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Selection of the WACC Percentile in the Context of Risks faced by Electricity Distribution

FINAL

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1. EXECUTIVE SUMMARY

Unison Networks Ltd has asked Andrew Shelley Economic Consulting Ltd (ASEC) to consider the issues relevant to the choice of the Weighted Average Cost of Capital (WACC) for regulated Electricity Distribution Businesses (EDBs) in the context of market and regulatory risks faced by those entities, and to the extent possible quantify any relevant impacts.

The WACC is an important component of setting the both the Default Price Path (DPP) and any Customised Price Path (CPP) for regulated electricity and gas networks, effectively setting the average rate of profit that is expected to be earned by these companies. The WACC cannot be directly observed, but must be estimated. The estimated parameters all have a margin of error, so the estimate of WACC also is subject to error and falls within a distribution. The New Zealand Commerce Commission (the "Commerce Commission" or "Commission") has adopted the practice of using the 75th percentile of that distribution. This practice has been adopted to reduce the likelihood of the true WACC for the regulated firms being greater than the estimated value. This is considered to be important because the costs of setting the WACC too high (higher prices and lower consumption) are considered to be less than the costs of setting the WACC too low (reduced discretionary investment by regulated companies and lower quality over time). In theory, this relationship could potentially be formalised as a loss function, enabling an optimal WACC to be selected. The High Court has noted that this position has been supported by the Commission's own experts. [1]

In setting the WACC, there are two issues that the Commission should address:

- The first issue is to select a WACC that ensures the objectives of Part 4 of the Commerce Act are met, and particularly that there are continuing incentives to invest in the relevant networks.
- The second issue is that one-sided or asymmetric risks are appropriately addressed. If these risks are uncompensated they will lower the expected return earned over time, and so will reduce the extent to which the first issue has actually been addressed.

In the best case scenario, an EDB making investments now can expect that from regulatory period to regulatory period it will earn its WACC, such that in approximately 45 years' time it will break even on the investment. Over the course of some regulatory periods there are likely to be periods of sub-WACC returns, if for example, CPI is less than forecast, demand is greater than expected, input costs higher than forecast, Government policy changes impose unanticipated costs, in other regulatory periods slightly above WACC returns may result from the opposite effects, but (in this best case scenario) if regulatory forecasts are unbiased then these effects should balance out and investors are kept whole over the 45 years. Critically in this best case scenario there is no unmitigated asset stranding (i.e., monopoly status endures) or catastrophic events. EDBs are unable to benefit from substantial upsides (e.g., proliferation of electrical vehicles) because the shortness of regulatory periods and the truncation of upside returns at each reset. It appears that this is the scenario that underpins the Commission's analysis of WACC.

1 Wellington International Airport Ltd & Ors v Commerce Commission [2013] NZHC [11 December 2013]. See [1465], [1467], [1470].

The Commission has not, to date, explicitly considered the second issue. There has been no considered analysis of the long-term market and catastrophic risks facing regulated businesses, nor whether those businesses can expect to earn their cost of capital over the longer term. Some limited consideration was given to catastrophic risk in the context of the CPP for Orion, but there has not been a broader consideration of the catastrophic risks faced by the industry. Given that these issues of asymmetric risk have not been addressed within the regulatory framework, it is not reasonable to consider the WACC percentile in isolation of the other Input Methodologies (IMs).

Perhaps the most pressing issue for electricity distribution is that the energy industry is on the cusp of massive revolutionary technological change. Solar PV is very likely to become economically viable in the next 5-10 years. This means that it will be cheaper for households (and businesses) to install rooftop solar than to continue to rely on electricity delivered via traditional means. There is a material risk that the distribution network will, over time, be relegated to providing back up capacity for peaks and/or when there is a component failure. New Zealand also presents networks with a relatively high risk of catastrophic events, with the potential effect of such events being highly material. In the face of these risks it seems very brave to assume a stable long-lived industry where the cost of assets can be recovered over a 45 year period (or longer).

Catastrophic event risk is not well handled within the current regulatory model, and is expected to increase. Catastrophic events will typically be earthquakes and major storms, but will also potentially include a range of effects from volcanic eruptions. Volcanic eruptions are less frequent than significant earthquakes, but the effects can be just as devastating. Further, I note that the IPCC's most recent report highlights that there are increasing risks to infrastructure from the expected increase in frequency of storms.

If the Commission intends to review the percentile at which the WACC is set, then it should do so as part of a process that comprehensively considers:

- The costs of a WACC that is too high vs setting a WACC that is too low, through a robust empirical process that systematically examines the economic costs associated with different WACC levels;
- Insurance of catastrophic events and whether it remains appropriate for EDBs to take demand risk following a catastrophic event;
- The appropriateness of indexing the RAB and deducting revaluation gains from revenue requirements;
- Support for changing price structures and contractual arrangements with consumers so that EDBs are not subject to stranding risk from advances in PV and battery technologies;

Much of this is amenable to quantitative analysis, but sufficient time is required for appropriate data to be gathered, models built, and testing by experts. In this report I consider the broad issues that would need to be considered in forming a definitive view on the appropriate percentile for the WACC. Where possible I also provide an initial quantification of some of the costs and benefits arising from the choice of WACC. However, this is not an attempt to systematically or comprehensively estimate the components of a loss function.

Setting the EDB WACC at the 75th percentile results in average delivered electricity prices being around 1.4% to 1.8% higher than if the WACC is set at the 50th percentile. The price elasticity of demand for electricity in New Zealand is likely to be approximately -0.4. Given this price elasticity, the difference in average delivered electricity prices will result in a deadweight loss of between $174,000 and $214,000 per year.

Given a VOLL of $14,900/MWh, the upper bound deadweight loss of $214,000 per annum equates to non-supply of just 14.36 MWh per year, just 0.005% of the reduction in consumption due to the increase in electricity prices. This is equivalent to an increase in SAIDI of 15 seconds over the weighted average SAIDI of 111 minutes and 35.5 seconds.

If the regulated WACC were to decrease, a rational response on the part If EDBs were to reduce discretionary investment. One option is for expenditure on undergrounding to be reduced. Fault rates on cables are significantly less than fault rates on overhead lines, so in most scenarios a reduction in undergrounding will result in fault rates that are higher in future than they otherwise would have been. Similarly, a reduction in non-essential capex for network resilience could, over time, result in SAIDI several minutes higher than if such investment had occurred. This suggests that any reduction in deadweight loss from a lower WACC percentile may be offset by higher SAIDI costs in the future.

EDBs could also decrease discretionary capital expenditure by increasing the amounts required from customers by way of capital contributions. Increasing capital contributions could result in economic costs of $11,900-$26,700 per year for each additional $1m of capital contributions. This result occurs because EDBs have a lower cost of capital than their customers. To achieve the same economic cost as the deadweight loss would require EDBs to increase capital contributions by a maximum of $18.0m, taking capital contributions to a maximum of 33.2% of the total amount of customer connection and system growth capex. This is within the bounds of what might be a reasonable increase in capital contributions if EDBs were no longer willing to fund discretionary investment.

Refinement of the above estimates into a loss function requires considerable additional analysis, including the development of engineering studies on network performance under various catastrophic events given different levels of discretionary investment. Other complex issues will also require resolution and agreement, such as the relationship between the regulatory WACC and discretionary capital expenditure by EDBs, and how reductions in discretionary capital expenditure would translate into economic costs (future SAIDI, amenity value).

Absent the time to perform such an analysis, the Commission should be wary of modifying its long standing position. The quantitative estimates provided above support the general proposition that there are economic benefits in setting the WACC above the mid-point. Clear evidence should be required that any proposed alternative is materially better than the Commission's position to date. To that end, I note that the Australian Energy Regulator has been granted broader discretion in its approach to setting the WACC for regulated network service providers, and has used that discretion to set individual parameters at or near the top end of the estimated range. The net effect of these decisions is that the WACC will also be above the midpoint.

2. INTRODUCTION

2.1. BACKGROUND

The Commission's duties include setting the Default Price Path (DPP) and any Customised Price Path (CPP) for regulated electricity and gas networks. The Weighted Average Cost of Capital (WACC) is an important component of a price path, effectively setting the average rate of profit that is expected to be earned by the relevant companies.

The WACC cannot be directly observed, but must be estimated. The estimated parameters all have a margin of error, so the estimate of WACC also is subject to error and falls within a distribution. The New Zealand Commerce Commission (the "Commerce Commission" or "Commission") has adopted the practice of using the 75th percentile of that distribution. This practice has been adopted to reduce the likelihood of the true WACC for the regulated firms being greater than the estimated value. This is considered to be important because the costs of setting the WACC too high (higher prices, lower consumption) are considered to be less than the costs of setting the WACC too low (reduced discretionary investment by regulated companies, lower quality over time).

Various aspects of the Input Methodologies used for setting the DPP were appealed to the High Court. The Major Electricity Users Group (MEUG) argued that the WACC should be set at the mid-point (50th percentile) of the distribution. The Court did not amend the Input Methodology for the Cost of Capital, nor did it find that MEUG had presented a materially better alternative. Instead, by way of *obiter dicta*, the Court expressed scepticism of the basis for setting the WACC above the mid-point, there being an absence of rigorous empirical analysis, and noted that it expected this scepticism to be considered by the Commission at the next seven-year review of the WACC. [2]

The Commission subsequently issued a notice of intention to undertake further work on the cost of capital input methodology, specifically focussing on the WACC percentile, prior to the reset of the price-quality path for electricity services later in 2014, and has invited interested parties to provide evidence regarding the appropriate WACC percentile that should be used under the cost of capital Input Methodologies.[3] Unison Networks Ltd has asked Andrew Shelley Economic Consulting Ltd to consider the issues relevant to the choice of the WACC for regulated EDBs in the context of market and regulatory risks faced by those entities, and to the extent possible quantify any relevant impacts.

2.2. STRUCTURE OF THIS REPORT

This report is structured as follows:

- Section 3 provides a brief survey of material market risks that electricity networks currently face, and the interaction of these risks with the low-user fixed charge regulations;

2 Wellington International Airport Ltd & Ors v Commerce Commission [2013] NZHC [11 December 2013] at [1486].

3 NZ Commerce Commission, Further work on the cost of capital input methodologies: Process update and invitation to provide evidence on the WACC percentile, 1700759.1, 31 March 2014, p. 2.

- Section 4 provides a brief survey of catastrophic event risks that electricity networks currently face;
- Section 5 discusses the rational response of investors to these risks;
- Section 6 provides quantitative estimates of the welfare impacts of setting the WACC at the 75th percentile; and
- Section 7 provides recommendations on the approach that should be adopted to selecting the appropriate percentile.

3. IT'S THE FUTURE, JIM, BUT NOT AS WE KNOW IT

This section provides a brief survey of the material market risks that electricity networks currently face. The information presented is not intended to be a comprehensive thesis, and nor should it be: in the real world this is often the extent of the information that Directors have when they are making material decisions about the strategy and future of their company.

My understanding of the Commission's implementation of the DPP and CPP is that there is no compensation for asymmetric risks.[4] Instead, the current regulatory model for electricity networks seems to be one predicated on the assumption of limited technological change that enables the costs of long-life assets to be recovered over a long period of time. Risks are assumed to be limited, so cash returns can be deferred to the future by revaluing assets, taking the revaluation gains as non-cash income in the current period, with the cash income recovered in future. These underlying assumptions are short-sighted and not supported by the experience of the 20th and 21st centuries. There is a significant risk that rapid and disruptive technological change will occur in the near future, with potential to be exacerbated by political party policies.

While these market risks are a separable issue from the WACC percentile, in the absence of any other mechanism to address these risks they provide a further reason to adopt a cautious stance in considering changes to the WACC percentile. If investors consider that significant asset stranding could occur in the future, then the expected return will necessarily be lower than the headline regulatory WACC. For this reason it is important to conduct a review that considers the risks and inter-relationships with other Input Methodologies.

3.1. Disruptive Technological Change: History Repeats

Time and time again a stable existing status quo has been disrupted by technological change. Disruptive change brings new winners, and often relegates the incumbents to the position of loser. Common examples include:

- The development of refrigerated shipping re-oriented New Zealand's production towards meat and dairy products, propelling it into the ranks of the wealthiest countries in the world (on a GDP per-capita basis). That advantage was lost in the 1970s when political change took away New Zealand's primary market;
- In little more than 100 years aviation has changed from a curiosity to a major industry that has revolutionised long distance transport. The advent of the Douglas DC3 in the 1930s revolutionised air travel, and in so doing began to displace rail transport as a means of long distance travel. The airline industry itself has had successive waves of innovation, with new generations of aircraft, the jet engine, and ever larger aircraft capacity. Each new development makes air travel relatively more cheaper and efficient than alternatives. Long distance passenger rail is now a novelty means of travel rather than a preferred choice.

4 NZ Commerce Commission, *Input Methodologies (Electricity Distribution and Gas Pipeline Services) Reasons Paper*, 22 December 2010, para. H2.3, p. 397.

- Eastman Kodak, having been the dominant firm for over 100 years in the camera and photographic supplies industry filed for bankruptcy in 2012, having failed to sufficiently adapt to the development of the digital camera. This occurred even though Kodak built an early model digital camera (1975) – Kodak's business model simply did not change fast enough to respond to the new technology.
- The computer industry has seen firms grow, become major players, and then fold or completely reorient their business as technology has changed. Many of the major players in the era of the mainframe and minicomputer are no longer in existence (e.g. Digital Equipment Corporation and Compaq), having failed to adapt adequately to the advent of the personal computer. Microsoft, the dominant manufacturer of operating systems for personal computers is now struggling to establish a foothold in the market for operating systems for smartphones and tablet computers.
- Even more prosaic industries are suffering from the pressure of technological change. Worldwide there is a decline in mail volumes as electronic communications, including email, replace traditional post. For example, the US Government Accountability Office finds that First-Class Mail volumes for the US Postal Service (USPS) declined 33% since peaking in fiscal year 2001, and total mail volumes had declined by almost 25% since 2006. As a consequence the USPS now "faces a critical shortage of liquidity that threatens its financial solvency".[5] New Zealand Post reports similar declines: FastPost volumes had dropped by 82% from 1998 to 2012, and total volumes had dropped 24% from 2002 to 2012.[6] That decline has continued further, and even accelerated, with New Zealand Post reporting a further 7.5% drop in volumes for 2013.[7]

3.2. SOLAR PV

Any rational long-term investor in a stable industry today should be looking ahead to the potential disruptive challenges that might arise, and the electricity industry appears to be on the cusp of such a change as solar PV is highly likely to become economic in the next decade.

