AGL response to the Australian Energy Market Commission

Advice of best practice retail price regulation methodology, Issues Paper, 14 June 2013

July 2013

Table of Contents

Executive Summary

General Comments

AGL welcomes the opportunity to make this submission to the Australian Energy Market Commission (AEMC) on the Issues Paper – Advice on best practice retail price regulation methodology, 14 June 2013 (***Issues Paper***).

The economic rationale for price regulation is very different in monopolistic markets as opposed to markets which are competitive or transitioning to being 'workably' competitive. In the case of competitive or transitioning markets, in seeking the balance between constraining potential market power and encouraging competition regulators need to ensure that price setting doesn't damage competition such that new entrants are discouraged from entering the market.

The retail electricity markets under consideration by the AEMC could be thought of as falling into one of three categories:

a) Competitive retail market (or transitioning to being 'workably' competitive) with price regulation;

b) Competitive retail market with no price regulation; or

c) Non-competitive retail market with some form of price regulation.

AGL has limited its comments as applicable to jurisdictions in which AGL has retail interests and have a competitive retail market (or transitioning to being 'workably' competitive) with price regulation i.e. NSW, South-East QLD and ACT. AGL has not commented on the suitability of specific methodologies to non-NEM regions i.e. Western Australia and Northern Territory.

While the AEMC notes in the Issues Paper that a number of approaches might be recommended to account for different market structures, AGL highlights that in developing advice for the SCER the Commission should acknowledge the role of price regulation in these different types of markets, including that it is not required in a competitive market.

Potential unintended consequences of national price regulation advice

AGL is concerned there appears to be no discussion in the Issues Paper of the potential unintended consequences of recommending a 'best practice' price regulation methodology which might be considered by some stakeholders as appropriate to be applied across a range of markets with different levels of competition and market structures.

On this basis, AGL requests that the AEMC confirm in their Final Report that any 'best practice methodology' for calculating a regulated retail electricity price is not relevant for calculating standing or market contract offers in deregulated competitive retail markets.

AGL appreciates the AEMC's efforts in seeking views from stakeholders in preparing their advice for the SCER. The timeframe means that stakeholders will not have a formal opportunity to comment on the AEMC's final advice to the SCER. AGL suggest that the AEMC should, if possible, seek formal feedback from stakeholders on their final advice or recommend that the SCER seek further consultation with stakeholders to ensure that adequate consideration has been given to stakeholder views.

AEMC's approach, objective and principles

AGL is of the view that it is not possible to consider a single set of objectives/principles/methodologies for regulating prices given the mix of monopolistic and competitive retail markets in the various jurisdictions and that many have moved to price deregulation.

The best practice methodology should clearly not apply to deregulated markets. However, the methodologies must provide the flexibility to be applied to both monopolistic and workably competitive markets and balance the different objectives when regulating these different situations.

AGL suggests that the proposed objective of price regulation in the Issues Paper requires further consideration due to the different market characteristics to which it applies:

- AGL agrees that the purpose of any retail price regulation should be to support the long-term interests of customers. It is imperative that in markets which have the framework established for achieving competition (i.e. markets with full retail contestability (FRC)) that any price regulation does not impede the development of competition. AGL suggest that it would be more appropriate for the objective to read "*In promoting the long-term interests of customers*"; and

- If competition exists then market forces are best placed to promote economic efficiency and in turn greater consumer benefit. In these circumstances, setting regulated retail prices with the objective that they "*reflect the efficient costs*" could become problematic because the risk of setting unreasonable costs and margin is not symmetrical i.e. if regulated prices in a competitive market are set higher than efficient levels retailers will compete away any additional margin. AGL suggest that the objective should aim to promote recovery of efficient costs.

Retail price components

The Issues Paper steps through the different components which are considered in setting a retail electricity price. AGL has provided comments on each of the components discussed. In setting a regulated price in a competitive electricity market AGL notes the following:

- The primary objective in setting a wholesale energy cost (WEC) allowance as part of regulated price in a competitive retail market should be to facilitate competition between retailers in that market. AGL maintains the view that in order to ensure development of retail competition a combination of the LRMC and market-based approach (i.e. 'LRMC as floor' approach) is the most appropriate methodology;

- The process to forecast an 'efficient' WEC for a set of regulated customers relies on detailed modelling which includes a large number of inputs and assumptions. The subjective nature of this process means that the forecast of an 'efficient' WEC carries with it a significant amount of risk for the efficient functioning of the competitive retail market. While using an approach such as 'LRMC as floor' can mitigate some of this risk, the selection of a modelling approach and the various inputs and assumptions can significantly affect the final result;

- Defining retail operating costs from the perspective of a standard or incumbent retailer is inconsistent with the objective of setting regulated retail prices to encourage competition. For the purpose of setting regulated prices, the retail operating costs should be based on a new entrant retailer which is not vertically integrated with distribution networks or power generators;

- The methodologies described in the Issues Paper to estimate retail margins will provide a range of results. AGL suggests that in a competitive market some discretion is required by the regulator to ensure that the retail margin is set at an appropriate level to promote competition;

- Any competition allowance included in a regulated price should be set in an open and transparent manner;

- A weighted average price cap (WAPC) is the most appropriate form of regulation where one or more Standard Retailers are setting numerous tariffs in a competitive market. The WAPC provides retailers with flexibility to reset or re-balance individual regulated prices whilst allowing network charges to be fully passed through; and
- Price determination periods of up to 3 years provide retailers with greater certainty than annual determinations. AGL consider where a price determination is longer than one year it is appropriate to include an annual review of certain cost components to ensure that the regulated price is set appropriately to meet the objectives of price regulation for the market in question.

1. General Comments

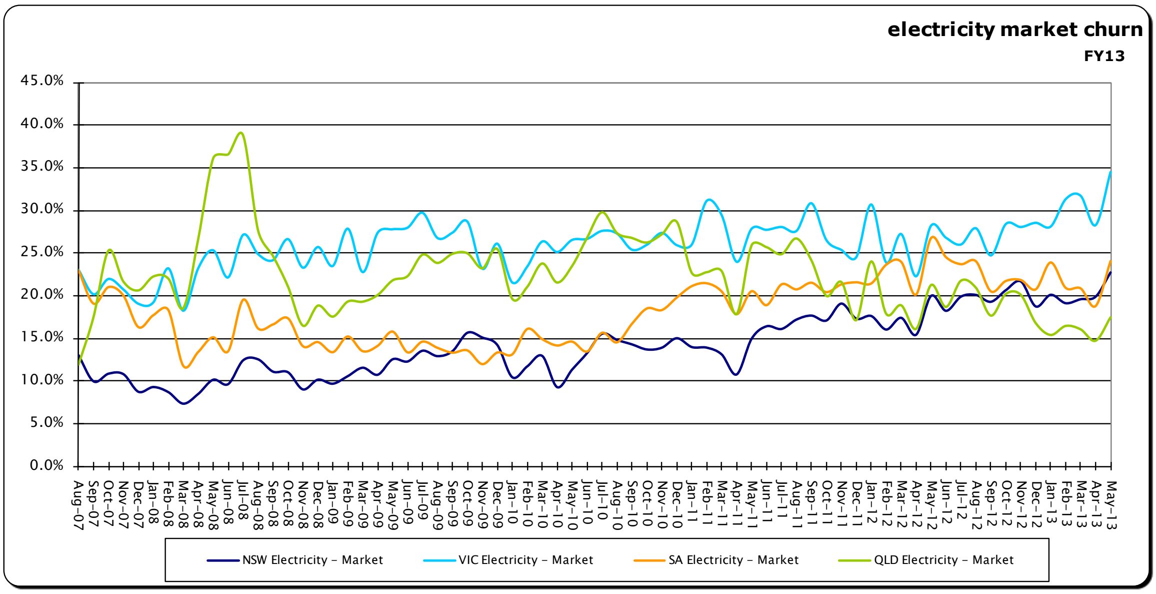
AGL welcomes the opportunity to make this submission to the Australian Energy Market Commission (AEMC) on the Issues Paper – Advice on best practice retail price regulation methodology, 14 June 2013 (***Issues Paper***).

1.1. Retail competition in the NEM

Any consideration of setting regulated retail electricity prices should be framed with respect to the policy objectives of full retail contestability (FRC), and in the interests of the market as a whole. The introduction of FRC permits retailers to compete for small electricity customers and provide customers with a choice of energy retailers. When setting the R component comprising of wholesale energy costs, retail operating costs and retail margin, it is important that competition is facilitated.

Over recent years NEM region retail electricity competition levels have been amongst the highest in the world. Figure 1 below shows the levels of customer churn in these markets over recent years.

Figure 1 – NSW, VIC, SA & QLD retail market customer churn



As has been clearly observed in other markets where retail prices are subject to regulation, both in the NEM and around the world, competition will not survive where the regulated price does not provide retailers with a sustainable level of margin across the years. Price path certainty at a sustainable level of margin is a necessary condition for retailers to have the confidence to invest in market entry.

1.2. Regulation in competitive and non-competitive markets

The retail electricity markets under consideration by the AEMC could be thought of as falling into one of three categories:

a) Competitive retail market (or transitioning to being 'workably' competitive) with price regulation;

b) Competitive retail market with no price regulation; or

c) Non-competitive retail market with some form of price regulation.

The purpose of price regulation in monopolistic markets is well understood and varying approaches have been applied in a range of different markets. The economic rationale for price regulation is as a mechanism to allocate efficiency savings in monopolistic markets between consumers and producers."[1] In effect, price regulation attempts to replicate how a competitive market would set an efficient market price in order to maximise the benefits for all market participants.

AGL has limited its comments as applicable to jurisdictions in which AGL has retail interests and have a competitive retail market (or transitioning to being 'workably' competitive) i.e. NSW, South-East QLD and ACT. AGL has not commented on the suitability of specific methodologies to non-NEM regions i.e. Western Australia and Northern Territory.

In a market which is competitive or is transitioning to being 'workably competitive the purpose of price regulation is very different to a monopolistic situation. In a competitive market the structures exist such that the allocation of savings between consumers and producers will occur at an efficient market price. On this basis, the economic function of price regulation ceases once competitive characteristics are established.[2] In a 'workably' competitive market, any price regulation should aim to limit the exercise of market power which could impede the development of competition and setting an efficient market price.

The risks of price regulation in these markets are also very different. As noted by Yarrow (2008):

> *"By definition, when dealing with pure monopoly the imposition of price controls will introduce no risks to competition, since there exists no competitive process capable of being harmed."*[3]

In the case of competitive or transitioning markets, in seeking the balance between constraining potential market power and encouraging competition regulators need to ensure that price setting doesn't damage competition such that new entrants are discouraged from entering the market.

While the AEMC notes in the Issues Paper that a number of approaches might be recommended to account for different market structures, AGL highlights that in developing its advice for the SCER the AEMC should acknowledge the different roles of price

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[1] Simshauser, When does retail electricity price regulation become distortionary?, AGL Applied Economic and Policy research, Working Paper No.33, July 2012. page 4.

[2] Ibid. Page 4

[3] Yarrow, Prof. G., Decker, Dr. C., Keyworth, T. Report on the impact of maintaining price regulation, Regulatory Policy Institute, January 2008. Page 12

regulation in these different types of markets, including that it is not required in a competitive market

1.3. Move to price deregulation

The Terms of Reference for the advice specifically addresses the need to ensure that any recommended approach to price regulation:

> *"should ensure that the approach to retail price regulation reflects the current extent of competition in the relevant market, and is consistent with removing price regulation in the future when competition is effective".*[4]

Any recommended price regulation methodology which is applicable to a competitive retail market needs to ensure that it would not damage competition. In order to promote the long-term interests of customers it is critical that retail competition is not undermined in markets which are transitioning toward price deregulation.

In recent months there has been increased recognition by State Governments and regulators of the benefits of moving to deregulate retail electricity prices for small customers. The South Australian Government deregulated retail electricity prices from 1 February 2013 and in June 2013 the Queensland Government announced that it would remove price regulation and introduce price monitoring for small customers in South-East Queensland from 1 July 2015.

Under the Australian Energy Market Agreement State and Territory Governments have committed to phase out price regulation where retail competition can be demonstrated to be competitive.[5] As noted in the Issues Paper, in December 2012 the Council of Australian Governments (CoAG) and the SCER reaffirmed their commitment to deregulate retail prices where competition is effective.[6]

In Victoria and South Australia the move to price deregulation was proceeded by an assessment of competition by the AEMC. In both cases the AEMC found that with effective competition the appropriate conditions existed for the implementation of price deregulation.

In the markets which AGL operates, NSW is the only State which hasn't already moved to deregulate retail electricity prices or announce a timetable for price deregulation.[7] As part of its most recent determination of regulated retail electricity prices IPART found that "competition in the NSW electricity market now protects customers against market power by offering more choices and better price and service outcomes" while also acknowledging that imposition of price regulation is a matter for the NSW Government to decide.[8]

AGL agrees with IPART's assessment on NSW competition, also broadly reflected in the AEMC's recent draft report on the review of competition in the NSW retail electricity market, and on this basis AGL is of the view that NSW should move to deregulate prices as soon as practicable.

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[4] Standing Council on Energy and Resources, Terms of Reference – Australian Energy Market Commission (AEMC) reporting on a best practice retail electricity pricing methodology. Page 2.

[5] Clause 14.13, Australian Energy Market Agreement, 2nd October 2011.

[6] Australian Energy Market Commission, Issues Paper – Advice of best practice retail price regulation methodology, 14 June 2013. Page 2.

[7] AGL has an equity interest in the ActewAGL Retail Partnership in the ACT.

[8] IPART, Review of regulated retail prices and charges for electricity, From 1 July 2013 to 30 June 2016, Electricity – Final Report, June 2013. Page 30.

1.4. Potential unintended consequences of national price regulation advice

In Section 1.1 of the Issues Paper the AEMC sets out the purpose of the advice requested by the SCER and notes that jurisdictions will be able to consider whether to apply this methodology in setting retail electricity prices and in developing their plans to transition to deregulation.[9] Since the request for the advice from the AEMC was released by the SCER on 14 December 2012, the changes in price regulation policy in South Australia and Queensland and the AEMC's draft findings on NSW retail electricity competition have been announced. These announcements represent a significant step for the continued development of competition in these markets. AGL is concerned there appears to be no discussion in the Issues Paper of the potential unintended consequences of recommending a 'best practice' price regulation methodology which might be considered by some stakeholders as appropriate to be applied across a range of markets with different levels of competition and market structures.[10]

Firstly, the AEMC should consider the impacts on existing retail markets with price regulation that could result from the release of their advice on 'best practice' methodologies. For example, AGL assumes that the AEMC does not intend that these methodologies should be used as an alternative methodology to the current approach used in jurisdictions that are currently within the period of an existing price determination.

AGL also note that the AEMC is currently consulting with retailers so that the approach used to establish retail price trends accounts for retailers' market contract prices rather than just published standing offer prices. On this basis, AGL request that the AEMC confirm in their Final Report that any 'best practice methodology' for calculating a regulated retail electricity price is not relevant for calculating standing or market contract offers in deregulated competitive retail markets.

Secondly, the Issues Paper also presents the benefits of a nationally consistent and stable method for setting regulated retail prices, including:

- *"Provides market participants in both retail and generation sectors with increased confidence when investing;*
- *Potential to lead to lower and more stable prices for customers;*
- *May also promote competition in retail markets; and*
- *Increased choice for customers in determining how their electricity is supplied."*

AGL question whether implementation of a national approach is feasible given the State-based approach to price deregulation. In fact, as discussed earlier, there may be unintended consequences from recommending a national approach to price regulation without clarifying that the approach is not applicable to competitive markets which have or are to be deregulated.

AGL question the basis for the view that a national approach to price regulation could have the "*potential to lead to lower… prices for customers*". Price regulation does not change the costs faced by electricity retailers. The inability of price regulation to shield customers from price shocks was noted by recently by IPART:

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[9] Australian Energy Market Commission, Issues Paper – Advice of best practice retail price regulation methodology, 14 June 2013. Page 2

[10] AGL note that in newly deregulated retail electricity markets price monitoring can have a role to ensure that the objectives of deregulation are being met.

"The recent increases in regulated retail electricity prices demonstrate that price regulation has not protected customers from 'price shocks' associated with changes in regulatory and policy settings."[11]

Price regulation can only ensure that, in a monopolistic market, retail prices are less likely to tend to inefficient levels.

