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By email: im.review@comcom.govt.nz

Dear Keston

Input Methodology Review

Introduction

Thank you for the opportunity to comment on the draft recommendations in the Input Methodology review (**IM Review**). Contact appreciates the Commerce Commission's (**Commission**) engagement with Contact to date on the IM Review.

Contact acknowledges the difficult task the Commission is faced with in accommodating emerging technology into a regulatory framework that was designed for a very different context. We are encouraged emerging technology has been identified as an issue, but feel more could be done to develop its potential for consumers. We therefore offer a number of suggestions in relation to the Topic papers identified below. Contact supports Input Methodologies (**IMs**) that are fit for purpose, create a level playing field for all sector participants, and which ultimately benefit consumers. This submission sets out Contact's analysis on:

a) Topic paper 1: Form of control;
b) Topic paper 3: The future impact of emerging technologies; and
c) Topic paper 4: Cost of capital issues.

Summary conclusions are provided below, and full analysis is contained in the appended paper.

Form of Control

Contact supports the Commission's proposal to move electricity distribution businesses (**EDBs**) to a revenue cap if it is linked to cost-reflective pricing (which we take to be demand tariffs, and to a lesser extent time of use tariffs, but not capacity charges). Otherwise, a revenue cap with energy-based pricing simply shifts risk away from EDBs onto consumers, without consumers benefiting in response through lower network investment and hence lower lines charges over the longer term. We note that under a revenue cap the rationale for the Energy Efficiency and Demand-side Management scheme will no longer exist, and it should be removed.

Emerging Technology

Contact believes emerging technologies are transforming energy markets by providing consumers with more choice and control over their energy supply. We believe the provision of emerging technology[1] is a fundamentally competitive activity, and should not be regulated. Emerging technologies will provide

[1] Emerging technology is taken to include (but not be limited to) solar photovoltaics, batteries, demand response, electric vehicles and associated infrastructure, and other new energy technologies which can be provided by a competitive market.

maximum benefit to consumers if competitive markets are free to innovate and provide products and services that consumers value. A market-led approach is consistent with the Commission's overall statutory objective to only regulate where there is no, or little prospect of, competition.

a) Asset recovery

Contact is unconvinced that emerging technology will cause consumers to disconnect from the grid at any time in the foreseeable future. As the Commission notes, there is inconclusive evidence that the risk of partial capital recovery has increased as a result of emerging technology. The Commission's proposal for accelerated depreciation, therefore, lacks compelling reasoning, and is not reflective of the risks EDBs face. The cost (even before considering security of supply issues) of grid defection far outweigh the cost of remaining connected to the network, making the possibility of such grid defection virtually non-existent. The proposal to shorten asset lives will raise distribution prices in the short term, resulting in current consumers bearing an increased cost which is unjustified.

b) Regulatory treatment of revenues and costs from emerging technology

Contact believes the draft finding on cost allocation are not in best interests of consumers. We have three key concerns with the draft finding:

- Consumers of regulated electricity lines services will be disadvantaged by higher lines charges;
- Consumers of emerging technology products and services will be disadvantaged as a result of less competition, and less product and service innovation; and
- There is likely to be significant negative impacts on other competitive markets (including spot and ancillary services markets as highlighted by the Electricity Authority (**Authority**)).

The current IM regulatory settings lack the necessary rigour to facilitate EDB regulated investment in new technologies whilst protecting the long term interests of regulated consumers. The cost allocation IM is inadequate and we are particularly concerned with use of the avoidable cost allocation methodology (**ACAM**). Using batteries as an example, ACAM enables an EDB to justify allocating 100% of the battery cost to regulated consumers, despite the battery also generating unregulated income which is retained by the EDB shareholders. Not only does this result in regulated consumers paying higher lines charges, but it creates distortions by enabling regulated monopolies to compete in contestable markets using regulated funding. In the appended report we highlight two examples:

- EDBs have generated $15m in unregulated reserves market revenue since 2009 through use of ripple control systems, with no benefit to consumers who have paid for the systems;
- EDB solar and battery trials are leveraging regulated funding by making all consumers of lines services in the network region pay for the trials; an opportunity not available to competitors.

Material changes to the IMs, including increased regulatory oversight, will be required to improve protection for consumers if emerging technologies are to be regulated assets. The current IMs are suitable for the regulation of traditional monopoly lines services, not emerging technology.

Contact supports EDBs obtaining the benefits of emerging technologies by contracting for network services from third parties, funded through regulated operational expenditure (**opex**) (for example, a third party aggregator of battery storage may provide a peak demand service to EDBs). Contact also supports EDBs investing and competing in emerging technology markets through ringfenced affiliates. The purpose of ringfencing is to create market-like conditions which ensure EDB related businesses operate at arms-length. This will ensure:

a) We avoid information asymmetry between EDB affiliates and third parties, requiring the EDB to disclose information about where emerging technologies can provide network benefits; and hence ensuring equal access to opportunities for all competing network service providers; and
b) Market-based operational and contractual terms are developed between EDBs and third parties, which enable EDBs to benefit from emerging technologies through network services agreements (or through programmes like Transpower's demand response scheme).

