23 October 2018

Miriam Dean CNZM QC
Chair, Electricity Pricing Review Expert Advisory Panel
C/- Panel Secretariat, Ministry of Business, Innovation and Employment
15 Stout Street
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By email: energymarkets@mbie.govt.nz

Dear Miriam

Contact Energy submission on the first report into the electricity sector

Thank you for the opportunity to provide feedback on the first report of the Electricity Pricing Review Panel (**Panel**) into the state of the electricity sector. We agree with the Panel's assessment that the electricity system is working well to produce reliable and sustainable electricity supply. Where it isn't working so well is for those customers who are struggling to pay all their household bills and we believe the government, the electricity industry and Contact can do more.

We trust that our submission highlights the positive action Contact has been taking and will continue to do so. There are many areas of the Panel's findings we agree with, others where we challenge the underlying data and, in some cases, we have provided alternative data and suggestions for the Panel to consider.

Overview

New Zealand has a world-class electricity system that is trusted by consumers and is the envy of much of the developed world. However, we accept there is always room for improvement. In identifying and making improvements it will be critical that decision-makers are aware of, and avoid, any unintended consequences.

Price and Affordability

Residential electricity prices have risen since 1990 but since 2014/2015, when the impact of the regulatory changes in the early part of the decade had settled, those prices have been flat. This has been achieved in an environment when the "pass-through" components of the customer's bill have continued to rise. This highlights the challenge of retailing electricity.

We fully expect the gross margin in retailing to continue to decline despite increasing efficiencies in the sector as technologies and the current regulatory development programme reduce barriers to entry. We also believe the projected electricity demand growth to be satisfied at wholesale prices no more than those observed over the last five years.

Contact agrees with the Panel that there is a group of vulnerable consumers who are struggling. This requires an appropriate social policy response by government. Well targeted policy responses will go some way to alleviating this issue and Contact is committed to the actions individually, and through our membership of the Electricity Retailers Association of New Zealand, to help vulnerable customers.

Our customers tell us they want choice, certainty and control which we satisfy with innovative products and services. The market is delivering and Contact's customers are able to access products such as weekly/fortnightly billing, SmoothPay and PrePay products, that have none of the traditional disadvantages of prepay, and better credit processes. We are proud of the work we are doing to ensure all customers have access to affordable energy and in the very near term will continue to release products, such as an un-discounted "no-frills" lowest tariff product.

Do the market settings need to change?

The current market design has done an extraordinary job of delivering dynamic efficiency in the generation of electricity. The right investments have been delivered at the right time and the right place, and at the least cost to the consumer. Any major changes in direction should only be considered with great caution.

With 29 distribution networks, Contact has consistently argued standardisation is essential to minimise barriers and to encourage competition and innovation for the benefit of consumers. We believe there is no doubt that competition will produce the best outcomes for consumers.

The benefits of competition are evidenced by the extraordinary growth in retail competition. Suggestions the current market design impacts the ability of independent retailers to enter and grow their market share don't stack up. There are challenges to achieving scale, but they are no different to those in any competitive market.

Emerging technologies have the potential to increase security of supply and resilience (through a more distributed, decentralised, lower carbon power system) and reduce prices for consumers. In our view, the challenge to harnessing the benefits of new technology is creating price signals and markets that incentivise new technology investment when and where it is needed.

The future

We are working with our customers, partners and suppliers to decarbonise New Zealand's energy sector. The decisions we make will go a long way to achieving New Zealand's decarbonisation goals but they require significant investment in new renewable energy. We would urge the Panel to ensure that any recommendations to change market settings take into consideration what they could mean for the necessary investment signals.

Conclusion

Our submission provides a detailed explanation of the above and we look forward to discussing these views with the Panel in due course.

Yours sincerely

Dennis Barnes

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Electricity Price Review

Summary of Feedback on Part Three

Contact's customers tell us they want choice, certainty and control, and today's competitive retail market has delivered these to an unprecedented level. Competition has encouraged retailers to compete vigorously on price and service, understand customers' needs and tailor product offerings accordingly, to a greater degree than at any time in history. Our evidence of this is that:

- Today, electricity customers enjoy an unprecedented level of tariff and retail provider choice, as well as a large array of fixed tariffs which provide certainty and control. This is evidenced both by Contact's tariff offerings expanding from 3 in 2014, to 10 today, as well as the number of retail companies growing from 11 in 2011 to 33 today;

- The voluntary rollout of smart meters – currently sitting at around 80% - has been a significant enabler;

- Independent surveys of consumer trust, net promoter scores, and customer complaints all point to a positive trajectory;

- The competitive environment has also placed downward pressure on the energy component of customer bills. Competition has compressed Contact's retail margins, with mass market margins reducing 9% since 2013. But, despite a highly competitive environment which has resulted in increased complexity, Contact's cost-to-serve has remained roughly constant at $250 in real terms (well below the Panel's estimate) since 2010.

- The current falling costs of generation supply options (e.g., wind), as well as the new era of intensified competition for generation driven by reducing solar PV costs, points to the possibility that - if managed efficiently through the current wholesale market framework - there will be pressure on the energy component of prices.

Contact's promise to customers is to make a positive different to their lives and prosperity. We will find solutions for every household to have access to energy. We agree with the Panel's assertion that, despite the significant benefits enjoyed by most customers as a result of vibrant competition, there is a group of customers who are struggling. We agree, and, jointly with other electricity retailers, we commissioned PwC to help define the vulnerability challenge.

Our own efforts so far have:

- Reduced the average debt at disconnection by 35%, increased reconnection times, and reduced the costs of disconnection and reconnection.

- Launched a number of products which have features targeted at customers who are struggling to pay their bills.

Contact believes the issue of customer hardship is the most pressing issue the industry faces. In our view, the industry's response, in collaboration with government and social agencies, must be properly targeted at the essence of the problem. Poorly designed or broad-based interventions at any point of the electricity supply chain will have impacts across the whole market. This includes investment and thus security of supply; a critical factor that the market has delivered on, with substantially superior outcomes for consumers than the 30 years of government-driven investment that preceded it.

We encourage the Panel to recommend that policy makers define the problem of hardship and target a response carefully in order to not risk the significant benefits customers are enjoying as a result of the high level of competition in the retail sector, nor the efficiency of the whole supply chain.

Solutions to issues and concerns raised in Part Three

Every customer's bill is a function of both their network tariff and their consumption levels. Figure 12 in the Panel's report showing the 'Impact of factors affecting consumption and price' clearly provides the signpost to the effective levers for impacting affordability. We would strongly recommend the Panel weight their recommendations for change to the factors that are most impactful to customers:

Price: Network prices are critical in determining the price paid by customers. Significant differentials in network prices are evident primarily due to location and population density.

Consumption: The quality of New Zealand's housing stock is key to reducing bills/improving affordability for customers.

In addition we will continue to find solutions for every household to have access to energy, including:

- Releasing products that have features targeted at helping those customers who are struggling e.g. SmoothPay, revamped PrePay, Weekly/fortnightly billing, No-Frills
- Improving our credit practices so customers incur less debt with us
- Equipping our customer service representatives with training and tools to help vulnerable customers

During a period of vibrant competition and downward pressure on the energy component of the bill we have improved outcomes for our customers. At the same time the monopoly network component of the bill has been steadily rising. The Panel could recommend that policy efforts are directed at how competition for distribution services could be strengthened and encouraged, so that, in the long run, we become less reliant on the blunt nature of monopoly regulation and we provide the optimal environment for incentives to innovate and compete.

Summary of Feedback on Part Four

Our feedback on Part Four continues the theme that vibrant competition is delivering very real and tangible benefits to consumers. Ultimately, the cost of energy to the final consumer is driven by the cost of electricity supply. The wholesale market framework that was established in the 1990s, and has been evolving ever since:

- Has been stable and performed extraordinarily well, in the context of other capital-intensive industries and electricity markets globally;
- Has largely delivered the right investments at the right price and at the right time, in a way which has maintained security of supply;
- Has delivered a 46% decrease in electricity sector greenhouse gas emissions since 1999;
- Is demonstrating that average wholesale prices are being disciplined by the threat of entry of new plant; and
- As commented on previously, the prospect of intensified competition for generation (and networks) from distributed energy resources bodes well for the future.

Hence we generally we agree with the Panel's assessment of the performance of the generation sector. If the Panel remains uncertain of their initial conclusions, we direct them to the report that we, along with other market participants, commissioned from Adjunct Professor Grant Read. This report provides a comprehensive framework within which the Panel can assess the performance of the wholesale market, and respond to others' assertions that excessive rents are being made.

While some may assert that there are barriers to competition to retail, and/or that a "two tier" retail market is emerging, we express the following caution:

- The compression in retail margins for Contact, discussed above, counters any assertions that large, vertically integrated retailers are able to preserve historical profit levels through restricting competition;
- The sheer number of new retailers suggests that there are few, if any, inefficient barriers to *entry*;
- The growth in market share of new retailers suggests there are few barriers to *growth*, other than the reasonable costs of expansion that any small business would experience in an industry with the complexity of electricity;
- Contact supports the growth of the Tier II retailers by providing flexible contracting arrangements to independent retailers helping them grow market share. We currently provide independent retailers with approximately 300GWh of supply, this equates to 43,000 homes. These contracts are shaped to match the consumption of retail customers, permit nomination across a selection of regional locations and are priced against the ASX with a small margin to reflect credit risk and volume;
- Widening spreads in short-term hedging markets should only be a concern for the Panel if they believed that it was prudent for independent retailers to be carrying out the majority of their risk management activity at the last minute;

- The portion of Contact's customer base which does not engage in switching appears to be an expression of their preference to not engage: our attempts to provide incentives to them to switch to alternative products traditionally have very low uptake.

This is not to say that improvements couldn't be made (as is the case with any complex system in a changing environment). While 93% of available prompt payment discount was taken up by Contact's customers, we are mindful of the current public discussion, and will launch a "no-frills" product which will provide the lowest tariff without a PPD component for customers who desire this.

Solutions to issues and concerns raised in Part Four

The electricity supply chain – from fuel and generation to the customer – is highly interconnected and complex. Competition will drive the ultimate price paid by the consumer to the lowest price required to maintain security of supply, but, in electricity markets, this requires a high degree of complex coordination. Poorly designed interventions will have impacts along the full supply chain, and must be considered very carefully. But the following options for the Panel are worth considering:

- We believe there may be value in investigating how save and win-back activity could be disciplined. However, we believe that this should not be done in such a way that limits the benefits from a customer's desire to shop around, as is the case in most workably competitive markets;

- The Electricity Authority's IPAG group has considered in some detail, and will make recommendations, about how innovation and participation by consumers, especially those with distributed energy resources (DER), could be enhanced. Given the significant expertise that has been invested in that group, we encourage the Panel to engage proactively with the IPAG members to understand how this might be best achieved;

- Reducing barriers to retail competition, especially in non-urban areas, could be reduced further with distribution tariff standardisation;

- We suggest the Panel considers the decision of the Commerce Commission to use an above mid-point WACC when determining allowable revenues for distributors;

- The open letter from the Commerce Commission which highlighted the challenges of the electricity distribution businesses monopoly position and their role in emerging technology. The comment from the Commissioner, Sue Begg makes the point well "We need to ensure that consumers benefit from advances in technology, while at the same time promoting the development of competitive energy markets. Regulated monopolies should not have an unfair advantage over existing and future competitors in this space."; and

- The Electricity Authority must get on and conclude a new Transmission Pricing Methodology.

Summary of Feedback on Part Five:

Technology has a sizeable role to play in improving outcomes for consumers – the service they receive, the products that are capable of being offered, the cost of their power bill, the reliability they experience, and the decarbonisation of their energy supply chain.

There are examples, some highlighted by the Panel, where the regulatory framework designed in the past did not fully appreciate the impact of batteries, automation and control systems, demand response and distributed generation. We are now in a better place to understand these implications, which may in turn require some carefully considered amendments to regulations or industry Code:

- It now seems clear that the low user fixed charge regulations are no longer delivering to their original intent, and may actually be resulting in outcomes counter to that intent;

- The extent to which the regulatory framework (legislation, regulations and Code) facilitates effective competition for the supply of distributed generation and network services, needs to be considered

- The purview of existing regulators (the Commerce Commission and Electricity Authority) over driving greater efficiency into the distribution sector needs clarification before inefficient investment, that will ultimately cost consumers, is made under the existing regulatory regime.

- We do not believe that environmental sustainability and fairness should be introduced into the Electricity Authority's statutory objective, but the degree to which the wider regulatory framework delivers these is worth considering.

- Regulatory settings should not prejudice some consumer groups at the expense of others.

Solutions to issues and concerns raised in Part Five

The existing regulatory work programmes can be adapted to deal with many of the issues raised by the Panel in the first report. We strongly encourage the Panel, that in making recommendations to implement the Panel's findings, it will be mindful of not duplicating existing work programmes but leveraging the capability, experience and knowledge that already sits within the industry's regulators.

ELECTRICITY PRICE REVIEW

SUBMISSION FORM

How to have your say

We are seeking submissions from the public and industry on our first report into the state of the electricity sector. The report contains a series of questions, which are listed in this form in the order in which they appear. You are free to answer some or all of them.

Where possible, please include evidence (such as facts, figures or relevant examples) to support your views. Please be sure to focus on the question asked and keep each answer short. There are also boxes for you to summarise your key points on Parts three, four and five of the report – we will use these when publishing a summary of responses. There are also boxes to briefly set out potential solutions to issues and concerns raised in the report, and one box at the end for you to include additional information not covered by the other questions.

We would prefer if you completed this form electronically. (The answer boxes will expand as you write.) You can print the form and write your responses. (In that case, expand the boxes before printing. If you still run out of room, continue your responses on an attached piece of paper, but be sure to label it so we know which question it relates to.)

We may contact you if we need to clarify any aspect of your submission.

Email your submission to energymarkets@mbie.govt.nz or post it to:

Electricity Price Review

Secretariat, Ministry of Business, Innovation and Employment

15 Stout Street

PO Box 1473

Wellington 6140

Contact details

Name	**Catherine Thompson**
Organisation	**Contact Energy**
Email address or physical address	**Catherine.thompson@contactenergy.co.nz**

Use of information

We will use your feedback to help us prepare a report to the Government. This second report will recommend improvements to the structure and conduct of the sector, including to the regulatory framework.

We will publish all submissions in PDF form on the website of the Ministry of Business, Innovation and Employment (MBIE), except any material you identify as confidential or that we consider may be defamatory. By making a submission, we consider you have agreed to publication of your submission unless you clearly specify otherwise.

Release of information

Please indicate on the front of your submission whether it contains confidential information and mark the text accordingly. If your submission includes confidential information, please send us a separate public version of the submission.

Please be aware that all information in submissions is subject to the Official Information Act 1982. If we receive an official information request to release confidential parts of a submission, we will contact the submitter when responding to the request.

Private information

The Privacy Act 1993 establishes certain principles regarding the collection, use and disclosure of information about individuals by various agencies, including MBIE. Any personal information in your submission will be used solely to help develop policy advice for this review. Please clearly indicate in your submission whether you want your name to be excluded from any summary of submissions we may publish.

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Summary of questions

Part three: Consumers and prices

Consumer interests

1. *What are your views on the assessment of consumers' priorities?*

We agree with the Panel's assessment that "there is no such things as a typical consumer…". Our customers tell us they want choice, certainty and control.

Customers express their preferences and influence the sector through their purchasing decisions. Their ability to influence and shape the products under offer are discussed later in this submission. Customer expectations are also fluid and continue to be shaped by their interactions with retailers from other sectors and globally.

Regulatory changes introduced in the last seven years - primarily switching and price transparency - have put customers firmly in control.

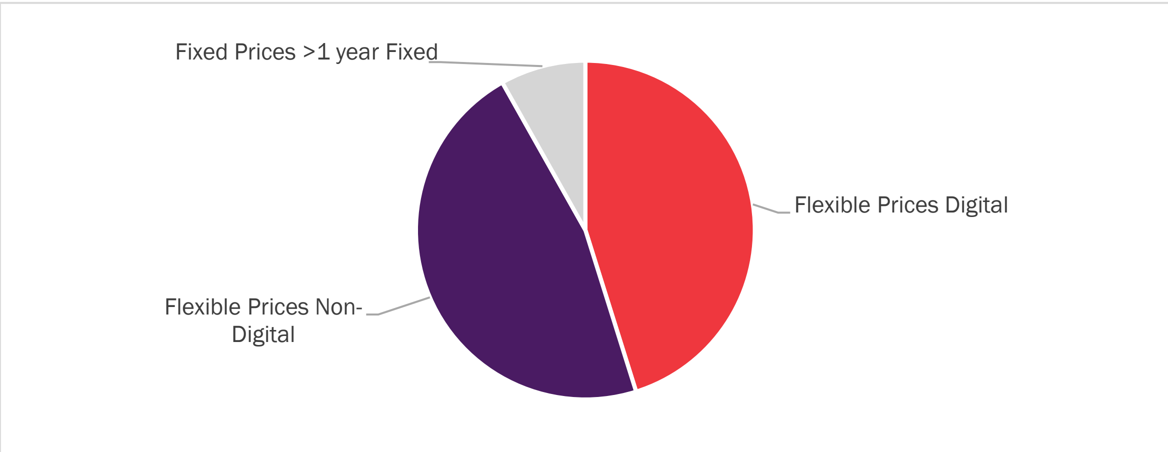
The entry of new retailers into the market has seen more competition and innovation in products to respond to customer preferences, with the number of retailers growing from 11 in 2011 to 33 today[1].

Contact's own product offering reflects this innovation, with limited customer plans in 2014 (see Figure 1) compared with multiple offerings in 2018 (see Figure 2).

Less than five years ago, we had just three main plans and no incentives for our dual energy or multi-site customers. Today ~40% of our customer base is on fixed plans with varying lengths to suit their needs and insulate them from price changes during their contract period. We also offer bundled packages including electricity, natural gas, LPG, broadband and multi-sites in response to changing customer preferences.

These changes are clear and direct evidence that customers' priorities are heard and being met.

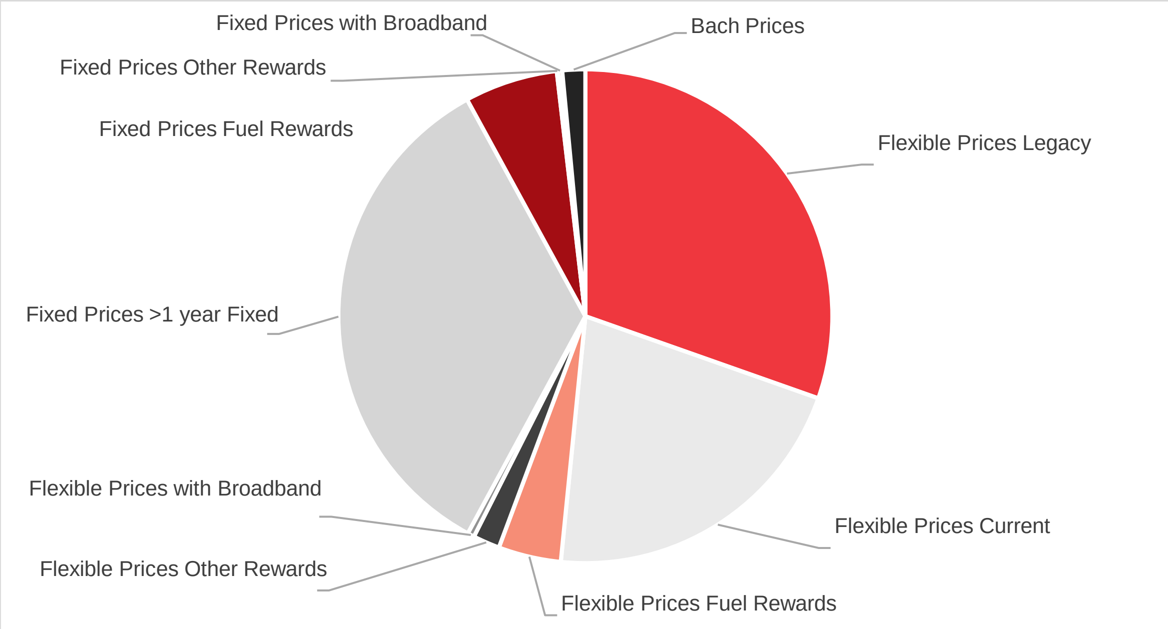
Figure 1[2]
Residential Customer Plans 2014



1 This is the number of retailer parent companies, the number of actual retailers is larger due to some parents having a number of retail brands

2 Contact's product offerings

Figure 2[3]
Residential Customer Plans 2018



The Panel observe that environmental consciousness is on the rise and drives consumer choice. Contact's recent customer research found that as an attribute "Sustainability/ Eco friendly" sits low down in the priorities of customers in choosing their electricity supplier. Price and service are the current priorities for customers. Overwhelmingly, customers are interested in price which has been flat to declining for the last five years. We discuss this in some detail in our response to Q4.

Our view is that customers value choice, certainty and control when assessing their energy provider and that with 40 plus retail brands each with bespoke product offerings in the market there are ample ways in which customers can purchase their energy.

3 Contact's product offerings

2. *What are your views on whether consumers have an effective voice in the electricity sector?*

We agree with the Panel's assessment that the electricity sector is complex and that despite there being a considerable number of mechanisms for consumers to have a voice they don't work for everyone. Having been concerned about the lack of a diverse customer voice in the electricity sector, in 2014 we launched our Regulatory Manifesto to put the customer voice at the heart of our regulatory advocacy, we have been advocating to:

Simplicity: promote simplification of the industry

Transparency: promote transparency, as defined by customers

Access: promote our belief that there should be a reasonable way for everyone to have access to energy

Competition/Efficiency: promote market design changes to ensure greater competition

Profitability: promote our view that it is in everyone's long term interest for investors to make a reasonable return on investment

In addition to our advocacy through the regulatory processes of the Electricity Authority and Commerce Commission the Regulatory Manifesto drove Contact to take a number of actions aimed at enhancing the customer voice in our sector:

In 2015 we drove the establishment of the Electricity Retailers Association of New Zealand (ERANZ) to promote and enhance a sustainable and competitive retail electricity market that deliver value to electricity customers. Much of ERANZ's work[4] has been focused on ensuring there is a customer voice in Commerce Commission and Electricity Authority's decision-making.

In 2017 we funded ERANZ to work with customer advocates and agencies to design solutions for customers struggling to access energy. This was preceded by working with all retailers on the Voluntary Practice Benchmark for the Electricity Retailer Management of Medically Dependent Consumers[5] (MDC) that has promoted more effective/practical working relationships with the government and social agencies responsible for assisting vulnerable customers.

The Panel quotes a reflection from a stakeholder that "some consumers want to engage but can't, some don't know how to and so don't, and some can engage but choose not to." The question is "could there be better customer engagement in regulatory processes?" The answer is undoubtedly "yes" but at what cost and would the benefits be material? The Commerce Commission has grappled with this for a number of years with limited success. Customers express their views by demanding new products and services and the market and regulators respond accordingly. The Electricity Authority and Commerce Commission have significant work programmes that have evolved to ensure they are responding to the risks and opportunities created by changing customer preferences and new technology. We will continue to support these work programmes in line with our customer centric Regulatory Manifesto.

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4 https://www.eranz.org.nz/submissions/

5.https://www.eranz.org.nz/fileadmin/user_upload/Voluntary_Practice_Benchmark_for_Electricity_Retailer_Management_of_MDC_August_2018.pdf

3. *What are your views on whether consumers trust the electricity sector to look after their interests?*

The Panel has observed that big businesses and institutions globally are grappling with a loss of trust. Contact's view is that New Zealanders do trust their energy providers, which is supported by independent research by the likes of Consumer NZ and the Reputation Institute. Consumer NZ's Survey of Energy companies found that 68% of households believed they could trust their retailer. This view is also supported by the Reputation Institute March 2018 Reptrack which found Genesis, Contact, Meridian and Mercury all rank in the top 25 of all NZ corporates for reputation.

Contact's view is that measuring trust, a subjective measure in itself, could also be looked at through the lens of Net Promoter Score and customer complaints (a lead and lag indicator). A Net Promoter Score (NPS), or advocacy, of a brand/ sector could be seen as a relative measure of trust in a category. At present we have a number of industry participants with NPS > +25 with Contact at +20 while Contact's customer complaints[6] have fallen from 60 in FY14 to six in FY18. In itself this does not provide a customer "trust" measure but the scale of complaints and the falling nature of these over the last three years, in our view, support the statistical findings from the Consumer NZ survey.

[6] Measured by complaints heard via Utilities Disputes Limited https://www.utilitiesdisputes.co.nz/

Prices

4. *What are your views on the assessment of the make-up of recent price changes?*

Context

The Panel's assessment of the trends in price changes will benefit from additional Information that will be provided through the submission process.

Figure 1 in the Panel's report is useful in delineating the traditionally recognised functions of: generation, transmission, distribution and retailing but it overlooks a number of further functions which impact customer bills. For completeness this list should include the wholesale purchaser of electricity (noting that as a generator Contact sells all our production into the wholesale market and then buys back sufficient supply to meet our customers' demand), thermal fuel (natural gas, coal and diesel) providers, the metering equipment providers (MEPs), financial markets such as the ASX and for ease we will use the term 'regulatory requirements', as all our customers are required to pay EA levies and taxes. In addition, a small but increasing volume of generation is bypassing the transmission, distribution and retailer functions.

As can be seen from this complete list the price paid by customers is the end result of a significant number of interactions between participants, some commercial such as the generators, thermal fuel providers and MEPs, Distributors, Transpower and finally the levy and tax requirements which are a function of legislation.

Vulnerable customers

Contact's own data is consistent with the Panel's finding that there are a group of consumers who are struggling. For these people they cannot afford to keep their homes warm, and many of life's necessities. This is untenable. This issue, however, is not unique to the electricity sector and requires an appropriate social wellbeing response by government.

Prices

The Panel's assessment of the composition of recent price changes is a confluence of Figures 5, 6, 7 and 8, each of which is provided at different granularity, and/or over different timeframes and referencing the separate roles of the industry participants in the composition of the final bill received by customers. In this section we provide the Panel with Contact's published numbers which are verified through annual reporting and investor communications.

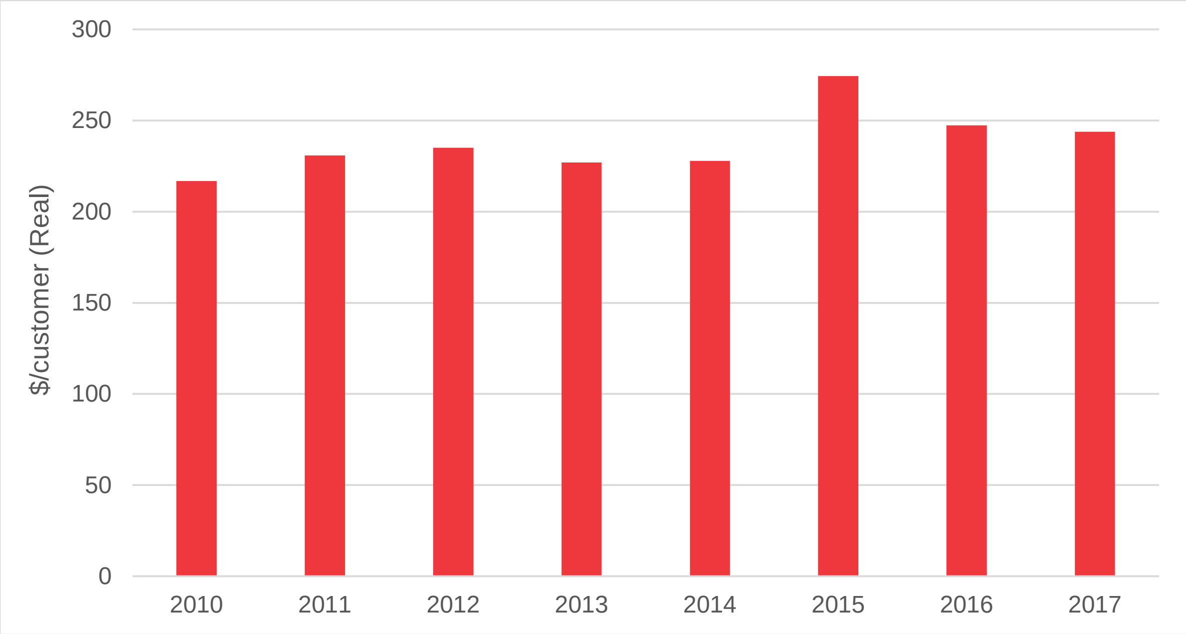
Retailing related costs

The Panel has assessed Contact's retail operating costs as close to $400 per customer per year. This includes the cost of metering services which is regarded as a direct cost of supply and amortisation of capital investment (which is not considered an operating cost). As evidenced in Figure 3 below actual operating costs are closer to $250 per customer[7]. As shown further below, Contact's total operating costs have stayed approximately constant since 2014. We also note that the comparison to Australian costs should take into account the different scale: retailing has a number of fixed costs (including corporate overheads) which, spread across a larger customer base, will be lower on a per-customer basis. Origin Energy's customer base is approximately 4.3m: more than twice the total electricity connections in New Zealand.

[7] This CTS curve comprises: Billing and payments, Credit, Metering , All labour, Sales and Marketing

Figure 3
Contact (Cost to serve), not including metering and capex amortization – 2017 real

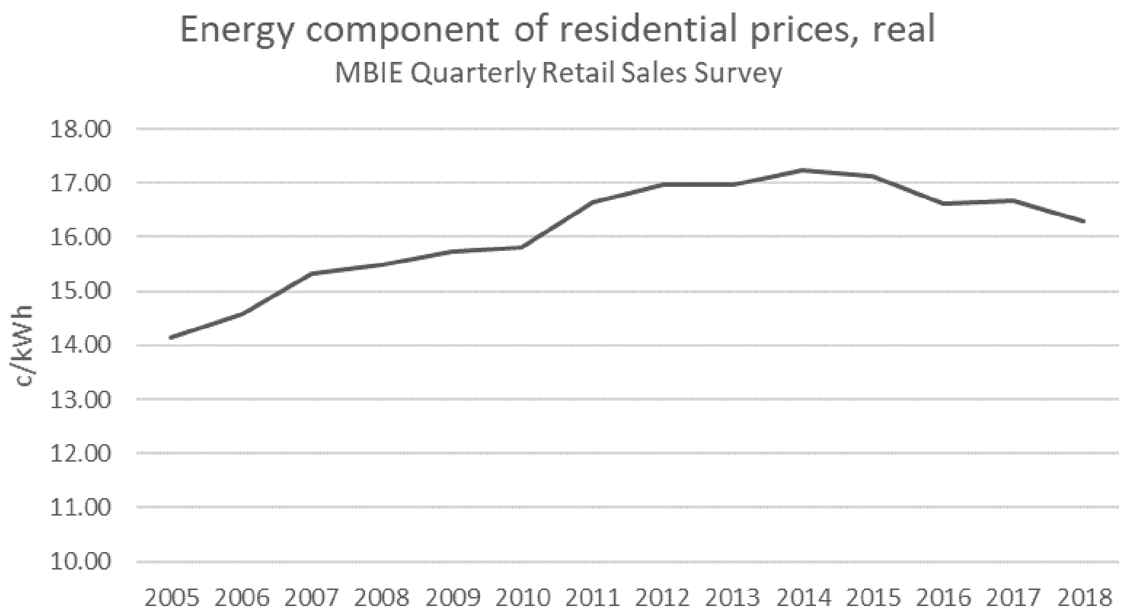
Source: *EPR panel*



As a general comment on the Panel's analysis, it is relatively silent on the fact that the retail prices generally (as illustrated in the Panel's Figure 5) and, particularly, the energy component of residential retail prices (as illustrated in Figure 4 below), has been declining (including Contact's) in real terms since 2014.

Figure 4

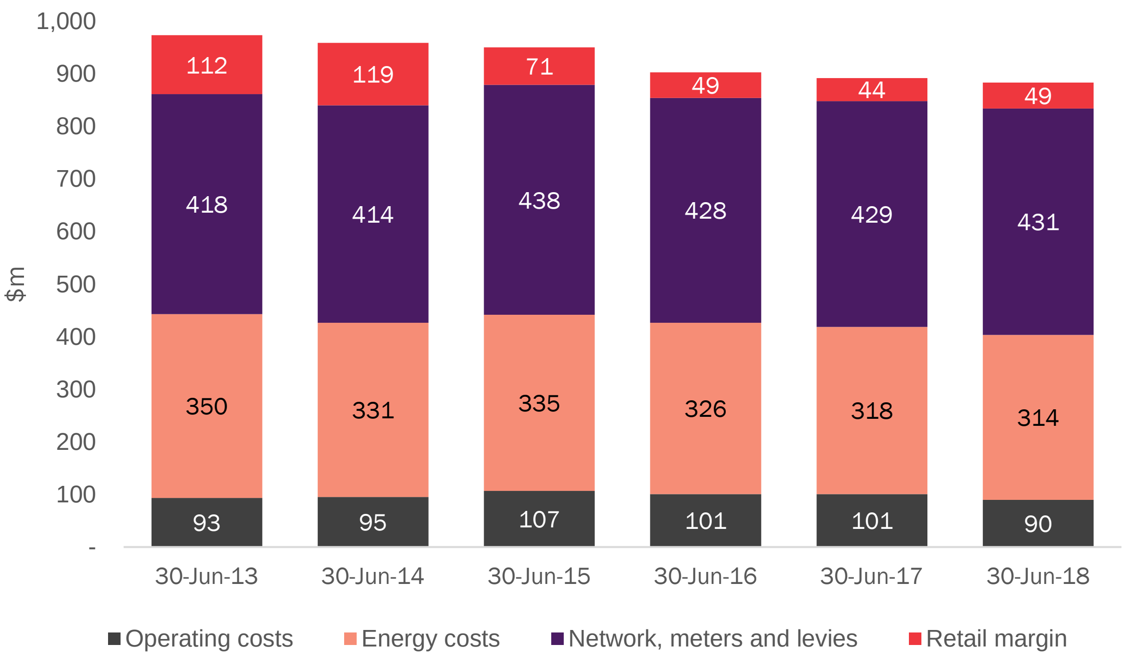
Energy component of residential prices



These more recent price trends have reduced Contact's margin from retailing significantly, as illustrated in Figure 5 below. Since 2014[8], Contact's retail margin has more than halved, from $119m to $49m.

Figure 5

Contact mass market - components of revenue



Energy costs per MWh have be kept flat at $85/MWh

We would urge the Panel to be careful in drawing conclusions about diagnosing any perceived problem based on assumed drivers of increasing retail prices, which may have altered since 1990, as evidenced in Contact's numbers.

We note, though, that the general effect of increasing network tariffs, especially on residential (or, more generally, mass market, which includes SME) customers is still observed over this more recent period, as it is for the prior period (2005 onwards, as illustrated in Figure 7 of the Panel's report). The impact on Contact's mass market revenue is shown in Figure 6 below, which shows Contact's net mass market revenue reducing by 1.3c/kWh since 2013, while the revenue collected for network, metering and levies (the largest component by far being network costs) increasing by nearly 15c/KWh. We have not been able to discern, for Contact's mass market customers, what proportion of this increase relates to transmission versus distribution. But MBIE data[9] suggests national average transmission charges to residential customers increased from 3c/kWh in FY2013 to 3.7c/kWh in FY2018, an increase of 0.7c/kWh. Indicative numbers from the Commerce Commission process suggest that transmission costs are forecast to reduce from 2021.[10]

Contact, as a retailer to fifth of New Zealand's ICPs is proud of our transparent approach to reporting on the components of revenue received from customers. Figure 6 is evidence of this.

Figure 6

Contact mass market revenue components expressed in c/kWh

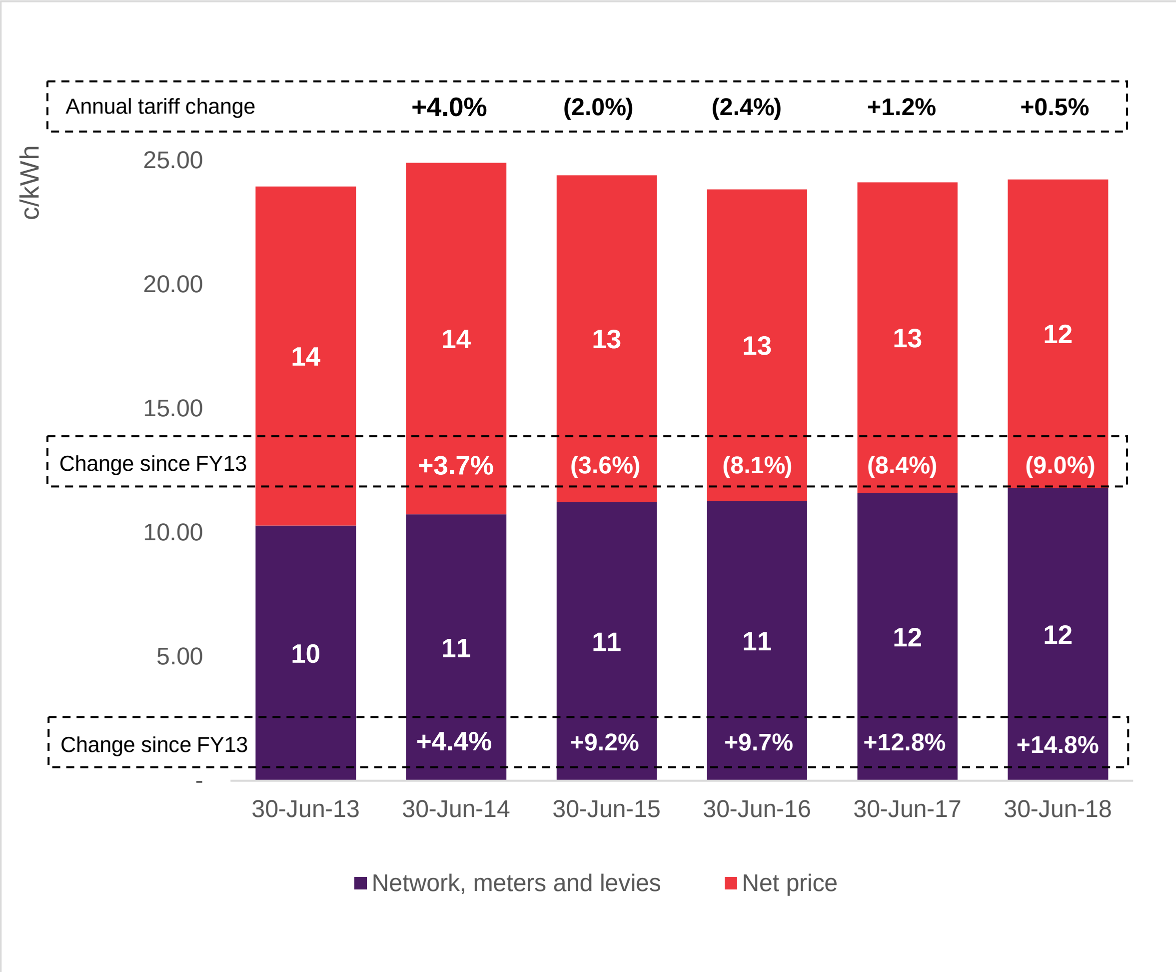


Figure 8 of the Panel's report provides an estimated breakdown of the charges by consumer type. Below Figure 9 and Figure 10 shows the breakdown for Contact's residential customer base. The Panel suggests that the retailer's component of the customer's bill is 5.5c/kWh, Contact calculates this to be 4.8c/kWh based on the fifth of the market that Contact supplies. Contact's average mass market tariff of 24c/kWh is 1c/kWh lower than the Panel's data, in addition the actual network costs paid are higher than calculated in the Panel's report. The competitive nature of the market gives us confidence that all our peers would have a similar average sales tariff and perhaps the differential includes the level of discounting (PPD) or the value of the upfront credits given to consumers.

[8] Contact's figures start at 2014 as this reflects when Contact began segment reporting which aligned with the maturity of the retail market following regulatory changes in the early part of the decade

[9] MBIE's Quarterly Survey of Domestic Electricity Prices, Transmission Component

[10] Transpower: Detail on 2018/2019 Transmission Prices. Published December 2017

Of the 4.8c/kWh collected:

- 1c/kWh relates to pass through costs collected on behalf of regulators (0.3c/kWh) and metering suppliers (0.7c/kWh); and
- 2.2c/kWh is to cover the direct costs of operation including billing, network reconciliations for 29 distribution networks with bespoke pricing constructs, operation of the contact centres, credit and collections including bad debt from defaulting customers, sales activity driven by the competitive market, marketing and incentives to retain customers and the approximately 400 staff that support our approximately 416,500 electricity customers.
- 0.3c/kWh covers 50% of the cost (the other 50% is allocated to Generation) of maintaining a corporate head office including governance and the Board of Directors, financial reporting and control function, ICT systems and statutory listing requirements,
- 1.3c/kWh (~4.6% of the final customer bill) is the margin for the retailer for the risk taken on retailing activities and return for the investment made in systems and new products and services. The retailer margin also needs to fund interest on working capital as the retailer needs to maintain liquidity to continue to operate and collect the money on behalf of all the electricity market participants.

Figure 7
Contact components of mass market electricity tariff (FY18 actual) cents/kWh

Source: *Contact FY18 actual*

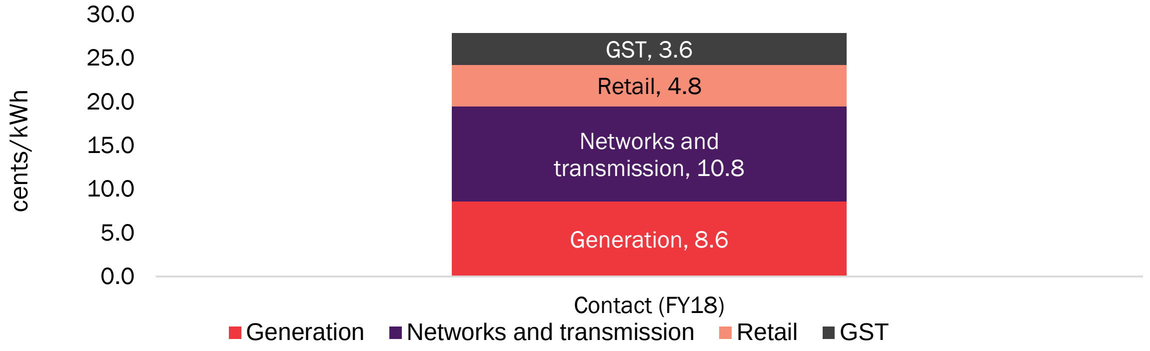
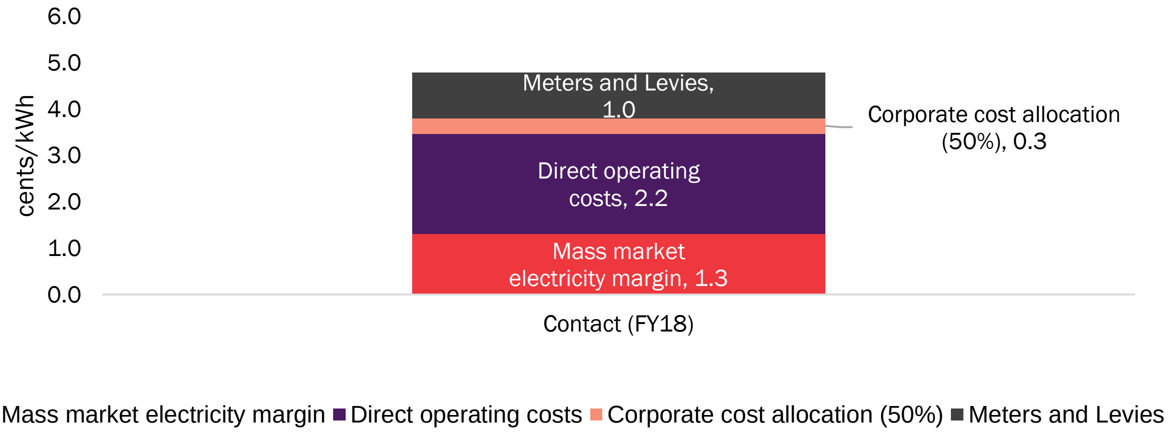


Figure 8
Contact components of retail component of the tariff

Source: *Contact FY18 actual*



The competitive nature of the market gives us confidence that all our peers would have similar average sales tariff and perhaps the differential includes the level of discounting (PPD) or the value of the upfront credits given to consumers.