1.5. Consultation

AGL appreciates the AEMC's efforts in seeking views from stakeholders in preparing their advice for the SCER. The timeframe of the preparation of the advice means that stakeholders will not have a formal opportunity to comment on the AEMC's final advice and recommendations to the SCER. AGL suggest that the AEMC should, if possible, seek formal feedback from stakeholders on their final advice or recommend that the SCER seek further consultation with stakeholders to ensure that adequate consideration has been given to stakeholder views.

1.6. Structure of submission

In this paper, AGL has responded to the Issues Paper in the following structure:

- Section 2 discusses the proposed approach, objective and principles for the advice;
- Section 3 discusses the different options for calculating the wholesale energy cost (WEC) allowance;
- Section 4 addresses issues related to network costs;
- Section 5 considers inclusion of retail operating cost and margin allowances;
- Section 6 discusses environmental and other jurisdictional schemes; and
- Section 7 considers the uses of form and pricing control.

AGL has also included in Appendix 1 a research paper by Professor Paul Simshauser (AGL Chief Economist and Group Head of Corporate Affairs) that discusses the nature of price regulation in retail electricity markets and different approaches to setting tariff caps and their impact.

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[11] IPART, Review of regulated retail prices and charges for electricity, From 1 July 2013 to 30 June 2016, Electricity – Issues Paper, November 2012. Page 2.

2. Approach, Objective and Principles

2.1. Approach

Question 1 Approach to advice
(a) Is the proposed approach to the advice appropriate for developing a best practice methodology for setting regulated retail prices?
(b) Are there any specific factors in relation to Western Australia and/or the Northern Territory that the AEMC should consider in developing a best practice method for regulated retail prices?

Proposed approach

As noted earlier, AGL is of the view that it is not possible to consider a single set of objectives/principles/methodologies for regulating prices given the mix of monopolistic and competitive retail markets in the various jurisdictions and that many have moved to price deregulation.

The best practice methodology should clearly not apply to deregulated markets. However, the methodology must provide the flexibility to be applied to both monopolistic and workably competitive markets and balance the different objectives when regulating these different situations.

As noted earlier, AGL has limited its comments as applicable to jurisdictions in which AGL has retail interests and have a competitive retail framework with price regulation i.e. NSW, South-East QLD and ACT. AGL has not commented on the suitability of specific methodologies to non-NEM regions i.e. Western Australia and Northern Territory.

The proposed approach set out in the Issues Paper for developing a best practice methodology appears to be appropriate for the task described.

2.2. Objectives

Question 2 Proposed objective of the advice
Is the proposed objective appropriate in guiding the development of the AEMC's advice?

Proposed objective

Section 2.3 of the Issues Paper describes the rationale for setting the proposed objective of retail price regulation. A number of key considerations are highlighted in the development of the proposed objective:

- The National Electricity Objective (NEO) is the overarching objective to the development of the AEMC's approach and therefore the best practice methodology should better allow for the NEO to be met;
- Retail price regulation should have regard to the long term interests of consumers;
- Where competition is feasible, regulation should also seek to facilitate competition in a way that will produce efficient long term outcomes;

- Competition allows prices to trend to efficient levels over time and these efficient levels are made up of two elements:
  - Cost efficiency – price regulation should allow businesses to recover only those costs that are efficient; and
  - Cost reflectivity – price regulation should seek to set cost reflective prices.

On this basis, the AEMC has developed the following as the proposed objective:

Box 2.1: Proposed objective of retail price regulation

Having regard to the long-term interests of customers, retail price regulation should determine electricity prices for small customers, which:

• reflect the efficient costs of providing retail electricity services; and

• facilitate the development of competition in retail electricity markets, where competition may be feasible.

These points considered by the AEMC and resulting proposed objective highlight a number of issues which AGL suggest require further consideration in defining an objective.

Long-term interests of customers and retail competition

The proposed objective for determining retail electricity prices is prefaced as "Having regard to the long-term interests of customers". AGL agrees that the purpose of any retail price regulation should be to support the long-term interests of customers. AGL believes that where the market can be demonstrated to be effectively competitive that price deregulation is the most effective policy option for promoting the long-term interests of customers. It is imperative that in markets which have the framework established for achieving competition (i.e. markets with full retail contestability (FRC)) that any price regulation does not impede the development of competition.

AGL suggest that rather than "*Having regard to the long-term interests of customers*" that it would be more appropriate for the objective to read "*In promoting the long-term interests of customers*". This change would align the objective with the wording of the current Australian Energy Market Agreement.[12]

Determining the 'efficient cost' of retail electricity services

As noted earlier, where competition exists in a market, then market forces are best placed to promote economic efficiency and in turn greater consumer benefit. In these circumstances, setting regulated retail prices with the objective that they "*reflect the efficient costs*" could become problematic.

This approach implies that a regulator is able to set a single level of efficient costs in the market that applies to all retailers. In a competitive market, asymmetric information and the complexity of energy markets means that a regulator, no matter how wise and well resourced, could never be expected to produce a reliable forward estimate of an efficient price.[13] The variety of retail businesses operating within the market with different

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[12] Clause 2.1(a) Australian Energy Market Agreement states that the objectives of the agreement include "The promotion of the long term interests of consumers with regard to price, quality and reliability of electricity…. services"

[13] Simshauser, When does retail electricity price regulation become distortionary?, AGL Applied Economic and Policy research, Working Paper No.33, July 2012, Page1.

structures and business strategies mean that the regulated price will not reflect the costs of all the market participants.

In this context, it is extremely important to acknowledge that the risks of price regulation are not symmetrical. In the event margins available under the regulated tariff are higher than is required, these margins are competed away. For example, currently in NSW AGL offers market contracts discounts of up to 17% on energy usage rates (based on standard contract charges).

However, if costs and margins are set below realistic levels then not only will competition be stifled, but second tier retailers will not seek to enter the market, and retailers will not have the incentive or the appetite to invest. Hence, the risk of underestimating the costs and margin is much greater than the risk of overestimation. Regulators should aim to ensure that any intervention in the electricity market does not adversely impact on the efficient operation of the market.

In light of the limitations of determining an 'efficient price' AGL suggest that the objective should aim to promote recovery of efficient costs. In a competitive environment, the regulated price forms the 'price to beat' in the market. Since competition in the retail energy market is primarily driven by the extent of discounting, it is important the regulated price is set at a level which allows retailers to develop offers which are sufficiently attractive for customer to switch and at the same time provide a sustainable rate of return.

The impact on the retail market resulting from over-regulation of a retail price cap was demonstrated in NSW between 2004 and 2006. The determination of regulated retail electricity prices by IPART for the period 2004 to 2007 was such that customer switching rates were at critically low levels between 2004 and 2006. The impact of this pricing decision was recognised by the Australian Energy Regulator, and IPART itself when setting prices in the following determination period.[14]

2.3. Principles

Question 3 Principles for the advice
Are the proposed principles appropriate in guiding the development of the AEMC's advice?

Proposed principles

Section 2.4 of the Issues Paper describes the principles, borne out of the proposed objective, for assessing alternative methods for setting the retail electricity prices and to guide the development of a best practice methodology. The proposed principles are:

- Principle 1: Cost efficiency
- Principle 2: Cost reflectivity
- Principle 3: Transparency
- Principle 4: Open and consultative process
- Principle 5: Predictability and stability
- Principle 6: Minimising the administrative burden

[14] Ibid. Page 6.

- Principle 7: Appropriate allocation of risk

AGL is broadly supportive of the principles, described in the Issues Paper, for developing price regulation in circumstances where it is warranted. However AGL is concerned that:

- no specific mention is made of promoting the development of competition in markets where competition is feasible. This should be a specific principle; and
- The principle of "Cost efficiency", while appropriate, needs to be clearly defined so that stakeholders can clearly understand how cost efficiency is determined and applied in both monopolistic and competitive retail markets. AGL believes this principle needs to be treated quite differently depending on the competitive state of the market being regulated.

3. Wholesale energy costs

3.1. Wholesale energy costs

Question 4 Wholesale energy costs
(a) As considered in our proposed objective, should the wholesale energy cost allowance aim to:
(i) recover the efficient costs retailers face at a particular point in time; or
(ii) have a more long-term focus in recovering costs?
(b) What is the appropriate method (or combination of methods) to estimate wholesale energy costs?
(i) Does the appropriate method differ depending on the state of competition in the market? For instance, should a different method be applied in jurisdictions that have limited competition in the wholesale market, such as Western Australia, Northern Territory or Tasmania?
(c) Are there are any other allowances or costs that should be included in the wholesale cost allowance? Eg, a volatility allowance or allowance for prudential capital?
(d) What sensitivities should surround the calculation of wholesale energy costs? Eg, in relation to estimating a carbon cost?

Objective of the wholesale energy cost allowance as part of a regulated retail price

The primary objective in setting a wholesale energy cost (WEC) allowance as part of regulated price in a competitive retail market should be to facilitate competition between retailers in that market. Because the WEC is such a significant component of a retailer's costs if the allowance is set at a level at which retailers cannot recover their cost of energy then this will reduce competition in the market. On this basis, the WEC allowance needs to ensure that retailers can recover their long-term energy costs. However, due to the potential short-term financial impact on retailers of a period of under-recovery of energy costs calculation of the WEC should include need a mechanism whereby the allowance can reflect short-term wholesale costs if the market moves above the long-term costs.

AGL maintains the view that the most appropriate methodology in order to ensure development of retail competition is using a combination of the LRMC and market-based approach i.e. 'LRMC as floor' approach. The 'LRMC as floor' approach was used in NSW in the determination of retail electricity prices from 2010 – 2013[15], and was only changed in response to an updated Terms of Reference for the regulation of retail electricity prices for 2013 to 2016.

An 'LRMC as floor' approach offers a number of policy benefits where price regulation exists alongside a competitive retail market:

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[15] NSW Minister for Energy, Terms of Reference for an investigation and report by the Independent Pricing and Regulatory Tribunal on regulated tariffs and regulated charges to apply between 1 July 2010 and 30 June 2013 under Division 5 of Part 4 of the *Electricity Supply Act 1995*.

Price stability and certainty

It is inherent that retail price regulation in a supply chain where wholesale prices are unregulated (within a -$1,000 to $12,900/MWh range) presents risks to retailers. As noted earlier, from a public policy perspective, it is generally accepted where there is competition, retail prices should be deregulated. Since price deregulation is a matter of government policy, where there is competition, standing contract prices should be determined using "LRMC as the floor" or "the higher of LRMC or market" approach so as to minimise any intrusion on the efficient operations of the competitive market.

As noted earlier, the risks associated with price regulation are not symmetrical. This is particularly true when considering how a WEC allowance should be set. In a competitive market when retailers' costs, which include short term market based costs, are lower than LRMC, retailers will discount to retain or acquire customers. Market contract prices therefore reflect the "efficient" price with discounts reflecting each retailer's assessment of their costs. However, where retailers' costs which may include hedges in the forward or futures markets are higher than LRMC, the "higher of LRMC or market" approach ensures the viability of retailers with different business models are not put at risk as the reduction in competition will not be in the long term interests of consumers. To the extent that retailers offer term contracts against the standing tariff, shifting the goal-posts in mid-flight results in policy uncertainty, which has real costs over the long run as Appendix 1 demonstrates.

Security of supply

AGL also draws the AEMC's attention to the role that electricity price regulation plays in the broader energy market.

The potential impact of a regulatory intervention into the retail market ha been recognised in Australian jurisdictions. The following extract is taken from the NSW Government Minister for Energy's 'Terms of Reference' to IPART for the review of regulated retail tariffs in 2006:

> *Regulated tariffs set below the cost of supply will also inhibit investment in the new generation required as the demand/supply balance tightens, as investors will not be able to recover their costs.*[16]*.*

The building of new generation plant is highly reliant on the underwriting of plant through credit worthy retailers. The underwriting of plant is most usually done through a Power Purchase Agreement (PPA) which is effectively a long term hedge contract. Retailers obtain their creditworthiness in part due to the stability of regulated retail tariffs. The requirement for credit worthy retail partnerships in new investment opportunities has become increasing important since the Global Financial Crisis (GFC).

At the present time electricity demand in the NEM is not growing as rapidly as had previously been forecast and there are questions over when any additional generation capacity will be required. However, retailers not only underwrite thermal generation investment to meet demand requirements, they also underwrite renewable generation to meet requirements such as the Commonwealth Government's Renewable Energy Target.

In addition, the importance of retailers underwriting new generation (thermal and renewable) projects is also heightened by the exit of Government-funding from thermal

[16] NSW Government Minister for Energy, *Terms of reference for an investigation and report by the Independent Pricing and Regulatory Tribunal on regulated retail tariffs and regulated retail charges to apply between 1 July 2007 and 30 June 2010 under Division 5 of Part 4 of the Electricity Supply Act 1995*, 30 June 2006

generation projects. In particular, State Governments have withdrawn from the development market to avoid the risk of crowding-out the private sector.

LRMC is an established methodology

The evolution of the Australian wholesale electricity market from a state-owned, centrally controlled system to an open competitive market has posed a range of challenges for the maintenance of retail price regulation. Retail price regulators have had to balance ensuring that wholesale prices are passed-through to ensure retailer viability while maintaining Government social policy objectives and balancing increasing network cost pass-through.

Using an approach which incorporates LRMC as an estimate for the wholesale energy cost is well-established in the context of setting regulated retail electricity prices. The LRMC methodology is currently used in determining NSW retail electricity prices for 2013 to 2016 and this approach has been used in recent years in Queensland and South Australia.

In some recent retail regulated electricity pricing decisions a range of arguments have been put forward against the use of a LRMC methodology in setting the WEC. These arguments have included:

- LRMC is an estimate of the long term cost of generation and does not represent the cost to a retailer of purchasing energy in the coming year;
- Using LRMC to calculate the WEC will not result in appropriate price signals to consumers; and
- Incorporating LRMC into a regulated price implies that retailers will altruistically support generators to recover their long-term costs.

AGL suggest that such arguments are driven by a desire to set a WEC allowance based on wholesale market prices which are lower than the long run cost of generation, rather than established economic theory. It might be true that in a purely monopolistic market, prices based on long run costs may not reflect the efficient cost at a point-in-time, however in a workably competitive market participants will set the efficient price and retailers will be forced to adjust their cost structures or exit the market. As regulators have imperfect information on which to determine the 'efficient cost' there is a real possibility that cost allowances could be set below actual costs faced by retailers, thus significantly damaging competition i.e. forcing premature exit from the market.

Methodologies for setting the wholesale energy cost allowance

In this section below AGL provides a discussion of the different methodologies available to regulators in setting the WEC and the sensitivities in the WEC methodologies.

Long run marginal cost approaches

The Issues Paper describes a long-run marginal cost (LRMC) approach as one which "estimates a retailer's energy purchase costs based on the long term cost of providing enough generation to meet demand". The three common methods identified are:

- Average incremental cost method;
- Perturbation (aka Turvey) method; and
- Greenfields method.

AGL notes that in recent years jurisdictional regulators have most commonly used the greenfields method to determine a WEC for a regulated retail electricity price.[17] A detail comparison of the different LRMC approaches and the benefits of the greenfields approach in developing a regulated price is provided by Frontier Economics as part of IPART's Review of regulated retail prices for electricity, 2013 to 2016.[18] A key reason for using this approach is that it incorporates capital costs of generation to meet the regulated load.

Market-based approaches

The Issues Paper describes the market-based approach as aiming to "simulate the operation of the wholesale energy market, which reflects the short-term, or more immediate costs that retailers face". Two methods, identified as the "most common" are described:

- Market modelling method; and
- Futures/forward contracting method.

Sensitivities in the wholesale energy cost methodologies

The process to forecast an 'efficient' WEC for a set of regulated customers relies on detailed modelling which includes a large number of inputs and assumptions. This means that the process itself can subjective in nature, and the result is that the forecast of an 'efficient' WEC carries with it a significant amount of risk for the efficient functioning of the competitive retail market. While using an approach such as 'LRMC as floor' can mitigate some of this risk, the selection of a modelling approach and the various inputs and assumptions within that can significantly impact the final result.

Market-based cost approach sensitivities

The Issues Paper highlights a number of sensitivities which AGL agrees can impact the forecast of an efficient WEC, these include:

- ***Retail load forecast***

In the NEM, the calculation of a market-based WEC relies upon forecast of the load which a retailer will need to supply i.e. net system load profile. The shape of the forecast load will determine how much load the retailer will be required to supply at particular times of the day. As spot market prices are generally higher at periods of higher demand this means that the 'peakiness' of the load is a critical factor in determining the level of spot prices a retailer might be exposed to, and this will affect how a retailer might choose to hedge their exposure to these spot prices.