Ringfencing will facilitate the development of a vibrant competitive market, benefiting consumers of both regulated services as well as consumers of emerging technology products and services. The Australian Energy Market Commission (AEMC) recently supported this view (see Appendix A), noting in particular:

> *"In the customer-centred future that we envisage for the energy market, the long-term interests of consumers will be best served by retailers and other energy service providers innovating and experimenting to offer products and services that consumers value… the Commission is concerned that allowing regulated entities to enter competitive markets is unlikely to support the development of a competitive energy services market… The ability to leverage regulated revenues, information asymmetries and the ability to discriminate in areas like connection processes would give regulated entities an unfair competitive advantage...* (Achieving this outcome) *requires effective ring-fencing that means that network businesses can't discriminate between their network business or related entities and third party service providers."*

Contact acknowledges ringfencing involves administrative costs, and believes these will be greatly outweighed by the long-term benefits to consumers derived from competitive markets. Regulators in other international jurisdictions, such as Australia and New York, support this view and are currently undertaking structural reform to benefit consumers of both regulated and unregulated services alike. We are concerned that the Commission may have overlooked the need for structural reform without consideration of the costs and benefits. We are also concerned that the requirement to not unduly deter investment by EDBs in the provision of unregulated services[2] may be having an influence which is not in the long term interests of consumers.

The current EDB regulatory model was not designed for the delivery of electricity from generation source to consumers by anything other than traditional poles and wires. We urge the Commission to reconsider its position that structural reform is not required at this stage, and to work with the Authority, Ministry of Business, Innovation and Employment (**MBIE**), and Government Ministers to ensure the opportunity is captured to create fit for purpose regulation to accommodate emerging technology is not missed. In Contact's view, unless the various regulatory/ policy agencies recognise the importance of market structure issues and take action, both regulated and unregulated markets will be affected to the detriment of consumers. Contact supports measures to facilitate reform towards a future-proof regulatory framework, to ensure consumers reap the benefits of emerging technology.

Finally, we believe it is imperative for regulators to act now to protect the long term interests of consumers. Waiting for a market failure before acting risks creating a self-fulfilling prophecy, by deterring investment from non-EDB competing emerging technology providers, whilst at the same time enabling EDBs to leverage their position as monopolies to develop regulated emerging technology businesses. These may become so entrenched that re-establishing a level playing field becomes a very difficult regulatory task.

[2] s52T(3) Part 4, Commerce Act 1986.

Cost of Capital

As expressed in our prior submission[3] we are concerned that market information indicates that cost of capital settings are resulting in consumers paying more for the regulated services than is appropriate. We see this primarily arising through the use of conservative estimates and/or methods for calculating cost of capital parameters, coupled with the additional 67th percentile allowance for above mid-point returns. We do not view such conservatism and resulting excess returns as being in line with the purpose of Part 4, and recommend improvements to estimates and methodologies to better meet this purpose. These improvements include:

- Removing companies whose operations have higher systematic risk from the comparable company set for deriving appropriate asset beta and leverage estimates;
- Using evidence from an improved comparator company set to assess whether there is a differential between EDB, Transpower and GPB systematic risk;
- Setting debt establishment costs in line with the Commission's and submitted evidence;
- Correctly adjusting for illiquid wholesale bonds in the calculation of debt premium; and
- Removing the term credit spread differential (**TCSD**).

In earlier submissions we have also explained our concern with the 67th percentile adjustment. While we acknowledge the significant work in 2014 to reassess this parameter, we believe it unnecessarily creates excess returns, and therefore should not be excluded from any cost of capital review. This parameter creates a clear incentive for EDBs and GDBs to favour capital expenditure over operating expenditure, and disincentives them to contract alternate distribution solutions from third parties. This is concerning in a world where new technologies and business models will provide alternates to poles and wires investment. We recommend the use of the 67th percentile adjustment be reviewed by the Commission, including assessment of other quality mechanisms within its power to address the concern around potential network underinvestment.

These conservative estimates and the use of the 67th percentile result in a substantial cumulative cost for consumers. Correcting for the conservative estimates alone would save consumers over $130m per annum, and including removal of the 67th percentile adjustment would increase this to over $200m per annum.

Finally, we are concerned no reduction in cost of capital has been considered given the proposed change in form of control and accelerated depreciation. Contact see both these changes as NPV positive for EDBs and have noted similar commentary from third party analysts. It would be of concern to us if through these changes value is being shifted from consumers to regulated company shareholders. While we have concerns with both individual charges, if they are adopted, it would be more appropriate for these to be NPV neutral, with offsetting changes in cost of capital.

Next Steps
Contact looks forward to continuing to engage with the Commission on the IM Review.

Yours sincerely

Catherine Thompson
General Counsel

[3] http://www.comcom.govt.nz/regulated-industries/input-methodologies-2/input-methodologies-review/cost-of-capital-im-review/.

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List of Appendices

1. Topic Paper 1 (Form of Control)

Contact supports a revenue cap for EDBs if linked to the adoption of cost-reflective pricing

The Commission has proposed that form of control for EDBs should be moved from a price cap to revenue cap. The rationale for the proposed change is:[4]

- *"it would remove the quantity forecasting risk, and therefore any potentially detrimental effect of that risk on EDBs incentives to spend efficiently;"*
- *"it would remove potential compliance disincentives on suppliers to restructure their tariffs to be more allocatively efficient (although this might be offset to some extent by a reduction in the short term in incentives for efficient pricing provided by a revenue cap):" and*
- *"it would remove a potential disincentive on suppliers to pursue energy efficiency and DSM initiatives."*

We have not seen any evidence of EDBs underinvesting under the current framework. Hence we do not see the above quantity forecasting risk as reason alone to adopt a revenue cap, and shift quantity forecasting risk onto consumers.

