AXIOM economics

Economic review of electricity generation and retail market issues

A report for Vector

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Executive summary

This report has been prepared by Axiom Economics on behalf of Vector. Its purpose is to provide an independent economic review of certain aspects of the first report into the state of the electricity sector ('the First Report') released by the Ministry of Business, Innovation and Employment's expert advisory panel ('the Panel').[1] Specifically, we have been asked to focus on the Panel's analysis and conclusions in relation to the wholesale and retail sectors, which are dispersed throughout Parts 3 and 4 of the First Report.

Background

Over the last decade, various attempts have been made to examine the state of competition in both the electricity retail and wholesale sectors, including whether market power is present and being exercised. For example, the 2009 Ministerial Inquiry[2] panel (the '2009 Panel') examined a retail margin analysis that had been undertaken by the then Electricity Commission (EC) in 2008. That analysis indicated, amongst other things, that:[3]

- at a national level, average margins[4] for incumbent New Zealand retailers were significantly higher than for their Australian counterparts and exceeded significantly those being earned by newer entrants;[5] and
- the regional data were even more troubling, with only a few network areas found to have margins below 8% (the higher of the levels observed in Australia) and many regions had margins above 12%.

The 2009 Panel concluded that, even allowing for a degree of estimation uncertainty, margins at these levels raised significant concerns about whether competition was acting as an effective restraint on prices.[6] Since that time and the publication of the First Report, no serious attempts were made to examine more closely the trends the 2009 Panel found so disconcerting. Instead, studies have focused on less significant factors, such as movements in retail market shares.[7]

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1 Electricity Price Review, *First Report for Discussion*, 30 August 2018 (hereafter: 'First Report').

2 *Improving Electricity Market Performance Volume two: Appendices,* A preliminary report to the Ministerial Review of Electricity Market Performance by the Electricity Technical Advisory Group and the Ministry of Economic Development August 2009 (see here). (hereafter: 'Ministerial Inquiry Report Volume 2').

3 Ministerial Inquiry Report Volume 2, p.106.

4 The margin referred to here is a net retail margins, i.e., retail earnings before interest and tax, expressed as a percentage of the total bill. *See:* Ministerial Inquiry Report Volume 2, p.104.

5 Ministerial Inquiry Report Volume 2, p.105.

6 Ministerial Inquiry Report Volume 2, p.106.

7 For example, from 2011 to 2015, the Electricity Authority (EA) prepared an annual 'market performance assessment' (the five editions of which are available here). Despite the 2009 Panel's adverse findings with respect to retail margins, these annual assessments did not re-examine the matter. Instead, the EA's analyses of retail markets focused on metrics such as market shares, switching rates and energy price components.

The 2009 Panel also performed an analysis which indicated that, on a nationwide basis, wholesale contract prices had, at times, exceeded the estimated cost of new entry for extended periods (12- to 24 months at a time). That was arguably problematic in and of itself – and not a sound basis to be confident that competition was effective. Indeed, had the analysis been undertaken on average spot prices (rather than contract prices) and/or for narrower geographic areas (such as for nodes prone to pivotal supplier situations) it is possible that very different relationships might have emerged.

In the ensuing years, several more comprehensive studies have been undertaken of the wholesale market, using sophisticated modelling of prices and costs. Many have addressed the perceived shortcomings of the high-profile study of the sector undertaken by Professor Frank Wolak for the Commerce Commission (Commission) in 2009,[8] including its failure to account properly for the opportunity cost of water. For example, the analyses of Browne *et al* (2012),[9] Philpott and Guan (2013)[10] and Poletti (2018)[11] all explicitly incorporate water values, and each detected several billion dollars' worth of market power rents.

Consequently, as at 2009, it is reasonable to state that significant uncertainty surrounded the effectiveness of competition in both the retail and wholesale sectors. And subsequent analyses of the wholesale market coupled with the well-documented trends in retail prices suggest that, when the Panel commenced its current review, it had even more cause to be concerned about potential problems in these markets than its predecessor.

Assessment of the generation market

The Panel's examination of the generation market is quite limited. By way of comparison, the Australian Competition and Consumer Commission's (ACCC's) electricity market inquiry report[12] contained more than 70 pages of in-depth analysis of the Australian wholesale market.[13] In many cases, this is attributably largely to the lack of data available to the Panel.[14] Nevertheless, the upshot is that the potential

8 See: *An assessment of market power in the New Zealand wholesale electricity market*; Frank A. Wolak; Stanford University; 2009, Report prepared for the New Zealand Commerce Commission (available: here).

9 Browne *et al* (2012), 'Simulating market powering in the NZ electricity market', *N.Z.Econ.Pap.46 (1)*, pp.35–50 (available: here) (hereafter: 'Browne *et al*' (2012)').

10 Philpott, A., & Guan, Z. (2013). *Models for estimating the performance of electricity markets with hydro-electric reservoir storage. Technical report*, Electric Power Optimization Centre, University of Auckland (available: here).

11 Poletti, S., (2018). *Market power in the New Zealand wholesale market 2010-2016,* University of Auckland (available: here) (hereafter: 'Poletti (2018)').

12 ACCC, *Restoring electricity affordability & Australia's competitive advantage, Retail Electricity Pricing Inquiry: Final Report,* 11 July 2018, p.59. (hereafter: 'ACCC Final Report').

13 That is the same length as the Panel's entire report, i.e., setting aside the overview and appendices, the First Report is 71 pages.

14 Indeed, the ACCC was able to avail itself of mandatory information gathering powers to obtain material that the Panel will only receive if industry participants provide it voluntarily.

problems highlighted in the various studies undertaken since 2009 have not, in our view, been examined sufficiently. For example:

- neither the net cash flow analysis nor the comparison of contract prices and new build costs establishes that prices and margins are consistent with workable competition, i.e., they cannot be used to rule out market power rents;
- the Panel acknowledges the potential for the exercise of transitory pricing power, and the EA's interpretation and application of the undesirable trading situation (UTS) provisions could serve to exacerbate these problems; and
- the Panel highlights – quite rightly – the importance of hedging instruments in enabling non-vertically integrated generators to compete, but arguably understates the potential shortcomings in the existing price signals.

More work therefore needs to be done before the Panel could conclude reasonably that competition in the wholesale market is workable. Of course, the Panel's ability to undertake those types of analyses will depend to a large degree on the data provided to it by the businesses. Ideally, the Panel would be privy to enough information to enable it to explore crucial matters such as:

- the relationship between average spot prices and either new generation costs or long-run marginal costs (see Appendix A) in more granular geographic locations over time;
- whether generators' margins differ significantly between vertically integrated businesses and those without natural hedges (i.e., without their own retail loads) and/or across geographies – and how those profits have moved over time;
- the number of trading periods in which spot prices exceeded, say, $300/MWh at any node across the country over time;[15,16] and
- offers and average output by technology[17] and the identity of marginal generators in each region over time by location, generator and fuel type.[18,19]

If adequate data are *not* provided to enable the Panel to undertake these types of analyses, it will undermine substantially the review. Irrespective of whether those data are provided, it may be worth considering imposing additional information disclosure requirements on generators and retailers, compelling them to report bespoke margins for their retail and generation operations in a standardised way. This information might be published, or it could simply be provided to the Commission on a periodic basis for monitoring purposes.[20]

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15 ACCC Final Report, p.59.

16 Note that this information is not easily obtainable from the Electricity Market Information (EMI) dataset – it would require significant work to extract.

17 *See for example:* ACCC Final Report, pp.56-57.

18 *See for example:* ACCC Final Report, pp.60-65.

19 again, these data are not readily obtainable from the EMI data service.

20 To that end, we note that the ACCC has recently been given an analogous monitoring role in Australia, whereby it will report periodically on prices and profits throughout the electricity supply chain (see: here).

Assessment of the retail market

The Panel has identified several potentially significant problems in the retail market. First and foremost, it rightly highlights the 'two-tier' market structure and the potential adverse effects this can have for both efficiency and equity. The two-tier dynamic may provide opportunities for established retailers to earn excessive profits from their disengaged customer bases – a group in which vulnerable consumers are likely to be overrepresented. This is consistent with the retail margin analysis performed by the EC in 2008, which indicated that incumbent retailers' profits were very high. Other potential problems include:

- the seemingly low levels of liquidity in the hedging market noted above – the resulting problems apply equally to retailers and generators, and may raise barriers to entry and expansion in both markets;
- the design and application of conditional discounts, which will almost inevitably result in passive, vulnerable customers being penalised disproportionately for costs that retailers are not, in fact, incurring; and
- the unexplained upward trajectory of retail costs, a trend that does not comport with what one might typically expect to observe in a market if competition is working effectively.

This suggests there is enough basis for the Panel to consider policy interventions targeted at improving retail market outcomes. The least interventionist approach would be to seek to improve the awareness amongst disengaged customers of the options available to them and the magnitude of the potential savings on offer. While potentially worthwhile, the main problem with such initiatives is that they may have only a small effect on any underlying problem. Recent experience in both the United Kingdom (UK) and Australia suggests that these strategies have had only a very limited impact on the level of customer engagement in each location.

Another lighter-handed initiative would be to limit the size of conditional discounts – especially prompt payment discounts – to the size of the potential savings. Such a step would ensure that disengaged and/or vulnerable customers are not being penalised disproportionately for costs that retailers are not, in fact, incurring when those conditions are not met (e.g., when payments are late). The ACCC has recommended precisely this intervention in Australia.

A further option would be to run 'auctions' for disengaged customers to offer other retailers the opportunity to serve them. Although this would clearly constitute a significant intervention it would be 'market-based'. If designed well, the process could enable disengaged consumers to benefit from competition without incurring the costs of searching and switching whilst, ideally, limiting any unintended consequences. It would consequently be less 'heavy-handed' than, say, introducing regulated retail price caps. The effectiveness and practicality of the initiative could also be tested by running small-scale pilots.

1. Introduction

This report has been prepared by Axiom Economics on behalf of Vector. Its purpose is to provide an independent economic review of certain aspects of the first report into the state of the electricity sector (the First Report) released by the Ministry of Business, Innovation and Employment's expert advisory panel (the Panel).[21] Specifically, we have been asked to focus on the Panel's analysis and conclusions in relation to the wholesale and retail sectors, which are dispersed throughout Parts 3 and 4 of the First Report.

The remainder of this report is structured as follows:

- in **section two** we provide some background on the various attempts that have been made to examine the state of competition in both the electricity retail and wholesale sectors, and explain why the Panel had cause to be concerned about both when it commenced its review;
- in **section three** we examine the Panel's assessment of the generation market and explain why it does not contain the types of analyses required to reach reliable conclusions about the state of competition – we then suggest some potential areas for further work; and
- in **section four** we review (and largely concur with) the various problems that the Panel identifies in the retail market, including its 'two-tier' structure – we then describe some potential policy initiatives for addressing those issues that the Panel may wish to consider.

We have also included additional material in two more detailed appendices. **Appendix A** contains an explanation of the relationship between short-run marginal cost (SRMC), long-run marginal cost (LRMC) and new investment in workably competitive energy-only generation markets. And **Appendix B** provides a more detailed account of two potential ways in which disengaged customers might be 'auctioned' to competing retailers, based on precedents from the UK and the Electricity Authority (EA).

21 Electricity Price Review, *First Report for Discussion*, 30 August 2018 (hereafter: 'First Report').

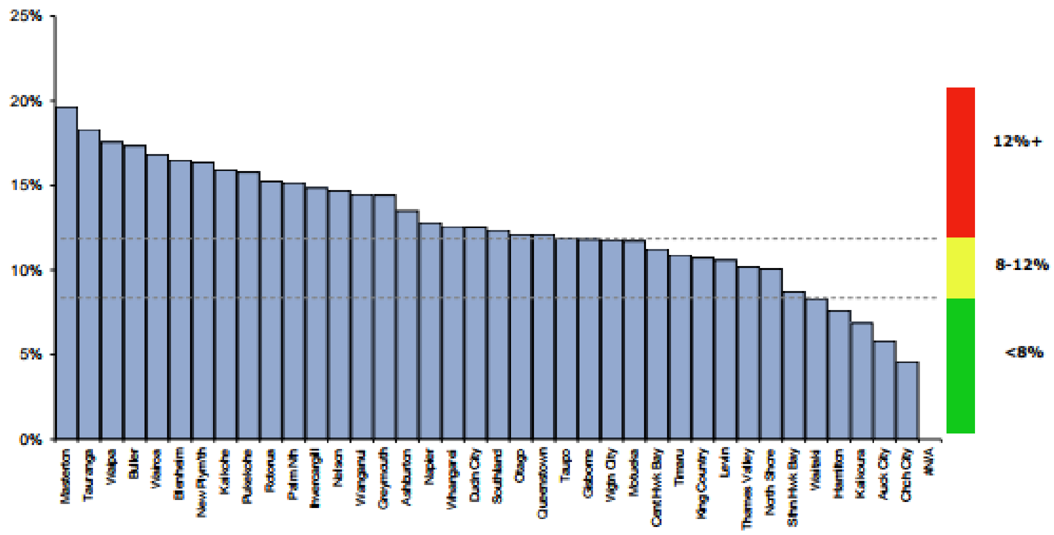
2. Background

Over the last decade, various attempts have been made to examine the state of competition in both the electricity retail and wholesale sectors, including whether market power is present and being exercised. We recap those studies below, including the potential problems that have been identified in each market. We then set out what we consider to be the key implications for the Panel's current work.

2.1 Findings of the 2009 Panel

A logical place to start is the work of the Panel's predecessor – the 2009 Ministerial Inquiry Panel[22] (the '2009 Panel'). The 2009 Panel examined a retail margin analysis that had been undertaken by the then Electricity Commission (EC) in 2008. That analysis indicated that, at a national level, average margins[23] for incumbent New Zealand retailers were significantly higher than for their Australian counterparts and exceeded significantly those being earned by newer entrants.[24] The regional data were even more troubling. Only a few network areas were found to have margins below 8% (the higher of the levels observed in Australia) and many regions had margins above 12%, as Figure 2.1 illustrates.

Figure 2.1: Estimated margins for incumbent retailers by network



Source: Ministerial Inquiry Report Volume 2, p.106 (see: here); Electricity Commission analysis.