- ***Spot price modelling***

In general, market-based approaches in the NEM require a forecast of the electricity spot market prices on a half-hourly or hourly basis on which a cost of serving a retailers load can be calculated. The spot price forecasts can affect the forecast cost to purchase energy retailers are exposed to because:

  - Retailers might be exposed to spot prices if their load is not fully hedged in the futures market or otherwise; and

[17] In NSW IPART currently use the greenfields approach to calculate the LRMC of supplying the regulated customer load and have done so since 2007. In South Australia, ESCOSA adopted a greenfields approach in setting the 2010-2013 price path prior to the South Australian Government moving to price deregulation.

[18] Frontier Economics, Methodology Report – input assumptions and modelling, A Draft Report prepared for IPART, November 2012. p10.

- If the retailer has entered into a hedging strategy the spot price forecast will affect the resulting cost or profitability of that strategy i.e. payout on cap contracts.

Forecasting electricity spot prices is a very detailed and specialised modelling exercise which is usually carried out by third-party consultants using proprietary information. The modelling exercise relies on a complex series of assumptions and approaches in an attempt to replicate generator behaviour is the spot market.

- ***Hedging strategy***

In recent years State regulators in the NEM using market-based approach have employed various hedging strategies to replicate the approach that a typical retailer might use to manage its price risk in the spot market. The hedging strategy defines the level of spot market risk that a retailer is willing to expose themselves to over a period of time, and therefore the additional cost a retailer is willing to accept to manage this risk. This approach assumes that all retailers will have the desire and ability to manage risk and will use a limited selection of financial products (i.e. typical futures contracts) to manage that risk. Some retailers might be willing to take on more risk than others based on their business strategy i.e. higher exposure to spot market if long generation.

In practice retailers will employ a range of different risk management strategies to hedge their exposure to spot market price risk. Using a single hedging approach simplifies the way a typical retailer would be considered to manage their risk exposure. For example, some retailers might use power purchase agreements (PPAs), long-term hedging arrangements or other financial products i.e. weather derivatives.

- ***Futures contract prices***

In a market-based approach which relies on a spot price forecast and a hedging strategy the final energy purchase cost requires selection of a type of financial product which is assumed that a retailer would use to manage its price risk. As noted earlier, there are a range of strategies which a retailer could use to hedge its price exposure in the spot market. Typically regulators have used either exchange-traded futures contracts (i.e. contracts traded on d-cyphaTrade) or 'over-the-counter (OTC) contracts (i.e. contracts between two parties, typically facilitated by a broker) to set to estimate the cost of hedging a retailers load in a particular period.

In recent regulated pricing decisions questions have been raised by stakeholders whether the use of futures contracts prices to determine a market-based energy purchase cost is appropriate when the level of liquidity in those markets for the period in question indicates retailers have not used these contracts to hedge a significant portion of their loads. AGL remains of the view that where there is insufficient liquidity in futures markets to demonstrate that retailers are actively using these markets to hedge their load then a market-based cost using futures prices cannot be relied upon as a reliable indicator of a typical retailers hedging costs.

<u>LRMC approach sensitivities</u>

There are also a number of sensitivities in calculating the LRMC of meeting a particular load (greenfields approach):

- ***Generation plant and fuel cost assumptions***

In determining the least-cost plant mix required to supply a load the relative cost of the different generation technologies available will determine the optimal mix of plant and the cost per unit of demand. The cost of individual generation technologies are built up based upon a number of data sets and assumptions. Because this type of calculation is well established in the electricity industry, therefore cost data on different technologies is generally readily available and often sourced from publicly available sources. In some cases, pricing regulators using an LRMC approach have determined their own set of inputs and assumptions for generation technology costs. While the merits of this can be judged on a case-by-case basis it is preferable that inputs and assumptions are based on publicly available sources which have been consulted upon by industry.

- ***Weighted average cost of capital (WACC)***

In calculating the LRMC of generation to meet a particular load the weighted average cost of capital (WACC) is used to discount cash flows over the life of each generation technology to determine the cost of deploying different generation plant. The WACC reflects the costs of financing the generation plant and therefore the overall LRMC of meeting the load is sensitive to changes in the assumed WACC.

Regulators using an LRMC approach generally recognise the importance of selecting an appropriate cost of capital. In its recent determination of NSW retail electricity prices for 2013 to 2016 IPART carried out a detailed analysis of different methodologies and input assumptions which could be used to calculate the WACC.[19] The detailed analysis serves to highlight the complex nature of assuming a WACC to be used in calculating a LRMC of generation.

Preferred methodology

AGL maintains the view that the most appropriate methodology in order to ensure development of retail competition is using a combination of the LRMC and market-based approach i.e. 'LRMC as floor' approach. In practice this requires the calculation of both the LRMC and market-based cost of serving the regulated retail load in question. The final WEC allowance is set at the greater of the two values.

3.2. Market fees and ancillary service fees

Question 5 Market fees and ancillary service fees

(a) What is the appropriate method to estimate NEM market fees?

(b) What is the appropriate method to estimate ancillary service fees?

AGL is satisfied that using the forecast AEMO budget requirements is the most appropriate approach for estimating future NEM market fees. Due to the relatively small cost and the absence of more accurate information using historical data to estimate ancillary service fees is an appropriate approach.

3.3. Energy losses

Question 6 Energy losses

Is using loss factors, as published by AEMO, the most appropriate method to estimate energy losses?

AGL agree that using the most up-to-date loss factors as published by AEMO is the most appropriate approach for incorporating losses into a regulated price.

[19] IPART, WACC Methodology, Research - Interim Report, June 2013.

4. Network costs

4.1. Network costs

Question 7 Network costs ***What issues should regulators take into account in passing through time of use network prices in setting regulated retail electricity prices?***

AGL considers that time of use network prices should be passed-through in setting regulated retail prices. If the principle of cost reflective pricing is to be adopted, it is entirely appropriate that network pricing structures are passed through to retail prices.

Given that the costs of network investments have been driving retail prices in recent years, it is important that network pricing signals are transmitted to end users.

It should be noted that Energy Australia in NSW has a time of use tariff – with peak, shoulder and off-peak rates - for residential customers since July 2004.

5. Retail operating costs and margin

5.1. Retail operating costs

Question 8 Retail operating costs

(a) What method should be used to estimate retail operating costs? Ie, should a "standard retailer" be used?

(b) If a "standard retailer" is used, how should the "standard retailer" be defined and what issues should be taken into account in defining a "standard retailer"?

(i) Are there any considerations specific to Northern Territory and Western Australia that should be taken into account when defining a "standard retailer"?

(c) Should benchmarking be used in determining the efficient level of retail operating costs? How could benchmarking be improved?

(d) How should retail operating costs be escalated over a determination period and how should the potential for productivity improvements be considered?

In AGL's view, where prices continue to be regulated even though the market is competitive, regulated prices should be set at a level which is sufficient to facilitate competition. Accordingly, the regulated price and, therefore, the cost build up, should not be the lowest possible price or average cost. In the long run, competition will provide market clearing prices which promote the efficient allocation of resources and ensure that prices are sustainable.

AGL considers that defining retail operating costs from the perspective of a standard or incumbent retailer is inconsistent with the requirement to set regulated retail prices to encourage competition. For the purpose of setting regulated prices, the retail operating costs should be based on a new entrant retailer which is not vertically integrated with distribution networks or power generators.

True competition can only occur if new entrants are encouraged to participate. New retailers introduce a greater dynamism in the retail market than existing standard retailers as they seek to gain market share through discounting and new products.

In a competitive market, if regulated prices are set too high then discounting will act to remove any additional headroom so if the retail operating cost allowance based on second tier retailers' costs then it will encourage further competition.

In essence, the key cost differences between a standard retailer and a new entrant retailer relate to:

- the proportion of the customer acquisition and retention costs (CARC) since a new entrant retailer has to acquire every customer; and
- the number of customers given the fixed costs of establishing and operating in the a retail market.

Benchmarks used by state regulators such as IPART and QCA may be useful but due to the "echo chamber" effect, they may not fully reflect current business practices and conditions. In the 2013 electricity price review in NSW, IPART examined a range of sources of information on retail operating costs including costs reported by publicly listed companies such as AGL Energy, Origin Energy and Australian Power and Gas. The wide range of reported costs is indicative of the difficulty in assessing the relevant costs. Nevertheless, publicly reported costs are useful in assessing the possible range.

5.2. Retail margins

Question 9 Retail margins
(a) What methodology should be used to calculate a retail margin? Ie, how should risks facing electricity retailers be compensated for?
(b) Should the retail margin be set as a fixed percentage of "total costs" (wholesale, network, retail) or of the controllable costs to the retailer (wholesale, retail)?

The Issues Paper refers to three methods typically used to estimate retail margins – expected returns, bottom-up and benchmarking. These methods have been employed by IPART in the 2010-13 and 2013-16 electricity price reviews in NSW. The Issues Paper asserts that these three methods should give similar results in theory. In practice, a range of retail margins are produced. To set the retail margin allowance, IPART had selected the appropriate retail margin from within the range of margins from these three methods. Hence, although these methods produce seemingly objective retail margins, some discretion is required to decide on the retail margin to use. These methods also are dependent on a number of assumptions which change over time. The retail margin allowance decided by IPART has been adopted by other jurisdictional regulators, in particular QCA and ICRC. AGL considers that, given the lack of other objective methods, the approach taken by IPART is appropriate.

The AEMC has noted that the setting the appropriate level of retail margin is important since setting it too high may result in inefficient new entry into the market and customers paying too much, while setting it too low will discourage efficient entry. In a competitive market, if prices are set too high, other retailers will be able to discount more to erode any windfall gain. If prices are too low, the lack of competition will ultimately result in higher prices, Therefore, the risk of setting prices (and margins) too low is much greater than risk of setting prices (and margins) too high.

In relation to the base to apply the percentage retail margin, in AGL's view, retail margin should be set as a percentage of total costs rather than the controllable costs to the retailer as some costs such as bad debts are a function of the total bill. Retail margin is generally defined in most industries, other than energy, as a percentage of revenue which will approximate the retail margin as a percentage of total costs. In practice, however, there should be little difference where it is set as a fixed percentage of total costs or the controllable costs as long as they are consistently set. For instance, as network charges comprise about 50% of total costs, the retail margin as a percentage of total costs will also be about 50% of the retail margin as a percentage of controllable costs.

5.3. Competition allowance

Question 10 Competition allowance
(a) Should some form of competition allowance be included in the regulated retail electricity price to encourage competition?
(b) How should this competition allowance be included in the regulated retail electricity price and how should it be estimated?

The AEMC has raised the issue of how, if a competition allowance is to be provided for, whether it should be included as part of:

- wholesale energy costs allowance (WEC),
- customer acquisition and retention cost allowance (CARC),
- retail margin, or
- a combination of cost components.

AGL agrees with the AEMC that the inclusion of any competition allowance should be transparent. In AGL's view, CARC should firstly be included as part of the cost build up and a separate competition allowance is added. This is similar to the approaches taken by IPART and the QCA although IPART had set a $/MWh allowance while the QCA had decided on a 5% allowance for headroom.

The inclusion of a competition allowance will reflect the way current retail electricity market actually operates with market offers being set as a discount to the regulated price. To set this allowance, the prevailing levels of discounting should be taken into consideration.

AGL considers the ICRC approach of excluding CARC or any competition allowance has been a major deterrent to the development of any meaningful retail competition in the ACT electricity market.

6. Environmental and jurisdictional schemes

6.1. LRET

Question 11 Large-scale renewable energy target costs
Which methodology is more efficient in terms of estimating the "price" of the compliance costs of the LRET - historic market prices, futures market prices, LRMC or the penalty price?

AGL is of the view that in determining the cost allowance for LRET compliance the QCA should consider the range of costs that would be experienced by a retailer sourcing LGCs not only from the market. In order to manage price risk and provide greater certainty retailers source LGCs from a number of sources including long term LGC off-take agreements or developing physical renewable electricity generation. The benefits of this approach have been recognised by jurisdictional regulators in recent years.[20]

AGL supports the use of a LRMC methodology for assessing the compliance costs associated with the LRET. AGL believes this is the most appropriate methodology given retailers of scale servicing a small customer load will invariably source a significant portion of their LGCs through long term PPAs with new entrant build renewable generation.

6.2. SRES

Question 12 Small scale renewable energy scheme costs
(a) How should the issue of the timing difference between when the STP is set under the SRES (by calendar year), and when regulated retail prices are set (by financial year) be addressed?
(b) Which methodology is more efficient in terms of calculating retailers' compliance costs of the SRES - the clearing house approach or a market based approach?
(c) If a market based approach is used, what methodology should be used in forecasting future STC market prices?

Calculating SRES compliance costs for retailers has been a difficult task for energy regulators and retailers alike over recent years. The nature of the SRES scheme is such that in recent years the cost allowances set by pricing regulators have in a number of cases not allowed for the recovery of scheme compliance costs in the regulated retail price. For example, for 2011-12 regulated retail prices the Queensland Competition Authority (QCA) used an estimate of the 2012 STP of 9%. The final 2012 STP was

[20] Essential Services Commission of South Australia, Expanded Renewable Energy Target cost pass through application made by AGL South Australia Pty Ltd, pursuant to the 2008-2010 Electricity Standing Contract Price Determination – Reasons for Decision, 16 June 2010. p.6

23.96%. This meant that retailers could have incurred additional costs of up to ~$5-6/MWh above what was allowed in the 2011-12 regulated price.

This issue of under-recovery of scheme compliance costs is largely due to the timing of the release of calendar year scheme targets when regulated prices are set on a financial year basis. In order to mitigate this risk some jurisdictions, such as NSW, have used a 'cost pass-through mechanism' to allow for costs to be recovered in subsequent regulated pricing periods. AGL supports the use of a cost pass-through mechanism. for dealing with the STP uncertainty.

AGL does not support the use of historical market prices to set a future cost of scheme compliance for retailers. AGL notes that numerous changes in the market and other regulatory decisions have meant that fundamentals of the STC market have changed over time, and this could continue over the period of the determination. AGL support the use of the clearing house cost as a proxy for the STC cost faced by retailers.

6.3. Jurisdictional schemes

Question 13 Jurisdictional energy scheme costs

(a) What factors should be taken into account in estimating the cost of jurisdictional environmental schemes?

(b) Is a national approach to estimating these costs appropriate given the differences between jurisdictional environmental schemes?

Due to the differences between jurisdictional energy efficiency and other 'green' schemes AGL is of the view that a single national approach for estimating the cost of compliance with these schemes would not be appropriate. Each scheme should be considered separately and a cost of compliance determined which takes into account the nature of the scheme and the information available relating to retailers costs of compliance i.e. for certificated schemes, market prices for certificates should only be used where it an be demonstrated that these markets are liquid and represent a reliable basis on which to estimate a retailers costs.

7. Form and timing of price controls

7.1. Form of regulation

Question 14 Form of regulation
(a) What is the most appropriate form of regulation to apply given our objective for retail price regulation?
(i) Does the appropriate method differ depending on the state of competition in the retail market? For instance, should a different method apply in jurisdictions with limited competition, such as Western Australia, the Northern Territory, and Tasmania?
(b) Should a form of regulation be applied to all cost components?
(c) What costs should be reflected in the variable and fixed components of regulated prices?

AGL considers that where price regulation is deemed necessary that a weighted average price cap (WAPC) is the most appropriate form of regulation where one or more Standard Retailers are setting numerous retail tariffs.

The WAPC provides retailers with the flexibility to reset or re-balance individual regulated prices whilst allowing network charges to be fully passed through. Although the WAPC operates within the overall price level determined by the jurisdictional regulator, there are situations where individual retail prices may increase more than others. The risk that the WAPC could result inequitable price changes would be unlikely to occur if there is sufficient competition.

7.2. Cost pass-through

Question 15 Determination length and within period pass through
(a) What is an appropriate length of a retail price determination?
(b) If a retail price determination lasts longer than a year, what cost components should be subject to an annual review and should the methodologies for estimating cost components remain unchanged?
(c) Should retail price determinations include a pass through mechanism? If so, what events should be included the pass through mechanism and what should be the materiality threshold?

One of the significant challenges for retailers operating in competitive markets with price regulation is the lack of certainty in year-on-year prices due to the methodologies employed by the pricing regulator. In these circumstances certainty can be improved by determinations of greater than one year (i.e. 3 years), open and transparent methodologies and clear guidance how prices will be updated during the determination.