However, we agree with the Commission that a revenue cap removes potential disincentives on EDBs to implement more allocatively efficient distribution pricing, given the potential increase in quantity forecasting risk (for example in a demand tariff scenario, a few very cold winter days would be expected to be have a greater impact on peak demand than on annual energy usage). For clarity, we take allocatively efficient pricing to include cost-reflective tariffs like demand (and to a lesser extent time-of-use) tariffs which provide peak signals to consumers about the long run costs of using the network, but not capacity charges.[5]

As a result of the considerations above, we are supportive of a move to a revenue cap *if it is linked to cost-reflective pricing*. We also share the Authority's concern[6] that moving to a revenue cap too early may remove some of the short term incentives on EDBs to move to efficient pricing. As an example, a revenue cap would insulate EDBs from revenue losses during a regulatory period due to falling volumes as a result of solar installations, potentially removing incentives to adopt efficient pricing relative to a price cap.

We do not support the proposed move to a revenue cap if cost-reflective pricing is not in place. Given distribution pricing reform is still at an early stage of consultation, we view this change by the Commission as premature, and potentially costly to other regulation processes and consumers.

There is no need for the Energy Efficiency and DSM scheme under a revenue cap

If a revenue cap is adopted, the Energy Efficiency and Demand Side Management (EEDSM) scheme should be removed. The rationale for the EEDSM scheme was that by taking volume risk during a DPP period under a price cap, EDBs face disincentives to make investments which reduce volume due to the loss of revenue which would result. This risk would be removed under a revenue cap.

[4] IM Review draft decision, Topic paper 1 – Form of control and RAB indexation (Table X1).
[5] With capacity charge being based on a physical capacity measure, such as fuse capacity, line capacity or gross anytime maximum demand over a multi-year timeframe.
[6] EA letter to the Commission dated 30 May 2016, http://www.comcom.govt.nz/dmsdocument/14338.

2. Topic Paper 3 (Emerging Technology), Chapter 3: Risk of partial capital recovery

Contact does not support the Commission's proposal to accelerate capital recovery to EDBs

The Commission has proposed that EDBs will be able to apply to reduce asset lives by up to 15%, effectively accelerating depreciation and hence capital recovery. The rationale for the proposed change is:[7]

- *"Allowing EDBs the option of a more rapid time profile of capital recovery is a precautionary measure to address increasing uncertainty regarding the risk of partial capital recovery;*
- *This proposed change mitigates the risk of potential future price shocks for consumers, which would likely be required to maintain the expectation of ex-ante financial capital maintenance (FCM) if (and when) the downside risk of partial capital recovery becomes more likely."*

We are concerned this proposal is neither justified nor needed due to:

- Lack of evidence of potential economic stranding;
- The Commission itself acknowledging there is lack of evidence to support the proposal; and
- Concern that the cost to consumers has not been correctly assessed.

Contact does not believe there is risk of economic stranding

The Commission has cited the reason for accelerated depreciation as the potential for economic stranding risk, not asset stranding risk (as the IMs allow for assets to stay in the regulated asset base (**RAB**) regardless of their utilisation). Economic stranding risk has been described by the Commission as *"at some future point enough consumers elect to disconnect from EDBs' networks such that the revenue EDBs are able to recover from the remaining customer base is insufficient to allow them to fully recover their historic capital investment."*[8]

The cost of going "off-grid" for an average residential consumer, with solar and batteries for example, is currently ~$120,000 (see example in Appendix B) in contrast to an average annual electricity cost of ~$2,000, due to the need to over-build to manage through days of low solar energy in winter. Even with that level of investment a consumer is likely to have considerably inferior security of supply than being connected to the network. Whilst solar and battery costs will continue to decline, we do not see consumers disconnecting from the EDBs' networks as a reality, now or at any stage in the foreseeable future.

Rather than consumers disconnecting, we see the distribution network as an enabling platform, providing consumers the ability to participate in energy markets to maximise the usage and value of their emerging technology assets (including solar, batteries and electric vehicles).

Lack of available evidence on capital recovery, therefore action is unjustified

The Commission itself has noted that it considers *"the available evidence is inconclusive on whether the risk of partial capital recovery for EDBs regulated business has increased, and by how much.*[9] The Commission's proposal to act at this stage is unjustified given the lack of available evidence, especially as

[7] Above n 4 (Table X1).
[8] Ibid (para 75).
[9] Ibid (para 81).

in other areas, such as ERANZ's proposal relating to the regulatory treatment of revenues and costs from emerging technology, the Commission has stated "*we do not consider ERANZ has provided sufficient evidence…"*.[10] We support further research on the implications of emerging technology on traditional network infrastructure so any measures relating to accelerated depreciation are evidence-based.

The Commission's proposal will result in higher costs for current consumers

The Commission has noted that its proposal is a "NPV neutral" measure. We think this justification is both incorrect, and incorrectly used for this change as:

- It does not explain why today's consumers should have to pay more for lines charges than future customers;
- The granting of an 'option' for EDBs to apply for accelerated depreciation is not an NPV neutral decision. Options are of value to the party that holds them, and a cost to those consumers who bear the potential impact of them; and
- Accelerating depreciation reduces the length of time for the recovery of capital, which in turn reduces exposure to future market, economic, technology and regulation changes. This reduction in risk for EDBs is not "NPV neutral" and has been seen as value positive by investors in EDBs.[11]

[10] Above n 4 (para 173).
[11] Deutsche Bank, Vector – ComCom saves Vector's cashflow (16 June 2016), and Macquarie, Vector – IM Review generally favourable (16 June 2016).