The Panel's figures and our own data presented in this section demonstrate Contact's improved efficiency as a retailer with reduced operating costs at a time when customers are demanding more from the retailer (as discussed in the answer to Q1). We fully expect the gross margin in retailing, excluding metering and levy costs (as evidenced in Figure 5) which has fallen from $206 million to $139 million over the period 2013 to 2018 (on a steady electricity price assumption) to continue to decline over time. We will maintain our focus on managing our cost base and improving our customer offerings but from this data it will be clear to the Panel that the retailing of electricity in New Zealand is a challenging business and there is nothing in our view to suggest that this will change.

We discuss later that we believe the wholesale cost of electricity will remain flat to declining and with retailing gross margins reducing we expect electricity prices (excluding the effects of transmission and distribution pricing) to continue to fall, even with an increasing demand outlook.

Allocation of distribution charges

The Panel highlight the shifting allocation of distribution charges from 1990 and consider the appropriateness of this shift from commerce and industry to residential consumers. This trend is clear from Figures 5 and 7. We expect the Panel will get significant feedback on this issue which we won't duplicate. However, we are curious why the Panel chose a start date of 1990.

First, this may imply that charges were well balanced amongst consumer groups at that time, and therefore any changes since then are "unbalanced". The Panel's choice of 1990 seems predicated on it being not subject to the "*distorting effects of …earlier, pre-reform years when significantly different structures were in place in the sector*[11]." However, we understand that some power boards (e.g., Auckland Electric Power Board) were still using the old Bulk Supply Tariff in the early 1990s, and the market did not transition to a genuine wholesale approach until 1996.

Second, the period leading up to the separation of lines and retail arms resulting from the 1998 Bradford reforms would have inevitably seen significant value shifting between the network and retail parts of the power boards; various initiatives included the separation of retail and lines charges in the mid-1990s and changes to network valuations. Ultimately, we believe that a sensible starting point for an assessment of the changes in tariffs would more likely be post 1999.

[11] EPR report, footnote 33

5. *What are your views on the assessment of how electricity prices compare internationally?*

We agree with the Panel's view that NZ prices compare favourably internationally. We note that, while it is tempting to make direct comparisons between countries, underlying characteristics such as fuel availability and costs, sector-specific charges (e.g., for regulatory programs), scale and market design all impact a country's ability to achieve a low-cost electricity system. In many ways, it is a remarkable achievement that a small, isolated country such as NZ is mostly beaten on price by countries that are substantially bigger.

Similar, we caution the Panel against making simple trend comparisons, such as its conclusion that "Since 2000, New Zealand's residential prices have risen faster than residential prices in most OECD countries, whereas New Zealand's industrial prices have risen at a slower rate than industrial prices in most OECD countries". Comparing sub-sectoral trends over an 18 year period does not in any way illuminate policy, regulatory, and market changes in those other countries, over the period of comparison. New Zealand largely completed its structural reforms in the 1990s, and was an early mover, while some of the other OECD countries may have made similar reforms more recently.

6. *What are your views on the outlook for electricity prices?*

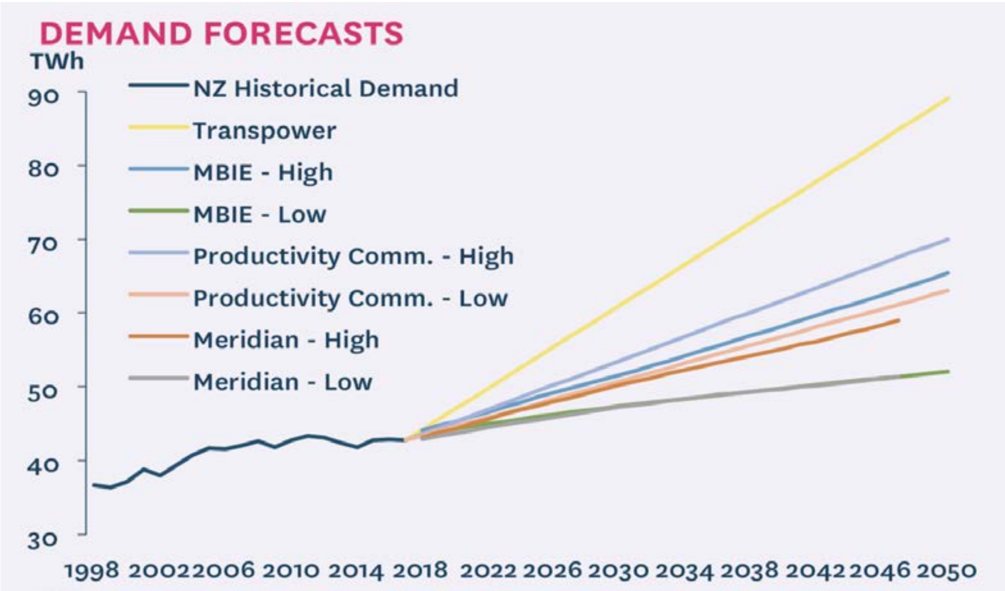
We agree with the Panel that, fundamentally, the future of electricity prices is a balance between the rate at which demand increases, and the rate at which technology costs may come down. Ultimately, it is the cost of expanding the generation fleet and upgrading transmission and distribution to securely meet demand over the long run which will drive retail prices, as these prices must ultimately recover the fixed and variable costs of electricity supply.

In terms of demand increases, we note that there is a range of views in the industry. Figure 9 below illustrates a number of these views; the differences relate to underlying assumptions about:

- Energy efficiency and intensity
- Economic growth
- Population growth
- Behaviour change
- Uptake of new technology (e.g., electric vehicles)
- Electrification of industrial processes

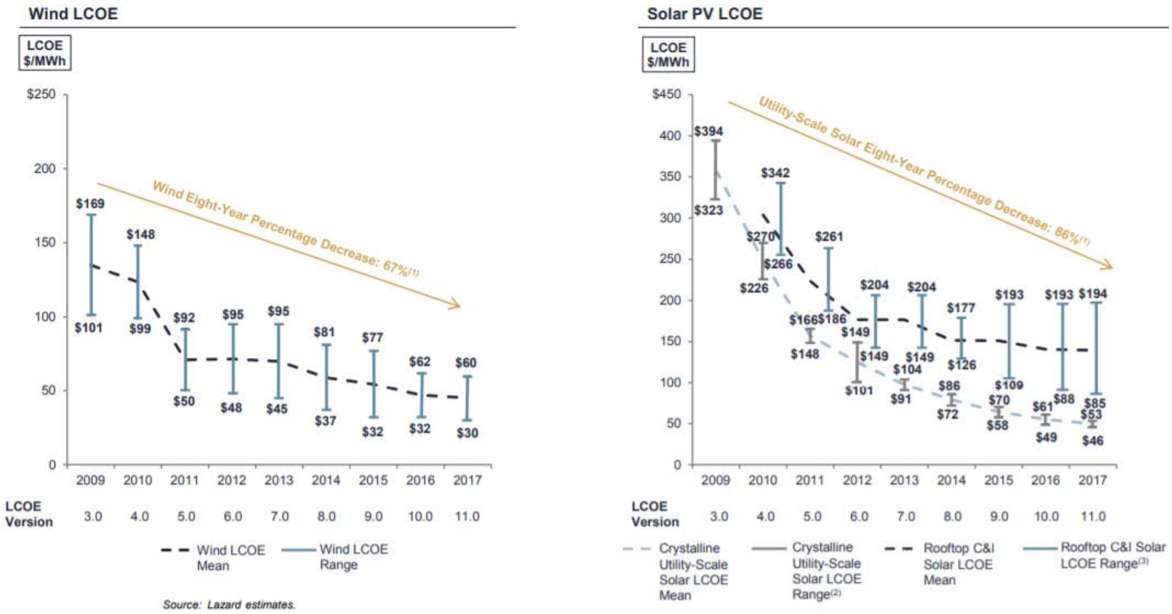
All projections in the chart below show that demand is expected to grow in the future. But it is the timing and rate of growth that is uncertain; the period of flat demand from 2007 after an extended period of growth at 2% per annum was not forecast. Our caution would be that the industry has consistently failed to achieve accurate demand forecasting.

Figure 9



In relation to technology costs, it is well known that the costs of some renewable technologies (e.g., wind, solar) have declined significantly over the past decade, and are expected to continue to do so. Financial advisory and asset management firm Lazard shows this rapid decline since 2009 for both technologies. Refer Figure 10 below.

Figure 10: Lazard's historical cost curve for wind and solar PV (Unsubsidized Levelised Cost of Energy–Wind & Solar PV)[12]



Lazard's cost curve for wind appear to resonate with wind generator's statement that "*the cost of wind generation has fallen around 85% since 1983*" and that "*the levelized energy cost for new wind generation in New Zealand is in the range of approximate $65 to $95 per MWh with significant variation from project to project*"[13]. These technology trends are expected to continue,

While grid-based generation investment is likely to pick up these cost reductions, to obtain maximum benefit from solar PV (as well as storage) trends, all customers should have access to distributed technology (noting the impacts on distribution networks), to enable increased competition in the distributed generation sector, as well as ensuring the benefits of falling solar costs reach customers.

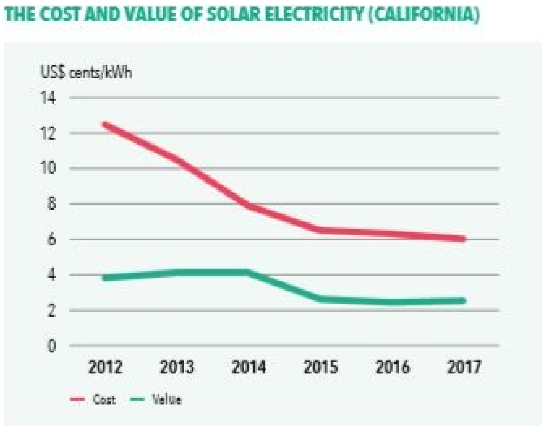
While the cost of intermittent renewable technology itself will likely continue to decline, the value of these technologies to the system, net of the cost of providing flexible generation to manage the intermittency, may decline as renewables' role in the electricity system increases. Infratil illustrate this as a comparison between the cost of solar and the value it provides to the system (Figure 11[14]). This highlights that enabling flexible plant to respond to these variations is an important challenge for decarbonization. Beyond the electricity market *per se*, there is a role for the Resource Management Act (and the National Policy Statement on Renewable Electricity Generation) and the decision makers (in most cases regional councils) to enable greater hydro reservoir ranges (and hydro ramp rates) to manage this intermittency, and the fact that solar will provide less electricity during the high demand time of year (winter).

[12] As quoted in Stevenson, Batstone and Reeve, 2018, "Transitioning to zero net emissions by 2050: moving to a very low-emissions electricity system in New Zealand"

[13] Meridian submission to Productivity Commission, Box 1, p5. See https://www.productivity.govt.nz/sites/default/files/sub-low-emissions-253-meridian-energy-701Kb.pdf

[14] Infratil Update September 2018

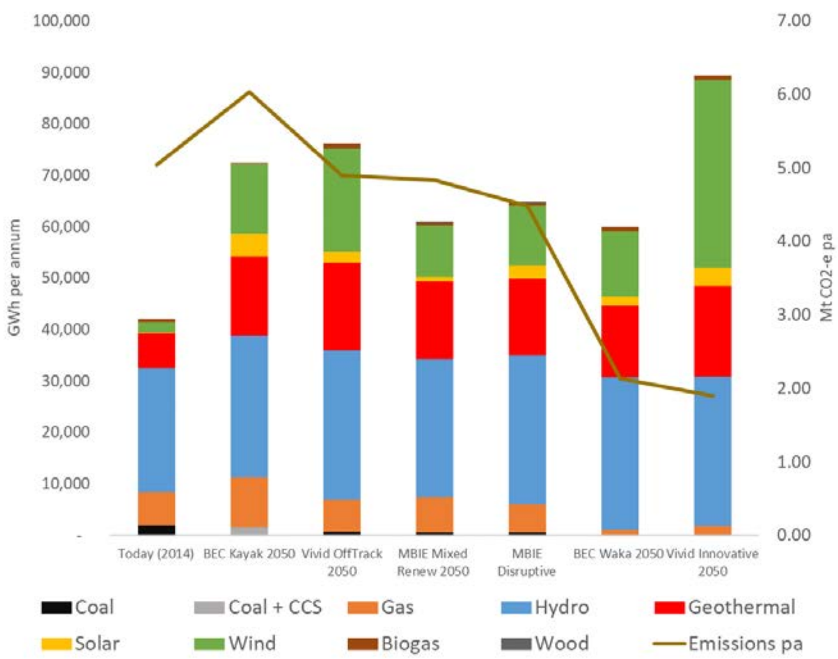
Figure 11



Finally, the cost of generation plant is only one factor in the cost of building new supply. The energy yield of particular sites, the costs of developing those sites, transmission, distribution and metering all contribute to retail prices.

The net effect of increasing demand and falling technology costs is hard to predict. However, the fact that meeting New Zealand's decarbonisation objectives is likely to result in significant investment in wind, especially in a high demand uptake scenario, as demonstrated in Figure 12[15], bodes well that wind's declining costs will flow through to electricity prices. Additionally, geothermal remains a competitive alternative to meet New Zealand's decarbonisation goals. As illustrated in the EPR[16] report, wholesale contract prices have fallen approximately in line with reducing costs of new generation over the past 10 years. This highlights that, in the wholesale energy market at least, contract prices do respond to the changing costs of investing in electricity supply expansion and we expect this to continue its downward trend. Contact has undeveloped geothermal resource and if developed we fully expect this to be at a lower cost than our last development in 2014.

Figure 12



[15] Stevenson, Batstone and Reeve, 2018, "Transitioning to zero net emissions by 2050: moving to a very low-emissions electricity system in New Zealand, Report for Productivity Commission."

[16] Ibid, Figure 14, p33

Affordability

7. *What are your views on the assessment of the size of the affordability problem?*

Contact agrees with the Panel's finding that there are a group of vulnerable consumers who are struggling. This is not unique to the electricity sector and requires an appropriate social policy response by government.

Hardship is a multi-faceted problem, and any assessment of its "size" must begin with a robust definition before the Government and policy makers move to possible solutions. To that end, together with a number of other retailers Contact commissioned PwC to undertake an assessment of how many households could be defined as being in a high degree of energy hardship. The Panel will be receiving that report through the submission from ERANZ.

8. *What are your views of the assessment of the causes of the affordability problem?*

Our discussion in Question 7 adequately covers our views on the causes. Figure 12 of the Panel's report reinforces that location, choice of heating fuel, size of household and the extent of insulation are the critical factors contributing to affordability.

9. *What are your views of the assessment of the outlook for the affordability problem?*

Our promise to customers is to make a positive difference to their lives and prosperity. We do this by taking action. As a retailer putting customers at the centre of everything we do we have been taking action that has and will continue to make a difference for our customers. Examples of this are:

- Our objective is to find solutions for every household to have access to energy and not be disadvantaged. The way we approach credit has also significantly changed over the last few years. Over the last quarter of FY18 the average debt at disconnection was reduced by 35% to $527. This has allowed customers to be reconnected faster, with 47% reconnected within 24 hours, up from 27% in FY17. We have also reduced the costs of disconnection and reconnection for our customers, and we've improved the number of reconnections made within the first 24 hours of a disconnection occurring.
- We recently launched our new PrePay product. This offers control and flexibility and enables better financial management for every household. This means our customers on this product will automatically get Prompt Payment Discount (PPD), they won't pay any additional fees and it applies to all our tariffs. The Panel has queried whether there is a need to enhance retailer of last resort provisions. The early results from the launch of this product would suggest that regulatory intervention is not necessary: 71% of our customers who would have failed our credit checking processes have signed up for PrePay. This is evidence of the market solving customer issues in a way that works for the customer.
- More than 10 years ago we introduced SmoothPay. This product allows customers to smooth their payments out over a 12 month period removing the winter peak of energy charges as customers use more energy during the winter months. Customers overwhelmingly tell us they love this product. This payment method applies to any product and doesn't cost the Customer anything to set up or maintain.

- Our customers told us matching their electricity bill to their pay cycle would really help. It is a simple thing but with 80% of kiwis on a weekly or fortnightly pay cycle getting a monthly bill can be a challenge. We introduced weekly and fortnightly billing in July 2018. We are the first large retailer to do this.
- We are launching products that will give customers the choice, flexibility and control that their household values. Our pipeline of products includes
    - 'no-frills' product which will allow customers to choose our lowest tariff without a PPD
    - giving customers a "free bill" so that we can help customers with their budgeting needs
    - 'free passes' so if a customer inadvertently misses paying their bill on time they will still benefit from PPD

Contact is going to continue to take action to give customers the choice, certainty and control they tell us they want.

Most of the new products can be offered because of the voluntary deployment of smart meters in New Zealand. Deployment of smart meters is sitting ~80%. Contact's deployment sits on average at ~80% but with a material deviation: metropolitan deployment is at ~87% while some of regions with low population density is between 65 and 75% roll out. Contractor resourcing and distance is a contributing factor[17]. Other factors would be customer refusals, landlord refusals, meter board issues and wiring issues. Despite these challenges, we have taken the decision to offer customers a smart meter and we will to do this at our cost[18]. Where we need help from the Panel is to ensure the ecosystem that sits around smart meter deployment is optimized. For example not all landlords co-operate with the installation of a smart meter and health and safety regulations have an impact on the role out of meters (many old meters have asbestos in them).

In the meantime we will continue to fund the deployment of smart meters for customers to be able to access products which continue to address the "affordability problem".

[17] Installation per contractor per day in a high population area would be about 10 per day, whereas the number could decrease to 5-7 in rural regions

[18] Between FY12 and FY18 Contact spent $6.4million on installation of smart meters into our customers' homes

Summary of feedback on Part three

10. *Please summarise your key points on Part three.*

Contact's customers tell us they want choice, certainty and control, and today's competitive retail market has delivered these to an unprecedented level. Competition has encouraged retailers to compete vigorously on price and service, understand customers' needs and tailor product offerings accordingly, to a greater degree than at any time in history. Our evidence of this is that:

- today, electricity customers enjoy an unprecedented level of tariff and retail provider choice, as well as a large array of fixed tariffs which provide certainty and control. This is evidenced both by Contact's tariff offerings expanding from 3 in 2014, to 10 today, as well as the number of retail companies growing from 11 in 2011 to 33 today;
- the voluntary rollout of smart meters – currently sitting at around 80% - has been a significant enabler;
- independent surveys of consumer trust, net promoter scores, and customer complaints all point to a positive trajectory;
- the competitive environment has also placed downward pressure on the energy component of customer bills. Competition has compressed Contact's retail margins, with mass market margins reducing 9% since 2013. But, despite a highly competitive environment which has resulted in increased complexity, Contact's cost-to-serve has remained roughly constant at $250 in real terms (well below the Panel's estimate) since 2010.
- The current falling costs of generation supply options (e.g., wind), as well as the new era of intensified competition for generation driven by reducing solar PV costs, points to the possibility that - if managed efficiently through the current wholesale market framework - there will be pressure on the energy component of prices.

Contact's promise to customers is to make a positive different to their lives and prosperity. We will find solutions for every household to have access to energy. We agree with the Panel's assertion that, despite the significant benefits enjoyed by most customers as a result of vibrant competition, there is a group of customers who are struggling. We agree, and, jointly with other electricity retailers, we commissioned PwC to help define the vulnerability challenge.

Our own efforts so far have:

- reduced the average debt at disconnection by 35%, increased reconnection times, and reduced the costs of disconnection and reconnection.
- launched a number of products which have features targeted at customers who are struggling to pay their bills.

Contact believes the issue of customer hardship is the most pressing issue the industry faces. In our view, the industry's response, in collaboration with government and social agencies, must be properly targeted at the essence of the problem. Poorly designed or broad-based interventions, at any point of the electricity supply chain will have impacts across the whole market. This includes investment and thus security of supply; a critical factor that the market has delivered on, with substantially superior outcomes for consumers than the 30 years of government-driven investment that preceded it.

We encourage the Panel to recommend that policy makers define the problem of hardship and target a response carefully in order to not risk the significant benefits customers are enjoying as a result of the high level of competition in the retail sector, nor the efficiency of the whole supply chain.

Solutions to issues and concerns raised in Part three

11. Please *briefly describe any potential solutions to the issues and concerns raised in Part three.*

Every customer's bill is a function of both their network tariff and their consumption levels. Figure 12 in the Panel's report showing the 'Impact of factors affecting consumption and price' clearly provides the signpost to the effective levers for impacting affordability. We would strongly recommend the Panel weight their recommendations for change to the factors that are most impactful to customers:

Price: Network prices are critical in determining the price paid by customers. Significant differentials in network prices are evident primarily due to location and population density.

Consumption: The quality of New Zealand's housing stock is key to reducing bills/improving affordability for customers.

In addition we will continue to find solutions for every household to have access to energy, including:

- releasing products that have features targeted at helping those customers who are struggling e.g. SmoothPay, revamped PrePay, Weekly/fortnightly billing, No Frills
- improving our credit practices so customers incur less debt with us
- equipping our customer service representatives with training and tools to help vulnerable customers

During a period of vibrant competition and downward pressure on the energy component of the bill we have improved outcomes for our customers. At the same time the monopoly network component of the bill has been steadily rising. The Panel could recommend that policy efforts are directed at how competition for distribution services could be strengthened and encouraged, so that, in the long run, we become less reliant on the blunt nature of monopoly regulation and we provide the optimal environment for incentives to innovate and compete.

Part four: Industry

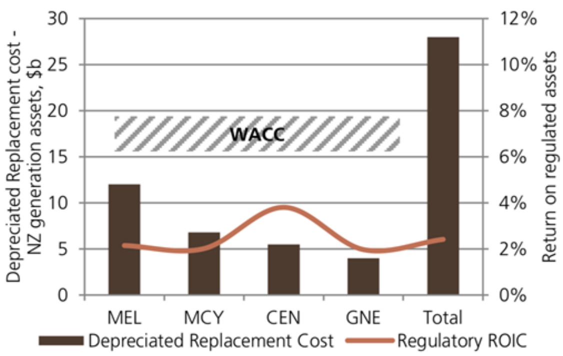
Generation

12.	*What are your views on the assessment of generation sector performance?*

We generally agree with the Panel's commentary on generation sector performance. Investments in generation over the period of analysis has delivered a 46% decrease in greenhouse gas emissions since 1999 (when the major generator market participants in their current form were established), while wholesale electricity prices have remained approximately constant over the same period. Numerous other countries would be very envious of this record.

We agree with the Panel's assessment of wholesale contract prices as compared to the LRMC of building new generation. However, we note that the Panel has only assessed this from a baseload perspective. Similar assessments need to be made for peaking plant (which do not earn the "average" price). But, fundamentally, we support the Panel's conclusion that "[contract] prices that were above costs on a sustained basis would suggest weak competition among generators, and that the entry, or threatened entry, of new generators was not restraining prices."[19] The fact that wholesale contract prices are trending downwards in line with the cost of new generation (little of which has actually been built) provides evidence that the generation market is being restrained by competition. Another way of looking at this issue is through generators returns relative to WACC. The conclusion in the September 2018 UBS[20] report, as evidenced in Figure 13 below, is that generators' returns relative to WACC have been restrained by competition.

Figure 13



Our analysis points to a depreciated asset base of c. $28b for NZ generation assets. This compares to our post tax profit estimates of c. $0.7b and implies a return for regulatory purposes of around 2.5%, well below WACC.

More broadly, we strongly encourage the Panel to interpret this analysis as showing that - to the extent that can reasonably and practically achievable in commodity markets around the world, let alone those with the complexity of electricity - the current market design has done an extraordinary job of delivering dynamic efficiency: the right investments have been delivered at the right time and the right place, and at the least cost to the consumer. While numerous market commentators would suggest that "more optimal" investment trajectories could be discovered, they are unable to provide concrete evidence that this would have been practically achievable, and/or they also fail to recognise that, under the current market framework, any errors of judgment in respect of investment would mostly be concentrated in the hands of private investors, rather than government (and thus taxpayers). While the current wholesale market design will, inevitably, need to continue to evolve with changing plant mix and consumer preferences, it is fundamentally a success. Major changes in direction should only be considered with great caution[21]as explained by Adjunct

[19] EPR report, p32

[20] UBS, New Zealand Electric Utilities: Winners and losers as cash-flow nirvana fades, 31 July 2018. NB the 'our' in the text box is referring to UBS

[21] We refer the Panel to Section 6.3 in the attached Read report for a discussion of the risks associated with the re-introduction of regulatory influence over investment decisions

Professor Grant Read in his report "An Economic Framework for the New Zealand Electricity Market"[22]. This discussion supports the Panel's assertion that, if wholesale contract prices were held sustainably above LRMC, generation entry would occur. It also strongly cautions against the types of analyses the Panel raises[23] that use estimates of SRMC to assess whether excessive profits are being made.

13. *What are your views of the assessment of barriers to competition in the generation sector?*

We reiterate our analysis above that there appears to be no evidence that generators have been able to sustain wholesale contract prices above the LRMC of new generation. Hence any assertion that barriers exist need robust evidence.

The Panel raises the issue that "smaller generators often cite the limited depth of the contract market as the key factor inhibiting their expansion or new generation entry"[24]. Assertions like this should be complemented with information regarding the price these smaller generators needed to secure from the contract market to expand or enter. Uneconomic investments should not be able to secure contracts from the market at a price that recovers their cost: indeed, this is the very point of our deregulated wholesale market design. In fact, over the past 5 years, few investments, irrespective of whether they were from smaller or larger generators, have been able to proceed due to the benign demand environment and low contract prices.

In respect of barriers, we also comment below in our answer to Question 14.

14. What are your views on whether current arrangements will ensure sufficient new generation to meet demand?

We direct the Panel to our answers above (Q6) regarding the outlook for generation.

We agree with the Panel that, more than any time in recent history, the generation sector is facing competition from small-scale generation such as rooftop solar panels. Hence the future will see competition between distributed systems and grid-based systems. These forms of generation need to be able to compete on their merits, in order to result in the lowest-cost outcome for all consumers. This may require some changes to the industry Code to ensure that the net benefits of distributed energy resources (DER), including storage, are properly recognised and reflected in the market for new generation. But again, the structure and nature of the wholesale market is fundamentally sound.

Further, while the absolute magnitude of some of the high-electrification demand scenarios suggest substantial investments in generation, this isn't all going to happen at once. While we welcome the question of whether the current market and industry arrangements can meet this level of demand, we reiterate that there is no evidence to date that it cannot.

[22] We particularly draw your attention to the discussion and analysis in Chapter 8 ("Appendix: Market Performance and Entry Barriers") which conducts an analysis of actual market returns to CCGT and OCGT peaking plant over the period 2010-2016, an identical period of analysis to that used by Dr Steve Poletti's report "Market Power in the NZ wholesale market 2010-2016". Earlier sections in the report (Chapters 2 - 4) expand on the issue of using SRMC estimates to assess whether excessive rents are being earned by generators.

[23] EPR report p32

[24] EPR report p34

Retailing

15.	*What are your views on the assessment of retail sector performance?*

We refer the Panel to our discussion regarding retail costs presented in our answer to Q4 above. The Panel asserts is that there may be evidence of a two- tier retail market developing. Taking each of the Panel's areas of focus in turn:

Switching: The Panel's findings traverse a number of drivers and outcomes of switching activity. Using tenure as a proxy Contact's customer numbers reflect the Panel's findings of how many customers are unlikely to have switched. In our experience many of these customers don't want to engage and we have no evidence the lack of engagement is for the reasons suggested by the Panel. Customers that have been with us for more than five years are challenging to engage. For example, typically when communicating price changes we offer customers an ability to choose a product with greater price certainty and control, uptake on these products is extremely low with 3.2% take up in 2017 and 1.62% in 2018.

Prompt Payment Discount: 93% of available prompt payment discount was taken up by Contact's customers. Our customers' tell us they value this but the recent public discussion on how this is perceived has caused us to take a look at our product offerings. We will launch a 'no-frills' product which will have no PPD but a lowest tariff. What we won't do is impose that product on all our customers. A one size fits all approach is not fair for customers and reflects the panels view there is "no typical consumer". We value offering choice which for us at Contact means offering up quality bundles of energy products and services.

Tariff dispersion: The limitations of our system haven't allowed us to compare the Contact numbers with the Panel's tariff dispersion in Figure 16 of the report. We are curious to learn whether the calculations include the TECT rebate in Tauranga. This averages about $400 per annum and will have a distortionary impact on the calculations. What we can assure the Panel is that we no longer offer the lower levels of PPD to new customers that would be included in the pre-2014 data used by the Panel so we expect the tariff dispersion to be significantly less.

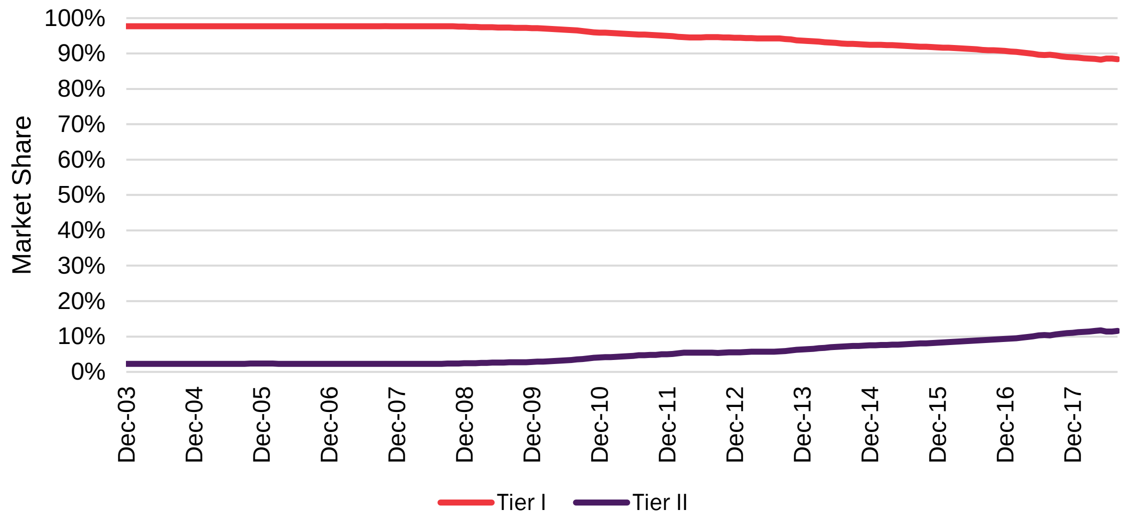
If the Panel concludes that intervention is required to remedy the findings of a two-tier market we would strongly caution against poorly designed regulatory interventions which may have unintended consequences. The Panel may be aware of the challenges in the UK with a number of retailers failing and with reports from the UK this week that the price cap is in danger of making bills more expensive after a 21% increase in the price of cheapest deals in a five month period.[25]

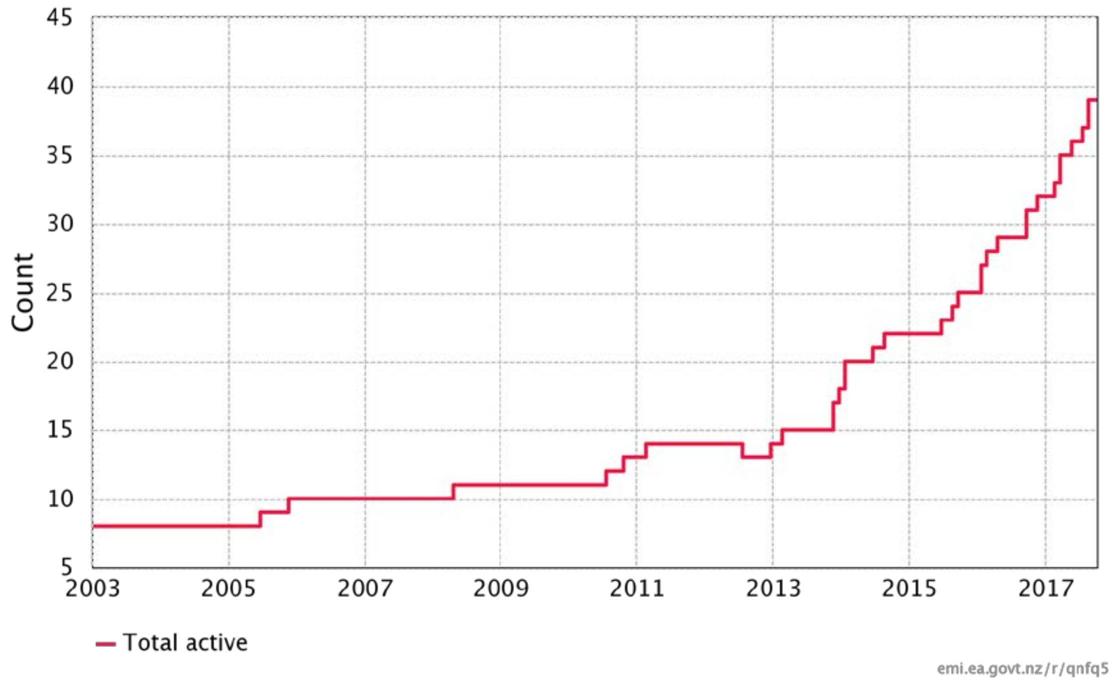
[25] https://www.thetimes.co.uk/article/usio-is-latest-energy-firm-to-burn-out-8skwjs95d?shareToken=62f3e2ed731c325fcf18484158ce8950;

16. *What are your views on the assessment of barriers to competition in retailing?*

The expansion of both the number, and market share, of Tier II retailers[26] suggest that there are few barriers to market entry. It would be very difficult to argue that there should have been a greater increase in the number of retailers over the past five years, than that observed (Figure 14 below).

Figure 14
Growth of Tier II retailers





[26] Tier I retailers are Contact, Mercury, Genesis, Meridian and Trustpower. Tier II are all other retailers.

In terms of barriers to expansion, the Panel cites the Australian regulator's belief that the decline in market share of larger retailers is "slow and doesn't appear to be gathering pace". We would like to know the basis on which this statement is made, and what pace is expected by the Panel. On 15 October 2018 Energy News reported on the September switching data and noted the success of all Tier II retailers in gaining customers from the large retailers[27]. The scale and pace of the Tier II growth is impressive.

We encourage the Panel to consider a broader range of factors which may limit, or delay, the expansion of smaller retailers. There are a number of factors that contribute to a "lumpy" cost profile as the number of customers served increases, for example:

- **Risk management**: with a small number of customers (shortly after entry) managing wholesale risk may be able to be absorbed or managed in a simple fashion, but as customer numbers grow, risk policies need to be developed, and a range of risk products may need to be negotiated and settled. This adds a prudent level of complexity.
- **IT systems**: e.g., customer relationship management and billing systems; initially a small number of customers can be dealt with and billed using simple systems, but growth requires more sophisticated and complex systems which have specific skill requirements and high up-front costs.
- **Pricing complexity**: competition is greatest in the urban centres, which may limit growth; if growth is pursued outside these centres small retailers must manage multiple use-of-system agreements (UoSAs) with multiple distributors, and thus multiple network charge structures.
- **Product range** – the range of products (e.g. electricity, natural gas, LPG, broadband, phone and potentially petrol) offered by retailers is increasing and this reduces a retailer's cost profile. However, all retailers (regardless of size) have the option of offering multiple products. The combined benefits of multi product offerings may also explain why some chose not to switch retailers. The days of a stand-alone electricity retailer are quite possibly numbered.
- **Distribution price allocation**: Given the wide range of allocation methodologies some regions are more profitable from an energy perspective than others. We believe it would be worth the Panel investigating whether this is a barrier to expansion.

We note that the Panel's commentary on retail barriers focuses on saves and win-backs. In an average year, Contact would save or win back approximately 750 customers on a net basis. We would not consider this is a material number. Secondly, while we are not opposed to the telecommunications model highlighted by the Panel[28] we would caution against any objective to eliminate the benefits a customer naturally should enjoy from shopping around. This is observable in many other commodity markets, where retailers, for example, promise to match or beat a competitor's price. Prohibiting saves and win-backs may also be problematic if a retailer is selling multiple products to customers.

[27] https://www.energynews.co.nz/news-story/switching/39568/trustpower-suffers-worst-customer-loss-year-electric-kiwi-continues-gains?utm_source=newsletter&utm_medium=email&utm_campaign=energy-news-newsletter

[28] EPR report p42 and footnote 103

Vertical integration

17.	*What are your views on the assessment of vertical integration and the contract market?*

We believe the Panel's assessment of vertical integration is appropriate. Vertical integration has costs and benefits; any case for structural separation would need an evidence-based assessment of the changes to the costs and benefits. We also believe that such an assessment would highlight the capital intensity (and risk profile) of generation investment; while some generation options in a vertically integrated portfolio offer flexibility that are not reflected in standard Over the Counter (OTC) or futures products, this flexibility comes at a cost – the need to secure fuel, operations and maintenance, and mid-life refurbishments, which are all capital-hungry aspects of operating a generation portfolio. Only once the true cost (and value) of a generation portfolio is established can the relative merits of vertical integration and independence be established.

We agree that vertically integrated firms have a much lower need to use contract markets than an equivalently-sized independent retailer or generator. This lower need is partly due to the $billions of capital they have invested in generation, in a risky market environment and no guarantee that they could continue to secure their LRMC in a highly competitive retail market. That said, liquidity does exist in OTC and ASX markets, the latter due to the voluntary market making agreements that exist between four of the five Tier 1 retailers and the ASX[29].

The evolution of the ASX has lowered the barriers to entry to smaller retailers but there are still costs and complexity associated with managing a futures portfolio. We would welcome a discussion on whether these costs could be further reduced, and whether a wider range of speculators could be encouraged into the market to further improve liquidity and efficiency.

The Panel highlights the issue of bid-ask spreads during scarcity periods; Contact would ask why any prudent independent retailer would be materially exposed to these spreads during the period of scarcity: an independent retailer would be courting disaster if it had left the bulk of its hedging requirements until the period when it needed the hedges. Indeed, the Electricity Authority's stress testing regime was introduced to explicitly encourage hedging in advance of stress periods, for this very reason.

In terms of the ability of independent retailers to compete with vertically integrated companies, Contact does sell material (and flexible) volumes directly to a large Tier II retailer that is consistently gaining customers. The pricing for these contracts is ASX-based and shaped (and located) to better match a retail profile and in FY18 we sold 302 GWh, equivalent to 43,000 households via this channel. We have made this structure available to other Tier II retailers and are ready to support increased sales to prudent retailers.

[29] We note that Trustpower does not participate in the market making arrangements.

18. *What are your views on the assessment of generators' and retailers' profits?*

We generally agree with the Panel's assessment that there is little evidence that generator retailer profits are excessive. A more robust assessment of this issue would be possible with business-unit level data (separating generator from retailer data) such as that Contact has been pursuing through its reporting and transparency around transfer pricing.

We reinforce our recent experience of a compression in retail margins, despite relatively constant costs-to-serve, as outlined in Q4. We also direct the Panel to Adjunct Professor Grant Read's attached report which highlights the need for the cashflows generated from wholesale and retail markets in order to pay back the fixed costs of generation plant. Read's assessment suggests that wholesale market cashflows have, if anything, been slightly insufficient in recovering the fixed costs for thermal and geothermal plant, based on today's costs, which underscores the importance of any additional premium arising from longer term contracts (OTC and retail customers) for vertically integrated generator retailers.

Transmission

19.	*What are your views on the process, timing and fairness aspects of the transmission pricing methodology?*

The Transmission Pricing Methodology needs to be settled. Contact's views through all the various consultation rounds over many years have been consistent and as requested by the Panel we won't repeat them here. Our urging would be for the Electricity Authority to get on and make a decision, make it in relation to future transmission investments only, ensure it is durable and that it provides certainty for customers contemplating the switch from fossil fuels to electricity.

Distribution

20. *What are your views on the assessment of distributors' profits?*

We agree with the assessment that distributor profits are largely in line with the WACC, however this assessment does not consider whether the use of a 67th percentile WACC is justified in the first place. We have commented in past submissions to the Commission[30] that using a 67th percentile WACC rather than a mid-point WACC costs consumers over $70m per annum, which by design is creating excess profits for distributors. We don't propose to traverse the issues here but would be happy to engage with the Panel if that would be useful.

21. *What are your views on the assessment of barriers to greater efficiency for distributors?*

One potential barrier is the structure of distribution prices. These are important as they create price signals needed to reduce peak demand and future network investment, to minimise costs for consumers.

In our experience dealing with networks and consumers on demand response trials we haven't got any evidence that simple TOU or demand charges are likely to have a material impact on load shape. In fact these tariffs have the potential to have unintended consequences including creating artificial peaks and over-reward new technologies like solar and batteries, placing additional costs on other consumers.

There are a number of possible approaches to creating efficient pricing signals (and more than one approach might form part of the overall solution):

- Granular distribution pricing (ultimately towards half hour 'spot' type pricing)
- A 'distributed system operator' (DSO) role at the distribution level, similar to Transpower's role as the System Operator at a transmission grid level
- It could also involve a 'demand response program' at the distribution level, again similar to Transpower's program at the transmission level

Due to New Zealand having 29 distribution networks, standardisation is essential to minimise barriers to entry for retailers, demand response and other service providers, to encourage competition and innovation for the benefit of consumers. Standardisation could be achieved in a number of ways, including through a DSO.

22. *What are your views on the assessment of the allocation of distribution costs?*

We will leave others to comment on this question.

[30] https://comcom.govt.nz/__data/assets/pdf_file/0016/61234/Contact-Energy-submission-cost-of-capital-update-paper-5-February-2016.pdf

https://comcom.govt.nz/__data/assets/pdf_file/0018/61128/Contact-Energy-Submission-on-IM-review-draft-decision-4-August-2016.pdf

23. *What are your views on the assessment of challenges facing electricity distribution?*

Competition will produce the best outcomes for consumers. To this end we support the "platform provider" model (as opposed to the "value added services model" noted by the International Energy Agency in their review of the distribution sector. The platform provider approach is essential to creating a level playing field between all new technology service providers, ultimately to support a competitive marketplace which delivers product and service innovation, and lower costs for consumers.

We have advocated our support for the "platform provider" model in numerous Commerce Commission consultations and will continue to do so but see the Electricity Price Review as an opportunity to review the legislative issues that get in the way of this[31].

[31] For example S52T(3) and 54Q of the Commerce Act and the definition of 'electricity lines services' in the Electricity Industry Act are examples

Summary of feedback on Part four

24. *Please summarise your key points on Part four.*

Our feedback on Part Four continues the theme that vibrant competition is delivering very real and tangible benefits to consumers. Ultimately, the cost of energy to the final consumer is driven by the cost of electricity supply. The wholesale market framework that was established in the 1990s, and has been evolving ever since:

- Has been stable and performed extraordinarily well, in the context of other capital-intensive industries and electricity markets globally;
- Has largely delivered the right investments at the right price and at the right time, in a way which has maintained security of supply;
- Has delivered a 46% decrease in electricity sector greenhouse gas emissions since 1999;
- Is demonstrating that average wholesale prices are being disciplined by the threat of entry of new plant; and
- As commented on previously, the prospect of intensified competition for generation (and networks) from distributed energy resources bodes well for the future.

Hence we generally we agree with the Panel's assessment of the performance of the generation sector. If the Panel remains uncertain of their initial conclusions, we direct them to the report that we, along with other market participants, commissioned from Adjunct Professor Grant Read. This report provides a comprehensive framework within which the Panel can assess the performance of the wholesale market, and respond to others' assertions that excessive rents are being made.

While some may assert that there are barriers to competition to retail, and/or that a "two tier" retail market is emerging, we express the following caution:

- The compression in retail margins for Contact, discussed above, counters any assertions that large, vertically integrated retailers are able to preserve historical profit levels through restricting competition;
- The sheer number of new retailers suggests that there are few, if any, inefficient barriers to *entry*;
- The growth in market share of new retailers suggests there are few barriers to *growth*, other than the reasonable costs of expansion that any small business would experience in an industry with the complexity of electricity;
- Contact supports the growth of the Tier II retailers by providing flexible contracting arrangements to independent retailers helping them grow market share. We currently provide independent retailers with approximately 300GWh of supply, this equates to 43,000 homes. These contracts are shaped to match the consumption of retail customers, permit nomination across a selection of regional locations and are priced against the ASX with a small margin to reflect credit risk and volume
- Widening spreads in short-term hedging markets should only be a concern for the Panel if they believed that it was prudent for independent retailers to be carrying out the majority of their risk management activity at the last minute;
- The portion of Contact's customer base which does not engage in switching appears to be an expression of their preference to not engage: our attempts to provide incentives to them to switch to alternative products traditionally have very low uptake.

This is not to say that improvements couldn't be made (as is the case with any complex system in a changing environment). While 93% of available prompt payment discount was taken up by Contact's customers, we are mindful of the current public discussion, and will launch a "no-frills" product which will provide the lowest tariff without a PPD component for customers who desire this.