AGL consider where a price determination is longer than one year it is appropriate to include an annual review of certain cost components to ensure that the regulated price is set appropriately to meet the objectives of price regulation for the market in question. As part of IPART’s 2013 to 2016 retail electricity price determination an annual review of selected cost allowances will be carried out for the final two years of the determination. AGL consider the approach used by IPART to review certain cost allowances during the price determination to be appropriate.

Appendix 1

Simshauser, When does retail electricity price regulation become distortionary?, AGL Applied Economic and Policy research, Working Paper No.33, July 2012

When does retail electricity price regulation become distortionary?

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Abstract
The case for price regulation in monopoly markets is clear, but its use as an artificial price cap in newly formed competitive markets transitioning from a monopoly requires much greater care. In contrast, price regulation ceases to have an economic function in effectively competitive markets, yet it represents a policy constraint in most NEM regions. Unfortunately, little effort has been made by policymakers to articulate the public policy objective of continued price regulation. In this context, this article contrasts two different approaches to the regulation of default tariff caps in intensely competitive retail electricity markets – a short run dynamic price approach, and a long run cost approach. Asymmetric information and the complexity of energy markets means that a regulator, no matter how wise and well resourced, could ever be expected to produce a reliable forward estimate of an efficient price in an intensely competitive market. Above all, relying on short run dynamics in an attempt to do so is completely incompatible with the manner in which the industry now facilitates the flow of investment and innovation. And if the flow of investment is disrupted, it will risk unwinding 15 years of market reform along with the presence of participant investment-grade credit ratings, the NEMs single largest asset in providing physical and systemic security. Using long run constructs on the other hand, particularly as a floor when setting artificial price caps, minimises the intrusion of regulatory policy constraints on the efficient operation of the market. Crucially, it accommodates the wide array of retail business models that currently exists in the NEM – the underlying source of the market's intensive competition.

Keywords: Electricity Prices, Resource Adequacy, Energy Policy.
JEL Codes: D24, L11 and Q48.

1. Introduction

Australia's National Electricity Market (NEM) has been a highly successful microeconomic reform. Designed in the early-1990s and implemented by 1998, it has led to substantial gains in productive, allocative and dynamic efficiency.[1] The NEM has been credited with contributing an additional $2 billion per annum to Australia's Gross Domestic Product (Parer, 2002; NCC, 2003).

The centrepiece of this reform was the structural disaggregation of fully integrated monopoly utilities, and the creation of a competitive, real-time, energy-only wholesale market which operates on a deregulated basis. Prices in the wholesale market are, however, especially volatile with time-weighted annual averages ranging from $25-$73/MWh, and half-hourly prices that can and do reach the market ceiling price of $12,900/MWh. This extreme volatility makes it an especially risky market for participants.

Another important aspect of energy sector reforms was the liberalization of the retail market. But despite Full Retail Contestability and the presence of intensely competitive retail markets, price

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[1] For example, in Queensland, the state considered to have the most efficient power industry in the pre-competitive environment, productive efficiency gains in power generation alone over the first eight years were calculated to be $2.2 billion, while dynamic efficiency gains from improvements in plant availability in New South Wales and Victoria amounted to $2.7 billion through avoided investments. See Simshauser (2005) at pp 25-27.

cap regulation remains intact in three of the NEM's four primary sub-regions for small customers. No clear public policy objective has been articulated for the continued use of artificial price caps, where competition is intense. Of course, the combination of a deregulated wholesale market and regulated retail tariff 'caps' can represent a particularly dangerous combination. The Californian Energy Crisis provides the obvious quantitative evidence of this statement.

Default tariffs, sometimes referred to as *standing tariffs* or *notified prices*, exist in all regions and are offered by virtually all retailers in one form or another. This includes the Victorian region, where price regulation has been removed. So how are default tariffs set within liberalized and semi-liberalized markets? Whether the market is price-regulated or not, historically, default tariffs (as distinct from competitive market offers) are typically set in a manner that is broadly consistent with industry long run marginal cost. The electricity tariff 'cost stack' comprises (1) a wholesale energy cost allowance to account for power generation, (2) regulated monopoly transmission and distribution network charges as set by the Australian Energy Regulator, (3) an allowance for retail costs and margins, and more recently, (4) allowances for environmental schemes such as Australia's 20% Renewable Energy Target, solar Feed-in Tariffs, and energy efficiency schemes.

The default tariff offers of energy retailers can be expected to rise above long run costs in liberalized markets like Victoria, New Zealand and Great Britain under system stress conditions. Conversely, default tariffs in these markets do not tend to fall below system long run marginal costs during periods of what Boiteux (1960) described as an over-equipment scenario because they are exactly that, a default offer for energy services. Default tariffs *must* be made available to all consumers without any knowledge of customer consumption levels, customer loyalty or tenor, potential transactional costs arising from switching, or credit characteristics. A default tariff must therefore account for considerable information asymmetries, including the potential for default customers to switch away at any time without penalty.

Default tariffs also perform a very important function in the competitive market because in practical terms they represent the '*price-to-beat'*. By contrast, competitive 'market contracts' are offered by incumbent and second tier retailers and at a discount to default tariffs in order to gain market share. This might take the form of (for example) a 5% discount for a one year term contract, a 7% discount for a two year term, a 10% discount for a three year term contract, and there may be additional discounts for early payments, dual gas and electricity contracts, or subscribing to solar modules and so on. The magnitude of discounting amongst rival retailers is generally inversely correlated with power system reserves, or put another way, discounting against the default tariff caps intensifies when system oversupply is perceived to be greatest. Regardless, setting default electricity tariff caps takes on a great importance in respect of the proper functioning of the retail market because it is the 'reference price' used by all retail marketers to construct their competitive offers, in many cases, for 3 years in tenor. If a regulated default tariff was set below cost, quite clearly, discounting would not be possible. If discounting was not possible, the businesses of energy retailers would be damaged, and competition would naturally deteriorate. In extreme over-regulation cases, the industry can experience financial distress and ultimately, insolvency as California demonstrated in 2001, and Western Australia demonstrated in 2010.

Within the default tariff cost stack, for the purposes of the ensuing analysis, the most important of the four components outlined above is (1) wholesale energy costs.[2] Historically, in regulatory determinations wholesale energy costs have been set by reference to prevailing estimates of the long run marginal cost of power generation, and in some cases blended with short-dated contract

[2] Monopoly network charges are just as significant in terms of value, but the Australian Energy Regulator sets network access prices for five-year periods, and they hence become a 'pass-through' charge for all users of the network.

prices in a 50/50 split.[3] A more recent innovation implemented in New South Wales involved setting the wholesale energy cost component of regulated default tariff caps by reference to short run prices, with the long run marginal cost (LRMC) of generation forming a 'floor' – essentially mimicking the behaviour of default tariffs set by competitive retailers in markets where price regulation has been removed. Another recent innovation in regulatory price setting was initiated by the South Australian regulator (ESCOSA) who developed a hybrid regime of market-determined default retail prices set within a regulated LRMC 'collar' – which also attempts to simulate a fully liberalized market outcome, albeit within defined tolerances.

In spite of the awkward combination of a deregulated wholesale market with retail price regulation in three of the four primary jurisdictions, the NEM has successfully navigated two key policy objective functions: (1) competition, which has been intense by any measure, and (2) resource adequacy, or the timely entry of new plant capacity, which has matched demand growth and reliability standards. Neither outcome has been a matter of accident. Historically, regulated default tariff caps (i.e. the *price-to-beat*) in NEM regions have, with few exceptions, been characterized by stable trajectories, were set at levels intended to be long run efficient rather than intrusive, and facilitated competition in retail supply under the artificial price cap. They similarly provided adequate policy certainty for integrated participants to invest in, or underwrite, the entry of new plant. However, the wholesale energy cost component of default tariff caps has suddenly become quite contentious, and policy uncertainty now prevails following the Queensland Competition Authority's 2012 decision to remove the reference to long run marginal costs within the default tariff cap, instead opting to use only short run efficient prices from the spot and 1-3 year contract market. Substantive changes in the determination of default tariff caps hence occurred in that State after a decade of *relative* policy predictability.[4]

These developments are extremely problematic because of the critical influence that default tariff caps have in terms of retail competition and innovation, and on investment in new power station capacity. Had such a policy adjustment been made during the period between 1998 and 2003, it may not have been as problematic as it is over the period 2004-2012 and beyond. The issue here is that the preconditions for investment have manifestly changed, as Nelson and Simshauser (2012) explain. It is now inconceivable that investment commitment, and raising the requisite debt finance for infrastructure with asset life-spans of 30 years or more, could be executed on the basis of a three-year forward derivatives market. A financing constraint now exists, and it is a global phenomenon (Finon, 2008).

Most regions of the NEM are currently oversupplied, and therefore regulating default tariff caps on the basis of short run efficient prices to levels below efficient industry long run costs is unlikely to be met with an immediate (i.e. short run) disaster. But taken together, tariff policy uncertainty and the requirement for long-lived capital-intensive plant investments do not fit neatly, at all. There may well be immediate, albeit transient, benefits to *inert* consumers associated with applying short run dynamics to default tariff caps. But there are very real long run costs to *all* consumers from policy uncertainty in energy markets. Investment flows within the NEM hinge quite critically on the ability of integrated utilities to maintain investment-grade credit ratings. This is not widely understood within the energy utilities themselves, let alone by policymakers, lawmakers and regulators. Indeed, the QCA (2012) decision provides the demonstrable evidence of this. A short run dynamic approach is distinctly intrusive on the workings of a competitive market because a regulator is using highly imperfect information and, by defining as efficient only those instruments with tenors spanning 1-3 years, risks using

[3] In the case of South Australia, observed market data was the Regulator's historical approach, but they tended to test the outcomes by reference to long run marginal cost. This proved to be a moot point because results from either analysis were largely similar. This is not, however, currently the case in all regions of the National Electricity Market, hence the purpose of this research.

[4] While the Queensland Government also made a policy commitment to freeze household Tariff 11, this is not the source of policy uncertainty as the Government is simultaneously coordinating reductions in network tariffs to ensure the competitive market is not distorted.

incorrect specifications of what constitutes an efficient price given the wide array of wholesale pricing instruments available. And if intrusive price cap regulation is applied in multiple regions of the NEM, it could very quickly eliminate the investment-grade credit that currently exists in the merchant energy industry. This would present a rather large problem vis-a-vis the physical and systemic security of the market.

The purpose of this article is to examine two differing approaches to setting default tariff caps given a policy constraint, i.e. based purely on short run efficient prices vs. combining short run dynamics with efficient long run marginal costs as a floor. This article is structured as follows: Section 2 examines the objective function of price regulation, particularly for energy markets transitioning from monopoly to competitive structures. Section 3 then examines the case for using short run market prices to set default electricity tariff caps in competitive markets. Section 4 reviews the case for using long run efficient costs as a floor in setting default tariff caps. Section 5 then examines the costs of policy uncertainty on energy costs. Policy recommendations and concluding remarks follow.

2. The objective function of price regulation

Before analysing the effects of different tariff policy settings, it is worth clearly defining the purpose of price regulation in the first place. The economic rationale for price regulation is as a mechanism to allocate efficiency savings in monopolistic markets between consumers and producers. The only circumstance in which price regulation has a role in a competitive market is to ensure a smooth transition for all market participants from a monopolistic market.

Price regulation ceases to have an economic function once a market exhibits competitive characteristics. Australian policymakers have explicitly acknowledged this through the *Australian Energy Market Agreement* whereby commitments have been made to deregulate prices once competition is demonstrated to be effective. In the energy sector, continued regulation of network charges, given the inherent monopoly characteristics of network service providers, is an appropriate policy instrument. Beyond that, it is in the interests of promoting economic efficiency and the greatest consumer benefit to allow market forces to determine the appropriate level at which prices are set, given effective competition in a market. Therefore, if the overarching policy objective is to ensure that long term price outcomes reflect underlying cost structures, effective competition will best achieve this.

If the objective of price regulation is to reduce or to manage vulnerable households, it will represent a poor *de facto* hardship policy because it *will not* achieve outcomes consistent with reducing hardship, and in the attempt to do so is likely to damage the competitive market. Importantly, in newly reformed competitive markets, the purpose of price regulation is *not* intended to be intrusive, or to second-guess market outcomes. As Yarrow (2008, p.6-8) noted, competition-based reforms emphasise the promotion of consumer interests, and consumers have longer term interests as well as shorter term interests:

> *Promotion of consumer interests might, therefore, require policies that lead to higher prices today, if the effect is to promote investment and innovation that can be expected to deliver better value for money in the future... It is therefore important to recognise that consumers can be harmed as a result of under-pricing because under-pricing tends to restrict the supply-side of markets, certainly in the longer-term by discouraging investment and innovation...*

2.1 Does rising regulation reduce competition?

Increasing regulation now in an effectively competitive market will have the effect of reducing competition in the future. This will not be in the long term interest of consumers. This is worth exploring in more detail using data from the NEM. Since the 1980s, there have been a number of industry reforms in Australia including airlines, milk, mobile and fixed line telephone services, electricity and gas amongst many others. The common underlying policy thematic in each case has been to establish a national competition framework and allow the market to deliver the appropriate price, quantity and quality of service to customers. A desirable characteristic of reformed markets is therefore aggressive rivalry amongst suppliers. The AEMC (2008a) noted that in the case of electricity this is important because as a low involvement and essential commodity, one of the best sources of customer information and education is via retail suppliers competing, and thus the proper functioning of the end-user market is important:

> *Marketing strategies implemented by retailers and the information they are providing is helping to increase customers' interest in energy products, to better inform customers about their options and to overcome the actual or perceived search and switching costs… (AEMC, 2007, p.51)*

There is no universal test that determines whether a market is competitive, although the AEMC (2008a, 2008b) has set out a framework to guide their analyses on behalf of jurisdictional governments. This includes a review of customer switching, the intensity of retailer rivalry, the ease of entry and exit, and so on. As required under the *Australian Energy Market Agreement*, the AEMC (2008a, 2008b) undertook independent reviews of the level of competition in Victoria and South Australia, and concluded that the energy markets were effectively competitive. Marketing rivalry between retailers was vigorous and conditions for entry and expansion were judged to be favourable, with incumbent retailers competing against 10 new entrants. New entrants had created a credible threat to incumbents, having steadily eroded 20% of their combined market share in Victoria, while in South Australia more than 60% had switched away from the incumbent retailers' default tariff. More than 90% of customers were aware of the ability to switch electricity retailer in Victoria and 82% were in South Australia. Retailers were contacting customers directly with discounted offers and non-price benefits.

On advice from the AEMC, Victoria proceeded with removing price regulation. The prevailing regulated default tariff caps in Victoria at that time broadly reflected industry long run marginal costs. Customer switching rates were 20%+, making it one of the most competitive energy markets in the world. Price regulation was removed in 2008 for business customers and 2009 for residential customers. By 2012, there are about 2.3 million residential electricity accounts in Victoria and with switching rates of 26%, 600,000 households change their electricity retailer annually. Table 1 provides a comparative analysis of NEM switching rates.

Table 1: **Residential customer switching rates by region 2004-2012**

Switch rate (Annual)	NSW	VIC	SA	QLD*	NEM
June 2004	5%	12%	11%	n/a	9%
June 2005	6%	20%	17%	n/a	13%
June 2006	9%	21%	19%	n/a	15%
June 2007	12%	26%	11%	n/a	17%
June 2008	10%	23%	17%	16%	16%
June 2009	11%	26%	15%	17%	17%
June 2010	13%	27%	14%	18%	19%
June 2011	14%	27%	18%	25%	20%
June 2012	17%	26%	22%	21%	21%
Total Customers	3.1m	2.3m	0.7m	1.3m*	7.9m
Active Retailers	11	14	10	12	21
Total Switching^	50%	70%	77%	66%	62%

*Queenland results adjusted to exclude the effects of the non-contestable Ergon franchise.
^Total switching means % of customers who have switched from the default tariff.
Data Sources: Datamonitor, ESAA, AER, QCA, IPART, ESC, ESCOSA AGL Energy Ltd.

A notable contrast exists in Table 1. In comparative terms, switching rates in NSW between 2004 and 2006 were critically low. The unambiguous reason for this was the over-regulation of the default tariff cap. This is not in doubt. The Australian Energy Regulator noted in its annual State of the Energy Market report that *'the NEM has had many instances where prices were held below cost, such as NSW'* (AER, 2009, p.207). And the NSW regulator noted of its own determination that *"there is a need for regulated tariffs to increase"* however their determination was designed to *"protect small retail customers from significant price shocks"* (IPART, 2004, p.1).

