-22 proposal*

The AER has accepted Powerlink's 2018-22 period proposed return on capital allowances with some minor changes, reflecting movements in market conditions since Powerlink's revenue proposal was submitted.

Powerlink is extraordinarily profitable, achieving many multiples of the returns that the AER assumes and many multiples of the returns being achieved by Australia's best performing ASX 50 companies.

The Queensland government is unlikely to have actually invested the reported 'share capital' levels. Over the past fifteen years, the Queensland government's investment in Powerlink there has been an accrued total return of:

- 23 times the returns achieved by the Australian construction sector (Lend Lease)
- 15 times the returns achieved by the Australian telecommunications sector (Telstra)
- 10.5 times the returns achieved by the Australian minerals and resources sector (BHP)
- 10 times the returns achieved by the Australian banking sector (NAB)
- 3.6 times the returns achieved by Australia's most profitable supermarket (Woolworths)

No other ASX 50 stock has come close to Powerlink's returns. These returns are being realised despite Powerlink being the most inefficient transmission network in the NEM. The primary driver of Powerlink's profitability is the AER's provision of excessive 'return on capital' allowances.

<u>The WACC/RAB Inconsistency</u>

The AER's methodology for determining the networks' 'return on capital' allowances does not appropriately consider the impacts of RAB indexation:

- The AER's methodology for estimating the required percentage returns (for both equity and debt) is based on the returns that investors require on their actual capital investments.
- However, the AER calculates its 'return on capital' allowances by multiplying those percentage returns to artificially inflated capital bases.

This inconsistent approach, together with the AER's incorrect gearing assumptions, is resulting in the AER providing 'return on capital' allowances well above the required levels – eg it is currently resulting in the AER providing 'return on equity' allowances to Powerlink of around four times the required level.

2. Do you agree the five assessment criteria used by McGrathNicol to assess the profitability measures are appropriate? If not, what alternative criteria should be used?

We note the two objectives identified by McGrathNicol in the scoping study to establish financial performance measures. The first objective: *Measure the actual profitability of the regulated entity* is broad and it is not clear what mechanisms, benchmarks or principles would be applied to determine 'actual profitability'.

The second objective appears to be more comprehensive and would potentially provide the AER with a broader capacity to scrutinise an entity's profitability, that is:

- Allow the AER to compare the actual profitability of the regulated entity to:
  - The allowed return on equity from its regulatory determination,
  - Actual profit of other regulated entities, and
  - Actual profit of other businesses operating in the Australian economy.

As noted, until the AER adopts a performance measurement framework to enable an accurate assessment of the profitability of regulated electricity and gas businesses, and comparable to that of other ASX entities, a true picture of profitability will not be established. An international benchmarking model would also be of benefit.

The five criteria identified by McGrathNicol appear to be comprehensive:
Criterion 1: requirements are based on clear concepts and performance measures are able to be calculated consistently over time.
Criterion 2: calculation does not require significant manipulation of data, or require assumptions to be made. The measure's calculation is not significantly impacted by accounting adjustments, taxation treatments, or the entity's financing structure.
Criterion 3: generally accepted by industry experts as a good measure of profitability, and easily understood and meaningful to persons without a financial background
Criterion 4: suitable given the industry characteristics (e.g. capital intensive, long life assets, regulated revenue and returns).
Criterion 5: readily able to be compared to other businesses in the sector and other businesses in the broader economy.

The ratings classifications detailed in the McGrathNicol scoping study in order to rate the appropriateness of the financial performance measures, appear to be satisfactory.

3. Do you agree that the identified data is required to develop the preferred profitability measures?

It is apparent that the lack of relevant data has been a key limitation to reporting on the profitability of network businesses. The Taskforce agrees with the need for the following data as suggested in the discussion paper:

- Return on Assets
    - Earnings before interest and tax (EBIT)
    - Regulated asset base (RAB)
- Return on Equity
    - Net profit after tax (NPAT)
    - Total equity
- Economic profit
    - Earnings before interest and tax (EBIT)
    - Pre-tax weighted average cost of capital (WACC)
    - Total assets
- Operating profit per customer
    - Earnings before interest and tax (EBIT)
    - Customer numbers

The Taskforce has repeatedly pointed to the obligation to have regard to the benchmarks in setting expenditure allowances.

We have raised in previous Government related submissions that, in promoting their interests on the calculation of the WACC, network businesses propose what they argue to be the WACC of the benchmark efficient network service provider. It is in these proposals that we consider the network companies have intentionally misled the AER, with a focus on three aspects:

- the calculation of the cost of debt
- debt and equity raising costs and
- income taxes.

Income taxes, debt and equity raising costs are compensated through cash allowances whereas the compensation for the cost of debt is determined as a percentage allowance to be applied to the regulated asset base (RAB).

With regard to debt costs, networks argue that their debt is high risk. They also argue that the credit rating of their debt determines their borrowing costs. However, the evidence from the actual yields on network bonds and the price paid for bank debt shows that network businesses' actual borrowing costs are much lower than implied by their credit ratings. This is because lenders recognise that networks are monopolies and hence, while credit rating agencies may, for example, assess the credit rating of a network business to be, say, BBB. Its status as a monopoly means that actual credit risks are lower, and hence lenders are willing to lend money at much lower rates than implied by their credit ratings.

With respect to income taxes, again a 'normative' model is applied (ie the specific circumstances are not examined) and the focus of argument on taxation allowances has been on the treatment of imputation credits. Network businesses have argued for much more favourable parameters, including successfully in the Australian Competition Tribunal (ACT), in applications for the review of the merits of the AER's decisions.