Seeing margins at these levels unsurprisingly prompted questions about whether retail competition was functioning effectively. The 2009 Panel noted that it was

22 *Improving Electricity Market Performance Volume two: Appendices,* A preliminary report to the Ministerial Review of Electricity Market Performance by the Electricity Technical Advisory Group and the Ministry of Economic Development August 2009 (see here). Hereafter: 'Ministerial Inquiry Report Volume 2'.

23 The margin referred to here is a net retail margins, i.e., retail earnings before interest and tax, expressed as a percentage of the total bill. *See:* Ministerial Inquiry Report Volume 2, p.104.

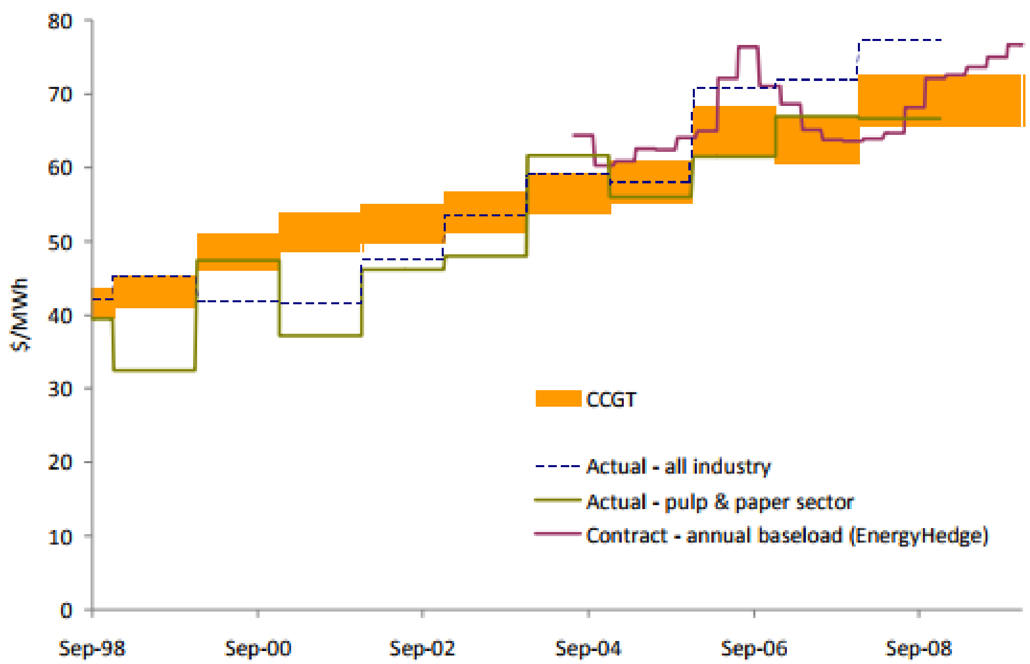
24 Ministerial Inquiry Report Volume 2, p.105.

possible that the wide regional variations in margins could stem from cost differences – but it ultimately dismissed that potential explanation as unlikely. It also observed that, if that had indeed been the key driver, it raised the issue of whether competitive pressures in the retail sector were strong enough to drive efficiency improvements. Overall, the 2009 Panel concluded that:[25]

> *'Even allowing for a degree of estimation uncertainty, margins at these levels raise significant concerns about whether competition is acting as an effective restraint on prices.'*

The examination of wholesale margins also provided relatively little solace. The 2009 Panel compared nationwide estimates of the cost of new entry to prevailing contract prices. The rationale presumably being that, in a workably competitive market, one would not expect to see prices exceed the cost of building new plant for prolonged periods, since this should prompt entry and expansion, driving profits back down to so-called 'normal' economic levels. Figure 2.2 illustrates what the 2009 Panel found.

Figure 2.2: Contract prices vs. cost of new generation



Source: Ministerial Inquiry Report Volume 2, p.94 (see: here).

The 2009 Panel concluded that contract price indicators and estimated new build costs had followed a broadly similar track through time, but that there had been periods when prices had risen above (and fallen below) entry costs for 12- to 24-months.[26] On that basis, it concluded that there was not clear evidence of 'persistent overshooting' or of market power problems in the wholesale sector. However, in our opinion, there were at least two potential limitations with the Inquiry panel's empirical assessment.

25 Ministerial Inquiry Report Volume 2, p.106.

26 Ministerial Inquiry Report Volume 2, p.94.

First, the analysis was at a relatively 'high level' – i.e., nationwide – and on contract prices. The picture might have been quite different if the exercise had been undertaken on, say, average spot prices, which might be affected more acutely by the exercise of short-term pricing power (e.g., periods where nodal prices might exceed, say, $1,000/MWh). Instead, the 2009 Panel implicitly assumed equivalence between contract prices and spot prices.

On its face, that assumption was not unreasonable. In theory, contract prices should reflect forward-looking expectations of average future spot prices, i.e., there should be a symbiosis between the two.[27] However, it is not obvious whether that relationship would be 'ironclad' if the wholesale market exhibited, say, large unpredictable price spikes. For example, if such spikes had been larger – or occurred with greater frequency – than anticipated or, alternatively, if they could not easily be factored into forward-looking assessments, then contract prices could have been *below* average spot prices, changing the picture presented in Figure 2.2.

The outcome might also have changed if the assessment had been undertaken for more granular geographies. The analysis assumed implicitly that the relevant market was nationwide, i.e., that there is a single national generation market. However, in our view, it is at least plausible that the North and South Islands might constitute separate economic markets, i.e., that a 'hypothetical monopolist' in the South Island would find it profitable to impose a 'small but significant non-transitory increase in price'.[28] There might also have been certain nodes prone to 'pivotal supplier situations' (a scenario we explore in more detail subsequently) that may have been worthy of specific attention.

Second, even the nationwide data raised some questions. For example, it is not immediately clear that 12 to 24-months is a reasonable period for prices to have exceeded the cost of new entry in an ostensibly competitive wholesale market, given its underlying economics characteristics. When new generation capacity is added – particularly base-load or mid-merit capacity – it is typically in large 'lumps', i.e., a big new thermal plant or a new wind farm. This has potentially important implications for the relationship between prices and the cost of new entry that one might expect to observe if competition is effective.

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27 Specifically, the price of hedge contracts is determined primarily by the balance of expectations as to the level and volatility of future wholesale spot price outcomes. If this were not the case – and the price of hedges was out of line with expectations of future spot prices – then profitable arbitrage opportunities would arise to close the gap.

28 The process of defining the boundaries of an antitrust market involves establishing the smallest area of product, functional and geographic space within which a hypothetical profit maximising monopolist could successfully impose a small but significant and non-transitory increase in price (a 'SSNIP'), usually of 5-10%. A SSNIP is only feasible when all current and potential sources of close substitutes for the firm's products have been included in the definition of the market. If, following an attempted SSNIP, consumers would be expected to switch their demand to close substitutes and/or alternative suppliers would enter the market and serve large volumes of the hypothetical monopolist's sales, the exercise would not prove profitable. In that circumstance, the definition of the relevant market would need to be expanded to encompass those services of either the demand-side or supply-side substitute. The exercise is repeated until a SSNIP *is* profitable, thereby suggesting that all relevant substitutes have been encapsulated.

Specifically, when new generation is added to the market (or, at least, new base-load or mid-merit plant), this should reduce the SRMC of supplying wholesale electricity from prevailing levels, which should then be reflected in average spot and, in turn, contract prices.[29] Moreover, if that new generation results in there being ample capacity (albeit in the substantial majority of trading periods) for an extended window, the ongoing SRMC of supply should remain at relatively low levels for a sustained period. Specifically, SRMC – and spot prices – should arguably then be below the cost of new entry for a significant window following a lumpy new generation investment.

Then, if the supply/demand balance tightens (e.g., if demand grows over time) and periods of scarcity become more common, the SRMC of supply might start to rise. In time, the SRMC of meeting (and curtailing) demand with the existing generation fleet should grow to be equal to or more than the cost of building new plant. At that point, in a competitive market, one would expect more new generation investment to occur. One might therefore expect that new 'lump' of investment to result in the SRMC again dropping back below the cost of building new plant for another extended period. But that is arguably not what Figure 2.2 shows.

For example, from 2002 to 2008, the wholesale contract price was comparable to – and often above for prolonged periods – the estimated cost of building new plant. For the reasons set out above, we are not as confident as the 2009 Panel that this is necessarily symptomatic of effective wholesale market competition. In our opinion, one could observe the relationship seen in Figure 2.2 and there might still be a market power problem. Indeed, as we explain below, several more comprehensive studies of the wholesale market undertaken since that time have estimated *substantial* market power rents.

2.2 Subsequent analyses of the retail market

Between 2009 and the publication of the First Report there was no serious attempt to 'drill-down' further into the retail margin analyses that the 2009 Panel found so disconcerting. From 2011 to 2015, the EA did prepare an annual 'market performance assessment'.[30] However, despite the 2009 Panel's adverse findings with respect to retail margins, these annual assessments did not re-examine the matter. Instead, they focused on issues of less significance, including, for example:

- Movements in market share indices such as concentration ratios and the Herfindahl Hirschman index (HHI). The EA observed that the market shares of incumbent retailers were falling, while new entrants' shares were growing. However, there were several limitations with the EA's metrics, as well as with retail market share statistics as an explanatory tool more generally; namely:

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29 See Appendix A. For an even more detailed account of the relationship between short- and long-run marginal costs in electricity wholesale markets, *see:* Green et al, *Potential Generator Market Power in the NEM*, A Report for the AEMC, 22 June 2011 (available: here).

30 The five editions of this assessment are available: here.

- The concentration ratios and HHIs were based on each retailer's share of total 'installation control points' ('ICPs'), i.e., customer numbers. Quite a different picture might have emerged had market shares been reported based on, say, shares of total retail revenue. If a new entrant had won, say, 5% of ICPs, but they were primarily 'low value' customers, its revenue share might have been much smaller, e.g., 1%.[31]
- The indices reflected nationwide market shares. Completely different patterns might have emerged if the shares had been measured on a regional basis. Indeed, the EC's analysis in 2008 revealed that retail margins were estimated as exceeding 12% in some network areas, suggesting that any problems might manifest only in certain geographic pockets.
- More fundamentally, any measures of market share – and movements thereof – are insufficient in themselves to establish whether a market is characterised by effective competition. Market power problems can still arise even at moderate levels of concentration, which is why competition agencies typically place limited weight on this factor when adjudicating upon mergers and acquisitions.[32]

▪ Switching rates, which measure the proportion of customers that change electricity retailers in a year. The EA noted that switching rates were relatively high by international standards. However, like market shares, switching rates do not reveal all that much about the state of competition in a market in isolation. For example, if the rate of switching increases from, say, 15% to 40%, is that a good or a bad thing? Could it simply reveal that more customers are dissatisfied with their retailers? Moreover, there are potentially more important matters to consider than the bare switching statistics themselves, such as:

- When are customers switching and why, e.g., what proportion of customers switch at the end of their contracts as opposed to 'mid-term' and how many churn simply because they have moved house, and so on?
- What type of customers are switching, e.g., is it only a sub-set of customers – say, low-value customers – that are actively engaging, leaving a relatively disengaged base of high-value customers for incumbent retailers to 'milk', so to speak, creating a 'two-tier' market dynamic (a point we return to later)?

▪ Movements in the energy price components (i.e., excluding the distribution and transmission network costs) of final retail tariffs. Namely, the EA found that, from 2011 to 2015, these components increased more slowly than retailers' costs. It therefore concluded that competitive pressure had limited retailers' ability to

31 To use an example from another industry: Ferrari has considerably fewer worldwide customers than say, Toyota, i.e., its global share of 'customers' is very low. However, your average Ferrari customer spends substantially more on a car than your typical Toyota customer, e.g., a Ferrari 458 might retail for NZ$500,000, whereas a Toyota Corolla might sell for, say, NZ$25,000, i.e., 5% of that sum. As such, Ferrari's share of global total sales revenue would be considerably greater than its annual share of customer numbers.

32 See for example the Commerce Commission's merger and acquisition guidelines: Commerce Commission, *Mergers and Acquisitions Guidelines*, July 2013, p.30 (available: here).

'pass-through' underlying cost increases to consumers. This analysis was flawed for two reasons:

- In workably competitive markets, increases in input costs should be *fully* passed-through to consumers[33] – it is usually only when competition is *less* than effective that cost pass-through is incomplete,[34] i.e., if the EA's analysis was correct, it is more likely to support the *opposite* conclusion to the one that it reached.
- It did not reveal whether the *absolute values* of those energy price components contained excessive profits, e.g., if there were excess profits embedded in the prices at the start of the time-series, and those prices then changed at a rate broadly commensurate with input cost movements, then they would have *continued* to surpass competitive levels through time.[35]

In short, although some of the matters examined by the EA in its analyses could, in some cases, have provided some useful insight into the state of retail competition, their overall explanatory power was rather limited. Importantly, the absence of any comprehensive assessment of retail profitability in the ensuing years meant that, when the current Panel was formed, there was no cause to discount the significant concerns that had been expressed by the 2009 Panel regarding the margins observed during the prior review.

2.3 Subsequent analyses of the wholesale market

Since 2009, more empirical analysis has been undertaken of the wholesale market than the retail market. The first source of analysis worth highlighting concerns the high-profile study of the wholesale market undertaken by Professor Frank Wolak for the Commerce Commission (Commission) in 2009.[36]

Professor Wolak compared wholesale spot market prices from 2001 to mid-2007 with his estimate of a 'competitive benchmark' price – which reflected primarily SRMC – and concluded that market power rents were present. That work pre-dated (and, in part, prompted) the 2009 Ministerial Inquiry. However, upon closer

33 Specifically, if competition is effective, prices should reflect the underlying costs of supply, including a reasonable, risk-adjusted return on capital. It follows that, in the absence of significant impediments to price changes, 100% of an input cost increase should be passed-through to retail prices to ensure normal returns (zero economic profits) over the longer-term.

34 For example, a monopolist's price will almost never reflect its underlying cost of supply. It will instead set its price based on the willingness of its customers to keep buying its product as it gets more expensive. Specifically, it will restrict output, raising its price *above* the cost of supply, thereby earning 'above-normal' returns (or positive economic profits), even in the long-run. This means that, when its input costs increase, it *cannot* fully pass-through those costs to final customers – because it has already been setting an 'above-cost' price. Mathematically speaking, in the strict case of 'pure monopoly' facing a linear demand curve, where the firm was previously charging the monopoly price, it will only be able to pass-through *half* of any input cost increase.