For policymakers and regulators, Table 1 reveals *at least* three important findings. First, in markets where there has been no evidence of regulatory intrusion (e.g. Victoria), switching rates are highest due to policy predictability. Second, over-regulation results in highly diminished competition and switching rates are low (i.e. NSW from 2004-2006). Third, even in Victoria, easily the world's most competitive energy market and Australia's most competitive industrial or product market (as Table 2 later reveals), competition is *not* perfect. This latter point merits further discussion.

When the AEMC (2008a) concluded that the Victorian market was effectively competitive and recommended removing price regulation, fully 60% of customers had moved off default tariffs. But importantly, by definition, 40% of customers had not. The market was not *perfectly competitive*. At last count, still only 70% of customers had moved from a default tariff, the implication being that 30% still remain on a default tariff. Does this represent a problem for policymakers?

Customers may find themselves on default tariffs because their market contract has matured and they have failed to act immediately – just as the holder of a fixed-rate housing mortgage defaults to a variable rate mortgage at contract maturity until some alternate decision is made. Other customers will remain on the default tariff simply because there are real transaction costs involved in switching, and to some households, the cost and inconvenience of switching outweigh any expected benefits associated with competitive market offers. Other households may choose to avoid fixed-term discounted contracts due to an imminent move-out or relocation. About 550,000 households switch away from AGL each year, and of these, at least 200,000 involve move-outs or relocation. Policymakers intent on regulating retail markets need to be cognisant of the fact that an individual household's economic utility function may be maximised despite being on a default tariff due to the existence of transactions costs or the other factors listed above. The whole purpose of energy market reform was to facilitate customer choice, not second-guess customer choice. Regardless, none of these issues require specific policy attention.

There will, however, be a residual set of households for which industry participants and regulators have no answer as to why they remain on a default tariff when discounted offerings exist. But as the data in Table 1 (and later, Table 2) reveals, it is definitely not through lack of competitor activity. For these residual households, the question is whether this represents a form of market failure that requires regulatory intervention.

2.2 Imperfect competition and price regulation

To be sure, retail electricity markets are a long way from the textbook model of perfect competition, even in the world's most competitive energy market, Victoria. But the threshold for what constitutes a competitive market cannot, under any circumstances, be guided by a textbook episode of perfect competition because it has long been accepted in economic theory and practice that no industry can exhibit the pure characteristics of this highly stylized model. Its place belongs in textbooks. Australian Courts define a competitive market on the basis of Clark's (1940) *"workable competition"* concept rather than any notion of perfect competition. So while competition is not *perfect*, the NEM's retail markets are *workably competitive* or using AEMC (2008a) terminology, *effectively competitive.*

If customer inertia is unusually high in a newly reformed energy market, and default retail tariff caps are set at *excessive levels*, the combination of the two variables can lead to supranormal profits being extracted by a dominant retailer, exercising market power. In the event, consumers would be paying more for their electricity services than necessary. These would be real costs that, given the unique circumstances of excess pricing, low switching and high customer inertia, would quite reasonably concern policymakers and regulators. However, while NEM retail markets are not perfectly competitive, they are *workably competitive* and it does not logically follow that intrusive price regulation should be applied to the entire market to deal with residual imperfections. To do so, one must first conclude that competition is manifestly inadequate, and the market cannot be relied upon to deliver cost-reflective prices under any conditions. The better view is to focus on switching campaigns, as the New Zealand Government has successful done.[5]

Nonetheless, given imperfect customer switching and imperfect competition, if price regulation forms a policy constraint by political processes, then the objective function should be to form a safety-net tariff, set at the long run sustainable cost of supply as Yarrow (2008) explains.[6] Price regulation in an imperfectly competitive market pursues a very different objective function when it attempts to deliver the anticipated benefits of competition to those customers who chose not to avail themselves to competitive market offers in the first place. At this point, the purpose of an artificial regulated tariff cap stops representing a safety-net price – and starts simulating what a competitive market is predicted to deliver, albeit with entirely inadequate information. This is of course the way in which to (legitimately) regulate a monopoly.

It is this issue that represents the crux of this article – to the extent that price regulation in a competitive market represents a policy constraint, how is this best implemented? Should the approach adopted by policymakers and implemented by regulators reflect *long run efficient costs*, or *short run efficient prices*?

2.3 Short run vs. long run efficiency - a familiar problem to the NEM

Attempting to analyse what constitutes an efficient benchmark represents a familiar debate in the NEM. When analysing the presence of market power in wholesale markets, constructs grounded in pure microeconomic theory commence with a model of perfect competition, and measure the 'mark-up' or multiplier of prevailing wholesale spot prices above an intensely competitive supply curve derived from purely short run marginal costs. In a market with minimal fixed costs or those characterised with an especially steep supply curve, such an approach may perhaps be almost acceptable. However, in power generation, which is characterized by heavy fixed costs, an especially flat aggregate supply curve due to the compression of technologies, and common fuel costs due to geographical limitations of power grids, such an approach ignores practical constraints of business economics. Indeed, Besser et al. (2002), Bidwell and Henney (2004), and Simshauser (2008) have demonstrated that perfectly competitive energy-only markets are inherently unstable, and therefore the exercise of whatever transient market power a generator might find itself with from time to time is, as Booth (2005) observed, to some extent justified on the grounds that bidding at short run marginal cost cannot possibly lead to the recovery of reasonable costs across the business cycle when wholesale market price caps exist. The measure of market power from an applied economics and regulatory perspective therefore, and by necessity, reverts to measures of prices against system long run marginal cost and fleet average cost as NERA (2011) explain. To be clear, regulatory intervention is not justifiable just because wholesale prices are maintained above short run efficient levels. Only when prices are sustained above long run efficient levels for multiple reporting periods is regulatory intervention warranted.

[5] In New Zealand, switching has now increased to 22% up from 14% only two years ago, largely driven by a government campaign focused on switching (VassaETT, 2012).

[6] As a policy constraint, Yarrow (2008) explains that a tariff cap should actually be set at a premium to Average Total Cost. See in particular Yarrow (2008) at page 30.

To the extent that reliability of electricity supply is considered an important objective function, and to the extent that vigorous market competition is considered the best form of consumer protection in the long run, artificially set default tariff caps should be viewed no differently than equivalent analyses applied to the wholesale market and market power. Therefore, if a small subset of customers remains on a default tariff cap during 'over-equipment', and that tariff is set at levels consistent with *long run supply costs*, while it may demonstrate that the market is not *perfectly* competitive, it is not obvious that a market failure exists, and it does not logically follow that urgent regulatory intervention in the form of intrusive price regulation is required.

As one (anonymous academic) peer reviewer noted, a truly competitive market will inevitably serve the interests of consumers better than that of a regulator over the long run, and if price cap regulation damages competition or investment in new plant through commercial intrusion, this should be of equal concern to policymakers. To provide some context around the notion of competition intensity in Australian industries, Table 2 provides parallel industry benchmarks on the basis of customer switching. Note that the NEM has the highest customer switching rate.

Table 2: **Annual industry switching rates in Australia**[7]

Industry	Switching Rate
NEM Electricity	21%
NEM Gas	18%
Broadband	15%
Mobile Phones	13%
Pay Television	12%
Insurance	12%
Airlines	10%
Banking	8%
Health	4%
Superannuation	4%

Electricity is often flagged for "special attention" because it is an essential service. Yet, electricity is no more essential than housing, food and health services. ABS data on household expenditure places energy into context – representing a comparatively small and stable component of total household income at 2.6% by comparison to housing costs (18%), food (16.5%) and health services (5.3%).

As Section 4 later reveals, the QCA (2012) prescribed intrusive price regulation in Queensland during 2012. Using QCA (2012) logic and the data in Table 2, one might logically conclude that the standing prices in the airline, communications, insurance, superannuation and banking industries all require price cap re-regulation, and evidently, in some cases, quite urgently! Clearly this is not the case, and makes the case for intrusive price cap regulation in retail electricity particularly difficult to sustain.

2.4 Price regulation and hardship

Another issue worth exploring in terms of considering the role of price regulation in competitive electricity markets is customer hardship. From a policymaker's perspective, the incidence of a vulnerable household on a default tariff cap may represent a legitimate concern. Vulnerable households, by their very definition, should be given access to the best prices available. To that end, if vulnerable households are not switching to competitive markets offers, what should be done?

[7] NEM electricity and gas switching rates from AGL; Broadband switching rates from Tindal (2008); Mobile Phone switching rates from Roy Morgan Research; Pay Television from Buddle (2008); Insurance switching rates from Tindal (2008); Airline switching rates from AMR Interactive; Banking switching rates from RFI; Health switching rates from PHIAC; and Superannuation switching rates from ASFA (2009).

Protecting vulnerable customers is important, and can justify the notion of maintaining a regulated safety-net tariff in the transition from monopoly. But once competition is effective, it is not obvious that regulation should be deployed across an entire market by a regulator with imperfect information to levels *perceived* to be an efficient competitive price – simply to protect those households who, for whatever reason, choose not to avail themselves to market contracts at discounted rates. Governments are best placed to deploy resources aimed at ensuring retailers and social welfare agencies have appropriate information to encourage such households to adopt the best tariff for their particular circumstances.[8]

Victoria has aptly demonstrated through its suite of hardship policies that regulated safety-net tariffs are simply not necessary in a competitive market for electricity services when other more targeted policy options exist for dealing with vulnerable customers. The better view is to design hardship-specific policies to deal with vulnerable customers and promote switching as New Zealand has successfully done, rather than obstruct the necessary microeconomic reform of an entire market to deal with what is ostensibly an acute issue for less than 5% of the population.

2.5 The adverse effects of over-regulating electricity tariffs

It is unclear to the author why a regulator or policymaker would advocate the setting of an artificial *tariff cap* below the otherwise observable practice of intensely competitive deregulated markets. However, the QCA (2012) opted for the unusual step of using short run market dynamics in an oversupplied market to set default tariff caps at levels which are currently substantially below industry long run sustainable costs. Apart from the Californian energy system meltdown of 2000, we are unaware of a single jurisdiction in the world with an intensively competitive wholesale and retail market that has regulated safety-net tariffs exclusively on the basis of short-run market dynamics when those levels are substantially below system long run costs.[9] Of course, doing so makes quite specific presumptions in relation to what constitutes the efficient construction of a competitive electricity hedge portfolio – a matter which is analysed in considerable detail in Section 4. But the consequences of doing so can be succinctly described as distorting supply-side incentives, and will serve to restrict the level of investment and innovation in retailing. Sections 2.6 and 2.7 analyse two particularly extreme cases.

2.6 The Californian Energy Crisis

The collision of deregulated wholesale energy markets with an over-regulated, artificially set, retail tariff cap is generally best illustrated by reference to the Californian power system meltdown of 2000. This case study is important because of the sheer magnitude of the collapse and the characteristics that led to what became known as the Californian Energy Crisis. In March 1998, the 45,000MW Californian system introduced Full Retail Contestability following two years of structural reform. As part of the changes, the regulated *price-to-beat* was frozen at June 1996 levels for four years. Regulatory authorities assumed, with considerable justification, that wholesale prices would fall and initially they did (Joskow, 2001).

But by the summer of 2000, the market experienced a substantial increase in the wholesale cost of electricity due to sharply rising natural gas prices, the implementation of a nitrous oxide Emissions Trading Scheme and interstate transmission constraints. Reiss and White (2008) noted that retail prices in 2000 were stable at US$110/MWh but rose sharply to US$230/MWh at the

[8] Customers in hardship benefit from greater diversity of tariff offerings to suit their particular circumstances as St Vincent de Paul (2012) have observed. For example, a vulnerable household with low usage would prefer a tariff with low fixed and higher variable charges. St Vincent de Paul (2012) demonstrated that the Victorian deregulated energy market facilitates such pricing innovation, whereas regulated tariffs discourage diversity of offerings, thereby preventing vulnerable customers from benefiting from tariff diversity.

[9] We also spoke to Frontier Economics on this matter. Frontier advises governments and regulators around the world and they are also unaware of any jurisdiction setting safety-net tariffs in a competitive market without reference to industry long run marginal costs.

start of the physical crisis period. Following the predictable 'bill shock' experienced by customers, there was loud negative public reaction which led the Californian State Government to cap prices (Joskow, 2001). Reiss and White (2008) noted that the price cap was set at about US$135/MWh. The existence of artificial retail price caps prevented the two large investor owned utilities, Southern California Edison and Pacific Gas & Electric from passing-on the high wholesale electricity costs to consumers. Joskow (2001) and Bushnell (2004) noted that both utilities were technically insolvent by early-January 2001. In just six months, a relatively successful electricity reform had collapsed and with it, two of the largest Investor Owned Utilities in the US.[10]

The start of the economic phase of the Californian crisis can be pinpointed to mid-2000 with the rise in wholesale prices and the over-regulation of retail tariff caps, while the start of the physical phase occurred towards the end of January 2001. A key issue at this point were implications arising from allocative inefficiency. A generally accepted principle in economic theory is that an under-priced commodity will be over-consumed. Reiss and White's (2008) analysed the weather-adjusted electricity consumption and billing data for 70,000 households in the San Diego area over a 5-year period spanning either side of the crisis. Prior to the crisis, the 70,000 households consumed an average of 6.1MWh per annum when electricity tariffs averaged around US$110/MWh. During the crisis, with electricity tariffs more than doubling to US$230/MWh, a genuine price-shock event was revealed because customers received their bills with a 3-month lag and without warning. Between the summer months of June and September of 2000, average household consumption declined by 13%. However, when the Californian State Government artificially suppressed tariffs to $135/MWh, electricity demand rebounded by 8%.

With the insolvency of the two utilities, many independent generators quite literally refused to produce power due to the high risk of not being paid. Shutdowns then increased from an historical average of 2,500MW to about 10,000MW. Consequently, between January and May of 2001, the State Government of California was forced to become the central buyer of electricity, and purchased US$8 billion in forward contracts to stabilize the grid.[11] The policy implications from this event are clear – if prices experience sustained over-regulation in competitive energy markets, State Government Balance Sheets will ultimately be required to fund energy supplies.

2.7 The case of Western Australia

In 2010, the State Government of WA overruled the independent economic regulator's recommended energy tariff increase of 30.2%, opting instead for a 10% increase. This followed a torturous history of energy tariff decisions. Electricity tariffs in WA were frozen for 11 years from 1997/98 as a result of government policy, which Simshauser, Molyneux and Shepherd (2010) noted translated into real price reductions of about 30%. Like California, wholesale electricity prices were expected to decline and for the majority of the 11 year freeze, they did. But as Simshauser and Wild (2009) observed, as with California, gas prices jumped rapidly from $3/GJ to $8/GJ due to supply constraints and rising demand, in the event linking to oil prices for the first time.

With half of WA's power produced by gas-fired generators, a $5/GJ gas cost increase translated to a roughly $40/MWh rise in the running costs of plant, on a base cost of about $45/MWh. Network augmentation was also running at pace. Throughout the three-year period to 2009,

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[10] Analysis by Joskow (2001) and Bushnell (2004) on the conditions that led to the collapse identify seven characteristics: (1) large increases in the demand for electricity; (2) a reduction in imports from neighbouring systems; (3) stalled entry; (4) the emergence of market power; (5) rising prices in the market for natural gas; (6) rising prices in the nitrous oxide Emissions Trading Scheme; and (7) suboptimal activity in the forward market for electricity. While the exercise of market power might at face value be considered the source of the problem, the literature is clear that this was a second order issue. Joskow and Kahn (2002) estimated that only 1/3 of the increase in wholesale power prices during 2000 was due to market power.