The networks' arguments however, do not reflect the reality of the taxation they incur. For example, the Queensland distributors, Energex and Ergon, were parties to an application to the ACT in 2010 to challenge the AER's decision on the imputation of dividends. But the full income tax of these government-owned distributors is paid directly to the Queensland Government. The imputation of their dividends is completely irrelevant. Although the distributors' argument prevailed in the ACT, the Queensland Government did not allow the Queensland distributors to raise their revenues by $490m to increase tax charges to consumers. However, in their further revenue proposals to the AER, these businesses again sought tax arrangements that did not reflect their own circumstances (i.e. that dividend imputation is entirely irrelevant to them since the taxation is paid directly to their state government owners).

It is not clear whether the taxation allowances for the privately owned distributors properly represents their actual tax costs. We are aware for example of taxation issues with SA Power Networks where they proposed that electricity consumers be charged a little under $450m, when their published financial statements in period showed that for the three years for each year data was available, SAPN received a tax credit of around $4m. This may have been due to the specific structure of SAPN and that taxes were being paid at some other level of the organisation.

Taxation concerns also apply to the privately owned Victorian distributors where it is understood the Australian Taxation Office were investigating several issues. This is a complex area, and potentially made more so due to the lack of transparency and current limitations to reporting on the profitability of network businesses and lack of relevant data.

In respect of debt and equity raising allowances, which are worth often several hundred million over the course of a regulatory period, the AER again applies a 'benchmark' model. There is no evidence that the businesses, (particularly the government-owned networks), incur anywhere near the allowances they seek (and which the AER approves). In particular, the government-owned networks do not incur equity raising costs (they are owned by governments) and their debt is arranged by state treasuries which do not incur many of the costs that the networks seeks to recover from their customers (which are based on the false assumption that they are privately owned).

The AER has supported the 'benchmark efficient' approach to the calculation of the cost of debt and equity and in respect of debt and equity raising costs. To date, the AER has accepted many of the network businesses' claims despite compelling evidence that they are not supported by evidence of their actual costs, and the AER has not acted on the advice of its advisors Professor Lally and Chairmont Consulting2. Under the current regime, the **networks are not required to disclose their actual borrowing costs. This must change.**

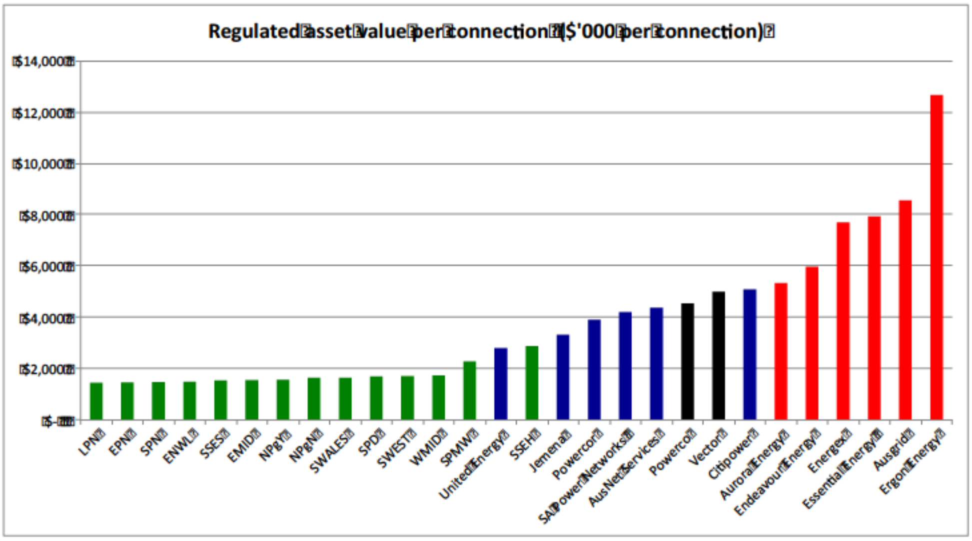
The Taskforce seeks a comprehensive assessment of the economy-wide costs and benefits of revising the electricity network and transmission businesses' regulated asset base (RAB) to efficient levels. We have long called for a review of the RAB of electricity network infrastructure in order to deliver real cost reductions to consumers.

There have been countless studies into the drivers of recent electricity cost increases and most of these studies have concluded that the RAB and the Weighted Average Cost of Capital (WACC) have been a driving force behind these increases.

Given the current value of the electricity distribution and transmission businesses' RAB, electricity costs will remain high *unless* there is a fundamental shift in the way the RAB is set and calculated into the future (i.e. reduced to more sustainable levels).

Regulatory asset valuations amongst distributors in the NEM (particularly those in NSW and Qld) are now extremely high by international standards. **Table 1** compares the regulated asset values per connection of Australian government owned distributors (the red bars) with the privately-owned distributors in Australia (the blue bars), New Zealand's two largest distributors (the black bars) and the British distributors (the green bars).

Table 1: Regulated asset value per connection in Great Britain, New Zealand and Australia[4]



Source: regulatory accounts, CME Analysis

[4] *regulatory accounts, CME Analysis*

A series of factors have contributed to the inflated RAB values for the distribution network businesses in the NEM, including the state based reliability standards and growth in demand in certain areas. None of these drivers however, have been as important as the regulatory framework governing the setting of the original RAB value and determining the ongoing valuation of the RAB in each regulatory determination.

Under the current regulatory framework, the AER has limited control to adjust the distribution network businesses' RAB, as the valuation methodology has been set within the National Electricity Rules (NER). The inability of the federal regulator to set network prices based on efficient RAB values has been demonstrated by the outcomes of the AER's revenue determinations in recent years, which have delivered unsustainably high electricity prices for consumers.