3.2.1. Solar Cells

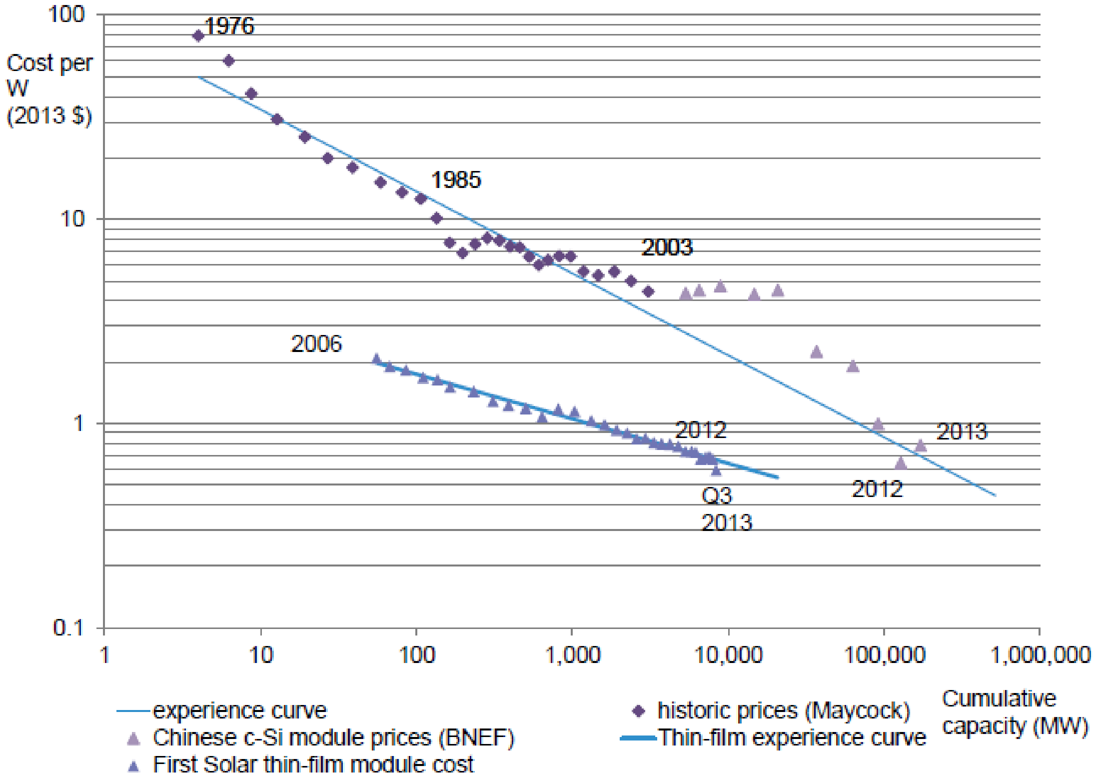
Bloomberg New Energy Finance (BNEF) recently published the chart in Figure 1, showing the exponential decline in the costs of solar photo-voltaics (solar PV) and the exponential growth in their deployment. Such decline in cost is similar to Moore's Law, which has seen the number of transistors on integrate circuits double approximately every two years, and consequent decreases in unit cost. Solar PV uses similar technology (silicon wafers), so as experience is gained it is reasonable to expect that gains will continue to be made. New technologies will also be commercialised, as illustrated by the lower (cheaper) line in Figure 1, which shows the experience curve for Cadmium-Telluiride thin film cells.

5 US GAO, *US Postal Service: Urgent Action Needed to Achieve Financial Sustainability*, 17 April 2013.

6 New Zealand Post, *Proposal by New Zealand Post to Minister for Communications and Information Technology*, January 2013. Percentages are calculated from the volumes presented in the text on p.7.

7 New Zealand Post Group, *Annual Review 2013*, p. 4.

Figure 1: The Declining Cost of Solar PV



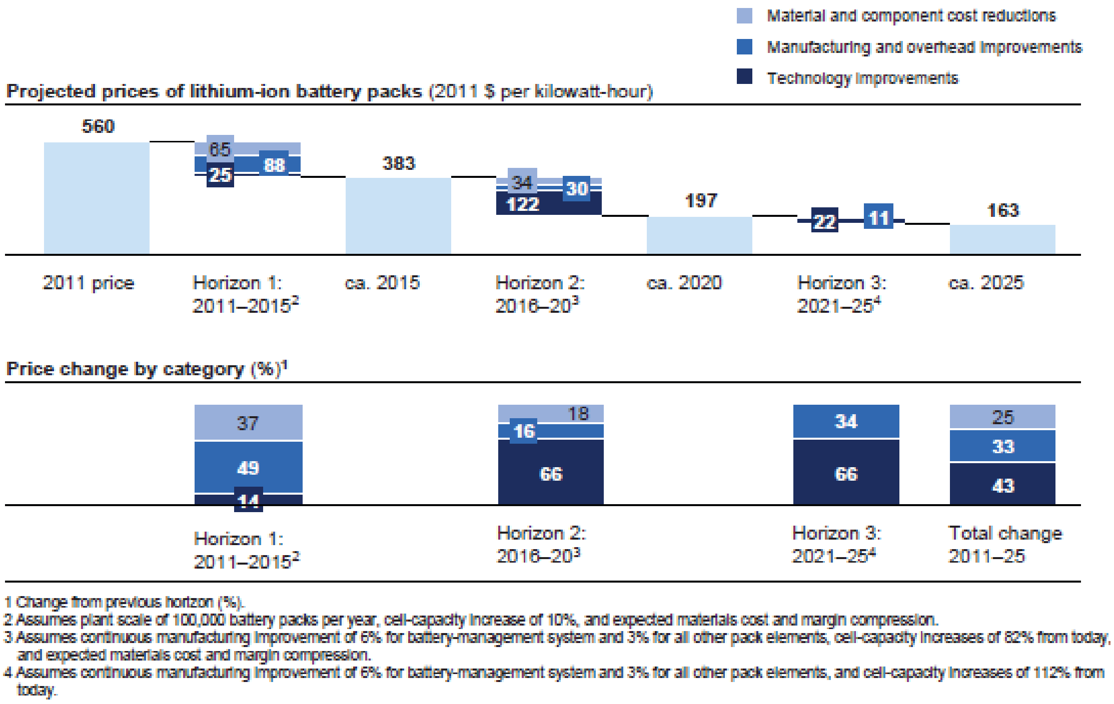
Source: Jenny Chase, "H1 Levelised Cost of Electricity – PV", Bloomberg New Energy Finance, 4 February 2014

3.2.2. Batteries

An important component of any distributed generation technology is the use of batteries to store energy for use during peak demand periods. For example, peak solar generation is during the middle of the day, which is not the peak period for demand, and wind can be essentially random (although it does have a stronger daytime component). Surplus electricity generated during the day could be stored or it could be sold to a retailer at the wholesale market price. If battery prices can be kept low enough then there is an advantage to storing electricity rather than selling it at a low price off-peak and buying it at a higher price at peak time. Batteries are also important for the viability of electric cars.

There are many storage technologies in existence and under investigation. Two that are commonly known are lead-acid batteries (used in automobiles) and lithium-ion batteries (offering a much higher "energy density"). In mid-2012, McKinsey predicted that lithium-ion battery prices would fall from US$560/kWh in 2011 to US$197/kWh in 2020 and US$163/kWh in 2025 (see Figure 2). About one-third of the potential reductions come from scale effects and manufacturing productivity improvements. On top of these improvements in a known technology, efforts are ongoing to find and develop new and improved storage technologies.

Figure 2: Forecast Decline in Lithium-Ion Battery Costs



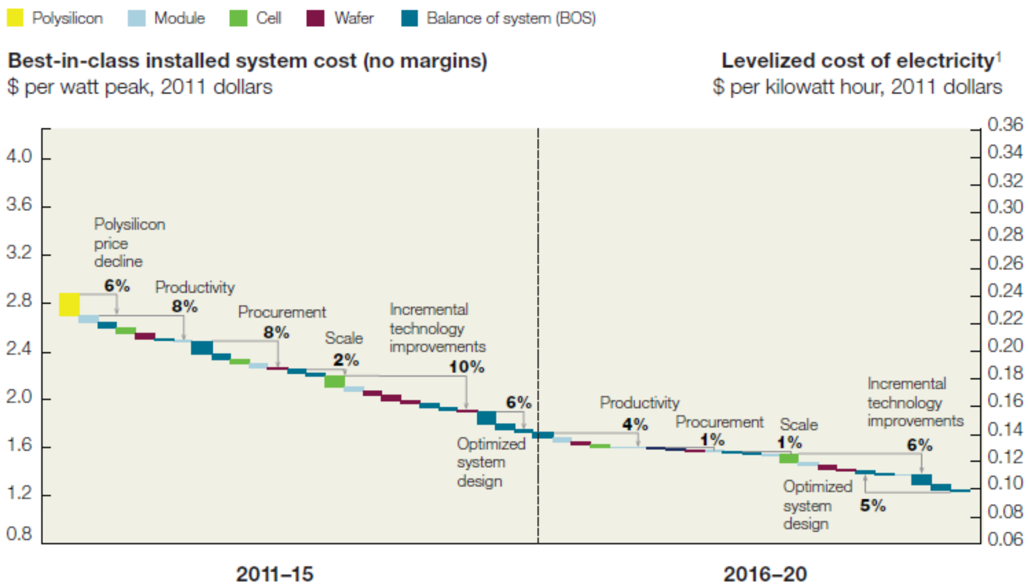
Source: Russel Hensley, John Newman, Matt Rogers, and Mark Shainian, *Battery technology charges ahead*, McKinsey & Company, July 2012.

3.2.3. Installed Cost

Of course, the solar cell and battery storage are not the only component of a solar PV installation, with installation, operating and maintenance costs all important. Considering the installed cost, Figure 3 shows McKinsey's (2012) forecast of cost reductions in the cost of solar PV systems.[8] McKinsey forecasts a reduction of 40% from 2011 to 2015, and a further reduction of over 12% for 2016-2020. Costs appear to be higher for smaller-scale domestic installations, but the same general cost reductions can be expected over time. While Solar PV is a niche technology at the moment, it is highly likely to become a mainstream technology commonly used to generate much of a household's energy needs.

8 Krister Aansen, Stefan Heck, and Dickon Pinner, *Solar power: Darkest before dawn*, McKinsey & Company, May 2012.

Figure 3: Forecast Cost Reductions in Multicrystalline Silicon Solar PV



[1]Levelized cost of energy; assumptions: 7% weighted average cost of capital, annual operations and maintenance equivalent to 1% of system cost, 0.9% degradation per year, constant 2011 dollars, 15% margin at module level (engineering, procurement, and construction margin included in BOS costs).

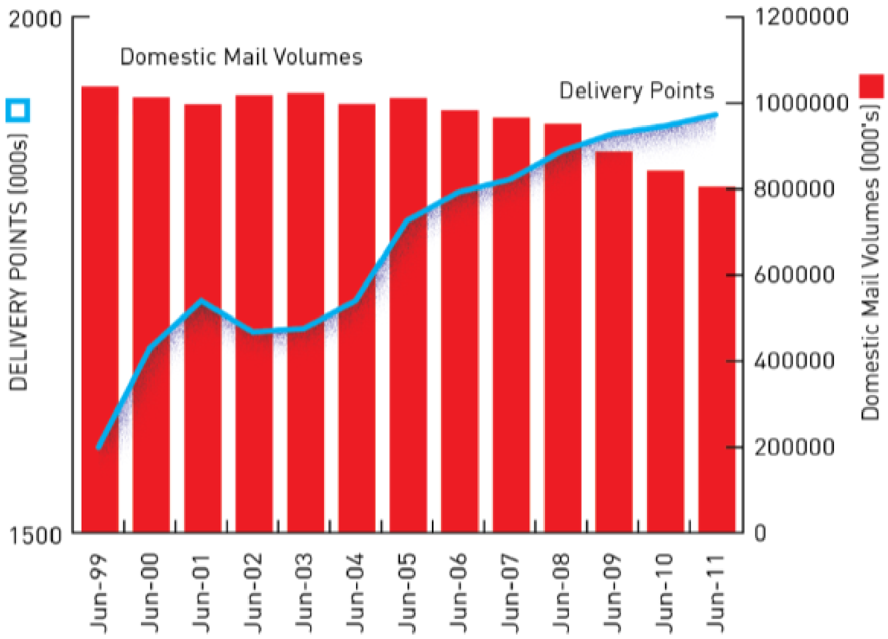
Source: Industry experts; Photon; GTM Research; National Renewable Energy Laboratory; US Energy Information Administration; Enerdata; press search; company Web sites; McKinsey analysis

Source: Krister Aansen, Stefan Heck, and Dickon Pinner, *Solar power: Darkest before dawn*, McKinsey & Company, May 2012

3.3. Of Postal Services and Electricity

Figure 4 shows New Zealand Post's decline in mail volumes over the period 1999-2011. A wise man with 20:20 hindsight could look at Figure 4 and state that New Zealand Post "should have" started to anticipate the structural change in the postal market way back in 2000 when volumes began to fall. Perhaps New Zealand Post staff and management were aware of the impending drop-offs in volume. A read of New Zealand Post Group's most recent annual review certainly shows that strategies are now in place to develop complementary businesses and diversify.

Figure 4: New Zealand Post Decline in Mail Volumes 1999-2011



Source: New Zealand Post, *Proposal by New Zealand Post to Minister for Communications and Information Technology*, January 2013.

Perhaps, though, there was also hope that the initial drop was just temporary and would reverse. Indeed, 2002 and 2003 show growth back to near previous volumes.

The period 2010-2012 for electricity consumption looks very much the same as the period 1999-2001 for postal volumes. Table 5 in the MBIE Electricity Data Tables gives totals of 40,339 GWh for 2010, 39,693 GWh for 2011, and 39,205 GWh for 2012. Perhaps with the forecast “rock star” economy, electricity consumption will continue to grow again. But it seems more likely that consumers have made permanent changes to increase the efficiency of their electricity usage. For example, there have been several years of subsidies for home insulation under the government-funded “Warm Up New Zealand” programmes,[9] and the reduction of electricity consumption from better insulated homes will now be permanent. Similarly, the efficiency of new appliances continues to improve, and public education campaigns are continually educating on the benefits of energy-saving practices, including the use of low-energy light bulbs. Increasing numbers of consumers are also looking to invest in generation, with companies set up to take advantage of the home insulation subsidies now turning to marketing solar PV systems.[10] While volumes may temporarily rise for a few years as the economic recovery takes hold, it seems likely that the longer term trend may be downwards, particularly in areas that are not experiencing rapid population growth.

9 The “Heat Smart” programme insulated approximately 235,000 homes over the period 2009-2013. The follow-up “Healthy Homes” programme is targeting a further 46,000 homes. See http://www.eeca.govt.nz/eeca-programmes-and-funding/programmes/homes/insulation-programme

10 See, for example, Greenstar energy solutions at http://greenstarinsulation.co.nz/solar-photovoltaic/

3.4. Low User Fixed Charge Regulations

The low user fixed charge regulations may effectively provide a cross-subsidy to those residences installing on-site generation and, as a consequence, are likely to exacerbate the problems arising as part of the customer base changes their use of the network to backup only.

When a residential consumer installs on-site generation their net demand will fall, and it is likely that the consumer will move from a standard user category to a low user category. This in turn means that the customer will have a low fixed charge and is less likely to pay the incremental cost of the backup capacity provided by the distribution network. Proper and appropriate pricing of backup capacity requires that the fixed costs of the connection and supporting network are recovered via fixed charges, for the level of backup that the consumer requires.

If network customers with on-site generation are not paying the full incremental cost of the backup capacity that they rely on then there is a cross-subsidy being paid by other customers of the network. By raising the price paid by other customers this raises the likelihood that some of those customers will also decide to install on-site generation.

Solutions to this problem include:

- Reform of pricing regulations so that prices reflect costs (i.e. higher fixed charges);
- Reform of pricing regulations so that the low user fixed charge does not apply to sites with on-site generation (effectively allowing a “backup tariff” to be developed); and
- More effective targeting of discounts at those socioeconomic groups that require them (such as the elderly).

There is political concern in New Zealand at the moment on energy poverty. Better regulation would see discounts targeted solely at those with a need for them, and not for every residence that records low use. Absent regulatory reform, the on-going requirement to offer low user tariffs in their current form will provide consumers with a strong incentive to reduce demand (including via distributed generation) to avoid allocations of fixed network costs.

4. CATASTROPHIC EVENTS

This section provides a brief survey of catastrophic and natural hazard risks that electricity networks face. Earthquakes are an obvious hazard, with potential for catastrophic damage in a number of areas around New Zealand. Those areas that are less prone to earthquake risk tend to be at higher risk from volcanic activity, including areas such as Auckland. Finally, other catastrophic risks are also considered, including IPCC warnings suggest that climate change could also have significant impacts on utility assets.