3. Topic Paper 3 (Emerging Technology), Chapter 4: Regulatory treatment of revenues and costs

Emerging technologies will deliver greatest value to consumers through competitive markets

In Contact's submission on the Commission's emerging technologies pre-workshop paper[12] we highlighted that emerging technologies deliver fundamentally competitive activities. The dynamics of competition, rather than regulation, will deliver the greatest value and best long term outcome for consumers from these products. We believe this is the case regardless of whether emerging technologies are located "in front of the meter" or "behind the meter", and regardless of the type of technology (including batteries, distributed generation, and all load control devices including hot water and heat pumps).

We also stated our view that Parliament's intention was for Part 4 to cover the monopoly conveyance service provided by lines companies, and not any other contestable services which lines companies might provide from time to time, including services from emerging technologies with multiple uses. We noted the statement in section 52 that Part 4 provides for the regulation of the price and quality of goods or services in markets *where "there is little or no competition and little or no likelihood of a substantial increase in competition."* Emerging technologies, unlike traditional network infrastructure, can clearly be provided by competitive markets, and hence should not be regulated.

Given the position above, we believe the Commission's draft proposal represents an undesirable outcome for consumers. In the section below we:

- Outline our key concerns with the Commission's draft findings;
- Highlight the negative impacts on both regulated consumers and competitive markets; and
- Recommend regulatory options in addition to the cost allocation IM for the Commission's consideration.

IMs cannot accommodate emerging technologies as regulated assets; the cost allocation IM is not fit for purpose; and structural reform is required

In its draft findings the Commission concluded that the definition of "electricity lines services" can incorporate emerging technologies[13] (we note that emerging technologies would not have been contemplated when the definition was originally drafted). As a result, EDBs can utilise their position as regulated monopolies to fund emerging technology assets and receive a regulated return in the same manner as traditional poles and wires assets. In relation to EDBs using emerging technologies and developing new business models, the Commission concluded that the current IMs can "*deal appropriately with likely developments.*"[14] Contact has a different view. We believe:

- Treating emerging technologies as regulated assets conflicts with the purpose of Part 4; and
- The current IM regulatory settings lack the necessary rigour to facilitate EDB regulated investment in new technologies, whilst protecting the long term interests of regulated consumers.

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[12] http://www.comcom.govt.nz/dmsdocument/14025.

[13] IM Review draft decision, Topic paper 3 – The future impact of emerging technologies (para 193-199).

[14] Ibid (para X7).

We query the Commission's draft finding that: "*the cost allocation IM addresses cross-subsidisation concerns,*"[15] and "*do not consider that the cost allocation IM gives EDBs an undue advantage.*"[16] Please see section 3.1 below for further detail on our views on the cost allocation IM.

We are also concerned that structural changes have not been considered necessary at this stage.[17] We believe proposals for ringfencing warrant serious attention because:

a) There has not been any analysis of the costs and benefits of ringfencing to consumers, which we note in Australia has led to its support by regulators. The Commission noted:

   "We note that it is plausible, if unclear to us at this stage, that the benefits of the above-mentioned economies of scope may be outweighed by the benefits associated with a requirement for market transactions (e.g. cost efficiencies) for delivering the services (both regulated and unregulated) that some emerging technologies can deliver;"[18] *and*

b) Proposals for ringfencing are being influenced by section 52T(3) in Part 4, which, in relation to emerging technologies, we believe may not be in the long term interests of consumers. Emerging technologies were unlikely to have been foreseen when section 52T(3) was drafted (similar to the definition of "electricity lines services"). The Commission noted:

   "s52T(3) requires that our cost allocation IM must not unduly deter investment by a regulated supplier in the provision of other regulated or unregulated services."[19]

We believe the Commission's draft finding will result in undesirable outcomes for consumers. Our key concerns are:

- Consumers of regulated electricity lines services will be disadvantaged as a result of the cost allocation IM and distortions in competitive emerging technology markets;
- Consumers of emerging technology products and services will be disadvantaged as a consequence of less competition, and less product and service innovation in competitive markets; and
- There will be significant negative impacts on other competitive markets (including spot and ancillary services markets as highlighted by the Authority).[20]

We believe the Commission must fully consider three regulatory options for emerging technologies

To ensure the best outcome for consumers, we believe there are three regulatory options for the treatment of emerging technologies that warrant the Commission's close consideration.

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[15] Commerce Commission draft decision presentation, pg. 7, 16 June 2016.
[16] Above n 13 (para 175).
[17] Ibid (para 183).
[18] Ibid (para 165).
[19] Ibid (para 166).
[20] EA letter to the Commission, dated 1 June 2016, http://www.comcom.govt.nz/dmsdocument/14337.

1. Cost allocation IM	2. Related party rules	3. Ringfencing
EDBs obtain benefit of emerging technologies through ownership as regulated assets	EDBs obtain benefit of emerging technologies through contracting as regulated opex	EDBs obtain benefit of emerging technologies through contracting as regulated opex
EDB ownership of emerging technologies subject to cost allocation rules; must allocate costs to regulated and unregulated services	*EDB ownership of emerging technologies precluded, however EDB affiliate can own emerging technologies subject to related party rules*	*EDB ownership of emerging technologies precluded, however EDB affiliate can own emerging technologies subject to ringfencing*

Use of the cost allocation IM and ringfencing are already under consideration by the Commission. Given the potential challenges caused by section 52T(3) in implementing ringfencing, an additional option which may be considered for the treatment of emerging technologies is to rely on the related party rules in the IMs and Electricity Distribution Information Disclosure Determination 2012 (**IDs**). We provide our views on the related party rules in detail in a later section, however, while they are an improvement on use of the cost allocation IMs to regulate emerging technologies, we believe these rules are unlikely to protect the long term interests of consumers. Our recommendation is to consider their use as an interim measure.