In terms of the methodology for determining the RAB, several deficiencies, include:

a. The initial regulatory valuations of the distribution and transmission businesses were determined when the networks were established in the mid to late 1990s. A number of valuation methodologies could have been adopted however, the regulator chose to apply the 'Depreciated Optimised Replacement Cost' (DORC) valuation methodology – a methodology that resulted in the highest possible RAB valuation for the networks.

b. The opening RAB methodology required the regulator to subsequently optimise the ongoing RAB value to reflect the efficient value of assets needed to provide the required services. This meant that if the networks invested in more network capacity than required, the regulator was supposed to exclude the value of the excess capacity from the regulatory asset base until such time as the additional network capacity was required. However, in practice, this capacity assessment has rarely been applied. As a result, consumers were faced with:
    - having initial regulatory valuations set at the highest possible levels using the DORC valuation methodology, based on the expectation that the ongoing RAB valuations would be subjected to optimisation; and
    - regulators not actually applying the required optimisation to the ongoing RAB valuations.

    In 2006 the AEMC made amendments to the National Electricity Rules which effectively removed the optimisation requirement, together with changes that ensured that all future CAPEX was automatically rolled into the RAB without any prudency or efficiency review. The removal of the optimisation and ex-post review provisions in 2006 was a major driver of over-investment.

c. The incentives for over-investment were particularly strong for government-owned networks due to their lower borrowing costs and the additional benefits that they realise from over-investment.

The Taskforce again contends that the network assets are substantially over-valued, not least in light of declining asset utilisation due to lower than expected demand.

The writing down of assets in the competitive market is commonplace and is provided for in International Financial Reporting Standards (IFRS). IAS 36 "Impairment of Assets" seeks to ensure that an entity's assets are not carried at more than their recoverable amount (i.e. the higher of fair value less costs of disposal and value in use)[5]. It also defines how the recoverable amount is determined. Similar rules are implemented in the regulation of gas in Australia and further in the United States a "used and useful" approach is applied in the regulation of utilities.

While several reviews attempted to modify the approach to RAB regulation, to date no changes or recommendations have been made by the AEMC or other Government departments that would change the current approach to valuing the RAB. The Queensland Productivity Commission (QPC), including members seconded from Queensland Government departments, considered reliability performance, the "adverse financial impact" on the state to write down the RAB and regulatory barriers. The adverse financial impact was linked to increased borrowing costs, lower shareholder returns and an adverse effect on the credit rating. The QPC also noted that the national electricity rules currently provide no scope for the AER to undertake a RAB write down – this is a principal regulatory barrier[6].

In its final rule determination in 2012 the AEMC blocked a proposed rule change that would have enabled a potential RAB write down. This decision blocked an opportunity to return to the optimisation rules that applied in the original NEM design.

Neither the QPC nor the AEMC conducted a detailed economy-wide analysis of the benefits associated with optimising the RAB and promoting efficient investment in, and operation of, the network identified by Professor Garnaut. Instead, both focused on the potential narrow impacts of such action on the network service providers and their shareholder owners. This is an unacceptable outcome; the risk should not be borne entirely by consumers, but rather equitably shared by the networks' shareholder owners and consumers. The sharing of risk ensures that the networks continue to aim for further efficiencies.

Notwithstanding these issues, the Taskforce continues to seek a change to the way electricity networks' RAB is calculated as part of their network cost and embedded in their submissions to the Australian Energy Regulator (AER). The regulatory framework for gas pipelines requires the assets to be optimised and the value of unused and redundant assets to be written down. The asset revaluation was removed from the electricity pricing rules, not surprisingly just prior to the electricity RAB valuations took off. Why is the regulatory pricing framework that applies to gas and electricity networks not consistent? If it were, electricity networks would be entitled only to a return on their useful and used assets, a small step towards real cost reflective pricing.

<u>Calculation of the weighted cost of capital (WACC)</u>

The calculation of the WACC for distribution and transmission businesses in the NEM are the drivers of unsustainable electricity costs for consumers. The calculation of the WACC must change.

The determination of the WACC for the electricity distribution and transmission businesses – an issue that is largely but not completely within the AER's discretion - is based on what the AER considers to be an adequate rate of return of a 'benchmark efficient transmission or distribution service provider'. The calculation of the WACC, by its very design, is meant to be abstracted by the actual cost of capital of regulated monopoly businesses.

[5] *CANEGROWERS submission to the Finkel Review:* http://www.environment.gov.au/submissions/nem-review/canegrowers.pdf
[6] *Ibid.*

As the Taskforce argued in our 2014 submission to the Senate inquiry into electricity network companies, distribution network businesses have promoted their interests on the WACC calculations by arguing that:

a. their debt is of 'high risk' (i.e. a BBB rating). In addition, they have claimed that the credit rating of their debt determines their borrowing costs. There is evidence however that the actual yields on network bonds and the price paid for bank debt shows that network businesses' actual borrowing costs are much lower than imposed by their credit rating. This is due to the fact that lenders recognise that networks are monopoly businesses and are willing to lend money at much rates than implied by their credit ratings. The evidence provided by Energy Users Rule Change Committee to the AEMC in 2011 shows that actual network borrowing costs, even during the peak of the financial crisis, were lower than suggested by the networks' credit ratings.

b. their imputation credits should be calculated on favourable imputation credits. As highlighted in the Taskforce's submission to the Senate Inquiry (above), an example from the Queensland distributors, Energex and Ergon shows that the full income tax of these government-owned distributors is paid directly to the Queensland Government. The imputation of their dividends is therefore completely irrelevant. It is still not clear to the Taskforce whether the taxation allowance for privately owned distributors properly represents their actual tax costs.

c. their debt and equity raising costs are higher than is actually the case. In particular, government owned network businesses incur nowhere near the costs of a comparative 'benchmark service provider. Government-owned network businesses do not incur equity raising costs – as they are government owned – and their debt is arranged by the respective state treasuries, at a rate lower than the network businesses seek to recover from their customers. This outcome arises from the incorrect assumption by the regulator that these businesses are 'privately' owned.