Solutions to issues and concerns raised in Part four

25. *Please briefly describe any potential solutions to the issues and concerns raised in Part four.*

The electricity supply chain – from fuel and generation to the customer – is highly interconnected and complex. Competition will drive the ultimate price paid by the consumer to the lowest price required to maintain security of supply, but, in electricity markets, this requires a high degree of complex coordination. Poorly designed interventions will have impacts along the full supply chain, and must be considered very carefully. But the following options for the Panel are worth considering:

- We believe there may be value in investigating how save and win-back activity could be disciplined. However, we believe that this should not be done in such a way that limits the benefits from a customer's desire to shop around, as is the case in most workably competitive markets;
- The Electricity Authority's IPAG group has considered in some detail, and will make recommendations, about how innovation and participation by consumers, especially those with distributed energy resources (DER), could be enhanced. Given the significant expertise that has been invested in that group, we encourage the Panel to engage proactively with the IPAG members to understand how this might be best achieved;
- Reducing barriers to retail competition, especially in non-urban areas, could be reduced further with distribution tariff standardisation;
- We suggest the Panel considers the decision of the Commerce Commission to use an above mid-point WACC when determining allowable revenues for distributors;
- The open letter from the Commerce Commission[32] which highlighted the challenges of the electricity distribution businesses monopoly position and their role in emerging technology. The comment from the Commissioner, Sue Begg makes the point well "We need to ensure that consumers benefit from advances in technology, while at the same time promoting the development of competitive energy markets. Regulated monopolies should not have an unfair advantage over existing and future competitors in this space."; and
- The Electricity Authority must get on and conclude a new Transmission Pricing Methodology.

[32] https://comcom.govt.nz/news-and-media/media-releases/2018/open-letter-to-better-understand-emerging-technologies-in-monopoly-parts-of-electricity-sector

Part five: Technology and regulation

Technology

26. *What are your views on the assessment of the impact of technology on consumers and the electricity industry?*

Technology will benefit consumers if the regulatory settings don't get in the way. Competition is and will continue to improve outcomes for consumers.

27. *What are you views on the assessment of the impact of technology on pricing mechanisms and the fairness of prices?*

We agree with the assessment.

28. *What are your views on how emerging technology will affect security of supply, resilience and prices?*

Emerging technologies have the potential to increase security of supply and resilience (through a more distributed, decentralised, lower carbon power system) and reduce prices for consumers. We need regulatory settings that create price signals and markets which efficiently incentivise new technology investment when and where it is needed.

Regulation

29. *What are your views on the assessment of the place of environmental sustainability and fairness in the regulatory system?*

We agree with the Panel's assessment of the need to incorporate environmental sustainability and fairness in the regulatory system is accurate. The solution to adequately dealing with these two important issues is most likely to lie in a "joined up approach between regulatory bodies and other government agencies" – and, we would add, market participants – than by amending the statutory objective of the electricity market regulator. As we state above, while the current wholesale market framework has evolved (positively) over the past 20 years, the fundamental building blocks have served its objectives well – especially the need to provide a generation and transmission system which delivers security of supply at least cost. We strongly caution against any measures which would distort the incentives which the current market framework provides.

We also reiterate that the issue of hardship needs to be carefully defined and scoped – the work we commissioned from PwC suggests it is a problem relating to 44,000 customers, and that the underlying issues are a complex set of factors spanning a range of social, economic, demographic and housing stock issues.

30. *What are your views on the assessment of low fixed charge tariff regulations?*

We have been advocating that the low user fixed charge regulations should be removed for over five years. We agree with the Panel that "there are likely to be better ways than mandatory low fixed charge plans to help those in energy hardship"[33]. We understand ERANZ will be making a fulsome submission on this issue.

31. *What are your views on the assessment of gaps or overlaps between the regulators?*

We agree that the regulation of access to distribution networks is an area in need of attention. We also agree that due to provisions in Part 4 of the Commerce Act, the Commission does not have a strong mandate to promote competition in distributed energy related markets.

[33] EPR report, p76

32. *What are your views on the assessment of whether the regulatory framework and regulators' workplans enable new technologies and business models to emerge?*

As discussed above, we agree that rules, some of them in the industry Code, may need to be amended to better facilitate competition between distributed energy services and grid-based electricity on their respective merits. We understand that the Electricity Authority's Innovation and Participation Advisory Group (IPAG) is considering these issues at present.

We agree that the regulatory framework was not designed for new technologies and business models. As highlighted in our response to Q23, there are clauses in the Commerce Act and Electricity Industry Act which are barriers to reform. These clauses are resulting in regulators managing consultation processes with restricted outcomes, which may not be the best option for consumers. For example, when considering the Input Methodologies, the Commission noted that any 'structural reform' was outside their jurisdiction. Additionally, consultation processes often lead to distributors referring to the relevant Commerce Act clauses to prevent reform, rather than enabling an objective assessment of what's best for consumers.

33. *What are your views on the assessment of other matters for the regulatory framework?*

While we believe that many of the additional matters outlined in this section of the Panel's report warrant further investigation, we caution that every regulatory investigation consumes resources. All issues should be assessed for their materiality to customer outcomes.

We reiterate our view that the most pressing issue is that of customers in hardship. Defining this problem well, and coordinating a response across multiple agencies, should be afforded the highest priority.

Contact's views on whether the Input methodologies are "fit for purpose" is well traversed in our Commerce Commission submissions[34]

34 For example S52T(3) and 54Q of the Commerce Act and the definition of 'electricity lines services' in the Electricity Industry Act are examples

Summary of feedback on Part five

34. *Please summarise your key points on Part five.*

Technology has a sizeable role to play in improving outcomes for consumers – the service they receive, the products that are capable of being offered, the cost of their power bill, the reliability they experience, and the decarbonisation of their energy supply chain.

There are examples, some highlighted by the Panel, where the regulatory framework designed in the past did not fully appreciate the impact of batteries, automation and control systems, demand response and distributed generation. We are now in a better place to understand these implications, which may in turn require some carefully considered amendments to regulations or industry Code:

- It now seems clear that the low user fixed charge regulations are no longer delivering to their original intent, and may actually be resulting in outcomes counter to that intent;
- The extent to which the regulatory framework (legislation, regulations and Code) facilitates effective competition for the supply of distributed generation and network services, needs to be considered
- The purview of existing regulators (the Commerce Commission and Electricity Authority) over driving greater efficiency into the distribution sector needs clarification before inefficient investment, that will ultimately cost consumers, is made under the existing regulatory regime.
- We do not believe that environmental sustainability and fairness should be introduced into the Electricity Authority's statutory objective, but the degree to which the wider regulatory framework delivers these is worth considering.
- Regulatory settings should not prejudice some consumer groups at the expense of others.

Solutions to issues and concerns raised in Part five

35. *Please briefly describe any potential solutions to the issues and concerns raised in Part five.*

The existing regulatory work programmes can be adapted to deal with many of the issues raised by the Panel in the first report. We strongly encourage the Panel, that in making recommendations to implement the Panel's findings, it will be mindful of not duplicating existing work programmes but leveraging the capability, experience and knowledge that already sits within the industry's regulators.

Additional information

36.	*Please briefly provide any additional information or comment you would like to include in your submission.*

An Economic Perspective on the New Zealand Electricity Market

E Grant Read

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EGR Consulting Ltd.

CONTENTS

Executive Summary

1. This paper has been prepared at the request of a group of market participants who are making submissions to the Electricity Pricing Review. It reflects on the lessons learned from 40 years of experience developing, implementing, and working within a variety of economic frameworks for the New Zealand electricity sector, including the development of optimisation models for reservoir management and planning, close involvement in the Energy Plan process within the old Ministry of Energy, and extensive participation in the market reform and design process, in New Zealand and elsewhere.

2. From time to time, considerable public concern has been attached to assessments of the degree of "market power" that might, or might not, be exercised by generators in the NZEM wholesale spot market. That is, in the extent to which highly volatile "spot prices" might deviate from the Short Run Marginal Cost (SRMC) of generation. We consider that concern to be largely misplaced because:

    - The general public has very little exposure to these spot prices, which are primarily used as internal transfer prices, coordinating the activities within and between industry participants.
    - Spot prices are largely driven by hydrology, and can vary greatly from year to year without indicating any trend at all in retail pricing.
    - The larger industrial/commercial consumers who are exposed to these prices should have the tools and understanding to mitigate any risk involved.

3. We believe that public concern, if any, should rather be focussed on the alternative measure known as Long Run Marginal Cost (LRMC) which provides a much more stable measure of industry costs, and does eventually determine retail pricing.

    - The extent to which spot prices deviate from SRMC is still an important topic, though, inasmuch as it impacts on the efficiency of operations within the industry and of those consumers who are exposed to spot prices.

4. This paper considers some basic questions that need to be addressed before considering the kind, and extent, of market power that might be considered appropriate, or inappropriate, in the NZEM, and describes a conceptual framework within which the relationship between the SRMC, LRMC, and historic cost recovery paradigms can be understood, and an idealised market design described that would, theoretically, allow all three to operate simultaneously.

5. We adopt an "economic" perspective, in which all power available in any particular dispatch period is valued equally, irrespective of the age or historical cost of the assets producing it. We explain the basic theory, which centres on the concept of SRMC-driven spot prices forming an optimal Price Duration

Curve (PDC) the shape of which is controlled by the LRMC entry cost of the mix of technologies best suited to meeting the national Load Duration Curve (LDC).

6. This implies an optimal plant mix for the system, and generalises and reconciles the SRMC and LRMC concepts by clarifying that, in equilibrium, LRMC should be the long run average of SRMC, but with LRMC controlling SRMC, in the long run, not vice versa.

   - Thus, if the NZEM "energy only" market design is working properly, we should see the PDC sitting at a level which just induces sustainable entry of the optimal plant mix.
   - Other markets achieve a similar effect by regulating spot prices to lie close to SRMC, but with capacity is at least partly paid for by explicit capacity payments.
   - Adding contracting to the framework allows the forward looking SRMC/LRMC pricing paradigm to be made consistent with a traditional backward-looking focus on historical cost recovery.

7. Conceptually, this creates and idealised market design, either a high degree of forward contracting, presumably at prices matching the LRMC of entry; and minimal deviations from SRMC pricing, in the short run. Theoretically, this could allow both short and long run efficiency to be maximised, simultaneously.

   - The transaction costs of imposing such a regime would be significant, though, as would the efficiency loss due to intrusive regulation.
   - In particular we would be concerned if contracting was centralised by a "single buyer", because we believe that such a role would become politicised, leading us back to eventually repeat the mistakes of the past, when excessive investments were made in over-priced and unnecessary plant, for essentially political reasons.
   - So, the market design instead relies on multiple participants making their own judgments about may things, including entry economics, and making their own arrangements, including finding their own balance between contracting ahead and relying upon spot revenue

8. We particularly focus on the conceptual and practical difficulties arising in markets relying heavily on renewables, and/or dominated by reservoir-based hydro. The general theory still applies, and optimal SRMC-based pricing should, theoretically, still cover LRMC entry costs, on average in the long run, for each technology in the optimal plant mix. But we identify three issues that will only become more important, as greater reliance is placed on intermittent renewable supply options, in future.

   - It is actually quite difficult to determine what participants actually believe the SRMC of hydro to be, though, let alone identify the motives behind any deviation from it, because a wide range of market behaviours and outcomes which might be thought to have something to do with market power are also quite likely to arise in a perfectly competitive market, or in a centrally planned environment.
   - Thermal SRMC can actually be hard to define with any real precision, too, given the fixed costs involved, and the upstream constraints in a

closed system making its SRMC opportunity cost co-dependent with that of hydro.

- Long term contracting for specific delivery volumes becomes difficult, too, because neither hydro nor thermal generators actually know how much they will be able to produce, or called on to produce, very far in advance.
- An initial empirical analysis suggests that, theoretically, more than 25% of industry revenue would need to be collected from periods of sustained high prices, mainly in very dry years. In other words, several years' worth of normal annual revenue would have to be collected in a single year, perhaps every 20 years or so.

9. We consider that such large sustained price spikes would not be allowed to occur, in practice. This threat of possible price capping in such circumstances implies a significant potential loss of revenue, which can be expected to discourage entry by potential entrants, particularly in extreme peaking plant. In any case, no commercial operator would enter solely in the hope of receiving such a risky and infrequent payment stream.

    - A healthy plant mix will only be sustainable if generators can supplement their income in wet, normal, and moderately dry years, in order to compensate for the expectation of not being able to recover the theoretically optimal requirement in extremely dry years.

10. Contracting, including retail sales commitments, can be used to greatly reduce the risk faced by generators, and to smooth revenue streams between wet and dry years. But it will not be practical for participants to sell their expected output under contract, though, when their real capacity and output is so unpredictable from year to year. So, their exposure to spot prices will be significant, but varying greatly from year to year.

11. That implies significant risk, but also opportunities and incentives to manage that risk by "exercising market power"; that is, by moving output levels closer to contract level than might be implied by a perfectly competitive analysis.

    - This will shift SRMC up, in wet to normal years when the aggregate generation sector will be contracted to supply less than potential output.
    - But it will shift SRMC down, in very dry years when the aggregate generation sector will be contracted to supply more than its potential output.

12. Alignment between prices and SRMC is still theoretically desirable, inasmuch as it provides more accurate signalling for efficient operation, both within the sector, and to consumers. But some deviation from SRMC pricing is likely to be one of the means used to sustain acceptable revenue streams through the long periods of relative surplus expected in a hydro dominated market.

    - This market has been designed to operate just like the vast majority of successful markets operating outside the electricity sector, and with similar cost structures, where pricing above SRMC has always been considered absolutely normal.

- Other sectors with similar cost structures, such as hotels and airlines typically recover costs via charges that are very different from SRMC partly, we suggest, because forward contracting is quite difficult in those sectors.
- The average price paid for electricity, though, has a strong contract component, just like the average price paid for "accommodation", or "transport", more broadly defined. Thus, both generators and consumers can protect themselves from the impact of spot prices, and any distortion of spot prices, should they see fit.
- The level of price distortion will reduce as the contracting level increases, because participants incentives to put upward pressure on prices falls off as contract levels approach perfectly competitive output levels, and then reverse above that.

13. Assuming current technology, and a diminishing contribution from thermal plant, pressure to achieve cost recovery by pricing above SRMC will become increasingly acute as the proportion of renewable generation increases, and (in theory) SRMC may alternate between zero and demand response values for extended periods of time.

    - But storage facilities, including hydro and potentially batteries and other emerging technologies will moderate that situation, and may allow the energy-only market to keep functioning much as it does today.

14. In our view, alignment of the PDC with LRMC entry costs, across the spectrum of plant types, is a much more important issue than alignment with SRMC, because:

    - Costs in the New Zealand electricity sector have traditionally been dominated by investment costs, rather than fuel costs, and this will become even more true, as the role of thermal generation options recede. So, the key issue must be to provide appropriate LRMC signals to guide investment decisions.
    - LRMC is not a "limit", though, because prices must equal LRMC, on average, being above that level for long enough to balance periods of excess supply, when competitive pressure may force prices below LRMC.

15. Thus, we argue that the most important measure of market performance, is the degree of alignment between the market Price Duration Curve and assessed entry costs for each plant type, as calculated for potentially risk-averse investors.

    - A simple empirical study on NZEM 2010-16 data concludes that the degree of alignment seems remarkably good, with most technology types slightly under-recovering entry costs for.
    - This is not surprising, in a market where LRMC is declining, with little entry occurring.

16. The results for extreme backup capacity are less encouraging, with Whirinaki only recovering very little of the revenue required to support entry of that kind of backup capacity:

- This is not too surprising, given that our analysis shows that Diesel OCGTs do not form part of the optimal plant mix, so long as gas is available at moderate prices.
- It may just be that the sample does not include any years dry enough to really require much contribution from Whirinaki, and/or there may just be excess capacity in the market, due to low growth in recent years.
- But it suggests that the focus of concern, if any, should probably still be more on mechanisms to incentivise adequate capacity provision than on the possibility of "gaming" producing excessive profits, a concern that is not supported by the empirical evidence anyway.

An Economic Perspective on the New Zealand Electricity Market

1 Introduction

Several questions have been raised, over the years, about the design of the New Zealand Electricity Market (NZEM), and particularly about the potential exercise of market power within that market, and specifically in the wholesale spot market, on which we focus here. It seems evident, from some discussions, that there is a divergence of view about what the market design actually is, or was intended to be, and perhaps about what it should be. And there is perhaps also confusion and/or disagreement as to how standard theory might be applied in a market dominated by hydro, and increasingly other renewables. This raises a particular risk that situations and behaviour may be assessed from a perspective derived from other markets, with different design philosophies, and that inappropriate and incompatible conclusions and "solutions" may then be imported from such markets.

Much public attention has sometimes been focussed on claims and counter-claims with respect to the extent to which "market power" has, could, or should be observable in the NZEM. The answers to such questions hinge crucially on the way in which market power is defined, and on the distinction between "exercise" and "abuse" of market power. But there is also evident tension between conclusions drawn from studies and concerns focussed on a narrow Short Run Marginal Cost (SRMC) perspective, and those derived from a broader Long Run Marginal Cost (LRMC) perspective.

This report is extensively based on an earlier report, originally commissioned by Mighty River Power.[1] That report was intended to assist in developing greater understanding, and awareness, of some key issues related to the design and expected performance of the New Zealand Electricity Market (NZEM) at that time. A similar discussion seems to have again come to the fore, though, perhaps in response to the recent First Report of the Electricity Price Review.[2] New issues are emerging, too, as New Zealand faces the challenge of not only increasing the contribution of renewable to meeting existing electricity demand, but expanding electricity production to meet new demands arising from the desire to increase electricity's contribution to other sectors, including transportation and heating. It may now be appropriate to ask, not only whether the current market design has been "fit for purpose" over the last 20 years or so, but whether it will still be fit for purpose over the next 20 years or so.

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1 *Economic Behaviour in a Hydro-Dominated Electricity Market* EGR Consulting Report for Mighty River Power, March 2009

2 *Electricity Price Review: First Report for Discussion*, NZ Government, 30 August 2018

This report does not really attempt to answer either question, but it seems appropriate to update what was written a decade ago, in light of new experience and emerging challenges. Thus, before considering any market power or performance issues, we start by reviewing the basic concepts underlying the New Zealand market design, the kind of pricing and behaviour patterns that might be expected (even) if market power were NOT being exercised. Specifically:

- In Section 2, we ignore hydro and other renewables entirely, and discuss some basic market design concepts, noting the difference between the "one part" market design adopted in New Zealand, and several other jurisdictions, and the "multi-part" designs used in some other parts of the world. We particularly focus on the difference this makes to expectations about the shape of the SRMC-based Price Duration Curve (PDC) for an optimally planned system, under realistic risk and regulatory assumptions, and discuss how that optimal PDC can be determined, and used to assess system performance.

- In Section 3, we consider some particular issues arising from the way in which hydro and other renewables affect the shape of the PDC, and the timing and risk associated with cost recovery requirements, particularly for long-lived hydro assets.

- Then, in Section 4, we turn to consider what might be considered legitimate, or illegitimate, exercise of market power in that kind of market context, and focus on the compromises that might be required to actually make this kind of market workable, for a hydro dominated electricity sector, in a real socio-political context. Finally, we summarise the conclusions from some very preliminary analysis of the actual performance of the NZEM, focussing on entry economics and cost recovery.

Three Appendices provide more detailed discussions of:

- The rationale behind the uncapped, LRMC focussed, locational market design philosophy of the NZEM, and the reasons why various modifications to that design were not adopted, even though they may seem attractive in the short term.

- The inherent difficulty of defining SRMC in hydro dominated electricity markets, and the kind of behaviour and price patterns that may be expected to arise in such markets, assuming perfectly competitive, or centrally optimised, responses to varying hydrological conditions.

- An LRMC focussed perspective on how we believe the performance of the NZEM should be assessed, illustrated by applying a simple spreadsheet analysis to approximate NZEM data.

Much has been written on some of the points touched on here, and much more could be written. Thus, a comprehensive treatment is not possible in this context, or timeframe. Our aim has been to provide a reasonably accessible overview of the issues, rather than an in-depth development of any one of them. Accordingly, we focus on the issues that are most pertinent, and perhaps most controversial, and do not attempt to "prove" any of the assertions made here, at either a theoretical or empirical level. No attempt is made to reference the large academic literature which might be brought to bear on these issues, either. However, the perspective presented here is based on an extensive personal history of involvement with, and research on, electricity sector issues, particularly in New Zealand, before, during, and after the market reform process. So, reference is made to earlier commentaries and studies by the current author and his colleagues, in the New Zealand context, many of which expand upon the points made here.

In particular the reader is referred to Culy et al [1996][3] for an economic perspective on the history of the New Zealand electricity sector prior to establishment of the current market. Read [1997][4] provides a perspective on the goals of the current market design, and a commentary on initial experience with it. Read [2010][5] provides an informal discussion of the properties and relative merits of a variety of mechanisms that could be used to provide adequate cost recovery for peaking/backup plant, in particular, in the NZEM context. And Read et al [2012][6] provides a high-level perspective on "gaming" issues in electricity markets, arguing that the "games" that matter most are the highest level games involving not just market participants, but Governments, Regulators and voting consumers, in establishing the regulatory regime under which the sector operates.

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3 J.G. Culy, E.G. Read, and B. Wright: "Structure and Regulation of the New Zealand Electricity Sector", in R Gilbert and E Kahn (eds.) *International Comparison of Electricity Regulation,* Cambridge University Press, 1996, p. 312-365.

4 E.G. Read: "Electricity Sector Reform in New Zealand: Lessons from the Last Decade" *Pacific Asia Journal of Energy* Vol 7, No 2, 1997, p. 175-191

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2 Market Design Concepts

2.1 Market Clearing Prices

The NZEM is a locational market, and electricity spot prices vary significantly between locations due to both transmission constraint and marginal loss effects. The principles discussed in this report can be generalised to apply to the interaction between supply and demand at the locational level and, with some modifications, to transmission between locations. We ignore this complication, though, and assume a hypothetical national market, in which all power generated and consumed is traded at a single node, without any restraint on transmission to, or from, that node.

At the most basic level, the NZEM is an "energy-only", or "one-part", market[7], in which all participants buy and sell at Market-Clearing Prices (MCPs). Thus, it is based on the principles that:

- All participants providing (or purchasing) energy at the same location should be paid (or should pay) at the same rate, irrespective of their offers (or bids);

- The entire remuneration for generators should be provided by these spot market energy payments, or derived from them by way of financial contracts written against them; and

- Competitive discipline is largely relied upon to discipline offering behaviour, and hence to control prices, with limited regulatory interventions in extreme circumstances.

This design has important implications for the pricing patterns we should expect to see arising from the market.

First, it is often loosely stated that, under "perfect competition" participant offers should be expected to reflect Short Run Marginal Cost (SRMC), and that MCP should thus reflect the marginal cost of generation at the industry level. That expectation is examined in greater depth later, but here we note that SRMC "offering" is not the same as SRMC pricing. It does not mean that individual plant, or firms, sell at their own SRMC, but that they all sell at the industry SRMC: That is, at the SRMC of the marginal producer at any particular time.

Second, in this kind of market, MCP is not determined solely by the industry supply curve, but by the interaction of supply and demand curves, either explicitly or implicitly. If there was no (voluntary) elasticity in the demand curve, MCP would

[7] We will use the former term, because "multi-part" offers may be employed in markets which are essentially "energy-only" in the sense that energy prices are capped only at very high levels, and there is no separate market for long term capacity investment.

(theoretically) equal the marginal cost of production until a capacity constraint was reached. But, at that point, the MCP should theoretically rise to very high levels, reflecting the cost to society of the involuntary load shedding needed to match demand to the available supply. In general, that cost would be much higher than for voluntary reductions of the type that might be expected in response to market price signals. This would be reflected in the "shadow prices" calculated by a centralised optimisation, and the same price pattern should be expected from a hypothetical perfectly competitive market.[8]

In the real world, demand will be somewhat elastic across the entire price range, though. Even if consumers do not submit a "demand curve" to the market, consumers who are exposed to MCP can be expected to respond to it, and that response should really be accounted for in a centralised optimisation, or evident in the market when plant capacity limits are reached. So, prices should sometimes be set by load reduction at levels below the SRMC of the most expensive generator, and expected to exceed the SRMC of generation, often by a very large margin when supply is short. And we expect such situations to become more frequent in future.

As discussed in Section 3.3, the expected marginal water values computed by reservoir management models inevitably account for the prospect of future load reduction interchangeably with generation. Thus, for several decades now, most New Zealand discussions have extended the definition of "SRMC" to include demand reduction costs, thus making it natural, but potentially misleading, to refer to MCP as the "SRMC price". But some parts of our discussion will need to distinguish between SRMCG(eneration), and SRMCD(emand).

2.2 Energy vs Capacity Pricing

Second, as an "energy-only" market, the NZEM differs significantly from markets in which participants receive supplementary payments for "capacity" in various forms.[9] As such, it should be expected to produce patterns of "energy" prices, which differ from those arising in such markets, and also from many traditional forms of regulated electricity pricing, in which explicit capacity payments (or peak) charges often feature

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8 Technically, a centralised optimisation may report "infinite" shadow prices, but these over-state the severity of the situation.

9 This discussion ignores ancillary service market(s). In New Zealand, these are "co-optimised" with the energy market, and ancillary service sales provide some additional revenue to support capacity investment. But this does not materially alter any of the discussion here. Ancillary service payments are only made to participants providing ancillary services, and only for the MW provided. This is not the same as providing a capacity payment to all capacity in the market, as occurs in markets that employ capacity pricing.

prominently.[10] What we might hope to see, though, is a pattern of energy prices in the NZEM broadly matching the optimal pattern of energy/capacity prices, in combination, in a centrally optimised electricity sector.[11]

A traditional centralised optimisation model would compute an SRMCG-based price corresponding to the MCP, so long as the optimally planned system was able to meet demand. There would be periods, though, in which an optimally planned system would be unable to meet demand, forcing some form of rationing to occur.[12] Provided the optimization model includes an economic representation of the costs incurred when load is not supplied, it will compute a shadow price limiting demand to equal total available generation capacity. In the optimisation logic, that shadow price represents an extra payment, over and above the SRMCG-based prices, to all capacity available at that time, reflecting the economic value each unit of capacity delivers by being available to limit shortage to the optimised level.

Ignoring economies of scale, this traditional optimisation problem is convex, and it can be shown that the costs of all capacity in the optimal plan will be covered if (and only if) this (notional) capacity payment is added to the (notional) payments calculated from SRMCG-based prices. Conversely, the SRMCG-based prices alone will always be insufficient to cover the investment cost of any plant, after fuel and variable maintenance costs are accounted for.

The same result applies equally in a hypothetical perfectly competitive market, with prices theoretically "spiking" up to the levels required to ration demand. In real life, this same price pattern may be approximated in two ways:

- By a combination of energy and capacity prices in a "two-part" market; or
- By energy prices alone in an "energy-only" market

In the first case, we might hope to see <u>energy</u> prices approximating the SRMCG of supply at all times, complemented by <u>capacity</u> prices approximating the capacity constraint shadow prices in a hypothetical centralised optimisation. In the second case,

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10 For many years, before there was any significant thermal generation in New Zealand, the wholesale "Bulk Supply Tariff" consisted entirely of such peak charges, meaning that "energy" was implicitly charged at a per unit price of zero. (This might be thought to be the SRMC of a pure hydro system, although that is generally not correct, as will be seen from later discussion.) A 50% energy component was introduced later. (See Culy et al [1996].)

11 Traditional capacity charges have at least partly reflected the cost of the transmission and/or distribution systems, and other overheads. In this discussion, though, it is only the "generation capacity" component of these charges which is relevant.

12 Put another way, there will always be a probability level beyond which it would be more economic to risk the possibility of non-supply, rather than to incur the cost of building supply facilities which will almost certainly never be used. A sufficiently detailed probabilistic optimisation will reflect this by determining an optimal trade-off between supply and non-supply, implying a finite probability of non-supply.

we might hope to see energy prices approximating the SRMCG of supply much of the time, but supplemented by moderately frequent (energy) price "spikes", reflecting SRMCD. And the value implicit in those price spikes should approximate the value which would be recovered from capacity charges under a "two-part" energy/capacity market design. In other words, the aggregate should equal the value of the capacity constraint shadow prices in a hypothetical centralised optimisation.

2.3 The PDC and Entry Economics

The simplified discussion above can be generalised in a way that fits more naturally with discussions of market economics. While the precise chronological pattern of loads is important for some purposes, much can be learned by analysing the cumulative distribution of loads over, say, a year, known as the Load duration Curve (LDC).[13] We can summarise the distribution of market prices, similarly, by creating a Price Duration Curve, or PDC, indicating the proportion of time for which prices are observed above each price level. Option Values (OV) for any plant type "x" can be determined from such curves, being the net operating profit to be made by that plant type, assuming that it operates at full capacity throughout the period for which the MCP exceeds its SRMC.

OV(x) is the value of a call option, with a strike price set at SRMC(x).[14] MCP is assumed to equal SRMC(x) all the time when plant x is partially loaded and hence "on the margin". So, the call option would actually have no value to x, during that period, in this hypothetical pure SRMC market. It does have value when x is operating at full capacity, since the MCP is being set by some more expensive plant, so we define:

- U(x) as the proportion of time[15] for which plant x is running at full capacity, which it will do whenever MCP exceeds SRMC(x).
- RV(x) as the revenue collected by x, while it is running at full capacity, so it is the sum of all prices in the PDC above SRMC(x)

Then we have:

$$OV(x) = RV(x) - U(x)*SRMC(x)$$

In words:

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[13] Normally the LDC specifies the number of hours for which load levels exceed each load level, over some period. But, more generally, we can think in terms of the percentage of time involved.

[14] We will ignore variations in operating efficiency across the output range, and note that, under competitive assumptions, plant will make no net operating profit when it is itself marginal, because the price will be set by its own SRMC.

[15] Or the number of periods if the LDC is defined that way. The formulae developed below assume that U is expressed appropriately for each context, so that annual running costs are compared with annual capital costs, etc.

OV(x) = Expected revenue for x assuming SRMC-based MCP prices
MINUS Fuel and variable operating costs for x, over the time it operates

Generalising the definition of SRMC to include load reduction costs, as above, a notional PDC for an energy-only market can be produced under competitive assumptions. Prior to the market, in the latter days of the Ministry of Energy, the New Zealand electricity sector was planned using OVs determined from a PDC defined in exactly this way, but created using shadow prices from the PRISM/SPECTRA models. It is not difficult to show that more capacity of each plant type should be introduced if, and only if, its SRMC-derived OV exceeds its Fixed (Capital + O&M) Cost, which we will refer to as FC.[16] This holds true in a centralised optimisation, but also for a market.

In other words, subject to some caveats discussed below, investors should have commercial incentives to introduce new capacity of each type when its MCP-derived OV exceeds its FC. The threat of such entry thus "disciplines" the PDC by ensuring that the total (OV) value of the PDC above the SRMC of each viable entry option matches FC, the LRMC entry cost of that option. If the OV at an SRMC level associated with plant x rises above FC(x) then we expect more capacity of type x to enter, thus depressing the upper part of the PDC until OV(x) reduces to match FC(x). If the OV at the SRMC for plant x falls below FC(x) then we expect no more capacity of type x to enter, while load growth, plant retirement etc raise the upper part of the PDC until OV(x) increases to match FC(x). So, in expectation, we should have:[17]

$$OV(x)=FC(x)$$

That is:

Fixed Cost for x = *Expected revenue for x assuming SRMC-based MCP prices*
MINUS Fuel and variable operating costs for x

This can then be re-arranged to form a relationship which should hold on average, over the long run:

Long Run Marginal Cost (LRMC) for x
= Fixed Cost for x + Fuel and variable operating costs for x
= Expected revenue assuming for x "SRMC-based" MCP prices

Scaling units appropriately, we get:

$$LRMC(x) = F(x) + SRMC(x) = OV(x)$$

16 In reality, investment is lumpy, and this matching is not exact. But this does not really affect the principles discussed here. In practice, we will compare annual cost recovery requirements with annual OVs.

17 Strictly, the "expectation" referred to here is the expectation of a generic potential entrant.

2.4 The Optimal PDC and Plant Mix

Many discussions seem to assume that there is a single well defined LRMC for the electricity sector as a whole. Each technology has its own LRMC, though, and we have just seen how that LRMC "disciplines" the PDC, in the sense that FC(x) determines RV(x), the total value of prices in that part of the PDC above SRMC(x). In reality, we may expect SRMC(x) and/or FC(x) to change over time, due to technological progress, resource depletion etc. Ignoring that possibility, though, the relationships above actually define a long run equilibrium PDC that is driven entirely by the economics of the entry technologies potentially available in a particular market. It also defines the optimal plant mix, in the following way:

- Generation technologies are often ranked in a "merit order", from the lowest running cost, up to the highest. The next plant up in the merit order, after plant x, will be x+1, with SRMC(x+1) greater than SRMC(x).
- But there would be no point even considering building plant of type x+1, with its higher running cost, unless its fixed cost FC(x+1) was lower than FC(x).
- This means that plant x+ 1 is more suited to meeting load levels closer to the peak that occur less often, while plant x is more suited to meeting load levels that occur more often.
- In fact, there will be a critical utilisation factor U(x), below which savings on capital cost more than offset the extra SRMC cost, making it cheaper to invest in plant x+1 than plant x, to meet higher, less frequent, load levels.
- It is not hard to see that:

  $$U(x) = (FC(x)-FC(x+1))/(SRMC(x+1)-SRMC(x))$$

  Or, in words, with appropriately scaled units:

  The extra annual fixed cost of investment in pant type x (rather than x+1

  Divided by:

  The extra annual running cost of using pant type x+1 (rather than x

At one extreme, we may be prepared to pay quite a high fixed cost for base-load plant like wind or run-of-river hydro, with an essentially zero SRMC. At the other extreme, we have "shortage" for which we pay no fixed cost, but face an SRMC set by the "shortage cost" or "Value of Lost Load", VoLL. In between, we can apply the formula above to each successive pair of technologies in the merit order, and find a range of technologies, each of which is best suited to meeting incremental load levels occurring with a frequency between U(x) and U(x-1). This same set of critical utilisation factors:

- Defines the optimal long run equilibrium PDC because, with SRMC pricing, we should have MCP= SRMC(x) over the hours when plant x is "on the margin", i.e. between U(x) and U(x-1).
- And, when applied to the LDC, determines how much MW capacity of each type should actually be built, and hence the optimal plant mix to meet that LDC.

These mathematical formulae, developed here in a market context, are exactly the same as those applying in a centralised optimisation. In fact, the approach described here was developed and applied to electricity sector planning by the New Zealand Ministry of Energy in the mid 1980's. And note that the first relationship, defining the optimal PDC, is actually independent of the LDC. Thus, while entry will keep occurring if the LDC grows over time, or to replace retiring plant, the equilibrium PDC itself should only change in response to changes in the fixed or variable costs of the potential entry technologies.

Markets are seldom really in equilibrium, and the actual PDC is unlikely to exactly match the optimal PDC calculated above. The entry dynamics discussed here, though, imply that market forces should be consistently acting to move the real PDC towards the optimal PDC determined by the entry costs expected in any particular year. When we talk about SRMC/LRMC alignment, then, we are not just talking about matching two specific values. Rather, we are talking about the alignment between two distributions of prices: the *observed* PDC in any year, and the *optimal* PDC determined by the entry costs that were expected in that year.

The relationship between FC and OV also implies an equivalent interpretation in terms of option valuation.[18] Thus, this optimal PDC concept plays a central role in electricity sector economics, and implies the following test that can be applied to each plant type in that optimal mix:

- The (own-generation weighted) average SRMC-based MCP received by base-load plant must match the LRMC of such plant;
- The (own-generation weighted) average SRMC-based MCP received by "shoulder" plant must match the LRMC of such plant;
- The (own-generation weighted) average SRMC-based MCP received by "peaking" plant must match the LRMC of such plant.

2.5 Cost Recovery

In discussing the alignment of LRMC with cost recovery requirements we need to specify which LRMC we are talking about. Some studies seem to focus solely on the LRMC of base-load entrants such as geothermal, and arguably wind and run-of-river hydro, and the theory above implies that should align with the Time-Weighted Average Price (TWAP). But the actual cost of meeting loads is higher than that, and corresponds to the Load-Weighted Average Price (LWAP), because the cost of covering peak and shoulder loads is higher than that for base loads. Under our simplified single node

[18] That relationship rests on the observation that, provided both are available, plant x, with its lower SRMC, will be fully dispatched, and operating at a profit, whenever plant (x+1) is dispatched. Thus it will receive all the revenue x+1 does, and make more profit per unit on it, because its SRMC is lower. This means that OV(x) is always greater than OV(x+1), and it is that difference in option values that justifies the extra cost of building capacity of type x, rather than type x+1, to meet load levels occurring more often than U(x).

assumption LWAP is equal to the Generation-Weighted Average Price (GWAP).[19] The discussion above applies to each plant type in the optimal mix, but it can be generalised to apply to each load class, too, or to the whole LDC:

- The (industry load/generation weighted) average SRMC-based MCP paid for any pattern of peak/shoulder/base load should match the LRMC of meeting such load, as determined by the optimal plant mix and PDC discussed above.
- The load weighted average SRMC-based MCP paid by any load class or component, should match the LRMC of the optimal mix of plant required to supply that load.

Accordingly, the alignment of the SRMC/MCP-based PDC with entry costs provides an important test of market performance. This alignment means that, if all plant expect to recover their LRMC costs when they enter, they actually should be able to cover their costs, on average, unless the market is disturbed in ways that were not expected at the that time of entry. Surprises always will occur, and the whole market may under- or over-recover as a result, and some projects will have unexpected cost over-runs, too. Entrants are assumed to account for all such possibilities in their decision-making, though, and should not enter unless they expect to cover their costs, on average. Individual expectations may differ but, unless aggregate industry expectations are biased, we should expect to see SRMC prices matching LRMC on average, across the PDC, over the long term.

Oddly, though, many discussions treat LRMC as if it were an upper bound on SRMC prices. Thus, it is common to see market price projections tracing a rising curve of "SRMC prices" up to the point where they equal LRMC, after which it is assumed that entry will occur and limit prices to LRMC thereafter. This may be a reasonable picture of the actual performance of many markets, including the NZEM in its early years, but it should be recognised that it can only be a valid picture of a market in disequilibrium, starting with excess capacity. From an economic perspective, it can not represent a typical, or sustainable, long term pricing pattern.[20]

What we should really expect to see, in the long term, is that aggregate annual SRMC-based prices sometimes lie above LRMC, and sometimes below it, equalling LRMC on average. Regulators seem generally comfortable with periods when SRMC prices lie below LRMC, and some may even try to force prices down in situations where they are above SRMC, even if that implies cost recovery below a long-term sustainable LRMC level. But it is by no means clear that the same regulators will look so benignly on extended periods when SRMC prices rise above LRMC. Rather than force prices up in

[19] Otherwise, the two would differ due to transmission losses and constraint rentals.

[20] Prices may also rise, over time, because LRMC itself is rising, perhaps due to resource depletion and increasing environmental pressures. But that issue is discussed in Section 3.5.

tight market situations, it seems more likely that prices could be capped below their theoretically optimal demand-rationing levels.[21]

Any restraint on SRMC pricing in such circumstances surely implies, though, that prices would have to rise above SRMC during surpluses, if a sustainable long run equilibrium is to be maintained, on average. Otherwise the market design had failed in one of its primary objectives: That of setting prices to sustainable levels, on average. More exactly, the issue is not whether prices will actually be restrained by some direct cap or indirect influence, which may be unknowable in advance, but whether potential entrants now think there is a possibility they will be restrained, and account for that possibility in making their operational/investment plans. The greater the perceived probability of capping, and the tighter the possible caps, during shortage periods, the greater the deviation from "SRMC" required to balance the books during surplus periods.

Attitudes towards that outcome may be seen as reflecting a fundamental conflict between the forward-looking perspective of economics, with its emphasis on finding the best use of resources irrespective of what they may have cost to develop; and the backward-looking perspective of accounting, with its emphasis on paying for resources already committed, whether or not they were economically justified in retrospect. They also reflect a conflict between the desire to provide efficient SRMC-driven signals to consumers operating installed electrical appliances etc, and the desire to provide efficient LRMC-driven signals to consumers as they consider investing in electrical appliances etc.

In Section 2.7, we discuss the kind of contractual mechanisms that could, theoretically, allow all three goals to be achieved simultaneously. But first we should discuss the possible impact of risk aversion.

2.6 Risk Aversion and PDC Inflation

As discussed in Section 3.4, risk is a rather more significant issue in hydro dominated markets, than it is for typical electricity markets, and it may not be easy to provide risk averse investors with sufficient assurance that they will be able to obtain an adequate return for the risk involved. But participants in all markets face the risk of strategic response from other participants, regulatory intervention, technical failure, and changes to load growth, technology or fuel prices. Accordingly, risk and risk aversion are important factors.

All of the above discussion may be thought of as assuming risk-neutrality, though. Thus, when we say that peaking plant will enter if its "OV exceeds its FC", this may be

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[21] In principle, some kind of price restraint has occurred whenever physical rationing, or shortfalls, occur. Arguably it also occurs when reliance is placed on public campaigns, aimed at encouraging individuals to sacrifice their own price-driven interests for the community good.

interpreted in NPV terms. But we have not actually said what discount rate is to be used when determining OV or, for that matter, FC. In reality, a potential entrant realises that investment in a peaking plant is naturally risky, and that any threat of intervention is likely to increase that risk. So, the potential entrant will presumably apply a risk adjustment to the discount rate used for project evaluation, thus raising FC by a potentially significant amount. Read et al [2007][22] argue that this could have a significant impact on the effective PDC expected in long run equilibrium, particularly in an energy-only electricity market:

- In a market which provides guaranteed payments for "capacity", the providers of that capacity should be expected to determine FC at a moderate discount rate, and this should be equivalent to the OV for such capacity determined from an optimal SRMC based PDC;[23] but

- Since participants in an energy-only market receive no such guarantee, they must determine FC at a "risk-adjusted" discount rate, and that FC should be equivalent to the OV for such capacity determined from a PDC with higher prices occurring with a higher probability.

One may argue about how significant this effect actually is, particularly in a market dominated by vertically integrated "gentailers" who are exposed to the risk of not being able to meet customer obligations if they can not access sufficient capacity in extreme conditions. In theory, though, if an energy-only market were reliant on stand-alone entry by independent generators, the PDC could be inflated to significantly higher levels than might be calculated on a risk-neutral perfectly competitive basis. The issue is whether those higher prices occur more often because market prices exceed SRMC, or whether it is that SRMC itself must be higher, more often. But it must occur somehow.

PDC inflation of this type is not necessarily inconsistent with "SRMC pricing". If market rules were to enforce SRMC pricing, but prices were not capped, potential entrants would simply refuse to enter, thus "withholding capacity" in the ultimate sense, until the PDC rose high enough to support entry, with an appropriate risk premium. In part this may occur because the lack of investment forces less efficient, and hence more expensive, plant onto the margin, more often. Thus, peaking plant may be required to generate more as "shoulder" or "peak support" plant, and shoulder plant as base-load plant. In part it may occur because shortages eventually become

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[22] E. G. Read, M. Thomas and D. Chattopadhyay "The Impact of Risk on Capacity Investment in Electricity Markets" keynote presentation, *IAEE Proceedings*, Wellington, 2007

[23] Such a guarantee does not eliminate supply-side risk, but probably reduces overall risk below normal commercial levels.

acute enough to force SRMC/shortage cost prices up to a level entrants find acceptable, given the risks involved.[24]

Read et al argue that the result will be a plant mix with less capital investment, higher running costs, and more shortage than may seem optimal, when assessed from a traditional central planning perspective, where aversion to commercial risk is not normally considered to be a significant factor. Alternatively, though, an equilibrium involving more entry, less shortage and a more balanced plant mix, could be sustained if potential entrants believe that their risks can be reduced by pricing above SRMC at peak times, and/or during surplus periods.

2.7 The Impact of Contracting

The market for trading financial contracts settled against NZEM spot prices has become much more active since the original paper was written, in 2009, and there is a danger that a focus on relatively short-term contract trading activity could obscure four fundamental things about the nature of such contracts:[25]

- First, the ultimate value of every contract will ultimately be determined by spot prices in the period when it matures.
- Second, no matter how many intermediate trades, or traders, are involved, contracts will only reduce risks of the original issue, or ultimate purchaser if backed, directly or indirectly, by the capacity to physically generate, or desire to physically consume, electricity.
- Third, under-contracted generators are effectively selling generation in excess of contract quantities at spot prices, so they still have some incentives to reduce output toward the contracted level, so as to increase the price at which they sell. But over-contracted generators are effectively buying in power to make up the contract quantities at spot prices, so they have some incentives to increase output toward the contracted level, so as to lower the price which they pay.[26]
- Thus, even though these contracts are not "physical", they do give participants incentives to align physical production/consumption, on the day, with contract quantities.