We encourage the Commission to:

1. Recognise the IMs and cost allocation methodologies are not fit for purpose for the provision of competitive offerings, such as emerging technologies;
2. Consider using the related party rules for treatment of emerging technologies until wider reform can be undertaking to establish ring-fencing or other pro-competition measures; and
3. Actively work with other regulators to determine appropriate changes to the IMs to promote competitive markets for emerging technologies. We note that overseas regulation precedent is for the use of ring fencing and other structural reform.

Market failure is not in the long term interests of consumers

In its discussion on the ERANZ proposal, the Commission has noted that "*regulators should only consider intervening where there is a market failure*"[21] and repeatedly called for further evidence to be provided for the case to be made for regulators to facilitate emerging technologies being provided through competitive market transactions rather than regulation.

Waiting for market failure before acting risks creating a self-fulfilling prophecy. We believe it is imperative to act now to create a level playing field and protect the long term interests of consumers. Not doing so creates the very real risk of deterring investment from non-EDB competing emerging technology providers, whilst at the same time enabling EDBs to leverage their position as regulated monopolies to develop emerging technology businesses – which may become so entrenched that re-establishing a level playing field in the future may become a very difficult regulatory task.

[21] Above n 13 (para 183).

3.1. Cost Allocation IMs

IMs framework is fit for purpose for regulating monopoly lines services, not emerging technologies

Our submission on the emerging technologies pre-workshop paper,[22] including the Castalia report,[23] highlighted our concerns with using the cost allocation IM to govern the sharing of costs relating to emerging technologies between regulated and unregulated activities. We do not intend to reiterate those concerns in this submission, but rather in the sections below we:

- Provide examples of where use of the cost allocation IM is not resulting in optimal outcomes for regulated consumers, as well as competitive markets;
- Explain why the Commission's proposed changes to the cost allocation thresholds will not fix these problems for new technologies; and
- Describe changes to the regulatory regime which would result in consumer interests being more likely to be protected if emerging technologies are to be regulated.

Cost allocation IM is currently disadvantaging regulated consumers

Existing EDB ripple control systems provide an example of where a regulated asset is being used to generate unregulated income. As a result of the cost allocation IM there is no corresponding benefit to regulated consumers. As shown in the slides included in Appendix C, since 2009 EDBs have generated (and retained for shareholders) ~$15m in unregulated revenue through offering load control through ripple control systems into reserves markets.

The Commission notes in its draft findings that when setting price paths "a*ny future revenue resulting from the use of emerging technologies, and associated with the supply of electricity distribution services, could be appropriately recognised as part of 'other regulated income."*[24] However, this does not consider unregulated income in the case like ripple control where assets are wholly funded by regulated consumers, but unregulated revenue generated is not considered by the Commission.[25]

We see nothing preventing EDBs from treating batteries (and any other potential load control devices) in the same way as ripple control systems, resulting in regulated consumers paying higher prices than if batteries and demand response were provided by competitive market service providers. Alternatively, with third party ownership of batteries and load control the benefits of unregulated revenue would be expected to be passed through to regulated consumers as a result of competition removing excess profits above a normal return on capital. We demonstrate this in slide 4 of the ripple control slides in Appendix C, which shows that with third party ownership of hot water load control, consumers could expect to obtain full value of their controlled load, including the "network value" (through regulated opex) and the unregulated reserves market income, rather than only receiving the network value under EDB ownership.

We agree with the Commission that by accommodating EDB investment in emerging technologies regulated consumers will benefit from lower charges, *relative to EDBs solely investing in traditional monopoly poles and wires infrastructure*. However, for the reasons outlined above, we strongly believe regulated consumers will benefit from even lower charges if there is a competitive energy services market which maximises unregulated income from emerging technologies and, as a result, minimises the cost of network services to consumers (via EDBs contracting through regulated opex).

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[22] Above n 12.
[23] http://www.comcom.govt.nz/dmsdocument/14045.
[24] Above n 13 (para 150).
[25] The Commission's 1 April 2015 DPP Reset financial Model shows that "Other regulated income" (Inputs tab, row 70) is considered in calculating price paths, but not unregulated income.

We are concerned that the Commission's focus on EDB investments in emerging technologies is only on reducing costs relative to EDB investments in traditional infrastructure, with a view that this approach meets its requirements under section 52T(3). We believe further consideration is warranted to determine whether the Commission's proposed approach will indeed result in regulated consumers getting the maximum value available from emerging technologies.

Cost allocation IM is currently distorting competition in unregulated markets

Vector's solar and battery trial in Auckland (the largest of its kind in New Zealand to date) provides an example of where including emerging technologies in an EDBs' RAB and utilisation of the cost allocation IM is distorting competition. The article in Appendix D provides an overview of the trial:

- Over 250 systems in trial
- Customers provided with a 3kW solar system and 11.6kWh battery
- Estimated total system cost ~$30,000[26]
- Customer upfront payment $2,000, ongoing payments $840pa for 12.5 years ($12,500 total)
- Estimated customer savings up to $1,000pa[2]

Whilst the customer payments contribute a small amount towards the cost of the system, the majority of the cost of the system is funded through the RAB, as shown in Vector's 2014 electricity disclosures. Schedule 6a and Schedule 14 (see Appendix E) show capital expenditure relating to a "Quality of Supply" project of $3.4m for a Solar PV program.[27] The effective result is that all regulated consumers of electricity lines services in the network region fund the balance of the individual customer trial systems through higher lines charges (and it is unclear whether this expenditure represented better value for regulated consumers than traditional poles and wires upgrades).