We note that the AER supports the 'benchmark efficient' approach to calculating the distribution and transmission businesses WACC and has accepted many of the network businesses' claims despite compelling evidence that they are not supported by the evidence of actual costs.

The calculation of the WACC for the transmission and distribution businesses must be based on evidence of the real borrowing costs and operating conditions of these businesses.

Transmission and Distribution businesses must be required to disclose their actual borrowing costs.

<u>Return on Equity</u>

We note the approach taken in Canada, where the Ontario Electricity Board calculates a return on equity to review the financial performance of electricity distributors, allowing a 3% variance on the expected return on equity.

As referenced in the CCP submission to the AER draft 2018-22 revenue decision Powerlink revised revenue proposal [7], a number of Australian and international investment consortiums attempted to purchase the NSW transmission network, TransGrid, which was sold for $10.3 billion, amounting to 165% of TransGrid's RAB value.

[7] *Consumer Challenge Panel submission to the AER draft 2018-22 revenue decision. Powerlink revised 2018-22 proposal*

Over recent TransGrid revenue determination processes, TransGrid made many assertions that the AER's approach to determining its return on equity allowances would not enable it to recover efficient financing costs or to attract equity investors – and claimed that it would result in lower investment in the network and a significant increase in TransGrid's financing risks.

The sale price achieved by TransGrid sits in stark contrast to those claims.

4. If you consider other profitability measures should be reported, what data is required to support those measures?

We have no specific comment here beyond the need to include a comprehensive examination and clear understanding of an entity's cost of borrowings, as noted above. Also noting that the measures used need to keep pace with changes in both technology and networks solutions, requiring periodic review and updating.

5. Do you consider we should use the same measures and data for all regulated businesses, or should we adopt different measures for different sectors (electricity/gas) or different segments (distribution/transition) of the energy sector?

The discussion paper notes that, for electricity businesses, the income statement contained in AER's annual reporting requirements provides both EBIT and NPAT, yet the AER does not currently require from entities, an annual balance sheet which would report total equity and total asset data. Therefore, to calculate the return on assets, return on equity or economic profit measures, the AER would need to include a balance sheet in its annual data collection from electricity businesses.

The Taskforce contends that it is imperative that a balance sheet is included in annual data collection and supports the adoption of a uniform approach to the income statement and balance sheet data requirements for all regulated businesses. A uniform approach would be across electricity and gas sectors (and preferably also) across different segments, that will enable benchmarking within sectors, an important consideration in light of the rate at which technology, network solutions and the market is evolving. It would also enable external benchmarking by facilitating comparison of the regulated business' profitability measures, between regulated businesses and across industries.

6. In addition to profitability measures, should we report other measures of financial performance? If so, how would these other measures contribute to the achievement of the NEO or NGO?

We note the additional financial performance measures suggested in the McGrathNicol scoping study, which include liquidity ratios, financing ratios and activity ratios. These may be helpful in assessing financial performance and to enable comparison across organisations of different size and across other industries.

Other considerations

The Taskforce recognises that regulation of electricity supply is complex, however while the National Electricity Law has established an overarching objective, the long-term interests of consumers and the Australian economy have been disregarded and ignored for too long.

The establishment of Energy Consumers Australia (ECA) in January 2015 has brought a greater degree of a consumer voice to the vast number of reviews and regulatory determinations occurring in the regulatory space since that time. Additionally, the Taskforce is supportive of the Consumer Challenge Panel (CCP) that has provided a 'direct line' between consumers and the AER.

The Taskforce acknowledges that the AER engaged a consultant to review the effectiveness of the CCP initiative and it is concerning that the AER expressed the opinion that the advice provided by the CCP did not substantially alter the matters or issues considered in their regulatory decision making process. This is of particular concern when it is claimed that the 'long term interests of consumers' are at the centre of decision-making.

Electricity use varies across agricultural businesses depending on industry, intensification of operations, location and structure of the business. Farms that require heating, cooling or irrigation have higher levels of electricity use. In some industries, electricity consumption is stable year-round, in others there can be significant seasonal variability. For some farmers, demand is flexible, providing choice as to when electricity is consumed. For others, demand is driven by factors beyond individual control, such as streamflow, the weather, and regulations that govern access to water, reducing options for an individual to manage their own demand[8].

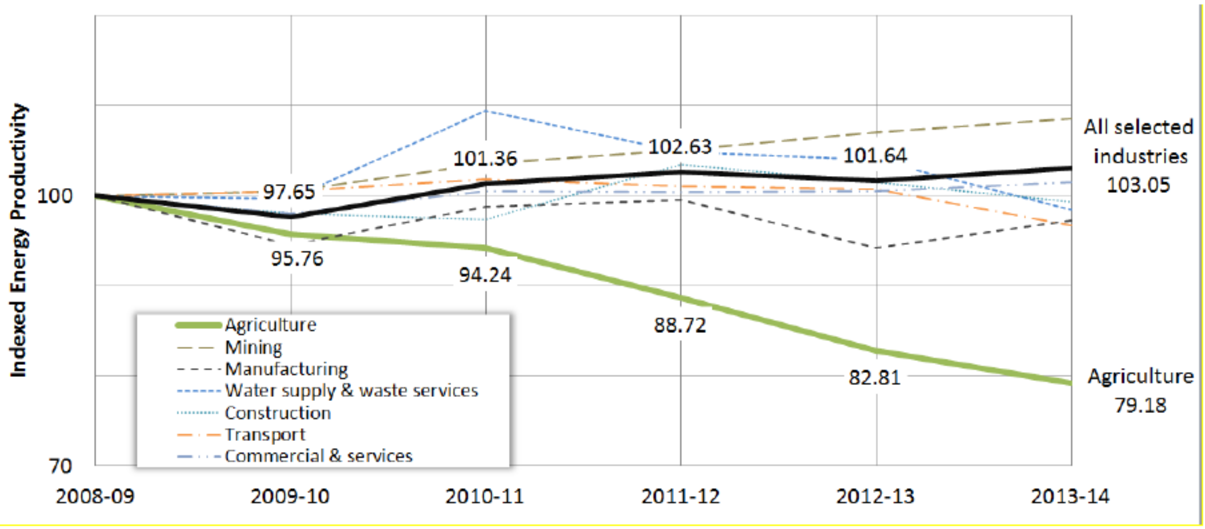
In Queensland, varying stakeholder feedback has been provided to the Taskforce on electricity supply in rural areas, highlighting the decreasing electricity-grid reliability experienced by many farmers and ancillary activities, such as processing and pumping of water. In some regional areas, reliability is an ongoing issue and, in some cases, it is decreasing. Disruption in electrical supply results in processing down-time, and unnecessary wear and tear on machinery, reducing the life-span of critical assets and infrastructure including energy efficiency measures.