Thus, while there may be many steps in between, the fundamental role of contracts is to bridge from the LRMC-dominated world of physical (investment in) generation capacity, through the SRMC-dominated world of spot market trading, and on to the

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[24] Price capping merely removes this second option and forces more reliance on the first, as discussed in Section 5.5.

[25] Except where "options" are referred to the contract here are assumed to be "Contracts for Differences" (CfD's), effectively specifying a buy/sell agreement for a fixed volume, at an agreed "strike price".

[26] Totally uncontracted generators, having no guaranteed income and relying solely on spot market prices to recover costs, represent an extreme case, and always have incentives to withhold generation in order to increase prices.

LRMC-dominated world of physical (investment in) consumption capacity, both industrial and domestic.

Provided contracts trade at a freely determined price, rather than being imposed on one side of the market or the other, the logic described above remains valid, with three major differences:

- Contracts have a direct impact on risk, and hence on the economics of entry and the long run equilibrium PDC. Entrants who can secure a significant part of their forward revenue via a contract[27], should be prepared to enter at a rate of return less inflated by risk (as discussed in Section 2.6), and hence discipline the PDC at a price point reflecting that lower rate of return requirement, ultimately lowering the average price charged to consumers.

- Contracts also alter behavioural incentives, so that some approximation to the equilibrium conditions discussed in previous sections may still apply, even in situations where the perfectly competitive assumptions underlying that discussion do not quite apply: that is in situations where participants may have the ability to profitably affect prices by the way they offer. But discussion of that issue will be deferred to Section 4, which discusses market power

- Because contracts re-define and re-assign risk between participants, but also over time, they can also allow the backward and forward looking perspectives to be reconciled, as discussed below.

Theoretically, a potential entrant should be able to sell a contract for the expected output pattern of a unit at around the expected value of that output pattern in the spot market, which it will be matching to its LRMC. Thus, looking forward, it will try to time its entry so that the OV of such a contract corresponds to the FC of its proposed plant. So, the economic optimality conditions described in Section 2.3 should be expected to hold, in prospect, at the point when a participant commits to building a new plant, at least when evaluated from that participant's perspective.

Looking back, though, participants may have quite different views, both about what their costs actually were, and about market performance. Thus, they may find a significant discrepancy between their cost recovery "requirements", and SRMC-based prices. If they have sold a contract for all their expected capacity, the forward-looking value of that contract may be higher or lower than expected, depending on these updated spot price projections. If their project is performing, though, in the sense that they can still generate that amount, then the price they receive will still be the contract price, not the MCP.[28] If that contract price met their expected LRMC-based cost recovery requirements at the time it was agreed, it will continue to meet those expected requirements as conditions change. Contracted entrants would then only have to deal

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[27] Perhaps implicitly though vertical integration.

[28] Projects never perform exactly as expected, but that is a normal commercial risk, rightly borne by the developer, and presumably accounted for in their rate of return requirements.

with any discrepancy between the actual and expected cost and/or performance of their own plant.

In reality, a perfect match between contracted and actual capacity, or perfectly competitive output levels, is unlikely, and virtually impossible for a hydro generator. But the perfectly contracted case describes the opposite end of the spectrum from that at which many analyses start; with a pure spot market and no contracts at all. Reality will lie in between, and generators will find themselves more exposed to spot prices as their optimal perfectly competitive generation levels deviate from contract levels. The closer the real world lies to the perfectly contracted case, though, the closer revenues will lie to cost recovery requirements, and to LRMC, as it was expected to be when the contract was signed. Ignoring any risk premia, the effect should be just to narrow the distribution of outcomes, rather than to alter expected values.

3 Cost Recovery Issues for Renewables

3.1 Introduction

The theory discussed in the previous section was largely developed in the context of systems dominated by thermal generation, but it mostly applies to renewable generation too. Renewable generation technologies often introduce new technical issues, though, and/or represent special or extreme cases of the standard theory. So, the application of some aspects of the theory may be challenging in the context of a move toward a 100% renewable system. Thus, this section highlights some issues of particular importance when analysing the behaviour and performance of renewable generation options, and of systems with a significant renewable component.

3.2 PDC for Renewables with no Storage

Discussion in the previous section focuses strongly on the concept of an optimal long run equilibrium SRMC driven PDC. Traditionally, that PDC has been assumed to consist of a set of steps, each representing the SRMC of some thermal plant type. But the SRMC of all non-storage renewables, including wind, solar, geothermal and run-of river hydro is extremely close to zero[29], until their capacity is fully utilised, at which point it becomes infinite.

This does not exactly cause the theory to break down, but it does require some re-thinking of how these technologies might complement one another, over various time cycles, and why the aggregate market might want to invest in a range of plant types, rather than in some single technology, when all have the same SRMC. But, in the non-storage case, the key thing to note is that applying the traditional analysis based on the SRMC of generation implies an optimal PDC where:

- The price is always zero, whenever any of these technologies is spilling energy due to lack of demand.[30]

- The price spikes to the shortage cost because demand exceeds the combined output available from all plant.

But the analysis implies that shortage, or demand response, would have to occur quite frequently in this non-storage 100% renewable system, because no plant can recover any costs except during shortage/demand response periods. During those periods the

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[29] Except geothermal plants, which face a non-zero steam royalty to resource owners, and may incur variable charges for carbon dioxide emissions.

[30] Spilling energy because a capacity limit is reached is another matter. In that case, the SRMC of that plant becomes infinite, but the market SRMC will be set by some other plant, most often at zero.

price should be expected to vary, too, and as the price must be set high enough to depress unconstrained demand (i.e. the demand at the "normal" SRMC price of zero, in this case) down to the volume that can actually be delivered, on a real-time basis.

This is not just a commercial issue, but an economic one. A perfect central optimisation, perhaps managed by a "single buyer" should actually come to the same conclusion as a perfectly competitive market with respect to the level of capacity to build, and the frequency of shortage. And while that agent might want to recover costs via charges structured in a different way, it would face a dilemma:

- It would have to physically limit demand in the periods where its chosen price was less than the shortage cost price required to supress demand down to capacity.

- Consequently, it would need to recover the revenue foregone in such periods by another charge, implying some other distortion, or by raising prices above SRMC in other periods, thus also suppressing demand below optimal levels in those periods.

Hopefully, participants would realise the advantage of maintaining a high degree of contract cover when facing this level of spot price variability, and sale of such contracts could still support entry at reasonable risk-adjusted discount rates. Even so, this theoretically pure SRMC pricing regime may be difficult to sustain. It seems likely that participants would learn to "exercise market power" by setting offers up in such a way that prices frequently rose above the SRMC of zero, even in periods when there was actually still some spare capacity.

Some level of demand response might be expected at any non-zero price level, though. So, if we broaden the definition of SRMC to include all forms of demand response (as has been traditional in New Zealand) including reactions to market prices, there is a sense in which the MCP would always equal "SRMC", in this case SRMCD. But non-zero prices would always be the SRMC of demand response, rather than of any generation technology, both above and below the nominal "shortage cost" level on a traditional PDC.

3.3 Treatment of Storage

Introducing hydro reservoir storage into the system raises some complex issues which are discussed in Appendix B, to which the reader is referred for more detail.

As noted there, many of these same issues actually arise in thermal power systems too, and especially in power systems dependent on small isolated, and relatively uncompetitive fuel supply sectors, as in New Zealand. Similar issues will also arise in power systems where battery storage plays a significant role, albeit over a much shorter time scale. Thus, the effective SRMC of solar or wind generation linked to a battery system will not necessarily be zero, but determined by the opportunity cost of using that power, rather than storing it to provide incremental supply at any time in the next day.[31]

Here, though, we focus on hydro storage systems, and just emphasise a few significant points that may easily be overlooked in a more detailed discussion.

Complexity

First, the determination of SRMC for hydro systems really is both complex and subtle. It is easy to say that the hydro SRMC is determined by the "expected marginal water value", EMWV, and that is true, at a high level. Reservoir management models generally only assess expected marginal water values for a few major reservoirs and, at that level, subtle differences in assumptions can have a major impact. This is particularly true with respect to the treatment of shortage costs and risk, both of which have a major impact on EMWV, and hence SRMC in the periods which matter most from a cost recovery perspective.[32]

Such EMWVs are often used to infer the SRMC of hydro generation but, at a more detailed level, most hydro generation in New Zealand comes from power stations forming part of a river chain. The SRMC for such stations is really determined by the difference between the upstream and downstream MWVs, and those MWVs can both change repeatedly across each day. Thus, at an hourly level, it is not clear that any New Zealand generator could actually compute hydro SRMCs to the level of detail discussed in Appendix B, let alone compute optimal deviations from that SRMC.

Retrospection

Second, the actual MWV of hydro can really only be known in retrospect. Looking back, we can determine how an incremental unit of stored water would actually have been used, and hence what the opportunity cost of releasing it earlier actually was. In retrospect we can trace the actual storage trajectory, and see that that incremental unit would have been used to displace a unit generated from a specific thermal power station at some point along that trajectory. Or we may see that the increment would have been carried in storage for some time, but eventually spilled, or used to meet demand that otherwise would not have been met.

31 Over time (e.g beyond 2035) it is conceivable that new technologies such as extensive demand side management, bio diesel, solar-thermal storage, etc may also have the potential to add meaningful marginal information back into system SRMC, and allow the energy-only market to function much as it does today. As yet, there does not appear to be an urgent problem that needs fixing.

32 Our discussion here, like most reservoir management models, assumes that equal weight is placed on all possible future hydrology sequences when computing the "expected" MWV. Intuitively, though, risk averse reservoir managers would like to put more weight on those sequences most likely to result in high future shortage costs. Doing so creates mathematical difficulties, so many modellers prefer to add buffer zones, or penalty functions to achieve a similar effect. Either way, the effect can be to greatly increase the assumed SRMC of hydro, in these critical situations.

What reservoir management models compute is the expected value of these true MWVs, because that is the best estimate that can be made at the time of computation, and the best basis for release decisions made at that time. And that expected MWV is also the appropriate value to be used in making offers to a perfectly competitive market, and hence (if marginal) in setting prices for that market.

Thus, a perfectly competitive market PDC should contain significant ranges of periods in which market prices lie between the SRMCs of the various thermal/demand response blocks. As discussed in Section 6.1, the prospect of high prices due to a possible future energy shortage, for example, feeds back into high opportunity cost–based offers from hydro, and typically high prices, for many periods before that event is projected to occur. Strictly speaking, though, this does not cause the PDC to inflate above SRMC levels. What it does is to cause the SRMC of hydro, as determined by these opportunity cost calculations, to rise, and this is reflected in the PDC.

But, if an expected MWV is created as a probability weighted sum of the true MWVs, then it can be decomposed back into its constituent elements. And those same weights can then be used to assign a proportion of the hours for which that source was on the margin to the PDC. Hence the stepped shape appearing in our PDC projection, vs the more continuous PDC shape that would normally be seen in a real market PDC, or one based on simulated expected MWVs.

Circularity

Third, there can be a significant degree of circularity in MWV computation. The MWV is defined as an opportunity cost of releasing water rather than saving it for future use. The best future use of an extra unit of water stored in one reservoir, though, may well be to displace a unit that would otherwise have been released from another reservoir at some future date. And the value assigned to that reservoir's release may correspond to displacing generation from another, and etc. So, all of these marginal water values are highly co-dependent with each other, and also often with the opportunity cost of using constrained (thermal) fuel stocks.

In the end, though, the extra increment of water will be seen to displace either a unit of generation from fuel imported into the system, or a unit of load reduction. Even now, while thermal generation remains possible, the probability of future load reduction rises as storage levels fall, and the "Value of Lost Load" (VoLL) soon comes to dominate in the EMWV calculation.

The true value of VoLL has been endlessly debated, and it clearly varies greatly with circumstances. Thus, it really should be replaced by a more sophisticated representation of the various types and depths of demand response and curtailment occurring in these very tight market conditions. Even if it were known with certainty, though, VoLL is obviously not a measure of any kind of supply side marginal cost. Consequently, EMWV hardly represents a traditional supply side SRMC either, when it has a high VoLL component.

Experience suggests that the reservoir management policy, across the entire storage range becomes quite sensitive to quite small variations in the assumptions made about VoLL. But this influence obviously becomes very important when EMWV reaches high levels, in those relatively rare situations that dominate any calculation of entry economics and cost recovery. In those circumstances, though, EMWV is almost entirely a mathematical construct, used to trade off the probability of some level of demand response/curtailment in some period against the probability of some other level of demand response/curtailment in some other period.

This interpretation of EMWV will become increasingly pervasive as the role of thermal generation diminishes. Ultimately, EMWV will always be determined by the opportunity cost of some form of future demand response, right across the storage range. That opportunity cost may not be determined by any explicit offer, though, but by an inferred response to a possibly "gamed" market price. And that seems to introduce potential circularities, and raise questions about benchmarking any analysis of market power that can only become more critical in future.

The issue of circularity seems even more important if EMWV is not calculated from an optimisation model, but inferred from market data, as in Tipping and Read [2012], and the various papers on which that was based.[33] That study assumed that market participants (in aggregate) were operating on the basis of a (national) EMWV curve of a specified simple form, and set out to find the curve parameters providing the best fit to market outcomes. In doing so, the authors implicitly assumed that all risk aversion and gaming considerations were already accounted for in the fitted curve. In other words, they assumed that participants based their offers directly on that curve, just as they would with a (hypothetical) true SRMC-based EMWV curve in a perfectly competitive market, without any further adjustments to lower risk, or influence prices.

In fact, a surprisingly good fit to market outcomes was provided by simulating market operation with participants making what they believed to be perfectly competitive offers based on that curve. That might be taken to imply that perfectly competitive hypothesis is at least plausible, as an explanation of NZEM behaviour. It certainly does not prove that there is no exercise of short run market power in the NZEM, though, and we would actually be surprised if that were the case. Thus, it may well be that an even better fit to market data could be found by re-estimating the EMWV curve, assuming that participants were marking up offers relative to SRMC determined by that curve.

The goal would be to determine the most plausible combination of EMWV curve, and level of gaming. Tipping and Read proposed to do this for the New Zealand market, but did not complete it.[34] This leaves us unsure as to how to interpret a study such as

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[33] J. Tipping & E.G. Read "Hybrid bottom-up/top-down modelling of prices in hydro-dominated power markets" in S. Rebennback, P.M. Pardalos, M.V.F. Pereira & N.A. Iliadis (eds) *Handbook on Power Systems Optimisation* Springer, 2010, Vol II, p213-238.

[34] Although the same paper calibrates a Cournot model of the Australian market in exactly that way.

that of Polleti [2018][35], where inferences are drawn about market power on the basis of simulations that assume a hydro SRMC determined by an underlying EMWV curve fitted to market data, using a method similar to that of Tipping and Read.

3.4 Risk

Section 2.6 has discussed the impact of risk on electricity market investment, in general, but participants in, and potential entrants to, markets with high renewables penetration face additional risks, at both operational and investment levels.

At the operational level, reservoir mangers have to adopt storage strategies that will see them covered across the range of possible future hydrologies. Section 6.5 discuss the issue further but, in New Zealand, risk aversion mainly implies withholding generation from the market over summer, in order to be sure of having enough water stored to get through the next winter. Since that also implies maintaining higher prices over summer, the implications are discussed further in the next section, on market power issues. Here we focus on investment issues faced by all participants in such a market.

For a start, investors must try to assess the true underlying supply/ demand balance, and the whole price probability distribution, from observation of prices in a relatively small sample of recent hydro years, which may have been significantly wetter, or dryer than average. Since extremes play a major role in determining expected values and risk, it might take several decades to collect an adequate sample, from a hydrological perspective. At the same time, though, observations of market conditions, as opposed to the hydrology distribution, will be rapidly outdated by changes to the system, fuel prices, market design and political conditions.

Then, once built, generation designed to provide the last increment of capacity to meet the 1:20 security standard used in traditional capacity planning might be expected to generate significant power in only one year out of twenty.[36] In fact, there is a non-zero probability that it will not be called upon ever, during its entire technically viable life-time.[37] In our view, this changes the situation with respect to competitive entry to such an extent that it becomes qualitatively different, and may require different regulatory and design approaches.

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[35] S. Poletti *Market Power in the NZ wholesale market 2010-2016*, Working Paper, University of Auckland, released September 2018.

[36] Our discussion will focus on that standard because it the loosest adopted in pre-market times. For many years a 1:25 investment standard was applied, while ECNZ adopted a 1:60 standard for operational purposes.

[37] This characterisation is obviously simplistic, but actually not far from the historic experience of stations such as Marsden B, or the original Whirinaki station. Short term price spikes will tend to provide more frequent revenue opportunities under current market arrangements, but the data presented in our final appendix suggests that the current Whirinaki peaker is not making any substantial return on its replacement cost, either [

Theoretically, all the standard theory discussed earlier, with respect to the adequacy of the PDC to support entry still applies. Theoretically, a perfectly competitive market with pure SRMC pricing, should still produce a PDC capable of supporting (i.e. recovering the cost of) an optimal mix of plant types. But we should pause to consider the realties implied by that theoretical statement. First, consider the equilibrium situation with strict SRMC pricing, and no contacting:

- The PDC we are talking about can no longer be thought of as representing an annual price distribution, corresponding to an annual LDC. It now summarises a price distribution representing performance of a particular system configuration over at least 20 hydrological years. But, in reality, participants know they will experience that distribution as a sequence of prices over 20 or more actual years, during which a great many factors other than hydrological variation will add to their risk.
- Theoretically, a fully diversified risk neutral international investor might be prepared to take a bet on this basis, in the belief that hydrology risk in New Zealand is unlikely to be correlated with anything else. But even that bet rests on the assumption that the theoretical dry year payouts implied by the optimised PDC will actually occur. And that assumption seems dubious, because the implied payouts seem large enough to potentially destabilise not just the electricity market, but the national economy and political equilibrium.
- Section 4.4 suggests that the proportion of cost recovery that needs to come from periods in which prices exceed the SRMC of a Diesel fuelled OCGT must lie somewhere over 25%. In Australia, we understand that similar calculations have led to price caps being set to a level at which OCGT plant can recover their annual costs in just 4-5 hours. And investors in the Australian market are probably fairly relaxed about that, in a situation where prices peak because of hot weather, which is more or less guaranteed to happen every year.
- In a hydro dominated system, though, we may expect to see very little cost recovery from periods in which MCP exceeds the OCGT SRMC, in normal years. As discussed in Section 2.2, this represents “missing money” not just for the OCGT, but for all capacity in the system. Over these years none of them would have been getting the revenue component that theoretically should be covering over 25% of their LRMC cost from this source, as they should under a pure SRMC market arrangement, in long run equilibrium.
- Thus, in this theoretical pure-SRMC market, the industry might collect, say, only 75% of its LRMC revenue requirement, in most years. Then, when a super-dry year does occur, the industry would typically need to collect something like 20 years’ worth of “missing money” in a single year: Say an additional 500% of its average LRMC revenue requirement, or around 670% of its “normal year” revenue.

This theoretical super-dry year payoff is surely implausible, though. No government or regulator is likely to countenance a nearly 10-fold increase in electricity prices in a single year, so the electricity sector, as a whole, could not achieve such a result. At that point, then, it would become apparent that the “missing money” foregone in normal years would truly be missing. And any investor who understands and predicts this kind of outcome, will realise that the theoretical promise of full cost recovery from a strict SRMC market is highly unlikely to eventuate in practice.

Further risk would arise as a result of errors in predicting load growth or under/over-investment, which would have a disproportionate impact on extreme peaking. Risk aversion would surely be significant in this situation, but even a risk neutral investor will be unwilling to invest in a situation where they can reasonably expect that regulatory intervention will deny them the opportunity to even recover their expected costs. Instead they will:

a. Hold off until prices become so high that they can reasonably expect to recover costs from revenue received in (fairly) normal years, and/or
b. Seek other ways to recover costs in normal years

As discussed in Section 2.7, the most obvious mechanism that could be used to achieve ahh steadier revenue stream is via contracting. Vertical integration by way of selling into retail markets has a broadly similar effect, and it is worth noting that vertically integrated "generators" will be largely locked into fixed price variable volume retail contracts for the duration of any likely dry year crisis. Thus, any rise in spot prices would have to be absorbed by transactions between their generation and retailing arms.

Section 4.3 also notes that generators will have incentives to maintain prices above SRMC levels, though, in periods when they have excess capacity, not contracted, or committed to retail sales. And that would cause the "bottom end" of the PDC to inflate, thus helping to support cost recovery, and hence entry, at least of the kind of capital-intensive plant best suited to meeting base/shoulder loads.

3.5 Non-Linear Cost Structures

The basic discussion of entry economics applies most clearly to "linear" cost structures, in which each unit of capacity or generation costs the same, across the entire planning horizon. Relaxing that assumption opens up a number of ways in which costs could vary, some of which have significant implications for renewable generation, in particular.

Economies of scale affect all generation technologies, to some extent, and it is well known that cost recovery can be an issue when the marginal cost of capacity is less than its average cost. In principle, that could be a significant issue for large scale hydro developments, but that now seems to be a largely historical issue. It is not a major issue for likely future, wind, solar or geothermal developments, though, and will be ignored here. Three other non-linear pricing issues may be relevant, though, in a situation where it is sometimes suggested that "old plant" may be receiving excess rents.

First, the cost of technologies such as wind and solar are declining over time, independently of any development in the New Zealand market, and Figure 14 from the EPR report[38] shows how this is affecting both LRMC estimates and market prices. Theoretically, potential investors in those technologies may actually respond to the

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[38] Figure 4.1 in this report

expectation of falling costs by delaying investment in that plant type until costs fall further. In the long run, though, falling costs must imply a steady decline in the prices that can incumbents can charge, without triggering entry. This figure suggests that, currently, older plant in the NZEM are unlikely to experience rising revenue streams, and may now expect to receive a lower total return than was anticipated at the time when their plant was built.

Second, though, the LRMC of new hydro typically rises over time, despite any technological progress. This is partly due to a continual process of tightening various regulations affecting hydro, pushing up the cost of new development. This raises the value of older developments, although that effect is countered, and possibly reversed, if the maintenance costs of older developments rise, due to refurbish/ retro-fit requirements.

The rising hydro LRMC cost curve also reflects a kind of depletion effect, though, as the cheapest and best sites are developed first. At first glance it is not actually obvious how the PDC analysis of Section 2.4, can be extended to allow representation of the various hydro development options that might be available in a particular context. If they were all assumed to have an SRMC of zero, the option with lowest capital costs would appear to dominate all others. But it will not even be possible to meet all requirements with this single project. So how can the total cost curves of all hydro options be adjusted to allow several hydro developments to appear in the optimal the mix?

c. First, assuming a zero SRMC implies unrealistically high generation for almost all hydro. So, for each potential hydro development, we must find the non-zero SRMC that will just use the water available, over a year.[39] Some will then appear as potential base-load plant, and some as potential peakers etc, and each may, or may not appear in the recommended optimal plant mix
d. Second, though, as hydro sites are developed they can no longer be included as development options. To be exact, they are now development options that have already been exercised, so their fixed “entry cost” is no longer relevant. Instead the PDC analysis itself will determine the option value (i.e. OV) of each project, and those option values will adjust, over time, with SRMC being tuned to keep output at a sustainable output level, as above.
e. Then, these existing projects will remain in the optimal plant mix, unless or until their OV falls below their fixed O&M cost, which can be expected to rise over time.[40]

It should be recognised that the process described above can not be used to define a “long run equilibrium” PDC, independently of the LDC. In fact, other things being

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[39] Ideally, this should be done for a variety of hydro years, implying a different OV for each year. The probability-weighted average of those OVs can then be compared with FC.

[40] The same is true, actually of existing thermal plant, with the difference being that their SRMC is normally assumed to be well defined, and to determine their energy contribution, whereas hydro is in the opposite position.

equal, it implies that the PDC must gradually rise as the LDC grows, and cheaper development options are exhausted.

Theoretically, rational investors would predict this phenomenon, though. If the opportunity to develop all sites were to be put up for auction in the same year, we should expect the sites that promised to deliver better value for money to attract premiums that investors would then see as part of their fixed entry cost. Poorer sites would attract lower premiums that would be further discounted because of the possibly very long delays, before development would actually occur, and the risks that might occur over that extended period.

Historical reality has obviously been very much messier than this, but theoretically, there should be no such thing as "cheap old hydro power". All power generated at the same time, and delivered to the same point is of equal value. What should be expected to differ is the wealth of the site owners. Then, whenever any asset is bought by a willing buyer from a willing seller that asset is implicitly re-valued in light of the knowledge and expectations available at that time. Such valuations may rise over time, or fall, or fluctuate, but hydro projects are no different from other assets, such as housing, in that regard.[41]

Finally, a technology like geothermal might suffer from a "site-depletion" effect, like hydro, but also a declining international technological cost curve, like wind and solar. The latter will be counteracted, though, by a third, local "learning curve" effect as each development increases understanding of the New Zealand geothermal environment. At a national industry level, that implies some incentive to bring investment forward (i.e. to enter when OV is still somewhat below FC), so as to benefits from whatever learnings may arise.

3.6 Long Lived Assets

Although many electricity sector assets have long lives, this is particularly true for hydro power stations and transmission/distribution lines. In both cases it is sometimes suggested that since certain assets were "paid for long ago" they should not now be expected to earn an economic return, and that perhaps some way should be found to discount charges (supposedly) intended to recover their costs.

During the reform process, we expressed concern that any increase in the valuation of transmission and distribution assets would increase the economic distortions inevitably

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[41] Historically, the "ownership" of development rights may be debatable, and many "sellers" may not have been willing. This obviously raises a large and complex set of historical, legal and social issues that lie well beyond our present scope. But, whatever the rights and wrongs of that debate may be, the practical outcome in New Zealand was that, in almost all cases, the State or some other public body obtained or assumed the right to develop, and whatever value might be assigned to that right has either been implicitly retained by taxpayers or ratepayers, or explicitly passed back to them, or at least their collective agent, when the asset was sold.

inherent in pricing regimes required to recover costs in a situation where the optimal SRMC price signal is essentially zero. We were particular concerned that "variabilising" fixed cost recovery charges would create artificial incentives to reduce consumption at times when such reduction actually saved no costs, and eventually to encourage uneconomic network bypass of various kinds. Our view was, and is, that the motivation behind much of the debate reflected much more on the social, organisational, and political history of the sector than it did to the underlying economics. [42]

Similar comments apply to some extent, to some extent, to the generation sector, where some discussions seem to involve a curious amalgam of forward-looking economic and historic accounting concepts, often mixed with strong doses of selective historical reminiscence, and social policy concern. Scale economies are much less significant in this sector, though, and the case for forward looking valuations, based largely on the economic value delivered by displacing the need for power from alternative sources always seemed much clearer for generation assets.

The actual historic record on "cost recovery" seems quite mixed. Culy et al [1996] reported that tariffs had actually under-recovered capital cost for long periods in the pre-market era. And, while some hydro projects clearly were "paid for years ago", the final round of pre-market hydro developments (e.g Clyde, and the Tongariro scheme) were passed into the ECNZ asset base at values well below their construction cost, while others (e.g. Marsden B and Whirinaki) were deemed to have essentially only salvage value.

In 2014, an extensive analysis by the New Zealand Electricity Authority concluded that, over the period from 1974 to 2013:

> *Based on the modelled generation costs presented in this paper, while the early- to mid-2000s saw retail charges increase relative to generating costs on average across all consumer types, at no time did average total charges exceed estimated costs. The cumulative under-recovery resulting from the negative margins shown above has been borne by a mix of taxpayers, and company shareholders. This*

[42] In particular, we saw no economic logic behind the seemingly arbitrary approaches taken to cost recovery for essentially similar networks serving households: Low fixed charges and high mark-ups on variable charges on the electricity network; High fixed charges with no variable charging for local calls on the telecoms network; and fixed charges bundled into local rates for other networks, such as wastewater disposal. At that time, though, it was easy to theorise about alternatives, because virtually all the assets were in some form of public ownership, and being transferred into new structures whose value would be retained by the public, either through direct or community ownership, or through the proceeds of asset sales based on any new valuation. Now, though, asset values are entrenched into a diverse set of organisations, under a range of ownership structures, making change much more difficult.

> *analysis finds no evidence of windfall gains over historical generation costs accruing to generators or retailers.*[43]

It seems to us that any logic behind accounting for "windfall gains" in power pricing should apply equally to "windfall losses", and those may well be greater. But, even if there had been "windfall gains", on average, that would not make the electricity sector any different from any other.

Standard economic theory would hold that what was paid for assets, and when, has no bearing on their current value, which is determined entirely by the net value of the services they will be able to deliver in future. Since the power produced by "old" assets is interchangeable with power produced by "new" assets, it seems obvious that the economic value of these assets is also the same, after accounting for their remaining useful life, maintenance cost and so on. Attempting to create a market in which "old power" was priced higher or lower than new power would be both complex and distortionary. At best, it would just shift rents into different pockets.

Some commentators seem to mis-read the intent of economic studies focussed on cost recovery. The issue has never been about whether this or that historic investment proved profitable, or not, or whether particular parties have received a "fair return" on their investment, in this sector or any other. The record above shows that some projects paid for themselves relatively quickly and have made a steady profit ever since, others suffered major cost over-runs and may never pay for themselves, and a few failed completely.

Of itself, though, the analysis of options that are no longer available is not relevant to potential entrants. The economic issue is really whether the historical evidence will convince them that they will receive a fair return, in future. So, they will focus most on whether the market returns being experienced by recent investments of the type they are actually in a position to make themselves, is covering entry costs, or not. Hence the relevance of the LRMC comparisons discussed elsewhere. But the longer-term historical record is also important inasmuch as it indicates the sort of risks they may face in future.

We expect the planning horizon over which entry assessments are performed to approximate a conservative lower bound on the expected asset life. Major hydro schemes may be expected to remain productive beyond the planning horizon, but that is mainly just a matter of computational convenience. The prospect of economic returns beyond the chosen horizon may still be recognised as a likely upside, though, as for investments in any sector. A realistic commercial discount rate may place little weight on the prospect of such returns, but investors will surely pay more for an asset they expect to own, and earn revenue from over the period beyond the planning horizon.

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[43] From Page ii of: *Analysis of historical electricity industry costs: Final report*. NZ Electricity Authority, January 2014

And surely no-one would be surprised if investors were to demand a higher rate of return if they suspected that a future regulator might intervene in ways which reduced profits over that period. If so, it should be recognised that the implicit prospect of making profits on “old” assets which “have already been paid for” has a significant impact on entry economics. Regulators may find it attractive to retrospectively change the rules, and appropriate some of the rents expected by the original investors for other purposes, e.g by capping prices. But they need to weigh the one-time gain from doing that. against the long-term impact such action may have on the rates of return that will be required by future investors, and hence on the price levels faced by future consumers.

3.7 Public Focus

Finally, we should note one aspect of the situation that is seldom mentioned, but seems to apply more strongly to renewable electricity generation assts than anything else in the sector, or probably the wider economy.

We suggested that the motivation behind different approaches to pricing of transmission/distribution assets reflected more on the social, organisational, and political history of each sector than it did to the underlying economics. The same is true, now, of developing renewable technologies such as wind and solar where, for many, the underlying issues are as much about the fate of the planet, and/or local landscapes, as they are about economics. But it seems particularly true for hydro assets, which seem to occupy a very special place in the hearts and minds of the New Zealand public.

Throughout our lifetimes, older New Zealanders, at least, have consciously or unconsciously developed a relationship with these assets which is quite different from the relationship we have with probably any other “productive facility”. We have protested and mourned the loss of natural landscapes, while simultaneously celebrating and enjoying the benefits of new lakes, roads, and landmarks. They appear in our photographs, and family memories, and influence the environments we relate to, far downstream from the projects themselves. But the promise of “cheap hydro power”, economic development and even “think big”, are all part of our national heritage and mythology.

Deep down, then, we are all “invested” in these projects, and all feel they are “our” assets in some sense quite different from what the legal documentation might define. And this colours debates about what are supposedly “economic” issues, in ways that are seldom explicitly recognised.

In our view, it is this feeling, rather than any economic logic, that underlies the arguments advanced over the years that ways should be found to pass the emotively labelled (and perhaps illusory) “windfall gains” on historic hydro projects through to the general public. So too, to some, extent the concern about the prospect of “market power rents” being earned, perhaps at our expense, on what we feel to be “our” assets”.

Comparison with other sectors seems enlightening, in this regard. The social logic is actually much stronger in housing sector, where there arguably have been major "windfall gains" over recent years. Even though national attention is now focussed on a "housing affordability crisis", though, we just do not see impassioned public pleas to solve the housing affordability crisis by requiring owners of older hotels, or houses, that were "paid for long ago" to charge lower rents, or to sell them at historic/discounted prices to the deserving younger generation. Nor do we see detailed studies of exactly how much might be at stake, or how it might be transferred.

Nor, in the electricity sector, do we see impassioned public pleas to lower the prices paid by the major commercial electricity users, who also draw power from old hydro assets. We do not see pleas to pass on the "windfall losses" implied by the historic cost of some hydro developments, and of thermal stations like Whirinaki and Marsden B in power pricing either. Since the economic logic, if any, seems the same, there is surely another social logic at work here. Indeed, the arguments we have seen on this topic seem to be less about whether there is an economic rent, but about whose pockets that rent should ultimately be assigned to.

To be clear, though, we are not actually rejecting the validity of that social logic, just arguing that it should be explicitly acknowledged, and not presented as some arcane re-interpretation of standard economics. During the reform process, our view was that, if the objective was to return some value to the general populace, then lowering wholesale prices to all, including industrial/commercial users, did not look like the most effective option. Other options were considered during the market design phase, including creation of a special "bonus" mechanism for hydro profits[44], giving away shares, retaining assets in public ownership, or simply returning the value realised from asset sales to the public funds.

The broad impact on the welfare of the New Zealand public was expected to have been much the same, given that all assets were in public ownership at that time. So, the debate ended up being mostly about economic efficiency, and pragmatism. As it happens, some assets have been retained in some form of public ownership, and some sold at what seemed to be fair market valuations at the time. Asset values will have changed since then, creating some subsequent benefit or loss to those private shareholders who took on that risk. A rising LRMC would imply upwards revision of old asset values, while the current experience of falling LRMC will presumably imply downwards revision. But that is true throughout the economy, and it is not valid to single out any specific sector or transaction for retrospective analysis.

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[44] G. Bertram, I. Dempster, S. Gale and S. Terry *Hydro New Zealand: providing for progressive pricing of electricity* Wellington: Energy Reform Coalition, 1992.

4 Market Power and Market Design

4.1 Definitions and Perspectives

Section 3.7 discusses some of the emotions underlying economic debates in the electricity sector, and the term "market power" clearly attracts attention from many quarters, ranging from the halls of academia to the wider public. ɪt is by no means clear that all those who use the term have the same thing in mind, or use the term consistently across their various spheres of involvement, though.

At one extreme, analytically inclined academics often use a precise mathematical definition, and state that market power is being "exercised" whenever market prices deviate from the SRMC of the marginal provider[45]. The recent growth in literature studying deviations from SRMC pricing in the electricity sector partly reflects its economic importance, its critical supporting role in modern society, and fears that the sector provides an environment where "gaming" may be facilitated. It should be said, though, that much analytical attention has also been driven by the fact that, at least from the advent of electronic computing, it has provided analysts with perhaps the richest, and most precise centralised "hard" dataset available for analysis.

- From the 1950's it has been a major testing ground for the development and successful deployment of centralised optimisation techniques, and large-scale hydro systems, in particular, still challenge the capabilities of stochastic optimisation algorithms. At the operational level, that paradigm focusses strongly on the calculation and equalisation of SRMC, over space and time. It is hardly surprising then, that we analysts trained in that tradition have a strong focus on SRMC.

- More recently it has been a major testing ground for the development and successful deployment of "smart market" ideas, in which decentralised operation, is still coordinated by essentially the same optimisation techniques, just deployed in a slightly different way. In that context, though we see "deviations from SRMC", and it is hardly surprising that analysts from essentially the same tradition now express strong concerns.

- Now, the sector is proving to be a major testing ground for the development and testing of theories about the role of both risk aversion and market power in motivating deviations from SRMC pricing, and in developing the software required to analyse such issues. Amongst things, the sector provides a

45 We have already seen that there is a sense in which market prices may always equal the "SRMC of demand reduction", and that becomes important in hydro dominated systems where Expected MWVs often reflect the assumed SRMC of demand reduction more than anything else. But, reflecting its origins in thermal systems, the analytical literature often ignores that potential circularity, and thinks of SRMC as being the SRMC of generation.

conveniently computable SRMC benchmark, and a wealth of historical data against with which performance can be compared.

At the other end of the spectrum, the general public seem very clear that they do not like “market power”, in the electricity sector, but appear to have very little idea as to how “deviation from theoretically optimal spot pricing” might be defined, how it might affect them, or how to recognise it in real life. At the highest level, this public fascination with the topic is actually very odd, and seems more reflective of the emotional factors discussed earlier than of any understanding of, or rational response to, the real economics of the sector.

Larger scale commercial/industrial consumers can be somewhat exposed to spot prices on which academic studies focus. and some may be fully exposed. But those consumers are well able to explicitly protect themselves against spot price volatility by contracting. Indeed, some will be in a position to profit from price spikes by reducing consumption, so as to effectively sell contracted quantities back into the spot market.

Only a very small part of domestic load is actually exposed to spot prices, though, and even their charges are significantly distorted, and even dominated, by an overlay of charges recovering the essentially fixed costs of the distribution and retailing sectors. In reality, then, spot prices could vary over a very wide range, and most domestic consumers would be totally unaffected. So far as they are concerned those prices should logically just be seen as transfer prices within organisations, and perhaps between organisations, which just happen to operate in a much more transparent manner than most other sectors they deal with. In particular, because the fundamental drivers of most spot price volatility are short term events such as wind or inflow variations, the occurrence of high prices at any particular time really gives no meaningful signal, to the general public, of a likelihood that retail prices will rise in future.

While it seems reasonable that the general public should be concerned about trends in their electricity costs, their logical focus should be on LRMC and long-term cost recovery, not on spot prices which may or may not deviate from SRMC. In fact, the same public that seems so easily excited when academics release results about electricity prices being “inflated by market power rents” seems quite oblivious to the reality that “deviation from SRMC pricing” is absolutely pervasive throughout the economy.

Every day, we are all actually paying prices above SRMC, and often involved in setting them too. No business owner thinks that “adding a mark-up” is anything but a routine, and probably automated, operation. And surely business owners realise that the wholesale price they pay for goods is already well above SRMC, due to mark-ups already added further up the supply chain. Everyone surely understand that mechanics, plumbers, lawyers, and consultants are routinely charged out at rates that often amount to a 100-200% mark-up on their wages. And, while those wages may reflect some kind of opportunity cost to the worker, they are generally well above the “true supply-side SRMC” of actually staying in the office for another hour. In many cases they are not even a short run marginal cost to the employer, either, because staff are on contract for fixed hours.

We may all seek ways to avoid these mark-ups, if we can, and so receive some goods or services at prices a little closer to their true SRMC. But most of us also understand three things:

- First, we understand that, in the long run, businesses will simply not survive to provide us with services unless they are able to recover their full costs in some way. We may complain about the high rates we are charged by sub-contractors, but the constant stream of bankruptcies arising in that sector must surely give us pause to consider whether we are really being "ripped off" on average. Perhaps we will conclude that substantial excess profits can be made in the sector, but the ultimate test is surely whether we would be willing to invest themselves.

- Second, we understand that, while those who possess some particular skills may be able to charge an extra premium because they are in temporary short supply, those rates will ultimately be disciplined by the prospect of new entry. We may complain about the rates we are charged by lawyers (or whatever). But the lawyers will tell us that, if we think their sector offers abnormally high rewards to those with the requisite underlying abilities, there is no reason why we, or our children could not go to law school ourselves, become trained, build up experience, and ultimately charge similar rates. We may protest that such a course of action involves long term commitments of time and money, and that it carries the risk that, by the time we are trained the market might not support the high charge-out rates we hoped for, particularly if many others enter with a similar hope. But that is precisely the point. Entering a competitive market is a long run investment with uncertain outcomes, and no-one will do it unless the returns look substantially better than those of more certain alternatives.

- Third, we at least implicitly understand that, while it may be academically useful to label the pervasive economy-wide "deviation from SRMC pricing" as an "exercise of market power" or "collection of market power rents", that labelling does not turn it into the kind of "abuse of market power" a Commerce Commission would, should, or could be concerned about. If it were, it would be investigating and intervening in virtually every sector, virtually all the time. That kind of concern, and action, must surely be reserved for situations where behavioural rules have been broken, or normal market disciplines do seem to have broken down in a sector, over an extended period. For example, it would be concerning if market outcomes did not seem consistent with the LRMC/entry barrier tests discussed in other sections.

Section 4.3 discusses analogies with other sectors, whose capital-intensive cost structures may be more closely analogous to that of the electricity sector. In all cases, though, the conclusion is the same: The normal test of sectoral performance, across the whole economy, is not whether prices deviate from SRMC, which is not even readily knowable in most cases, but whether prices match the LRMC entry cost. If prices are below LRMC we should expect to see more firms exiting (or downsizing) than entering (or expanding), until prices pick up (or the whole sector disappears). If prices are above LRMC we should expect to see more firms entering (or expanding) than exiting (or contracting), until prices fall to LRMC. Or, if that does not happen we should look to see what barriers might be preventing entry, and what might be done about it.[46]

The fundamental direction of electricity sector reform in recent decades is based on the realisation that modern communications/optimisation technology makes it possible to efficiently coordinate multiple generators in the same power system, and provide them with the ancillary service support they need to allow independent operations, and entry. Thus, the contention is that, now, the electricity sector can be treated much like any other. So, in the next section, we ask why, at least some parts of the world, there is still a very strong desire to treat it very differently from the rest of the economy, and particularly to focus on SRMC rather than LRMC perspectives.

4.2 Complementary Pricing Paradigms

The electricity sector has long attracted more than its fair share of attention from analytical economists of various schools. This is partly due to the fact that this kind of analysis is just not possible in other sectors, but also its economic importance, and critical supporting role in modern society. There has been widespread concern, too, that the electricity network, at least, is a natural monopoly, whose owner might, unless restrained, hold society to ransom, and extract monopoly rents, at whim. Thus, the whole sector has typically been either publicly owned, or heavily regulated, in most jurisdictions, with much attention devoted not only to its "optimal" operation, but to its optimal interaction with the wider society, particularly via pricing.

From an early date, the SRMC focus noted above lead naturally to a desire to see consumers facing "SRMC prices", so that they could coordinate their own activities optimally with the optimised centralised dispatch, or market. But real time SRMC pricing was not possible, in the past, and nor would it have been socially acceptable, at least in a hydro dominated system like New Zealand's.

An optimally planned (and priced) system, should produce essentially the same volatile SRMC pricing pattern as an idealised perfectly competitive market. But that reality has historically been obscured by both pragmatic and political factors. Rather than raise prices to SRMC levels high enough to choke off demand during times of relative shortage, reliance has been placed on public appeals and physical restrictions. Prices have not been forced down to SRMC levels during times of relative surplus either, and certainly not to zero in systems where water spills in wet years.[47]

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[46] E.g by relaxing limits on training schemes in the examples above.

[47] In New Zealand, prices charged to the generality of loads were held constant, in nominal terms, over long periods with significant inflation, and then sometimes increased very abruptly. It is true that the system also veered between really quite significant under- and over-supply, but these price changes were generally driven by politics, and government revenue requirements, more than the underlying sectoral economics ,though. In fact, some of the largest price increases occurred during times of relative surplus. .

There was also a long-standing debate, though, between this SRMC paradigm, and two alternative paradigms:

- First, there has always been a strong economic argument that really it should be LRMC that guided consumer decision-making, and that principle was accepted (if not necessarily acted on) by the New Zealand Ministry of Energy in its later years.

- Second, though, it was widely accepted that assets built to meet public electricity demand must be paid for, preferably by electricity consumers, leading to widespread regulatory focus, particularly in the United States, on defining and determining what those costs actually were, typically in historical accounting terms.[48]

This may be seen as reflecting a fundamental conflict between the forward-looking perspective of economics, with its emphasis on finding the best use of resources irrespective of what they may have cost to develop; and the backward-looking perspective of accounting, with its emphasis on paying for resources already committed, whether or not they were economically justified in retrospect. And some discussions about "cost recovery" suggest that the fundamental conflict between these forward and backward-looking perspectives still remains.

We also see, though, a conflict between the desire to provide efficient real time SRMC-driven signals to consumers operating installed electrical appliances etc, and the desire to provide efficient LRMC-driven signals to consumers investing in electrical appliances etc. In other words, there is a tension between achieving productive and allocative efficiency in the short run, versus dynamic efficiency in the longer run.