We query the Commission's assertion that "*we do not consider that the cost allocation IM gives EDBs an undue advantage.*"[28] In our view the ability to fund solar and battery projects in this way provide EDBs with a clear advantage over non regulated competitors for numerous reasons, including:

- For a non-regulated competitor to undertake a similar trial, they would need to have funded 100% of the cost of the solar and battery assets, and not receive a guaranteed return on that funding;
- A non-regulated competitor undertaking a similar trial would also have needed to agree a demand response contract with Vector to access the network value provided by the battery operations; and
- In addition to the cost of the solar and battery assets, it can cost millions of dollars to develop an emerging technologies sales platform. A non-regulated competitor needs to raise capital and take risk on building a sales platform, whereas an EDB will receive a guaranteed return on such investment because it is simply part of delivering the regulated service (with electricity lines services being provided by solar and batteries).

We note that although the example above is based on a customer solar and battery trial, we believe the same issues are present for all emerging technology assets, regardless of whether located "in front of the

[26] Contact analysis, including battery enabling full utilisation of solar energy to offset electricity imports.
[27] We also note that the cost allocation (schedule 5d) and asset allocation (schedule 5e) disclosures are consolidated and do not provide information on how emerging technology assets are allocated (if allocated). In addition the reports supporting the allocations (schedules 5f and 5g) are not made public.
[28] Above n 13 (para 175).

meter" or "behind the meter", and regardless of the type of technology (including batteries, distributed generation and all load control including hot water[29] and heat pumps).

In our view, there is a serious risk that by enabling EDBs to unfairly leverage their monopoly position as a provider of regulated services into emerging technology activities, competing providers will be deterred from entry as they cannot compete on terms available to EDBs. This has the potential to result in emerging technology markets being the exclusive domain of EDBs, which over the long run will result in less price competition, less product and service innovation, and less efficient utilisation of emerging technology assets. Ultimately this would result in consumers having less choice and obtaining less value from emerging technologies than what could be provided by a competitive energy services market.

Whilst we appreciate that issues relating to competitive markets are not directly within the Commission's jurisdiction, we encourage the Commission to revisit its position that structural changes are not necessary at this stage. We believe further consideration by the Commission is justified, including working with other parties including the Authority and MBIE to review whether current regulatory settings will maximise the benefits of emerging technologies for consumers of both regulated and unregulated products and services.

Proposed changes to Cost allocation IM will make an immaterial difference

We have previously highlighted our concerns with ACAM in our submission on the pre-workshop paper. Using batteries as an example, an EDB can justify allocating 100% of the battery cost to regulated services, despite providing a mix of regulated and unregulated services as a result of its full discharge capacity being used from time to time for network purposes (like ripple control, or any load control system for that matter).

By our calculations, EDBs are able to invest in hundreds of millions of dollars of batteries under the ACAM methodology (further details below). This provides the ability for regulated monopolies to operate in contestable markets using regulated funding. As highlighted by the Authority,[30] this has the potential to seriously distort competitive market outcomes. The Authority's primary concern was the impact on spot and ancillary markets. We are also concerned with the impact on:

- Regulated consumers obtaining maximum benefit from emerging technologies;
- Nascent markets providing emerging technology products and services to consumers; and
- Investment by non-EDBs in emerging technologies at "grid-scale".

To limit usage of ACAM, the cost allocation IM utilises three thresholds which determine whether EDBs can use ACAM to allocate costs between regulated and unregulated services: [31]

- Revenue materiality threshold 20% (if an EDB is below this threshold ACAM can be used to allocate operating costs and asset values, regardless of the thresholds below);
- Operating costs materiality threshold 15%; and
- Asset values materiality threshold 10%.

The Commission's draft findings on emerging technologies include a table which calculated current materiality threshold values for each EDB, for each of the three thresholds (see Appendix F). The Commission has proposed lowering the revenue materiality threshold from 20% to 10%. As shown in the

[29] For clarity we are not proposing existing EDB generation and load control assets (including ripple systems) be removed from RABs, but believe to facilitate competitive demand response markets and maximise consumer benefits, new assets should be provided by non-regulated energy service providers.
[30] Above n 20.
[31] Electricity Distribution Services Input Methodologies Determination 2012, Section 2.1.2.

Commission's table, this will only impact one EDB, being Counties Power who is between 10-20% on the revenue threshold and currently using ACAM for both operating costs and asset values, whilst being above both the operating costs and asset values thresholds.

Regardless of whether the revenue threshold is 20% or 10%, EDBs can still use ACAM for asset values if they are under the 10% asset values threshold. The Commission's table shows that all networks, with the exception of Counties Power, are under the 10% asset values threshold. As a result of the asset values threshold, EDBs are able to invest in a very material amount of emerging technology assets whilst using the ACAM methodology. For example:[32]

- Vector could invest in up to $260m of batteries under ACAM;
- Powerco could invest in up to $130m of batteries under ACAM;
- Orion could invest in up to $100m of batteries under ACAM.