Affordability and reliability are key for agricultural producers – wholesale price spikes and outages can result in annual returns for some farmers being undermined over a period of a few hours. However, overinvestment to enhance reliability comes at the expense of affordability. Efficient investment in, combined with efficient operation and use of, electricity services is crucial for farmers, other consumers and the wider economy.

Most sectors of Australian industry have achieved significant gains in energy productivity over the past decade. The conspicuous exception is agriculture where energy productivity is declining.[9] The chart below shows a decline of 21% since 2008.

[8] *National Farmers Federation submission to the Finkel Review, http://www.environment.gov.au/submissions/nem-review/national-farmers-federation.pdf*
[9] *(Eyre, 2016) http://www.aginnovators.org.au/blog/new-thinking-needed-about-regional-electricity-supply*

Figure 1: Indexed energy productivity performance of industry sectors. Agriculture energy productivity has declined 21% since 2008 (Eyre, 2016).



Analysis by NSW Farmers has suggested that greater reliance on diesel due to higher electricity costs, as irrigators switch from mains electricity to diesel generators, is a key factor in low energy productivity.

Improving agricultural energy productivity largely depends on access to affordable electricity. Electrification is a priority for most sectors of agriculture and is a requirement of the new technologies required to achieve general productivity gains (eg precision agriculture, automated control systems, electric vehicles robotics). Yet, we are moving in the wrong direction as exorbitant network charges drive irrigators to substitute electricity for diesel and to disconnect from the grid.

Attempting to segregate what needs to form the highest priority objective potentially ignores the diverse needs of consumers and geographic and user density factors that drive the economics of electricity supply in regional areas.

The current electricity grid, with its reliance on centralised generation, is an inefficient way to supply electricity to many regional and remote locations. Areas with a low density of users and sharp seasonal demand peaks (ie. in typical of irrigation districts) are the least cost-effective to supply under the current model.

A strategic integrated least cost planning approach is necessary to identify more cost effective ways to manage demand, improve service delivery and incentivise agribusiness to stay grid connected.

The high impacts of electricity pricing is being felt not only by the agricultural sector but by all consumers. The Energy Consumer Sentiment Survey (ECSS) undertaken by the ECA (published in February 2017) revealed:

- 60-70% of small businesses expressed a 7 out of 10 rating for satisfaction with reliability of electricity services
- Very low levels of satisfaction in relation to value for money for electricity services with consumers ranking electricity behind gas, internet, mobile phone, insurance, banking and water services.

Of further interest, the ECSS and the UMR Strategic research company report indicated that the primary reason consumers are investing in PV panels or behind the meter solutions was to manage consumption and to gain control of costs. The 2017 ECSS results found 34% of households are considering installing solar systems in the next 5 years, while 27% are considering installing battery storage. Small business interest in the technology is also strong, with 51% of small businesses considering installing solar systems and 49% battery storage in the next five years.

These movements in investment patterns indicate that consideration of prices paid by consumers should be a key focus by the regulator and across grid planning. This is particularly important given the upcoming pricing trends for electricity that have been earmarked by various institutions engaged in the NEM.

For example, the *AEMC 2016 Residential Electricity Price Trends* report highlights that electricity bills are anticipated to rise between $28 and $204 by 2018–19.[10] As decisions are made managing the transition away from coal fired generation, the impact of price pass-throughs that will be fed back to consumers requires careful consideration. The CSIRO/ENA *Energy Network Transformation Roadmap* found that more than $16 billion in network investment could be avoided by 2050 if distributed energy resources are optimised. The rate at which technology and the market is evolving also means that non-network solutions, involving less long-lived capital investments that can be adjusted with the circumstances, are preferable. To avoid further flow back of costs, any investment in centralised energy infrastructure must be carefully considered.

Greater focus is needed on the approach to managing peak demand loads across the NEM. Building additional power plants specifically to meet the small number of peak demand periods every year is the most expensive way to deal with potential blackout incidences. A more sensible policy approach would involve a cross network energy efficiency strategy to lower the overall load that consumers place on the network and encouraging co-generation or tri-generation capacity amongst high energy users.

Co-generation is significantly more efficient than gas and coal fired power generation as it produces heat energy as well as electricity that can be used for industrial processes. Electricity market reform could reduce electricity demand and gas use by encouraging gas cogeneration (as well as renewable energy). Efficiency measures for gas consumption can be encouraged through the State based energy efficiency schemes such as the Victorian Energy Efficiency Target and NSW Energy Savings Scheme; these have recently been broadened to include gas.