[11] This occurred via California Legislature passing Assembly Bill 1X, which among other things allowed the State Government to take over the bulk of the purchasing responsibilities from the two 'financially moribund' utilities (Bushnell, 2004).

rather than keep pace with rapidly rising industry costs, residential electricity tariffs were frozen by policy. As a result, in February 2009 the WA Office of Energy recommended power prices rise by 116% over the ensuing 3 year period – a decision which was subsequently rejected. With tariffs set below cost, as was the case in California, WA's largest generator, Verve Energy (which harboured policy-induced losses) was technically insolvent by early-2008 and was ultimately propped-up by the State through fiscal injection. By mid-2010, the WA Energy Minister drew the obvious conclusion:

> *As a responsible Government, on behalf of the taxpayers of WA, we cannot continue to subsidize Verve's losses… we were left with the reality that a subsidy of almost $1.5billion would be required over three years to keep Verve Energy viable… [Raising electricity prices, thereby] improving the financial position of the corporation [will] ultimately reduce the subsidy paid to cover the difference between the cost reflective price of electricity and the price paid by consumers - taxpayer funds that could be used on other priority areas such as schools, hospitals and roads.*[12]

3. The case for setting default tariff caps using short run market dynamics

Price cap regulation in Queensland's intensely competitive retail electricity market is currently a policy constraint. The most recent price determination by the regulator involved shifting the approach to setting the default price cap within the competitive retail market to levels perceived to be efficient by reference to spot and short-tenor forward contract prices. Such an approach reflects a view that the use of LRMC calculations, for example, leads to unnecessary premiums in energy bills (see QCA, 2011; IPART, 2011; ICRC, 2010). To understand why this is thought to be the case, it is worth reviewing what an LRMC calculation entails.

LRMC calculations for the purposes of setting default tariff caps typically uses a *Greenfields* approach to power system modelling in which aggregate electricity demand is assumed to be met by a fleet of state-of-the-art new entrant plant, with that fleet calibrated to ensure that the optimal mix of base, semi-base and peaking plant is deployed, thereby utilizing the rich blend of fixed and variable costs of the three technologies in order to minimize the cost of supply.[13] Additionally, such an approach (for all intents and purposes) essentially optimises the number of 'tolerable blackouts' to avoid inefficient costs associated with an 'over-equipment' scenario.[14]

LRMC calculations are forward looking and ignore sunk investment decisions. If wholesale market clearing prices were to prevail at LRMC levels, recalling that LRMC is defined by using state-of-the-art investments, less efficient or poorly run plants would incur losses, efficient plant would post normal returns and plant with unique endowments would accumulate excess returns – to the extent of their special endowment. Under an LRMC framework, default tariff caps would be adequate to ensure that new plant of the appropriate technology, capital structure and resource cost can enter profitably and meet the expected returns of the marginal capital deployed. In a region such as Queensland, the load factor-adjusted long run marginal cost of thermal power equates to about $80/MWh. LRMC calculations for each region will vary depending on load factors, system size and resource endowments.

A principal argument against the use of LRMC in default tariff cap settings is that it is unlikely to bear any resemblance to the short run price of energy in the present year as it ignores the allocative and dynamic efficiency of markets – specifically, oversupply and undersupply events, movements in fuel prices, and the impact of historic contractual positions. For example, short run load-adjusted contract prices in Queensland are, at the time of writing, thought to be trading at

[12] Ministerial Media Statement, Peter Collier, WA Minister for Energy, 21 September 2010. Available at http://www.mediastatements.wa.gov.au/Pages/Default.aspx?ItemId=134025&

[13] Frontier Economics (2012) explains variations to this basic Grenfields approach.

[14] To be clear, no power system in the world has been built to eliminate blackouts – the cost of doing so is prohibitive.

about $62/MWh, well below the LRMC result of $80/MWh due to structural oversupply. Additionally, as the *Greenfields* approach is often applied to the region and sub-load in question, it ignores the scale benefits that arise from interacting as a national market with multiple jurisdictions, technology and fuel types, load diversity and weather diversity. The issue here is that in attempting to simulate a competitive retailer's *actual* cost of supply, LRMC estimates are illusive and are unlikely to be a good proxy in any year.

Further arguments in favour of using short-run efficient prices as the benchmark are that a regulator can simulate the construction of a balanced portfolio of 1, 2 and 3-year hedge contracts with data observable from the futures market, and combine these with half-hourly forecasts of future spot prices (using 'black box' modelling), which it is argued, represents the actions of a 'prudent retailer' in an energy market. By contrast, the use of LRMC in setting default tariff caps is argued to exclude the effects of contracting.

While LRMC calculations are acknowledged as being a reasonable reflection of the annualized costs associated with investment in power plant equipment, ACIL Tasman (2012) argued that in a deregulated market, generation investment decisions are in the hands of investors and accordingly, losses incurred or rents accrued from the short run market should remain with those investors. In particular, they highlight that the NEM was designed to ensure that inadequately performing plant or poorly-timed entry of new plant would not be subsidized by electricity consumers. They further argued that default tariff caps relying on LRMC calculations could potentially impose the cost-consequences of inefficient investment decisions on end-users.

ACIL Tasman (2012) therefore concluded that synthetic LRMC constructs created by energy retailers, such as long-dated Power Purchase Agreements[15] (PPA) or direct investments involving internalised PPAs between generation and retail divisions, do not represent efficient contractual arrangements on an intra-cycle basis. That is, PPAs are designed to provide stable returns to asset owners and in theory should cost no more than the accumulation of spot market and short-dated contract purchases across the energy market business cycle. And so the logical presumption is that intra-cycle gains and losses arising from PPAs should be marked against the short-run market, with the competitive advantage or disadvantage of those PPAs being crystallised annually.

A key issue arising from excluding LRMC calculations from the determination of default tariff caps is whether resource adequacy can be achieved, or more specifically, whether new entrant generation investments would be stifled or delayed. However, ACIL Tasman (2012, p.8) were perfectly clear in their rejection of such notions. In particular, they noted that they do:

> *"...not accept this argument on the basis that, as generation and load move to balance with load growth, NEM market prices (combination of expected spot and contract) would be expected to increase to a level which will encourage new generation. This is inherent in the NEM design, as supply-demand tightens, prices rise and new generation investment occurs. This means that if applied in future years, [the wholesale cost*

[15] PPAs are the primary instrument used to facilitate new plant entry, and are inevitably struck at the long run costs of a given technology for banking purposes. As Nelson and Simshauser (2012) explain, PPAs are quite fundamental to the reliable flow of supply-side investments in the NEM. PPA's can probably be traced back to the early 1980s, and were first associated with thermal plant but are now most common with renewable plant. They are usually very long-dated agreements that contain a fixed price which escalates annually, to purchase most or all of the power from a given power station. PPAs for thermal plant usually comprise two revenue streams (1) fixed monthly payments which occur regardless of output, and (2) variable monthly payments based on output and the fuel consumed in the process of production. So the fixed payments typically include funds adequate to pay for labour, non-fuel materials, scheduled debt repayments, taxation costs and a normal return on capital to owners. To be sure, PPAs come in all types, sizes and tenors, and for renewable plant such as wind farms, they usually involve a simple price, expressed in $/MWh, for all output including any environmental certificates. PPAs almost always have performance requirements, e.g. plant availability targets or production targets and if not met, financial penalties apply.

> *allowance within default tariffs] would be expected to reflect price rises associated with a tighter supply-demand balance...”*

The QCA (2012) on the other hand acknowledge that incorporating *LRMC*, particularly using the method in NSW and South Australia where it forms the *floor* of artificially-set default tariff caps, may provide additional security for investment in generation. But QCA (2012) considered that such a requirement is *not necessary given current market conditions* (i.e. oversupply). To that end, the QCA (2012) noted that including LRMC calculations within default tariff caps does not benefit the financial stability of incumbent (i.e. not new entrant) generators unless retailers were acting altruistically. An important position taken by the QCA (2012) and others is the view that regulated default tariff caps should not be used to correct concerns of resource adequacy, this is instead a more fundamental market design issue.

In summary then, proponents of using short run dynamics to set default tariff caps argue that LRMC does not reflect an efficient price at any time, and if clearing prices are in fact equivalent to LRMC it is merely by chance. Default tariff caps set with an LRMC floor also ignore the benefits of contracting and the benefits of power system diversity arising from inter-regional transmission connections and load diversity. Moreover, it is argued that LRMC as a floor is simply not necessary to deliver security of supply, because short run wholesale prices will inevitably rise when supply is constrained, and investment will occur. And, setting default tariff caps at an LRMC floor runs the risk of consumers paying higher prices than is necessary for energy and may subsidise poorly-timed or inefficient investment decisions in generating plant.

4. The case for setting default tariff caps using LRMC as floor

The starting premise for setting default tariff caps using *LRMC as floor* is that the case for regulating competitive retail electricity tariffs is weak to begin with for all of the reasons outlined in Section 2. But to the extent that price regulation forms a policy constraint, advocates of LRMC and in particular, *LRMC as floor*, argue that default tariff caps should form a ‘safety-net’ rather than try and second-guess what the competitive price should actually be through the use of short run dynamics as if the industry were in fact an inefficient monopoly.

As highlighted earlier, a short run dynamic approach is distinctly intrusive on the workings of a competitive market because a regulator is using highly imperfect information and, by defining as efficient only those instruments with tenors spanning 1-3 years, risks using incorrect specifications of what constitutes an efficient price given the wide array of wholesale pricing instruments available. All of the arguments from Section 3 ignore one fundamental reality – competition within Australia’s retail energy markets is intense by global standards with most customers on competitive market offers. As Yarrow (2008, p.30) observed:

> *If, in classic fashion, a price cap were set at a level close to average total cost including a normal return on capital, the effect would be that an efficient supplier would necessarily earn a less than normal rate of return, with damaging implications for investment and innovation. In terms of profits, the supplier would see an upside that was truncated by regulatory controls alongside a downside that was increasing as competitive constraints grew. To avoid any highly damaging incentive effects, any price cap must be above the level at which it would be set for a monopoly with the same cost structure...*

Professor Yarrow’s observations are clear enough. In a competitive market with a policy constraint, *LRMC*, (or some margin above it) should form a floor when setting an artificial market price cap. The QCA (2012) appears to have missed this point. While the QCA (2012) would argue that its remit was to calculate an *actual cost of supply* rather than a safety-net price, it does not logically follow that short run dynamics that are demonstrably below long run sustainable cost meet this definition. On the contrary, Section 2.3 explained that the generation sector is distinguished by its heavy fixed costs, and the threshold for efficiency cannot be considered purely by reference to short run dynamics, particularly when such an approach collides with the manner in which investment flows are facilitated, as Section 4.1 later reveals.

The QCA (2012) queried why increased security would be needed with regulated prices through the use of *LRMC as floor*, but not if price regulation was removed - where only market prices are available. What the QCA were trying to suggest is that in liberalised markets, there is no regulated price to match (i.e. market focal point), and therefore standing tariffs must surely revert to short run market dynamics across the business cycle, rising above and below LRMC in line with supply imbalances. They do not, however. And there is no evidence that standing tariffs ever have in competitive retail energy markets. The point made by the QCA indicates an inadequate understanding of how standing offers of energy retailers are set in global liberalised markets. In regions where price regulation has been removed such as Victoria, New Zealand and Great Britain, each retailer posts a *standing price* and this is invariably based on that retailer's *house view* of the long run marginal cost of supply, or under system stress conditions, at (the higher) short run dynamic prices. Standing offers, as noted earlier, need to account for considerable asymmetric information, market conditions, and portfolio costs. In contrast, competitive market offers invariably arise with discounts at varying levels of intensity depending on contract tenors and industry fundamentals - to win market share and increase revenues. Importantly, price regulation in an effectively competitive market that conflicts with these basic practices will, by definition, be intrusive.

And so to the extent that price regulation forms a policy constraint due to political processes, competitive clearing prices in retail markets should be set by the hands of market forces, not those of a regulator second-guessing the appropriate level of Bertrand (i.e. price-based) competition amongst rival retailers, particularly where the regulator is demonstrably equipped with inadequate information, and uses their own mis-specified benchmark of what constitutes a prudent retailers' hedge book and energy purchase costs. As Yarrow (2008, p15, p21) has noted:

> *...price regulation in competitive market situations generally harms economic efficiency... It can be said that regulators, no matter how wise and no matter how well resourced, could be expected to make significant mistakes – because the problem has to do with information. The determination of a competitive price is a process that makes use of huge amounts of information, of such scale and scope as cannot feasibly be processed by a single decision making unit such as a regulatory agency...*

An insurmountable difficulty for a regulator is, therefore, to define a prudent retailer's hedge book because retailers are no longer uniform in terms of financial structure, scale, scope, strategic intent and most other business variables. Where price regulation represents a policy constraint, reverting to some idealised hedge book based on short run dynamics as the single point of reference will by definition damage any business that has a long-term planning bias. Conversely, pure reliance on LRMC will eventually damage any business that has a short-term planning bias. And to be sure, regulators *must* assume that firms in effectively competitive markets span either end of the business planning spectrum. Unless innovation is considered undesirable, or consumer preferences are thought to homogeneous, there should *not* be a single benchmark portfolio. Put another way, businesses with a short-run planning bias will be highly competitive in over-equipment scenarios, whereas businesses with a long-run planning bias will be highly competitive (and crucially, industry stabilising) in under-equipment scenarios. It is not in the best interests of consumers or Australia's macro economy to have this level of competitive diversity truncated through intrusive price regulation.

4.1 *No matter how wise* – the broken merchant model

Yarrow's (2008, p.21) *'no matter how wise'* reference was demonstrated with almost textbook precision in the 2012 regulatory determination in Queensland. This determination managed to produce a manifest error by attempting to define what constituted the structure of a prudent retailers' hedge book – in particular, using only short-run hedge instruments with a maximum of three years in tenor. To be fair, a hedge book of this structure might well have been a reasonable or representative market benchmark prior to 2004.[16]

But as Finon (2008) and Simshauser (2010b) observed, and as Nelson and Simshauser (2012) clearly demonstrate, profound changes occurred globally in the market for power project finance from about 2004. Specifically, merchant plant relying on 2-3 year hedge contracts for entry became completely "un-bankable". The merchant model is now essentially broken. But it was not always this way.

Initially, energy markets around the globe were formed with an expectation that new power projects would be developed and project financed with long-dated structured debt, with their income streams arising from spot and short-dated forward market contracts of 2-3 years in tenor. ACIL Tasman (2012, p.8) argued that *'as supply-demand tightens, prices rise and new generation investment occurs'*. Such outcomes have long been demonstrated in theory (Schweppe et al. 1988; Stoft, 2002; Hogan, 2005; Newbery, 2006) and initially, a vast amount of generating capacity was indeed banked on this basis. For example, Simshauser (2010b) noted that the NEM has more than 20,000MW of privately owned (i.e. pre-existing and new entrant) generating plant, and fully more than 17,000MW (85%) was project financed. Similarly, Joskow (2006) noted that in the US, about 230,000MW of new plant was initially developed or acquired on this basis, most of which was project financed.

However, in the case of the NEM, of the initial 11,000MW of plant that was privatized, most facilities at one stage or another faced some form of financial distress with no less than 11 plants subsequently experiencing a change in ownership (Mayne, 2010).[17] And in the US, Finon (2008) noted that by 2005, more than 110,000MW of the 230,000MW of plant developed experienced some form of financial distress or bankruptcy proceedings. Consequently, obtaining project finance for the development of power generating assets in energy-only markets, in the absence of long-dated PPAs, is simply no longer possible as Nelson and Simshauser (2012) demonstrate. The global financial crisis has only intensified the situation, along with the risk tolerances of the project banks. The last truly merchant power project in the NEM of note was the 840MW Millmerran coal plant in 2002, and has since experienced financial distress and required urgent recapitalisation in 2012. This is not a NEM-specific issue. As Finon (2008) observed, this is a truly global phenomenon associated with competitive energy pools.

So how has the NEM navigated Resource Adequacy following the change in the risk parameters of project banks? Thus far, participants have reorganized themselves into investment grade credit-rated, vertically integrated, merchant utilities that span retail supply and power generation, albeit with generation typically being 40-70% of their peak retail demand. The generating plant portfolios of the vertical entities are in all cases a mix of their own direct investments (with internal or synthetic PPAs between generation and retail divisions) and PPA-sponsored power projects which are owned and operated by independent generators. How then, can a prudent retailer's hedge book be defined by a *duration* of approximately two years when all new entrant

[16] This definition of a 'prudent retailer' may be satisfactory amongst smaller second-tier retailers, whose demand for hedge contracts does not materially move prices in the forward markets. But defining as prudent only 1, 2 and 3 year hedge contracts for an entire industry is a complete mis-specification of a highly complex market.

[17] Mayne (2010) reported 10 plants changing ownership due to financial distress. We report 11 plants due to AGL's acquisition of Loy Yang A in 2012, at which time the plant was also in financial distress.

plant, including renewable plant, requires PPAs with tenors of no less than 10-15 years? The answer is, it can't.[18]

This can be further explained by reference to the construction of debt portfolios as a useful analogy. Industrial firms, banks and governments raise debt using a variety of instruments, facilities and tenors. This is especially true of the utilities industry, the world's 3rd largest issuer of debt, where term issuance frequently spans from very short dated instruments to 15 year international bond placements or structured bank facilities (Simshauser, 2010a; Simshauser and Nelson, 2012). In contango markets, short-dated debt instruments are demonstrably cheaper than long-dated debt instruments. Yet firms actively issue longer-dated debt under these conditions. Why is this? They raise debt using a variety of facility tenors in order to reduce interest rate and refinancing execution risks in future years.