As discussed later in Section 5.1.3, the current implementation of the DPP and CPP provides incomplete compensation for catastrophic events. While these catastrophic risks, as with market risks, are a separable issue from the WACC percentile, in the absence of any other mechanism to address these risks they provide a further reason to adopt a cautious stance in adopting the WACC percentile. If investors consider that significant losses could occur in the future due to catastrophic events, then the expected return will necessarily be lower than the headline regulatory WACC. For this reason it is important to conduct a review that considers the risks and inter-relationships with other Input Methodologies.

Furthermore, catastrophic events are relevant to the consideration of the benefits to consumers of discretionary investment by EDBs. Investments in network resilience will reduce the impact that the events outlined in this section will have on consumers.

4.1. EARTHQUAKES

The two major Christchurch earthquakes were magnitude 6.3 (Christchurch) and 7.1 (Darfield). In the wake of Orion's experience we may be tempted to assume that the experience in Christchurch is about what would be expected from any catastrophic event. There have, however, been much larger quakes. Figure 6 shows a diagram published by GNS Science of "notable" shallow earthquakes since 1848.[11]

New Zealand's biggest recorded earthquake is the magnitude 8.2 Wairarapa earthquake in 1855. The earthquake education section of GNS' website states:[12]

> *On an international scale, the 1855 earthquake is of major significance in terms of the area affected and the amount of fault movement. About 5000km² of land was shifted vertically during the quake. The maximum uplift was 6.4m near Turakirae Head, east of Wellington. The maximum horizontal movement along the fault was about 18m. This is the largest displacement along a vertical fault line ever recorded!*

11 The definition of "notable" is not provided.

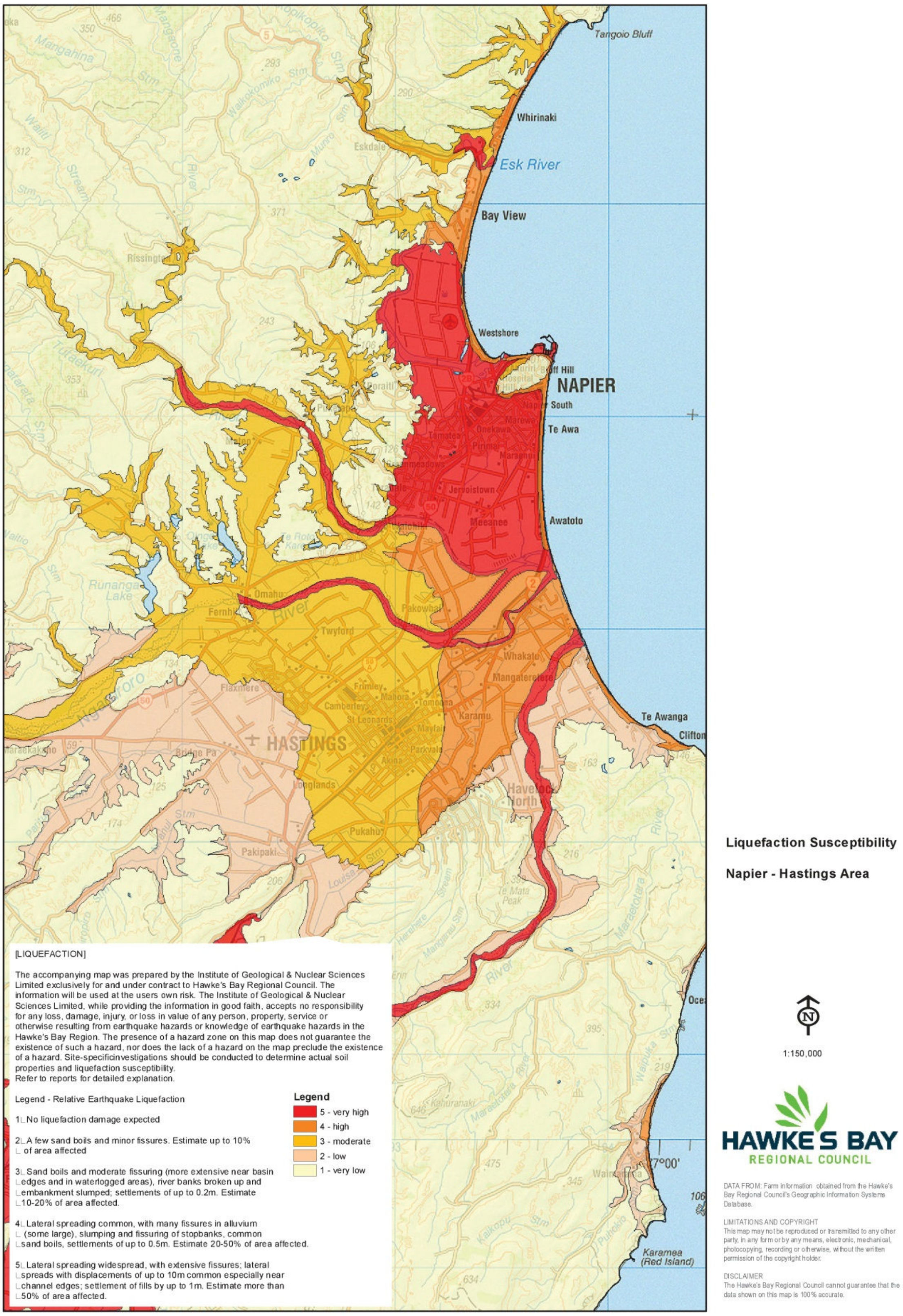
12 http://www.gns.cri.nz/Home/Learning/Science-Topics/Earthquakes/New-Zealand-Earthquakes/Where-were-NZs-largest-earthquakes , retrieved 18 April 2014.

More detailed analysis of GNS data reveals that there have been 237 quakes of magnitude 6.0 or greater in the last 200 years. Based on this limited data set, a quake of 6-7 magnitude can be expected somewhere in New Zealand every year, a quake of 7-8 magnitude can be expected once every 7.7 years, and a quake of magnitude 8 or higher can be expected once every 100 years. Furthermore, a rupture of the Alpine Fault is expected in the near future, with an estimated 85% probability of a rupture causing a magnitude 8+ earthquake in the next 100 years.[13] Magnitude is measured on a logarithmic scale, so a magnitude 8.1 earthquake would release approximately 10 times as much energy as the Darfield earthquake.

Christchurch's experience has highlighted that it is not just the direct damage caused by shaking that is of concern (such as damage to structures and slope failure), but also the liquefaction. Potential for liquefaction varies considerably across New Zealand, with river plains (e.g. Christchurch, Manawatu) and areas that have been raised by previous earthquakes (Wellington, Hawkes Bay) being at significant risk. Figure 5 shows the liquefaction potential in the Napier-Hastings area: not only could significant areas of the network be damaged in a major earthquake, but Napier-Hastings could experience similar issues of population resettlement (and the requirement to build replacement infrastructure) as Christchurch.

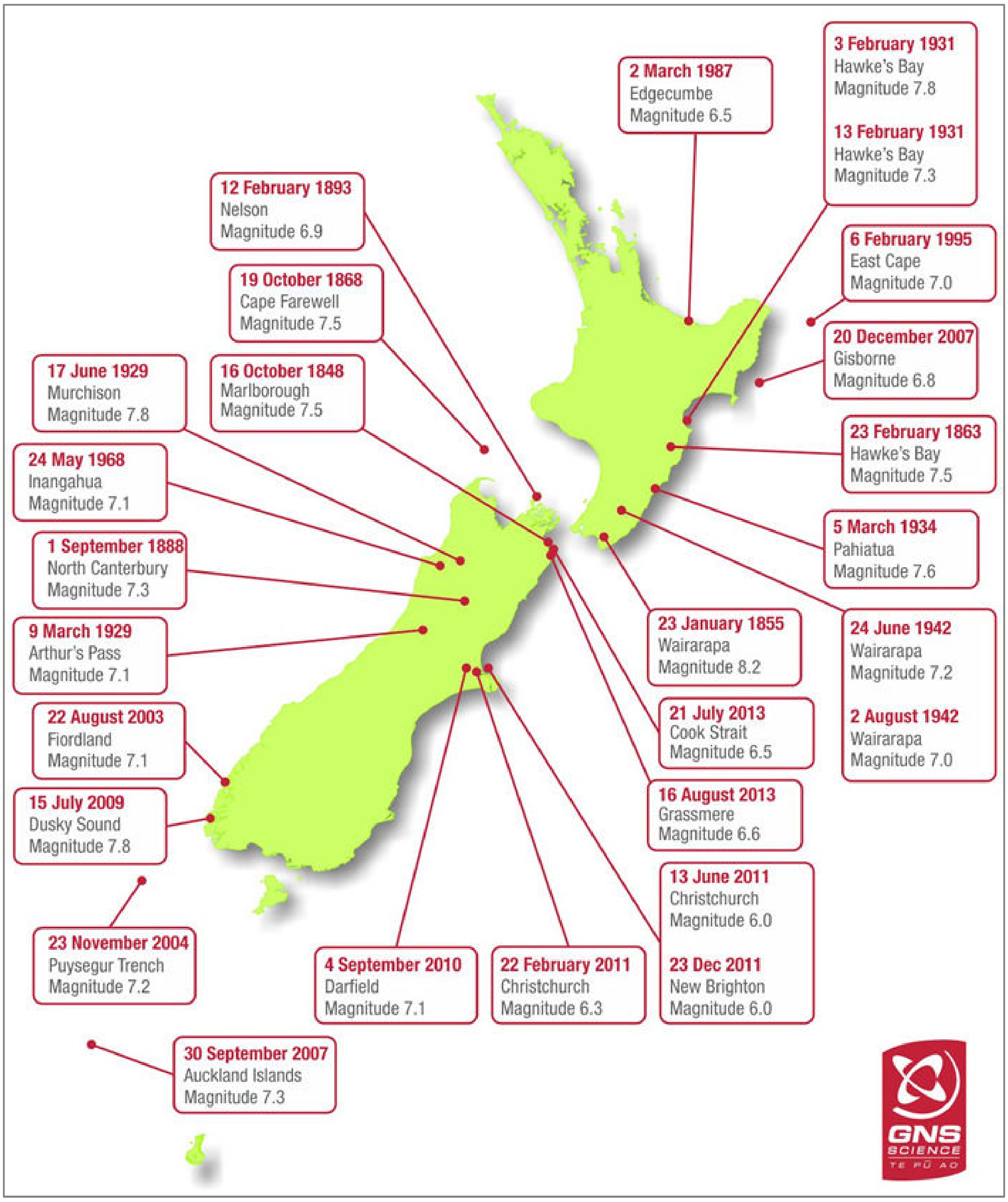
13 Thomas Robinson and Tim Davies, "Potential geomorphic consequences of a future Great (Mw 8.0+) Alpine Fault earthquake, South Island, New Zealand", *Geophysical Research Abstracts*, Vol. 15, EGU2013-255, 2013

Figure 5: Liquefaction Potential in Napier and Hastings



Source: Hawkes Bay Emergency Management, Engineering Utility Lifeline Operators, http://www.cdemhawkesbay.govt.nz/Hawkes-Bay-Civil-Defence-Emergency-Management-Group/Engineering-Lifeline-Utility-Operators_IDL=2_IDT=495_ID=1810_.html accessed 18 April 2014.

Figure 6: Notable Shallow (< 30km deep) Earthquakes Since 1848



4.2. Volcanic Hazards

Areas such as Auckland and Taranaki have a low risk of earthquake-related hazards such as liquefaction, but a much higher risk of volcanic hazard. The Central Plateau (including Rotorua) also face significant eruption risk.

4.2.1. Ground Hazards

So called "ground hugging" hazards from an eruption include lava, ash flows, lahars, and landslides. Figure 7 (page 15) shows the potential ground-hugging hazards for Taranaki, and similar maps exist for the area around Tongariro National Park. Ground hazard maps for other areas are more difficult as the likely location of an eruption is more difficult to predict.

4.2.2. Volcanic Ash

Ground hugging hazards have the potential to damage or destroy small localised areas of a network, as might occur, for example, with a tornado. Much more significant for electricity networks is ash (or "tephra"). The immediate and most common impact of as fall is flashover, an electrical short-circuit across an insulator, which will occur if the ash is moist.[14] In the absence of heavy rain, this requires that all affected structures are cleaned, which could take considerable time and cost in an urban network. Other significant impacts are controlled outages during the ash cleaning, line breakage due to ash loading, and abrasion and corrosion of exposed equipment.[15]

A significant eruption could also see population displacement as has occurred with the Christchurch earthquakes, which in turn would necessitate abandoning part of the existing network and building new infrastructure.

Figure 8 (page 16) and Figure 9 (page 17) show the ash fall hazard zones for an eruption in the Auckland Volcanic Field and Okataina Volcanic Centre, respectively. Note that the Auckland ash fall hazard map is independent of wind direction, whereas the Okataina ash fall hazard map assumes the prevailing wind direction. Different wind directions could result in higher ash fall in Tauranga, or even ash fall in Napier and Hastings.

Figure 10 (page 18) shows the actual distribution of ash falls from the 1995 and 1996 eruptions from Mt Ruapehu, graphically illustrating how wind direction significantly alters the area affected by ash. If the wind in either of the 1995 eruptions had been more westerly then there could have been sufficient ash deposition in Napier-Hastings to cause significant clean-up issues for electricity distribution.

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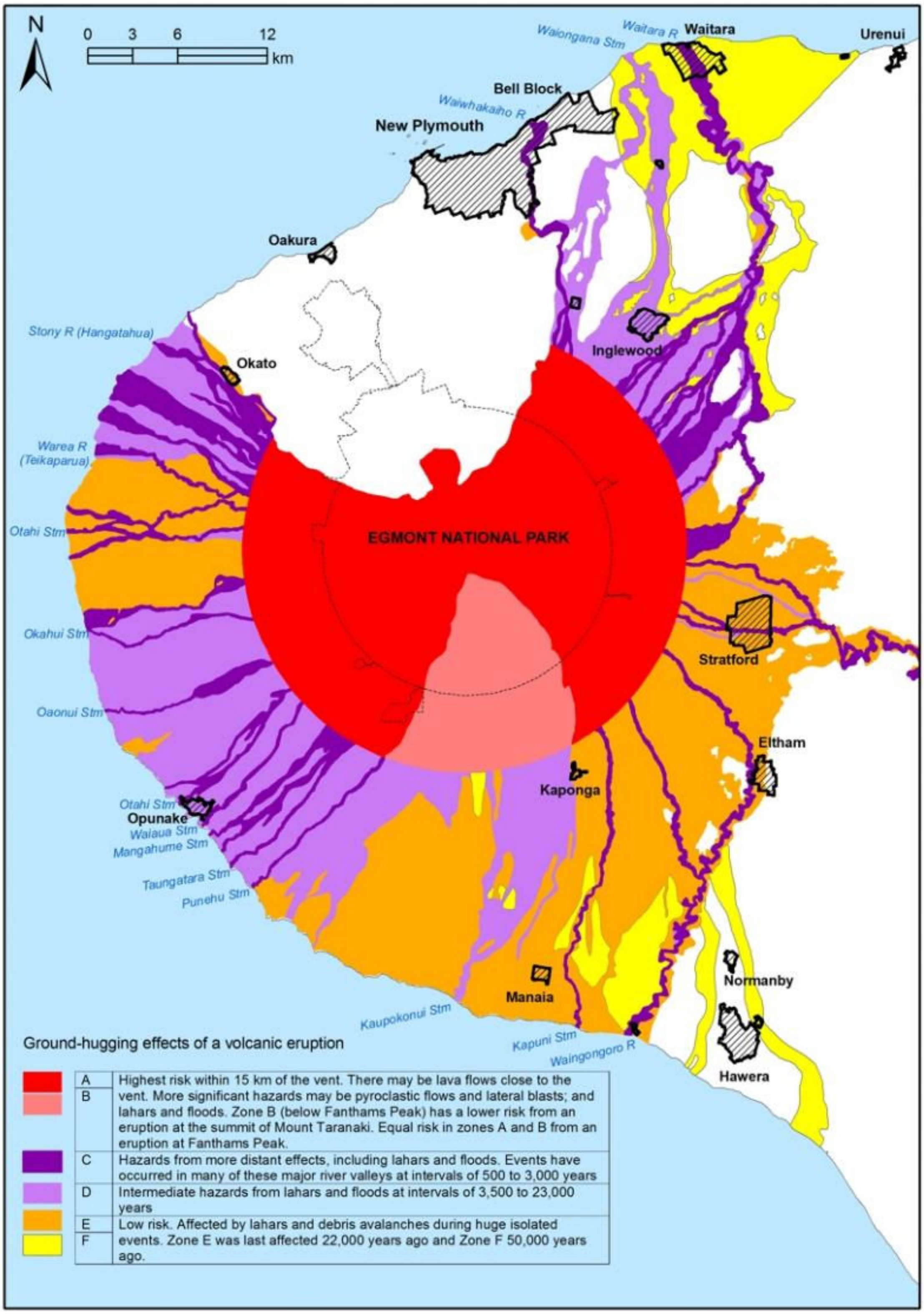
14 Thomas M. Wilson, Carol Stewart, Victoria Sword-Daniels, Graham S. Leonard, David M. Johnston, Jim W. Cole, Johnny Wardman, Grant Wilson, Scott T. Barnard, "Volcanic ash impacts on critical infrastructure", *Physics and Chemistry of the Earth* (2012):5-23.