Those debates dogged the sector for some decades. Ultimately, though, it was realised that all three views are complementary, not conflicting. In fact, the unified framework discussed in Section 2.7 resolves the conflict by showing that, if scale economies can be ignored, the expected value of SRMC prices should equal forward-looking LRMC, in the long run and, looking backward, that alignment should also recover the costs anticipated at the time of entry.

In principle, then this framework would allow long term investment decisions, including generator entry, to be based on LRMC contract prices, while deviations from contract volumes would face SRMC-based spot prices. It was hoped, then that markets would succeed, where centralised planning had obviously failed, in allowing more SRMC price signals to be passed through to consumers who could respond, while also

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[48] It may seem odd, to the inheritors of that tradition, but this cost-based focus was largely absent in some systems, where assets were directly owned by the government. In New Zealand, construction costs were incurred in a different Government department, and the legislation only placed a very loose limit on the contribution to capital requirements expected to come from electricity revenues. Implicitly, within the Government's accounts, there was very wide discretion for electricity sector losses or profits to be transferred to or from taxpayers. Nor was there much concern, given their assumed commonality of interest.

minimising fluctuations around the LRMC benchmark, and recovering costs, or at least ensuring that the cost recovery risk was faced by investors, rather than by the electricity consumers or taxpayers.

So far as we know, this theory is not seriously in dispute between the advocates of LRMC and SRMC based approaches to evaluating market performance. At least in principle, all would like to see a pattern of market prices aligning with both, across hydrology years, and time periods within each year. Presumably all realise that costs must ultimately be recovered from, too, and most will agree that recovery should be electricity consumers.[49] The conflict, if any, relates to the relative weighting that should be placed on alignment with each principle, if compromises must be made. And, specifically, the extent to which prices might need to deviate from SRMC in order to achieve sufficient cost recovery, with acceptable risk, in practice.

4.3 Design Alternatives

Probably all would agree that the NZEM market design is not perfect, but there would be far less agreement about what changes might improve it. Most would agree, though, that it is better to have an imperfect market design that works, and produces broadly acceptable outcomes, than one that is theoretically perfect, but impractical, or implies unacceptable outcomes. Thus, the NZEM market design is inevitably a compromise, the perfection of which is limited by two key factors:

- The fact that, with New Zealand's population approximating that of a large suburb in a major international city, it is simply not worthwhile to devote the same level of resources to debating, designing, implementing, operating, or monitoring market design features that might seem desirable in larger markets overseas. It also makes it much more difficult to achieve the levels of competition that might be expected elsewhere, particularly given the discrete nature of large-scale hydro generation projects.

- The fact that the market is isolated, dominated by hydro, and served by a relatively sparse transmission network. This means that participants must manage more risk than elsewhere, and face a potentially major problem in maintaining acceptable cashflows, as discussed below. And it makes it even more difficult to achieve a high level of competition at particular locations. It also means, though, that each major participant's situation is really quite different from any other, making it very difficult for a regulator to understand all the issues involved, let alone design or implement common "solutions" that work effectively equitably across all participants.

Both factors have, quite reasonably in our view, lead to a situation in which participants have been left to sort out a variety of arrangements for themselves, or between

[49] Although some older New Zealander's may still recall the days when that did not seem to be the case, as noted elsewhere.

themselves, that might have been specified by a regulatory process elsewhere. We should reasonably expect the trade-off to be acceptance of a lower degree of "optimality" and/or certainty about optimality with respect to some aspects of market performance.

Still, the original market design was undertaken with some care, albeit in an environment with few established international precedents to follow, and it has been refined over time. Appendix A discusses a number of alternative design features that were considered and, rightly or wrongly, rejected during that process. We did not, and do not, necessarily agree with all the choices made, but we do consider that those choices were made in a reasoned and reasonable manner. Only time will tell whether they should be re-visited, in light of market experience, or changing conditions.

As discussed in Section 5.2, though, we do agree that, if compromises must be made, long term alignment of wholesale prices with LRMC (or more exactly with the optimal PDC determined by LRMC entry costs) is more important than short term alignment with SRMC, in a capital-intensive industry. In fact, Section 3.4 suggests that the extreme volatility of strict SRMC pricing in a hydro-dominated sector is very unlikely to be socially acceptable if passed straight through to consumers, and that constrains the extent to which strict SRMC pricing can be implemented through the various levels of the industry.

SRMC alignment is still highly desirable, though. While Section 3.7 argues that the attention sometimes focussed on this issue by the general public is unwarranted, it does have an impact on both the internal efficiency of the industry, and the accuracy of the price signals provided to incentivise efficient utilisation of electricity by consumers. And Section 2.7 explains how a high degree of contracting could theoretically allow long term decisions, including generator investment, to be guided by LRMC, while short term decisions respond to SRMC prices.

Is the "ideal" achievable (or ideal)?

Some may see the discussion of contracting in Section 2.7 as grounds for arguing that all generation, and hence all load, should be contracted for its expected output at all times, and over all time scales. In theory, it might be thought that would minimise risks, remove the need for prices to deviate from SRMC, and allow both long and short-term markets to operate with minimum distortion, and maximum efficiency.

We believe that "ideal" is not actually achievable, though, particularly in the volatile environment of a hydro dominated sector, where participants can not sell all their output via long term contracts, because they do know, in advance, how much they will be able to produce. Perhaps more importantly, it could really only be implemented by creating a "single buyer", who would establish, or oversee establishment of, contracts with all generation capacity.

Section 5.3 discusses several reasons why that option was rejected in the WEMS market design phase. Perhaps the most important, is that it would re-create the situation which lead the New Zealand electricity sector into so much trouble before the market reforms. The investment pattern of the entire sector would then be driven by the judgements of a single entity, thus increasing national risk, relative to a market situation where the judgments of multiple parties contribute to a self-correcting incremental response to changing conditions and perceptions. Most damagingly, that entity would inevitably become captured by an essentially political imperative not to quickly abandon announced plans that were becoming inappropriate, and also become subject to political influence to distort planning choices in one direction or another, depending on the party in power.[50]

Accordingly, preference was given to less centralised alternatives that might appear less "perfect", but promised to be more robust in the long term. Those alternatives involve somewhat messy looking compromises, though. So, it seems pertinent to ask:

- What kind of market design compromise might be reached? And also, what degree of deviation from SRMC pricing might be inevitable, acceptable, or even desirable, in such a market?

Conversely: Is the observed level of deviation in the market and something that could or should be "corrected"? Or is it perhaps optimal, when seen from the context of some broader theoretical framework?[51]

How are costs recovered in capital intensive industries?

In a hydro dominated electricity sector, we face three closely related problems:

- The need to ensure adequate cost recovery for enough peaking capacity to cover LDC requirements in very dry years, which occur quite infrequently

- The fact that the natural SRMC pricing structure of the sector implies that all generators should recover a substantial part of their costs from revenue, in those years, that is not likely to be socially acceptable,

- The implication that, not just potential peakers, but all participants may see a serious enough risk that they will not actually recover costs, that they become reluctant to enter except at high rates of return that will raise costs to consumers.

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[50] Note that the evidence presented in Section 4.4 suggests that, in this critical respect, the New Zealand electricity sector has performed markedly better during the NZEM era, than it did during the era of State control, under the NZED or MoE.

[51] We make no comment here, on the level to which prices might actually be deviating from SRMC, because we have not studied that question. But we have no doubt that they will deviate, if only because even a large and diverse electricity market will become un-competitive when supply is tight in particular times and places, and partly because the true SRMC pricing pattern is probably too extreme to be acceptable.

Read [2010] discusses a wide range of alternative arrangements that might be used to deal with this situation in the electricity sector. But, first, it might be helpful to see how this kind of situation is dealt with in other sectors whose cost structures are similar.

There are, in fact, many industries with basically similar, capital-intensive cost structures to electricity. So, the critical question to consider is this: If regulation to force a high level of contracting, and/or SRMC pricing is the right answer for electricity, why is it not adopted more widely throughout the economy?

The cost structure of the electricity sector is actually little different from that in many other industries, where prices routinely exceed SRMC, because prices need to be maintained at such levels in order to provide an adequate return on investment, given the risks involved. But we will focus on two sectors with which we are all very familiar: airlines, and hotels. The extra weight of a passenger really makes very little difference to the fuel consumed by an airliner, and a hotel really only faces an incremental room cleaning cost, plus the cost of some tea, coffee and toiletries. In both cases SRMC is very low, except on rare occasions when all capacity is fully booked.

In both cases, though, SRMC pricing is a rare exception, typically linked to what might be considered a pseudo-contractual deal designed to secure customer loyalty. Prices in both industries are moderately volatile, in both the short and long term, once special offers are taken into account. But “worse”, from an economic perspective, there will often be empty seats that could easily have been filled by grateful passengers, had they been offered at the “true SRMC price”, of close to zero. Hotels routinely charge positive prices, even quite high prices, on nights when there are actually spare beds, and SRMC close to zero.[52]

In fact, we have already argued that deviation from SRMC pricing is ubiquitous in the everyday world of business, even in sectors which can be reasonably considered “competitive”. So why do regulators not intervene to force SRMC pricing in all of these industries? Clearly, regulators are taking a wider and longer-term perspective. They understand that what is really most important, particularly in capital intensive industries, is that the market facilitates efficient investment over time, in the form of new aircraft, hotels, software packages etc. Accordingly, they rightly focus on the existence of possible barriers to entry, and accept that short run pricing will be routinely distorted, with consequential impacts on short run efficiency.

Let us be clear: These deviations from SRMC pricing do impose real costs on the economy. There really are people sleeping under bridges when beds are free at the Hilton. There really are empty seats in planes and movie theatres that would have been filled if tickets were free. And consumers, every day, go without all kinds of goods that they find too expensive at retail prices, but which they would readily buy and use if available at the SRMC of production and distribution. The aggregate cost of all these

[52] The software industry is “worse”, because a download really has no SRMC at all, and there are no capacity limits either, so no reason why SRMC prices should ever be much more than zero.

distortions must be very great indeed. Our point here is not to criticise such practices, though, but to note that, despite the obvious distortion and inefficiency, pricing above SRMC has long been considered legitimate, indeed necessary, if not desirable. In fact, many, if not most, desirable economic outcomes require investments, the fixed costs of which can not realistically be recovered without "distorting" prices away from, and often well above, SRMC.

These situations are not quite analogous with the electricity sector. The services delivered by hotels differ in various ways, and they each strive to create their own niche market, within which they are shielded somewhat from competitive pressure. And they each charge their clientele what they are prepared to pay, or more exactly what enough of them are prepared to pay to keep the hotel full enough, on average, to cover its LRMC cost in the long run. There is no centralised market-place dispatching bed-nights, capacity is not filled in strict merit order, and they do not all receive a price set by the SRMC of the marginal provider.[53] If we imagined a whole collection of hotels , though, differentiated only by SRMC, with bed-nights assigned centrally, each would actually be less able to charge prices much above their own SRMC, because all their SRMCs would be low, until all bed capacity was filled.

That scenario is obviously unrealistic, and no-one would invest in hotels if required to recover costs in that way. It is not much different from the emerging situation in an increasingly renewable electricity sector, though, with the distinction that reservoir storage does at least allow a physical trade-off between providing services in one period, vs another.

What role do contracts play?

There is another common factor at work here, though. What these industries have in common is that perfect forward contracting is not possible, or more exactly that the transaction costs of such contracting would exceed the economic costs of living with the distortions implicit in the current regime.

We have referred to the hotel sector, above, but it should be recognised that this is actually just a small subset of a much broader accommodation sector. In that broader sector, it is actually quite possible to contract forward, and most people actually do manage it, with respect to the vast majority of their person-night requirements. The most common form of forward contracting is called "home ownership", and home-owners spend most of their person-nights in their own homes, paying only SRMC per additional night. But they still pay LRMC, in total, because they also pay the fixed cost of purchasing a home, which is ultimately disciplined by the cost of construction. Those with term rental agreements are in much the same situation.

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53 Arguably, if a merit order were to be formed, accommodation might be ranked more by quality of service than by SRMC, but we can not say that customers would pay the Hilton price at a backpackers, just because the Hilton is full. So, the analogy is not exact.

The hotel sector just represents an extreme outlier in the distribution of accommodation contracting arrangements, from ownership though rentals, time shares etc, to hotels. And hotel accommodation works out to be the most expensive, per night, mainly because it is unrealistic to expect customers to enter into contracts to book hotel beds for anything like the term over which the fixed costs of building a hotel must be recovered. So, the hotel supplier must often run with spare capacity, and recover all of their costs, with a considerable risk element, from “spot sales”.

Even though their SRMC is low, their role is, in effect, similar to that of a peaker in the electricity sector. Theoretically, they might set prices at SRMC most of the time, and then try to recover the shortfall on their entire LRMC cost by charging extremely high prices for the few nights when all accommodation in town is at capacity. But they know that would be both risky and socially unacceptable. So, instead, they must recover their LRMC cost, by charging prices far above SRMC for all the bed-nights they can actually sell, even when there is spare capacity. Even so, we expect they face higher risk than “base-load” accommodation providers, and thus require a higher rate of return, thus pushing the prices they must charge to achieve cost recovery even higher.

Similar comments apply to the “transportation” sector, in which airlines and taxis also lie at one extreme of a wide spectrum of arrangements, covering that part of the demand which customers can not reasonably foresee, or arrange for themselves, and hence can not make long term arrangements for, by buying a car, for instance. In these cases, what we should expect to see, and in fact do see, is a whole spectrum of arrangements being offered; ranging from arrangements in which the customer takes full responsibility for the fixed costs, e.g by outright purchase of a house or car, and then obtains per unit “service” at SRMC; through to arrangements in which the customer takes no responsibility for the fixed costs, and can only obtain “service” at prices that recover LRMC, with a suitable risk-adjusted rate of return. In fact, any one customer, at different times and for different reasons, is likely to access “accommodation”, or “transport” via a mix of any or all of these arrangements. The less flexible those terms are, the more firm the contract, and the more nearly the contract price approaches (the fixed cost portion of) a low-risk LRMC, and the per unit consumption price approaches SRMC.

Similarly, too for the ideal electricity market. The theory lying behind an energy-only electricity market like the NZEM is that loads should be sufficiently motivated to contract forward to ensure that a reasonable balance is struck, with the majority of load covered by contracts, and thus hedged against spot market risk, but with suppliers also free to extract a reasonable risk-adjusted rate of return from that part of the load that opts not to contract forward, thus forcing suppliers to take all the risk of providing for a load which may not even eventuate.

This is the way effective markets generally work, and customers in most markets know and understand that, if they leave their bookings to the last minute, they might get a bargain, but they may equally be left out, or end up paying a premium price for the last bed in town. This point may not be well understood by consumers in the electricity sector, though. Understandably they compare contract prices, retrospectively, with the spot prices that actually eventuated. Much of the time, it turns out that spot prices were low, and they may feel that they paid "too much" for the contract. But this retrospective assessment ignores two important effects:

- First, a CfD on electricity prices, particularly in a hydro-dominated system, includes a significant component of "insurance" against the possibility of very high prices. And the very nature of insurance contracts is to provide a negative return, when assessed retrospectively, in most periods.

- Second, the proper comparison is not against the prices that actually did occur, but against those that would have occurred, had the contract not been in place. Collectively, consumers should recognise that the less they are prepared to contract forward, the higher the risks faced by generators, and the higher spot prices will have to be to provide an adequate rate of return. For most individual consumers, the effect of their contracting will be insignificant, but some major electricity users will be large enough to have a noticeable impact in a small market like New Zealand, and particularly in transmission constrained regional sub-markets.

How do contracts change behaviour?

There is another factor coming into play here, though, because contracting materially affects the incentives larger participants in the electricity market have to influence prices away from SRMC.

Using conventional CfD contract forms, hydro generators will have to find a compromise between being under contracted in wet years, and over-contacted in dry years. Thermal generators will have to make the opposite compromise.[54] Both will then find themselves incentivised to maximise output to minimise the price and cost of power bought in when they are over-contracted, and to reduce output so as to increase the price of extra power sold, when under-contracted. Both actions will move prices away from SRMC, and both may be interpreted as "exercise of market power" in the spot market. Both are also ways to smooth revenue streams, and achieve acceptable cost recovery, with acceptable volatility, over the hydrological cycle.

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[54] In theory, thermal generators can largely avoid being under- or over-contracted by selling "call options", with a strike price set at their own SRMC. The value of such a contract should be OV, as discussed above, and that can be matched to FC, as discussed. Scott and Read [1996] (T.J. Scott & E.G. Read: "Modelling Hydro Reservoir Operation in a Deregulated Electricity Sector", *International Transactions in Operations Research*, vol.3, no.3-4, 1996, p. 209 221) showed how such contracts can be assigned in a way that produces perfectly competitive industry outcomes, even when participants have Cournot incentives. In theory, such contracts should be attractive to loads looking for peak power, and to hydro producers looking for dry-year backup power. In reality, the market for such contracts may be thin, and generator output may need to be sold in some bundled form more suited to consumer requirements, and backed by a portfolio of plant and/or contracts. If so, potential thermal entrants may find it difficult to compete with vertically or horizontally integrated incumbents, and this may create barriers to entry. But that does not alter the principles discussed here.

In part, competing pressures will move MCP in opposite directions. In wet years, over-contracted thermal may seek to keep prices down, while under-contracted hydro seeks to keep them up, and vice versa in dry years. Typically, though, the whole industry will be under-contracted, in aggregate, relative to what could be produced in a wet year, especially when wind speeds are high and loads are low. The aggregate pressure will thus be towards keeping spot prices up and cost recovery up, rather than dumping the entire potential surplus on a demand side which will not be prepared to pay much for it, because it will not be geared up to find short term uses of any great value for such intermittent supply.

The aggregate pressure may be in the opposite direction in very dry years, though, when the supply side may seek to damp down the prices that it needs to pay to (implicitly) "buy back" contracted output from those consumers who can respond to price signals, so as to meet obligations contracted for delivery to less flexible consumers.

What balance should be struck?

Finally, returning to the original question, we re-iterate our view that the natural structure of SRMC prices in a hydro dominated market will not support anything like an optimal plant mix, without significant modification to create much less volatile payment streams for all parties. In particular, most generators will somehow need to receive revenues above SRMC prices in order to cover their costs, during periods of relative surplus.

To a large extent, participants may achieve the required stabilisation by contracting. It seems impossible, though, that generators would be able to sell their entire potential generation capacity in such a way as to end up with contract positions exactly matching perfectly competitive outcomes, in real time. In a world of imperfect contracting, though, generators may not be financially viable unless spot prices also exceed SRMC during extended periods of relative surplus. So, they can be expected to "exercise market power", so as to influence prices in that direction during periods when they are under-contracted.

Against that, though, we also expect them to "exercise market power" so as to restrain price rises during periods when they are over-contracted. In any case, we expect that the sector understands that it simply could not recover costs by charging very high prices for sustained periods in very occasional super-dry years. And the calculations in the next section suggest that the inability to do so implies a quite substantial expected shortfall, probably exceeding 25%. So, we suspect that an energy-only market of the NZEM type can only work if prices are allowed to settle significantly above SRMC on average, in wetter hydrology years.

Relying on ill-defined mark-ups and mark-downs like this may be considered a less than perfect way to run a market, but this is, in fact, the normal way in which most other markets operate, with considerable success. If that is not deemed to be acceptable, Read [2010] canvasses a number of other options that could be considered, but concludes that no option is perfect, or clearly better than the status quo.

The current design gives participants more freedom than in some markets, particularly those with a pre-market heritage of close regulatory supervision, but it is by no means clear that the cost of closer supervision would be justified, in terms of better outcomes, overall. As it stands, this market has been designed to operate just like the vast majority of successful markets operating outside the electricity sector, and with similar cost structures, where pricing above SRMC has always been considered absolutely normal.

Given the current market design, then, the more participants can rely on contracting the less they must rely on marking up offers above SRMC, and the less incentive they have to do so. But determining the optimal balance between these two mechanisms goes well beyond our current scope, a does estimating the extent to which each may be relied upon in the current market. Thus, we are not in a position to say that the market has "got the balance right". But we certainly could not say that the market has "got the balance wrong", either.

Indeed, we are not sure how that question could definitively be addressed. A first step, though, might be to ask whether the rates of return being sought by potential investors in various technologies are sustaining a plant mix approximating what we might expect from a centralised optimisation, with an acceptable shortage risk. Thus, an initial analysis along those lines is presented in the next section.

4.4 NZEM Evidence[55]

The discussion above suggests that the broad health of the market, in terms of supply/demand balance and price/ entry equilibrium can actually be assessed very easily, without recourse to detailed simulations or complex gaming models. Or, At least, such high-level analyses can be used to put the results of such detailed modelling into a proper perspective.

If the high-level analysis suggests that the market is not performing well, then more detailed studies can help to identify more exactly what is going wrong, and perhaps how to fix it. But if the high-level analysis suggests that the market is performing well, then negative results from more detailed studies need to be understood and interpreted in that light. If the outcomes seem good, even though detailed modelling indicates that "something is going wrong", we may need to ask whether the detailed problems identified are actually as real or material as they may seem.

Market outcomes

Some very useful analysis has already been performed, and summarised by Figure 4.1, which reproduces Figure 14 from the EPR report. This actually suggests that the market is performing very well, in terms of aligning average spot prices with LRMC, but it

[55] All data discussed in this section supplied by S. Batstone

compares base load contract prices with base load LRMC estimates. Although other analyses in that paper highlight how the costs of meeting different load profiles differ, it does not directly address the key issue of incentives for investment in peak/support plant. Accordingly, we have undertaken a very preliminary indicative analysis of that issue in Appendix C, the results of which are summarised here.

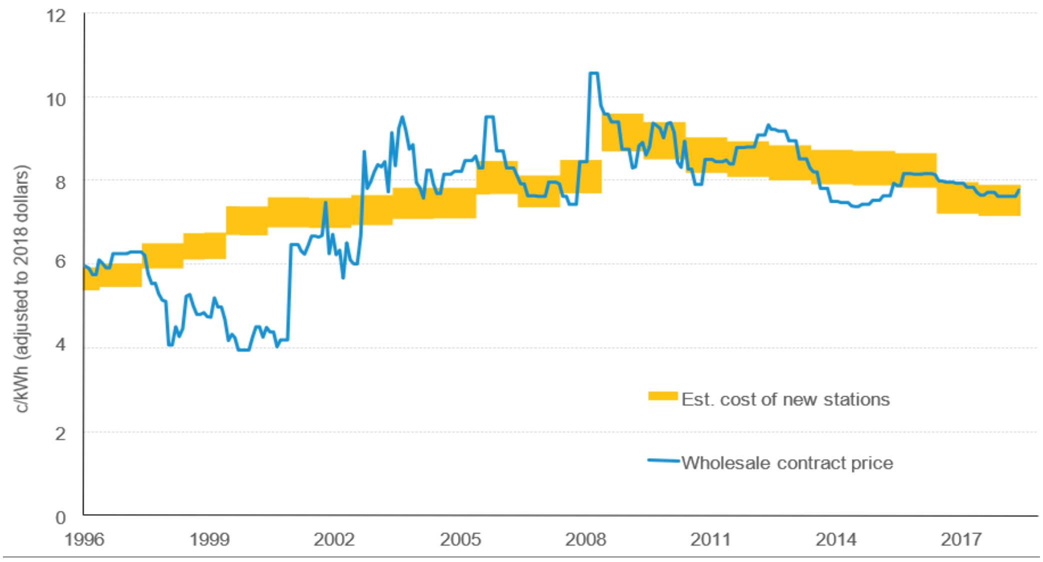

Figure 4.1 Wholesale contract prices versus cost of building new power stations

First, the theory developed in Section 2.4 suggests that we should check the alignment between the market PDC and entry costs, right across the spectrum of entry options. In order to do that, we need entry cost data, and the following table has been supplied by the participants in this study.[56]

PLANT TYPES	Shortage	Diesel OCGT	Gas OCGT	CCGT	Geothermal
Fixed ($/MWy)	$ -	$ 128,500	$ 138,500	$ 184,000	$ 556,000
Variable ($/MWH)	$ 1,648.00	$ 308.00	$ 67.00	$ 53.00	$ 7.00
Reliability (%)	100.00%	95.00%	95.00%	94.00%	95.00%

Table 4.1: Entry Cost Data

[56] The shortage cost has been set to a rather low value for technical reasons, but that can be ignored for the illustrative purposes of the present discussion. The effect of the reliability estimate is just to scale the effective fixed cost component up. In this simplistic analysis, the "geothermal" entry represents base-load renewable capacity whose output is not correlated with the LDC, and hence can expect to receive a "base-load" price. Geothermal has been used in this illustrative analysis, because it is the simplest example to analyse.

Then, Figure 4.2 shows the number of hours for which the spot price exceeded the assumed SRMC of several plant types, over the months of 2010 to 2016.[57] Figure 4.3 then sums these values and compares them with the standing costs for the respective technologies, as discussed in the previous section.

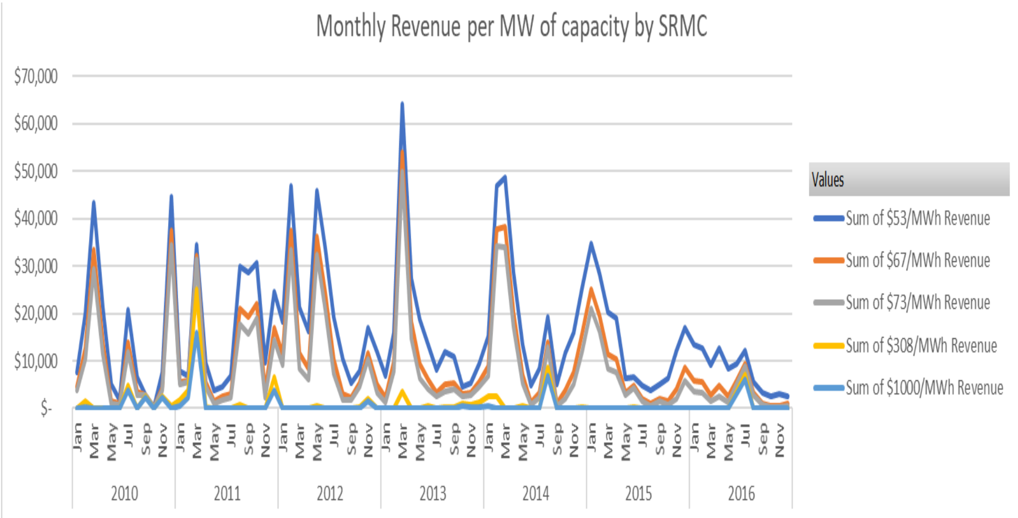

Figure 4.2: Spot price contours

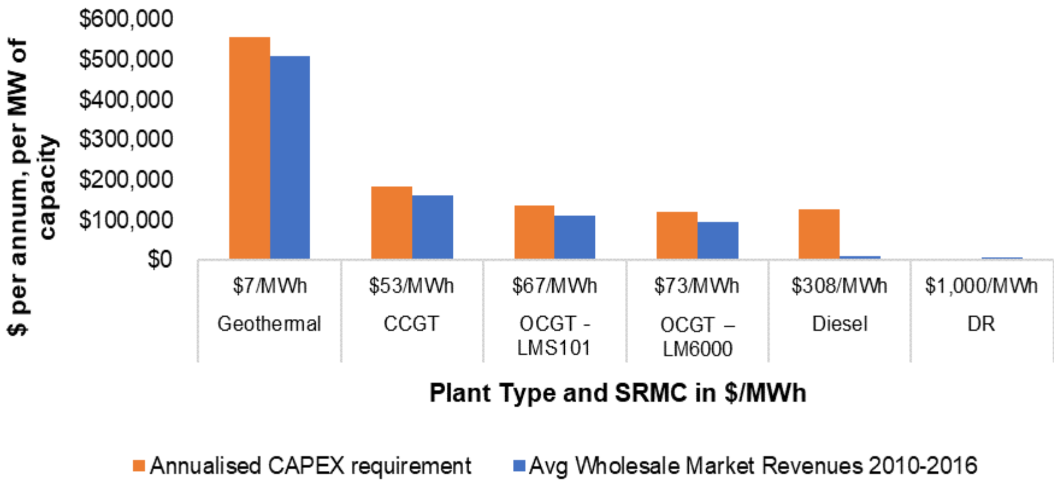

Figure 4.3: CAPEX vs Operating Profit

Basically, this analysis expands on that in the EPR report, to paint a picture of an electricity market exhibiting perhaps surprisingly good alignment with the theory outlined in Section 2.4. No thermal plant type seems to be quite recovering its costs, but that is not surprising, in a market where LRMC is declining, and only limited entry occurring. Most plant types seem to be very nearly recovering costs, though. That could be taken to indicate that the threat of competitive CCGT/OCGT entry was still disciplining the PDC effectively in this 2010-16 period, or that other competitive

[57] This is an upper bound because operators may not always be able to predict price spikes and dispatch their plant to exactly capture them.

pressures (e. g from coal) applied. At least, even if generators are pushing prices up, there is certainly no evidence of overcharging, here, relative to an LRMC standard.

Nor do we see evidence of anything likely to be characterised as "overcharging", in any other sector. It may be that thermal plant, in particular, are pricing their offers up in ways designed to recover as much of their LRMC cost as they can. And it would surely be astonishing if any other business, in any other sector, did not take some advantage of such opportunities as they arise.

Some years ago, the Electricity Technical Advisory Group (ETAG) wrote that "*Using the LRMC benchmark, there is no clear evidence of the sustained or long-term exercise of market power* [in the NZEM]".[58] We might phrase that slightly differently, because we expect that under-contracted generator participants must often have both incentives and opportunity to make offers above SRMC. We also expect that, when supply is tight, over-contracted generator participants will have both incentives and opportunity to offer below SRMC. And both practices may be characterised as exercise of market power, in the spot market.

We find it hard to see how that unilateral exercise of market power could be characterised as abuse though. As discussed elsewhere we would have thought that it was normal business practice, and also probably necessary to make the current market design work with a socially acceptable degree of price volatility, and at commercial rates of return that deliver acceptable costs to consumers on average, over the long term. The relative merits of some alternative market designs are discussed in Appendix A, but the evidence considered here seems entirely consistent with the ETAG conclusion, if we interpret it as applying to the exercise of market power in the market for generator entry and/or long-term contracts. Thus, we see no evidence, emerging from this LRMC driven analysis, of the sustained or long-term exercise of market power in that entry market.

Nor do we see evidence of market power being abused in the spot market to produce price spikes that are higher or longer than they need to be, if the criterion is a requirement to sustain an optimal plant mix with an acceptably low probability of shortage. The evidence we would cite is the situation faced by the diesel fired OCGT at Whirinaki, which seldom runs and would seem to be recovering very little of the entry cost for that technology. This is broadly consistent with the analysis discussed below, which suggests that, so long as spot gas is freely available at a modest price in dry years, this kind of liquid fuelled development would not form part of the optimal plant mix. So perhaps it is not surprising that this station was not constructed in response to market signals. The degree of under-recovery here is much greater than even that analysis would suggest, though.

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58 *Improving Electricity Market Performance Volume One: Discussion paper* 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 (p40)

Based on this evidence, market prices would have to spike to much higher levels and/or for much longer, in order to support such entry. So, taken at face value, this evidence tends to reinforce the concerns we have expressed elsewhere, that the potential for over-charging during times when prices spike above the SRMC of liquid-fuelled OCGT capacity is really not the biggest potential problem with the New Zealand market. If anything, the evidence suggests the reverse, that more extreme spot market price patterns would be needed to support the backup capacity required by a market increasingly dependent on renewables. Or, that other market mechanisms may be needed if that kind of pricing pattern proves to be socially and/or politically.

This observation does needs to be interpreted with considerable care, though. It could be that the market environment is restraining participants from making aggressive offers when the supply/demand balance is tight, and that action may therefore be required to refine the market design in order to provide the backup likely to be required in future. But other factors may have been at work during this period, too:

- Perhaps other features of the market arrangements, including the impact of any potential dry year compensation in a vertically integrated industry means that a station of this type can deliver value to participants by means other than spot market sales.
- Perhaps, despite the concerns of some critics, capacity really was in excess supply over this period. That would not be surprising, given the lack of load growth, and would be expected to correct itself as new capacity is required to meeting increasing demands, e.g from electrification of transport.
- Or perhaps we have yet to see the "super-dry" conditions under which this capacity will eventually pay for itself, both physically and commercially.

Peaker Support Recovery Requirements

Table 4.2 below calculates the levels to which prices would have to spike in order to justify the capital cost of the last MW of OCGT peaker capacity required to limit the number of hours of shortage to the values shown.[59] The first row corresponds roughly to the standard applied in setting price caps for the Australian market. If we imagine market prices spiking to these levels for 4 hours every year, then the last peaker MW would just cover its annual fixed cost of around $130,000/MW over those 4 hours, and require no further revenue for the rest of the year.[60]

But all other MW available during those 4 hours would receive the same revenue, and that revenue would be required to cover a significant proportion of their fixed costs for

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[59] This table has been prepared using the Diesel OCGT data, but the gas OCGT gives very similar values <u>for the last MW</u> of capacity which, in both cases, is only utilised for the number of hours shown, making the fuel cost almost irrelevant.

[60] Note that this is for the last MW. The station may well run at less than full capacity during other hours of the year. But, in a strict SRMC market, it will not make any profit from doing so, because the MCP would be set to its own SRMC during those hours. The only hours that contribute any profit are the 4 hours for which the full capacity is utilised.

the year, in a strict SRMC market. Thus, the CCGT, for example, would also receive around $130,000/MW over those 4 hours, making a slightly greater profit than the OCGT because its SRMC is lower, and then need to make up the remaining $56,000 or so, over the rest of the year.

annual hours	percent of time	VoLL ($/MWh)	hours every 20 years
4	0.046%	**$ 34,124**	80
8	0.091%	**$ 17,216**	160
16	0.183%	**$ 8,762**	320
32	0.365%	**$ 4,535**	640
64	0.730%	**$ 2,421**	1280
87.6	0.999%	**$ 1,852**	1752

Table 4.2 VoLL requirements for peaker cost recovery

If the same shortage probability standard was applied in New Zealand, though, it might (very simplistically) occur as a pattern of 80 hours over a few weeks in the middle of a very dry winter, once every 20 years. In that case, the last MW of peaker capacity should theoretically receive no return at all until those events occurred, then collect around $2.6m in the 20th year. Importantly, all other capacity in the system would have the same experience, with respect to this significant revenue component, in this pure SRMC market.

Reality will obviously be more random than this. Cost recovery would probably be spread over more years and, given the amount of notice that might apply to a developing hydro crisis, New Zealand might well feel that a lower VoLL could be applied. If so, though, it would still need to be spread over enough hours to support the last MW of peaker capacity. So, by construction, the net effect, in terms of industry cost recovery patterns, should be much the same.

Industry Cost Recovery Proportions

As discussed in Section 2.4, the entire optimal PDC can actually be derived from the technology parameters in Table 4.1 alone, irrespective of the LDC. This determines the range of utilisation factors over which each technology would be the least cost way of meeting incremental load. Applying this approach to the thermal data alone produces a simple PDC consisting of one step for each thermal SRMC, and representing the way in which the thermal system would be used to meet the net LDC after accounting for the contributions from renewables with variable output, such as hydro. In this case, those contributions were not optimised, but taken direct from market data, and formed into a monotone "Generation Duration Curve" (GDC).

The utilisation factors defined by the optimal PDC can then be projected onto the residual LDC remaining, after hydro contributions have been accounted for. A tool has been developed to allow various implications of that breakdown to be calculated and displayed graphically. For example, the data above, applied to an LDC and GDC drawn from 2010-2016 data, suggest the LDC being met by the plant mix illustrated in Figure 4.4.[61]

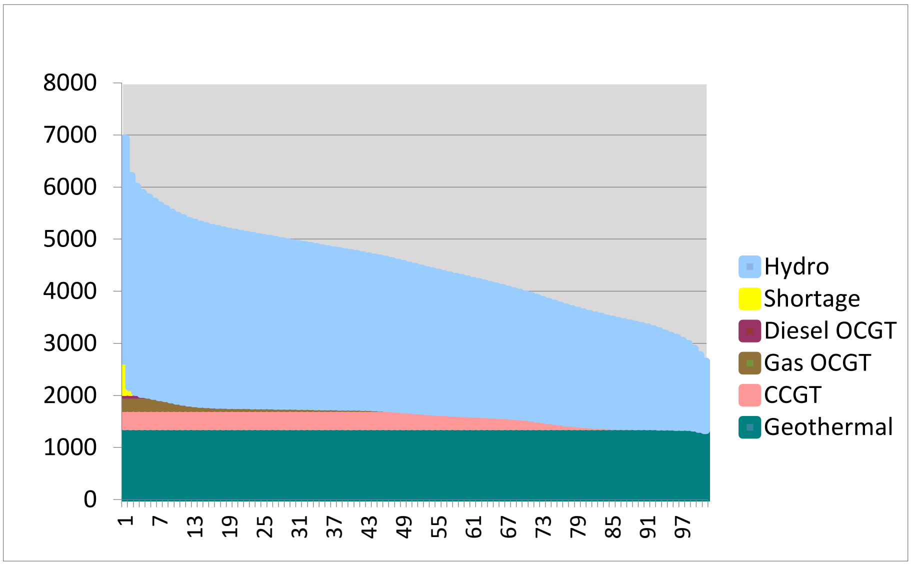

Figure 4.4 Optimal LDC filling Plant Mix

We stress that this analysis is purely illustrative of the kind of analysis we suggest could be performed to provide guidance as to the likely optimal plant mix and PDC against which real market data could be compared. We have not had time to treat the hydro sector properly, and note the market PDC will definitely not be a simple step curve, because some hydro generator will often be on the margin, setting the MCP at a level related to its own Expected MWV. That expected MWV is a weighted average of the true MWV, determined by the SRMC of the technology which a stored unit of water will ultimately displace, in the hydrology scenario that actually occurs. The true MWV can only be known in hindsight, but must correspond to one of the steps in our hypothetical optimal stepped PDC.[62]

Results are also naturally sensitive to assumptions made about both shortage and demand response options that could appear both above and below the SRMC of an OCGT in the merit order, and that can cause some instability, because the prototype

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[61] This LDC has been adjusted by adding a peak oriented component to represent the probability of breakdowns occurring, because those are the situations in which extreme peak capacity would most likely be called upon.

The Hydro contribution is input data representing the observed distribution of output from existing plant.

The "Geothermal" contribution really represents all base-load renewables, including wind.

[62] Section 7.5 discusses a hypothesis about the relationship between the observable PDC, in which the expected MWV of hydro, plays a major role, and this hypothetical stepped PDC, but also expresses some significant caveats.

tool used here can not make fine distinctions within the first 1% of the LDC: That is, in the range covered by the estimates in Table 4.2.

Still, despite all these caveats, it seems worth noting that, over a wide variety of parameter settings, this very preliminary analysis suggests that in a pure SRMC market, the sector as a whole would have to rely on receiving at least 25% of its total cost recovery requirements from periods when prices are spiking above the SRMC of the last MW of peaking capacity in the system. Significantly higher proportions are reported for many parameter settings, particularly if investors in extreme peaking capacity are assumed to be risk averse.

These estimates seem quite consistent with those we have seen previously, all the way back to the original WEMS market design process. In fact, they can be checked directly against the data in Table 4.1. As discussed in Section 7.5 of the Appendix:

- Clearly the extreme peaker itself, whether gas or Diesel fired, must recover 100% of its costs when prices are above its SRMC.
- And, since the peak revenue component is common to all MW capacity available at the time the extreme peaker is running at full capacity, only the residual fixed cost of any other capacity will be recovered over the rest of the year.
- So, the proportion of its fixed cost which technology x recovers during the time the peaker is running at full capacity must be close to FC(peaker)/FC(x).
- Those proportions work out to be 75% for the CCGT and 25% for geothermal, if the extreme peaker is gas-fired, as implied by this data.
- Thus, recovery proportions in excess of 25% seem entirely plausible for the generation sector as a whole.

5 APPENDIX A: NZEM Market Design Choices[63]

5.1 Background

The history of the New Zealand electricity sector prior to establishment of the current market is surveyed by Culy et al [1996], while Read [1997] provides an update, with commentary on initial experience with the current market design. That design evolved in several stages, starting with corporatisation of the Government's electricity sector assets as the Electricity Corporation of New Zealand (ECNZ). The key electricity market design options, including much of the theory discussed in the previous section, were then debated extensively during the late eighties and early nineties, with the current author being heavily involved in those debates. The detail of those debates, or of subsequent history, is not important, but the following summary may be helpful in trying to understand the reasons why the current design was adopted. In particular, it is important to understand that these design choices were made consciously, after careful consideration, and based on a reasonably complete grasp of the theoretical options, and the consequences likely to follow from the design choices available.

From a wholesale electricity market design perspective, the first major step was establishment of a simulated SRMC-based market pricing framework by the Electricity Corporation of New Zealand (ECNZ). That pseudo-market could be described as an exercise in self-regulation by what was then a (near) monopoly. As described by Read and Sell [1987],[64] the development introduced the key elements of the market pricing framework described in previous sections, including half-hourly spot pricing combined with longer term contracts defined as financial "contracts for differences" (CfDs). The key difference was that the half-hourly "spot prices" were not determined by competing market offers, in real time, but by running ECNZ's optimisation models, a week in advance. This was an early attempt to simulate the operation of a perfectly competitive market, with strict SRMC pricing. But the "market" also operated within quite tight limits, because there was a requirement for the distribution companies, who bought ECNZ's output at that time, to be contracted for a very high proportion of their load. Importantly, cost recovery required the addition of an "up-lift" payment, called the Pool Price Margin, which effectively played the role of the "capacity payments" discussed here.

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[63] This appendix is based on Section 3 of Read [2009.

[64] E.G. Read and D.P.M Sell: *A Framework for Electricity Pricing.* Arthur Young report, released by the Electricity Corporation of New Zealand, November 1987.

The current market design was basically established by the Wholesale Electricity Market Study (WEMS) of 1992, in which the current author played a major role.[65] So far as the wholesale market is concerned, it recommended three major changes to the ECNZ pseudo-market. First, the ECNZ assets were to be broken up, and strict model-based SRMC pricing was to be replaced by a more normal market arrangement, in which prices would be determined by competing offers, in an un-capped market. Second, requirements to contract for a high proportion of load, via cfd "energy" contracts were to be relaxed. But, third, a requirement was to be imposed that load serving entities cover a high proportion of their load with "capacity tickets" defined as call options, and providing protection against extreme price spikes. Thus, this would effectively have been a "two part" market.

WEMS was then followed by the Wholesale Electricity Market Development Group, WEMDG [1994][66]. The WEMDG group included extensive representation from the industry, as for WEMS, but also from consumer groups, and it deliberately employed different consultants, so as to benefit from a wider perspective. Still, it basically endorsed the WEMS design, with one key difference. Whereas WEMS had advocated what was basically a two-part energy/capacity market, WEMDG rejected the capacity ticket proposal, thus creating the energy-only NZEM design, which we have described here. That design was then implemented in 1996, following separation of TransPower and partial divestiture of ECNZ generation assets to form Contact Energy, as a competitor to ECNZ.

The WEMDG wholesale market design remained basically unchanged when the remaining ECNZ generation assets were divided between competing SOEs, and full retail competition establishment, with vertical integration, in 1999. Since that date the most significant events have been Government intervention to build dry year backup capacity at Whirinaki, and the establishment of the Electricity Commission. But neither change affected the fundamental structure of the market.

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[65] See, in particular:

J.G. Culy, E.G. Read, and F.T. Baird *A Managed Transition Toward a Facilitated Market: Rationale*, New Zealand Wholesale Electricity Market Study Report, WEMS/4 October 1992

and

Towards a Competitive Wholesale Electricity Market, New Zealand Wholesale Electricity Market Study Report, WEMS/5 October 1992.

[66] WEMDG *New Zealand Wholesale Electricity Market, Wholesale Electricity Market Development Group, Final Report.* 1994

5.2 LRMC-Focussed Design Philosophy

Much of the literature on electricity market behaviour uses SRMC pricing as a reference point. The designers of the NZEM also had a thorough understanding of that SRMC perspective, having previously been involved with, and advocated, a market design based on strict SRMC pricing. Nonetheless, WEMS and WEMDG placed greater emphasis on a long run perspective, to the likely detriment of SRMC pricing, and thus short run efficiency. So, it seems pertinent to ask why.