35 For example, if applied to a monopoly price, such an analysis would not reveal any problems.

36 See: *An assessment of market power in the New Zealand wholesale electricity market*; Frank A. Wolak; Stanford University; 2009, Report prepared for the New Zealand Commerce Commission (see: here).

scrutiny, several limitations were identified – including a failure to account properly for the opportunity cost of water, a key component of the costs of hydro generation.

Given the raft of adverse commentary that Professor Wolak's report attracted, it is perhaps unsurprising that the 2009 Panel decided ultimately to largely ignore its findings. However, since the release of that report and the immediate aftermath, others have revisited Professor Wolak's approach and sought to address the various criticisms. For example, Browne *et al* (2012) constructed a model that sought to overcome some of the limitations in that earlier work. Their analysis yielded results that were broadly consistent with Professor Wolak's, i.e., they detected 'market power rents'. Specifically, the authors concluded:

> *'Our analysis finds* ***substantial market power*** *in the New Zealand electricity market. Across the two years we analyse, we estimate total market rents at $2.6 billion …*
>
> *…in our view, it would be very difficult to accurately model prices in the New Zealand Electricity Market without allowing for some market power, even after accounting for the opportunity costs for water.'* [emphasis added]

The subsequent work of Philpott and Guan (2013)[37] reached a very similar conclusion. They used a stochastic programme to estimate counterfactual 'competitive benchmark' water values and reported market rents as well as productive inefficiency of actual dispatch compared to the hypothetical competitive level. For the year 2005, they calculated market power rents of $935.4 million – an estimate that resembled very closely the analogous figure calculated by Professor Wolak in his study ($950.7 million).

Most recently, Poletti (2018)[38] compared wholesale market outcomes with a competitive market benchmark,[39] factoring in water values and hydro dam water level data. He estimated market power rents of $6 billion in the seven years from 2010 to 2016. These rents are therefore similar or even higher, as a fraction of revenue, to those found by Professor Wolak. In summing up his results, Dr Poletti offered the following observations about the critiques that had been made of Professor Wolak's work and their relevance:[40]

> *'Many of the critiques of the Wolak report are in our view tenuous and are used to justify the prevailing market arrangements. In particular, no attempt is made to quantify the market impact of the critiques. Instead they are used to dismiss the Wolak findings in their entirety. Our methodology, which uses fitted water values and demands dynamic consistency in the lake levels over the course of the year for the benchmark and market power simulations, directly addresses the substantive critique of the report. In our view the other critiques are not substantial. Nonetheless they are mostly taken into account by our methodology, which*

37 Philpott, A., & Guan, Z. (2013). *Models for estimating the performance of electricity markets with hydro-electric reservoir storage. Technical report*, Electric Power Optimization Centre, University of Auckland (see: here) (hereafter: Poletti (2018)).

38 Poletti, S., (2018). *Market power in the New Zealand wholesale market 2010-2016,* University of Auckland (see: here) (hereafter: 'Poletti (2018)').

39 He also compared the competitive benchmark to the prices simulated by the computer agent-based firms trying to maximise profits. This approach yielded similar market power rents to the comparison with actual market outcomes.

40 Poletti (2018), p.43.

calculates market power as the difference between competitive and simulated prices, which nets out to a large extent any errors in marginal cost estimations.'

Another source of subsequent analyses of the wholesale market has been the EA's annual market performance assessments – of which five editions were released between 2010 and 2015. These publications included a series of analyses of generators' incentives and abilities to engage in unilateral strategic conduct. For instance, the EA sought to estimate the frequency with which generators found themselves 'net pivotal' in the market (i.e., in a position where projected demand could not be met without their generation capacity, enabling them to create 'artificial scarcity' and engineer price increases – of potentially considerable magnitudes).[41]

These assessments suggested that, from 2010 to 2015, there was only a small number of generators – usually Meridian and Genesis – that found themselves in positions to substantially 'ramp up' their wholesale bids if they were so inclined, safe in the knowledge that they would still be called upon to run. Moreover, this scenario occurred in only a small number of trading periods – around 1.5% of the total in 2015. However, as useful as this analysis was, it did not establish either that wholesale margins were reasonable, or that competition was effective. There are several reasons for this, including:

- The nature of wholesale electricity markets means that a generator only needs to find itself in a 'net pivotal' situation a few times to be able to increase its returns well above the cost of new entry through *unilateral* action (i.e., without also relying upon an accommodating/concerted response from other generators – see below), if it elects to do so. For example, although 1.5% of trading periods might not seem like a lot, in truth, it is material, i.e., it may be more than enough to give rise to substantial problems if generators act on those opportunities.[42]
- The EA did not examine the potential for the *coordinated* exercise of substantial market power, which could also result in prices above competitive levels. The wholesale market is essentially a 'repeated game' and, through those ongoing interactions, it is conceivable that some of its participants might have found ways to coordinate their conduct in ways that result in higher prices, e.g., by each potentially spilling water over and above the amounts necessary for operational purposes to reduce their future capacity – and, in the process, increasing wholesale prices.

For those reasons, prior to the release of the First Report, questions also remained about the degree of competition in the generation market, including whether margins were reasonable. Most notably, subsequent analyses had indicated that

[41] *See for example:* Electricity Authority, *Electricity Market Performance, 2015 Year in Review,* p.51 (see: here).

[42] Given the magnitude of potential spot prices during 'net pivotal' situations (e.g., prices of $10,000/MWh or more), a small number of periods of very high spot prices during, say, colder winter months could have a very large effect on the average annual spot price over the long run. For a more detailed examination of the potential exercise of market power in wholesale electricity markets, see: Green et al, *Potential Generator Market Power in the NEM*, A Report for the AEMC, 22 June 2011 (available: here).

Professor Wolak's conclusions regarding the existence of substantial market power, whilst discounted at the time, could not be dismissed so readily. Furthermore, although the EA explored various strategic incentives in recent years (including the incidence of 'net pivotal' trading periods), it neither sought to compare prices and costs at a granular level, nor explored fully the potential for market power to be exercised in other ways, e.g., through tacit coordination.

2.4 Implications

The 2009 Panel found that retail margins often exceeded the levels that might be expected to prevail in a well-functioning, effectively competitive market over the long-term. It also estimated that, on a nationwide basis, wholesale contract prices had, at times, exceeded the estimated cost of new entry for extended periods. That may have been problematic in and of itself – and if the analysis had been undertaken on average spot prices and/or for narrower geographic areas it is possible that other issues may have emerged. Consequently, as at 2009, it is reasonable to state that significant uncertainty surrounded the effectiveness of competition in both the retail and wholesale sectors.

Subsequent analyses did little to assuage those concerns – quite the opposite, in fact. Little substantive analysis was undertaken of the retail sector and several more comprehensive assessments of the wholesale market estimated substantial market power rents. It follows that, when the Panel commenced its review, it arguably had even more cause to be concerned about potential problems in both the retail and wholesale markets than its predecessor. In the following sections, we therefore examine the analysis presented in the First Report and consider whether it provides a sufficient basis from which to garner conclusions about the state of competition in the wholesale and retail markets and to develop policy responses.

3. Assessment of the generation market

The Panel states that strong competition is the vital ingredient in an efficiently operating generation market.[43] We agree. Unfortunately, in our view, the First Report does not contain the types of analyses required to reach reliable conclusions about the degree of competition in the wholesale market. By way of simple comparison, the ACCC's Final Report contained more than 70 pages of in-depth analysis of the wholesale market specifically. That is the same length as the Panel's entire First Report.[44]

That is not always the fault of the Panel. It can in many cases be attributed to a lack of data. Indeed, the ACCC was able to use its information gathering powers to obtain material that the Panel will only be able to receive if industry participants provide it voluntarily. Nevertheless, the upshot is that the potential issues highlighted in the various studies of the wholesale market undertaken since 2009 (e.g., in Browne *et al* (2012), Philpott and Guan (2013) and Poletti (2018)) are not explored sufficiently in the First Report, as we explain below.

3.1 Pricing and profitability

One of the most important indicators of the degree of rivalry in a market is whether prices and margins are consistent with what one would expect to observe under conditions of workable competition – a topic that is addressed in more detail in Appendix A. The First Report contains two key quantitative analyses of wholesale market outcomes in this respect, which we examine in turn.

3.1.1 Analysis of net cash flows

The first empirical exercise presented in the First Report is an analysis of generators' and retailers' net cash flows (as such, the following observations apply equally to the retail sector).[45] Unfortunately, this assessment provides no useful insights into the state of competition in either sector. The following acknowledgement in the accompanying Technical Paper is very telling:[46]

> *'…a comprehensive assessment would require detailed information on the capital and operating costs for generation and retailing activities. This data was not available* [sic].*'*

Without detailed information on capital and operating costs, it is all but impossible to undertake a robust analysis of generation and retailing margins – and so it has proved in this instance. The Panel's efforts to press ahead despite the dearth of information is admirable but, despite those endeavours, the resulting assessment

43 First Report, p.31.

44 Setting aside the overview and appendices, the First Report is 71 pages.

45 First Report, Figure 20.

46 Electricity Price Review, *Technical Paper to accompany first report*, p.7.

provides no indication of whether generators' or retailers' profits are either reasonable or excessive.

Even in the best of circumstances, an assessment of net cash flows over time does not provide any real indication of whether returns have exceeded the levels one would expect to observe in a workably competitive market. That is because such an exercise is incapable, in isolation, of demonstrating whether:

- either generation or retail prices have exceeded significantly – and sustainably – the LRMC of supply; or
- retail or generation returns have been systematically above the weighted average cost of capital (WACC) required by generators and retailers, given the risks associated with providing their services.

Moreover, the analysis contained in the First Report only illustrates how the overall levels of net cash flows have moved over time. There is nothing meaningful to be gleaned from this assessment regarding the prevailing state of rivalry between retailers, because:

- the Panel presents no evaluation or views regarding the levels it would expect net cash flows to be in a competitive market, e.g., there is no benchmarking against international markets or anything of that ilk; and
- as such, even though the overall level of net cash flows has remained relatively constant since around 2004/05, that does not rule out the possibility that the businesses in question have been earning excessive returns.

Compounding matters, the cash-flow assessment itself exhibits numerous other shortcomings that mean the data themselves are not reliable – again due to a paucity of information. For example, the Panel acknowledges that:

- the analysis does not distinguish between retailing and generation – it is a combined metric, which diminishes further its relevance;
- some of the data include cashflows from gas retailing in New Zealand and generation or retail investments in Australia – both of which are irrelevant; and
- no data exist for the period from 1999-2002.

The upshot is that, although the Panel has found no evidence that generator-retailer profits are excessive, there is also no evidence that they are not. Until more data are provided, it will not be possible to know one way or the other.[47]

3.1.2 Comparison of contract prices and new entry costs

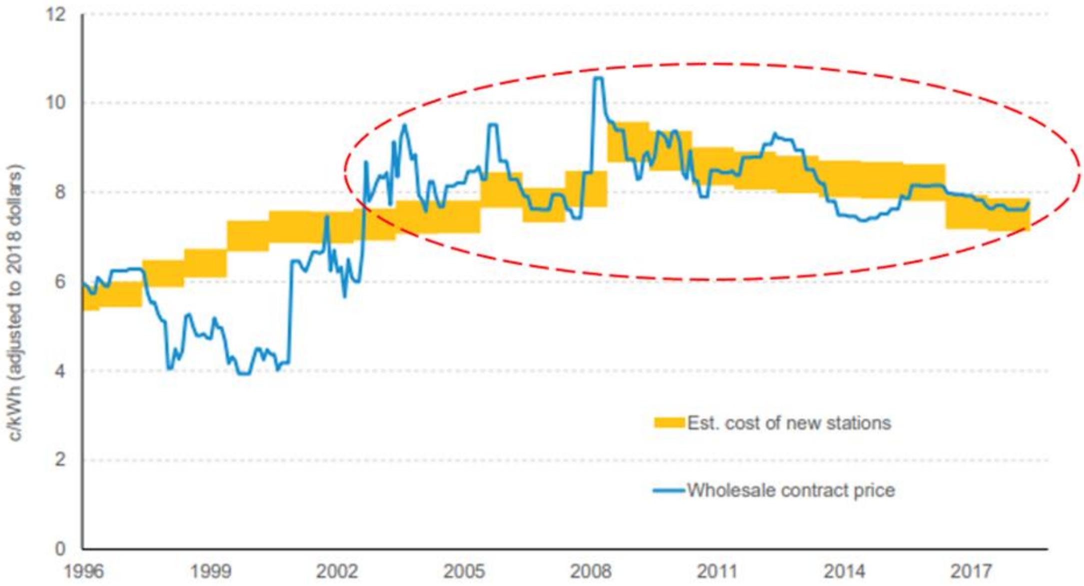
The second quantitative analysis presented by the Panel is an updated version of the comparison between contract prices and new generation costs that was undertaken by its predecessor, i.e., the 2009 Panel (see Figure 2.2 above). The Panel concludes that, because contract prices and new build costs have tracked one another

[47] We provide some additional observations on these data availability issues when we set out our conclusions below.

reasonably closely over time, competition appears to have been effective in constraining wholesale prices. However, this analysis exhibits the same limitations as the 2009 assessment, which we described earlier.

First, Figure 3.1 illustrates that,[48] since 2002, contract prices have been comparable to – and often exceeded – estimated build costs. As we explained previously, given the economic characteristics of generation (i.e., its 'lumpiness'), one might have expected to see more sustained periods of contract prices *below* this level if competition was working effectively. At the very least, the relationship observed in Figure 3.1 does not constitute a sound basis for ruling out the existence of any market power problems.

Figure 3.1: Contract prices vs. cost of new generation



Second, the analysis is again undertaken only at a highly aggregated level – and with contract prices. It therefore remains to be seen how the picture depicted in Figure 3.1 might change if the exercise was undertaken using average *spot* prices, which might be affected more acutely by the exercise of short-term pricing power (e.g., periods where nodal prices might exceed, say, $1,000/MWh). Additionally, the outcome might change further if the analysis was undertaken for more granular geographies, e.g., at nodes more prone to pivotal supplier situations.

3.1.3 Implications

To summarise, the Panel's assessments of wholesale pricing and profitability reveals little about the current state of competition. The assessment of net cash flows is, as the Panel effectively concedes, not probative. And, in our opinion, the highly aggregated comparison of contract prices and new build costs does not demonstrate that competition has been effective at restraining prices. Put simply, neither analysis can be relied upon to rule out the existence of substantial market power problems.