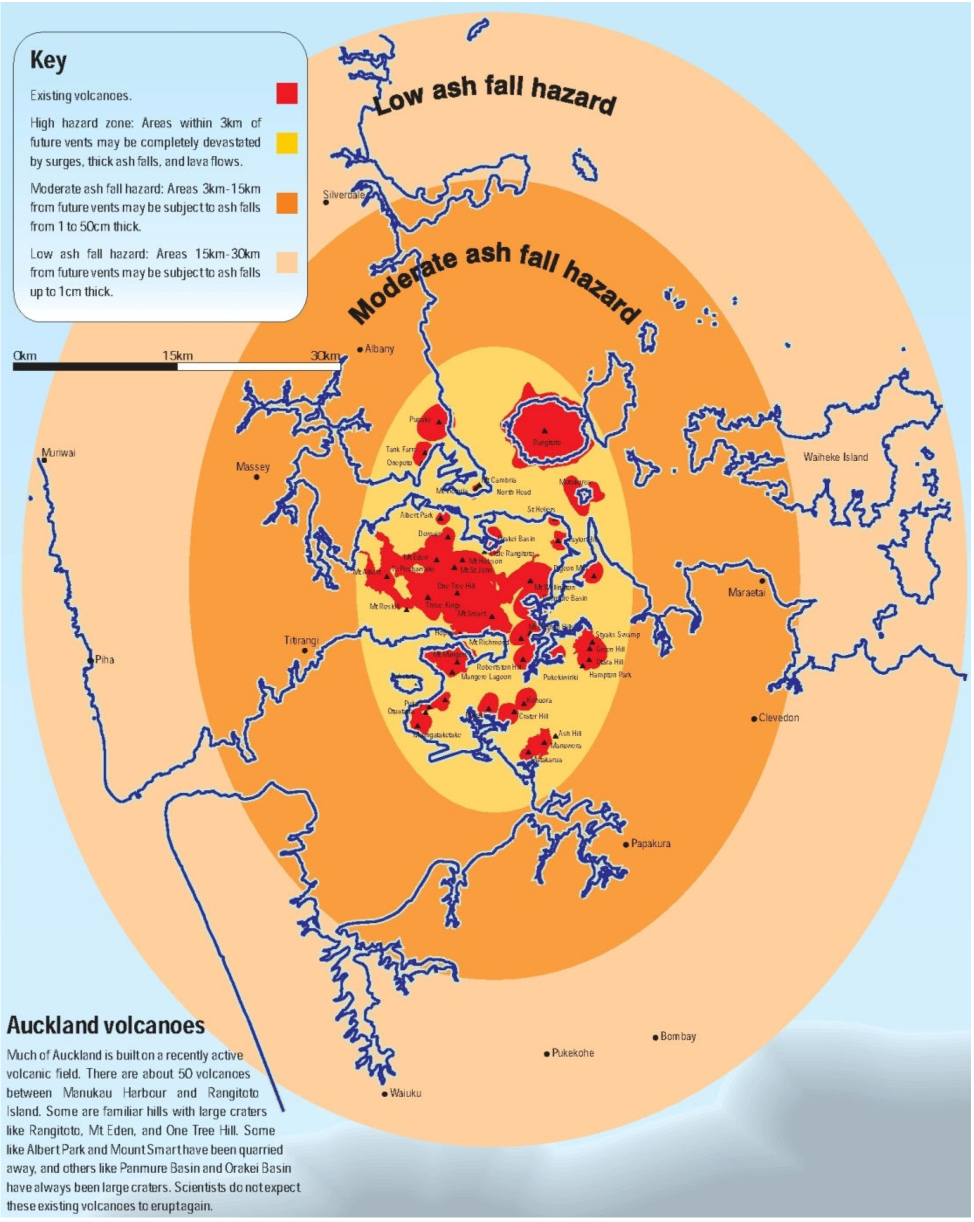
15 Op cit.

Figure 7: Ground Hugging Hazards from an Eruption for Taranaki



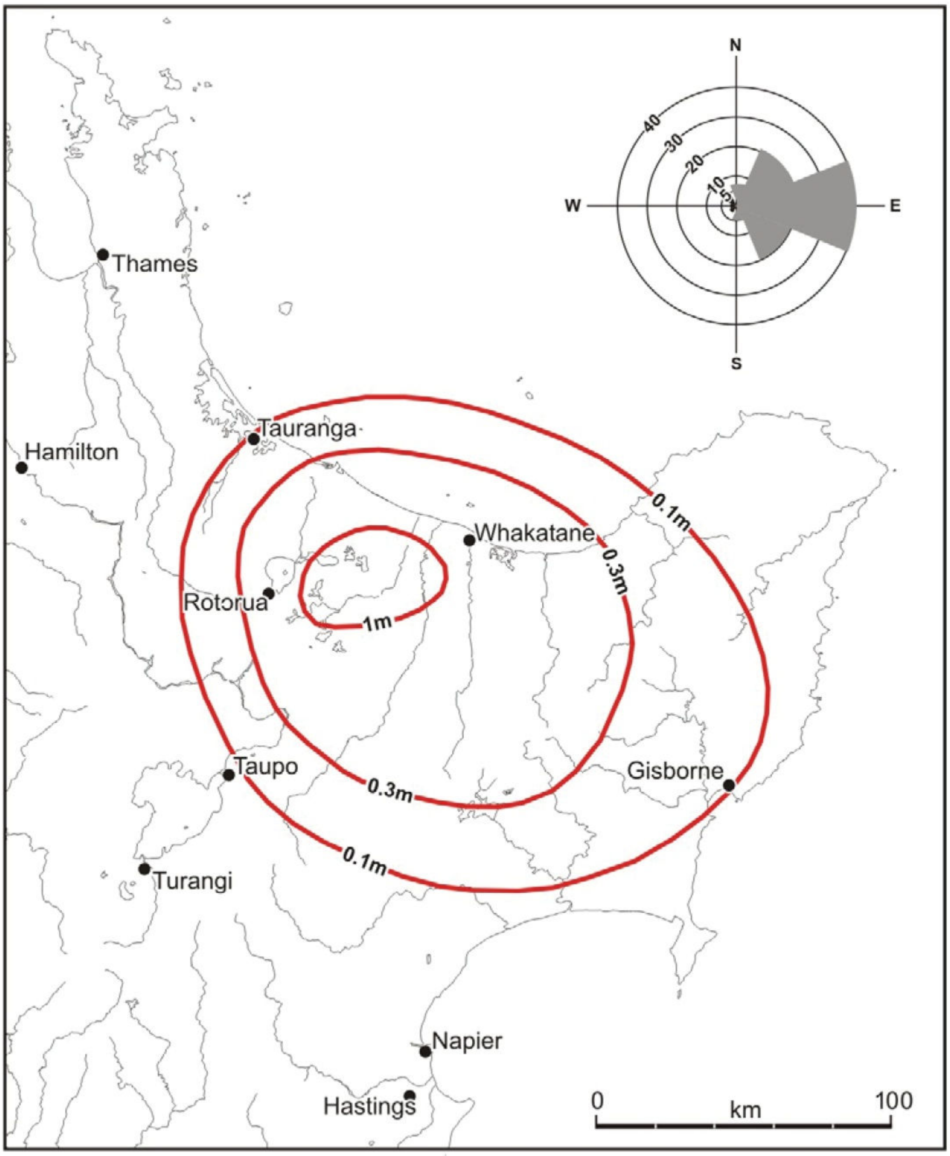
Source: “Volcano Hazard Zones”, Taranaki Regional Council, http://www.trc.govt.nz/volcano-hazard-zones

Figure 8: Auckland Ash Fall Hazard Zone



Source: *Auckland Volcanic Hazards*, Institute of Geological&Nuclear Sciences Limited and the Auckland Regional Council, http://www.seismicsolutions.co.nz/downloads/Auckland-Volcanic-Hazards.pdf

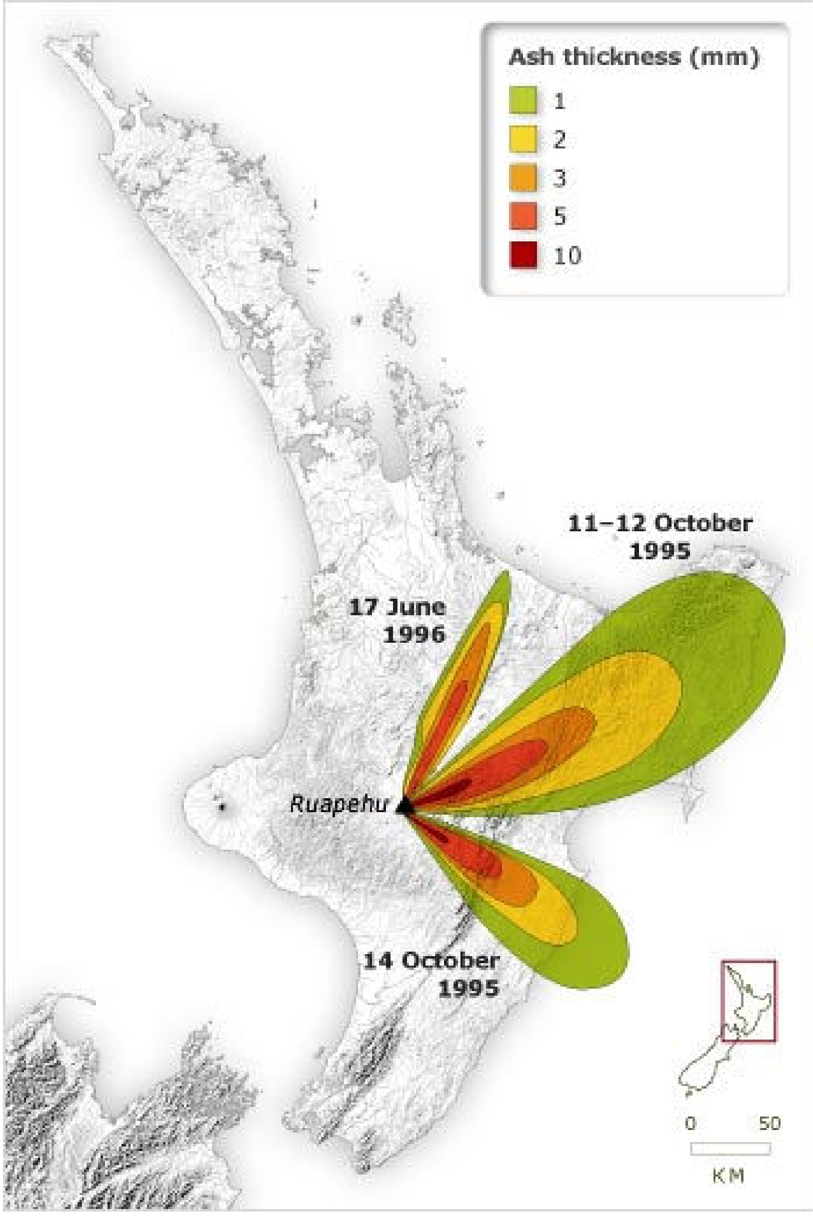
Figure 9: Okataina Volcanic Centre Ash Fall Hazard Zone



Sketch map showing possible thickness and distribution of ash fall deposits from a typical moderate to large scale explosive eruption at OVC (after Nairn 2002). The rose diagram shows typical wind directions and speed.

Source: B.J. Scott, *Rotorua District Council Hazard Studies, Part 1 Volcanic and Geothermal Hazards*, GNS Science Consultancy Report 2010/67, October 2010.

Figure 10: Ruapehu Ash Falls, 1995-1996



Source: http://www.teara.govt.nz/en/map/6881/ruapehu-ash-falls-1995-96 , accessed 20 April 2014.

4.3. Other Catastrophic Events

A range of other catastrophic events are likely, including storm damage (wind, tree falls), landslides, floods, and tornadoes. Some of these events will generally be localised (tree falls, tornadoes), although recent experience with high wind events (e.g. Canterbury 2013) indicates that it can take many days to restore power following such events. Distribution infrastructure will often survive following a flood, provided that water was slow moving. Where water is faster moving it can scour out pole foundations and require pole replacement.

The Fifth Assessment Report from the International Panel on Climate Change (IPCC) includes a chapter specifically addressing expected impacts of climate change in Australasia.[16] The IPCC suggests that some of these adverse weather events may become more common. Rainfall patterns are expected to change:[17]

> *Annual average rainfall is expected to decrease in … the north-east South Island and northern and eastern North Island of New Zealand (medium confidence), and to increase in other parts of New Zealand (medium confidence).*

The IPCC goes on to state:

> *Rising sea levels and increasing heavy rainfall are projected to increase erosion and inundation, with consequent damages to many low-lying ecosystems, infrastructure and housing.*[18]
>
> *…*
>
> *Under a high emissions scenario (RCP8.5), global mean sea level would likely rise by 0.53 to 0.97 m by 2100, relative to 1986-2005, whereas with stringent mitigation (RCP2.6), the likely rise by 2100 would be 0.28 to 0.6 m (medium confidence).*[19]

Estimates of historical mean sea level rise for New Zealand are consistent with global estimates, so it is likely that projections of rises in average global sea level can be applied directly to New Zealand.[20]

In addition to these global changes, parts of the New Zealand land mass are sinking due to geological processes.[21]

> *Regional subsidence, from slow-slip events, has increased the relative sea-level trend in the wider Wellington City area since ~1997. This trend varies across Wellington from subsidence of around 1 mm/year on the Kapiti coast up to between 2 to 3 mm/yr along the Wairarapa coast, but it is not clear for how long this will persist.*

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16 Working Group II, "Australasia", *Climate Change 2014: Impacts, Adaptation, and Vulnerability*, Volume II: Regional Aspects, chapter 25, International Panel on Climate Change, 28 October 2013.