This can be demonstrated by simple example. Any firm in any industry that held a concentrated debt portfolio of 1, 2 and 3 year instruments with tenors maturing in 2008 and 2009 will have experienced a four-fold increase in credit spreads by comparison to those that applied in 2006 and a high risk of outright refinancing execution failure because liquidity in the global debt markets reduced from US$3.2 trillion to just US$1.1 trillion over the that period (Simshauser, 2010a). Clearly, the financial implications of such debt congestion led many firms with these characteristics to experience financial distress or bankruptcy.

Similarly, for a large energy retailer whose demand for hedge contracts is non-trivial relative to the size of the total market, constructing a balanced hedge portfolio comprising energy market instruments of varying tenors is designed to achieve parallel outcomes – taking a long term view of the market to reduce recontracting price and volume execution risks, particularly during periods of power system stress conditions. Accordingly, the notion that long-dated hedge contracts or PPAs are somehow sub-optimal instruments that should be marked annually against short run dynamics through intrusive regulatory intervention (i.e. an artificial tariff cap) displays an inadequate understanding of basic portfolio theory. Firms respond to the regulation they encounter. And so at the very least, a regulatory determination using this structure, whether intended or not, dis-incentivises a diversified portfolio approach to market risk management, and especially those constructed with a long-term view. All of this is generally accepted (and Nobel Prize winning) financial economic theory dating back at least as far as the 1950s. As Frontier Economics (2012) noted:

> *The QCA's rationale for rejecting the use of LRMC appears to be based on a short term view of market conditions, which does not take account of the longer term consequences on Queensland, and indeed on the National Electricity Market. The rejection of a regulatory mechanism that is acknowledged as providing superior electricity market security outcomes based on "current market conditions" is unprecedented in Australia. To investors, the switching from one regulatory mechanism to another to take advantage of a transitory oversupply of capacity due to a combination of economic downturn and regulatory intervention means that the Government, on advice from the QCA, will just as easily switch regulatory formula again when circumstances inevitably change some time in the future. This regulatory risk creates its own inefficiency. While the QCA is unconcerned about this effect in the "current market conditions", it should be remembered that planning for new plants occurs years in advance of when it is needed. The QCA's short term thinking, based on current market conditions, will inevitably and adversely affect the long term competitiveness and security of the Queensland electricity supply industry.*

[18] The QCA (2011) and ACIL Tasman (2011) had further mis-specified a 'prudent retailer' in earlier drafts of their Queensland tariff determination by presuming that a spot price forecast with a Probability of Exceedence greater than 50% would represent a cap price on hedge contracting. Fortunately, both organisations retracted their position after the somewhat hostile reception the concept received by energy retailers.

4.2 Is illusive LRMC actually a problem?

Another central criticism of the use of LRMC in setting default tariff caps is that actual costs of supply in the current year bear no resemblance to LRMC calculations. John Maynard Keynes noted that long run equilibrium 'is illusive' more than 80 years ago, as did his principal economic combatant, Freidrich von Hayek (Wapshott, 2011). And so we should quickly rule out the possibility that this observation is at all contentious. Keynes' observation applies to macroeconomic analysis and all the industries that comprise the macro economy, including electricity supply. Yet neither Keynes nor von Hayek meant to imply that LRMC calculations are somehow not important, or have no relevance to the actual costs of supply. On the contrary, LRMC calculations are by their very definition a reflection of the efficient costs of new capacity, the price at which PPAs are struck at, and represent the centre of market gravity for forward contract prices of all tenors. If one accepts that electricity is not a terminal product, then LRMC has a very fundamental relevance in order for investment to meet demand growth, aged asset replacement, or both.

The QCA (2011) also argued that regional Queensland customers were unable to access the competitive market and so LRMC was inappropriate under 'current circumstances' given lower short run dynamics. This was a most unusual position to take because Ergon Energy's 690,000 regional Queensland customers are heavily subsidised to begin with due to the very high cost of network charges and the prevailing uniform (State-wide) tariff policy. That is, regional Queensland customers are currently subsidized to ensure they pay no more than their metropolitan peers, despite the substantially higher network charges. The aggregate subsidy paid between 2008-2012 was a surprisingly large $2.08 billion and totalled about $400 million for each of the past two years – a subsidy charged against the Queensland Governments' balance sheet. Since regional customers are paying substantially less than the actual cost of supply, it is nonsensical in economic theory and practice that they should feature in any way in a decision on the economic efficiency of the intensely competitive southeast Queensland retail market.

Another key issue raised by the Queensland Competition Authority was the tendency of competitive retailers to 'flip-flop' in their views on regulated pricing methodologies. On the one hand, when the wholesale market is experiencing system stress and short run prices are demonstrably above system long run marginal cost, retailers argue en-masse for the use of short run market dynamics in setting default tariff caps because they cannot secure hedge contracts at the lower LRMC set-point. On the other hand, when the wholesale market experiences structural oversupply, retailers argue for the use of long run marginal cost to account for long term hedge contracts or PPA commitments they have made – all of which appears *'entirely too convenient'*. I have remained perfectly consistent on this matter, and while I cannot be sure of the specific intent of each market retailer, when I combine the Authority's two observations, they describe an *LRMC as floor* approach to setting default tariff caps. That is, use LRMC during an over-equipment scenario, and use market prices in under-equipment scenarios to set a safety-net tariff to the extent that it is a policy constraint, and avoid intruding on the efficient workings of the market. Accordingly, I find no prima facie inconsistency with retailers' preferred methodology whatsoever, and I note that in the most recent Queensland regulatory inquiry, all (non-government) retail participants supported an *LRMC as floor* approach, where price regulation represents a policy constraint. While acknowledging the perils of price regulation in competitive markets, to the extent that price regulation represents a policy constraint, such an approach will minimise any intrusion on the business planning imperatives of retailers, spanning from those with a short-term bias to those with a longer-term bias.

A further observation I would make is that the historical approach to setting default tariff caps in Queensland would have quite predictably led to apparently conflicting or 'flip-flopping' views by retailers because the set methodology involved a 50/50 averaging of LRMC and short run dynamic prices. Under a 50/50 approach, if short run market prices increased substantially due to under-equipment, the tariff cap would be sub-economic for marginal customers because the LRMC component would dilute the short run market price signal. Conversely, during an over-equipment scenario, the LRMC component would be diluted by short run market prices, making prior PPA and investment commitments by entities with a long-term planning bias uneconomic at the hands of regulatory intervention rather than the competitive market.

Another criticism of the use of Greenfield LRMC calculations in the determination of default tariff settings is that it was said to overlook the benefits of interconnection and load diversity benefits. The regularity and intensity of disconnects between the physical power system and the financial stability of the system is striking, as the AEMC (2012) has aptly observed. Indeed, as Simshauser, Molyneux and Shepherd (2010) demonstrated, a region of the NEM can, in theory, be expected to meet all physical reliability criteria whilst simultaneously being chronically short of financial hedge capacity from market-long physical participants. They found that in spite of interconnection and a substantially oversupplied physical market, simultaneous shortages in the hedge markets can result in surprisingly large premiums over spot prices (in Queensland for example, at one point almost \$7/MWh on a \$28/MWh base in the mid-2000s). Ultimately, firms must manage and hedge their positions, and cannot rely on physical power system flows to do so without accepting considerable financial risk, and so such criticisms of LRMC are invalid. To the extent that a firm must hedge a given customer segment to reduce such risks, using any of the wide array of available contract tenors, it should be obvious that its price will be structured to match its generalised load profile. Regardless, at the most fundamental level, debate on price regulation methodology in competitive markets should not be trying to minimise an artificial tariff cap with that degree of resolution given its potential adverse effects on competition and the extreme complexity and uncertainty of the forecasting assignment.

4.3 Capital market imperfections and the impact of short run pricing on investment

Section 4.1 noted that a key finding in Nelson and Simshauser (2012) was that while energy markets experienced an initial wave of investor enthusiasm for new plant, the global experience of the merchant power plant has mostly involved financial distress or outright bankruptcy, and so since the mid-2000s, purely merchant power plants have not longer been bankable. PPAs have therefore become pre-conditions to raising project finance. Put another way, scale-efficient demand-side participants in energy markets are encouraged to write PPAs, vertically integrate, or both because it has become a financing constraint, as Simshauser (2010b) explains in considerable detail.

Recall from Section 3 that an important position taken by the QCA (2012) was the view that regulated default tariff caps should not be used to correct concerns of resource adequacy, and that this is instead a more fundamental market design issue. Such an observation discounts the fact that the market design, while by no means perfect, has not led to supply shortages because industrial organisation has overcome risks that are otherwise inherent in energy-only markets as ERIG (2006) predicted. Intrusive price regulation is, however, quite capable of disrupting this. Indeed, whether intended or not, by opting to deploy short run dynamics the QCA (2012) has actively disrupted the very risk mitigant that the market has efficiently delivered to overcome these constraints. Firms actively respond to the regulatory incentives they encounter, and because a short run dynamic approach to price cap regulation renders long-dated PPAs sub-economic in over-equipment scenarios through the annual, regulatory-induced mark-to-market process, they will be dis-incentivised.

At the macro level, consumers may pay more for their energy in cyclical downturns with the presence of PPAs by comparison to a market based purely on short run dynamic prices. But their delay, or worse, absence, will have an impressing effect during each cyclical upswing. To be clear, none of this line of reasoning should be interpreted to suggest that PPAs or direct investments by integrated entities should somehow be free of losses. Poorly structured, mispriced PPAs or inadequately timed investments will inevitably result in lost profits, as they should. I noted earlier that discounting against default tariffs intensifies during periods of 'over-equipment'. Inevitably, discounting in the retail market, particularly at the margins, will squeeze revenues such that some or all PPAs will become loss making from time to time at the hands of the competitive market.

If the reason for adopting a short run dynamic approach to setting default tariff caps attempts to redress a perceived market imperfection (i.e. default customer inertia), regulating prices down to short run dynamics in market troughs can achieve this but it will merely exchange one market imperfection by intensifying a far more material market imperfection – resource adequacy. Far from any neutral effect on resource adequacy, short run dynamic tariff cap determinations would be an unambiguously pro-cyclical pricing policy, thus aggravating an already extremely volatile market. As Frontier Economics (2012, p.6) noted in their analysis of the consequences of regulating default tariff caps below sustainable industry cost:

> *…not only would a retailer be prevented from recovering the costs of efficient [investment or PPAs] under the QCA's [short run] approach, but additional [investment or PPAs] would tend to lower future market prices and the QCA approach would take advantage of this lower price to lower the regulated retail price cap in the future, further undermining the financial viability of the retailer. So, rather than retailers not appreciating the linkage between the LRMC and the market price as the QCA claims, it seems as though the QCA does not understand the forces that drive electricity market prices…*

The issue that Frontier Economics (2012) focused on was the fact that in theory, direct investments or PPAs are written to facilitate the entry of new plant as energy market prices rise above entry costs. But since the nature of power plants is frequently characterized by scale economies, lumpy plant entry will lower short run prices in the immediate post-entry market environment. This observation by Frontier Economics (2012) dates back at least as far back as Bain (1956), Sylos (1957) and Modigliani (1958), and subsequently sprouted an entire field of economic literature. These effects have also been quantified in considerable detail specifically in relation to the NEM in Simshauser (2001, 2006), and so it should not be necessary to repeat such analyses here. Suffice to say that spot and contract prices invariably fall below the long run marginal cost of supply in the immediate post-entry period before recovering in later periods.

These post-entry market price shocks in the wholesale market are capable of being absorbed, albeit imperfectly, within vertically integrated energy portfolios where price regulation is not intrusive. The reason for this is that there are multiple rivals whose businesses comprise complex portfolio of supply-side contracts and investments that are matched off against an equally complex portfolio of demand-side contracts, written over time against standing tariffs at varying levels of discounts, tenors, terms and conditions. This point is quite crucial, and forms the largest part of the asymmetric information facing regulatory authorities. But what is patently clear to those working within industry is that post-entry price shocks simply cannot be absorbed if regulatory authorities regulate the standing tariff *unilaterally* below industry long run sustainable costs during episodes of over-equipment, that is, by capturing the short run dynamics that arise from an investment commitment itself, particularly when the standing tariff forms a whole-of-retail market reference price for discounting.[19]

[19] The reason for this is that all prior contracts, which have been fundamentally premised on rational price path, will be out-of-the-money. In 2011 in Queensland for example, marginal contracts were being offered by rival retailers at a 10-12% discount (c.$15/MWh) over a 3 year term against the default tariff. In applying short run dynamics to the price cap, the Queensland regulator reduced the wholesale cost allowance by $19/MWh for 2012, thus forcing all retailers to reduce or withdraw their discounts. Such liquidity events requires a complete re-pricing of all contracts in the market place along with system changes running into the tens of millions, all to account for a regulator's view as to what they believe is an efficient price under conditions of asymmetric information.

Investment commitments can be delayed. And since the regulatory incentive under a short run dynamic approach to setting default tariff caps is to delay entry as Frontier Economics (2012) observes, merchant utilities will inevitably respond to the policy and regulatory incentives they have been given. In the event, incumbent firms will delay entry or writing PPAs to minimize portfolio losses associated with the post entry environment. This is more than a theoretical possibility as Section 4.4 later reveals. And to be clear, economic losses associated with a large portfolio of customers pinned to a sub-economic default tariff cap will greatly overrun any imaginable lost profit from delaying a marginal power plant investment.

If plant entry is delayed, what would this mean for electricity customers? It should be obvious that the energy market business cycle would be extended and intensified through protracted periods of higher prices. And delayed entry would simply be an outworking of the distortionary effects of the price regulation facing the industry. Additionally, maintaining a short run dynamic approach to setting default tariff caps will have the effect of transmitting the full business cycle of the world's most volatile commodity market into household retail tariffs, but with even greater intensity. Such an approach would therefore be pro-cyclical. It is difficult to see how such an outcome is in the best long run interests of consumers. As Brand (2010) and Alexander (2010) noted, stable and predictable tariffs aid the budgeting decisions of all households, not just vulnerable households. In contrast, an LRMC floor calculation is dramatically less volatile.

Further, it is difficult to overstate the implications for investment in merchant generating equipment, and innovation in retailing, arising from a change in tariff policy perceived to be efficient by a regulatory authority by reference to their own portfolio design of short-dated hedge contracts. A key reason for this is that the public sector has exited from making investments in risky merchant power generating assets, with the last commitments made back in 2007. Simshauser (2010b) noted that publicly-owned utilities were directly or indirectly[20] responsible for more than 70% of all new power generating capacity from the start of the NEM in 1998 through to 2007. However, public utility involvement since has ceased by policy, due to the balance sheet constraints of state governments. The power sector in Victoria and South Australia was privatized in the late-1990s. Queensland privatized its retail sector in 2007 and its remaining state-owned generators will be prohibited from investing in new plant, while New South Wales privatized its retailers and some generators[21] during FY11 and has announced its remaining generators will be privatised in 2013. As a result, power system resource adequacy has been fully transferred to the competitive private sector – where it is best financed.

But achieving resource adequacy, let alone an optimal plant mix in energy-only markets, is not without risk. This observation is underpinned by a substantial body of academic research.[22] As noted earlier, one of the key observations from the work undertaken by Finon (2008), Simshauser (2010b) and others on navigating resource adequacy is the critical importance of long-dated PPAs, written by investment grade credit-rated utilities in order to facilitate timely investment.[23] As (anonymous academic) peer reviewers of this article noted, should PPAs prove elusive through the distortionary effects of poorly guided retail price regulation, it raises policy questions of whether capacity payments might well provide an alternate avenue for resource adequacy in the NEM. Such measures have not been necessary thus far in the NEM's 15-year history, but neither have default retail tariffs been regulated solely on the basis of short-run market dynamics during that history, and to levels which are distinctly sub-economic from a long run cost perspective. If these conditions change and a form of market failure becomes apparent, supply-

[20] Indirect involvement in new power generating assets by Government Owned Corporations was most typically by way of writing long-dated Power Purchase Agreements (underpinned by their investment grade credit ratings).
[21] Generators in NSW were effectively privatised by selling the marketing rights of the power stations.
[22] See for example Bidwell et al. 2004; Bushnell, 2005; Roques et al. 2005; Joskow, 2006; Finon, 2006 and Simshauser, 2008 amongst others.
[23] It is worth noting that niche retailers or generators with retail businesses that do not hold an investment grade credit rating are *not* capable of writing PPAs sufficient to satisfy project banks. That is, the PPA counterparty must hold an investment grade credit rating, i.e. BBB- or greater.

side options such as introducing capacity payments to the NEM will clearly warrant a more fulsome analysis by national policymakers as potentially corrective policy counter-weights to intrusive regulatory actions of jurisdictional regulators.