48 This is a slightly modified version of Figure 14 from the First Report.

3.2 Transitory pricing power

Despite concluding – without sufficient basis, in our view – that competition has been effective at constraining wholesale prices, the Panel did observe that generators have exercised *transitory* market power by sharply raising prices in the spot market for brief spells.[49] It also noted that:[50]

- the threat of new investment does not restrain prices in these situations; and
- the short-term contracts market can act as a form of insurance against such exposure, making it important that it functions effectively.

We agree on both counts. However, there is another potentially important factor that the Panel might have explored. Specifically, in our view, the way the EA has historically interpreted and enforced the Undesirable Trading Situation (UTS) provisions risks exacerbating the problems associated with the exercise of short-term pricing power.

3.2.1 Application of UTS provisions

A UTS is defined as an extraordinary event which threatens, or may threaten confidence in, or the integrity of, the wholesale market that cannot be resolved under the Code. The most high-profile – and controversial – UTS proceedings have typically involved scenarios in which a generator has found itself pivotal in a region and acted upon the ensuing opportunity to substantially increase its bids and the resulting wholesale price.[51]

One such example was Genesis' bidding conduct on 26 March 2011, when it found itself in a pivotal supplier situation within the Waikato area. That conduct caused spot prices to reach approximately $20,000/MWh over several hours in Hamilton, and regions north of Hamilton, when the national grid operator, Transpower, closed part of the grid to upgrade its lines into Auckland.[52] This was deemed subsequently by the EA to be a UTS.

However, Genesis' conduct was *not* found subsequently to be in breach of any applicable rule or law. Rather, it was the *market outcome* that was found to be unacceptable. Specifically, Genesis' behaviour was found not to constitute manipulative trading activity and it was also deemed to be consistent with managing its own internal risk positions. In response:

- The EA proposed to reset offer prices for 26 March at levels reflecting the cost to purchasers of alternative sources of supply or the cost of curtailing demand. These were the estimated costs purchasers would have incurred to avoid the very high spot market prices had they received accurate price forecasts.

49 First Report, p.33.

50 *Ibid*.

51 A generator is 'pivotal' when it is not possible for total demand in a region to be met without the generation output of that plant.

52 For further details see: here.

- The EA then ultimately set the prices at $3,000/MWh. It believed that this would address the UTS, while preserving incentives for electricity purchasers to hedge their risks from exposure to spot prices. These actions were subsequently upheld by the High Court on appeal.

In other words, this 'market conduct-focussed' approach led the EA to, in effect, apply a retrospective price cap (an approach that was affirmed on appeal). Following the Genesis UTS proceeding, the EA amended the *Electricity Industry Participation Code* (the Code) to include explicit provisions relating to pivotal supplier situations. Criteria were introduced to convey to market participants how they can remain in a 'safe harbour' in such scenarios, thereby avoiding a regulatory response. To qualify for a safe harbour, a generator must:[53]

- offer all its available capacity – energy and reserve – that is able to operate in a trading period;
- act to submit, revise, or withdraw an energy or reserve offer in a timely manner after receiving the information that triggered this action; and
- when it finds itself in a pivotal position, either:
  - prices and quantities in its offers do not result in a material increase in the price in the region where it is pivotal (assessed by comparing prices in the immediately preceding trading period or another comparable trading period in which it was not pivotal);
  - its offers when pivotal are generally consistent with its offers when not pivotal; and
  - it derives no financial benefit from an increase in the price in the region where it is pivotal.

However, the existence of these safe harbour provisions did not discourage Meridian from taking advantage of a net pivotal position to sharply increase spot prices in the South Island on 2 June 2016. When faced with a peak shortage in the North Island – and attendant exposure to its retail load – Meridian submitted bids for its South Island generation units that caused spot prices to reach as much as $4,000/MWh.

This conduct – and the resulting increase in spot prices – prompted retailer Electric Kiwi to allege a UTS had occurred.[54] However, the EA determined subsequently that a UTS had *not*, in fact, taken place – and the prevailing spot prices were permitted to stand. In reaching its decision, the EA stated that:[55]

> *'Meridian's offer behaviour was not an unusual response for a market participant facing the risk of financial loss as a result of the tight and uncertain market conditions that existed in the North Island over the relevant trading periods. There is evidence that a similar approach*

[53] Electricity Authority, *Improving the efficiency of prices in pivotal supplier situations*, 4 June 2014, pp.2-3.

[54] For further details, see: here.

[55] Electricity Authority, *The Authority's decision on claim of an undesirable trading situation; Electric Kiwi's claim in relation to trading periods 35-40 on 2 June, Final Decision*, 6 July 2016 (available: here).

is also used by other industry participants to manage the risk of financial loss when faced with similar scenarios of basis (or locational) price risk. That this type of offer behaviour has occurred regularly in the past, without creating a UTS, suggested that the behaviour alone was not sufficient to warrant a UTS finding.'

In other words, the EA determined that it was acceptable for Meridian to engage in trading behaviour that, in effect, took advantage of its pivotal position to create a shortage in one location to cover its retail exposure in another. In our opinion, it is questionable whether such conduct would be permitted in, say, the context of a financial market. We note for example that, in a recent presentation to the EA's Market Development Advisory Group (MDAG), Mr Colin Magee of the Financial Markets Authority explained that:[56]

'Trading which created a shortage in one market in order to affect prices in another market would be considered to have an illegitimate purpose, as would trading to push a price up in one market being used to offset losses in another market.'

In our view, the way in which these previous UTS applications have been treated by the EA (and, in the Genesis proceeding, the High Court) does little to dissuade generators from placing very high offers when they find themselves in a pivotal position – even if a UTS is found subsequently to have occurred. This is especially the case if the business in question can point to some form of 'internal risk mitigation' strategy as a potential justification for the behaviour.

3.2.2 Implications

The way the EA has interpreted the UTS proceedings suggests there is little downside to pivotal generators engaging in strategic bidding conduct to engineer short-term price spikes. The 'market-conduct' based approach employed by the EA means the risk of the generator being found in breach of the Code itself is negligible. In all likelihood, the worst thing that might happen is the EA declaring a UTS and retrospectively 'clawing back' some of the resulting financial gains.

Moreover, the Meridian precedent indicates that if a generator can rationalise its bidding conduct by reference to some form of 'risk mitigation' strategy, the EA may determine that no UTS has occurred at all. In our opinion, this is a potentially unwelcome development. It is perhaps for this reason that the MDAG is exploring this matter at present. In our opinion, it would be worthwhile for the Panel to do the same in the next part of its review.

3.3 Vertical integration and contracting

The Panel observes that a new entrant seeking to compete in the generation sector has two choices. The first is to create a natural hedge through an affiliated retail operation to offset its exposure to low spot prices. The second is to remain a 'stand-

56 Market Development Advisory Group, Minutes, Meeting number 6 (available: here).

alone' generation operation and procure reasonably priced financial hedges to cover its risks. There are considerable challenges associated with either approach:

- the first strategy involves entering two markets at once, which raises substantially the costs of entry;[57] and
- the success of the second strategy depends crucially on the performance of the contracts and derivatives market.

It follows that if the contract market is illiquid, thereby exhibiting 'murky' price signals (i.e., wide bid-offer spreads[58]), this can have a substantial adverse impact upon non-vertically integrated generators – many of whom are new entrants. Smaller generators often cite the limited depth of the contract market as the key factor inhibiting their expansion or new entry.[59] To that end, Cumulus Asset Management has observed previously that:[60]

> *'New Zealand stands out to us as having among the lowest levels of wholesale liquidity relative to its size, and one of the highest levels of vertical integration.'*

The Panel points to particular problems that arose during the winter of 2017, when bid-offer spreads spiked as high as 15%.[61] However, the spreads observed *outside* of this window are also high compared to similar markets in other jurisdictions, and to markets for other commodities. For example, Ofgem data on the UK's wholesale electricity market show that spreads for forward contracts typically average 0.5% or less.[62] That is a substantial discrepancy.[63]

For those reasons, in our view, the Panel is consequently correct to single out the contract market as a key area of focus for the next part of its review. We agree that improving the depth and resilience of the contract market is a matter that should be given high priority. Indeed, in our opinion, it is far from clear that the market is performing effectively at present – or at least as well as it could be, given the trends seen overseas.

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57 It is not a simple matter to procure a sufficiently large base of retail customers within a short timeframe – especially given the 'stickiness' exhibited by many disengaged/passive customers (a subject we return to subsequently when we consider the 'two-tier' retail market).

58 Bid-offer spreads are a useful indicator of liquidity, since they indicate the extent to which prices reflect market value. A tight (low) bid-offer spread is likely to indicate there are many participants in the market. Tight spreads should encourage entry, because participants are confident of being able to buy and sell at a fair cost..

59 First Report, p.34.

60 Cumulus Asset Management, *Submission by Cumulus Asset Management on the Consultation paper titled – Hedge Market Development: Enhancing trading of hedge products,* 14 July 2015, p.1. (see: here).

61 First Report, Figure 19.

62 Ofgem, *Wholesale Power Market Liquidity: Annual Report 2016*, Figure 13, p.24 (see: here).

63 This in part reflects the introduction of compulsory market-making obligations in the UK (with regulated bid-offer spreads). However, even prior to the introduction of those obligations, spreads were significantly narrower than in New Zealand.

3.4 Conclusion

The Panel's examination of the generation market is quite limited and provides no basis for it to confident that competition in the generation market is effective. By way of comparison, the ACCC's electricity market inquiry report[64] contained more than 70 pages of in-depth analysis of the Australian wholesale market.[65] In many cases, this is attributably largely to the Panel's lack of data.[66] Nevertheless, the upshot is that the potential problems highlighted in the various studies undertaken since 2009 have not, in our view, been examined sufficiently. For example:

- neither the net cash flow analysis nor the comparison of contract prices and new build costs establishes that prices and margins are consistent with workable competition, i.e., they cannot be used to rule out market power rents;
- the Panel acknowledges the potential for the exercise of transitory pricing power and the EA's interpretation and application of the UTS provisions could exacerbate these problems in the future; and
- the Panel highlights – quite rightly – the importance of hedging instruments in enabling non-vertically integrated generators to compete, but arguably understates the potential shortcomings in the existing price signals.

More work therefore needs to be done before the Panel could conclude reliably that rivalry in the wholesale market is working to constrain prices to competitive levels. Of course, the Panel's ability to undertake those types of analyses will depend largely on the data provided to it by the businesses. Ideally, the Panel will have enough information to explore crucial matters such as:

- the relationship between average spot prices and either new generation costs or LRMC (see Appendix A) in more granular geographic locations over time, consistent with what we described above;
- whether generators' margins differ significantly between vertically integrated businesses and those without natural hedges (i.e., without their own retail loads) and/or across geographies – and how those profits have moved over time;
- the number of trading periods in which spot prices exceeded, say, $300/MWh at any node across the country over time;[67,68] and

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64 ACCC, *Restoring electricity affordability & Australia's competitive advantage, Retail Electricity Pricing Inquiry: Final Report,* 11 July 2018, p.59. (hereafter: 'ACCC Final Report').

65 That is the same length as the Panel's entire report, i.e., setting aside the overview and appendices, the First Report is 71 pages.

66 Indeed, the ACCC was able to avail itself of mandatory information gathering powers to obtain material that the Panel will only receive if industry participants provide it voluntarily.

67 Note that the ACCC presented such an analysis in its Final Report. *See:* ACCC Final Report, p.59.

68 Note that this information is not easily obtainable from the EMI dataset – it would require significant work to extract.

- offers and average output by technology[69] and the identity of marginal generators in each region over time by location, generator and fuel type.[70,71]

If adequate data are *not* provided to enable the Panel to undertake these types of analyses, it will undermine substantially the review. Irrespective of whether those data are provided, it may be worth considering imposing additional information disclosure requirements on generators and retailers, compelling them to report bespoke margins for their retail and generation operations in a standardised way. This information might be published, or it could simply be provided to the Commission on a periodic basis for monitoring purposes.[72]

69 *See for example:* ACCC Final Report, pp.56-57.

70 *See for example:* ACCC Final Report, pp.60-65.

71 Again, these data are not readily obtainable from the EMI data service.

72 To that end, we note that the ACCC has recently been given an analogous monitoring role in Australia, whereby it will report periodically on prices and profits throughout the electricity supply chain (see: here).

4. Assessment of the retail market

The Panel devotes considerable attention to affordability issues throughout the First Report. It emphasises especially the potential adverse consequences associated with the 'two-tier' market structure that has emerged in the retail market. We agree that this and other related issues identified by the Panel, such as the effect of conditional discounts and trends in retail costs, should be of significant concern. In our opinion, the potential efficiency and equity problems that may result warrant scrutiny and, potentially, a policy response of some form. We explore these matters below.

4.1 The 'two-tier' retail market

As the Panel notes, recent wide-ranging and high-profile reviews of the electricity sectors in both the UK[73] and Australia have revealed 'two-tier' markets in which the benefits of retail competition have accrued primarily to 'active' customers. Those customers who are willing and able to spend the time and effort required to review the various retail electricity products on offer can often secure much lower prices than those customers who are not. The Panel has observed a similar trend in New Zealand. In our view, this may give rise to significant problems.

4.1.1 Engaged versus disengaged customers

When a New Zealand electricity retail customer's contract is due to expire, she will typically be sent a letter and/or email from her current retailer, advertising the various products it is currently offering and recommending that she gets in touch. If she does not respond to that overture for whatever reason – i.e., she neither explores the alternative offerings of her current retailer nor looks more broadly at other firms' products (e.g., via the 'what's my number' website) – she will then be rolled-over onto a plan without any fixed term (much like the standard variable tariff[74] in the UK or a 'standing offer'[75] in Australia).

Specifically, each retailer has a plan that does not require a customer to agree to a 'fixed term', or to prices that are locked-in for a period (typically from 12- to 24-months). For example, Contact has its 'freedom plan' (see: here) and Genesis has its

[73] *See:* Competition and Markets Authority, *Energy Market Investigation, Final Report,* 24 June 2016 (hereafter: 'CMA Final Report'). The full report is available: here.