17 Op. cit., p. 3.

18 Ibid.

19 Op. cit., p. 11.

20 R.G Bell and J. Hannah, Sea-level variability and trends: Wellington Region, Prepared for Greater Wellington Regional Council, HAM2012-43, National Institute of Water & Atmospheric Research Ltd, June 2012, p. 36.

21 Op. cit., p. 37.

Put into context, all of this may result in a rise in absolute sea level in the order of 0.1m-0.5m in the next 50 years – the outer extent of the life of typical distribution assets. In some areas land subsidence may add a further rise of around 0.1m.

This sea level rise will mean that areas which currently are at risk at flooding from spring tides and tidal surges will experience much more regular flooding, areas that do not currently flood will begin to flood, and the impact of coastal storms will be more significant.

In summary, the risk of floods in some areas may decrease due to decreased rainfall, while in other areas it is likely to increase due to a combination of rainfall and rising sea levels. Of most relevance to electricity distribution, over time increased flooding may provide the impetus for depopulation of an area, although without the area being declared uninhabitable it is likely that some of the population would remain. Under section 61 of the Electricity Act 1992, electricity distribution networks will be legally required to continue to supply these areas if they were supplied at 1 April 1993. This will place upwards pressure on distribution costs, potentially amplifying the extent to which alternatives to distributed electricity are economically viable.

5. THE RATIONAL INVESTOR RESPONSE

5.1. SUMMARY OF INVESTMENT RISKS

5.1.1. Stranding through Technological Change

Section 3 discussed some of the likely areas of technological change that will affect the electricity industry. The effects of technological change will differ by vertical segment (generation, transmission, distribution, retail). Focussing just on distribution, the following is likely:

- For the near future, distribution will continue to be required for those consumers that do not invest in on-site generation, and to provide peak-support and back-up for those that do have on-site generation;
- Over time, the role of the distribution network may become solely that of providing back-up supply *for those who are prepared to pay for it* (i.e.; some consumers may disconnect entirely from the network);
- Investments in network resilience may lose their value as, over time, resilience is provided by thousands of small generation units distributed throughout the network;
- Capacity enhancements may have a short life as growth in demand reverses;
- Changes in network configuration and protection equipment are required to handle bi-directional flows and voltage issues.

5.1.2. Asset Revaluation in the Presence of Stranding Risk

The lower the up-front cash return that is available to the distribution investor, the more that the investor will seek to avoid investment, particularly when there is a significant possibility of asset stranding. As has previously been submitted to the Commission, these incentives are exacerbated by the use of indexed historic cost for asset valuation, which has the practical effect of deferring cash returns to the future. Counsell and Shelley (2008) showed that if an asset has a 50 year life then by the 30th year of the asset's life un-indexed historic cost has recovered 60 percent of the investment cost.[22] With inflation at a constant 2 percent per annum indexed historic cost has only recovered 27.5 percent of the investment cost. This is a very significant difference in the quantum of the original investment that will be lost if the asset becomes stranded or is otherwise destroyed. Shelley and Thomas (2009) introduce assumptions about the probability of asset stranding and calculate the increase in the rate of return that is required to compensate for stranding.[23] Given the assumptions employed,[24] "in order to achieve NPV=0, it is necessary to increase revenues by approximately 6.22% with [indexed historic cost] and 4.77% with [un-indexed historic cost]" (p. 56).

22 Counsell, K. and A. Shelley, *Comments on Commerce Commission Exposure Draft of Informational Disclosure Requirements*, CRA International, 7 March 2008.

23 Shelley, A. and M. Thomas, *Regulatory Provisions of the Commerce Act*, CRA International, 16 February 2009

24 Shelley and Thomas (2009) assume no stranding risk for the first three years of the asset's life, then a probability of 0.5% per annum until the 10th year of the asset's life, and a probability of 1% per annum thereafter.

5.1.3. Catastrophic Events

Section 4 discussed some of the catastrophic events that could befall electricity distribution networks in New Zealand, particularly earthquakes and volcanic eruptions. Some of the potential implications of climate change were also discussed.

Catastrophic event risk is also under-compensated in the current regulatory model. The Commission has always held out that the CPP intended to cover the unique circumstances of a particular regulated business, including where it "need to invest more in its network than provided for under the default price-quality path or may have been affected by an event outside its control."[25] The Christchurch earthquakes gave the Commission the opportunity to demonstrate to EDBs exactly what this means in practice. The Commission's message was very, very clear:[26]

> *X17 … We do not consider consumers should bear all the risks and costs associated with the Canterbury earthquakes. The ability of investors to diversify their investments means they are generally better placed to manage demand risk of catastrophic events (such as earthquakes) than consumers. In addition, allocating all the costs and risks of catastrophic events to consumers would create a moral hazard (ie, a supplier may take a risky approach to managing catastrophic events, knowing that consumers would bear the full costs after the event if a catastrophe occurs).*
>
> *X19 We consider that the risks of any future catastrophic events should also be shared between Orion and consumers. In particular, Orion should receive ex post compensation for additional net costs incurred in responding to future catastrophic events during the CPP period prior to the re-opened path taking effect, but receive no additional compensation for lower-than-forecast revenues. Ex post compensation for an approved level of additional net costs incurred due to a future catastrophic event is provided for under a CPP re-opener.*

To paraphrase, the best that a regulated business can expect if there is a catastrophic event is to obtain an allowance for the extra costs of re-instating its network. There will never be any compensation for loss of revenues or loss of profits.

The Commission's position means that the regulated firm will absorb the full cost of reduced revenues as and when they occur, but there will be no second-order effect on returns from the requirement to invest to replace assets. Conceptually, this could be thought of as allowing a write-off of damaged assets to be treated as depreciation, with revenues consequentially increased, and no net effect on profits after the initial period of loss.

25 NZ Commerce Commission, "Customised price-quality regulation", Fact Sheet, 23 November 2012.

26 NZ Commerce Commission, *Setting the customised price-quality path for Orion New Zealand Limited*, Final reasons paper – [2013] NZCC21, p. 7.

5.1.4. Potential Material Reduction in Allowed Rate of Return

PWC estimates the post-tax nominal WACC for firms listed on the NZX.[27] As at 30 June 2013, PWC's mid-point estimates are 6.6% for Horizon Energy Distribution Ltd (HEDL) and 6.4% for Vector. As at 29 April 2013, the Commission determined the post-tax nominal WACC for electricity distribution businesses for the 5 years from 1 April 2013 had a mid-point of 5.43% and a 75th percentile of 6.14%.[28] If PWC's estimates are representative of the WACC for EDBs then there is a material risk that even the 75th percentile WACC under-estimates the required WACC.

In addition to the risk that the allowed rate of return under-estimates the required WACC, regulated suppliers also face the on-going risk that there will be a material reduction in the allowed rate of return, whether from the current consultation, a future review, or through the political process. Reducing the allowed return from the 75th percentile WACC to the 50th percentile WACC makes a significant difference to the cash return available to the investor. If inflation used to determine asset revaluation rates averages 2.0% then the 75th percentile WACC of 6.14% equates to a 4.14% cash return, and the 50th percentile WACC of 5.43% equates to a 3.43% cash return. A reduction from 4.14% to 3.43% reduces the cash return by 17.1%. The reduction in total return is less in relative terms (-11.6%), but accounting accruals are cold comfort when significant future asset stranding is a strong possibility, and New Zealand faces a relatively high risk of catastrophic events.

5.2. INVESTOR RESPONSE

The economically rational investor would not continue to invest more and more money in the electricity distribution system, expecting that over the long term and with sufficient revaluations that a normal return will be earned. Instead, the investor would seek to:

- implement some form of insurance against catastrophic events;
- identify areas to reduce investment;
- earn an up-front cash return to reduce the proportion of investment value that is eventually stranded; and
- participate in the technologies that will eventually supplant much of the need for today's networks.

27 PWC, *Appreciating Value: New Zealand*, Edition four, September 2013.

28 NZ Commerce Commission, *Cost of capital determination for information disclosure year 2014 for specified airport services (March year-end) and electricity distribution services* [2013] NZCC 10, 29 April 2013, p. 2, para 2.2.

When considering investment in new technologies it is important to differentiate between investors and the incumbent firms that they currently invest in. History reveals that individual firms are not particularly good at investing in the new technology. From the examples in section 3.1, Eastman Kodak, Digital Equipment Corporation, and Compaq are all companies that sought to participate in the new technology but still failed. Investors are more likely to reallocate their funds away from the incumbent towards an emerging competitor rather than assuming that the incumbent will become successful in the new technology. With pure market-driven investment this would mean that investors would seek to maximise cash returns from the incumbent and reduce the extent to which the incumbent invests in long life assets that have an uncertain future.

Faced with the reduction in cash returns caused by the use of indexed historic cost, the potential reduction in the WACC percentile, and the risks of asset stranding, it would be rational for owners of electricity distribution networks to reduce their capital expenditure. This can be achieved by:

- Reducing discretionary capital expenditure such as investments in network resilience, which may become redundant well before the end of the asset's life; and
- Increasing reliance on capital contributions to fund network growth.

5.2.1. Insurance

Perhaps the real lesson from Orion's CPP application is that regulated firms should seek comprehensive business interruption insurance to cover lost revenues in the months following a major disaster, with the cost of the premiums recovered as normal opex. I understand that such insurance is not available commercially at reasonable rates, so regulated firms should consider establishing a captive or co-operative insurance company. This is still not without risk, as (a) in the initial period of establishing the premiums they will be a cost not forecast by the Commission's models so returns will be depressed; and (b) it is possible that the Commission could seek to disallow such premiums. The regulated firm also faces a very real risk that if a catastrophic event occurs in the early years of such a captive company, then there may be insufficient cover. The Commission has stated that: [29]

> *Should a self-insured risk eventuate during the CPP period, then the supplier will not receive ex post compensation for that event via a reconsideration of the price-quality path.*

A regulated supplier should take this statement at face value. There is no suggestion that the amount of insurance payout will be considered, it is a clear black-and-white statement that if a self-insured risk eventuates then there will not be any ex-post compensation via reconsideration of the price path. Firms are faced with the risk of establishing a company and receiving an inadequate payout after having depressed returns due to premiums, or relying on the Commission's approach in the Orion CPP.

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29 NZ Commerce Commission, *Setting the customised price-quality path for Orion New Zealand Limited*, Final reasons paper – [2013] NZCC21, p. 88.

5.2.2. Reduce Discretionary Capital Expenditure

Regulated suppliers undertake a range of discretionary capital expenditure that is for the benefit of their customers but is not required to meet the quality standards specified in the relevant price-quality path. For example, EDBs may undertake under-grounding of overhead lines. This can improve reliability over time and provides improved amenity value. EDBs may also undertake network reinforcement that improves resilience in the event of catastrophic and adverse weather events. EDBs will continue to comply with quality standards if they do not undertake this discretionary capital expenditure, but the economic gains that were possible (improved quality of supply and resilience, improved amenity value) will be forgone.

5.2.3. Increase Capital Contributions

Capital contributions arise when a utility requires a customer to contribute to the cost of any investment required by their connection. Universal service obligations only apply to existing connections, so the upgrading of connections or addition of new connections is purely voluntary, and the utility can elect to require the customer to contribute to cost when revenue with standard pricing is expected to be less than what is required to recover the cost of the investment.

Typically capital contributions might arise because a customer has specialised or high cost requirements; or because there is a stranding risk (including for new subdivision developments and for industrial customers that might exist at the site for a shorter time period than the life of the assets).

A rational response in the face of declining levels of allowed return and potential disruptive technological change is for the utility to require a greater proportion of investment costs to be covered by capital contributions. If the utility's Board sets a hurdle rate for investment that is independent of the allowed rate of return set by the regulator, then a reduction in the allowed rate of return will directly reduce the revenue expected under standard pricing (e.g. a downwards P0 adjustment), which would then lead to an increase in the shortfall between revenue and cost. Similarly, the prospect of technological change could lead the utility to place a higher weighting on the probability of asset stranding, which in turn reduces the present value of expected future revenues, and requires higher capital contributions.

Increasing the level of capital contributions is an economically rational response for an investor facing increased risk, but it also has the effect of shifting investment from a low cost of capital industry (the regulated utility) to a higher cost of capital industry (the customer).

6. WELFARE IMPACTS

6.1. PRICE ELASTICITY OF DEMAND

The price elasticity of demand measures the ratio of the percentage change in the consumption of a good or service with a percentage change in the price of that good or service. A price elasticity of demand of −0.4 means that for a 1% increase in price there will be a 0.4% reduction in consumption.

The price elasticity of demand for any good or service cannot be directly observed, but must instead be estimated. This is not a straightforward task, as demand can change for many reasons other than just price. For example, in the retail electricity market consumption can change because of the weather, the efficiency of appliances (increased efficiency reduces consumption), increased penetration of certain types of appliances (e.g. air conditioning replacing solid fuel heaters), etc. An attempt must be made to untangle the effects of all of these factors from changes in the real price of electricity.

Deriving a price elasticity of demand is a difficult and complex process, and few estimates have been developed for New Zealand. It is therefore appropriate to consider studies from broadly comparable countries. Table 5 in Appendix A summarises elasticities from Fan and Hyndman (2010)[30] for South Australia, and Berstein and Madlener (2011)[31] for a group of OECD countries. Other studies cited by these two studies are also included. The results from Fan and Hyndman (2010), and the studies cited in that study, are generally supportive of a price elasticity of demand in the range -0.3 to -0.4, with some values outside that range. Bernstein and Madlener's (2011) estimates for the group of OECD countries is consistent with a long run price elasticity of -0.4, with near inelastic demand in the short run. Country-specific results calculated and cited by Bernstein and Madlener provide a much wider range of estimates, but there is no particular reason to choose any estimate as being more likely for New Zealand. Considering the full range of estimates, it seems likely that the best point estimate for a **long run price elasticity of demand for electricity** in New Zealand is −0.4.

6.2. EFFECT OF THE WACC PERCENTILE

The current DPP is set with a 75th percentile vanilla WACC of 8.77%. The 50th percentile WACC is 8.05%. The analysis in this section estimates the effect of the choice of the 75th percentile rather than the 50th percentile on EDB revenues, average delivered electricity prices, and consumption. The deadweight loss from the reduction in consumption is calculated.

6.2.1. Effect on EDB Revenues

The Commerce Commission's financial model of 30 November 2012 can be used to calculate the impact that using the 75th percentile WACC rather than the 50th percentile WACC has on revenue for EDBs. As shown in Table 1 below, the use of the 75th percentile WACC has the effect of increasing revenue by 5.5%.

30 Fan, Shu and Rob Hyndman, "The price elasticity of demand in South Australia", Working Paper 16/10, Department of Econometrics and Business Statistics, Monash University, August 2010.

31 Bernstein, Ronald and Reinhard Madlener, "Responsiveness of Residential Electricity Demand in OECD Countries: A Panel Cointegation and Causality Analysis", FCN Working Paper No. 8/2011, Institute for Future Energy Consumer Needs and Behaviour (FCN), April 2011.

Table 1: Effect of 75th Percentile WACC on Expected Revenue

	2013/14 Expected Revenue ($000)
75th Percentile WACC	1,169,000
50th Percentile WACC	1,108,128
Increase	60,872
Percentage	5.5%

6.2.2. Effect on Average Delivered Electricity Prices

A one percent rise in the price of electricity distribution translates into a much smaller percentage increase in the price of delivered electricity. As shown in Table 2 below,[32] distribution is estimated to contribute around 26% to 32% of the cost of a consumer's bill. A 5.5% increase in the price of electricity distribution will therefore increase electricity prices by around 1.4% to 1.8%.