We also note that even if an EDB is above the ACAM thresholds, the IMs enable the EDB to elect to use OVABAA instead of ABAA.[33] OVABAA is in place as a cost allocation mechanism to prevent EDB investment in other goods and services (including unregulated activities) being unduly deterred by the use of ABAA (as a result of the section 52T(3)). The practical impact is that OVABAA enables EDBs to reduce any asset value or operating cost which was allocated to the unregulated service using ABAA, back to what would have been allocated to the unregulated service using ACAM. Given the ability of EDBs to subjectively determine what allocation is required to not unduly deter investment (regardless of the underlying business performance of the EDBs unregulated activities), in our view ACAM can effectively be used in any scenario, regardless of the cost allocation thresholds. This effectively removes any limit on the amount of batteries or other emerging technology assets which an EDB can invest in under ACAM.

Material changes to the regulatory regime are needed to increase protection for consumers if emerging technologies are to be regulated

As a result of the concerns we have with the use of ACAM, in our pre-workshop paper submission we proposed using ABAA as a single approach given it most closely allocates capital and operating costs to the services which those costs relate. The Commission has stated a preference for reducing the revenue threshold from 20% to 10% as it "*minimises the additional compliance costs that might be incurred by requiring a larger number of suppliers to change their accounting systems to support the change in cost allocation approach.*"[34] In our view a thorough assessment of the costs and benefits of using ABAA as a single approach is warranted, including whether section 52T(3) is having an adverse impact by retaining cost allocation methodologies which are not in the best interests of consumers.

Whilst the use of ABAA rather than ACAM in relation to emerging technologies would increase protection for consumers, we firmly believe competition, rather than regulation, will best serve consumer interests in relation to emerging technologies. This is especially the case in New Zealand, due to the "light-handed" nature of the regulatory regime in place for EDBs. In our view, if emerging technologies are to be regulated, consumer interests are likely to be more protected under a regime with robust regulatory oversight, including but not limited to:

- Capital expenditure based on detailed assessment rather than the use of historical benchmarks;
- Operating expenditure based on detailed assessment rather than the use of historical benchmarks;

[32] The Commission's table appears to only consider electricity related asset values, whereas the IMs suggest that the threshold analysis should also consider other regulated services in aggregate (such as gas). As a result, the battery investment numbers calculated above for Vector and Powerco would be influenced by assets related to other regulated services (and in fact would be materially higher once other regulated assets are considered).

[33] Above n 31 (section 2.1.2.4(c)).

[34] Above n 13 (para 116).

- Investment tests for growth capex, including requiring an assessment of non-network solutions;
- Investment tests for replacement capex (noting a rule change underway in Australia);
- Non-network options reports to be published for third parties when considering investment; and
- A shared asset mechanism enabling unregulated revenue to be shared with regulated consumers.

It is clear that the current EDB regulatory framework, including the cost allocation IM, was not designed with emerging technologies in mind. Whilst we commend the Commission on proposing changes to the cost allocation IM to increase protection for consumers of regulated services whilst accommodating emerging technologies within the regulatory framework, we do not believe tightening the cost allocation rules will make any material difference to the adverse impacts which regulating fundamentally competitive activities will have on regulated and unregulated consumers.

In our view the current framework remains "fit for purpose" for the assets it was intended to regulate – monopoly lines services. We believe consumer interests will be best served by regulating monopoly lines services, rather than incrementally reforming the cost allocation IM to accommodate emerging technologies.

3.2. Related Party rules

Use of the related party rules would be a better outcome for consumers than the cost allocation IM

Given the shortcomings identified in the previous section relating to use of the cost allocation IM for emerging technologies, consideration of more structural change is warranted. In its draft finding the Commission cited section 52T(3) as a barrier to implementing ringfencing reform.[35] An option which does not appear to have been considered to date is to preclude EDB ownership of emerging technologies as regulated assets, and rely on the existing related party requirements in the IMs and IDs to promote a level playing field and prevent regulated suppliers from extracting excessive profits. This option is more likely to meet the requirements of section 52T(3) than implementing ringfencing rules.

The related party provisions are already widely used by EDBs, including for construction and maintenance related activities. Related party transactions accounted for a third of operating expenditure ($155m in related party transactions) and one quarter of capital expenditure ($179m in related party transactions) declared by EDBs, GDBs and GTBs under ID in 2015.[36] Given administrative costs have not undermined efficiencies for such a large volume of activity, it is reasonable to suggest that the related party rules would also not present a barrier to EDBs contracting for network services from affiliates.

Due to the light-handed nature of the related party provisions, this option will have negligible impact on EDBs' ability to access any economies of scope which might have been available through ownership of emerging technologies, which can be accessed through network services contracts with related parties.

This approach has advantages for regulated consumers over EDB ownership of emerging technologies, including, but not limited to:

- Avoiding regulated consumers funding 100% of emerging technologies and not benefiting from unregulated income (under ACAM), as in principle there is no reason a contract between an EDB and a third party needs to cover more than the competitive value associated with the regulated service;
- Avoiding regulated consumers taking the risk of locking in particular technologies by transferring this risk to a third party, as the third party will fail to renew a network services contract if the technology fails to perform or is rendered obsolete (for example, a network deciding to rollout a single battery option rather than the market deciding between numerous battery options).

The approach also has the potential to improve competition in the supply of emerging technology products and services (both at "network scale" and "behind the meter") by:

- Requiring the EDB to disclose information to a third party about where emerging technologies can provide network benefits;
- Requiring operational terms to be defined between the EDB and a third party (ideally governed through a bilateral contract), similar to existing ripple control arrangements with consumers (for example, a network may be able to load control for up to 4 hours in a 24 hour period); and
- Requiring a price signal to be created between the EDB and a third party for the network value.