[74] The SVT is the 'default' plan that UK customers are placed on if they have not selected another deal, e.g., a 'fixed price' plan. SVTs are energy packages where the price per unit is dependent on the base rate of the Bank of England. If the rate goes up, then so do energy prices, but similarly if the rate decreases then users will benefit from lower fuel costs. As such, users of SVTs experience large levels of fluctuation. SVTs are typically the most expensive plans offered by UK retailers and are used most commonly by people whose fixed rate deal has run out and whom have not chosen another plan (i.e., who have defaulted back to the SVT), or by people who have recently moved into a property and not selected another offer. The tariff is for a period of indefinite length: there is no specified termination date, i.e., it is 'evergreen'.

[75] Standing offer contracts are basic energy contracts with non-price terms and conditions regulated by governments and enforced by legislation. Like SVTs, they are the 'default' contracts that a customer will be assigned to if she has not selected an alternative 'market based' offer. Critically, Australian retailers are free to set the price of standing offers and they are invariably more expensive than most 'market contracts'.

'no fixed term plan' (see: here). These plans essentially serve as 'default' tariffs for disengaged customers. If a customer's existing contract expires and she does not choose another deal, she will be placed on her retailer's variant of this tariff. From that point forward:

- the customer's retail prices are unlikely to be fixed – the retailer will almost certainly be free to change them depending upon market conditions; and
- the customer will not have a contractual 'expiry date' (the tariff is 'evergreen'), i.e., if she remains disengaged, she will simply remain on that default arrangement year after year.

The financial consequences of reverting to these types of 'default plans' can be stark, since they tend to be among the most expensive in the market. There will almost always be cheaper plans available to customers if they are prepared to shop around – even if all they do is look at the other deals being offered by their current retailers. To be sure, agreeing to a fixed term plan is not entirely riskless (e.g., prices could conceivably drop in the interim, and break-fees may apply if a customer switches before the contract expires), but the potential savings can be substantial.

This begs the question: with such significant savings on offer, why do some customers remain passive? Some customers may have made a deliberate and educated decision to not explore their options, i.e., because they value their time more than the potential savings on offer. That is their prerogative and, some would say, should not be of any cause for concern. But there are several other more problematic reasons for customer disengagement – several of which are identified by the Panel in its First Report. For example:[76]

- Although some passive customers may have made a conscious decision not to engage in the market, it may not have been an *informed* choice. For example, some may think they will only be able to save 'a few dollars here and there' and choose not to explore other options on that basis when, in truth, the potential savings may be far greater.[77] Indeed, some might have considered it well worth their time to shop around if they had known they might save, say, several hundred dollars per year.[78]

[76] Although third-party intermediaries can sometimes mitigate the problems described below by assisting customer navigate the complexities of the market, they are not a panacea. For example, vulnerable customers may be just as ill-equipped to deal with third-party intermediaries as they are to engage in the market directly. Other customers may harbour suspicions – rightly or wrongly – about the motivations of such parties and be reluctant to deal with them (*See for example*: Australian Energy Market Commission, *Final Report, 2014 Retail Competition Review, To COAG Energy Council 12 August 2014*, p.24.). Furthermore, as the ACCC noted recently, such services can add costs to the electricity supply chain through any commissions that they charge to retailers. *See:* ACCC Final Report, p.275.

[77] *See for example*: Newgate Research, *Consumer Research for Nationwide Review of Competition in Retail Energy Markets,* report for the AEMC, June 2014, pp.41, 117 and 173.

[78] To be sure, it is not unusual for some customers in competitive markets to be less knowledgeable than others. For example, a customer may buy a pair of shoes at a store in the city, unaware of the fact that they are for sale at a considerable discount at the store's factory outlet in the suburbs. However, a potentially important distinction here is that customers *have a choice* about whether to buy a new pair of shoes – they can choose not to do so. But they really have no option but to buy electricity from somewhere – and it can account for a material proportion of their total annual

- Customers may be time poor. For example, a family may often be fully occupied with the myriad other critical aspects of running a household and have little or no time to spare weighing up different electricity offers (especially if it is under the – perhaps mistaken – impression that no significant savings can be made). When renewal letters arrive from electricity retailers, insurance companies and so on, they might therefore be skimmed briefly, then cast aside.
- Some customers may attempt to engage in the market but revert to passivity after becoming disillusioned with its complexity – especially if they attempt to look beyond the prompt payment discounts and lump sum inducements that tend to be the focus of retailers' advertising efforts. A customer seeking details of the individual tariff components they she will be paying under a plan may need to locate inconspicuous weblinks, navigate multiple webpages and, ultimately, decipher complex tables of price elements.
- Among the passive customer group will also be some people who, for a variety of reasons, may find it more difficult to engage with the market. For example, English may not be their first language, or they may be elderly and less confident comparing offers online. These factors can make it much harder for those customers to explore their options. They may, in truth, be highly price sensitive and be willing to invest the time and effort into searching for a new supplier – if only they were able to do so.[79]

We therefore agree with the Panel that there is good reason to think that many New Zealand customers will be disengaged and, consequently, paying significantly higher retail prices than they need to be. Moreover, it cannot be assumed that those passive customers have made a deliberate, informed choice to remain disengaged – thereby consciously accepting the higher prices that result. Rather, there are other more worrisome explanations for customer disengagement. For example, low-income and vulnerable customers are likely to be over-represented amongst the disengaged, given the difficulties they face navigating the market.[80]

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expenditure. A lack of knowledge may therefore be of much more concern when one is dealing with an essential service of this kind.

79 Simshauser and Wish-Wilson (2015) describe this as 'inter-consumer misallocation'. Arguably, this is neither efficient nor equitable. It is not necessarily efficient, since the lower prices being offered to those active customers on cheaper offers – who have shopped around – are being funded, at least in part, by vulnerable customers that may be equally (or more) likely to be on those offers if they were able to switch. Again, this is not a problem that is unique to the electricity retail sector – vulnerable customers will often experience similar challenges when buying products in many competitive markets. However, it might again be said to be particularly troubling in these circumstances, considering the essential nature of the service in question and the potentially large expense involved. *See: Simshauser* & Whish-Wilson, *Reforming reform: differential pricing and price dispersion in retail electricity markets*, AGL Applied Economic and Policy Research, Working Paper No.49, June 2015, p.25.

80 The analysis of switching rates contained in the paper does little, if anything, to assuage those concerns. As the Panel effectively – and rightly – concedes those data are not currently reliable, because it is not known how many of those customers are simply moving houses. And in any case, they do not preclude the existence of a sizeable base of disengaged customers whom retailers can then charge significantly higher prices.

4.1.2 Implications

Widescale customer disengagement can have profound effects on the development of electricity retail market competition. The most obvious consequence of incumbents being privy to a significant base of passive customers is that the market – or, at the very least, a substantial portion thereof – may cease to be what might ordinarily be regarded as workably or effectively competitive. Renowned Australian economist and academic, Professor Maureen Brunt, has described workable competition as:[81]

> *'…a situation in which there is sufficient rivalry to compel firms to produce with internal efficiency, to price in accordance with costs, to meet consumers' demand for variety, and to strive for product and process improvement.'*

As the analysis in Appendix A explains in more detail, if competition is workable then, if average prices are persistently above the long-run cost of supplying a service this should, in time, prompt a supply-side response. Specifically, entry and/or expansion should occur from firms chasing the resulting profits, thereby restoring average prices to levels that reflect long-run costs. However, when a market is characterised by large incumbent suppliers with lots of passive customers, this symbiosis between prices and costs can break down. The New Zealand electricity retail market appears to exhibit these conditions:

- much like in the UK and Australia, New Zealand has several (in this case, five[82]) large electricity retailers who account for the lion's share of the market; and
- it is reasonable to surmise that, just as in the UK and Australia, a significant portion of those retailers' customers are passive (for the reasons set out above).

These structural and behavioural dynamics mean that new entrants and smaller retailers – of which there is a significant number in New Zealand – may be vying primarily for the 'active' customer segment which, by definition, is likely to be especially price sensitive and may offer only relatively low margins. The various factors we described earlier that have contributed to the passivity of the remaining customers may serve as potentially considerable obstacles to those rival suppliers acquiring them – even though they are likely to be the most lucrative targets. This means that larger retailers may be relatively insulated from the threat of competition when it comes to their inert customers.

This may place the big retailers in a strong position to charge those disengaged customers prices that exceed – perhaps significantly – the long-run cost of supplying the services, without having to be too concerned about losing them to rivals.[83] Moreover, if an incumbent does lose a previously disengaged customer to a smaller rival, it is not without options. For example, it may choose to respond by seeking to

81 Brunt, M (1970), 'Legislation in search of an objective', in J.P.Nieuwenuysen (ed.), *Australian Trade Practices: Readings*, Melbourne, Cheshire, p.238.

82 Genesis, Mercury, Contact, Meridian and Trustpower.

83 More specifically, the higher prices charged to passive customers may result in an average price across *all* the retailer's customers that exceeds the long-run cost of supplying them.

win back that customer as soon as possible. Such a response may be worthwhile, even if it necessitates offering the customer a lower price to return, because:

- although the customer may then be paying those lower prices for the term of her contract, if she becomes passive once more, there may be a good chance that she will revert to a more expensive offering once that deal expires; and
- it will have caused the rival retailer to incur acquisition costs for no benefit and, unlike the larger retailers, smaller firms are unable to fund such efforts through the higher prices received from disengaged customers.

Dr John Small went as far as to suggest recently that passive electricity retail customers could constitute a distinct market that could be monopolised.[84] We agree. The factors described above make it entirely plausible that a hypothetical retail monopolist could profitably increase prices above the (theoretical) competitive level,[85] without reducing its overall profitability, implying the existence of a bespoke 'antitrust market'.[86] The ACCC has also highlighted this two-tier dynamic and lamented the adverse consequences for overall retail market outcomes:[87]

> *'…incumbents have benefitted from large parts of their customer bases being inactive or disengaged from the competitive market, often remaining on high-priced standing offers. Incumbents are able to make very attractive offers to retain customers, effectively through cross-subsidies paid by their inactive customer cohort. This has enabled incumbents to compete only selectively, and with a disproportionate focus on efforts to retain profitable customers rather than win new ones. In that environment, new entrants and smaller retailers are competing only for the 'active' part of the market which is price sensitive and only low-margin. This model of competition has not delivered a dynamic and competitive market in which many retailers compete vigorously, driving efficiencies and providing innovative products to attract and retain a broad range of customers.'*

Widespread customer disengagement gives rise not only to potential inefficiencies, but also to legitimate equity concerns. It inevitably results in a transfer of wealth from passive customers – some of whom have little choice but to remain so due to difficulties engaging in the market – to active customers. Although equity is inevitably a subjective concept, in our opinion, many reasonable observers might well regard such a scenario as unfair. Those wealth transfers may also contribute to problems such as energy poverty, e.g., to households being unable to afford to adequately heat their homes.

For those reasons, widespread customer disengagement in the electricity retail market is not something to be dismissed lightly. Even if it is not especially difficult

84 Small., J (2018), *Competition and Regulation in New Zealand*, prepared for Competition Law and Policy Institute of New Zealand Workshop, 10-11 August, 2018, p.20.

85 Note that this thought experiment must be undertaken using a hypothetical competitive price as a reference point. If the exercise is undertaken using, say, a monopoly price as the starting point then, by definition, no further price increase would be profitable (since the monopolist would already be maximising its profits). One would therefore reach the erroneous conclusion that the market definition needed to be expanded. This is known in economics as the 'cellophane fallacy' (after a famous US case involving the wrapping material).

86 *Supra* note 28.

87 ACCC Final Report, p.xi.

to start an electricity retail business in New Zealand, the two-tier market structure means that the barriers to *expansion* may be considerable, hindering the effectiveness of competition. Most notably, customer disengagement may present opportunities to established retailers to earn excessive profits from their passive customer bases. That is entirely consistent with the retail margin analysis performed by the EC in 2008 (see Figure 2.1).

Recall that this analysis indicated that, at a national level, average margins for incumbent New Zealand retailers were significantly higher than for their Australian counterparts and exceeded significantly those being earned by newer entrants.[88] Moreover, only a few network areas were found to have margins below 8% (the higher of the levels observed in Australia) and many regions had margins above 12%. For the reasons we set out in section 3.1.1., the Panel's analysis of net cash flows does not alleviate the concerns raised about the magnitude of retail margins by its predecessor.

This serves to reinforce the danger of relying upon simple metrics such as market shares and the number of retailers as gauges of the effectiveness of competition. Indeed, it is worth remembering that there are also large numbers of new entrants in the Australian and UK retail markets – yet that did not preclude the respective competition agencies from finding profound competition problems in each instance that warranted policy intervention, including the introduction of regulated retail tariffs (this has been proposed in Australia[89] and has happened in the UK[90]).

4.2 Other retail market issues

The Panel also identified several other potential problems in the retail market that cast further doubt over the effectiveness of competition. For example, as we noted earlier, the analysis of hedging market liquidity set out in section 3.3 applies equally to retailing and raises equivalent concerns. In addition, the prevalence and effects of conditional discounts and the observed trends in retail costs are sources of potential concern worthy of further examination.

88 Ministerial Inquiry Report Volume 2, p.105.

89 The ACCC recently recommended abolishing 'standing offers' (Australia's variant of the default tariff) and replacing them with a regulated tariff to be determined by the AER. The ACCC indicated that the regulated price should reflect the efficient cost of operating in the region, including a reasonable margin as well as customer acquisition and retention costs (*see:* ACCC Final Report, p.252). Note that the ACCC's proposals are still under consideration by the government.

90 On 19 July 2018, the *Domestic Gas and Electricity (Tariff Cap) Act 2018* received royal consent and became law (see: here). The law required Ofgem to place a temporary cap (which will expire in 2020 unless it is extended) on SVTs and default fixed-term tariffs 'as soon as practicable' and to review the level at which the cap is set every six months thereafter. The cap is not intended to replace competition. The objective is to protect passive customers from high prices, whilst ensuring enough cheaper tariffs are offered to engaged consumers. *See:* Ofgem, *Default Tariff Cap: Policy Consultation Overview document*, 25 May 2018, p.7 (available: here).

4.2.1 Conditional discounts

The main way that electricity retailers market their offers is through conditional discounts. For example, a customer may be offered discounts for bundling gas and electricity, paying by direct debit and receiving correspondence by email. But, as the Panel highlights, by far the largest discounts are offered to customer who pay their bills on time. Prompt payment discounts can sometimes exceed 20% and are the main way in which retailers promote their products. These discounts are invariably displayed much more prominently in marketing materials than the underlying tariffs themselves, which are often difficult to find.