There is also opportunity to manage pricing impacts in the network that consumers currently use. In January 2016, Professor Ross Garnaut released a paper[11] stating that *"forcing high network charges on consumers in the face of declining use of the grid would impose a bigger penalty on consumers and businesses than a consumption tax, or even a carbon price. Metrics including the falling cost of renewables, reduced demand levels, should be applied to network assets to ensure that the network was priced properly…..and the first step towards rational pricing is to write down the value of redundant grid capacity".*

[10] *How much will electricity prices rise in 2017 across Australia, available via: https://www.finder.com.au/how-much-will-electricity-prices-rise-in-2017-across-australia*

[11] *Garnaut, R. (2016). Australia after Paris: Will we use our potential to be the energy super-power of the low-carbon world? Public lecture hosted by the Young Energy Professionals, State Theatre Centre of Western Australia, Perth (21 January 2016).*

Tariff Structure

The Taskforce supports a review of network tariffs. **These should be designed to ensure that irrigators and other businesses in non-congested parts of the network are not forced to meet the costs of network investments made to overcome congestion in other parts of the network.**

The current level of prices and the structure of network tariffs incentivises food and fibre producers in the NEM to consider alternative energy sources – to move off the grid - or forces them to shut down their high energy intensive irrigation equipment. The decision not to use high energy equipment significantly reduces productive capacity.

There will be significant pressure to change the current model of electricity tariffs with rapid technology change in energy hardware and software. The market will ultimately need to move to a model where customers will interact with the network in a way that suits them. The centralised grid model will be 'competing' in a market where consumers may be able to cost-effectively 'opt-out' of grid-supplied power unless it provides appropriate reliability and price. A preferred option may be for customers to move to a genuine net-metered model where they are able to trade power between their own and other nearby sites, paying DNSPs for local use of network. This model may increase grid utilisation as customers install optimum generation and storage on their sites, rather than overcapitalising in plant at individual sites with the aim of going off-grid. Accordingly, this model would secure revenue for DNSPs, though in the form of a (time-and-distance-weighted) network transport fee rather than the current network charging regimes.

The incentive to move to alternative energy sources has intensified since a 2014 rule change made by the AEMC which mandated the move to 'cost reflective tariffs'. The 2014 AEMC rule change on distribution network pricing has caused a transition to 'cost reflective' tariffs – demand driven tariffs or Time of Use Tariffs - which has had (and will continue to have) a significant impact on irrigators' and growers' electricity costs. While demand based tariffs are a sensible approach when congestion and constraints exist in the system, it is an absurd strategy to deploy when:

a) There is spare capacity in the National Electricity Market
b) Food and fibre producers have limited information about their energy use and the tariff structure applicable to them.

Congestion is used by many networks as justification for price structures. Yet a recent report by Sapere Research concluded that network congestion data used by Ergon in its Queensland tariff proposal overstates congestion by a factor of approximately 375. The scale of this pricing distortion added up to $1.8 billion over five years.[12] Similar congestion modelling of NSW networks undertaken by the Institute of Sustainable Futures, using data provided by the networks, indicates similarly nil to low numbers of areas / regions impacted by network congestion. Prices in all NEM states would appear to be being distorted by these exaggerated congestion claims.

However, despite the information available in relation to congestion, in reality it is difficult to make appropriate assessments about what constitutes an appropriate tariff (and pricing) structure when so little is known about individual consumption patterns or investments behind the meter. As highlighted by the recent review into the Security of the National Electricity Market:

> *'The growing number of distributed energy resources could also impact on power system security. They are not centrally controlled or visible to AEMO and there is currently no formal*

[12] *Sapere. (2016). Errors in Australian Energy Regulator's Draft Decision on Ergon Energy's 2016 Tariff Structure Statement, November 2016. Commissioned by CANEGROWERS Launched on 15 February 2017. See http://files.canegrowers.com.au/queensland/web-CANEGROWERS-Sapere-Report-Launch-document.pdf*

national framework for collecting information on them (such as their location, date of installation, controller settings, brand, model and real time energy statistics). This means that power system models and forecasts are less accurate than in the past, particularly when the output from distributed energy resources is high and fluctuating'.[13]

Given the inaccuracy of AEMO energy forecasting historically, it is concerning that these forecasts will become progressively more unreliable. However, irrespective of the increased challenges to forecasting demand, the regulatory framework governing network charges is having real impact on food and fibre producers no.

In the case of Queensland, QFF has modelled the impacts of moving towards cost reflective tariffs[14] on irrigators in the St George district. Based on our analysis, implementation of demand tariffs on irrigators in St George will increase electricity bills between 200% and 300%. In one example, an irrigator who currently is on Tariff 62 (with an associated bill of $150,000 per year) would be forced to pay $450,000 under the new tariff arrangements despite no alternation in his electricity use. Such an exponential increase in input costs cannot be absorbed by a cotton producer or any agricultural business in a similar circumstance.

In NSW, 185 primary producers will be forced to switch to 'Time of Use' or 'Demand Driven Tariffs' which will result in cost increases of up to 100 per cent with no corresponding change in electricity use. The resulting cost pressure is significant and illustrates the vulnerability of irrigators to the current regulatory framework governing electricity producers where the AEMC rules require a shift to cost reflective tariffs.

The introduction of 'cost reflective tariffs[15]' on agricultural producers results in severe reductions in farm profitability and results in perverse operational outcomes. The tariffs and associated costs are pushing food and fibre producers to alternative energy sources – moving them away from the electricity grid – or forcing them to shut down their electricity intensive irrigation equipment.

Without the acknowledgement of the requirements of consumers, irrigators may abandon the grid which will have significant implications for those who do not have the choice or ability to move off the grid. These impacts will be particularly amplified for rural and regional communities or in 'end of line' scenarios. In these situations, rural communities may often be reliant on large industrial users paying for electricity to maintain their electricity infrastructure and generation capacity. While the Taskforce supports investigation of alternative solutions for 'end of line' scenarios, a complete abandonment of the grid is not in the interest of broad rural and regional consumers.