Table 2: Contribution of Costs to Delivered Electricity Price

	Ministerial Review[33]		Adjusted	EA Fact Sheet[34]	Adjusted
	c/kWh	%	%	%	%
GST	2.5	11%		11.1%	
Retail Cost & Margin	3.0	14%	15.2%	32.1%	36.1%
Meters	0.5	2%	2.5%	2.7%	3.0%
Distribution	6.3	28%	32.0%	23.2%	26.1%
Transmission	1.9	9%	9.6%	7.4%	8.3%
Generation	8.0	36%	40.6%	23.5%	26.4%
Total	22.2	100%	100.0%	100.0%	100.0%

32 The percentage should be read from the "Adjusted" columns, so is 32.0% using the data from the Ministerial Review, or 26.1% using the Electricity Authority Fact Sheet. The two sources have separated out GST as a component of cost, but this artificially lowers the contribution of each source of cost to the final price. GST is a proportional mark-up on all cost items for consumers that are not GST registered, and is effectively absent for customers that are GST registered. In either instance, it is incorrect to separately list GST as a cost item.

33 *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, p. 12

34 Electricity Authority, *Fact Sheet 2: Breakdown of a typical bill*, 26 March 2013, p. 1.

6.2.3. Effect on Consumption

Although the price of delivered electricity will on average be 1.4% to 1.8% higher than it otherwise would, the price change is likely to differ across consumer groups, as the pricing principles allow for an EDB to take price elasticity of demand for different customer groups into account when allocating costs to set prices. In practice this often means that highly price sensitive industrial loads will have non-standard prices and contracts, and as a consequence might not experience the full extent of the average price increase.

Given a price elasticity of demand for electricity of −0.4, the 1.4% to 1.8% increase in average electricity distribution prices would have a long-term impact of reducing consumption of delivered electricity by between 0.57% and 0.70%. This reduction in consumption of delivered electricity will occur via a combination of three mechanisms:

- a direct reduction in consumption of delivered energy, so that less of an economically beneficial activity occurs;
- an indirect reduction in consumption, by (over time) use of more efficient appliances or investment in more efficient processes; and
- substitution away from delivered electricity to another form of energy, which may include an alternative form of delivered energy (such as natural gas, biomass, or coal) or on-site generation of electricity (e.g. solar, use of waste process heat).

Total observed electricity demand is approximately 40,000 GWh per annum. Table 5 in the MBIE Electricity Data Tables gives totals of 40,339 GWh for 2010, 39,693 GWh for 2011, and 39,205 GWh for 2012. It is likely that demand has since increased given the increase in economic activity, so an estimate of 40,000 GWh seems reasonable. The reduction in consumption of delivered electricity would therefore be between 229 GWh and 281 GWh.

6.2.4. Deadweight Loss

The deadweight loss is the reduction in consumer surplus resulting from consumer response to the increase in EDB revenues. Figure 11 below summarises the calculation of the deadweight loss.

The maximum value of the deadweight loss is calculated as 0.5 x reduction in consumption x increase in price. As discussed above, the increase in EDB revenue could be expected to lead to a decrease in consumption of delivered electricity of between 229 GWh and 281 GWh per year. The uplift in EDB revenue equates to $1,522/GWh. Given the estimated parameter values, the maximum deadweight loss is between $174,000 and $214,000 per year.

Figure 11: Calculation of Deadweight Loss from WACC Uplift

		Amount	
Consumption Change	%	-0.6%	-0.7%
Consumption	GWh	40,000	40,000
Reduction in Consumption	GWh	-220	-220
Revenue Uplift	$000	60,872	60,872
Unit Revenue Uplift	$/GWh	1,522	1,522
Deadweight Loss	$000	-174	-214

Deadweight loss analysis assumes that the only change in demand results from less of an economically beneficial activity occurring (i.e. the first bullet above). The other two sources of demand reduction listed above might or might not be more dynamically efficient than continuing to consume electricity delivered via the existing transmission and distribution networks. Given the short time available for this analysis we are not, however, able to assess either the extent to which each form of demand reduction will occur, nor the extent to which each is dynamically efficient. This means that the estimates of deadweight loss calculated above are upper-bound estimates.

6.3. Underground Cables, Fault Rates, and Amenity Value

The undergrounding of distribution lines is one area of discretionary capital expenditure, and the reduction of the allowed rate of return may impact directly on the level of undergrounding. Undergrounding of distribution assets has the beneficial effects of reducing fault rates and improving amenity values.

6.3.1. Fault Rates

Analysis of the information disclosure data for the year ended 31 March 2013 reveals the weighted average fault rates shown in Table 3.

Table 3: Weighted Average Fault Rate by Asset Type

Asset Type	Fault Rate (faults per 100km)
Subtransmission lines	5.42
Subtransmission cables	1.35
Distribution lines (excluding LV)	10.77
Distribution cables (excluding LV)	4.51

Source: ASEC calculations. Fault Rate is calculated as the ratio of total faults to 100km of line or cable across all EDBs. This will equal the weighted average fault rate across EDBs, with weights equal to the km of line or cable owned by each EDB.

Every 100km of sub-transmission line that can be converted to underground cable would, on average, reduce the fault rate on the relevant line from 5.42 faults per year to 1.35 faults per year. Every 100km of distribution line (excluding LV) that can be converted to underground cable would, on average, reduce the fault rate on the relevant line from 10.77 faults per year to 4.51 faults per year. The immediate impact on consumers of such investments requires estimates of:

- The typical number consumers affected by the undergrounding;
- The typical duration of an outage arising due to a fault on the relevant type of asset; and
- An estimate of the Value of Lost Load (see section 6.4 below).

The data for the first two bullet points above is not immediately available. However, I would expect assume that the data should be able to be extracted from EDBs fault reporting systems, so the analysis should be able to be completed in future.

To obtain a more accurate picture of the economic costs and benefits it would also be appropriate to simulate (using monte carlo analysis) to accommodate a range of weather events, wider weather events, and catastrophic events. Cables will have far superior performance to overhead lines in the event of extreme weather events, but may perform worse than overhead lines in certain significant earthquake events. This aspect of the analysis will be more network-specific, but could be conducted by obtaining engineering estimates of the ability of cables to survive particular types of network events in particular locations.

6.3.2. Amenity Value

The amenity value from undergrounding is the perceived value to consumers from not having overhead lines in their neighbourhood. Put another way, the presence of overhead lines imposes a visual cost and the removal of those lines by undergrounding eliminates that cost.

Although the existence of amenity value is widely recognised, there does not appear to be a large body of literature estimating the magnitude of amenity value. One recent study which may be applicable to New Zealand is provided by McNair et al (2010) who estimate the willingness-to-pay for undergrounding in established residential areas in Canberra.[35] McNair et al estimate an average willingness-to-pay of A$6,838 per household, although there is considerable variation across households, including by age and income.

In order for these amenity values to be expressed in a form comparable to the other economic costs and benefits presented in this section it would be necessary to:

- Either convert the amenity value to an annual cost or convert the annual costs expressed in other parts of this report to a present value. This conversion should be performed using a social discount rate rather than the estimated cost of capital for EDBs. With a social discount rate of 4%,[36] a willingness-to-pay of A$6,838 converts to an annual value of A$323.55 (45 years) to A$429.13 (25 years).
- Convert the estimates from Australian dollars to New Zealand dollars, using either an exchange rate or purchasing power estimate; and

The willingness-to-pay could be further adjusted to reflect the average age composition of New Zealand society.

6.3.3. Net Benefit from Undergrounding

A comprehensive calculation of the net benefit from undergrounding would need to take account of the relative capital and maintenance costs of cables and overhead lines, and rely on an estimate of the relationship between the allowed rate of return and the quantum of investment in undergrounding.

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35 Ben J. McNair, Jeff Bennett and David A. Hensher, "Households' willingness to pay for undergrounding electricity and telecommunications wires", Occasional Papers #15 2010, Crawford School of Economics and Government, Australian National University, June 2010.

36 Shelley *et al* (2007) estimated a post-tax real discount rate for New Zealand of 3.5%, with a range of 2% to 6%. For the purpose of the present analysis, this estimate of the social discount rate has been rounded to 4%. See Andrew Shelley, Jeremy Hornby, and Michael Thomas, *Discount Rate for the Grid Investment Test*, 29 March 2007, available online at http://www.ea.govt.nz/dmsdocument/3429.

Even though the effect of the regulatory WACC on undergrounding cannot be quantified at this time, it is reasonable to infer from the differences in fault rates between overhead lines and underground cables that a reduction in the rate of undergrounding will result in fault rates that are higher in future than they otherwise would have been.

6.4. Cost of Non-Supply

The Electricity Authority provides estimates of the cost of non-supply ("value of lost load" or "VOLL") for outages of different duration (10 minutes, 1 hour, 8 hours), for different types of load (residential, small non-residential, medium non-residential, large non-residential), across three different regions (Auckland, Taranaki, Canterbury). The cost of non-supply can vary significantly depending on the precise duration, load type, and location selected.

If discretionary EDB investment is focussed on building resilience, then that resilience is most likely to have an effect with a large scale event (weather, earthquake) that results in a prolonged outage. On that basis, the 8 hour estimates of the cost of non-supply are to be preferred.

The weighted average cost of non-supply for the Auckland region is $14,900/MWh, weighted by consumption across residential, small non-residential, medium non-residential, large non-residential. VOLL for the Auckland region lies between that of Canterbury ($18,690/MWh) and Taranaki ($9,377/MWh).

6.4.1. Equivalent Non-Supply

We can now calculate the annual loss of supply that is equivalent to the deadweight loss from the increase in EDB revenue. Given a VOLL of $14,900/MWh, a cost of $214,000 per annum equates to non-supply of just 14.36 MWh per year. To put this in context, the loss of supply is 0.005% of the reduction in consumption due to the revenue uplift.

6.4.2. Equivalent Change in SAIDI

The non-supply that is equivalent to the deadweight loss can be converted to an approximate SAIDI value to put it into context.

Analysis of the information disclosure data for the year ended 31 March 2013 reveals that the weighted average SAIDI across all EDBs is 111 minutes and 35.5 seconds (weighted by ICPs).

The same data reveals that the average annual consumption is 14.77 MWh per ICP per year. Immediately we see that the equivalent loss of supply of 14.36 MWh per year is less than the average annual consumption of a single ICP. There was an average of 2,076,546 ICPs for the year, so the result is a very small number.

SAIDI is calculated as the total duration of outages across customers divided by the total number of customers. This means that if 1 customer experiencing a 100 minute outage has the same effect on SAIDI as 20 customers experiencing a 5 minute outage. It is the aggregate duration of outages across ICPs that experienced a loss of supply that is the important number.

The average annual consumption of 14.77 MWh/ICP equates to 1.686 kWh consumption per ICP per hour. A loss of 14.36 MWh is equivalent to the loss of 8,518.4 "ICP hours" [= 14.36MWh / (1.686 kWh/ICP/h x 0.001 MWh/kWh)]. These lost "ICP hours" are the same as the numerator of the SAIDI calculation: they are the total duration of supply lost across whichever ICPs have lost supply. Given the average of 2,076,546 total ICPs, the lost ICP hours are equivalent to an increase in SAIDI of 15 seconds (0.0041 hours).

This is a trivial increase in SAIDI that would disappear into the annual variability of outages. It is likely that any negative impact on discretionary investment by EDBs would have a much larger impact than this over time. It is easy to envisage that *not* building resilience into the network could, over time, allow outages to continue to occur that would otherwise been avoided, and in so doing have SAIDI several minutes higher than if such investment had taken place. This illustrates that the costs of not investing (several minutes of SAIDI over time) are much higher than the costs of a higher WACC (15 seconds of SAIDI).

6.5. Increased Capital Contributions

The economic cost of an increase in capital contributions can also be estimated by calculating the increase in the annualised dollar cost of the investment when it is shifted from a low cost of capital industry (EDBs) to a higher cost of capital industry.

For the share market as a whole, PWC estimates a post-tax nominal WACC of 8.4%.[37] Very few firms (eight) have a WACC as low as that of the two EDBs – all other firms have a higher WACC. Of particular note, agriculture and fishing has a post-tax nominal WACC of 10.0%, building materials & construction 11.5%, Textiles & Apparel 14.6%, and Transport 10.0%.

Shifting a distribution investment from an EDB to an industrial customer could result in a very significant increase in the economic cost of the investment. If, for example, a $1m investment is associated with a factory with a 25 year life, financing at the EDB allowed rate of return of 8.77% provides an annual payment of $88,636 (monthly payments). If the cost of the investment is directly borne by the customer, and the customer's cost of capital is 10.0%, the annual cost is $100,562, an increase of $11,900 or 13% over the EDB costs. If the cost of capital is 11.5%, the annual cost is $115,297, an increase of $26,700 or 30% over the EDB costs.

Table 4 overleaf shows the calculation of the quantum of capital contributions required to achieve the same economic cost as the deadweight loss from reduced consumption. Depending on the assumptions, just an extra $6.5m - $18.0m of capital contributions incurs the same economic cost. To put this in to context, in the information disclosure for the year ended 31 March 2013 EDBs disclosed a total of $111.8m for consumer connection and $186.5m for system growth capex,[38] making a total of $298.3m of capital expenditure that could potentially be funded through capital contributions. For the same period EDBs disclosed a total of $81.2m for capital contributions,[39] 27.2% of the potential maximum. An additional $18.0m of capital contributions would increase the total capital contributions to $99.2m, 33.2% of the potential maximum. This is the maximum increase required for the economic costs of additional capital contributions to equal the deadweight loss from the 75th percentile WACC. The magnitude of this maximum increase does not seem unreasonable, and could be exceeded with more stringent capital contributions policies.

37 Supra, note .28.

38 NZ Commerce Commission, *EDB Information Disclosure Requirements, Compendium of completed EDB ID Schedules 1-10 templates*, 29 November 2013.

39 Op. cit.

Table 4: Calculation of Quantum of Additional Capital Contributions Equivalent to the Deadweight Loss ($m)

			Cost of Capital Contributions per $1m	
			Low	**High**
			$11,900	$26,700
Deadweight Loss	**Low**	$174,000	14.6	6.5
	High	$214,000	18.0	8.0

Source: ASEC calculations.

6.6. SUMMARY

Setting the EDB WACC at the 75th percentile results in average delivered electricity prices being around 1.4% to 1.8% higher than if the WACC is set at the 50th percentile. The price elasticity of demand for electricity in New Zealand is likely to be approximately -0.4. Given this price elasticity, the difference in average delivered electricity prices will result in a deadweight loss of between $174,000 and $214,000 per year.

Given a VOLL of $14,900/MWh, the upper bound deadweight loss of $214,000 per annum equates to non-supply of just 14.36 MWh per year, just 0.005% of the reduction in consumption due to the increase in electricity prices. This is equivalent to an increase in SAIDI of 15 seconds over the weighted average SAIDI of 111 minutes and 35.5 seconds.

If EDBs were to reduce discretionary investment, including reduction in non-essential capex for network resilience, SAIDI could be several minutes higher than if such investment had occurred. Fault rates are also likely to be higher where the reduction in discretionary capital expenditure reduces the rate of undergrounding.

Increasing capital contributions could result in economic costs of $11,900-$26,700 per year for each additional $1m of capital contributions. To achieve the same economic cost as the deadweight loss would require EDBs to increase capital contributions by a maximum of $18.0m, taking capital contributions to a maximum of 33.2% of the total amount of customer connection and system growth capex. This is within the bounds of what might be a reasonable increase in capital contributions if EDBs were no longer willing to fund discretionary investment.

7. SETTING THE PERCENTILE

The Commission has the task of setting the WACC at an appropriate point in the distribution of potential WACC estimates. This section addresses a number of issues that the Commission should consider when setting the WACC percentile.

The so called "buffer" provided by the use of the 75th percentile is not a relevant consideration when considering market and catastrophic risk: I understand that the 75th percentile was only ever set on the basis that the economic costs of setting the WACC too low were greater than the economic costs of setting the WACC too high, it was not set to be a buffer against other risks.