Pay on time discounts incentivise consumers to make timely payments of their bills – and that is clearly of some benefit to retailers. Timely payment means that the retailer does not have to spend time and money following-up on unpaid accounts and may conceivably lead to a reduction in bad and doubtful debt expenses. However, it is far from clear that the pay-on-time discounts on offer in the market currently provide an accurate reflection of the size of the savings that retailers are achieving. In our opinion, there is good reason to think that the discounts exceed those cost savings by a substantial margin.

Intuitively, it seems implausible that a retailer would reap a saving equal to, say, 10-20% of a customer's bill if she pays on time. Or, put another way, it does not seem feasible that a retailer would incur a *cost of that magnitude* when a customer pays *late* – at least not on average. The widespread application and magnitude of prompt payment discounts prompted several commentators – including Steve O'Conner, the chief executive of Flick Energy – to suggest that they are little more than late payment fees in disguise.[91] The basic assertion was that:

- the discounted prices (i.e., after the application of prompt payment discounts) represent the *true* standard retail prices of electricity;[92] and
- customers that fail to pay on time are consequently being hit with a penalty that exceeds substantially the cost to the retailer.

This assertion was all but confirmed recently by the CEO of Meridian Energy, Neil Barclay, when he announced that the business would be doing away with prompt payment discounts. Consistent with the analysis set out above, Mr Barclay acknowledged that the magnitude of the discounts being offered exceeded considerably the costs that Meridian was incurring when its customers paid late:[93]

> *'When we looked at the cost of following up to recover debt, it was a fraction of the value of the discount we were taking away. That makes it manifestly unfair.'*

91 Stock., R. 'Claims that electricity "prompt payment discounts" are a late payment system punishing the poor' in *stuff.co.nz,* 17 June 2018 (available: here).

92 In other words, the implicit contention is that if prompt payment discounts were hypothetically prohibited, the undiscounted price of electricity would not increase by a magnitude equal to the discounts that were previously in place – any price rises would be of a small margin.

93 New Zealand Herald, Staff Business, *Meridian Energy axes 'unjustifiable prompt payment discounts*, 17 September 2018 (see: here).

Mr Barclay stated that Meridian would instead start offering 'guaranteed' discounts to *all* its customers. The move is expected to cost the retailer $5 million, which Mr Barclay has said will *not* be recovered from elsewhere in customers' bills (see: here). Again, consistent with the analysis set out above, this suggests strongly that the discounted prices have historically represented the *true* standard retail prices and that revenue from prompt payment discounts has largely been pure profit.

It is also very hard to dispute that these types of conditional discounts – and prompt payment discounts in particular – have had disproportionately adverse effects on passive, vulnerable customers. The Panel has highlighted that this category of customers is far more likely than most to pay their bills late due to financial adversity.[94] Mr Barclay indicated that this was one of the reasons Meridian stopped offering the discounts.[95] In other words, conditional discounts give rise to both efficiency *and* equity concerns.

4.2.2 Retail costs

The Panel notes that, since 1990, a large rise in retailing-related costs has contributed significantly to the observed increase in retail prices. Retailers' reported costs have risen steeply, particularly marketing and information technology related costs – and now exceed substantially the levels observed in Australia.[96] The Panel concludes that retailing charges were the biggest component of residential price rises between 2004 and 2018 (3.5 c/kWh, or 30%).[97] This prompts it to remark that:[98]

> *'Some of the increase may be due to outlays that directly benefit consumers, such as loyalty programme costs, but it is unlikely to account for much of the increase. Retailers' operating costs now exceed the transmission charge component of residential bills (which is 10 per cent). These factors raise questions about what is behind rising retailers' costs, and how to reverse the trend.'*

We agree that significant questions exist regarding what is behind these increases and whether consumers have received any benefits to justify the higher prices they have had to pay as a result. The trend certainly does not reflect what one might typically expect to observe in a workably competitive market. Indeed, rivalry contributing to higher costs and prices does not fit with the usual notion of competition. We therefore agree that this is an area that should be investigated further by the Panel.

94 First Report, Figures 15 and 19.

95 Mr Barclay observed that: 'Prompt payment discounts were introduced with good intentions, but over time they have come to disproportionately impact those who can least afford to pay their energy costs. They disadvantage customers who are struggling the most' (see: here).

96 First Report, Figure 17.

97 First Report, p.22.

98 First Report, p.40.

4.3 Potential policy responses

In our opinion, the analyses contained in the First Report and set out above suggest there is sufficient basis to consider policy interventions targeted at improving retail market outcomes. For example, several potential steps could be taken to try and address some of the problems arising from the two-tier market structure, including the affordability issues emphasised by the Panel.

4.3.1 Promote greater customer awareness

The least intrusive policy response would be to seek to improve the awareness amongst disengaged customers of the options on offer to incentivise them to explore those alternatives. The public sector can play a key role in any such endeavours. For example, one of the themes to emerge from the Australian Energy Market Commission's (AEMC's) recent retail market reviews in Australia is that customers are more likely to trust information supplied by governments or regulatory agencies.[99] Additional investment could consequently be made in making public price comparison websites (like 'what's my number') as simple as possible and, potentially, available in multiple languages.

Governments and community groups may also be well-placed to increase awareness amongst passive customers – including the vulnerable. For example, those entities might undertake targeted media campaigns (e.g., advertising in different languages, and through local radio and niche newspapers) to promote mindfulness of the potential benefits from shopping around.[100] To that end, the ACCC recently recommended that additional government funding (to the tune of $43 million, market-wide – or $5 per household) be put towards a grant scheme for consumer and community organisations to provide targeted assistance to vulnerable customers to improve energy market literacy.[101]

These consumer engagement strategies may have *some* effect in improving outcomes for passive customers, without giving rise to unintended consequences. Specifically, they may reduce the number of previously disengaged and/or vulnerable customers that remain on more expensive tariffs. But that effect may only be marginal. Indeed, for many years the AEMC has been trying to promote greater customer awareness – through both its annual retail reviews and its consumer engagement blueprint. However, despite those initiatives, the ACCC's recent review of the retail market concluded nevertheless that a large part of the customer base remained disengaged.

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99 See: AEMC, *Final Report, 2014 Retail Competition Review, To COAG Energy Council 12 August 2014*, p.24.

100 Many of these potential steps are set out in some detail in the AEMC's 2013 consumer engagement blueprint. See: *AEMC consumer engagement blueprint.*

101 This targeted support would be designed to help vulnerable consumers to participate in the retail electricity market and choose an offer that suits their circumstances. *See:* ACCC Final Report, p.226.

Customer engagement strategies proved to have a similarly limited effect in the UK. Professor Martin Cave – a member of the Competition and Markets Authority (CMA) – noted that, in the three years leading up to the CMA's Final Report on its energy market investigation (released in June 2016), a wide variety of information remedies and other pressures had been tried[102] and 'had not made a dent' in the proportion of customers on standard variable tariffs.[103] For those reasons, although similar initiatives may be worth pursuing in New Zealand, they may need to be complemented by additional policy steps to 'shift the needle'.

4.3.2 Restrictions on conditional discounts

Another potential means of assuaging the adverse effects of the two-tier market structure is to place some limits on the form of conditional discounts, including discounts for prompt payment. As we explained above, these discounts have substantial adverse effects on disengaged and vulnerable customers. And although Meridian has committed to removing them, it remains to be seen whether other retailers will respond in kind.[104]

In Australia, the ACCC concluded that, although it was important for retailers to be able to incentivise customers to act in ways that reduced retail costs, it was appropriate to place some restrictions on the *size* of conditional discounts. Specifically, it recommended that the magnitude of conditional discounts – such as prompt payment inducements – be limited to the financial savings that a retailer can reasonably expect to make if a consumer meets the relevant criteria. It also concluded that retailers should be able to justify the magnitude of the discount if requested by the Australian Energy Regulator (AER).[105]

In our view, it is worth exploring whether there is merit introducing similar restrictions in New Zealand. Limiting the magnitude of such discounts to the size of the potential savings would ensure that passive, vulnerable customers are not being penalised disproportionately for costs that retailers are not, in fact, incurring when payments are late.[106] Just as in Australia, retailers could also be required to justify the magnitude of the discount if requested by the Commission.

102 These measures had covered such things as bill formats and customer prompts, barrages of publicity adverse to energy companies concerning the level of their charges, and very large amounts of column inches, TV advertising and other advice devoted to explaining how to switch suppliers. *See:* CMA Final Report, p.1415.

103 This was despite the fact that the SVT was, at that time, more than £300 per year more expensive than the competitive benchmark for a dual fuel customer. *See:* CMA Final Report, p.1415.

104 *See for example:* Bradley, G., 'Genesis Energy says Meridian Energy's tactics unhelpful', *New Zealand Herald,* 9 October 2018 (available: here).

105 ACCC Final Report, p.269.

106 It may also cause retailers to redirect their marketing efforts away from these types of discounts, e.g., it might prompt at least some to emphasis more prominently the unit prices (i.e., per kWh) that they are charging.

4.3.3 Auctions for passive customers

One of the chief potential problems described above is that there may be a large share of the existing retail customer base that is either unable or unwilling (for various reasons) to engage in the market. New entrants may therefore be able to acquire significant volumes of lower-value price-sensitive customers quite quickly by offering cheap deals; but attracting the disengaged customers of incumbents may be a far more painstaking process. Progress on this front may be extremely slow and incremental at best. Put simply, it may be very difficult for newer entrants to win significant volumes of passive customers.

In other markets, opportunities do sometimes arise for rivals to win large numbers of previously passive customers from incumbents. For example, the migration from copper to fibre services in New Zealand and Australia's telecommunications markets presents a rare opportunity for parties historically disadvantaged by the presence of vertically integrated incumbents to secure customers - even the historically disengaged.[107] This raises the question of whether it may be feasible to replicate an analogous 'collective switching event' in the electricity retail sector, i.e., to create more competition for passive customers.

In principle, a 'generational' switching event could be created in New Zealand's electricity retail market through auction processes. The basic concept would be to identify those customers of the bigger retailers who had not engaged in the market for a significant period – many of which will be vulnerable consumers – and to then offer potential competitors the opportunity to present them with an alternative offer. There are many ways to conduct such an auction, but the essential steps might include the following:

- disengaged customers would need to be defined in some manner and identified;
- those customers – or some sub-set of them – would then need to be disclosed to rival retailers, who would be offered the opportunity to present their competing offers, e.g., via an administrative process, with a 'winner' subsequently selected;
- customers might then be sent letters describing the new winning offer (or offers) and the savings that they entail relative to their current deal (presumably based on their historical consumption patterns); and
- those customers might then have a certain number of days to accept or decline the overture, depending upon whether it is 'opt-in' or 'opt-out':
  - if the process is 'opt-in', customers would remain on their current deals unless they accepted the alternative offer; and
  - if the process is 'opt-out', customers might automatically be switched, provided that is estimated to deliver them a cost saving.

[107] Once a customer has access to fibre, she will have access to a product not previously available. This introduces a rare 'consideration/re-contracting event' for the entire market of fixed-line customers analogous to, say, the release of Apple's original iphone. Moreover, if the existing copper networks are ultimately decommissioned, passive customers may have no choice but to engage in the market.

The concept of auctioning electricity retail customers is neither new nor unprecedented. In the UK, Ofgem recently conducted a successful 'collective switching trial' for 50,000 disengaged customers[108] (many of whom would have been low-income customers – for more details see: here and here). Encouraged by that success, Ofgem intends to conduct further auctions involving even more disengaged customers in the coming months (a more detailed description of the UK collective switching trial is provided in Appendix B).

Analogous processes also exist in New Zealand. For example, the EA has put in place an administrative process for reallocating customers if their retailer defaults that includes, amongst other things, a two-stage auction process. Although this framework is currently used only when a retailer fails (i.e., when customers have *no choice* but to switch providers), a modified version could be applied to reallocate disengaged customers – indeed, the basic concept is the same (a detailed description of this auction process is contained in Appendix B).

To be sure, various design and implementation challenges would need to be addressed before this policy could be put in place, such as how many auctions to hold, for which areas and for which customers. However, these issues are likely to be addressable, and the effectiveness and practicality of any such auction process could also be tested by running small-scale pilots in the first instance – just as in the UK. For example, a trial could be undertaken in, say, one of the 29 distribution foot-prints throughout the country.

Although this would clearly constitute a significant intervention, it is still relatively 'market-based'. Retailers would effectively be competing to supply a sub-set of the retail market. If designed well, the process could therefore enable disengaged consumers – including the vulnerable – to benefit from competition without incurring the costs of searching and switching whilst, ideally, limiting any unintended consequences on the rest of the market.[109]

4.4 Conclusion

The Panel has identified several potentially significant problems in the retail market. First and foremost, it rightly highlights the 'two-tier' market structure and the potential adverse effects this can have for both efficiency and equity. The two-tier dynamic may present opportunities to established retailers to earn excessive profits from their disengaged customer bases – a group in which vulnerable customers are likely to be overrepresented. This is consistent with the retail margin analysis performed by the EC in 2008 (see Figure 2.1), which indicated that incumbent retailers' profits were very high. Other potential problems include:

108 It also conducted a smaller trial in January 2017, whereby 10,000 disengaged customers were provided with better tariff offers from alternative suppliers by post, see: here.

109 For example, it would be less 'heavy-handed' than, say, introducing regulated retail price caps. Prices would be set via market-forces, not by a regulator with imperfect information.

- the seemingly low levels of liquidity in the hedging market that were described in section 3.3 – the resulting problems apply equally to retailers and generators, and may raise barriers to entry and expansion in both markets;
- the design and application of conditional discounts, which will almost inevitably result in passive, vulnerable customers being penalised disproportionately for costs that retailers are not, in fact, incurring; and
- the unexplained upward trajectory of retail costs, a trend that does not comport with what one might typically expect to observe in a market if competition is working effectively.

This suggests there is enough basis for the Panel to consider policy interventions targeted at improving retail market outcomes. The least interventionist approach would be to seek to improve the awareness amongst disengaged customers of the options available to them and the magnitude of the potential savings on offer. While potentially worthwhile, the main problem with such initiatives is that they may have only a small effect on any underlying problem. Recent experience in both the UK and Australia suggests that these strategies have had only a very limited impact on the level of customer engagement in each location.

Another lighter-handed initiative would be to limit the size of conditional discounts – especially prompt payment discounts – to the size of the potential savings. Such a step would ensure that disengaged and/or vulnerable customers are not being penalised disproportionately for costs that retailers are not, in fact, incurring when those conditions are not met (e.g., when payments are late). The ACCC has recommended precisely this intervention in Australia.