In part, the decision was motivated by the difficulty of objectively determining what SRMC might actually be, in a hydro dominated system, as discussed in Section 6. In part, it reflected an aversion to intrusive regulatory intervention, as discussed in Section 5.4. But the WEMS/WEMDG/NZEM market design also emphasised an LRMC perspective, primarily because it was believed that what really mattered most in the electricity industry, like any other capital-intensive industry, was to get the long run signals right. And this decision was made despite a realisation that it could imply sometimes significant deviations from SRMC pricing, with consequent economic distortions:

- It was never expected, at least by the designers, that the market would be seen to produce optimal short run operational outcomes, for the capacity mix actually available. If one thinks one has full knowledge of the costs involved, it should always be possible to show that a theoretically superior outcome could have been produced, particularly in hindsight. But the point is that such "knowledge" is essentially an illusion, because the costs are not necessarily even well defined, let alone agreed. The market outcome should therefore never appear optimal, from any one perspective, but should hopefully be more robust, being produced by the interaction between a variety of participants, with different perspectives, each informed by intimate knowledge of their own situations, at least.

- Nor was it expected, at least by the designers, that the market would produce spot prices that were particularly "low", for the capacity actually available. As we have seen spot prices must be high enough, on average, to cover the full fixed and variable costs of whatever investments are actually made. But the point is that competition and innovation in a de-regulated <u>investment</u> market was expected to provide a better national portfolio of investment options, implemented at lower development costs, and this was believed to be the key factor in keeping average price levels, including spot prices, lower than they would otherwise need to be to cover the cost of the required level of capacity investment.[67]

This long-term emphasis seemed particularly important in New Zealand, where costs have traditionally been dominated by the investment costs of transmission, and of renewable generation. Section 6 discusses the difficulty in defining SRMC for such sources, but the point here is that, even when it is defined, that SRMC is not, of itself, a real cost to the economy.

The SRMC assumed in traditional analyses is primarily a "fuel cost", and that is typically assumed to be a real marginal cost to the electricity sector, without much consideration of cost structures in fuel supply sectors. But renewable generation capacity has (virtually) no real SRMC at all. As argued elsewhere, the gas sector fuelling much of New Zealand's thermal generation is in a not very different situation, either, because it is isolated from international markets. In both cases, costs are dominated by large scale exploration, development and construction, with very low variable operating costs.

As discussed in Section 6.3, internal calculations within those sectors can determine an "SRMC-like" opportunity cost which is useful for coordinating operations over time and space. But, looking at the situation from the perspective of the New Zealand Government, the only true short run marginal costs seemed to be:

- On the supply side, the cost of imported fuels, and some aspects of domestic coal production.
- On the demand side, the cost of reducing electricity or gas supply available for other uses, perhaps at other times.

Accordingly, it was thought that the impact of price/dispatch distortions on total supply costs would be proportionately much smaller than in a typical thermal-dominated electricity sector. The SRMC concept still has a significant role within that framework, in terms of coordinating operational decisions within the supply sector, and perhaps between demand and supply sectors. Thus, the main focus of concern with respect to "distortion" of any actual or implicit SRMC was in terms of its impact of short-run economic efficiency.

Conversely, it was thought the bulk of power sales would occur via mid- to long-term contracts, the price of which would and should align with LRMC entry costs, with moderate variation in both directions as the demand/supply balance shifted from year

[67] There was never any reason to expect that prices would be lower than they had been historically, either. As explained by Culy et al, electricity pricing in New Zealand, particularly for domestic consumers, had been historically driven as much by politics as by a requirement to recover costs, and it was not considered desirable that that situation should continue. And of course development costs were expected to rise, because cheap accessible hydro development options had either been exploited or protected from development, while the introduction of the Resource Management Act meant that environmental concerns would have significant cost impacts on new projects, rather than being over-ridden by statutory declarations, as had often happened in the past.

to year. So, it was also well understood that the actual degree of any short run distortion, and also of any short run wealth transfer, would be heavily dependent on the level of contracting. In a perfect world, all loads might be contracted for 100% of their expected requirements, using option contracts which ensured that they were fully hedged for that expected requirement, but also 100% exposed to spot prices for any deviation. Under those conditions it can be shown that the incentives of producers to deviate from SRMC offers is actually minimal, so distortion becomes a non-issue, and risk is also minimised.[68]

On the demand side, it was also believed that, while low demand elasticity may imply significant short run volatility of SRMC prices, and possibly allow significant deviations from SRMC prices, it also suggests that the actual economic impact of such deviations will be small.[69]

In any case, even if spot prices are highly distorted, heavily contracted loads will have minimal real risk exposure. Theoretically, their marginal decisions should still be affected, but this is only true if spot prices are actually passed through to them. In reality, the vast majority of retail customers in New Zealand, accounting for a significant proportion of the load, do not face spot prices in real time. In fact, they may not see any change to price signals at all, even when spot prices are elevated for several months.

This has obvious implications for any consideration of the wealth transfer effects of these prices. But it also has significant implications for market design choices. To the extent that the economic rationale for enforcing SRMC pricing in the spot market rests on the belief that this will enhance allocative efficiency by reducing distortion to consumption patterns, that rationale is undermined by the observation that the prices charged to decision-makers controlling consumption do not reflect the dynamic structure of spot prices anyway. Accordingly, it was considered that the inefficiency due to deviation from SRMC in the spot market, while still significant, would probably be less than that arising from other distortions in the sector.[70]

In summary, then, it was considered that if a compromise had to be achieved between short and long run efficiency, it was better to err on the side of fostering long run efficiency. Thus, the key issue was believed to be reducing barriers to entry, and avoiding intrusive regulation, not just because of the direct expense involved, but also

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[68] See T.J. Scott and E.G. Read: "Modelling Hydro Reservoir Operation in a Deregulated Electricity Sector", *International Transactions in Operations Research*, vol.3, no.3-4, 1996, p. 209-221.

[69] That is, consumers will not curtail their normal activities by much when prices rise, at least in the short term. They may suffer a personal or commercial loss as a result of paying higher power bills, but that is not a welfare loss to the nation, merely a wealth transfer.

[70] Historically, a much greater distortion resulted from the fact that, under central planning, electricity prices were not varied in response to changing hydrological conditions at all. And, in the current context, one would also think that a much greater distortion arises, at least for domestic customers, as a result of limits being placed on fixed charges, thus forcing fixed costs to be recovered by adding substantial mark-ups onto the energy price component, whether or not it reflects SRMC.

because of its likely negative impact on productive efficiency. The implication is that, in this market design, fostering allocative efficiency by aligning prices with SRMC was, at best, to be a secondary consideration. In fact, we have argued that the design actually relies upon prices deviating significantly from SRMC, on a regular basis, to provide a sustainable environment for long run capacity investment.

Our goal here is not to argue for a particular market design, or to explore options for what the NZEM design could, or should be. But the extent to which prices should be allowed, or expected, to deviate from SRMC depends partly on market design choices. Thus, the next few sections briefly consider the rationale behind design choices made in three key areas, and examine the implications of those choices, in terms of their expected impact on behaviour in the market, and performance of the market. Those choices relate to four key questions, namely:

- Why is there no central buyer?
- Why are offers not regulated?
- Why are prices not capped?
- Why is there no capacity component?

5.3 Why is there no central buyer?

For some time, consideration was given to a market design in which a central buyer determined how much capacity was required, and conducted competitive tenders for that capacity. That central buyer might then have entered into long term physical contracts covering the standing costs of the purchased capacity, in return for the right to dispatch that capacity at its assessed SRMC, or to offer it into a market dispatch at that price. Alternatively, the central buyer might have avoided any involvement in dispatch, by entering into long term financial contracts covering the standing costs of the purchased capacity, in return for corresponding call options with strike price set to the assessed SRMC.

Theoretically, this kind of arrangement might seem ideal, in that it is designed to incentivise, or enforce, strict SRMC bidding, and hence achieve "perfect" intra-sector coordination and perfect operational price signalling to consumers, while also guaranteeing recovery of actual investment costs. Indeed, this kind of arrangement may well prove to be the best compromise approach to the purchase of extreme dry year back-up capacity, for example. It should be recognised, though, that this type of "solution" has problems of its own:

- First, it would involve the central buyer in all the problems of determining a "fair" SRMC for each plant type, and adjusting that over time. In reality, the hydro SRMC would vary constantly, so the central buyer would effectively have to buy the right to determine short/mid/long term hydro dispatch, or to optimise the timing of its calls on an equivalently complex and flexible financial contract.[71]

- Second, in a small and locationally diversified sector like New Zealand's it would actually be very hard to determine what the central buyer should be buying. Is it "energy capacity", or "peak capacity" or "storage capacity", or some combination of them all? Is it "anywhere in the South Island", or "anywhere in the North Island", or somewhere locationally more specific? And how to account for seasonality, reliability, variability, and correlation with existing sources?
- Third, given all those possible variations, how much competition would there actually be in each tender, and what rules and exceptions might have to be created to deal with situations where there really only one option met any specific requirement; and/or each option met parts of several requirements? It seemed inevitable that the central buying process would become heavily politicised. Potential entrants would have strong incentives to lobby for purchasing to be biased toward capacity of the type they could offer, and other lobby groups would seek active involvement, too.
- Fourth, the central buyer would obviously have to determine how much capacity of each type it needed to buy, and how much it was prepared to pay; thus implicitly determining an "acceptable" LRMC, and PDC. Many felt that there was little point in developing a market if such fundamental parameters were ultimately set by bureaucratic processes rather than by market interaction.
- Last, but perhaps most importantly, the creation of a central buyer seemed unlikely to solve the central problem that had plagued the New Zealand electricity sector for more than a decade: That the Government itself had become politically invested in perpetuating construction programmes that were adding excessive over-priced capacity, largely to maintain employment, while seeking to sell that over-capacity at a heavy discount to overseas interests. That specific scenario had, by then, been dealt with by creating ECNZ and giving it commercial incentives. But it was thought implausible that future governments could be restrained from responding to any perception of capacity inadequacy by putting pressure on a central buyer (or ECNZ had it continued in that form) to raise capacity targets, and probably to bias electricity sector development in directions designed to serve other interests. That concern remains valid, in our view.

5.4 Why are offers not regulated?

Despite the emphasis on achieving long run efficiency, consideration obviously could, and was, given to mechanisms designed to achieve maximum short run efficiency as well, thus providing the best of both worlds. One obvious option would be to try to force offers to match SRMC. But that option was rejected, for two main reasons.

[71] See: E.G.Read & P.R Jackson "Financial Reservoir Models: Supporting Competition in Integrated Hydro Systems" Presented to ORSNZ conference, Wellington 2014

First, the decision was partly motivated by the difficulty of objectively determining what SRMC might actually be, in a hydro dominated system. Those difficulties, which are elaborated in Section 6, were very much appreciated by the designers of the NZEM, who had extensive experience with the development of computer models to perform such assessments. Thus, it was thought wise to avoid a market design in which alignment with SRMC was a primary goal, implying a requirement to make, justify, and debate such assessments a major focus of activity.

More generally, the idea that intrusive regulatory intervention might lower costs was considered to fly in the face of conventional regulatory wisdom, at least as understood in most sectors other than electricity. Productive efficiency gains seemed most unlikely at the organisational level, where the transaction costs involved in that whole process, including the de-motivating and distracting impact of intrusive investigations and interventions, would most likely outweigh any benefits. Efficiency gains would be conceivable at the sectoral level, though, if it could be shown that the loss in coordination (allocative) efficiency, due to distortions away from SRMC pricing under the status quo, were greater than the increased transaction costs, plus losses in productive efficiency within firms, and dynamic (investment) efficiency, due to regulatory intervention. After much debate, though, the WEMS study concluded that this was not likely, partly because the actual impact of SRMC pricing at the wholesale level would often not be passed through to the retail level (because of contracted prices), as discussed in Section 5.2 above. The overheads of establishing such a function in the small New Zealand market were also considered to be a significant issue.

Second, though, it was considered that forcing offers down to SRMC levels would actually not be desirable, in terms of maintaining a long run equilibrium, with acceptable capacity margins, for the reasons already discussed in Section 2.5. As discussed in Section 4.3, it was believed that the electricity sector should evolve toward a paradigm which has proved successful in other sectors, under which prices might deviate significantly from SRMC. In the absence of a perfect contract market, this was thought necessary in order to support sufficient entry by risk averse investors, and also to provide discipline to that contract market, and encourage consumer contracting, as discussed in Section 4.3.

In most sectors, it is also clearly understood that the market simply will not work if the supplier is restrained from charging premium prices to customers who refuse to book ahead. What incentive would anyone have to book ahead if they knew that a regulator would force suppliers to make seats/rooms available at a near zero SRMC to last minute purchasers?[72] And what incentive would a potential hotelier have to invest, if they suspected that a regulator might intervene in this way? The overall effect would surely be to delay investment until accommodation shortages became common enough that

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72 In reality there would still be some incentive, but only at peak times when customers may fear there will not be enough capacity, in aggregate. But that motivation would also be largely removed if a regulatory authority were to impose “capacity standards” and “supply obligations” on these sectors, as is not uncommon in the electricity sector.

hoteliers could reasonably expect to make an acceptable profit, given the risks, by charging premium prices when all accommodation was fully booked.

Similarly, a requirement to force electricity suppliers to offer SRMC prices in the spot market could reasonably be expected to kill the contract market for electricity, and thus to make entry riskier, and less attractive. The overall effect would again be to delay and distort investment, raise prices, and increase the frequency of shortages, as discussed in Section 2.6. Consumers may find such measures attractive, in the short term, because they depress prices temporarily, and have the appearance of "controlling market power" by banning "capacity withholding". But, while one may be able to force incumbents to make existing capacity available, forcing potential entrants to create new capacity is another matter. Such measures will not really serve consumer interests, in the long run, if their effect is merely to ensure that the capacity needed to meet consumer requirements is "withheld" from the investment market.[73]

Of course, another option would be to regulate contract prices, rather than spot market offers or prices. Simply regulating prices would not suffice, though, unless contracts were actually available. Thus, consideration was given to requiring generators to offer contracts at regulated prices. If the entry market is reasonably competitive, this kind of intervention seems unnecessary, since contract prices should ultimately be disciplined by the contracts offered by competitive entrants. Still, the prospect of driving prices down will always seem attractive in the short run. There would be limited value in pursuing such a policy, though, unless it could be effective in depressing prices over the long run. And we have already argued, in Section 2.6, that forcing prices down below a level capable of supporting risk averse entry will distort investment patterns and imply a greater likelihood of shortage than would be considered optimal under central planning paradigm. In fact, Section 2.6 argues that, without an explicit capacity payment, entry of peaking plant could never be supported at all, if prices could never rise above the SRMC of such plant. [74]

Still, it might be thought that at least such intervention could produce a sustainable long run equilibrium with lower prices, so long as the reduced security standard was considered "adequate" by the regulator and/or entry of sufficient peaking plant could be subsidised. Unfortunately, this is not true, though, unless demand is actually declining faster than the rate at which existing capacity fails. If any new, or replacement, capacity is to be built at all, prices must eventually rise to the level where

[73] Ironically, though, consumers may continue to support such short-sighted policies, even in the long run, because their reference point is the capacity that has actually been built, and the efficient utilisation of that capacity. Unfortunately, they have no way of knowing what investment opportunities have been deterred, and how much this has driven prices up.

[74] Technically, entry might not be deterred if the potential entrant could be assured that the allocation of discounted contracts was a one-off event, never to be repeated. But, once such intervention has occurred, it is hard to see how anyone could be certain it would never happen again. And the prospect of such intervention poses a two-fold threat for an entrant, who must consider the probability of later finding their own position being undercut by new discounted contracts issued by other parties, or being forced to issue discounted contracts of their own.

that capacity becomes economic. Thus, for example, the regulator could insist on contracts being available at expected SRMC prices, and this may depress prices temporarily. But the long run impact must be to delay entry until the capacity situation is tight enough that the SRMC based PDC, including shortage components, is high enough to finance that new plant. In other words, the long run PDC may be distorted, but average price levels must be essentially the same, despite the intervention. In fact, we should expect the PDC to be higher, if regulatory action increases perceived risks for potential investors.[75]

Overall, routine regulation of spot or contract offer prices did not, and does not, seem a particularly attractive option, and was rejected by both WEMS and WEMDG. Given the emphasis, on long run efficiency, it was felt that regulatory attention would be better directed to reducing entry barriers, for example.[76]

75 Although the PDC could be lower, if the intervention was implemented in a way that reduced perceived risk, e.g by guaranteeing contracts for potential entrants.

76 The offering pattern of incumbents is not irrelevant in that context, since it may form part of an entry deterrence strategy. Such gaming strategies relate to market power issues that are not considered here, but the plausibility and likely effectiveness of that type of strategy in the New Zealand context was considered speculative, and pervasive regulation did not seem justified simply as a precautionary measure.

5.5 Why are prices not capped?

Most other electricity markets impose some kind of cap on prices, although that cap may be set at very high levels in other energy-only markets, such as Australia. Obviously, this is an option that could be, and was, considered for implementation in New Zealand, too. In part it was rejected because of a general aversion to regulatory intervention. But it is also not consistent with the general market design paradigm, and theoretical framework described in previous sections.

Market price or offer caps obviously have a direct impact on the PDC, and hence on the economics of entry. Any (actual or prospective) capping of market prices implies a diminution of (actual or prospective) revenue to both incumbents and potential entrants, and thus implies a prima facie risk of deterring entry, leading to under-supply of capacity in the long run.[77] In theory, the optimal plant mix, under perfectly competitive or centrally optimised assumptions, must imply a finite probability that generation capacity will be fully utilised. And that implies a finite probability that prices will have to rise high enough to reduce demand, without any form of physical intervention, in those situations of full capacity utilisation.

Accordingly, if price caps were to be imposed, or if potential entrants think that there is any possibility of such caps being imposed in future, capacity adequacy could only be assured by one of two mechanisms. Either:

- Some means must be found to reward capacity by payments additional to those received from the energy market; or
- Participants must be allowed recover the deficit by pushing prices above their perfectly competitive SRMC levels when capacity is less than fully utilised.[78]

As discussed in Section 5.6, WEMS actually proposed a two-part energy/capacity market in which participants would have received payment for capacity, as well as for energy. But that proposal was not implemented, and the point here is that, if no capacity payment is provided, the value taken out of the market by capping the price must be replaced by some other means, if optimal entry is to be supported. The only way this can occur, in an energy–only market, is by allowing the sub-cap PDC of energy prices to inflate, as discussed in Section 2.5. That is, the lower the price cap, the greater the extent to which prices must be allowed to settle above SRMC at other times. The

[77] Here we interpret “capacity adequacy” in terms of the optimal economic level of capacity, that is the level at which the marginal benefit of extra capacity equals its marginal cost. Of course, this may differ significantly from public/political perceptions of capacity adequacy.

[78] Read [2010] discusses the Australian regime more fully, and suggests that, while the market price cap obviously stops prices rising above a certain level, it arguably also acts as a kind of “target” to tacitly coordinate offers at prices just below the cap. Thus, it is unclear whether it reduces or increases revenue, overall.

alternative, if SRMC pricing is enforced right across the PDC is to accept greater distortion of the long run entry profile.

Thus, no explicit price cap was imposed in the WEMS design. It was widely felt, though, that the industry was subject to an implicit “threat of regulation”, and that this threat would inevitably impose limits on how high prices could rise, and how long high prices could be sustained, during any real crisis. In other words, it was thought likely that if a serious and prolonged crisis occurred, most likely in a dry year, the Government of the day would not sit idly by and let the industry raise prices to their theoretically optimal level: That is to the level at which price alone was sufficient to reduce demand back to a level that could be met by available capacity. Instead measures would most likely be introduced to subsidise entry of alternative supplies, and/or to force prices down, while rationing demand by other means.

An implicit price cap of this nature has much the same impact on the top end of the PDC as an explicit cap, and thus implies a similar requirement to inflate prices above SRMC over the lower part of the PDC. Similarly, retail price caps have obvious political attractions, but even the prospect of such caps would have a chilling effect on investment. Basically, if market participants have any reason believe that there may be limits on their ability to charge what the market will bear during periods of extreme short supply, they must compensate by charging more than SRMC during other times and/or withhold investment.

As it happens, the scenario that unfolded was that, rather than introduce a capacity market, entry of one particular peak-lopping plant (i.e. Whirinaki) was subsidised, without making equivalent capacity payments available to other market participants. That may have seemed like an attractive short-term expedient, but it should be recognised that using a subsidised peak-lopping plant to effectively cap the top end of the PDC creates similar issues to imposing a price cap. The price capping potential of Whirinaki was demonstrated by the Electricity Commission during the winter of 2008 when market prices were affected by the offering of Whirinaki below SRMC, with unrecovered costs in the market being recovered by the EC levy.

Such “subsidised” entry could actually be economically optimal, if timed so that the plant might be expected to operate profitably, at a reasonable commercial discount rate, on the basis of receipts from spot market sales.[79] If so, the resultant PDC could also be optimal, and entry by other plant types would not have been unduly discouraged. But

[79] This does seem possible if entry is otherwise being deterred by factors that made it too risky. For example, it may be that loads are reluctant to contract, perhaps because they believe that they may not secure the benefits of contracted capacity for their own exclusive use, physically or commercially, if a real crisis occurs, and/or prefer to rely on the political process for protection. In that case, the “subsidy” required may be more in the form of guaranteeing expected revenues so as to reduce the risk premium, than increasing expected revenues. Effectively, the regulator would be contracting on behalf of all consumers, collectively, because the transaction costs of doing so are lower than the transaction costs of each individual trying, and probably failing, to negotiate an acceptable contract on their own.

if a genuine subsidy does need to be paid, in expected value terms, it must be that SRMC prices, at the top end of the PDC, are not enough to cover the FC of this entry. In other words. OV is less than FC, for the subsidised plant. But that would also then be true for all other plant.

Conceptually, imposing a cap on the energy market price may be thought of as equivalent to allowing the market price to find its natural level, above that cap, but then automatically issuing every MW of load with a (retrospective) 1 MW call option, the strike price of which is set at the cap. If that cap/strike price were to be set at the SRMC of the most expensive plant in the system, then that plant could never make an operating profit from spot market sales. In order for the plant mix to be optimal, the OV of the equivalent call option (as determined by that part of the PDC where prices exceed this maximum supply-side SRMC) must still equal the FC of that plant. But the market can now only be in long term equilibrium, with sustainable entry of peaking plant, if that plant, at least, receives a capacity payment to cover its FC.[80]

Recall, though, that the OV for any plant is just the value of a call option applying in all periods where the MCP exceeds its SRMC, including those periods when it also exceeds the market price cap. In other words, the optimal (uncapped) OV for plant with lower SRMC equals the optimal uncapped OV for peaking plant, plus the value of a call option based on capped market prices, and applying all the time when MCP exceeds that SRMC. So, a market price cap that reduces the OV of peaking plant will reduce the OV of all capacity by exactly the same amount. Thus, whatever subsidy is required to make investment in peaking plant profitable, the market must also pay the same amount, per MW, to all other capacity, if an optimal plant mix is to be maintained.

In particular, capping prices at the SRMC of peaking plant would reduce its OV to zero, thus requiring a subsidy equal to the full investment cost of peaking plant, FC_{peak}, in order to maintain an optimal investment level for such plant. And the same will be true for all other plant types in the optimal plant mix. In the absence of a capacity market, these cost recovery requirements can only be met by allowing a markup on SRMC

80 This follows because no markup is possible on its SRMC price, which forms the market price cap. More generally, the cap could be set to some higher level, so that some operating profit is made, and only a partial subsidy is required. The same will be true if the market price is only capped by a subsidised entrant, because the market prices can then be expected to rise above the "cap" on some occasions.

prices, set so as to restore the PDC to a level that is just sufficient to support optimal entry for each plant type in the optimal capacity mix.[81]

In other words, capping the PDC carries with it the implication that the remainder of the PDC must somehow be inflated in a similar manner to that discussed in Section 2.6. This is not to suggest that price capping, or subsidised entry, will allow, or facilitate incumbents to raise prices in the short term. If incumbents have insufficient market power they may well have to accept a loss in value in the short to medium term. Thus, consumers may benefit from lower prices over that period, too. But the point is that, in the long term, entry will be deferred until it can be supported by the capped market PDC: That is, until the uncapped portion of the PDC rises high enough above its optimal level to offset the loss in value from capping at the top end.[82]

In summary, market price caps are employed in many markets, for fairly obvious reasons, but they seem problematic, and were not favoured by WEMS or WEMDG. In principle, capping market prices distorts the PDC, and leaves us with the option of subsidising plant to operate during the time when the market price binds, or perhaps accepting a sub-optimal plant mix. Thus, even the Australian market, which sets its market price cap to a very high level, also retains a "reserve trader" concept, under which some plant is contracted to operate only when the price cap binds.

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[81] Specifically, assuming that FC_{peak} is expressed in terms of an annuity, a plant operating for H hours per year, on average, must receive an average price premium of FC_{peak}/H \$/MWh, over and above the SRMC price which might be expected assuming an optimal plant mix, under perfect competition. The logic of Section 2.5 suggests that, in order to sustain entry of plant near the top of the merit order, these mark-ups would have to be concentrated near the peak period, when that plant operates, and this may not be possible if the SRMC of that plant is close to the market price cap. Thus, it may be necessary to set the price cap well above the highest SRMC. Otherwise, a range of high SRMC plant may still need to be partially subsidised, even if they are able to price right up to the market cap, when operating.

[82] It has sometimes been suggested that intervention of this form risks starting the market down a "slippery slope" scenario, under which more and more capacity, of all types, must be subsidised to enter. Provided enough peaking plant continues to be subsidised, though, it should be possible to keep the probability of shortage to an optimal level, or less, and to keep prices below their optimal level, if not down to the SRMC of peaking plant, at the top end of the PDC: That is in those periods when the peaking plant operates. But, even with SRMC pricing, the PDC can still inflate by deferring entry, and shifting investment from more to less capital intensive plant, including the subsidised peaking plant. Indeed it must inflate in this way if long run equilibrium is to be maintained. The result is a sub-optimal plant mix, with higher costs, and of course higher prices are required to cover those costs but, although no formal proof has been attempted, it does seem possible that a sustainable equilibrium could exist. There is still an incompatibility, though, between maintaining SRMC pricing and maintaining an optimal plant investment pattern, in an energy-only market:

5.6 Why is there no capacity component?

Finally, many jurisdictions have adopted some form of market, or centralised contracting, for capacity. One way to do this would be to require loads, or load serving entities, to buy "compulsory insurance", in the form of "capacity tickets", or "cap contracts",[83] as proposed by WEMS. The implication would be to force the price of such contracts up until it is high enough to underpin entry of whatever capacity is needed to meet a security standard considered "acceptable" by the regulator.

This was the original WEMS design and, under that proposal, it was hoped that the price of capacity tickets could eventually be set entirely by market forces, both on the supply and demand side. Thus, it was hoped that, ultimately, the provision of such an instrument would allow trading to reach an economic equilibrium, in which purchasers of capacity tickets were satisfied that they had bought an adequate level of "insurance", at a price which allowed capacity ticket suppliers to recover their costs.

It was expected, though, that the market would have to be "managed", at least initially, by setting a capacity ticket coverage requirement to be met by load serving entities. Thus, the level of security, and corresponding demand for capacity tickets, would be set by some non-market process and could, in principle, be made arbitrarily high. But the market could still reach a sustainable equilibrium to supply that amount of capacity, even if the capacity standard was actually excessive in economic terms.[84]

This kind of market design imposes some overheads, but reduces the risk for potential entrants, and particularly for peaking plant. So, it may be expected to lead to greater competition, lower risk premiums, and lower prices, in the long run. Many North American markets include some form of capacity payment mechanism, and some academics have recently recommended designs very much like the original WEMS design.[85]

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83 In other words, "call options", with a relatively high strike price, effectively creating a market price cap, from a load perspective.

84 Despite the hopes expressed by WEMS in this regard, it was clearly felt that the capacity level which any regulatory authority might set was likely to be higher, even in the long run, than the "economic: capacity level: That is, the capacity level that customers would freely choose, if faced with the true cost of meeting the standard, assuming they had sufficient understanding of the situation, could contract robustly enough to secure the benefits of contracted capacity, and had no incentive to game the political process. If so, that would exacerbate many of the problems discussed here, but does not really change the nature of those problems, or of those conclusions.

85 P Cramton and S Stoft: *The Convergence of Market Designs for Adequate Generating Capacity with Special Attention to the CAISO's Resource Adequacy Problem* A White Paper for the Electricity Oversight Board 25 April 2006

H-P Chao and R Wilson : *Resource Adequacy and Market Power Mitigation via Option Contracts* Electric Power Research Institute 03/18/2004

There is no universal agreement on this issue, though. It would be fair to say that, while WEMS concluded in favour of a two-part energy/capacity market design, opinion within the WEMS study group was actually fairly evenly balanced. After further consideration, the more broadly representative WEMDG group clearly favoured the energy-only design. And it should be said that, when the effect of dry years, ad hoc intervention, and supply side shocks is stripped away, we are not aware of any convincing evidence that this market design actually has produced a capacity shortfall in New Zealand.[86]

It should be recognised, too, that this market design is by no means unique to New Zealand. A number of other markets, including Australia and Singapore, have adopted energy-only designs with apparent success. Most recently, Texas has adopted a design very similar to the New Zealand market, after many years of experience with alternative market paradigms, and extensive observation of alternative market designs operating elsewhere in North America.

Of itself, neither option is really ideal. Theoretically, customers in an energy-only market may expect to face higher prices, greater price volatility, and more frequent outages than might be considered "ideal", and then they would face in a market with capacity payments, or traditional regulation. But society may prefer to opt for this market design if the transaction costs of contracting, or establishing more elaborate and/or intrusive market regulation to avoid this situation, exceed the benefits from doing so. Thus, the energy-only market design may be optimal if the costs imposed by the obvious dis-benefits are less than the transaction costs of adding a capacity component to the market design, and/or imposing more rigorous regulation.

In particular, concern may be expressed that this arrangement gives the body setting capacity requirements considerable power to set requirements in excess of what market participants would willingly pay, if contracting on their own behalf. The resultant distortion to the plant mix could well be greater than that implied by not having a capacity market in the first place, and the cost would ultimately have to be borne by consumers. WEMDG, which included significant consumer representation, obviously found these arguments persuasive and, while alternative proposals have been raised from time to time, consensus in the industry probably still supports that position, on the grounds that:

S Oren "Generation Adequacy via Call Options Obligations: Safe Passage to the Promised Land" *The Electricity Journal* Volume 18, Issue 9, November 2005, Pages 28-42

[86] Appendix C outlines a preliminary study which finds, if anything, evidence of surplus capacity, in the recent past, although it remains to be seen whether prices can rise high enough to support development of the new peaking capacity that may be needed to complement future development of renewables.

- The transaction costs of imposing a contracting regime, or establishing more elaborate and/or intrusive two-part market arrangements, may well be more than the costs of persisting with an energy-only market design; and

- Despite public perceptions many analysts believe that the energy-only market design is actually performing well enough, in terms of providing sufficient capacity, and reasonable prices.

The point here, though, is not to debate whether WEMDG’s judgement was, or is, correct, or to promote any alternative design. The point is merely that the NZEM now operates according to an energy-only design. As such, it relies upon prices deviating significantly from SRMC, on a regular basis, so as to provide a sustainable environment for long run capacity investment.

5.7 Conclusions

It should be clear, from our discussions that we consider the NZEM design to be predicated on the assumption that significant deviation from SMRC pricing is not only acceptable, but necessary, at least in some situations. Without that freedom, we consider it unlikely that participants would be able to obtain sufficiently high spot or contract prices to underpin the economics of sustained new entry, particularly for peaking plant. This is particularly so when one considers the inherent risk involved in investing in such plant. Thus, in opting for an energy-only market design, WEMDG acted consistently by not placing limits on offers or market prices.

If prices or offers were to be limited, the likely intent would be to force prices down and/or capacity provision up, in the short run. In the long run, though, these two goals seem incompatible. If a sustainable equilibrium is to be maintained in the market, intervention must be accompanied by, or expected to induce, a balancing reaction:

- Intervention to force market prices down, on any occasion, must be offset by an expectation that, in the long run, prices will rise on other occasions, either because participants withdraw existing capacity when it becomes uneconomic to maintain that capacity in the spot market, or because potential entrants withhold potential capacity from the investment market, until average prices cover entry costs, with sufficient certainty.

- Intervention to force capacity provision up is really only possible if the regulatory authority itself enters the market as a buyer of capacity, or requires market participants to do so. If that occurs, though, prices must ultimately rise to induce, or at least cover the costs of, extra capacity provision.

In particular, capping prices, or requiring electricity suppliers to offer SRMC prices in the spot market, or the threat that this could happen in future, can be expected to have a negative impact on the contract market for electricity, and to delay competitive entry until the expected PDC, and the risk of shortage, rise higher than is likely to be considered desirable. Selectively subsidising entry may serve to keep the probability of shortage down to an acceptable level, and this has actually occurred in the NZEM. Theoretically, though, it implies the likelihood of distortion to the remainder of the plant mix, and raises issues which, in our opinion, remain unresolved in the NZEM at this time.

One possible market design would force spot prices down to SRMC, while guaranteeing capacity payments in some way. The regulator could run a competitive tender for capacity contracts, or require loads to do so. WEMS proposed the latter, using "capacity ticket" contracts for peaking (or more exactly in the NZEM context, "dry year backup") capacity. This kind of market design might improve both long run and short run efficiency, but it might not perform significantly better than the current design. It does impose overheads, and create problems of its own and thus it was ultimately rejected by the NZEM designers.

As a result, the NZEM became a simple unconstrained energy-only market. Theoretically, if risk were not an issue, and/or contracting perfect, such a market might produce a perfect alignment between both short and long run economics, with spot prices at SRMC and contract prices at LRMC. But risk is an issue, and contracting imperfect, in this market as in any other. Thus, adequate entry is expected to be partially supported by allowing spot prices to exceed SRMC, particularly at peak times, but also in other circumstances. The threat that prices will significantly exceed SRMC is also a fundamental part of the market design, since that threat is supposed to motivate forward contracting by loads, and hence entry by alternative suppliers.

In other words, this market has been designed to operate just like the vast majority of successful markets operating outside the electricity sector, and with similar cost structures, where pricing above SRMC has always been considered absolutely normal.

6 APPENDIX B: SRMC for Hydro and Energy-Limited Thermal[87]

Discussion of economic behaviour in electricity markets often focuses on the extent to which prices are considered to deviate from SRMC. The previous sections have suggested that prices may actually have to deviate from SRMC, perhaps significantly, in order to produce a sustainable equilibrium, particularly in an energy-only market design such as the NZEM. But this section focuses on the other side of that question, namely determining what SRMC might actually be in a system dominated by hydro and energy-limited thermal plant.

It will be seen that this is actually quite a complex question, and that the SRMCs of hydro, gas, and coal plant can be expected to exhibit quite complex patterns, correlations, and connections, over daily, weekly, monthly and annual time scales.[88] We should make it clear, though, that none of the discussion in this section relates to deviations from SRMC pricing, let alone market power. In this section we assume SRMC pricing, and merely:

- Explain the kind of price patterns, correlations and connections that would arise, internally, within any sufficiently detailed centralised optimisation;
- Note that exactly the same patterns, correlations and connections should be expected in a hypothetical perfectly competitive market; and
- Argue that the same general conclusions should (hopefully) apply in real markets, if they are working properly, even though participants may not be able to clearly articulate or analyse how all of these factors interact.

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[87] This appendix is a very lightly edited version of Section 4 of Read [2009]. As such, it reflects the conditions of that time, particularly wrt respect to the role of thermal generators, and their fuel supplies.

[88] Strictly speaking, SRMC is actually difficult to define in thermal systems too, even without consideration of energy limits. This is because unit commitment decisions must be made, perhaps on a daily or weekly basis and, once committed, plant may not wish to shut off even when market prices are below their fuel costs for a few hours. Similarly, once de-committed, plant may not wish to start up, even when market prices are above their fuel costs for a few hours. This implies variation in the effective SRMC over a daily or weekly cycle. This observation applies to some plant in the New Zealand system, too, but it will be ignored here because it is a relatively less important feature, and is also relatively well understood from studies in other markets.

6.1 SRMC for Major Reservoirs

Although our discussion has already referred to conditions in the hydro-dominated NZEM market, most of that discussion is not actually specific to hydro systems. Electricity markets are inherently risky, and all markets face the central problems of coordinating short run supply and demand side activities, while incentivising efficient entry by risk averse investors in the long run. Thus, the basic market design considerations are the same. But some of the problems discussed above are exacerbated in a hydro market setting.

Obviously, hydrological risk is a major factor in such markets. In the absence of any storage capacity, hydro generation could only utilise flows as they arrived, and load would have to be curtailed to match those flows. It may be argued that the SRMC of hydro generation would be zero in such a market, but this would only be true when flows exceeded what was required to meet the load level which might be induced by a zero price. The rest of the time, the effective SRMC of hydro would effectively be infinite, or at least indeterminate, and the "SRMC" market price would actually be set by the marginal cost of curtailing load to the level which could be generated, given the real-time inflows. So, the market could be expected to experience a volatile bi-modal price distribution, alternating between zero, during times of surplus, and shortage cost levels, during times of relative shortage.[89]

This price pattern may be thought of as similar, on average, to that in a variant of the traditional regulated pricing regime that relied entirely on capacity/peak payments, with no "energy" charge at all.[90] All the standard theory still applies, though, and the expected long run average price level should still be that required to induce new entry, given the market risk.

Introducing thermal generation, still with no hydro (or fuel) storage, would reduce price volatility by introducing intermediate price steps, corresponding to the SRMC of each thermal unit, with a significant probability that the price would lie at one of those levels. But this does not fundamentally change the situation and, again, the above theory still holds.

Introducing hydro storage has a more radical impact, though. Clearly, it will mitigate uncertainty by allowing flows to be stored for use in the most needy periods, and this will reduce short run price volatility. But this means that the SRMC of hydro is no longer zero (or infinity), but is given by a "marginal water value" (MWV), which is the "opportunity cost" or "option value" of a marginal unit of water stored for future use. In a pure hydro system, that marginal unit of stored water may ultimately be spilled, in

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[89] The frequency of shortages would probably be quite high, in such a system, although the price implications of modest shortages may also be modest.

[90] And that is exactly the way the "Bulk Supply Tariff" was structured in New Zealand, for many years, while the system was purely hydro.

which case the opportunity cost of using it today will turn out to be zero. Or it may ultimately help to reduce a future shortage, in which case the opportunity cost of using it today will be some kind of load reduction, or shortage cost, and may be very high. But the effective SRMC for hydro generation is given by the expected marginal water value at any time, and this will not normally lie at either extreme, but vary continuously as storage levels, and expectations, change.

The calculation of these expected MWVs lies at the heart of reservoir management optimisation, in a centrally planned system.[91] In New Zealand, the old NZED STAGE model, and the PRISM/SPECTRA models developed by the MoE, both made that calculation explicit, and this is also true of newer models such as SDDP. In other models the MWV calculation is implicit, but mathematically equivalent. Thus the "SRMC" of releasing water from a storage lake is almost always the "expected opportunity cost" of not having that water available for use in some future period.[92]

If there is no thermal generation in the system, that expected opportunity cost will be a weighted average of the spill value (zero) and the shortage cost arising when demand can not be fully met. Thus, it will vary as a function of the calculated probability of spill occurring before the next time the reservoir is empty; or conversely of the reservoir being empty before the next time it is full. And that varies as the state of the reservoirs varies, over time, but will clearly be lower if the reservoirs are relatively full, for the time of the year, thus reducing the probability of future shortage.

The addition of thermal generation to the system does not fundamentally change this, but tends to mitigate the effect. As the proportion of thermal increases, so does the probability that prices will be set directly by the SRMC of some thermal generator, rather than by the expected MWV of some hydro generator. Thus, the weight given to expected spill and shortage events may actually be quite small in determining MWVs, most of the time. Instead, expected MWVs will normally be set by the likelihood that a unit of water saved now will eventually be used to displace generation from some

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[91] Extensive discussion of the theory of MWV calculation for the deterministic case may be found in E.G. Read [1982a]: *Economic Principles of Reservoir Operation I: Perfect Foresight*, International Short Course on Reservoir Scheduling, University of Tennessee, Knoxville, (CBA Working Paper No. 151. E.G. Read [1982b] *Economic Principles of Reservoir Operation II: Uncertain Future*, International Short Course on Reservoir Scheduling, University of Tennessee, Knoxville, (CBA Working Paper No. 152) extends it to the stochastic case.

[92] The only exceptions are when the reservoir is either empty or full, in which case, the "expected opportunity cost" relates to the marginal cost of the thermal generation, or load shortfall, in the current period, because the optimal policy is to release whatever inflows arrive, for a while, and the MWV equals avoided by passing through those inflows. Where water must be released, or spilled, because is not possible to store any more water for the future, this MWV may be zero.

thermal generator at some future date, the value of which will be determined by the SRMC of operating that thermal generator.[93]

6.2 SRMC in River Chains

It should be recognised that the theory discussed above applies to all reservoirs and "head ponds"[94], at all levels in the system, and over all time periods. In all cases, the relevant opportunity cost is calculated over the period until the reservoir storage bounds are next expected to be reached.[95] And in all cases the MWV must change when such a bound is reached. Specifically, Read [1982a] explains why, somewhat counter-intuitively, the MWV must rise whenever an upper storage limit is reached, and must fall whenever a lower storage limit is reached.[96]

If the reservoir is large, then it will typically reach its upper and lower limits, or at least threaten to reach its limits, around the same time each year, thus operating under an annual cycle in which MWV rises at one time of the year (prior to winter for most New Zealand reservoirs) and falls at another (after winter for most New Zealand reservoirs). But a small reservoir will exhibit exactly the same kind of behaviour over a shorter period, often operating on a weekly or daily cycle. So, it may typically reach its upper limit, or at least threaten to reach its upper limit, before the morning peak, then reach its lower limit, or at least threaten to reach its lower limit, after the evening peak. And

[93] Or at least that is the conventional wisdom, derived from markets in which it can be assumed that the SRMC of operating a thermal generation is itself well-defined. As discussed in Section 6.3, though, that is not necessarily the case where thermal plant is "energy limited", as may often be the case in New Zealand.

[94] These are small storages, immediately above a hydro station, often with only a few hours storage capacity.

[95] It is easiest to think about a deterministic problem here, where we know the inflows, and can determine the optimal time at which storage should next reach one or other limit. The stochastic version of this theory, as described by Read [1982b], is quite complex. The principles discussed here carry through to that case, though, except that changes occur more subtly and continuously, as expectations change over time.

[96] This result, and the timing of the change, is clear-cut in a deterministic optimization model. In reality, because of uncertainty, operators try to avoid having reservoirs actually reach their storage bounds, and the MV change occurs a little more gradually, over several periods, as the threat of reaching the bound builds up, and then recedes. But this requirement to try to avoid actually reaching the limits means that the effective bounds on storage range are actually tighter than a deterministic model would imply, and managing storage to those tighter effective limits means that the total MWV change over the periods involved must actually be greater than for a deterministic model. Thus, consideration of a deterministic model still provides a reasonable guide to real-world behaviour.

this means that its MWV must also cycle daily, rising before the morning peak, then falling after the evening peak.[97]

When reservoirs are linked into river chains the situation becomes much more complex. While it is common to talk, for example, about the MWV of “the Waikato river chain”, this is not a well-defined concept. Each reservoir, or head pond, has its own MWV, fluctuating in accordance with its own optimal operating cycle. And, while river chain optimisation seeks to keep all stations operating on synchronised cycles, this is often not possible, due to capacity imbalances and flow delay times. In such a chain, the SRMC of release is not determined by the MWV of the releasing reservoir, at the time of release, either. It is determined by the difference between the MWV of the releasing reservoir, at the time of release, and the MWV of the downstream reservoir, at the time that incremental release is expected to arrive there, which may be several hours later.

Conversely, the MWV of the upstream reservoir must be determined by a trade-off between the opportunity cost of not keeping water in that reservoir, for later release, and the opportunity cost of not having that water arrive at the downstream reservoir, for release there, after some delay. In each case, though, the opportunity cost must be calculated on the basis of the opportunities available before that reservoir next reaches a storage bound. And the periods involved may be very different for the two reservoirs because they may be of very different size, and (given the delays) at very different stages of their daily cycle.[98]

The point of this discussion is not to develop an optimisation algorithm to resolve these issues, but to note their complexity. That complexity becomes much greater once it is realised that one can not resolve the issue by considering just two stations. One would have to iterate both up and down a whole chain of stations, to find a generation dispatch solution, and MWV pattern, that was simultaneously optimal for all stations in the chain. Overlaying uncertainty about both inflows and market prices does not make the

[97] A really small reservoir may have two cycles in each day, one for each peak. In the limit, a station with no storage becomes a so-called “run-of-river” station, for which the MWV for each trading period is effectively determined by the market price in that trading period. (As noted earlier, the SRMC of increasing supply from such a station is not zero, as is sometimes asserted, but indeterminate, because it can not produce any more than the minimum of its capacity or the inflows it receives.)