Even in the absence of parameter error, the regulated WACC should only be set at the expected midpoint WACC if the cash flow scenario it applies to reflects the expected outcome for regulated suppliers, including market and catastrophic risks. The scenario currently underpinning the DPP is more akin to the best case scenario that a regulated supplier would face, and thus the midpoint WACC would result in an expected return that was less than required by investors or suggested by the market.

These two considerations – (i) economic costs of a WACC too low vs economic costs of a WACC too high, and (ii) market and catastrophic risks faced by regulated suppliers – must both be subject a robust and rigorous estimation process in order to arrive at the appropriate level of WACC for regulated suppliers. As discussed later in this section, such a process necessarily requires the development of a significant body of additional analysis and extensive consultation on some issues.

In my view, the adoption of a conservative approach that sets the WACC at a value higher than the mid-point is supported by the approach adopted by the AER in Australia. While the precise regulatory setting is different, the AER's most recent guideline on the cost of capital has adopted parameters at the top of estimated ranges, in some instances guided by alternative models which suggest higher estimates. The effect of this is that the calculated WACC must be higher than the value that would result from adopting mid-point values for all parameters.

7.1. THE PURPOSE OF THE 75TH PERCENTILE

In its broadest context, setting the regulatory WACC at the 75th percentile of the WACC distribution is appropriate because:[40]

> *the social costs of setting allowed rates of return too low probably outweigh the costs of setting allowed rates too high*

More formally, this approach can be quantified in a "loss function". As noted by the High Court at [1438]:[41]

> *The loss function would estimate the social harm done by overestimating and underestimating the WACC and provide guidance as to where the expected harm would be minimised.*

40 NZ Commerce Commission, *Revised Draft Guidelines: The Commerce Commission's Approach to Estimating the Cost of Capital*, 13 June 2009, p. 52, para. 239.

41 Wellington International Airport Ltd & Ors v Commerce Commission [2013] NZHC [11 December 2013] at [1486].

Although the use of a loss function was never formally adopted by the Commission,[42] the High Court notes at [1464] that:

> *The rationale for the Commission's approach comes closest to having a clear basis … in terms of the loss function that was discussed at the Cost of Capital Workshop. …*

The Court goes on to note the high degree of support for the loss function approach:

> *[1465] The notable feature of the Cost of Capital Workshop discussion, and of related submissions, is the absence of supporting material. There was widespread agreement that the loss function approach was appropriate.*

The Court specifically notes support at the Cost of Capital Workshop and earlier for the loss function approach from Professor van Zijl [1438, 1442, 1465], Mr Balchin [1466], Professor Bowman [1467] and Dr Lally [1467]. The Court concludes at [1470] that there was strong support for "the Commission's approach to the asymmetric costs of over and underestimating the WACC", "including from the Commission's Experts."

The Court also concludes at [1460] that:

> *all the Commission's reasoning points to the choice following from, in its view, unavoidable uncertainties and asymmetric costs being permanent features of the regulatory framework*

This, again, is consistent with the principles underpinning the loss function approach, as the relative costs inherent within the loss function would determine the specific point in the range at which the WACC was set.

The Commission also implicitly supported the loss function approach in its written submissions to the Court on MEUG's two-tiered WACC proposal. At [1435] the Court reports that the Commission considered that the proposal would:

> *offer insufficient protection to consumers from the risk of underinvestment, since the higher WACC would apply for only a short part of the life of assets.*

In other words, part of the reason for selecting any percentile above the midpoint is to avoid the losses that might arise from underinvestment if the WACC is too low. This is an explicit leg of the loss function approach.

In summary, the purpose of the 75th percentile is to set the WACC at a level that recognises the economic costs of setting a WACC too low outweigh the costs of setting a WACC too high. This approach can be formalised as a loss function, and experts for both the Commission and regulated suppliers have consistently supported a loss function approach for determining the appropriate percentile for the WACC.

42 Op. cit., para 242.

7.2. The Irrelevance of the "Buffer"

In the determination on Orion's CPP, the Commission argues that the practical effect of the 75th percentile is to provide a buffer against catastrophic event risk.[43]

I disagree with the Commission's argument for the following reasons:

1. If all of the parameters of the WACC were known with certainty then the 75th percentile would equal the mid-point and there would be no buffer. Regulated firms would continue to be exposed to material market risk (asset stranding) and catastrophic risk, and there would need to be a separate mechanism to compensate for these risks.
2. The purpose of adopting the 75th percentile is to reduce the likelihood that the true WACC is less than the regulated WACC, and hence minimise the likelihood that the relatively larger economic costs of a WACC that is too low are avoided. It is this specific issue – the costs of a WACC that is too low vs the costs of a WACC that is too high – that the Court suggested should be subject to robust empirical analysis. If the 75th percentile happens to be the optimal percentile to minimise the economic costs of incorrectly judging the regulatory WACC, then assuming that regulated firms can recover the costs of market and catastrophic risks from that "buffer" automatically ensures that the *expected* return is less than the optimal percentile.

In short, the two phenomena (parameter error and compensation for risks) are quite different and ideally should be treated as such. The buffer is solely related to parameter error and is irrelevant when considering compensation for market and catastrophic risks.

7.3. Regulation Should be Based on Expected Outcomes

In setting the WACC, there are two issues that the Commission should address:

- The first issue is to select a WACC that ensures the objectives of Part 4 of the Commerce Act are met, and particularly that there are continuing incentives to invest in the relevant networks.
- The second issue is that one-sided or asymmetric risks are appropriately addressed. If these risks are uncompensated they will lower the expected return earned over time, and so will reduce the extent to which the first issue has actually been addressed.

In the best case scenario, an EDB making investments now can expect that from regulatory period to regulatory period it will earn its WACC, such that in approximately 45 years' time it will break even on the investment. Over the course of some regulatory periods there are likely to be returns below the WACC, if for example, CPI is less than forecast, demand is greater than expected, input costs higher than forecast, or Government policy changes impose unanticipated costs. In other regulatory periods returns above the WACC may result from the opposite effects. However, in this best case scenario, if regulatory forecasts are unbiased then the periods of above- and below-WACC returns should balance out and investors are kept whole over the 45 years.

43 NZ Commerce Commission, *Setting the customised price-quality path for Orion New Zealand Limited*, Final reasons paper – [2013] NZCC21, p. 142.

In this best case scenario there is no unmitigated asset stranding (i.e., monopoly status endures) or catastrophic events. EDBs are unable to benefit from potential upsides (e.g., proliferation of electrical vehicles) because the shortness of regulatory periods and the truncation of expected upside returns at each reset. It is only in this best case scenario that setting the regulatory WACC at its midpoint value would result in supplier returns that are expected, over the long term, to equal the WACC.

The Commission has not, to date, explicitly considered the second issue, that of one-sided risks that lower the expected rate of return. There has been no considered analysis of the long-term market and catastrophic risks facing regulated businesses, nor whether those businesses can expect to earn their cost of capital over the longer term. Some limited consideration was given to catastrophic risk in the context of the CPP for Orion, but there has not been a broader consideration of the catastrophic risks faced by the industry. Given that these issues of asymmetric risk have not been addressed within the regulatory framework, it is not reasonable to consider the WACC percentile in isolation of the other Input Methodologies (IMs).

Regulation should be based on expected outcomes not the best case outcome. The *expected outcome* for regulated suppliers is that there will be asset stranding and there will be some catastrophic events. The *expected return* for those suppliers is the return after an appropriate allowance has been made for these adverse events. In order for the midpoint WACC to be the appropriate cost of capital to apply to regulated suppliers, the expected scenario would need to be the same as the best case scenario. Given the market and catastrophic risks faced by EDBs, either the WACC will need to be set above the midpoint or compensation provided by way of an opex allowance. This adjustment is in addition to, and independent of, the analysis concerning parameter uncertainty which suggests that there is a lower economic cost from setting the WACC too high than from setting the WACC too low (Section 6).

7.4. AER's Approach to the Cost of Capital

In previous years expert reports and submissions by regulated companies have drawn the Commission's attention to the "persuasive evidence test" applied by the Australian Energy Regulator (AER) when determining the parameters that should be applied in the calculation of the weighted average cost of capital for regulated entities. The AER described this test as follows:[44]

> *The AER considered that persuasive evidence is likely to include objective and verifiable empirical market evidence and theoretical reasons, so long as they are well founded, which when relied upon suggest one particular conclusion should be adopted over other competing conclusions. The AER considered this may include expert empirical analysis, and expert theoretical reasoning, so long as any expertise given is not outside the expert's areas of expertise. However, the AER further noted that persuasive evidence is not limited to evidence presented by experts (in this sense referring to academics and economic consultants). Persuasive evidence can also be presented by industry stakeholders, consumer stakeholders and the regulator. It is the quality of the evidence not the source which is of relevance.*

44 AER, *Review of the weighted average cost of capital (WACC) parameters – Electricity transmission and distribution network service providers*, Final decision, May 2009, pp.83-84.

Following a rule-change proposal by the AER in 2011, the Australian Energy Markets Commission (AEMC) amended the National Electricity Rules and National Gas Rules in 2012. The AER no longer applies the persuasive evidence test, but instead has broad discretion to consider a range of "estimation methods, financial models, market data and other evidence" when setting the guideline cost of capital for regulated firms. This rule change could, in theory, result in the AER choosing to adopt conservatively low parameters for the cost of capital. However, in practice the AER has in some instances considered a wider range of evidence than was previously prescribed, but has adopted parameters at the top end of the relevant ranges and/or has effectively continued with the persuasive evidence principle.

Judgements that were consistent with the persuasive evidence principle were the term for the return on equity (10 years) and the benchmark credit rating (BBB+). In relation to the term for the return on equity, the AER states:[45]

> *On balance, **we are more persuaded by** the arguments for a 10 year term, than the arguments for a five year term. …*
>
> *We have adopted a 10 year term in past decisions. **Maintaining our previous position, in the absence of good reasons for change, promotes certainty and predictability in decision making**.* [emphasis added]

In respect of the benchmark credit rating, the AER states:[46]

> *We propose to use a benchmark credit rating of BBB+ or its equivalent to estimate the return on debt. Our position is based on:*
>
> - *a single credit rating of BBB+ is consistent with the definition of the benchmark efficient entity;*
> - *the view that credit ratings should be relatively steady for businesses considered to be close comparators to the benchmark efficient entity over time;*
> - *empirical evidence of credit ratings from businesses considered to be the closest comparators to the benchmark efficient entity ;*
> - *a credit rating of BBB+ is **consistent with the previously adopted value**.*
>
> [emphasis added]

For the equity beta the AER adopted a parameter at the top end of the estimated range:[47]

> *we propose a point estimate for beta of 0.7. Our proposed point estimate is **at the upper end of our 0.4–0.7 range**. We have used overseas energy networks to inform our point estimate … these results support choosing a point estimate in the upper end of our range.*
>
> [emphasis added]

45 AER, *Rate of Return Guideline – Explanatory Statement*, December 2013, p. 49.

46 Op. cit., pp. 152-153.

47 Op. cit., p. 86.

The change away from rules that narrowly prescribed a particular form for the cost of equity allowed the AER to consider alternative models. While the AER continued to employ the Sharpe-Lintner CAPM as its "foundation model", it also gave weight to the predictions of the Black CAPM:[48]

> *[U]nder the Black CAPM, firms with an equity beta below 1.0 should have higher returns on equity than what the standard Sharpe–Lintner CAPM predicts. This is because, as a result of different starting assumptions, the Black CAPM predicts the slope of estimated returns will be flatter than for the standard Sharpe–Lintner CAPM. This information informs our proposal to select a point estimate at the top end of the 0.4–0.7 range of empirical estimates.*

In setting the Market Risk Premium that applies under the Sharpe-Lintner model the AER has also selected a point from the upper end of the range, and has even increased its previously adopted value:

> *We note our estimate of 6.5 per cent is a departure from our most recent decisions. In the most recent decisions we have consistently adopted 6.0 per cent.*[49]
>
> *Historical averages of the MRP are widely used by financial practitioners and regulators in Australia. While a point estimate of 6.0 per cent is common, the choice of the averaging period and judgements in the compilation of the data result in a range for plausible estimates of the MRP of about 5.0–6.5 per cent. We consider historical averages the best source of evidence available to estimate the MRP.*[50]

In reaching this conclusion, the AER again considered evidence from a wider range of models that suggested a higher parameter value was appropriate: [51]

> *[W]e give DGM estimates greater consideration than other forward looking estimates of the MRP, such as dividend yields, implied volatility and credit spreads. This reflects our assessment of the relative strengths and limitations of these sources of evidence.*

In all of these examples, the AER has either effectively adopted the persuasive evidence principle or it has for other reasons adopted a value from the upper end of the parameter range. This will potentially result in a materially greater WACC than would result from a mechanistic calculation based on the midpoint of each range.

7.5. Suggested Approach

In my view, the WACC percentile should not be changed independently of consideration of other factors affecting the expected return earned by regulated firms. Two related processes need to be undertaken:

1. A robust empirical analysis of the costs of a WACC that is too high (higher prices causing a reduction in consumption) vs the costs of a WACC that is too low (lower returns causing a reduction in discretionary investment); and

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48 Op. cit., p. 88.

49 Op. cit., p. 95.

50 Ibid.

51 Op. cit., p. 97

2. Analysis of the adequacy of cash flows for regulated firms given a range of potential market and catastrophic risks. If mechanisms are not developed to address these risks then the relevant costs will need to be factored into the analysis in the prior bullet.

In undertaking this analysis, the Commission should be mindful of the approach recently adopted by the AER. Although rule changes no longer mean that the AER is required to apply the persuasive evidence test, in effect it did apply this test. Furthermore, the AER did not mechanistically apply the midpoint of estimated ranges for its model of choice, but instead considered evidence from alternative models that pointed to adoption of an estimate from the upper end of a range.

Section 6 presents a preliminary analysis of the welfare effects of setting the WACC at the current level (75^{th} percentile). The deadweight loss from reduced consumption is straightforward to calculate and could readily be applied at any percentile. What is less straightforward is estimating the costs of reduced discretionary investment if the WACC is too low. Section 6 does not provide a direct calculation, but instead places the deadweight loss into the context of economic losses in the event of supply outages (future SAIDI higher than it would otherwise be if less investment in resilience) and higher capital contributions.

The required analysis is complex and exceeds what has been presented in Section 6 of this report. In order to complete this analysis, it will be necessary to:

- Complete a more detailed analysis of capital investment plans for EDBs to identify what capex is discretionary;
- Develop a linkage between EDB returns and the level of discretionary capex (both customer connections and system growth);
- Model the economic effects of regulated suppliers requiring greater levels of capital contributions;
- Model the effect of lower discretionary investment on future network reliability;
- Model potential technological change within the electricity industry and the impact on asset stranding;
- Conduct engineering studies to determine the likely performance of the network in the event of a range of potential catastrophic events, and hence model the impact of potential catastrophic risks on both EDB returns and expected reliability; and
- Further develop estimates of the economic value of other relevant variables such as undergrounding (being one category of discretionary capital expenditure);

Monte carlo analysis could be used to determine changes in aggregate welfare and the adequacy of cash flows across a range of possible futures, including those where catastrophic events and/or technological change occur. The use of monte carlo analysis for this purpose was used by Shelley and Thomas (2009).[52] Monte carlo analysis of catastrophic events would also be important for determining the effect of future catastrophes on SAIDI in the presence and absence of capital expenditure on network resilience. Scenario analysis could be used to test the impact of technological change.

52 Note 24 supra.

Finally, it is noted that while engineering studies are likely to be relatively robust, employing objective criteria and standard forms of analysis, establishing the link between EDB returns and discretionary capex is likely to be more contentious and require extensive consultation.