A further option would be to run 'auctions' for disengaged customers to offer other retailers the opportunity to serve them. Although this would clearly constitute a significant intervention it would be 'market-based'. If designed well, the process could enable disengaged consumers to benefit from competition without incurring the costs of searching and switching whilst, ideally, limiting any unintended consequences. It would consequently be less 'heavy-handed' than, say, introducing regulated retail price caps. The effectiveness and practicality of the initiative could also be tested by running small-scale pilots.

Appendix A SRMC, LRMC and pricing

In this appendix we provide a more detailed explanation of some of the core economic concepts discussed at various points throughout this report. Specifically, it contains an explanation of the relationship between SRMC, LRMC and new investments in workably competitive energy-only generation markets.[110]

A.1 Short run marginal cost

In the short run at least one 'factor of production' is fixed, i.e., a firm cannot instantaneously add new production lines to its factory. It is therefore not possible for a firm to increase the quantity of a product that it is supplying by expanding its existing capacity. The only way that firms can increase supply is to use their *existing* capacity, i.e., to produce more with what they already have. SRMC can therefore be thought of as the cost of meeting an incremental change in demand, *holding capacity constant*.[111]

This is often construed simply as the operating and maintenance costs associated with providing the product. At times, that can be correct, but *not always*. When an incremental change in demand can be met through increased supply from existing capacity, the SRMC *will* be equal to the operating and maintenance costs associated with producing those additional units. However, at other times, SRMC can be significantly above the marginal operating and maintenance expenditures incurred serving incremental demand.

Specifically, an important but often overlooked element of SRMC is that, when supply *cannot* expand to match the incremental change in demand, SRMC rises to whatever level is necessary to *curtail* demand to match supply. Specifically, in situations where there is an increased risk of shortages, the costs associated with this demand side component can cause SRMC to rise *well above* variable costs. Importantly, it is during these periods of scarcity that firms can make a contribution to their *fixed costs*, which do not vary with output over the short-term and are therefore not a component of SRMC.

Kahn (1988) offers the example of a bridge that is contemplating charging a toll. The incremental operating, maintenance and capital costs caused by each additional vehicle on the bridge are practically zero but, as Kahn observes:[112]

> *'[W]hat if charging a zero toll would, at certain hours of the day, produce such an increase in traffic that cars lined up for miles at the bridge entrance and a crossing took an hour instead of a few minutes? In that event, the SRMC of bridge crossings, at those times, is not zero. It can be envisaged in terms of congestion: the cost of every bridge crossing at the peak hour is the cost of the delays it imposes on all other crossers. Or it can be defined in terms of*

110 The material in this appendix is drawn largely from: Green et al, *Potential Generator Market Power in the NEM*, A Report for the AEMC, 22 June 2011 (available: here).

111 It can also be specified as the cost that would be avoided by having to meet a slightly reduced level of demand.

112 Kahn (1988), p.87.

opportunity cost: if A uses the bridge at that time, he is taking up space that someone else could use; therefore, the cost of serving him is the value of the space or capacity to others who would use it if he did not.'

In other words, in times of scarcity, the cost of serving one customer must, by definition, include the value foregone by other customers who cannot be served as a result. For example, if Auckland's water supply began to run low, continuing to supply some customers may mean placing restrictions on the usage of others. The costs imposed by those restrictions may be very high and may include costs such as plant losses in residential gardens and parks, reductions in agricultural output, diminished quality of golf courses and higher production costs for breweries. All those costs form a part of the SRMC of serving one customer in circumstances where that implies restricting supply to another.

Although SRMC can be estimated as at any point in time, its magnitude varies from one point in time to another. Its application in the context of decisions affecting the future (such as, following Kahn's example, whether to build a second bridge to relieve congestion) therefore relies as much on probability and expectation as on fact. A forward-looking SRMC is the sum of the various additional costs arising under different scenarios (holding capacity constant), multiplied by the probabilities of these scenarios occurring. Formally, the expected SRMC is given by:

- the SRMC when supply exceeds demand (i.e., operating and maintenance costs), multiplied by the probability that supply exceeds demand; *plus*
- the SRMC when supplies are less than demand (i.e., *including* the costs of shortages) multiplied by the probability that supply is less than demand.

To summarise, SRMC can be defined as the cost of an incremental change in demand, holding capacity constant. Importantly, its estimation takes account of the potential costs of shortages faced by customers. In the event supply cannot expand to match demand, SRMC rises to whatever price level is necessary to curtail demand to match available supply.

A.2 Long run marginal cost

In the long run, all factors of production are variable and so incremental changes in demand no longer need to be met from current capacity alone. Rather, firms have the option of expanding capacity to meet an incremental increase in demand and, equally, of reducing their capacity to meet a slightly reduced level of demand. LRMC can therefore be thought of as the cost of supplying a specified, permanent increment in demand, allowing for future augmentations in supply.[113]

[113] Note that the LRMC of adding capacity (and the LRAC associated with reducing capacity) will be determined by the operating and capital costs associated with the optimal investment profile needed to meet the relevant increment (or decrement, as the case may be) in demand. This may comprise investment by both existing market participants and by new entrants, and, potentially, investment in different production technologies. When the term LRMC is used throughout the remainder of this memo, it should be interpreted in this way, i.e., as the LRMC *for the market*.

In most industries it is not practicable to add capacity in very small increments.[114] Rather, there are often 'economies of scale' associated with augmentations. For example, once a business has purchased land it may make sense to construct a two-storey office building, even if not all that space will be used right away. This is because adding the second storey now will be much cheaper than building it later. Taking the analogy one step further, it is likely to be yet more expensive (in unit cost terms) to add capacity 'room by room'.

In other words, capacity is often added in 'lumps' rather than very small increments. The likely effect of a permanent increment in demand is therefore to *bring forward* the time at which a planned future 'lump' of capacity needs to be added – by firms that are already in the market and/or by new entrants. The LRMC is therefore the costs – both operating and capital costs – associated with undertaking that expansion *sooner than would otherwise be the case* in response to the incremental change in demand, and the associated congestion costs.[115]

This implies that where capacity must be added in 'lumpy units' (rather than in very small increments), this gives rise to *time-dependent fluctuations* in LRMC. Specifically, the LRMC of supply in such a market will be relatively low when capacity utilisation is low and the next capacity expansion is some distance in the future, but will rise as capacity utilisation increases and the timing of the next expansion is nearer. Specifically:

- in the time period immediately following a capacity expansion, the LRMC of the next increment to capacity is low because the value of any potential deferral of that future capacity requirement is relatively low due to the effect of discounting; and
- as spare capacity declines over time and the need to invest in new capacity approaches the LRMC of the next increment to capacity increases, because the value created through any potential deferral is closer in time and so less (negatively) affected by discounting.

In other words, LRMC *changes over time* as new capacity is added. This is because the cost today of, say, bringing forward by one year a $1m investment that would otherwise have taken place in 12 months' time is much greater than the cost today of that same one-year rescheduling applied to a $1m investment expected to be made in 10 years' time, because of the time value of money.[116]

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114 The exception is industries in which assets are highly mobile and capacity can be added in very small increments. In these circumstances, any level of demand can be met by quickly adding (or subtracting) capacity, i.e., there is never any need to curtail demand. Of course, such industries are rarely seen in practice. We explore this in more detail below.

115 To be clear, LRMC does *not* equal the total operating and capital costs associated with that expansion. This is because an incremental increase in demand does not generally result in investment that would otherwise never be required; rather it brings forward the timing of an expansion.

116 Put another way, the *value* today of *deferring* by one year a $1m investment expected to be made in 12 months' time is much greater than the value today of that same one-year deferral applied to a $1m investment expected to be made in 10 years' time.

In summary, LRMC reflects the cost of serving an incremental change in demand in a market, assuming all factors of production can be varied. Importantly, because LRMC is a long run concept, it accounts for the fact that firms have the option of *expanding their capacity* to meet an incremental increase in demand. Measuring LRMC involves estimating the costs involved with undertaking a capacity expansion *sooner than would otherwise be the case* in response to that change in demand.

A.3 Relationship between SRMC and LRMC

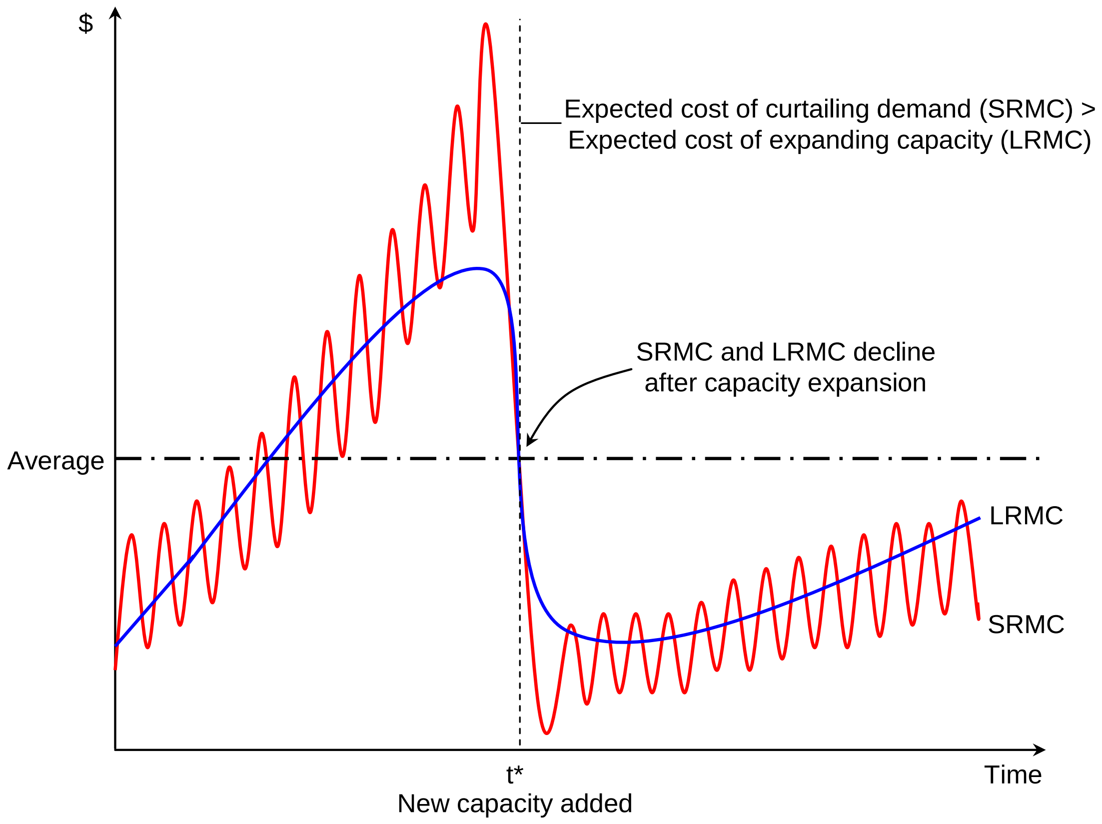
The previous sections explained that SRMC is the cost of an incremental change in demand, holding capacity constant, whereas LRMC reflects the cost of meeting that change in demand assuming capacity can vary. Unless assets are highly mobile and capacity can be added in very small increments – conditions that are rarely seen[117] – there is no reason to expect SRMC and LRMC to be the same *at any particular point in time*. However, there is still a strong 'in principle' link between SRMC, LRMC and capacity expansion decisions.

Specifically, when demand is growing over time, or subject to short term fluctuations, SRMC can be expected to increase to the point at which the cost of curtailing demand exceeds the cost of expanding capacity to *meet* that demand, i.e., when LRMC < SRMC. In the first instance, medium term demand growth can only be met through increased risk of congestion, or the need for demand curtailment during short run peaks. However, there eventually comes a 'tipping point' at which the expected SRMC of *curtailing* demand increases beyond the expected LRMC cost of expanding capacity to *meet* that demand, at which point new investment takes place.[118] This occurs at t*, in Figure A.1 below.

117 When these conditions are present, *there is no distinction* between SRMC and LRMC since, by definition, there is no difference between the short run and the long run. Any level of demand can be met by quickly adding (or subtracting) capacity and so the need to curtail demand never arises. In these circumstances, SRMC and LRMC are always equivalent, and constant at all times. Of course, industries that exhibit such characteristics are rarely seen.

118 The same principles apply to a market in which demand is *declining* over time. In the first instance, declining demand can be met by firms continuing to supply the market with their existing capacity. However, there will again be a 'tipping point' at which the long run costs that would be *avoided* by reducing or redeploying capacity exceed the SRMC of continuing to supply the product at the current level of capacity, at which point capacity is redeployed to other markets where returns are more attractive.

Figure A.1: SRMC, LRMC and capacity expansion



Beyond t* there is significantly more capacity and the probability of shortages emerging that will require demand curtailment is much reduced. SRMC is therefore lower, on average, than during the period leading up to t*. LRMC is also much lower after t* than during the period immediately prior. This is because, beyond t* the LRMC of the *next expansion* is low, because the cost associated with bringing forward that future capacity requirement is relatively small because of discounting.[119]

Of course, in practice, it is often very difficult to time capacity expansions and reductions to coincide perfectly with the emergence of inefficient levels of demand curtailment, i.e., when scarcity is either too common or too infrequent. This is particularly the case when capacity must be added and withdrawn in large increments that alter substantially the supply/demand balance. There may therefore be times when:[120]

119 This is again because the costs that would be incurred today by deferring by one year a $1m a capacity expansion that is expected to be made in 12 months' time are much higher than the costs that would be avoided by undertaking that same capacity reduction in 10 years' time. It follows that LRMC must fall immediately following a capacity expansion, since the next expansion is, by definition, more distant than prior to the investment.

120 Government intervention may also affect the relationship between SRMC and LRMC. For example, government taxes and subsidies can affect the economics of various investment propositions and, potentially, the LRMC of expanding capacity. Such interventions may therefore also influence the time it takes for the SRMC of curtailing demand to reach the new LRMC benchmark.

- SRMC is *above* LRMC for a period as the market waits for new capacity to come on-stream; and
- SRMC is *below* LRMC for a period as the market waits for redundant capacity to be re-deployed elsewhere.