Driving prices – through network tariffs - towards a scenario where electricity from the grid becomes unviable, is in no-one's interest. There continues to be no modelling or understanding of the broad impacts that will occur through high prices forcing large customers to seek off grid solutions.

There should also be an assessment of whether a network transport fee, payable by customers who may generate power at one site and consume at another, is established. The fee could include a consideration of distance and a peak time component consistent with the points above.

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[13] Dr Alan Finkel, Independent Review into the Future Security of the National Electricity Market (Preliminary Report)
[14] As per the Australian Energy Market Commission rule change in 2014 on the distribution network pricing arrangements.
[15] Cost reflective tariffs in most cases refer to demand based tariffs. These already apply to consumers that use over 160 mWh in NSW. In Queensland consumers are being transitioned to demand based tariffs with the transition to be complete in 2020. In Queensland demand based tariffs apply to consumers who use over 100 Mwh.

Improvements to regulatory processes undertaken by the AER

The current 'propose-respond' arrangement as part of the AER pricing determinations process, creates a significant advantage for network businesses relative to the regulator, and effectively places the onus of proof on the regulator to demonstrate that the businesses' proposals are incorrect or flawed. While the AER is able to interrogate and question various aspects of network business submissions during the pricing determinations and seek information, the regulator is not free to set the agenda.

This process leaves the regulator constrained and enables network businesses to effectively inundate the regulator through the weight of material it provides. The vast weight of materials presented to the regulator by the networks makes it virtually impossible for the regulator to consider all available information.

This weight of material also disadvantages consumers and our own Taskforce members, who do not have the resources to adequately review and respond to this material. As such, consumers (rightly or wrongly) place an additional expectation on the AER to provide clarity on the proposals, their decisions and to any queries that arise, particularly where there is a range of conflicting views presented.

This current examination of profitability measures for regulated gas and electricity network business, provides an opportunity for the **AER during the revenue determinations process, to set the agenda** in relation to preferred measures, data required and issues relating to financial performance.

Changes to institutional responsibilities in the NEM

There are significant changes that must occur in the roles and responsibilities within the NEM. This was highlighted by the ECA in their submission to the Finkel Review:

> "*AEMO is the institution charged with national transmission planning and maintaining security and reliability of supply. The current arrangements - where key reliability functions reside within the AEMC's Reliability Panel, and transmission planning is done by AEMO in Victoria, but transmission businesses in other jurisdictions - do not support the whole-of-system approach needed to run a highly complex, integrated national network*."

There is also clear bifurcation of roles and responsibilities by AEMC and the AER. It is interesting to note that the AEMC has not once approved a rule change put forward by consumers. For its part, the AER views its role narrowly, as a regulator that oversees compliance with those rules. The AER appears not to take an active role in proposing rule changes despite having a clear role in doing so and receiving significant advice from its own CCP of the deleterious effect of existing rules. The AER has also received strong customer feedback over the impact of the resulting electricity price spiral on the international competitiveness of their businesses.

Appropriate standards for the security and reliability of the electricity system

A combination of high reliability standards and poor demand forecasting has been responsible for the over capitalisation and investment in the electricity network. Reliability standards set across the NEM warrants close review. The Institute of Sustainable Futures produces a constraints map of the distribution network and according to the data (provided directly by the networks), there are no areas warranting investment as a result of excessive demand. A similar picture is painted in Queensland where according to *Ergon's 2016 Distribution Annual Planning Report,* 98 per cent of the low voltage network has enough spare capacity to meet all forecast peak demand growth for the foreseeable future. This data supports our argument that there has been an inefficient level of capital investment undertaken by the network companies in the previous ten-year period, which has resulted in a 'gold plated' infrastructure network.

To avoid any future network expansion and unnecessary augmentation, a close review of the reliability standards is warranted. In particular, an assessment of consumers' 'willingness to pay' for future grid reliability would be timely in light of alternative energy supply options which potentially provide 'back-up' supply through off-grid solutions and/or the existence of energy storage systems. It can be assumed that given these alternative options, consumers' willingness to pay for high reliability from the grid has diminished to a degree (or will diminish when the technologies are proven to be viable).

<u>The role/impact of new technologies</u>
The energy industry is in the midst of technological disruption, both in the physical technologies for the generation, storage and use of power; and in 'soft' technologies that can monitor, manage and securely trade power. The availability of these technologies is increasing rapidly.

The Queensland Government is working closely with the AEMC and stakeholders to develop new models for grid usage such as virtual net metering, peer to peer trading etc. including but not limited to:

- Where a farmer has multiple network connections, they can have renewables connected to the main NMI/account, and credit against consumption at a separate pump connection against the solar generation (with a 'grid transport fee');
- a farm business could generate enough power at one site with a bioenergy plant to cover the consumption at a number of separate (but nearby) sites, by offsetting that consumption against generation at the main site (with a 'grid transport fee).

To allow these new grid usage models to work, the AEMC will need to develop new rules. It is thought that the avenues currently being investigated by the Queensland Government could have been supported via the adoption of the rule change for Local Network Generation Credits (ERC0191) which was rejected by the AEMC in its draft determination. It should be noted that rule changes will be required to allow virtual metering, and additional leadership by the COAG Energy Council will be required to facilitate the adoption of decentralised energy generation and greater renewable energy deployment.

Across the grid, considerably higher levels of planning and data collection are required to ensure there is no reoccurrence of historically inaccurate demand predictions. Already, approximately 1.5 million rooftop solar systems are in place, and it is predicted that there will be 1.1 million battery storage systems in place in conjunction with PV panels by 2035[16]. There is no current understanding of the behind the meter investment and as such, the contribution these resources make to energy generation is VERY poorly understood. Smart meters will play an important role in improving the performance and delivery of the National Electricity Objective in the future.

Smart meters at end-user premises, as opposed to simply metering energy use for bulk billing purposes, are required to provide vital information. Smart meters allow both distributor network businesses and electricity end users to have better information on how energy is consumed, and to better control that use, including in the use of end-user generation systems.