APPENDIX A: PRICE ELASTICITY OF DEMAND FOR ELECTRICITY

Table 5 below summarises the elasticity estimates from a range of studies. Estimates are drawn from Fan and Hyndman (2010)[53] for South Australia, and Berstein and Madlener (2011)[54] for a group of OECD countries. Other studies cited by these two studies are also included.

Table 5: Estimates of the Price Elasticity of Demand for Electricity

Source	Country	Sector	Time Period	Estimates
Fan and Hyndman (2010)				
Fan and Hyndman (2010)	South Australia			-0.36 to -0.43, -0.42
Studies cited				
Filippini (1999)	Switzerland	Cities, residential		-0.3
NIER (2007)	Australia	residential	long run	-0.25
		commercial	long run	-0.35
		industrial	long run	-0.38
King and Chaterjee (2003)	Review of 35 studies			average -0.3, range: -0.1 to -0.4
Reiss (2005)	California	residential	annual	-0.39
Bernstein and Madlener (2011)				
Bernstein and Madlener (2011)	Selected OECD (listed below)	residential	short run	-0.05, -0.06
		with country-specific results that vary significantly		
	Austria		long run	ns
	Denmark		long run	-0.87, -0.80
	Finland		long run	-1.03, 0
	France		long run	ns
	Germany		long run	0, -0.16
	Greece		long run	-0.58, -0.56
	Ireland		long run	ns
	Italy		long run	ns
	Japan		long run	-1.36, -1.37
	Mexico		long run	-1.28, -1.16
	Netherlands		long run	ns

53 Fan, Shu and Rob Hyndman, "The price elasticity of demand in South Australia", Working Paper 16/10, Department of Econometrics and Business Statistics, Monash University, August 2010.

54 Bernstein, Ronald and Reinhard Madlener, "Responsiveness of Residential Electricity Demand in OECD Countries: A Panel Cointegation and Causality Analysis", FCN Working Paper No. 8/2011, Institute for Future Energy Consumer Needs and Behaviour (FCN), April 2011.

Source	Country	Sector	Time Period	Estimates
	Norway		long run	ns
	Portugal		long run	-0.80, -0.67
	South Korea		long run	-0.58, -0.66
	Spain		long run	-0.34, -0.30
	Switzerland		long run	ns
	UK		long run	-0.12, -0.14
	US		long run	-0.23, -0.21
	OECD group		**long run**	**-0.38, -0.39**
Studies cited				
Athukorala & Wilson (2010)	Sri Lanka		short run	-0.16
			long run	-0.62
Dergiades & Tsoulfidis (2008)	USA		short run	-0.39
			long run	-1.07
Halicioglu (2007)	Turkey		short run	-0.33 to -0.46
			long run	-0.52 to -0.63
Holtedahl & Joutz (2004)	Taiwan		short run	-0.15
			long run	-0.15
Hondroyiannis (2004)	Greece		long run	-0.41
Nakajima (2010)	Japan		long run	-1.13 to -1.20
Nakajima & Hamori (2010)	USA		long run	-0.14 to -0.33
Narayan & Smyth (2005)	Australia		short run	-0.26 to -0.27
			long run	-0.47 to -0.54
Narayan et al (2007)	G7		short run	-0.11
			long run	-1.45 to -1.56
Zachariadis & Pashourtidou (2007)	Cyprus		long run	-0.43
Ziramba (2008)	South Africa		short run	ns
			long run	ns

Note: ns = not significant (i.e. statistically not significantly different from zero)

APPENDIX B: CURRICULUM VITAE

ANDREW SHELLEY

MA (first class honours) Economics
Massey University

B.B.S. Information Systems
Massey University

Andrew Shelley is a regulatory economist with over 15 years' experience analysing complex economic and regulatory issues for energy-intensive, network and infrastructure industries. His recent work focuses on analysing the firm's response to regulation, including the impact of New Zealand's proposed emissions trading scheme on energy-intensive and emissions-intensive firms, and the impact of formal price control on utility revenues, cash flows, and investment.

Andrew has particular expertise in the electricity and telecommunications industries. He has advised on electricity transmission and distribution regulatory issues such as asset valuation, cost of capital, revenue requirements, pricing structure, and cash flow modelling. In addition to providing regulatory advice he has appeared as an expert witness in commercial arbitrations relating to New Zealand's electricity market, and developed expert evidence for a number of court cases. He has also advised firms in industries such as gas transmission and distribution, forestry, postal services, and rail networks.

Andrew's previous employment includes the positions of Principal at CRA International, Senior Consultant at PHB Hagler Bailly Asia Pacific Ltd, Costing & Economics Manager at Telecom New Zealand Ltd, and Strategic Analyst and Pricing Analyst at Transpower New Zealand Ltd. Mr Shelley is located in Wellington, New Zealand.

Andrew is a member of the New Zealand Institute of Directors and a member of the New Zealand Safety Council.

PROFESSIONAL HISTORY

2013 – **current**	President, Fly DC3 New Zealand Inc Director, Flight 2000 Ltd
2010 – **current**	Director, Aviation Safety Management Systems Ltd Senior Consultant, The Lantau Group
2008 – **current**	Director, Andrew Shelley Economic Consulting Ltd Senior Consultant, Oakley Greenwood Pty Ltd
2008 – 2010	Consultant, CRA International
2001 – 2008	Senior Associate, Associate Principal, and Principal, CRA International
1999 – 2000	Senior Consultant, PHB Hagler Bailly – Asia Pacific Ltd
1998 – 1999	Costing and Economics Manager, Network Group, Telecom New Zealand
1995 – 1998	Pricing Analyst and Strategic Analyst, Transmission Services, Transpower New Zealand Ltd
1995	Analyst Programmer, Foodstuffs (Wellington)
1993 – 1994	Study for Master of Arts
1990 – 1993	Analyst Programmer, Farmers' Mutual Insurance Group

CONSULTING EXPERIENCE

Utility Price and Revenue Regulation

- Advising Vector Ltd on various aspects of pricing for electricity distribution and gas transmission and distribution.
- For Contact Energy, preparation of a report analysing whether the balance of Transpower's "economic value" (overs and unders) account was consistent with what would be expected in a workably competitive market.
- Advising Unison Networks Ltd in its responses to the New Zealand Commerce Commission's implementation of the price control provisions contained in the Commerce Amendment Act. This has included preparation of advice in respect of, and preparation of submissions and expert reports in response to the Commission's consultations on "Regulatory Provisions of the Commerce Act", "Input Methodologies", regulatory taxation, asset valuation, and cost allocation.
- For Energex distribution network (Brisbane), development of a cost-based pricing model for regulated distribution services. This project also included the provision of advice on pricing policy, particularly with regard to developing prices that reflected the impact of demand growth on capital expenditure. Delivery of the pricing model also included provision of a user guide, technical documentation, and user training.
- On behalf of Unison Networks Ltd, preparation of a submission in response to the New Zealand Commerce Commission's initial proposals for resetting the price path and quality thresholds in 2009.
- Advising Vector Ltd on economic issues arising from the New Zealand Commerce Commission's draft decisions on price control for gas distribution services.
- For the Electricity Networks Association, preparation of a submission to the New Zealand Electricity Commission on Transpower's proposed transmission pricing methodology, and on proposed changes to the Benchmark Transmission Agreements.
- Advising a New Zealand generator on the principles of utility revenue requirements.
- Advising a New Zealand utility on issues of cost allocation related to setting regulated prices.
- For Vector Ltd, a detailed financial analysis of the implications of placing Vector under formal price control.
- For a New Zealand electricity lines business, development of a financial model to assess the relative performance of all electricity lines businesses under the Commerce Commission's CPI-X price path vs formal "building block" revenue regulation.
- Preparation of a series of expert reports for Unison Networks Ltd in response to the New Zealand Commerce Commission's draft intention to declare control of Unison, and for use by Unison in its subsequent Administrative Settlement negotiations. This work included analysis of the cost of capital, cash flows, financial ratios, and capital expenditure under various price control scenarios, as well valuation issues.

- An assessment of the costs and benefits of Transpower being placed under formal price control.
- Advising NGC on the calculation of excess profits, including detailed consideration of the theoretical basis for calculating excess profits, arguments on the treatment of gains on sale and the appropriate treatment tax effects.
- Advising a major Asian utility on recent developments in the regulation of infrastructure industries in selected countries.
- Developing a comprehensive financial model for an Australian Distribution Network Service Provider to analyse how the firm's financial performance would respond to different forms of regulation and price and revenue controls.
- Development of a comprehensive simulation model to assess the impact of a wide range of potential regulatory changes on a major Asian utility.

Cost of Capital

- Advising Unison Networks Ltd in its responses to the Commerce Commission's implementation of the price control provisions contained in the Commerce Amendment Act 2008, including advice on the appropriate weighted average cost of capital (WACC) for electricity distribution.
- For the Economic Regulation Authority in Western Australia, providing advice on the WACC to apply to a regulated railway.
- Advising various energy sector clients on the cost of capital appropriate for investment in electricity generation in Australia, Hong Kong, Malaysia, and the Philippines.
- Advising Transpower on the appropriate discount rate for use in the Grid Investment Test.
- Advising an Australasian transmission network owner on the appropriate asset beta for its WACC calculation.
- For an Australian telecommunications operator, advising on the cost of capital and method of asset value annuitisation for a submission to the Australian Competition and Consumer Commission.
- Assessment of the WACC for various activities of a major Australasian telecommunications firm, with particular emphasis on the impact of the regulatory regime. This included a detailed review and critique of approaches to setting regulated rates of return for telecommunications firms in Australia, North America and the United Kingdom.

New Zealand Electricity Market and Transmission

- Analysing the net benefits of Avoided Cost of Transmission payments to Distributed Generation.
- Advising two providers of Distributed Generation in negotiations concerning prices with a distributor.
- Advising a New Zealand electricity retailer and generator on economic issues related to the Ministerial Inquiry into the Wholesale Electricity Market.

- For a New Zealand electricity lines business, providing expert testimony in a commercial contract arbitration on the relationship between transmission charges and embedded generation.
- Advising Transpower on the appropriate discount rate for use in the Grid Investment Test.
- For the Electricity Networks Association, preparation of a submission to the New Zealand Electricity Commission on Transpower's proposed transmission pricing methodology, and on proposed changes to the Benchmark Transmission Agreements.
- Advice on forecast prices in the New Zealand wholesale electricity market.
- For Meridian Energy, analysing the magnitude of the potential benefits that might arise from the Electricity Commission encouraging investment in transmission alternatives.
- For a New Zealand electricity generator, preparation of a report on the economic consequences of short notice extension of transmission outages.
- For a New Zealand electricity market participant, providing a review of the principles of electricity transmission pricing.
- Critique of Transpower's valuation and pricing for a small New Zealand electricity lines business. This work included a detailed revaluation of parts of the Transpower network based on an alternative engineering assessment of the required network assets.
- Development of "opportunity cost" valuations of the power generated by a hydro scheme. The valuations were based on the forecast cost of alternative generation schemes, and included the effects of potential carbon taxes or tradable emissions permits.

Other Projects

- For Pacific Steel, development of a financial model to assess the relative impact on competitiveness of the New Zealand Emissions Trading Scheme (NZETS) and proposals under Australia's Clean Energy Futures Plan (CEFP).
- For the Ministry for the Environment (MfE), quantifying the potential impact of the proposed New Zealand Emissions Trading Scheme on three energy-intensive businesses. This work included the development of spreadsheet-based financial models for each of the three businesses, including separate models for "manufacturing", "full import" and "importation of intermediate product".
- Advising the Inland Revenue Department on economic issues related to tax avoidance litigation.
- Provision of advice on the costs and benefits of converting plantation forestry to dairy farms, including valuation of the impacts on greenhouse gas emissions.
- Providing economic advice and analytical support to the New Zealand Commerce Commission in a Commerce Act s36 case.
- For the New Zealand Ministry of Health, collation and analysis of data on the operating costs of air ambulance services.
- Advising an Australian electricity generator on the market for renewable energy certificates (RECs).

- For the New Zealand Electricity Efficiency and Conservation Authority (EECA), quantifying the benefits of the direct use of natural gas.
- Assessment and valuation of strategic options (including sale and acquisition options) for a New Zealand electricity lines business.
- For an Australian electricity generator, developing a framework for the valuation of easements used by electricity networks, including a review of the regulatory approach to easement valuation.
- For Telecom NZ Ltd, contributing to a number of public submissions to the New Zealand Telecommunications Commissioner, with particular emphasis on incentive effects of regulatory proposals and dynamic efficiency, cost recovery, reasonable rate of return on capital, funding of telecommunications service obligations (TSOs), and accounting for intangible benefits when calculating the cost of TSOs.
- Providing advice on how to adjust for differences in wage rates, cost of capital, and factor intensities in an international benchmarking study.
- Valuation and assessment of a proposed long-term contract for rail transportation, including a review of the approaches to rail price regulation in Australia.
- Review of the process and rules for the New Zealand Government's 2GHz radio spectrum auction.

Selected Public Consulting Reports

Avoided Cost of Transmission (ACOT) payments for Distributed Generation, Final Report, Prepared for the Independent Electricity Generators Association, 31 January 2014.

Cost of Capital and Leverage, Final Report, Prepared for Unison Networks Ltd, 2 September 2010.

Rents, Regulatory Commitment and the Role of Long Term Contracts, Final Report, Prepared for Unison Networks Ltd, 19 August 2010.

Regulated Returns for Australian and New Zealand Electricity Distribution, Final Report, prepared for Unison Networks Ltd, 15 August 2010.

Balance of the EV Account for Transpower's HVDC Assets, Prepared for Contact Energy, 8 August 2010.

Comments on Cost Allocation and the Regulatory Asset Base, Prepared for Unison Networks Ltd, 15 March 2010.

Implementing the Deferred Tax Approach, letter to Unison Networks Ltd, 26 January 2010..

Input Methodologies: Economic Issues, Prepared for Unison Networks Ltd, 13 August 2009.

with Anna Kleymenova and Tim Giles, *WACC for TPI's Iron Ore Railway*, Prepared for Economic Regulation Authority, 11 June 2009.

with Mike Thomas, *Regulatory Provisions of the Commerce Act*, Prepared for Unison Networks Ltd, 16 February 2009.

with Jeremy Hornby and James Mellsop, *Response to Commerce Commission's Discussion Paper: Threshold Reset 2009*, Prepared for Unison Networks Ltd, February 2008.

with Lewis Evans, Jeremy Hornby, and James Mellsop, *Comments on Commission's Draft Decisions Paper on Supply of Gas Distribution Services*, Prepared for Vector Ltd, 29 November 2007.

with Jeremy Hornby and Michael Thomas, *Discount Rate for the Grid Investment Test*, Final Report, prepared for Transpower NZ Ltd, 29 March 2007.

with Erik Westergaard, *Consultation on the Proposed Transmission Pricing Methodology*, Final Report, prepared for Electricity Networks Association, 2 February 2007.

with Jeremy Hornby and James Mellsop, *The Costs and Benefits of Regulating Transpower*, Final Report, prepared for Transpower NZ Ltd, 27 February 2006.

with Lewis Evans, Jeremy Hornby, and James Mellsop, *Cross Submission on the Intention to Declare Control of Unison*, Final, Prepared For Unison Networks Limited, 21 December 2005.

with Lewis Evans, Jeremy Hornby, and James Mellsop, *Review of the Commerce Commission's Intention to Declare Control of Unison*, Final Report, Prepared For Unison Networks Limited, 28 October 2005.

with Michael Thomas, *Net Benefits of Transmission Alternatives*, Final, Prepared for Meridian Energy Limited, 22 July 2005.