However, such instances of 'misalignment' are neither unexpected, given the imperfections that can affect real world markets, nor a cause for concern, provided that they are transitory. Even accounting for such periods, there is no reason to expect SRMC to differ materially from LRMC, on average, provided they are properly defined and assessed over a sufficiently long timeframe. Equally, although both SRMC and LRMC can fluctuate over time, there is no reason to think that either will diverge over the long term.

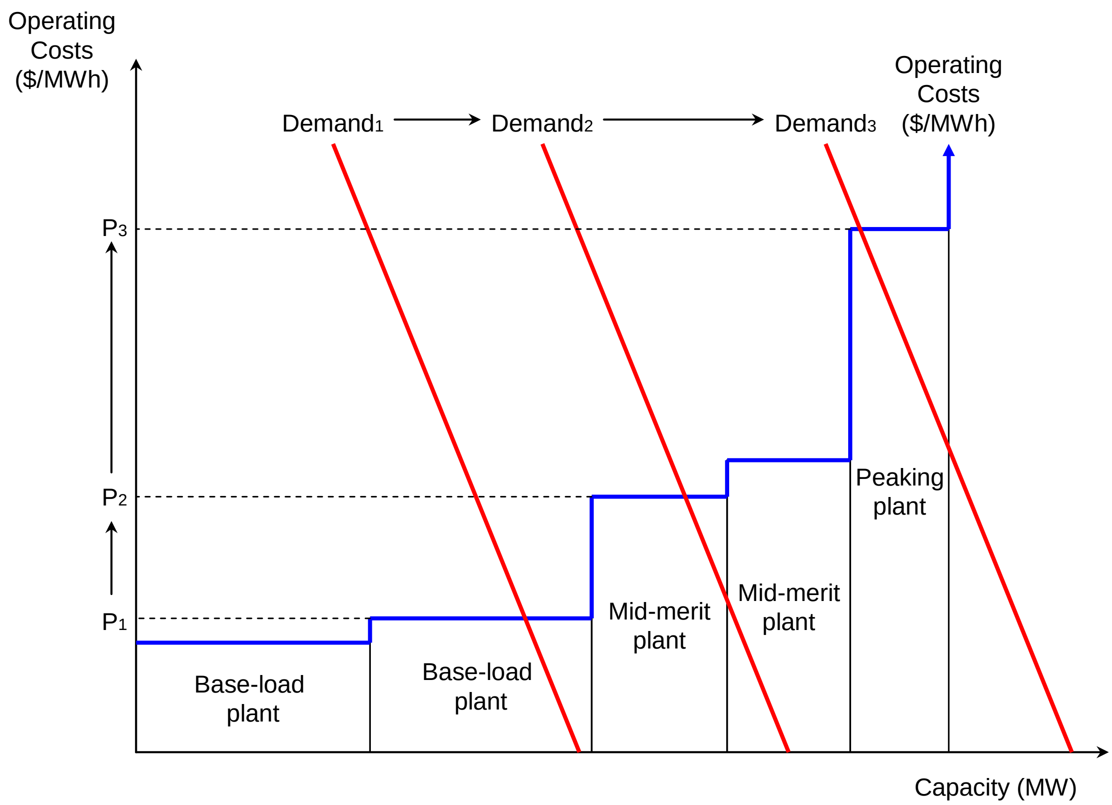
A.4 Application to energy-only wholesale markets

The unusual features of the electricity generation market give rise to highly variable SRMCs. The wholesale market design is directed towards promoting competition between generators that produces prices that reflect those variable SRMCs. Specifically, the expectation is that, most of the time, generation plant should be 'dispatched' according to its economic merit order, as given by the ascending SRMC of running each type of plant (as determined by the respective operating and maintenance costs – the cost of curtailing demand during times of congestion is discussed subsequently).

Although generators are permitted to offer their capacity at any price, the existence of competing offers by alternative plant owners normally constrains the prices that generators can bid. For example, a base load plant that bids substantially above its operating and maintenance costs (or withholds capacity) risks not being dispatched and being forced to incur the expense of shutting down and restarting its plant. For this reason, generators can *generally* be expected to offer to supply the market at a price that reflects their short run operating and maintenance cost and are *generally* scheduled to run in line with their economic 'merit order'.

Figure A.2 below illustrates that, although a generator may offer its capacity at a price sufficient to cover only its operating and maintenance cost, the price that it actually *receives* during a half-hour period is equal to the offer of the last generator that is dispatched in order to meet demand (the marginal generator). This means that generators with lower running costs (base load and mid-merit plant that is 'infra-marginal') will make a profit from the market prices set at the highest bid that enables them to make a contribution to their fixed investment costs. But how does the *marginal generator* cover its investment costs? The answer is no different from that in any other workably competitive market.

Figure A.2: Economic merit order



Specifically, when there is a possibility that the existing generation capacity will not be able to meet demand, prices in the market must rise to reflect the increased SRMC of curtailing that excess demand. In situations where there is a risk of shortages, the costs associated with this demand side component can cause prices to rise *well above* the operating and maintenance costs of the marginal generator. It is during these periods of scarcity that those generators can make a contribution to their *fixed costs*. Indeed, this is the *only way* that such plants can cover their capital costs in an energy-only market.

The expected spot price is therefore based on a probabilistic assessment of possible future outcomes and the costs they entail. Specifically, it is the sum of the various additional costs arising under different scenarios, multiplied by the probabilities of these scenarios occurring. Formally, the expected spot price is derived using the same formula described above:

- the SRMC of the marginal generator when supply exceeds demand (i.e., operating and maintenance costs), multiplied by the probability of that scenario occurring; *plus*
- the SRMC of the marginal generator *plus* the SRMC of curtailing excess demand when supply is less than demand multiplied by the probability of that scenario occurring.

In electricity generation markets, the cost of curtailing demand is termed the 'value of lost load' (VoLL) and reflects the amount that customers would be willing to pay to avoid a disruption to their electricity service. For large industrial users (e.g., an aluminium smelter) that amount may be very high. The expected spot price can therefore be expressed as follows:[121]

Expected Spot Price = [(1 – LOLP) x SMC] x [LOLP x VoLL]
Where:
LOLP = Loss of load probability
SMC = System marginal cost, ie, the SRMC of the marginal generator
VoLL = Value of lost load

When the probability of shortage is low, prices can be expected to resemble the operating and maintenance costs of the marginal generator (often a base-load or mid-merit plant). However, as the probability of a shortage begins to increase (which will happen once demand starts to approach the 'outer limits' of the merit curve), spot prices start to increase above this level and begin approaching VoLL. In the extreme scenario in which a shortage is certain (i.e., if the LOLP = 1), the expected spot price *is* VoLL and a price equal to that level should transpire for the period in question (although, in practice, most regulators place a cap on how high the spot price can rise).

Periods of high prices are necessary to cover generation costs in the aggregate, to ration demand and, critically, to provide an *inducement for new investment* by firms chasing those high prices. Indeed, when scarcity in the market causes spot prices to increase high enough, or frequently enough that the average spot price exceeds the LRMC of constructing additional capacity[122] over that timeframe then:

- firms already in the market have an incentive to expand their generation capacity to take advantage of those periods of high prices; and
- new firms have a stronger incentive to enter the market and offer new generation capacity, chasing those high prices.

In other words, provided that the electricity market is workably competitive, the period over which spot prices rise to reflect the increased risk of congestion, or the need to curtail demand, is finite. Specifically, once the cost of that curtailment (as represented by SRMC) has risen to a level that exceeds the costs of adding capacity (as represented by LRMC), entry and expansion can be expected to occur over the longer-term to *meet* that demand.

In this respect, a workably competitive wholesale electricity spot market functions no differently from most other workably competitive markets. Specifically, any

[121] Hunt & Shuttleworth (1996), *Competition and Choice in Electricity*, Wiley, p.173.

[122] The LRMC of adding capacity is determined by the operating and capital costs associated with the optimal investment profile need to meet the relevant increment in demand. This may comprise investment by both existing market participants and by new entrants, and, potentially, investment in different production technologies. For example, depending upon the circumstances, the most efficient expansion profile may involve investment by both existing generators and new entrants, and a mix of generation technologies, e.g., base-load, mid-merit and peaking plant and, potentially, transmission and interconnector capacity.

change in market conditions that results in prices that are significantly and persistently *above LRMC* should, in time, prompt a supply-side response that restores prices to these levels. Of course, this supply-side adjustment process cannot necessarily be expected to be *perfect*. Because generation capacity cannot be added or removed in 1MW increments, it can be difficult to time 'lumpy' capacity expansions and reductions to coincide with the theoretical 'trigger point'.

Specifically, there may be times when average spot prices (and SRMC) are *above LRMC* for periods, as the market waits for the next increment of capacity to come on-stream. In other words, prices that diverge from LRMC for significant periods of time may *still be explicable* in an electricity generation market. However, provided competition in the market is at least workable and the concept of LRMC is properly understood, these periods of 'misalignment' should still only be temporary.

Appendix B Collective switching processes

One of the potential solutions to the 'two-tier' market problem that we have suggested the Panel explores in the second phase of its review is an auction process for disengaged customers – a group that is likely to contain many of the consumers experiencing affordability problems. The concept of auctioning electricity retail customers is neither new nor unprecedented. Below, we provide two case studies: one from the UK and another from New Zealand.

B.1 UK collective switching trial

Following its lengthy investigation of competition in the UK electricity retail market, the CMA recommended (amongst other things) that Ofgem establish a 'Disengaged Customer Database'.[123] The six large suppliers (the 'big six') were consequently compelled to give Ofgem the contact details of those of their customers that had been on SVTs for more than three years. From February to April this year, Ofgem then ran a 'collective switch trial' involving 50,000 of those passive customers. The process was run as follows:[124]

- 50,000 disengaged customers (i.e., those who had been on SVTs for at least three years) of Scottish Power (one of the big six) were selected at random;
- those customers were contacted and given the opportunity to 'opt out' of having their personal potential cost savings calculated by the Ofgem-appointed 'consumer partner organisation', Energyhelpline;[125]
- Energyhelpline then went to the market and asked retailers what they would be prepared to offer to supply those disengaged customers, i.e., there was an exclusive tariff negotiated by Energyhelpline on behalf of those customers;[126]
- that exclusive tariff was ultimately one offered by E.ON – another member of the big six – presumably on the basis that it was the lowest price or offered the best deal for most of the customers in the group;[127]

123 Details of Ofgem's disengaged customer, including high-level descriptions of each of its various initiatives are available: here.

124 An Ofgem PowerPoint presentation providing an overview of the collective switch trial is available: here.

125 It is unclear how many customers chose to opt out of the trial.

126 Although it is unclear, it appears that rival retailers had to bid for *all* those disengaged customers collectively (i.e., make the *same* offer to *all* of them). It is also not obvious whether there were any limitations on the terms and conditions that needed to be offered, e.g., whether offers had to be for a certain term (e.g., 2-year deals), whether a certain price structure had to be offered, if prompt payment discounts (or late fees) had to be included. However, the most likely scenario is that each retailer was required to comply with a standard suite of conditions to ensure that offers were reasonably consistent and comparable.

127 No clear explanation is offered for why Energyhelpline chose the E.ON offer for the 50,000 customers, e.g., whether it was based on the largest collective savings across that group, or creating savings for the largest number of customers within the group.

- customers then received a letter[128] outlining the potential cost savings to be made if they took the E.ON deal, and supplying details of how to switch to that offer online or over the phone – links were also supplied to enable them to undertake a wider search comparing other market tariffs; and
- it was then up to customers to decide whether to switch, i.e., this final step was 'opt-in' – they did not have to 'opt out' of being switched to, say, the exclusively negotiated tariff.

Ofgem labelled the trial its most successful initiative to date,[129] with 22.4% of customers switching – around half of whom chose the exclusive tariff negotiated by Energyhelpline (i.e., the E.ON deal). Customers who switched to the exclusive tariff were estimated to save around £300, on average.[130] On the strength of those results, Ofgem has decided to launch two larger scale trials (presumably involving more than 50,000 customers) in the northern autumn, i.e., around September.

B.2 The EA's process for managing defaulting retailer situations

When a retailer goes out of business in New Zealand (i.e., when it 'defaults'), the EA oversees a process[131] whereby it notifies the customers of the failed retailer and urges them to choose another. If some customers fail to switch then, after 14 days, the EA begins to assign them to new retailers – first by running a two-stage tender process and then by mandatory allocation. The EA first invites other traders to tender for the remaining customer base. The tender is held on the following terms:

- All retailers are invited to submit a bid for all or some of the customers of the firm in default. The terms offered by the recipient retailer must be its standard tariff at the date the EA was notified of the default or a lower price.
- The EA allocates customers randomly to the retailer bidding the lowest price according to the quantity it bid; and then to the retailer with the next lowest price, and so on until all customers are assigned, or no bids remain.
- Customers are assigned on the terms and conditions established through the tender (including price), not the terms and conditions of the retailer in default.
- The recipient retailers have the option to notify changes to their terms and conditions (including price) according to their standard process. Similarly, customers have the option to switch to a different retailer at any time.

If there are still some unassigned customers following the first auction, the EA may then invite all retailers to submit a bid based on a fixed term offer:

128 It is unclear whether this letter was from Energyhelpline, E.ON, Ofgem or Scottish Power.

129 Ofgem's letter to stakeholders describing the findings of its collective switch trial is available: here.

130 Savings were not estimated for customers who switched to other market offers.

131 *See:* EA, *Guideline for managing trader default situations,* Version 1.1, 9 June 2015 (available: here).

- the price must be either the retailer's standard tariff or a lower price, but for a fixed term; the fixed term is intended to provide the retailer with certainty about recovering the economic costs of acquiring the customer;
- customers are randomly allocated to the trader bidding the lowest price weighted by the length of the fixed term (price multiplied by the length of the fixed term measured in days), and so on; and
- customers have a two-week grace period to change retailers but, after that period has lapsed, they may be required to pay the economic costs of exiting if they terminate the fixed term contract early.

If the two-stage tender process does not result in all customers being allocated to a new retailer, the EA will assign those that remain to retailers servicing customers in the same network area (or areas) based on their market shares, e.g., each retailer's share of installation control points (ICPs) for each metering installation category (i.e., category 1, 2 and 3 and above).

Although this framework is currently only used when a retailer fails (i.e., when customers have no choice but to switch providers) a modified version could be applied to reallocate disengaged customers. Indeed, the basic concept is the same, and so the EA's existing guideline could be used as a useful blueprint.