According to the Energy Networks Association (ENA) "*As technology and energy markets develop rapidly, smart meters and other devices will benefit individual consumers. Customers should receive*

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[16] *Dr Alan Finkel, Independent Review into the Future Security of the National Electricity Market (Preliminary Report)*

practical information and more rewarding tariff structures that match their needs; be able to control their energy use to get better deals and participate in new markets, such as exporting energy to the Grid through solar panels or supporting energy storage options as these develop commercially"[17].

While rules are now in place that will allow for a very gradual transition of consumers to smart meters i.e. when a meter upgrade is required or following the completion of the solar bonus scheme, we believe that if future grid needs are to be catered for, it is critical that transition to smart meter solutions should occur much more rapidly.

There are many issues to be resolved to facilitate the roll out of smart meter technology. These include:

- issues of smart meter connectivity in regional areas due to telecommunications blackspots
- data privacy and security concerns associated with smart metering arrangements
- education of consumers so they are aware of the shift away from 'bulk' electricity pricing on to time of use and load based metering
- the transitional arrangements for historical costs associated with older meter installations as metering responsibilities shift away from the network companies and on to retailers; and
- transparency of metering costs for consumers as retailers take on metering responsibilities.

In many cases, larger agricultural users have been mandated to 'upgrade' their meters to smart or interval based meters at their own cost. We believe that the challenges associated with a smart meter roll out must be addressed in order to develop a full understanding of our network capacity and the energy needs for the future NEM.

Broader regulatory reform is required to drive the regulatory change needed within the NEM. The network rules do not allow for localised solutions currently evolving within the existing network. The regulatory process should enable the market to respond quickly to allow for widespread adoption of these technologies that would allow customers to increase the utilisation of electricity networks.

For example, businesses in regional areas would benefit from the ability to 'net-off' their generation and use or trade with nearby sites, paying a small fee for the use of the local network (network transportation fee) rather than full network and retail costs. Solutions such as peer-to-peer trading may offer greater local network utilisation and stability, offering new revenue opportunities for DNSPs and result in less sub-optimal options such as 'do nothing' or eventual independence from the grid.

Distributed energy generation may represent a cost-effective approach to increasing the reliability of electricity supply above current grid levels. It may also be accompanied by cost measure benefits of 'local energy trading system' – where utilities can provide customers with solar and storage and allow their output to be traded in a suburban network. Such approaches require significant changes in the way incumbent utilities (e.g. Ergon, Essential Energy) manage their business models and will require networks to look to a more 'distributed' model, while the implications for centralised generation, and for retailers, will also be significant.

The rule changes required to allow this to occur need to be initiated urgently to ensure that remaining connected to the electricity network is a viable option for regional businesses, and in fact, the preferred option. It needs to be made absolutely clear that the network rules need to promote new solutions not protect existing owners.

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[17] *Changing the Face of Energy Management. Electrical Comms Data. Jan/Feb 2015. Vol. 14 No.6. pp. 32-34.*

Improvements to governance and regulation in the grid

Despite the attempts by various review processes to disentangle the regulatory structure of the Australian Energy Markets, our view remains that the current governance structure is highly complex and provides little opportunity for individual consumers or stakeholder representative bodies to engage effectively with the three key entities: Australian Energy Regulator (AER), Australian Energy Market Commission (AEMC) and the Australian Energy Market Operator (AEMO).

The tiered overview of the various governance bodies, regulators and COAG committees, does not provide a clear picture of the roles and responsibilities of these entities. There is a lack of transparency and clear delineation of responsibilities which makes it virtually impossible for food and fibre producers to fully engage with the governance bodies.

Fundamental reform is needed within the existing regulatory arrangements, not simply minor 'fine-tuning' that has characterised so much of the regulatory debate to date. We support, and have been engaged in, the activity emerging from some of the recommendations of the Finkel review.

The Taskforce proposes the following further reforms:

a. The Competition Principles Agreement should not apply to state government monopoly electricity networks. The application of this agreement to electricity networks is obviously contrary to the legitimate commercial and economic purpose of this agreement for government owned businesses that provide services in competitive markets. No longer subsuming the network monopolies under this agreement will mean that the economic regulation of the government owned monopolies will recognise the state government's ownership, and regulatory allowances for the cost of capital will be established accordingly.

   This will bring the regulation of government owned networks back into line with the long-established practice in Australia (which prevailed until the Competition Principles Agreement) and will mean that the economic control of government owned network monopolies in Australia will be consistent with the approaches adopted in the economic regulation of government owned networks in other countries including the United States, Germany, Austria and Scandinavian countries.

b. Government owned network monopolies must be economically regulated by the state governments that own them. This is the long-established tradition in Australia until the reforms that led to economic regulation initially by state government regulators and subsequently by the AER. The outcomes delivered by these ostensibly independent regulators have, as we have shown, been highly unsatisfactory. Political accountability for the prices charged by state government distributors must rest with the governments that receive their profits and taxes.

c. The excessive asset valuation must be addressed through write-down of the networks' assets. The AER's current examination of profitability measures for regulated gas and electricity network business may offer some solutions as part of this endeavour.

d. The AEMC should NOT have any role in the economic regulation of networks. The bifurcation of economic regulation between the AER and AEMC is a unique model internationally.

e. The form of regulation (specifically periodic price/revenue controls as opposed to other forms of regulatory control) should be reviewed.

Finally, in the context of possible privatisations of the transmission and distribution businesses in NSW and Qld, the question arises how partially privatised distributors should be regulated. Notwithstanding the complexity of this issues, our view is that if ‘privatisation’ takes the form of minority private shareholder participation, and governments continue to retain majority ownership and control, then the network should be regulated by the government, not by the AER.

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