4.4 The links between new plant entry, PPAs and retail tariff caps

Where price regulation does not intrude on the efficient workings of energy markets, investment in new plant or PPAs are able to be formed in a timely manner. This scenario is usefully contrasted with a regulated price outcome where an entire regional market was subjected to a sub-economic default tariff cap, as the NSW regulator subsequently noted was the case with its own determinations during 2004-2007 (IPART, 2006). In a market where a regulator presides over price caps at levels below long run sustainable costs, all retailers experience an instantaneous step-change in the profitability of all customers since market contracts are typically written at discounts to the default tariff, and are capped by the default tariff (since customers have a right to switch back to the default tariff offering). Either way, this represents a "revenue shock event" to all energy retailers. Under such conditions, it becomes intractable for credit-rated retailers to write long-dated PPAs in a timely manner since there is little prospect of obtaining an economic return in the short term. And as noted in Section 4.1, plant entry in the NEM without a PPA is no longer a bankable proposition. ACIL Tasman (2012, p.8) expressed the view that *"prices will rise and new generation investment occurs"*. However, generation investment does not *occur* as if it were some automated process, it must be originated or facilitated by a firm with an investment-grade credit rating, or a firm with a particularly large balance sheet and an appetite for merchant energy price risk.

Once again, we should turn to a quantitative analysis of plant investment patterns in the NEM to demonstrate these concepts in practice. Table 3 summarises wholesale market data from 2004-2007 for NSW and its two adjacent and interconnected regions, and coincides with the sub-economic regulatory determination period NSW. Note in Table 3 that NSW had by far the highest wholesale spot market price at $41.92/MWh, the highest absolute market value at $11.3 billion, and in the period preceding 2004-07, NSW also had the highest present value of forward prices in the short-run over-the-counter market at $36.36/MWh.[24] Crucially, during the preceding period, the market operator's annual 'Statement of Opportunities" highlighted that the NSW region would experience a 'Lack of Reserve' by the summer of 2006 (NEMMCo, 2003). On this basis, one would quite reasonably expect that a dominant proportion of the 1,969MW of new plant capacity built in the NEM during 2004-2007 might have been sited in NSW.

However, esaa (2010) data reveals that not a single MW was built in NSW over this period. All capacity investments were directed to either Queensland or Victoria – the two adjacent regions to NSW. The reason for this otherwise unexplainable outcome is in fact intuitively logical; writing PPAs in NSW was a sub-economic activity. Since retailers were unable to economically underwrite a PPA in NSW during that period, none were written, and so no investment occurred.

Table 3: **Base load prices and energy market value from 2004-2007**

NEM Region	3Yr Forward Price 2H2003* ($/MWh)	Actual Spot Prices 04-07 ($/MWh)	Aggregate Generation (GWh)	Aggregate Market Value ($m)
NSW	36.36	41.92	269,828	11,310
QLD	34.30	34.35	231,242	7,943
VIC	33.08	35.07	210,387	7,378
Total/Avg	34.58	37.43	711,456	26,631

Source: AFMA, AEMO. *3 year forward calander year base load contracts covering CY05-CY07.

[24] It is also worth noting that the 3-year forward curve for base load swaps throughout the period 2001-2004 was in contango in NSW, and in backwardation in QLD.

One might be tempted to conclude that no problem actually existed since the combination of interstate investment and interconnection ensured reliability was met in NSW. But this misses the point. Regulatory settings induced a *merchant investment blackout* in NSW. If the same regulatory approach was systematically applied across all regions, it is not obvious that an investment blackout or non-trivial delays wouldn't cascade across the NEM.

Predictably, following a shift in economic policy settings whereby NSW default tariff caps were reset at the total supply chain market cost with an LRMC floor, a surprisingly large 71% (or 1,742MW) of the 2,462MW of investments in new capacity in the NEM from 2008-2010 were sited in NSW (esaa, 2010). Of this, just one 400MW plant was committed prior to the change in the regulated price path, albeit in anticipation of the then looming regulatory change (Simshauser, 2010b). None of this is at all surprising once the formal links between capital market imperfections, project financing constraints and retail electricity prices are correctly identified, and understood.

5. The costs of policy uncertainty

Since the NEM's formation in 1998, there have been 54 region-years of experience in default tariff determinations, and only four of these years could be considered problematic – the 2004-2007 NSW determination, and the QCA (2012) result for Queensland. The 2012 Queensland result will stand for a 12 month period whilst simultaneously, the newly elected Queensland Government will review its economic framework for default tariff determinations for future periods. What if the short run dynamic approach were to be retained in Queensland for future periods? And what if this approach was systematically adopted by other regions?

Adopting a short run dynamic approach to default tariff determinations makes certain assumptions in relation to the construction of a hedge portfolio, which is thought to be efficient. For the reasons already identified, it is not, however. In effect, through the incentives that regulation endows on a market, long-dated instruments would effectively be declared uneconomic – the debt market equivalent of shutting down medium and long term bond markets. In this sense, default tariffs will have been over-regulated and will have become distortionary.

Short run benefits would accrue to some customers, specifically, inert customers and those (already) subsidised customers in regional Queensland. Beyond this, there are no other obvious short run benefits. Long run costs on the other hand will be non-trivial if the underlying thesis from Sections 2 and 4 are correct. First, future investment in new plant will be delayed as Frontier Economics (2012) noted. To be clear, this should not be interpreted as a scenario of systemic blackouts. To claim otherwise would be disingenuous. But the incentives to invest in new plant clearly change under a short run dynamic approach to regulated pricing and if investment plans were delayed by a 12 month period and coincided with a 1-in-10 summer event, supply constraints and summer blackouts during the delay period would be more than a theoretical possibility, as would unnecessary run-ups in wholesale prices compared to a counterfactual scenario.

Second, new investment will more than likely involve low capital cost 'peaking' plant regardless of whether it is the most efficient technology or not. When policy uncertainty is heightened, investment in low capital cost plant represents a logical capital allocation response by industry because marginal capital at risk is minimised as Nelson et al. (2011) explain. And third, the cost of capital can be expected to rise relative to a counterfactual scenario.

Nelson et al. (2011) quantified the costs associated with carbon policy uncertainty in the NEM in which investment preferences of merchant utilities displays a distinct bias away from optimality and towards low-capital, high-operating cost plant. While their study focused on carbon policy uncertainty, the effects of default tariff policy uncertainty are as significant as carbon policy uncertainty. So while the underlying reasons for uncertainty may be different, the regulatory effects of tariff policies based on short run dynamics are identical. Nelson et al (2011) found that investment inefficiency costs to NEM consumers due to adverse technology selection would amount to $2 billion per annum by 2020, as did Deloitte (2011), who added that if sustained, would climb to $5 billion pa by 2025. Crucially, however, neither of these analyses contemplated a heightened cost of capital – this was held constant.

Simshauser and Nelson (2012) on the other hand held technology selections constant and focused on the cost of capital impacts of policy uncertainty in the NEM – and specifically, in the context of conflicting policy signals. The marginal efficiency of debt capital for thermal plant was found to rise by 200 basis points (bps). Rathmann et al. (2011) and Varadarajan et al. (2011) found that policy clarity around renewable energy market prices leads to variations in the cost of debt of between 200-600bps, while Neuhoff and DeVries (2004) observed a cost of debt penalty of up to 600bps in markets where electricity prices were highly cyclical and did not enable end-to-end pricing at long run costs. These are real costs to consumers that would apply in the long run, and should also be of concern to policymakers and regulators. By applying 300bps (toward the lower end of this range) to the cost of debt finance used by a merchant plant, and adjusting the capital structure owing to the flow-on effects of debt-sizing parameters arising from differential interest rates using the PF Model and associated plant cost parameters in Nelson and Simshauser (2012), the cost differential amounts to $2.95/MWh. Applied to NEM aggregate demand, the cost of policy uncertainty would equate to an additional $590 million in deadweight losses each year.

If regulated tariff caps are set sub-optimally during over-equipment scenarios, then a rather obvious corollary can be expected. The customer portfolios of retailers with a long-run planning bias would be at risk of becoming uneconomic relative to an otherwise entirely credible diversified hedge portfolio. On a single region basis, while destructive, this may not prove fatal. But if this became a systemic NEM problem, it could be expected to place material downward pressure on the credit ratings of all merchant utilities – indeed, it is hard to believe that investment grade credit ratings of the NEM's integrated entities (i.e. the only entities with investment grade credit ratings) could be sustained given the past investment and PPA commitments of those particular firms. If merchant utilities lose their investment grade credit ratings, the NEM's "principal asset" from a physical and systemic market stability perspective, the integrated firms will be unable to write bankable PPAs for thermal or renewable power projects. If this were to occur, it seems plausible if not likely that Governments would be drawn back in to finance new plant investment, or at the very least, the entire market structure would require a redesign to avoid the highly inefficient financing costs that would otherwise prevail.

6. Policy Implications and Concluding Remarks

Of all the arguments presented in favour of a short run dynamic approach to default tariff setting, not a single piece of quantitative evidence has ever been presented in support of the case for its use. Reasoned arguments were certainly constructed to suggest that the use of LRMC risks layering-in unnecessary premiums into default tariff caps – but crucially, only after specifying how an efficient hedge portfolio should be formed. Yet, to define that an efficient contract hedge book comprises only 1, 2 and 3 year futures contracts is a complete mis-specification of a complex market. Given how the flow of investment into the industry is now facilitated, such an over-simplified construct, presented as the 'only efficient solution', is nonsense. No quantitative evidence has ever been produced to indicate why or how *LRMC as floor* leads to inefficient outcomes. And references to transient differences that exist between short run dynamic prices and efficient long run economic costs, no matter how long such differences might exist, are simply not credible in economic theory or practice for an industry with heavy fixed costs.

Of the recent NEM regulatory literature advocating the use of short run dynamics, the notion of excessive customer inertia, imperfect competition and the exercise of market power is the only argument that seems remotely capable of withstanding disciplined academic scrutiny. But a key finding of this article was that customer inertia is not a systemic or widespread issue with 62% of the NEM's customers having switched energy retailers. Competition is intense, and customer switching rates are dramatically higher than other industries, including other essential service industries.

It should be obvious that if all regions in the NEM followed the QCA (2012) approach to setting default tariff caps, and did so on a sustained basis, the incentive facing all firms would be to principally use short-dated hedge contracts. Any significant deviation by a retailer would likely be met with financial disaster. Left to its own devices with such a binding and distortionary regulatory constraint, the entire NEM Model would face risk of eventual collapse because integrated entities would lose their credit ratings. Investment in new thermal and renewable power projects, including those required to meet the 20% Renewable Energy Target, would face sharply higher debt costs at best, or become simply intractable at worst. Either way, such outcomes would impose unnecessary costs on consumers, and require policymakers to intervene because these effects are long-run inefficient and *are* completely avoidable. Above all, this would risk unravelling more than 15 years of sustained microeconomic reform in energy supplies.

Nelson and Simshauser (2012) demonstrated that the Merchant Power Producer, which utilised short-dated contracts of 1, 2 and 3 year terms, is a "broken model". It is difficult to see how applying the principles' of a demonstrably broken model to an entire industry that is otherwise operating competitively and efficiently represents good public policy. QCA's (2012) contention that this is a market design issue is just not credible.

Another important finding in this article is that placing sole reliance on short run dynamics is likely to be pro-cyclical due to investment incentives. It is difficult to see how a 'pro-cyclical' approach to default tariff cap determinations serves the best interests of households over the long run, given sharp cyclical upswings and regulatory lag.

As to how efficiently resource adequacy is navigated in the future depends quite crucially on the expected retail prices. In the absence of distortionary price regulation, merchant utilities will make the investments and underwrite the requisite long-dated PPAs that was once the liability of State Governments. This is far from being a theoretical point. Over the past 12 months in Victoria, AGL Energy invested $3.1 billion acquiring an incumbent plant while Origin Energy completed a new $800 million plant. In the NSW market where the regulated default tariffs mimic those of Victoria through their *LRMC as floor*, Origin Energy and TRUenergy acquired incumbent plant for $1.5 billion. The three utilities have also underwritten more than $2 billion of wind farm developments in South Australia. And in Queensland prior to their shift away from an LRMC reference in default tariffs, $2 billion of new gas-fired plant had been facilitated by Origin Energy either through direct investments or through writing PPAs. In aggregate, this accounts for more than $7 billion of invested capital in the space of just five years by the investment-grade integrated utilities – an outcome that was predicted, and noted as efficient, by ERIG (2006) six years ago.

To be clear, advocates of the short run approach to setting tariff caps do not suggest that regulated prices should be set below cost. The issue that distinguishes this camp is their definition of what constitutes fair and reasonable business costs. The difficulty for energy retailers in this debate is that their hedge books *are not* structured in a uniform fashion. Some retailers own generation plant. Others have written long-dated PPAs to facilitate new entrant generators into the market. Others still will have opted to use exotic (non-vanilla) hedging instruments that modify the risk and return of their business model. And to be sure, some retailer will in fact use only 1, 2 and 3 year futures contracts. None will have made long-dated commitments with the thought in mind that the policy guiding default tariff cap determinations would change materially. In effect, while short run dynamic advocates may not intend to create sub-economic default tariff caps, historic decisions means that following this approach will deliver such an outcome for any market participant with a longer-term planning bias. That a regulators' decision can render otherwise legitimate business practices sub-economic should be of considerable concern to policymakers. It should also be obvious that a consequence of such an approach is to direct retail businesses down a regulatory-induced homogeneous path – hardly an outcome consistent with a competitive and innovative market.

NSW data from 2004-2007 contained in Sections 2 and 4 provided important insights. With known sub-economic tariffs, the competitive market was paralysed with switching rates as low as 5%. Additionally, despite having the most favourable wholesale market conditions for investment of the three east coast states and a looming capacity shortage, requisite new plant NEM was developed outside NSW because front-end integrated cost recovery was intractable, and front-end cash yields *are important* to capital-constrained private firms as Nelson and Simshauser (2012) explain. Following the shift to an *LRMC as floor* approach, switching rates in NSW are now 17% and investment flows in new plant and privatised plant have totalled almost $3 billion.

Ultimately, retail tariff caps can facilitate, or distort, a competitive market. So how should policymakers proceed? First, the objective function of price regulation (as a policy constraint) in retail energy markets needs to be clearly articulated so that the cost consequences of policy uncertainty are minimised. Second, to the extent that it represents a constraint, it is quite essential that policy design is *not* incompatible with the manner in which investment flows are now facilitated. Third, policy design should not incentivise or produce a market full of homogeneous retailers, based on an inflexible benchmark of what constitutes an efficient outcome under a certain set of conditions – this will only serve to stifle innovation and will come at great cost to consumers in the long run, especially those who actively search for competitive deals. Fourth, price regulation in competitive markets should acknowledge that they do not have a secondary objective function of *de facto* hardship policy. Doing so will almost certainly achieve two outcomes; damage competition, and fail to reduce the incidence of genuine hardship. The diversity of tariff offerings in deregulated markets produces better outcomes for vulnerable consumers than in markets where flat regulated tariffs are incumbent. Energy hardship policies are essential, but not via price regulation. And finally, to the extent that residual customer inertia is considered a market imperfection worthy of policy treatment, campaigns to promote customer switching and choice are known to be highly successful and non-distortionary, as New Zealand has aptly demonstrated.

Above all, any energy market policy, as Simshauser (2010b) explains, should be tested against its impact on the investment grade credit of the merchant industry. Absent this "prime asset" the NEM is likely to cease functioning efficiently. Taken together, these policy principles formally rule out the prospect of utilising short run dynamics in setting a price cap in a competitive market. On the other hand, the prevailing approaches to setting default tariff caps in NSW and in South Australia are not inconsistent with these principles

Increasing regulation is certain to damage competition. No amount of short run window dressing or methodological tinkering by regulatory authorities will be able to defy economic gravity for long. Over the long run, price regulation will be distortionary and will not be in the best long term interests of consumers.

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