[98] Suppose, for example, that the delay time is 2 hours, peak load is at 6pm, and both reservoirs actually hit their storage minimum soon after, say at 7pm. Then the MV in both reservoirs will be high until 7pm, but then drop suddenly. But the SRMC of release from the upstream reservoir is not determined by the MWV, but by delayed MWV difference. And that difference will actually rise suddenly at 5pm, because water released after 5pm will arrive too late to also be released to meet the evening peak from the downstream reservoir. After 7pm the SRMC will drop abruptly, though, because water in the upstream reservoir is then too late to be released to meet the evening peak from either reservoir. This example is over-simplified, though. The optimal solution may well avoid having SRMC rise so high at the peak time by having the upper reservoir reach its minimum at 5pm. But that would mean that the daily output cycle of the two reservoirs was offset by the delay time, which means that they can not both be in synch with the load cycle.

situation any less complex, either. Read [1979][99] illustrates the kind of operational patterns that may emerge, using the Waikato river chain as an example. That thesis developed MWV-based methods for optimisation of major long-term storage reservoirs, but found the river chain optimisation problem too complex to tackle in this way. Other attempts in the literature have been similarly abortive, and river chain optimisation packages generally solve a "primal" version of the problem, in which the MWV is only implicit, and generally not reported.

Thus, many hydro system operators may not even be aware of the theory discussed here, or conscious of the MWV patterns implicit in their dispatch solutions. Those MWV patterns are potentially quite complex, though, and the SRMC of generation will generally differ between stations in the chain, and between periods of the day. It is quite possible, for example, that the SRMC of generation from one station in the chain may be zero at exactly the same time as the SRMC of release from another is very high.[100] If generation can be drawn from anywhere in the chain, the SRMC of generation from the chain as a whole will be less volatile, but it will rise as increasing requirements must be met by release schedules of decreasing efficiency, and should be expected to vary over the daily cycle, perhaps significantly.

Despite all this, many discussions assume that we can think of the entire chain as having a single piece-wise linear SRMC "supply curve". Conceptually, and ignoring uncertainty, such an SRMC "curve" could be derived by a technique known as "parametric programming", in which an optimization model representing the river chain, with all of its downstream storage, generation, flow, and delay time restrictions is asked to produce more and more output. Conceptually, we could expect that such an SRMC curve might start out fairly constant, while the output requirements can be met without fully utilizing the chain's capacity in any respect, and then rise in progressively steeper steps as various constraints start to bind. But the situation is actually much more complex than this, because the inter-temporal linkages implied by the storage and delay terms mean that the SRMC curve for any period depends directly on the output requirements in all other periods. Thus, we can not actually derive a piece-wise linear SRMC supply "curve" for any one period. Instead we must determine a multi-dimensional piece-wise linear "surface" for all periods simultaneously. Uncertainty about future demand and supply conditions also means that this surface will evolve continuously, as expectations change over daily, weekly and longer cycles.

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[99] E.G. Read *Optimal Operation of Power Systems*, Phd Thesis, University of Canterbury, 1979.

[100] If there are limits on spill, or on river flows, MWV can actually be negative at some points in the river chain, particularly during flood conditions. And SRMC, which is a difference between successive MWVs can be zero, or even negative, if water must be released to meet minimum flow requirements at some point in the chain.

6.3 SRMC of Energy Limited Thermal

Section 6.1 discusses the conventional wisdom on MWV determination for hydro systems, on the assumption that SRMC of thermal generation is itself well-defined. Unfortunately, in New Zealand, that is not always the case either, because much of the thermal capacity is actually "energy-limited", and not in a very different situation from hydro. Conceptually, gas "reservoirs" actually have similar characteristics to hydro reservoirs, except that they are not replenished, and drawdown occurs monotonically over many years, rather than in daily, weekly, or annual cycles. Thus, the same general theory applies, except that the MWV is replaced by a "Depletion Related Opportunity Cost" (DROC), and (under deterministic assumptions) this rises steadily over the years at the discount rate, until the reservoir is empty. [101]

Of itself, this physical analysis does not imply any significant extra constraints on the power system. Nor does it imply any difficulty in determining SRMC for gas-fired generation, because DROC changes over such a much longer time horizon than MWV, and is not much affected by year to year variations in the demand for gas-fired generation, e.g due to hydro fluctuations. In reality, though, gas producers also have cashflow requirements, and often sell gas via "take-or-pay" contracts that require purchasers to make annual contract payments, and then impose restrictions on the extent to which gas "purchased" in one year can be rolled over for later use, and the extent to which gas to be "purchased" in later years can be used earlier. Maximum and/or minimum restrictions may also be placed on daily, weekly or monthly quantities.

The problem is that when any of these restrictions bind, or threaten to bind, optimal utilisation of this (perhaps artificially) limited resource implies the need to adopt an opportunity costing methodology that is conceptually very similar to that for hydro. And the true opportunity cost-based SRMC of gas-fired generation will then cycle on a daily, weekly, monthly or annual basis, just as for hydro.

To see this, first consider a very simple hypothetical case, in which there is only one gas-fired generator, in a hydro-dominated system, and that generator is supplied under an annual "take-or-pay" contract with no provision at all for roll-over, or purchase of extra gas, and no opportunity to trade. So, this generator's annual gas purchase must be used, or lost, within a year, and the generator faces very much the same situation as a hydro generator with a stock of water than must be used, or lost, within a year. The supply, in this case, is not (normally) at risk, but the demand, being the residual not supplied by hydro, certainly is. And the "per unit cost" is, in principle, irrelevant in determining the SRMC for gas supplied under a contract that effectively involves

[101] DROC can never fall, because the reservoir is never full after the first period, whereas MWV does fall, every time an upper storage limit is approached. Strictly speaking, MWV should rise, like DROC, at the discount rate, over the hours, days or months when storage is not approaching either limit. But this effect is generally ignored on those relatively short time scales.

payment of a lump sum, agreed in advance, for a fixed quantity of gas. Once agreed, this becomes a fixed cost, just like the capital cost of hydro plant.[102]

Such a generator is "energy limited", and must ration its use of its limited gas resource entirely on the basis of opportunity costs, calculated so as to just use up that resource over the annual time horizon. A centralised optimisation model, optimising the dispatch of such a plant in the context of a hydro-dominated system, would ignore the purchase cost of the gas, and endogenously determine an opportunity cost, and hence an SRMC for gas generation, so as to achieve that goal. But that same model would also have to determine opportunity cost based MWVs for each hydro reservoir in the system. Thus, the SRMCs for hydro and gas would be jointly determined, and very closely related, and neither would be determined by the contractual "purchase price" of gas. In a wet year, the opportunity cost SRMC of gas would have to fall low enough to ensure that the annual gas quantity was used, despite the hydro surplus, and the correspondingly low MWV. In a dry year, the opportunity cost SRMC of gas would have to rise high enough to ensure that only the annual gas quantity was used gas was used, despite the hydro shortfall, and the correspondingly high MWV.

In reality, such a system is unlikely to exist, because such inflexible gas-fired generation actually does nothing to complement annual fluctuations in hydro output. If the system were that inflexible, the SRMC of both gas and hydro would probably fall to zero in wet years, leaving water to spill and/or gas unused. And the SRMC of both gas and hydro would have to rise high enough to produce electricity prices high enough to choke off demand in dry years. In reality, gas–fired generation would have to provide greater flexibility than this, in order to play a swing producer role in a hydro-dominated system. This flexibility could be provided by contract provisions to purchase, anticipate, or defer, the supply of incremental gas. Or flexibility could be provided by arrangements to trade gas with other users, as (expectations with respect to) hydro inflows vary, on a short to mid-term basis.

Either way, the per-unit costs relating to such incremental trading, purchase, anticipation or deferral, will become relevant to the opportunity cost calculation. They do not render that calculation irrelevant, though.

First, in the limit, if the gas market is flexible enough, and this generator is physically and commercially unrestricted in trading its gas in that market, the opportunity cost of using gas purchased under its take-or-pay contract for generation will still not depend

[102] There are logical connections, in the longer run, because participants will not enter into contracts to purchase gas that they think is over-priced, on average, relative to the prices they can obtain for gas-fired generation in the electricity market. This impacts on the LRMC of gas-fired generation, but the discussion here relates to determination of SRMC, as hydro output varies, in a time-frame where contract provisions will already have been agreed.

on the price it paid for that gas at all. Instead it will be the market traded price for gas at that time.[103]

Also, in the limit, if variations in electricity generation account for a sufficiently small proportion of the gas market, the market traded price for gas will not fluctuate much as a function of inflow conditions in the hydro sector. This may well be the situation in the US or Europe, say, where there are many alternative uses for gas, and a relatively liquid market will be able to absorb the fluctuations induced by hydrological variations in their, comparatively small, hydro generation systems. And under those circumstances, the daily, weekly, monthly and annual quantity provisions normal in gas contracts may turn out to have very little influence at all on the calculation of gas opportunity costs, and hence SRMC.

We have not investigated current conditions in the New Zealand gas market but, at least historically, the situation in this small isolated market has been rather different from that in the US.[104] Any trading flexibility will serve to mitigate the effects discussed here, but only unlimited trading would eliminate them entirely. And the gas market has not been liquid or flexible enough to allow unrestricted trading within daily, weekly, monthly or annual time frames.[105] Gas-fired generators have faced physical and/or commercial restrictions on their trading; and the range of variation in electricity generation required to fully match fluctuations in hydro generation has been a significant proportion of the total gas market. Unless the daily, weekly, monthly and annual quantity restrictions in gas supply contracts were to become so relaxed that they could be ignored, we consider that the opportunity costing of gas for electricity generation must remain a significant issue.

Those opportunity cost calculations may be relatively more complex than for hydro, because the opportunity cost of using gas now might be determined by the implied need to trade more or less gas on the market, purchase incremental gas from the supplier now or later, bring forward gas usage planned for a future day, week, month or year, or defer gas usage to a future day, week, month or year. Just as for hydro, though, the calculations must be continuously revised, as expectations change with respect to the future requirements for gas-fired generation, due to variations in load, hydro inflows,

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[103] As above, the contract price for gas may align closely, on average over the long run, with traded prices, but that is because the traded price determines the contract price, not vice versa. Thus, one price may be substituted for the other, for the purposes of long-term studies. But it would be a mistake to use (historical) contract prices as a proxy for (forward looking) market prices, when determining the SRMC for gas generation on a time scale of moths or shorter.

[104] Isolation is not complete, because gas can be indirectly exported as methanol, for example, and imports remain a long-term options. But the New Zealand situation is still very different from that in the US, for example.

[105] That is of hourly quantities within a day, daily quantities within a week, weekly quantities within a month, or monthly quantities within a year.

or plant availability. And the calculations should really consider a wide range of possible future scenarios, looking forward.

In fact, the theoretically correct opportunity cost calculation may be so complex that it is not actually performed, explicitly, by the managers of gas-fired generators. But that is not the point. The point is that the implied SRMC of gas-fired generation must actually be changing whenever the manager adjusts output so as to avoid violating any kind of daily, weekly, monthly or annual quantity restriction, irrespective of how that manager may conceptualise, or rationalise, that decision.[106] In particular, if the manager (wrongly) thinks of the per quantity price in the contract as setting "SRMC" then he or she may think that what they are doing is adjusting offers to reflect something other than SRMC. But that is not actually the case. What is really happening is that the effective SRMC itself is varying, in accordance with daily, weekly, monthly and annual cycles. Since those variations are strongly linked with the dynamics of, and fluctuations within, the hydro sector, the SRMC of gas is also strongly linked to the SRMC of hydro, and vice versa, and both vary jointly, but not identically, in all of those time scales.

The above discussion suggests that gas-fired generation is significantly less flexible, and its SRMC correspondingly less obvious, than it is assumed to be in many studies and models of the New Zealand electricity system.[107] This in turn, means that greater flexibility must be found from other sources, and that further complicates the SRMC calculation, unless those sources themselves are fully flexible. Neither geothermal nor wind add any significant controllable flexibility to the system, and their SRMC might best be described, like that of run-of-river hydro, as indeterminate. Perhaps oil-fired generation, which is seldom used, might be considered flexible enough that a well-defined (if considerably uncertain) SRMC can be determined from the world traded price of the relevant grade of oil, adjusted for transport. Shortage costs may also be considered to provide a clear SRMC component, free of any opportunity cost considerations, although the level of that component is a matter of debate.

The situation faced by coal may be a little different from that of gas, though. In this case, there will be a genuine SRMC element in the calculation, if there are options to increase supplies at extra cost, and unrestricted by daily, weekly, monthly or annual limits. There may also be a genuine SRMC element if there are options to trade coal between electricity generation and alternative uses, either in New Zealand or

[106] Hourly restrictions are different, and can be properly accounted for in electricity market offers without any inter-temporal opportunity cost calculations.

[107] Including SPECTRA for example, where these restriction are ignored for algorithmic convenience.

overseas.[108] Historically, though, those options have been limited and, while we have not investigated current market conditions, we suspect that the bulk of the coal supplied to generation plant is still supplied from relatively inflexible sources, on contracts with significant take-or-pay elements. And we suspect that there will not be a sufficiently liquid market for the grade of coal used in electricity generation, or significant alternative users outside the electricity sector, with enough flexibility to absorb the wet/dry year swing. At least, we think it unlikely that the market will be so liquid that generators can assume no limits to their trading. So, a very similar opportunity costing logic applies to coal, too, particularly if there is a coal stockpile involved.

Again, we suspect that the opportunity cost calculations theoretically required here may not be performed, explicitly, by the managers of coal-fired generators. But, again, that is not the point. Conceptually, and analytically, the effective SRMC of coal-fired generation is changing whenever the manager adjusts output so as to avoid violating any kind of daily, weekly, monthly or annual quantity restriction, irrespective of how that manager may conceptualise, or rationalise, that decision. The manager may even think that they are adjusting offers to reflect something other than the "SRMC" implied by the per quantity price in the contract, but that is not actually the case. What is really happening is that the effective SRMC is varying, in accordance with daily, weekly, monthly and annual cycles. Once more those variations are strongly linked with the dynamics of, and fluctuations within, the hydro and gas sectors. So, the SRMC of coal is also strongly linked to the SRMC of hydro and gas, and all probably vary jointly, but not identically, in all of those time scales.

[108] Unlike gas, (as at 2009) nearly half of New Zealand's coal is exported, suggesting that fluctuations in the requirements of coal-fired generators could possibly be accommodated by varying export quantities. This option is only relevant, though, to the extent that coal intended for these two uses is actually substitutable, in the time frame necessary to deal with variations in hydro availability. If coal is being diverted from export, the export coal would have to be an acceptable input, chemically and physically, for generation purposes, and the physical infrastructure would have to be in place to transport it from the export mine to the station. Export contracts would also have to be flexible enough to allow variation in quantity, or substitution of alternative coals, sourced internationally. Similarly, if coal is being diverted to export, it would have to be an acceptable input, chemically and physically, for its intended purpose in the export market, and the physical infrastructure would have to be in place to transport it from the mine supplying the station to the export port. But, while we have not investigated this market, we understand that much of New Zealand's coal exports consist of metallurgical coking coal, from mines in the South Island, whereas coal-fired generation capacity is situated inland, in the North Island. In any case, the opportunity cost of diverting metallurgical coking coal to be burned in power stations is likely to be very different from the SRMC of their normal fuel.

6.4 Locational Issues

While Section 76.2 talks about several generation stations in a river chain, and flow delays between them, it has nothing directly to do with locational issues. In fact, it assumes that generation from all stations in a chain is interchangeable, in the sense that it can be sold at the same price, in each period. Similarly, the discussion of SRMC/price interactions between hydro and gas/coal "reservoirs" implicitly assumes that "the market" exists at a single location, so that a single price applies to all capacity.

This is a reasonable approximation if there are no transmission limits between the locations involved, as will often be the case for stations in a single river chain, for example. But the NZEM is a locational market, and we should consider locational issues, too.

Basically, all of the logic above applies at each location, but the prices, and implied opportunity costs at those locations are not independent. Thus, the state of South Island hydro storage will still affect the assessment of SRMC for North Island hydro, and for North Island coal/gas stations, too. But the effect may be attenuated by marginal losses and/or transmission limits, on intervening lines. In the absence of losses, it can be shown that the MWV in similar reservoirs will often be exactly equal, in equivalent energy terms. But the presence of losses means that equality will only be maintained within an error bound given by +/- the marginal losses. Transmission limits may further limit the system/ market's ability to trade-off storage in one reservoir against that in the other, thus leading to a greater divergence in MWVs.

In a perfectly competitive market, the prices in various regions will be set by the opportunity cost-based SRMC of the generation capacity that can meet incremental loads in that region, in the period concerned. These prices will be equal across the system, +/- marginal losses, if no transmission limits apply, but may diverge more strongly when transmission limits apply. MWVs will also tend to diverge more strongly where transmission limits apply, but this effect will be significantly less extreme, because the MWV of a reservoir reflects the opportunity cost of being able to use water to meet load requirements at any time up until that storage is next expected to reach, or at least threaten, its bounds. Even if transmission is limiting, many of those opportunities may relate to future periods in which free trade will be possible, and that will tend to align MWVs through all earlier periods, back to the present. But, if MWVs are tending to diverge, due to surplus inflow in one region, say, one reservoir will tend to release at its maximum, and the other at its minimum, during periods when inter-regional trading is possible. In that case, the SRMC of hydro generation is no longer set by the MWV, and will be indeterminate.[109] The implication is that local prices are

[109] Theoretically, it will be +/-infinity, depending on the release bound involved.

not set by this hydro station, and may be much higher (if release is at its maximum), or much lower (if release is at its minimum).[110]

None of this really changes the conclusions reached above, though. While the transmission system may limit the strength of some interactions and linkages, in absolute terms, the complexity of those linkages, and the corresponding SRMC patterns, is increased. In the limit, MWVs may diverge significantly, as one region becomes increasingly isolated from the other, in terms of electricity market trading, on the margin. At other times, though they will be closely linked, as above. As noted earlier, then, opportunity costing means that each participant's SRMC, in any period, may change as a result of changes in variety of factors other than that participant's own supply position, in that period. But now the factors which might affect SRMC estimates in this way include (expected) changes in the status of transmission constraints. And, so long as a generation station is not marginal, its marginal production cost may consistently be above or below the nodal MCP there.

6.5 Risk Aversion

Finally, while the theory discussed in previous sections relates to uncertainty, and hence may be thought to imply some consideration of "risk", we have not actually considered "risk aversion" at all. It should be recognised that risk is a rather more significant issue in hydro dominated markets, than it is for typical electricity markets. We have noted that it may not be easy to provide risk averse investors with sufficient assurance that they will be able to obtain an adequate return for the risk involved, but risk aversion also plays a major role at the operational level. The impact of risk aversion on the management of energy-limited generation seems to have been almost entirely ignored in the international literature, but bears further examination.[111] It should be obvious that a contracted hydro generator can be expected to err on the side of caution, by setting water aside so as to be available to meet future contractual and/or retail commitments under a wide range of possible hydrological and/or market outcomes. Similarly, for an energy-limited coal or gas generator.

This is not wrong, and it is not new. Indeed, while public sector reservoir management was always based on a balanced sample of historical hydrological years, it was also biased in the direction of caution by adding "buffer zones", "safety factors" etc. Realistically, the general public expects a high degree of reliability in its electricity supply, which means that it will almost always be found, in retrospect, that "too much" water was retained early in the season, only to be released later when, on average, the

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[110] Actually, the same will often be true for reservoirs with differing storage/inflow/release characteristics, even without transmission limits. So long as a generation station is not marginal, its marginal production cost may consistently be above or below the nodal MCP there. As discussed earlier, this will often be the case for stations in a river chain, even when no transmission limits apply.

[111] One exception is: A L Kerr, E.G. Read and R.J. Kaye "Reservoir Management with Risk Aversion", *ORSNZ Proceedings* 1998, p167-176.

market supply situation will actually be less tight. This is optimal, and it occurs because there is considerable asymmetry between the costs and risks involved in under-supply, and those involved in over-supply.

The key point here is to note that this pattern of behaviour will involve setting a price on hydro (or coal/gas) generation that differs significantly from the SRMC that would be calculated by a centralised optimisation model that assumes risk neutrality.[112] Specifically, generators will typically be retaining supplies (with upward price pressure), prior to the winter season, only to release more later, when, on average, market prices may actually be lower. This may seem irrational, or perhaps manipulative, from a risk neutral perspective.[113] But the need to behave in this way is dictated by the desire, indeed the effective requirement, to operate cautiously. Risk aversion may also be expected to amplify the response to events that, in themselves, may not seem major, but that might be considered as indicators of an increased likelihood that more severe problems will arise in future periods.

6.6 Conclusions

The above discussion provides a reasonably comprehensive guide to the difficulties of determining SRMC in a hydro dominated market environment, with energy-limited thermal plant. In practice there are a great many "reservoirs" involved, operating over a wide variety of time scales. Effectively, coal and gas stocks form extra "reservoirs", and this further complicates the assessment of opportunity costs, and hence of "SRMC".

In principle, and to a large extent in practice, the SRMC of production from any one of these sources can not be determined independently from that of any other. But the theoretical linkages described above are not created by the market, and have nothing to do with "market power". A sufficiently detailed centralised optimisation model would account for them all endogenously, and internally compute SRMC "shadow prices" for all of these resources, jointly, in the course of determining its optimal dispatch solution. Those shadow prices may not be reported but, if examined, they are likely to exhibit quite complex patterns of variation, and connection, on daily, weekly, monthly and annual time scales. Most importantly, whether reported or not, these internally

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[112] That is for virtually all centralized optimization models of which we are aware.

[113] Consideration may usefully be given to whether profits could actually be increased, on average, by such a practice, but that is not our concern here. As noted above, participants withholding water early in the season may actually be forgoing a profit on the marginal unit withheld, when assessed at market prices. But this does not actually tell us whether such withholding increases or decreases overall profits, once price impacts are accounted for. In fact, profit maximising oligopolists generally appear to be forgoing profitable sales on marginal units, in order to push up the price received for the units actually sold.

calculated SRMC prices would determine and explain the dispatch solution produced by the centralised optimisation model.[114]

Theoretically, a perfectly competitive market should be able to perfectly account for all of these linkages, and reproduce all of these subtle SRMC interactions. In reality markets are not that perfect, and nor are the information sets or models available to market participants. So, they must account for many of these effects subjectively, using their best judgement, rather than through formal analysis. This makes it rather hard to say, objectively, what SRMC actually is, for any participant, in this kind of market situation. One would expect individual judgements to differ, for a great variety of reasons.

Broadly, though, opportunity costs will depend on future market prices, which depend on the offers expected to be made by other participants, which depend on the SRMCs assessed by those other participants which, in the case of hydro or energy-limited thermal, are also opportunity costs. Of course, these opportunity costs will be assessed, internally and privately, by competing generators. Thus, each participant must determine the MWV in their own reservoir(s)/stockpile(s), taking account not only of the probability distribution of their own inflows, or supply contract provisions, but also the assessments which they expect each of their competitors to make with respect to the opportunity costs of operating their own hydro/coal/gas resources, given their own private data and probability assessments. And each of those assessments is, itself, equally complex, and also dependent on each of those other parties' assessments of one's own situation.

The general effect is that changes in (perceptions about) the likely supply situation of any plant, whether energy-limited or not, must cause all energy-limited participants to re-assess their SRMCs, in ways which tend to reinforce one another. Thus, a developing dry year, or a major plant failure will, and should, immediately cause all hydro/gas/coal participants to raise their SRMC assessments. All of this means that SRMC values for hydro, and for energy-limited fuels, will regularly rise to quite high levels, possibly every autumn, in anticipation of a possible crisis, long before the period in which the crisis is predicted to (potentially) occur, and while storage is still relatively high. And they can be expected to remain at such levels, often for several months. Occasionally they will continue to rise until an actual shortage occurs. But most often they will just fall back to more normal levels because the looming crisis dissipates

[114] Once stochasticity is accounted for, the true complexity actually becomes too great for many optimisation models to handle. For example, although its PRISM predecessor once had a coal stockpiling module, SPECTRA does not model annual energy limits on either gas or coal. So, it can not capture the kinds of interaction described here, and must assume an exogenously determined SRMC for both fuels. This approximation is not correct, but it is required because the optimization methodology employed in that model can not readily be generalized to handle a larger number of "storage reservoirs". If managers employ such limited models, and take them as a guide to "SRMC", they will then need to "adjust" SRMC for opportunity cost effects, outside of the model, and perhaps iteratively adjust model inputs, to achieve an acceptable outcome. But that does not change the fact that it is really the SRMC itself that is changing, as above.

and/or is averted. Thus, in a hydro dominated power system, and particularly one with energy-limited thermal plant, a properly operating market can be expected to exhibit quite significant variations in average price from year to year, depending on hydrological conditions. And prolonged periods of elevated prices can routinely be expected, even in years which, in retrospect, turn out not to have been particularly dry.[115]

Since it is the change in expectations, rather than any change observed in the current period, that is supposed to drive MWV, the impact on behaviour can also be counter-intuitive. It might be thought, for example, that a tightening of the demand/supply balance causing prices to rise in the current period would always induce an increase in output, or at least no decrease. That would be the case for plant that is not energy-limited, and also in cases where a single, short, one-off, event, such as short generator outage or dry period, has no discernible impact on longer term MWVs, and thus on the SRMC supply curve. The situation may be radically different for energy limited plant, though, if such an event creates the expectation of an ongoing trend, or extended situation. As soon as the likelihood of an extended outage or drought becomes apparent, hydro and energy limited gas/coal generators should re-assess their opportunity costs, and raise offer prices, so as to reduce output, and conserve water/fuel to be used in later periods when the or drought may create an even tighter supply/demand balance. That is, their SRMC curves should rise to such an extent that their output actually reduces, even though the demand for output, and the prices obtainable, have increased in the market. This may occur over a period of months, for a prolonged outage or anticipated drought. Or it may occur over a period of hours, for relatively short outages, or load increases, for example. [116]

Finally, it might be thought that all of these correlations and connections between the effective SRMCs of energy-limited plant have something to do with "market power", or even "collusion". But, while, both market power and collusion could certainly arise in such an environment, this discussion of correlations and connections actually has nothing inherently to do with either. Nor is there anything particularly unusual about what is going on here. The revaluation of contracted gas, or stockpiled coal, due to a change in the expected availability or price of hydro power in the local electricity market is no different from the revaluation of those same resources due to a change in the expected availability or price of oil on world markets. And nor does it differ from the routine revaluation of shares, or of hotel rooms or airline seats due to changes in perceptions about likely supply or demand.

In all cases the opportunity cost, and hence the SRMC, do actually change, at least when these concepts are properly defined in economic, rather than accounting terms. And

115 Noting that New Zealand has relatively small reservoirs, which do not allow much storage carryover from year to year.

116 See P Stewart, E.G. Read and R James: "Intertemporal Considerations for Supply Offer Development in Deregulated Electricity Markets" *IAEE Proceedings*, Zurich 2004

that re-assessment may imply an initial reduction in output as part of the optimal response to a developing crisis. This is merely an optimal reaction to changing expectations, such as would occur in a sufficiently sophisticated centralised optimisation, or in a perfectly competitive market. All that is different here is that the interactions are more obvious and more explicit, when considered in the context of a relatively small and inflexible system, and applied to commodities such as water, electricity, gas, and coal, for which liquid international markets may not be readily accessible from New Zealand, in the required time frame. In this context, many feedback loops which might normally be considered "open" in many analyses elsewhere, must be treated as "closed", implying a need for something more like a general equilibrium type analysis to calculate opportunity costs jointly, and simultaneously, rather than applying partial equilibrium analyses sequentially and/or independently.

To repeat, then, we are merely explaining the kind of price patterns, correlations and connections that would arise, internally, within any sufficiently detailed centralised optimisation, and arguing that exactly the same patterns, correlations and connections should be expected in a hypothetical perfectly competitive market. Real markets may not exhibit all of these patterns, correlations and connections quite so explicitly, and participants may not even be able to clearly articulate or analyse how all of these factors interact. But a market in which such patterns, correlations and connections were not evident should be judged to have fallen short of the ideal, perhaps significantly so, and that should be a matter of concern.

Real markets may also provide opportunities for the exercise, and perhaps abuse, of market power, and this may distort pricing patterns away from the perfectly competitive ideal discussed here. That is another matter, and not our concern here. We would say, though, that the complexity of the underlying situation does make it difficult to determine whether, and to what extent, market outcomes might actually have deviated from the perfectly competitive ideal, on average, or in any instance.

7 APPENDIX C: Market Performance and Entry Barriers

(prepared in association with Dr S Batstone)

7.1 Discussion[117]

We have argued that attempting to enforce SRMC pricing would be inappropriate in the NZEM context, and that makes assessment of deviations from SRMC of limited relevance. Instead, we suggest that the emphasis should be on whether the market is fulfilling its intended function which is, primarily, to provide appropriate long run signals, while facilitating short run coordination between alternative suppliers, and between them and consumers. Thus, we should really be asking:

- Does the PDC align with the LRMC of relevant plant?
- Are there any barriers to competitive entry by alternative suppliers which might allow prices to persist above LRMC?
- Are there problems in the contract market, and/or the wholesale/retail "contracting chain" which are leading to sub-optimal results, such as excessive risk for entrants, leading to increased risk of non-supply?

In principle, ignoring the possibility that incumbents may raise barriers to entry, it is actually very easy to determine whether NZEM prices are, or have been, "too high" in recent years:

- If entry has been excessive, and we now have "too much" capacity, then we might conclude that prices (or price expectations), if anything, have been too high over the period when that excessive entry was occurring. And we might expect to see market forces now pushing prices below LRMC level, as a result of excessive entry.
- If entry has been inadequate, and we now have "too little" capacity, then we might conclude that prices (or price expectations), if anything, have been too low over the period when that inadequate entry was occurring. And we might expect market forces perhaps now pushing prices above LRMC level, as a result of inadequate entry.

This simple test indicates the basic direction which investigations of market pricing should be directed, either to discover why prices have been too high, or why they have

[117] This section is basically the Appendix of Read [2009], with minor editing. The next section builds on this by providing some illustrative numerical assessments of capital recovery proportions, based on NZEM price and cost data.

been too low. Thus, it is pertinent to ask where the current NZEM PDC lies with respect to long term entry costs.

Read [2009], from which the above text was drawn, did not attempt any numerical analysis of these issues, a deficiency which will be remedied in the remainder of this appendix. Looking at Figure 7.1 below (Figure 14 of the EPR report) we see that 2009 was actually the peak year, in terms of both market prices and estimated LRMC for new plant. Since then, both have trended down, more or less in synch, over a period where load growth has also fallen drastically.

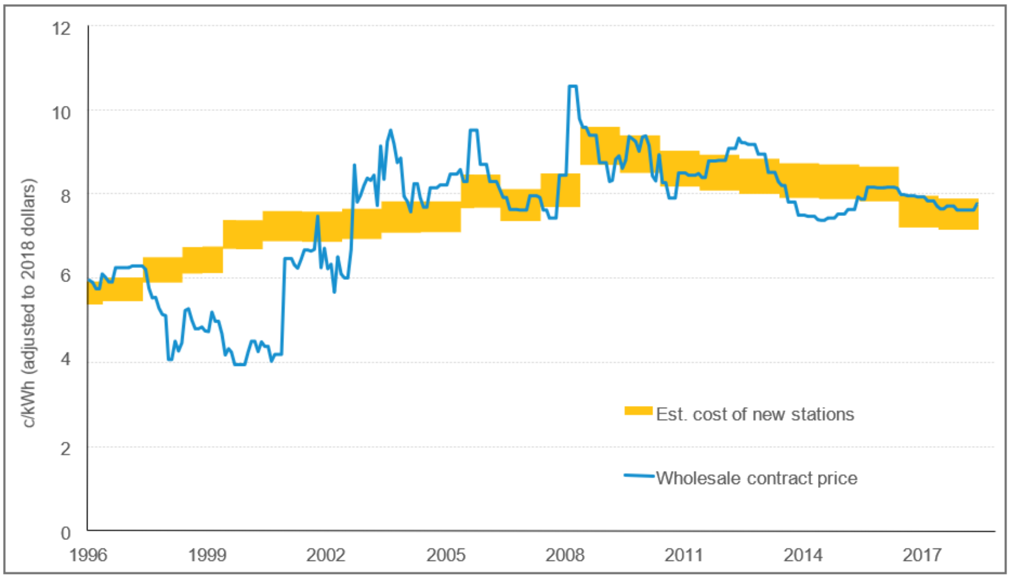

Figure 7.1 Wholesale contract prices versus cost of building new power stations[118]

Arguably, Figure 7.1 suggests that the conditions observed back then, which so alarmed some commentators at the time, really were just a case of "temporary overshoot", of the type discussed in our report at that time. Thus, the historical discussion provides an interesting illustration of the way in which perceptions may change over time, and of the way in which, despite the inevitable "noise" induced by hydrological variations, the market has adapted in a relatively robust and timely fashion to those changing perceptions.

Our 2009 report stated that:

[118] Original *Source: Concept Consulting analysis.*
Prices and costs are adjusted for inflation and expressed in 2018 dollars.

We note that entry has been occurring over recent years, which suggests that the PDC should be matching FC for at least some plant types. There are three complications to consider, though.

- *First, there are other reasons why investment might have been too low, if it has. For example, the new SOEs formed by the breakup of ECNZ, had a limited set of feasible development options and the lead times to develop options have extended significantly. Also, there has been a significant learning curve with respect to technologies like wind generation over that period. So, investment could lag market demand, for those reasons.*

- *Second, a rational investor, or central planner, should be asking what the PDC looks like over the whole range of hydrological conditions, not just what the PDC has looked like over the very small sample of hydrological conditions that actually occurred in the past few years. One does not, or should not, build new capacity in response to high prices driven by dry year conditions, but in response to a shift in the underlying probability distribution from which that price sample was drawn. Thus, it is quite possible to observe (temporary) high prices and (underlying) excess capacity in the same year, in a perfectly competitive or centrally planned system. The study by Tipping et al [2004/2010]* suggests *that the NZEM seemed to have experienced a higher than average number of dry years* (in its early years), *with correspondingly higher prices. This can be expected to have raised public awareness, and concern, to levels which are probably not justified by the underlying supply/demand balance.*

- *Third, it is the expectation of future prices that should drive investment, and that expectation may turn out to be significantly in error, if the market experiences some kind of shock. In this case, the NZEM has recently experienced a series of shocks, all in the same direction. Apart from the ongoing impact of local "environmental" resistance to developments, the system has seen an unexpected reduction in gas availability, rising world fuel prices, the sudden imposition of policy driven restrictions on capacity investment, and possibly inflow reductions due to climate change. These will all have raised expected LRMC levels, and we should expect to see prices rising now, reflecting an upward shift in the (expected) long run equilibrium PDC, with a higher probability of shortfall, to account for these factors.*

  Further, because these changes were not expected, we should expect to see price overshoot, with prices lying above even the new (higher) LRMC levels for a few years while the market adjusts to the new situation. Basically, if the market was (thought to be) in long run equilibrium prior to these effects becoming evident, we should now expect to see the market out of equilibrium, and experiencing

> *relative shortage.*[119] *Conversely, if the market now appears to be in equilibrium, and if the PDC is not now lying above the new LRMC levels, we should really be concerned to explain why there was excess capacity investment, relative to expectations, in prior years."*

Leaving aside the weight of public opinion and political concern, we are not trying to express any opinion here as to whether there actually is "too much", or "too little" capacity in the NZEM, or whether prices have been "too high", or "too low". But, if there is, a regulatory response might be envisaged:

- *In the first case, regulatory intervention may be justified to place downward pressure on prices, perhaps by tightening offer rules if, but probably only if, it can be shown that this is not just a temporary situation resulting from a "shock", but a long-term structural problem, presumably arising out of a lack of competition in the market for entry.*

- *In the second case, regulatory intervention may be justified to place upward pressure on prices, perhaps by adding capacity payments or loosening offer rules if, but probably only if, it can be shown that this is not just a temporary situation resulting from a "shock", but a long-term structural problem, arising perhaps out of fear of a political intervention in response to higher prices.*

These are not the only possible conclusions, though. While this market design perspective does suggest a lesser degree of concern about deviations from SRMC pricing, it does suggest that the market for entry may be a legitimate focus for concern. At the national level, we are concerned, primarily, about whether entry into the generation market is competitive, or whether incumbents might raise barriers to competitive entry:

- *One possible way of deterring entry would be for incumbents to refuse to provide necessary supporting "ancillary services", but the NZEM market design makes this quite difficult.*

- *Another obvious strategy would be for incumbents to block access to desirable development sites, or resources, and this possibility may be worthy of examination in the NZEM context. This would not produce a PDC which was "too high" relative to actual entry costs, but would imply that entry costs, and hence the PDC, were too high.*

- *But there is another, less obvious, way in which incumbents might raise barriers to entry. A central concern in the literature about "entry deterrence" is that incumbents could deter entry by building too much plant, then pricing high, but*

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[119] *The issue here is not whether any of the factors have really changed, but whether market analysts today employ more, or less, optimistic cost/availability assumptions than they did a few years ago, when performing their FC/OV comparisons.*

> *threatening to price low for long enough to drive out any competitor which might be tempted to enter.*

This hypothesis was advanced in an early NZIER study of NZEM design issues,[120] *but its relevance to current conditions is debateable. If the strategy were being played effectively, it seems possible that there could be too much capacity, and prices which are also too high, on a sustained basis. Or, if the strategy failed, and did not actually deter entry, we could see entry followed by a period in which there could be too much capacity, but with prices which are too low to sustain further entry, possibly falling to SRMC levels.*

Again, we come back to the very basic question, though: "Is there too much capacity in the NZEM?" If not, it seems unlikely that this entry deterrence game is being played. And, if the entry market is deemed to be reasonably competitive, we must then ask whether market power is really a major problem in the NZEM, given its design goals.

But this discussion has been focussed on entry to the generation market, at the national level. All of these issues become more critical at a regional level, and for retail markets. At that level, entry may require being able to:

- *Build generation capacity in the right place, and/or*
- *Gain physical access to generation elsewhere via transmission system enhancement, and/or*
- *Gain commercial access via some form of transmission capacity right.*

The first will obviously be difficult, in many instances, while the last is not possible under current market arrangements (i.e. in 2009)*, and opinions vary with respect to the effectiveness of current transmission planning processes. Thus, barriers to competitive entry into regional retail markets could possibly be a legitimate focus of concern. Still, while many of those barriers may create an environment in which the exercise, and potential abuse, of market power is more likely, most are not likely to have been created by market power, or for the purpose of enhancing market power. Nor does the existence of potential barriers prove that market power exists, or has been abused.*

[120] *See SJ Gale & AE Bollard "A Theoretical Approach To Electricity Generation Restructuring" NZIER Report to the Officials Working Group, July 1990*

7.2 Analysis[121]

7.2.1 Introduction

The discussion above suggests that the broad health of the market, in terms of supply/demand balance and price/ entry equilibrium can actually be assessed very easily, without recourse to detailed simulations or complex gaming models. Or, At least, such high-level analyses can be used to put the results of such detailed modelling into a proper perspective.

If the high-level analysis suggests that the market is not performing well, then more detailed studies can help to identify more exactly what is going wrong, and perhaps how to fix it. But if the high-level analysis suggests that the market is performing well, then negative results from more detailed studies need to be understood and interpreted in that light. If the outcomes seem good, even though detailed modelling indicates that "something is going wrong", we may need to ask whether the detailed problems identified are actually as real or material as they may seem.

At first glance, Figure 7.1 actually suggests that the market is performing very well, in terms of aligning prices with LRMC, but two cautions need to be considered:

- First, we need to distinguish between the possibility that "gaming", for example, is increasing long term profits at the expense of consumers, and the possibility that it might be increasing costs. While the first concern might be dismissed by simply assessing whether market participants seem to be receiving excess profits, the second might increase costs to consumers without increasing profits at all. And that should arguably be of more serious concern to society. Thus, the concerns raised by Philpott and Guan [2018][122] deserve serious consideration, but they can not be addressed by the simplistic analytical approach pursued here.[123]

- Second, though, Figure 7.1 has been prepared using base load contract prices and base load LRMC estimates. Although other analyses in that paper highlight how the costs of meeting different load profiles differ, it does not directly

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[121] The analysis reported in this section has been prepared with the assistance of Dr Stephen Batstone, whose input is gratefully acknowledged.

[122] A. Philpott and Z. Guan *Fine Tuning Frank: Electricity Market Benchmarking Experiments* Presented to EPOC Winter Workshop, August 2018 http://www.epoc.org.nz/ww2017.html

[123] Briefly, Philpott and Guan suggests that significant inefficiencies are occurring because the market is managing reservoir storage differently from the way their optimisation model suggests to be optimal. And other studies suggest a similar imbalance: Specifically, that South Island reservoirs are being managed more conservatively than might seem optimal. That obviously raises the question of how conservative reservoir management should be, and what priority should be placed on keeping the lights on in the South, under dry conditions. But that debate can not be resolved here.

address the key issue of incentives for investment in peak/support plant. So, we have undertaken a preliminary analysis of that issue here.

7.2.2 NZEM Entry Data

We can look at the entry cost/price equilibrium issue in two ways:

- We can determine the actual PDC from market data, and then ask whether it is structured in a way that looks like it is being disciplined by ongoing entry by the plant types required to support the LDC of consumer demand requirements.

- Or we can construct the optimal PDC from entry cost data, and then ask how well the actual PDC matches that optimal PDC.

The key input required for both analyses is the entry cost data for a realistic range of plant types. Traditionally, this kind of analysis has been performed using a range of thermal plant types, including coal, entry of which seems unlikely in the current policy environment.

Theoretically, that does not stop us performing a traditional analysis to determine whether entry would be economic, if it were permissible. But the significance of that analysis seems moot, if it computes a signal to which no plant can actually respond. Conversely, if there is no plant able to enter at, say, SRMC(x), there is no market discipline acting to keep its option value, OV(x), equal to its fixed cost, FC(x), and so no reason to expect that relationship to hold in future market PDCs[124].

Also, while this PDC-based analysis can be generalised to assess the viability of hydro developments, each such development contributes a different mix of energy capture, peak capacity, and storage, making it difficult to determine a generic impact of hydro in terms of shaping the PDC. Recent experience suggests that further development of hydro capacity will face very stiff opposition from environmental groups in New Zealand, and may even be offset by reductions in the effective capability of existing plant. So that possibility will be ignored here. The prospect of new generation development, and of demand side response, will continue to shape future PDCs, though, in the sense that equilibrium implies a requirement for the cumulative PDC above their SRMC to match their fixed costs. So:

- The CCGT entry cost still seems relevant, at least for historical comparisons, as does gas-fired OCGT entry. In fact, we understand that significant gas-fired capacity has already been granted consent to enter the NZEM, and such entry

[124] Here we continue to use the abbreviations of Section 2.2. We refer the reader to that section for definitions. But recall that OV(x) is determined by the difference between the sum of prices in hours above its own SRMC and the per unit cost of running plant x, for that number of hours at SRMC(x).

may be accepted as a necessary support to support the pursuit of increased reliance on renewables, by electrification of sectors such as transportation.

- The entry cost of liquid fuelled OCGT (referred to as Diesel below) is arguably relevant for the future, too, as an extreme dry year backup option. Studies elsewhere suggest that it may be very difficult to maintain reliable supply in an insular hydro-based system without such backup. Arguably, too, an OCGT that is (almost) never used is (almost) as renewable as any technology, and the overall environmental impact largely depends on other factors, including the impact of its physical presence, and manufacturing processes.

- Above that, “shortage” is still a relevant option, even though the actual fixed and variable costs for that option are always a matter of debate.

- But, as thermal generation options are withdrawn, other forms of demand response are likely to become increasingly important, as a routine feature of market operations, across the price spectrum.

- Wind is far from a conventional “reliable” base-load plant, but its impact in terms of disciplining the PDC shape will effectively be that of base-load plant, unless its output pattern is correlated with the PDC.[125] But note that the PDC under discussion here should really be interpreted as a probability distribution over all seasons and hydrology years. So, the seasonal pattern of wind contributions, and any correlation between wind and hydro contributions will have an impact. Accordingly, we suggest that some adjustments may need to be made when using wind entry cost data in this highly simplified context.

- Solar differs from wind, in that its contribution is strongly correlated with the LDC and hence PDC. Thus, while its viability could be assessed in a similar way, its potential contribution to shaping the PDC has been ignored in this preliminary analysis.

- Geothermal is a still a major contender for competitive entry in the New Zealand context. Since geothermal is the simplest base-load option for analytical purposes, we will use this as our base-load entry option in this initial analysis. Because entry opportunities are locationally specific, care is required to account for the impact of locational price differentials and transmission pricing on entry economics. But that is true, to some extent, for all technologies in this kind of broad-brush national analysis.

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[125] In New Zealand, energy contributions from wind do not seem strongly correlated with the LDC. But we understand there is some evidence suggesting a drop-off in wind contribution at the very top of the LDC, and hence probably of the PDC. We also understand that market prices tend to fall when wind generation is high. Both effects would reduce the commercial viability and economic contribution of wind power, but will be ignored here.

Accepting the caveats above, and ignoring the possibility of demand response at prices below that of a Diesel fuelled OCGT, the indicative data in Table 7.1 has been provided by the participants to this study, for the purposes of this very approximate preliminary assessment. Note that shortage costs are notoriously difficult to estimate, and depend strongly on factors such as the duration and depth of the shortage, and the amount of notice given. So, the value displayed here is only indicative of a range of values to be discussed later.[126]

PLANT TYPES	Shortage	Diesel OCGT	Gas OCGT	CCGT	Geothermal
Fixed ($/MWy)	$ -	$ 128,500	$ 138,500	$ 184,000	$ 556,000
Variable ($/MWH)	$ 1,648.00	$ 308.00	$ 67.00	$ 53.00	$ 7.00
Reliability (%)	100.00%	95.00%	95.00%	94.00%	95.00%

Table 7.1 Indicative Entry Cost Data

A critical issue here is the WACC to be used in assessing the FC component of entry costs. As a base level the above estimates use 8%. But as discussed in Section 2.4, investors in peak/support capacity, such as OCGT plant, are likely to require a higher rate of return to compensate for their income stream being much more volatile, and almost certainly riskier. So, following Read et al [2007], an alternative set of results is presented below using a “utilisation risk premium” of 50%. This implies a risk-adjusted return requirement ranging from 8% for base-load plant up to 12%, for extreme peaking plant with a utilisation factor close to 0%.[127]

7.2.3 Actual PDC and Cost Recovery

First, we should compare the cost recovery requirements specified above with actual results from the NZEM. In doing so, we emphasise several caveats:

- First, the entry cost data from the previous section, which will be used again here, should be treated as only indicative. As discussed in Section 6.3, for example, the true SRMC of gas-fired plant may vary quite considerably, and in complex ways, depending on upstream constraints, the availability of spot gas, the drawdown of contracts, and other factors such as the value of any associated condensate.

[126] The shortage cost has been set to a rather low value for technical reasons, but can be ignored for the purposes of the present discussion. (The illustrative value of 1648 is et so that, with this data, the probability of shortage sits at exactly 1%). The effect of the reliability estimate is just to scale the effective fixed cost component up. In this simplistic analysis, the “geothermal” entry represents base-load renewable capacity whose output is not correlated with the LDC, and hence can expect to receive a “base-load” price. Geothermal has been used in this illustrative analysis, because it is the simplest example to analyse.

[127] This adjustment allows us to explore the implications of relying on merchant investment in peaking plant. In reality such investment may always be undercut by vertically and/or horizontally integrated portfolio players, who may be prepared to accept rates closer to their portfolio norm.

- Second, all of this discussion relates primarily to potential independent generators, entering on a "stand-alone" basis. It takes no account of contract commitments, retailer obligations, or the EA's requirement to compensate customers when shortage is threatened.

- Third, real life complications will reduce participant's ability to actually capture all the potential benefits implied by the OV calculation. In about 1% of periods the analysis is implicitly assuming that a CCGT could switch on and off just to grab a single trading period of positive margin, despite there being mostly low prices either side. This seems unlikely, especially after accounting for startup costs. We have, somewhat crudely, accounted for this effect by reducing the availability of CCGT by a further 1% in the calculation of OV, and have used an average heat rate (supplied by the participants based on actual data) in the calculation of the SRMC.

- Fourth, we are assuming that participants can accurately predict the periods for which generation would be profitable

- Finally, we assume no correlation between price and plant unavailability whereas, in reality, high prices will often be triggered by unit breakdowns.

Accordingly, Figure 7.2 effectively shows an upper bound on the OV available for to each of several plant types, differentiated by their assumed SRMC.

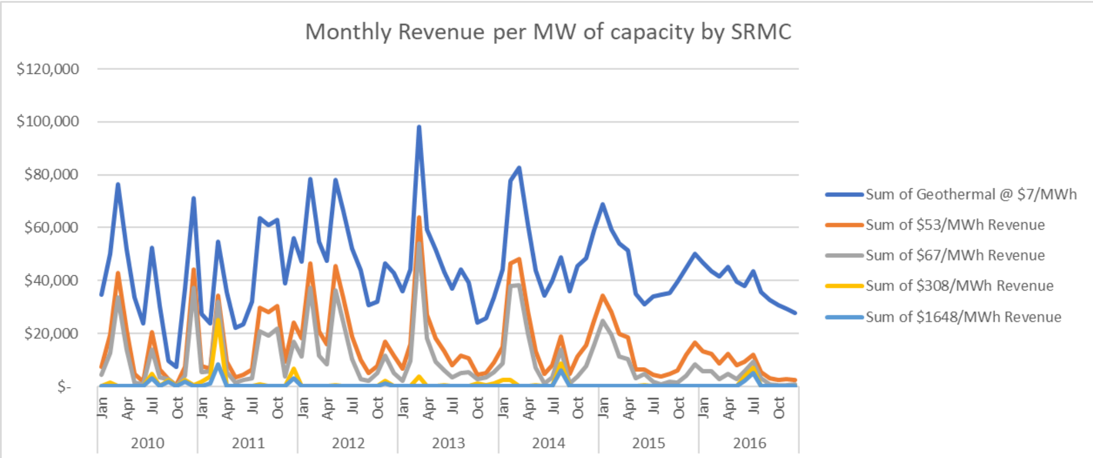

Figure 7.2: Spot Revenue Contours for Differing SRMCs

Then, Figure 7.3 sums these values and compares them with the standing costs for the respective technologies, as discussed in the previous section. Basically, this analysis expands on that in the EPR report, to paint a picture of an electricity market exhibiting perhaps surprisingly good alignment with the theory outlined in Chapter 2.

No thermal plant type seems to be quite recovering its costs, but that is not surprising, in a market where LRMC is declining, with only limited entry occurring. The caveats above suggest that the degree of under-recovery is probably rather greater than that shown here. Ignoring that possibility, though, most plant types seem to be very nearly recovering costs, and that could be taken to indicate that the threat of competitive CCGT/OCGT entry was still disciplining the PDC effectively in this 2010-16 period[128].

Removing potential entrant technologies must (other things being equal) increase sector costs, and raise the equilibrium PDC. So, we would expect to see upward pressure on prices across the mid-range of the PDC in future, even in a perfectly competitive market. We see no such reliable trend in this period, though.

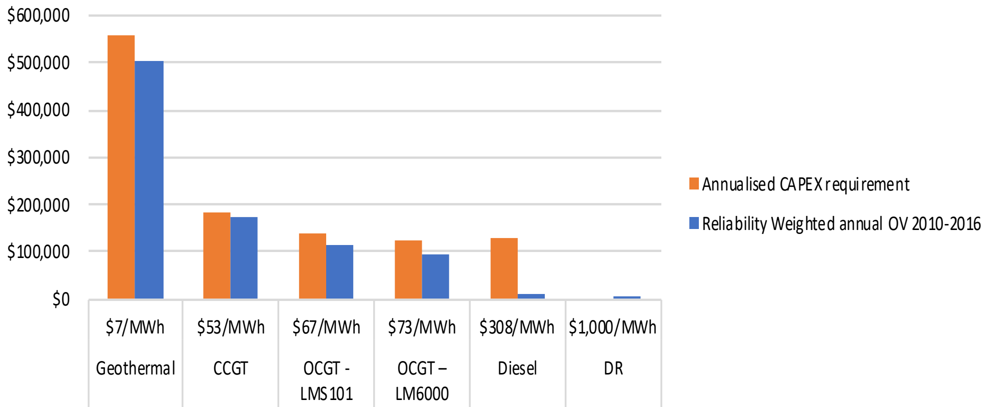

Figure 7.3: CAPEX vs Operating Profit

Nor do we see evidence of anything likely to be characterised as "overcharging", in any other sector. It may be that thermal plant, in particular, are pricing their offers up in ways designed to recover as much of their LRMC cost as they can. And it would surely be astonishing if any other business, in any other sector, did not take some advantage of such opportunities as they arise.

Some years ago, the Electricity Technical Advisory Group (ETAG) wrote that "*Using the LRMC benchmark, there is no clear evidence of the sustained or long term exercise of market power* [in the NZEM]".[129] We might phrase that slightly differently, because we expect that under-contracted generator participants must often have both incentives and opportunity to make offers above SRMC. We also expect that over- contracted generator participants will have both incentives and opportunity to offer below SRMC. And both practices may be characterised as exercise of market power, in the spot market.

We find it hard to see how that unilateral exercise of market power could be characterised as abuse though. As discussed elsewhere we would have thought that it was normal business practice, and also probably necessary to make the current market

[128] Although competition with coal fired generation, which has been ignored here because it is not an expansion option, was a factor in this period, too.

[129] *Improving Electricity Market Performance Volume One: Discussion paper* 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 (p40)

design work with a socially acceptable degree of price volatility, and at commercial rates of return that deliver acceptable costs to consumers on average, over the long term. The relative merits of alternative market designs are discussed in another appendix, but the evidence considered here seems entirely consistent with the ETAG conclusion, if we interpret it as applying to the exercise of market power in the market for generator entry and/or long-term contracts. Thus, we see no evidence, emerging from this LRMC driven analysis, of the sustained or long-term exercise of market power in that entry market.

Nor do we see evidence of market power being abused in the spot market to produce price spikes that are higher or longer than they need to be, if the criterion is a requirement to sustain an optimal plant mix, with an acceptably low probability of shortage. The evidence we would cite is the situation faced by the diesel fired OCGT at Whirinaki, which seldom runs and would seem to be only recovering about $1/10^{th}$ of its entry cost. This is broadly consistent with the analysis above, which suggests that, so long as spot gas is freely available at a modest price in dry years, this kind of liquid fuelled development would not form part of the optimal plant mix. So perhaps it is not surprising that this station was not constructed in response to market signals.

The degree of under-recovery here is much greater than even that analysis would suggest, though. As discussed above, the ongoing availability of well-priced flexible gas for occasional use seems uncertain, and gas fired options may not be available at all in future. So, liquid fuelled OCGTs may well need to play a greater role in future, and supporting such entry may become a significant issue. Based on this evidence, though, market prices would have to spike to much higher levels and/or for much longer, in order to support such entry.

This observation does needs to be interpreted with considerable care, though. Perhaps the market environment is not encouraging offer behaviour to be aggressive enough when the supply/demand balance is tight. In which case, action may be required to refine the market design in order to provide the backup required in future. But other explanations seem plausible, at this stage:

- Perhaps other features of the market arrangements, including the impact of any potential dry year compensation in a vertically integrated industry means that a station of this type can deliver value to participants by means other than spot market sales.
- Perhaps, despite the concerns of some critics, capacity really has been in excess supply over this period, although we note that during the study period, two gas plants were fully decommissioned, and half of Huntly's Rankine capacity was retired. But overcapacity is perhaps unsurprising, given the lack of load growth, and would be expected to correct itself as new capacity is required to meeting increasing demands, e.g from electrification of transport.
- Or it could just be that we have yet to see the "super-dry" conditions under which this capacity will eventually pay for itself, both physically and commercially.

Still, taken at face value, this evidence tends to reinforce the concerns we have expressed elsewhere, that the potential for over-charging during times when prices spike above the SRMC of liquid-fuelled OCGT capacity is really not the biggest potential problem with the New Zealand market. If anything, the evidence suggests the reverse, that more extreme spot market price patterns will be needed to support the backup capacity required by a market increasingly dependent on renewables. Or that other market mechanisms may be needed if that kind of pricing pattern proves to be socially and/or politically unacceptable.

7.2.4 Peaker Support Recovery Requirements

Actually, the cost recovery requirements for peaker support can be deduced directly from the peaker entry cost in the table.[130] Table 4.2 below calculates the levels to which prices would have to spike in order to justify the capital cost of the last MW of OCGT peaker capacity required to limit the number of hours of shortage to the values shown.[131] The first row corresponds roughly to the standard applied in setting price caps for the Australian market. If we imagine market prices spiking to these levels for 4 hours every year, then the last peaker MW would just cover its annual fixed cost of around $130,000/MW over those 4 hours, and require no further revenue for the rest of the year.[132]

The critical thing to note here is that all other MW available during those 4 hours would receive the same revenue, and the mathematical relationships imply that they if they do not get that revenue they will not meet their fixed cost recovery requirements for the year, in a strict SRMC market. Thus, the CCGT, for example, would also receive around $130,000/MW over those 4 hours, making a slightly greater profit than the OCGT because its SRMC is lower, and then need to make up the remaining $56,000 or so, over the rest of the year.

annual hours	percent of time	VoLL ($/MWh)	hours every 20 years
4	0.046%	**$ 34,124**	80
8	0.091%	**$ 17,216**	160
16	0.183%	**$ 8,762**	320
32	0.365%	**$ 4,535**	640
64	0.730%	**$ 2,421**	1280
87.6	0.999%	**$ 1,852**	1752

Table 7.2 VoLL Requirements for Peaker Cost Recovery

[130] This table has been prepared using the Diesel OCGT data, but the gas OCGT gives very similar values for the last MW. In both cases, this last MW is only utilised for the target number of hours shown, making the annual fuel cost almost irrelevant.

[131] The formula here is just: *VoLL(target) = SRMC(peak) + FC(peak)/((Availability(peak)*target)*

[132] Note that this is for the last MW. The station may well run at less than full capacity during other hours of the year. But, in a strict SRMC market, it will not make any profit from doing so, because the MCP would be set to its own SRMC during those hours. The only hours that contribute any profit are the 4 hours for which the full capacity is utilised.

If the same shortage probability standard was applied in New Zealand, though, it might (very simplistically) occur as a pattern of 80 hours over a few weeks in the middle of a very dry winter, once every 20 years. In that case the last MW of peaker capacity should theoretically receive no return at all until those events occurred, then collect around \$2.6m per MW in the 20th year. Importantly, all other capacity in the system would receive this same revenue flow component, in this pure SRMC market: being significantly short for "19" years, then receiving 20 years' worth of this shortfall in one year.

Reality will obviously be more random than this. Cost recovery would probably be spread over more years and, given the amount of notice that might apply to a developing hydro crisis, New Zealand might well feel that a lower VoLL could be applied. If so, though, it would still need to be spread over enough hours to support the last MW of peaker capacity. So, by construction, the net effect, in terms of industry cost recovery patterns, could be much the same.

7.2.5 Peak Period Cost Recovery Proportions by Technology Type

Perhaps surprisingly, the data in Table 7.1 can be used to infer what proportion of its fixed cost recovery requirement each MW of capacity available at the time the extreme peaker is running at full capacity should theoretically receive during those hours.

- Clearly the extreme peaker itself, whether gas or Diesel fired, must recover 100% of its costs when prices are above its SRMC.
- And, since the same revenue component is common to all MW capacity available at the time the extreme peaker is running at full capacity, each other MW will only need to recover its residual fixed cost over the rest of the year. [133]
- So, the proportion of its fixed cost which technology x recovers during the time the extreme peaker is running at full capacity must be close to FC(peaker)/FC(x).
- Those proportions work out to be 75% for the CCGT and 25% for geothermal, if the extreme peaker is gas-fired, as implied by this data.

The proportion of aggregate generator fixed cost recovered during the time the extreme peaker is running at full capacity must then be a capacity weighted average of these individual cost recovery proportions. So, it must be something greater than the minimum proportion calculated here, which is 25%.

A base-load generator with an SRMC of zero would only have fixed costs, while an extreme peaker running for only a few hours a year is actually in a very similar position. Intermediate plant types also have significant annual fuel costs, which are at least covered by SRMC pricing over the hours they run, so this contributes to capital cost recovery. But the total cost to be recovered, for each MW of capacity installed, falls

[133] Ignoring the SRMC running cost differential, which is a relatively small component, for the small number of hours involved.

monotonically as we move from base to peaking plant. So, the proportion of cost recovery occurring over the peaker running period increases monotonically, implying values greater than that for base-load (25% on this data).[134]

That estimate aligns well with estimates we have seen previously, all the way back to the original WEMS market design process. It also aligns well with results from the more sophisticated analysis discussed below.

7.2.6 The Optimal PDC and Base-Load Cost Recovery

A more sophisticated approach would be to try to estimate what the optimal equilibrium PDC might actually be, and what cost recovery might be expected from it. As discussed in Section 2.4, the entire optimal PDC, and plant mix, can also be inferred from the technology parameters in Table 4.1 alone, irrespective of the LDC. This determines the range of utilisation factors over which each technology would be the least cost way of meeting incremental load. Applying this approach to the thermal data alone produces a simple PDC consisting of one step for each thermal SRMC, representing the way in which an optimal mix of these technologies would be used to meet any LDC, or net LDC after accounting for the contributions of renewables, or whatever.

Section 2.4 develops the following formula for U(x) the utilisation factor below which plant x should be fully loaded, and plant with higher SRMCs should be running too, and setting the MCP.

$$U(x) = (FC(x+1)-FC(x))/ (SRMC(x)-SRMC(x+1))$$

As noted there, this relationship, which defines the optimal PDC, is actually independent of the LDC. Thus, while entry will keep occurring if the LDC grows over time, or to replace retiring plant, the equilibrium PDC itself should only change in response to changes in the fixed or variable costs of the potential entry technologies. So, when we talk about SRMC/LRMC alignment, we are really talking about the alignment between the observed PDC in any year, and the optimal PDC determined by the entry costs that were expected in that year.

Some years ago, a prototype spreadsheet tool was developed to perform this kind of analysis, in order to explore and illustrate the theory advanced by Read et al [2007]. Effectively, the tool just performs the simple algebra described in Section 2.4 to determine the range of utilisation factors over which each technology would be the least cost way of meeting loads, that is U(x+1)-U(x) in the terminology of Section .2.4. The tool computes these “Optimised LDC Classes”, and various implications of that breakdown are then calculated and displayed graphically. This prototype uses a

[134] The last MW installed, for each plant type, has a lower total cost to cover than the first and, in equilibrium, the cost to be recovered on the last MW of capacity type x equals the cost to be recovered on the first MW of the next (higher SRMC) plant type in the merit order, x+1.

relatively coarse discretisation of the LDC into 1% steps, though, and only allows for a limited range of technology types.

According to that tool, Diesel OCGT capacity of the type appearing in Table 1, should actually not appear in the optimal plant mix at all. Examining the analysis, we see that this occurs because, it is really not much cheaper to build than gas-fired OCGT capacity, and significantly more expensive to run. So, at these relatively low shortage cost levels, shortage becomes preferable once Gas fired OCGT capacity is exhausted.[135]

In our view. the trade-off between gas and diesel fired OCGT capacity is less clear than it may appear. A critical factor that is often overlooked in this kind of analysis is the need to compare plant, like for like, and MW for MW, when playing exactly the same role, or at least having exactly the same utilisation factor. But this simplified analysis assumes that fuels are freely available, at the SRMC price quoted, right across the range of utilisation factors determined for each plant type.

In this case, the utilisation factor below which gas-fired OCGT capacity becomes more economic than gas-fired CCGT capacity is around 45%, and it seems quite plausible that such plant would be able to buy reasonably priced gas, as required. But the utilisation factor above which shortage is preferable to gas-fired OCGT capacity is only 1%, so that is the utilisation factor expected by the "last MW" of OCGT entry. Such infrequently used capacity might really need to be pay a significant premium to buy large quantities of flexible "dry year gas", as required, potentially making its SRMC much closer to that of a liquid fuelled OCGT. Alternatively, the cost of some kind of flexible gas option contract might need to be added to its capital cost, making the comparison with liquid fuelled OCGT capacity look quite different.

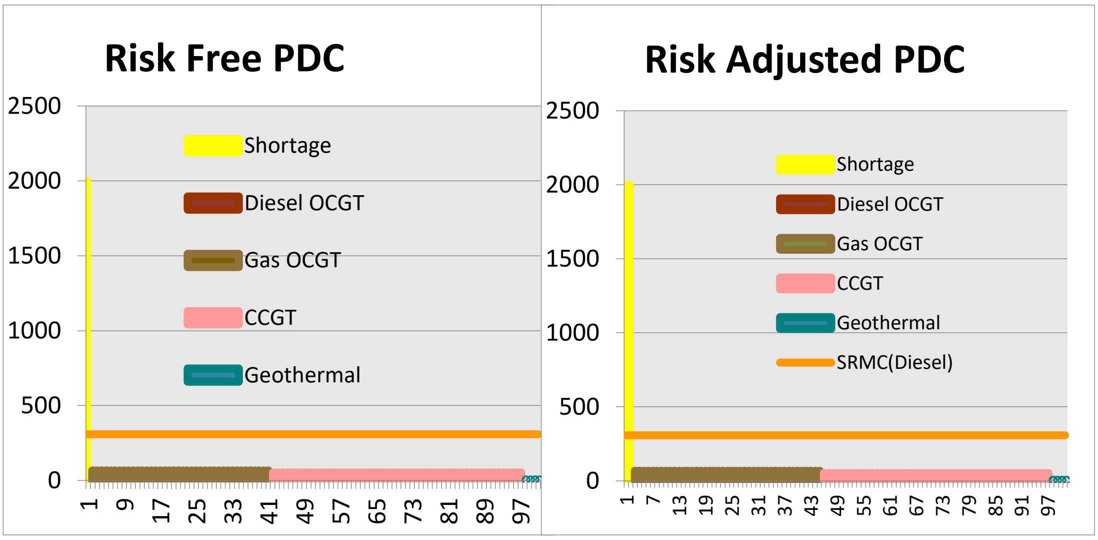

Figure 7.4: Risk Neutral and Risk Adjusted PDCs

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135 The diesel SRMC is shown, though, as a reference point.

The two PDC's shown here were formed using the data in Table 4.1, but with the shortage cost set a little higher, at VoLL = $2000. In the risk neutral case, shortage actually occurs in 1% of time periods, and in 2% of time periods when a 50% risk premium is applied to investment in extreme peaking capacity. That aligns with the theory put forward in Section 2.6, but suggests that the VoLL value is really too low. The values derived in Table 4.2 may be considered more realistic, but notice that the lowest of those values implies a shortfall probability of 1%, which is the discretisation level used in his prototype tool. Thus, VoLL has been chosen here largely for illustrative purposes.

Theoretically, we can compute the proportion of time a base-load plant would be recovering its costs at each PDC price level, directly from these PDCs, irrespective of the LDC. Figure 7.5 displays this, for the two PDCs above, suggesting that 26% of a base-load generator's revenue would be recovered during times of shortage, rising to 41% if peak capacity investors are risk averse. This large jump reflects the 1% discretisation interval referred to above, but the direction of change is valid. Other experiments show that increasing the capital cost of the gas-fired plant brings the Diesel OCGT into the mix, and that actually reduces the proportion of costs recovered in shortage periods. But it increases the total collected at prices of SRMC(diesel) or above.[136]

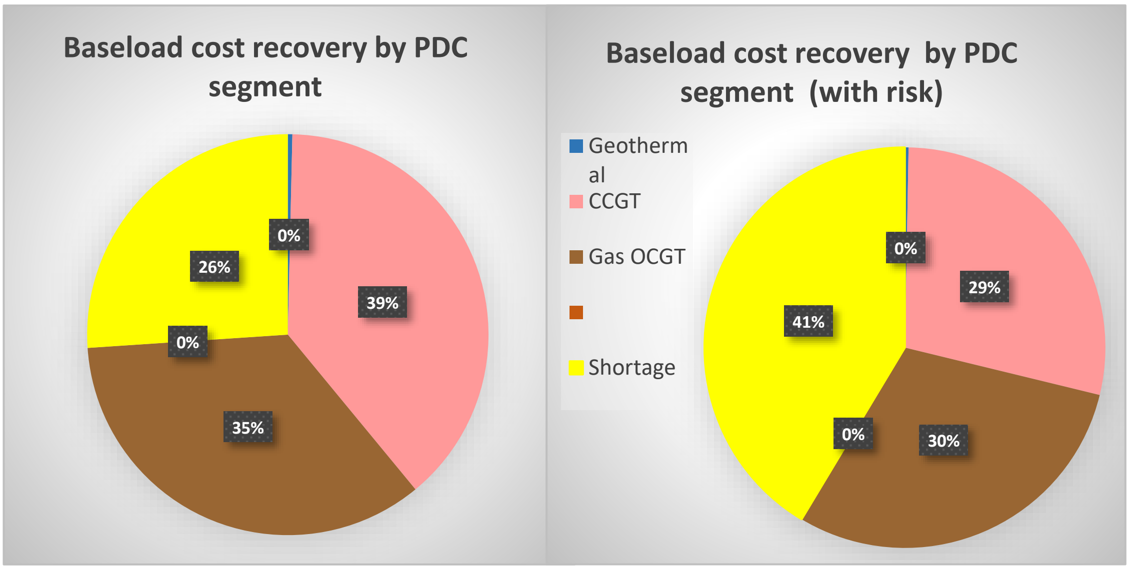

Figure 7.5 Risk Neutral and Risk Adjusted Baseload Cost Recovery

Ideally, we should be using a much finer discretisation, and experimenting with much higher VoLL values, but the point of this discussion is really just to illustrate the kind of analysis that can be done using very simple data. It is worth noting, though, that the

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[136] There is also a small proportion of cost recovery shown here in periods when geothermal is on the margin: That is because our base-load generator s assumed to have an SRMC of zero marginal cost, whereas Geothermal, in this dataset, has a positive SRMC

cost recovery from shortage periods here is quite compatible with the 25% minimum estimate derived above.

There is another issue here, though. These PDC and pie charts do not depend on the LDC, so they will always come out the same, no matter what LDC we might want to determine an optimal thermal plant mix for. In particular, we get these same results when using this data with the residual LDC for the NZEM, after subtracting the hydro generation. And we believe that would be valid if hydro was, like wind or geothermal, a largely passive contributor to meting loads in each period, as implicitly assumed when forming a hydro “Generation Duration Curve” (GDC) as is done below.

NZEM prices would not really change this abruptly between discrete levels, though, and one of the reasons is that, even if the sector was perfectly competitive, hydro generators will submit offers based on expected MWV’s that represent a probability weighted bundle of possible outcomes. So, we should expect to see prices varying continuously between the levels marked.

The fact that expected MWVs, and market prices, are varying continuously between these discrete SRMC levels theoretically makes no difference to the operation of any of those generation options, in our idealised SRMC-driven market. What determines their operation is just whether the market price is above, or below, their SRMC. The intermediate price levels occurring when hydro is on the margin, do make an apparent difference, though, to the OV of all plant generating at that time.

Note, though, that the true value delivered by each MW generated in any of these periods is actually unknown, at the time of generation. It just saves a unit of hydro generation, the true marginal value of which will only become apparent over time. Retrospectively, though, the true MWV actually can be known, as discussed in Section 3.3, and will always equal either zero (if the extra water is eventually spilled), or the SRMC of some type of generation or load reduction. So, each expected MWV can be decomposed as a probability weighted sum of the underlying SRMC values in this equilibrium PDC, or spill. Conversely, the actual market PDC will look like a “fuzzy” version of the hypothetical stepped PDC, but still with the same basic shape, peaking to the same (shortage cost) levels. The question is whether it has the same expected value.

If the MWV-based price received in the period represents the weighted average of all these possible PDC prices we could imagine this payment being withheld until the valuation of each contribution becomes clear. Or we could think of it as the price to be paid now, for a contract whose ultimate value will later be discovered by the purchaser.

We may hypothesise that if the expected MWV is an unbiased estimate of the ultimate PDC values, the expected value of the OV contribution should just be the expected value of the contributions calculated from the stepped PDC. And we could interpret the PDC as representing the distribution of the true MWVs, which will only be known in hindsight. In other words, we could take it as defining the proportion of time for which each technology will be marginal, either directly, in that period, or indirectly because hydro was on the margin, offering its expected MWV, which implicitly includes a probability that the unit of water used today will be made up by using this technology some future period, when it will be on the margin.

This interpretation is very tentative, though, and should be treated with caution. We have not attempted a proof, but suspect that whatever proof may be advanced we expect that some rather heroic assumptions may be required.[137] Ultimately, we suggest that a somewhat more explicit treatment of reservoir limits and management would be desirable. In the meantime, we stress that the results presented here should be treated as indicative and illustrative.

7.2.7 Optimal Plant Mix and Sectoral Cost Recovery

NZEM load/hydro data

In order to discuss the optimal plant mix for a particular system, we must determine the LDC that plant mix needs to cover. In this case, the thermal system being optimised must cover the residual LDC after accounting for hydro contributions. Thus, we need the New Zealand LDC, and a corresponding hydro "Generation Duration Curve" (GDC).

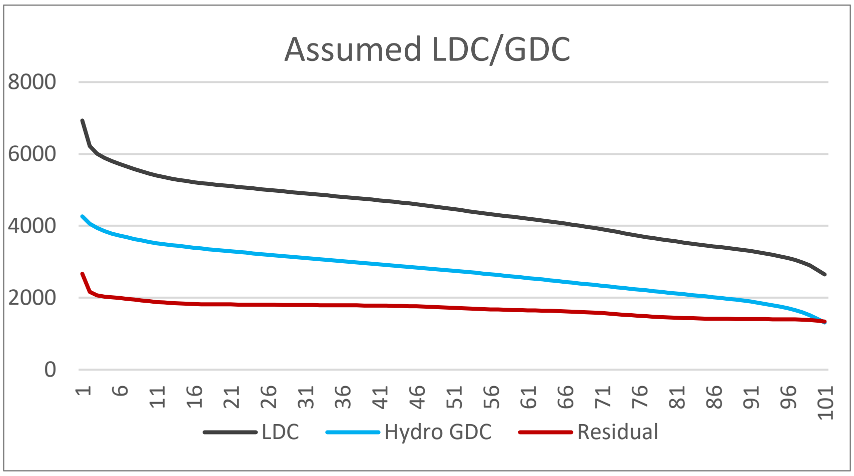

Figure 7.6 Illustrative Duration Curve Data 2010-2016

The data we have used is summarised in Figure 7.6, which also reports the Residual LDC formed by subtracting the GDC from the LDC. Ideally, the entry economics analysis should actually account for GDCs fitted and filled for say, wet, normal, and dry hydro years, with some accounting for limits on inter-seasonal reservoir capacity.

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[137] In particular, the possibility of reservoir storage limits forcing spill seems likely to affect the expected ted value. We note that, while the hydro GDC is based on real performance, and thus reflects the effects of all constraints, and the analysis models the possibility of "geothermal spill" at times of low load, the analysis has no representation of hydro spill due to reservoir limits being reached. Thus, it implicitly assumes that energy can be optimally scheduled into the residual LDC as required, even across and hydrology years, which is obviously unrealistic.

But our prototype tool uses a single GDC, effectively representing the whole range of hydro generation levels over the group of years studied, in this case 2010-16. Similarly, for the LDC.

Subtracting that GDC from that LDC thus effectively assumes that the sector will somehow have managed to schedule the peak hydro output over that entire period to match the peak load level over that entire period. Not surprisingly, this very coarse assumption creates some minor non-monotonicities in the residual LDC, and that creates some significant issues for an analytical approach that matches thermal plant entry to a residual LDC assumed to be monotone. So, a minor adjustment was performed to create an LDC that is very similar to the original, but implies a monotone Residual LDC, shown as "mono resid" in Figure 8.3.

That Residual LDC is slightly peakier than the original, but it still does not fully represent the peak demands that would be placed on the thermal backup system. Traditionally, the peak demand on the thermal system was likely to occur if breakdowns occurred when load was high and hydro flows low. Increasingly, though, a combination of low solar and wind output will greatly add to those factors, creating a potentially much larger spike in thermal backup requirements when heating loads peak on still winter nights.

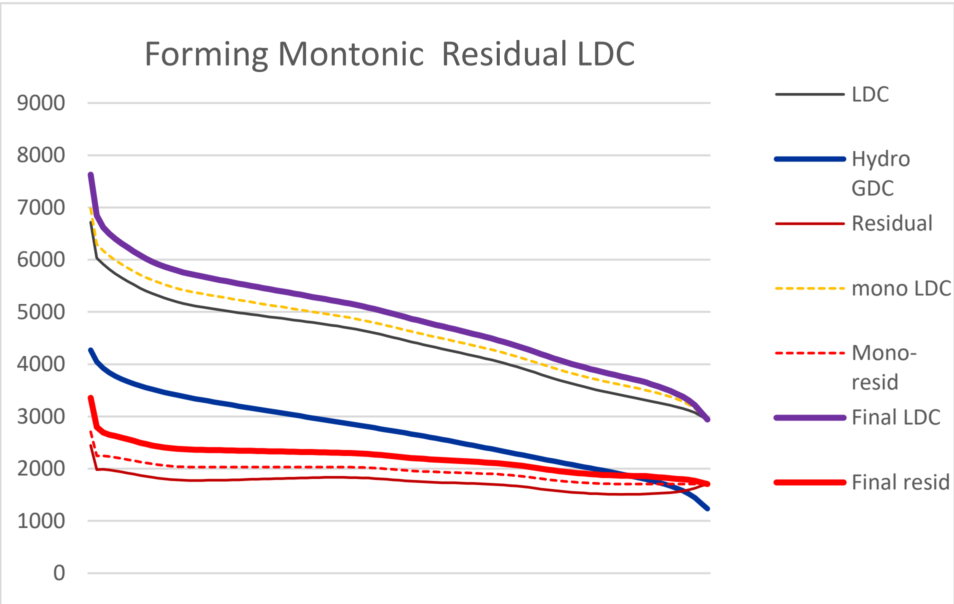

Figure 7.7 Forming the Illustrative Residual Load Duration Curve

This effect has traditionally been represented by creating a convolved "effective LDC" to be faced by each successive plant type, working up the merit order, after accounting for breakdowns. The result can not be exactly represented in a composite sectoral LDC like those shown here, but the broad effect is to add a "pseudo-load" component on to the LDC which increases strongly toward the extreme peak.[138] No attempt has been made to assess the appropriate additional component for this particular study. Instead, a rather arbitrary component has been added, inferred from earlier illustrative data. We make no claims with respect to the accuracy or appropriateness of this additional component, and regard it as purely illustrative of the general phenomenon. Although increasing the peak further will imply a somewhat greater proportion of cost recovery in peak periods, it makes little difference to the illustrative discussion below.

Plant Mix to fill NZEM LDC

From the NZEM entry data, we have already determined an optimal PDC, characterised by a critical utilisation factor for each plant type. So, all we have to do now is to locate those utilisation factors on the residual LDC, and slice that LDC into bands to be met by the various available technologies. Figure 7.8 shows the result of applying this approach to the RDC discussed above, using the PDC in the previous section.

We see that a strong emphasis on cost recovery at prices determined by thermal technologies need not imply a strong role for thermal plant in meeting load requirements. In fact, the figure suggests that their role in the optimal plant mix is really quite modest. As discussed above, it will actually be hydro "on the margin" in many of these periods, with the type of thermal generation, or demand response, ultimately displaced only being revealed at a later date.

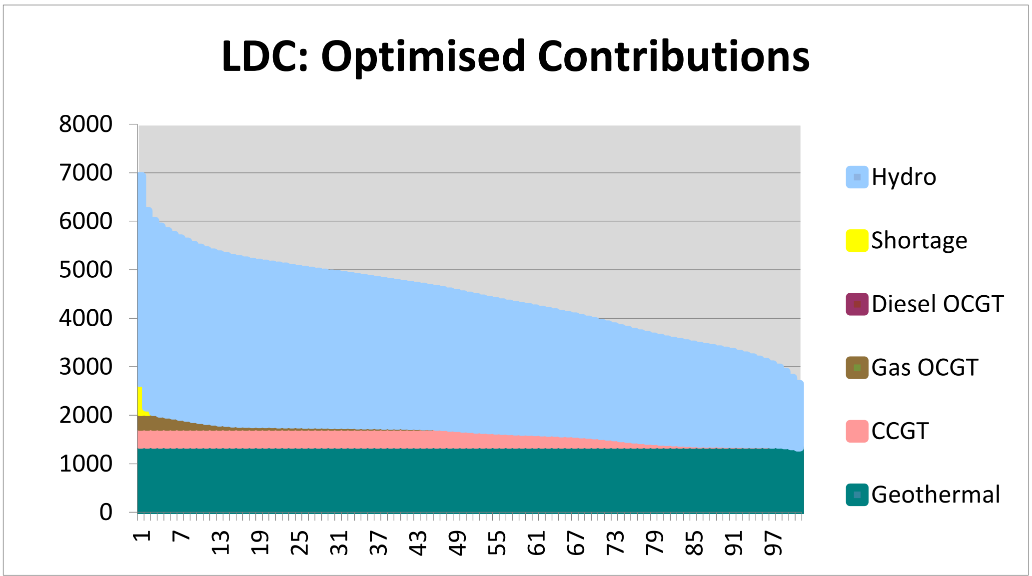

Figure 7.8: LDC Filled by Optimal Plant Mix

[138] The apparent increase in load is obviously not real, but it is offset by matching each effective Residual LDC with thermal capacity that is implicitly assumed to be 100% available, with unavailability accounted for by increasing the effective capacity cost.

Cost Recovery Proportions

We have already discussed estimates of the proportion of their total costs that base-loaded plant might expect to recover in periods when prices spike to shortage cost levels. Other plant will need to recover an even higher proportion of costs during these high-priced periods, though, ranging up to 100% even for gas-fired OCGTs in this example, where Diesel OCGTs do not appear in the optimal plant mix.

If we boldly make the further simplifying assumption that prices are perfectly correlated with load, we can multiply the price in each hour of the PDC by the load in each hour of the LDC, to create a "Revenue Duration Curve" (RDC) for the sector as a whole. From that, we can produce the following pie chart for total industry cost recovery.

While it is obviously very approximate, this analysis suggests that 35% of the revenue required to cover generator costs should be collected in periods when prices are above the SRMC of a gas-fired OCGT peaker, and (approximately) 0% when our base-load (non-storage) renewable option (geothermal in this case) is on the margin.

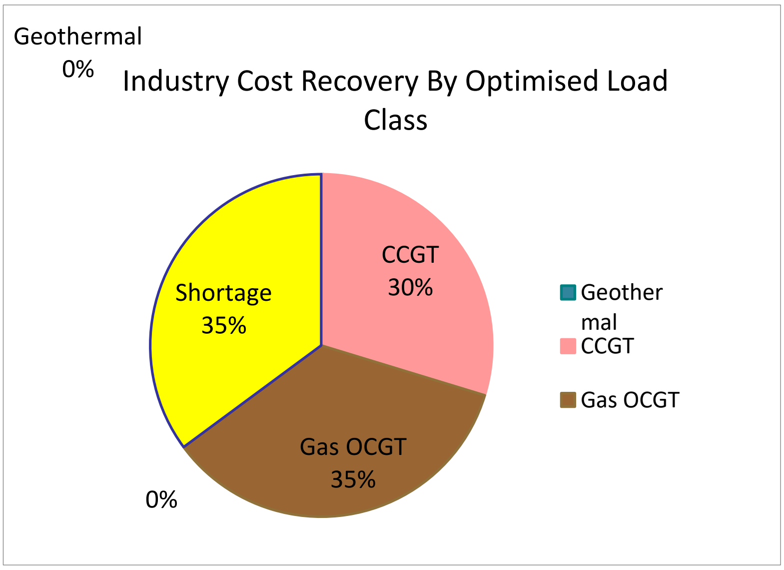

Figure 7.9 Industry Cost Recovery: Risk Neutral Case

These results are definitely subject to some error due to the discretisation of the LDC blocks into 1% classes, though. Nor would we actually want to see shortage occurring in 1% of hours, on average. Section7.4 explores some alternatives involving much fewer shortage hours, but we suggest that none of these variations really makes any difference to the overall cost recovery proportions.

The peaker may recover its costs running at full capacity for 4 hours a year, with VoLL set at $34,692. Or it may recover its costs running at full capacity for 87.6 hours a year (ie1%), with VoLL set at $1,648, as in our spreadsheet analysis. In a more sophisticated analysis, and/or less regulated market environment, it may run at various levels and receive a range of prices set by various levels of demand response. But the per MW total to be recovered is the same, and that same total needs to be recovered by every other MW of capacity operating at that time, in order to provide the cost recovery theoretically guaranteed by an energy only market, with strict SRMC pricing.

We stress again the experimental and illustrative nature of the techniques and results presented here. But the industry cost recovery proportions estimated here, of 25% for base-load plant, and 35% across the whole plant mix (ignoring risk) are quite comparable with other estimates we have made or seen, including the estimates made in Section 7.5. Experimentation with a range of adjustments available within the tool confirms a consistent view that the proportion is likely to be at least 25%, and maybe significantly higher, in an idealised competitive market, with SRMC pricing. So, we believe the results do provide some high-level guidance with respect to the interpretations to be put on results from more detailed analyses.

We also note the implication that, because aggregate pattern of generator output obviously matches the LDC, this same pricing pattern should be considered indicative of the pricing pattern that loads should face, in a hypothetical SRMC-driven market. In reality domestic loads in New Zealand typically face charges in which many fixed costs are "variabilised" into a per kWh price. In theory, though, the cost structure of the industry implies that they should be facing lower energy prices, offset by much higher fixed charges to recover transmission/distribution/ retailing costs. This analysis suggests that, if consumers do not want to face significant spot price variability, a significant insurance premium for dry year backup might logically be included in retail pricing, arguably as a fixed cost item.

Modelling Demand Response

Finally although the above discussion focussed mainly in thermal plant, we are actually moving closer to a 100% renewable system, in which thermal SRMCs become irrelevant, and SRMC revenue should theoretically be zero, if any form of energy is being "spilled".[139] So, theoretically, if thermal generation is eliminated, the proportion of costs recovered during "demand response" periods will eventually have to rise to 100% in a strict SRMC market, because that will be the only way to match demand to supply at other times.

In this preliminary analysis, though, the only one form of "demand response" allowed for is load shedding, at an assumed cost well above the Diesel SRMC. We could better analyse this emerging situation by adding one or more "demand response" blocks, priced at SRMCs both above and below that of a Diesel OCGT. These would represent the range of demand responses that might be expected to occur when market prices are in that range, whether due to opportunity costing of hydro release, or "gaming", or both.

[139] This does not quite happen in these results, because "geothermal" is assumed to have a non-zero SRMC.

We will not do that here, though. partly because (due to the limited number of technologies that the prototype tool can accommodate) we would need to drop a thermal technology for each demand response option added, but also because the assumptions would be rather speculative.

Cost estimates for demand response and shortage are notoriously varied and often difficult to assess. Shortage costs have traditionally been assessed for involuntary "power cuts", with the cost depending significantly on the amount of warning given, e.g by low inflow/lake levels. Values of the order of $5,000/MWh have been suggested when warning is given, rising to $10,000 without warning. These are significantly lower than some of the values calculated in the table above, perhaps implying a greater willingness to tolerate in the NZ market than in some other markets.

Voluntary demand response to high prices is slightly different. MW capacity shortfalls may drive short-term price spikes that do not actually induce much response, unless they are expected. But factors like low inflow levels create energy shortages that drive prices up over a period of time, giving consumers more time to plan and execute response strategies. Broadly, it has been suggested that demand reduction of about 5% might occur at sustained prices between $500-$1,000/MWh, and another 5% at sustained prices between $1,500-$2,5000/MWh.

But we note that demand response is rather like hydro development, in that opportunities are specific and limited. Simplistically, just setting a demand response price allows the analysis to implicitly assume that the system can call on unlimited quantities of that response at that price. Thus, rather than allow a probability of "shortage" it will always recommend reliance on "response" at any assumed SRMC below VoLL, unless that option also has some associated "fixed cost".

Many demand response options will have identifiable fixed costs, including the installation of equipment, the training of staff, and so on. But they will often also be specific to some class of equipment and user, such as supermarket freezers, or whatever. And no matter how attractive it might look, it is unrealistic for a model to recommend "installation" of say, 10MW of capacity from such a source if there is only 5MW available across the nation.

We might think of imposing a physical capacity limit in such a case, but an optimisation will deal with that by assigning a shadow price to the imposed constraint. That shadow price would then represent the net economic value associated with the opportunity of developing that particular form of demand response, once all direct costs have been accounted for. The PDC analysis will only produce a realistic plant/response development mix, then, if we include that opportunity cost in our assessment of fixed costs. In the context of our tool that would involve iterating on the fixed cost to achieve realistic utilisation of each demand response option. While that may provide a more realistic perspective on the future shape of the sector, it would not greatly enhance the conclusions discussed here, and lies beyond our current scope.