The extent to which competition is improved in the supply of emerging technology products and services will largely depend on the effectiveness of the related party requirements in the IDs creating a level playing field (including price, terms, availability and transparency of network services contracts) between

[35] Above n 13 (para 166).
[36] IM Review draft decision, Topic paper 7 – Related party transactions (para 25.3).

EDB related parties and competing external energy service providers. We comment on the related party rules in a section below.

Third parties can provide network services from emerging technology assets

Arguments that suggest the promotion of emerging technology markets are dependent on EDBs investment are ill conceived. We note the statement below made by the ENA in their submission on the Commission's emerging technologies pre-workshop paper:

> *"Potential benefits of restricting ENB investments in emerging technologies are unclear. In fact, it may be detrimental as the market may not emerge at all if ENBs are not active."*[37]

It may be that this view was formed due to a lack of visible activity in battery markets from gentailers and independent energy service companies at the time, relative to battery trials underway by EDBs. In our view, this is a direct result of the regulated funding advantages which EDBs receive, enabling business models and battery trials to be funded by regulated consumers.

We firmly believe that with regulatory settings in place which promote competition, a vibrant energy services market will develop, with the ability to provide network services to EDBs. This then enables regulated consumers to take advantage of the costs of emerging technology. We note the following recent activity:

- Solarcity is providing storage as a service, with Panasonic batteries providing capacity to Transpower's demand response program;[38]
- Contact is undertaking battery trials on the Orion network, with aggregated control enabling the batteries to be automatically dispatched based on signals from both Orion and Transpower to reduce network peak demands;
- Genesis has announced residential battery storage trials with Enphase;[39] and
- Numerous independent solar companies are also providing battery storage.

In addition to activity in New Zealand, network service provider business models[40] are being developed (both "network scale" and "behind the meter"). AES and AGL Energy provide just two examples:

- AES is the largest owner of energy storage in the world with 136MW operational and 228MW under construction or in late stage development, and is a third party provider of primary and secondary frequency regulation, reserve capacity and other network services to both regulated and open market "merchant" entities;[41]
- AGL Energy has a New Energy division which provides battery storage to customers and is building a network services business model.[42] A demand response trial in early 2016 with 68 customers aggregated control of air conditioners as a minimum 25kW virtual power plant providing a reduction in peak demand in area of United Energy's network experiencing load growth.[43]

The Commission should be wary of arguments by EDBs that there are constraints which require in-house investment over contracting with a third party, such as the statement below by Unison. In our view,

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[37] www.comcom.govt.nz/dmsdocument/14027.
[38] http://www.solarcity.co.nz/blog/media-releases/sunny-weather-attracts-wellington-solar-storage-power-system/.
[39] http://newsroom.enphase.com/releasedetail.cfm?releaseid=935389.
[40] For example, a third party aggregator of battery storage may provide a peak demand service to EDBs.
[41] Statement provided by AES via email, 26th June 2016.
[42] http://www.slideshare.net/informaoz/marc-england-agl-energy.
[43] https://www.agl.com.au/about-agl/media-centre/article-list/2016/march/agl-trials-impacts-of-emerging-technologies-on-the-grid-and-energy-bills.

battery and demand response control system technology is already very sophisticated, and provides a greater level of control than ripple control systems which currently provide network services to EDBs.

> *"an EDB may prefer to provide battery storage solutions in-house because of the degree of control, coordination and integration necessary to achieve desired network outcomes."*[44]

Related party rules are unlikely to protect the long term interests of consumers

Effective related party rules are essential to protect the interests of regulated consumers and prevent distortions in competitive markets. We agree with the Commission that the existing related party rules could function better:[45]

> "*We have limited visibility of related party transactions on the non-regulated entities' side. Combined with regulated suppliers' level of control over related party transactions, we are concerned with the risk that suppliers may be able to generate excessive profits under the current rules."*

We note that the related party rules state that for the purposes of disclosure, the cost of a service acquired from a related party must be based on one of six defined methods.[46] We assume that the intent is for actual transaction pricing to match disclosure pricing. Of the six defined methods, we are particularly concerned with (d) which enables the price paid to be determined with full discretion by the EDB, so long as the following thresholds are met:

- The value of transactions with the related party is less than 1% of total regulated revenue; and
- The value of all related party transactions is less than 5% of total regulated revenue.

Based on the Commission's cost allocation threshold analysis (see Appendix F), below is an example of the value which be contracted with the price at full discretion by the EDB:[47]

- Vector can contract up to $6m of network services from a single related party ($31m in total);
- Powerco could contract up to $4m of network services from a single related party ($18m in total);
- Orion could contract up to $3m of network services from a single related party ($14m in total).

This quantum of related party contracts not only has the potential to have an impact on regulated consumers, but has the potential to have a very material influence on developing competition in emerging technology markets. As an example, an EDB affiliate could provide battery storage as a service to homeowners, with the battery providing a service to both the regulated EDB and the homeowner. It would be up to the EDB to determine what price it pays the EDB affiliate for network services. This could be set at a level which recovers the full battery cost for the EDB affiliate over the term of the service agreement with the homeowner, with the EDB able to treat the cost as directly attributable to the regulated service. This would then enable the EDB affiliate to provide the storage as a service product to the homeowner at a very low cost (possibly zero), making it very difficult for unrelated third parties to effectively compete with the EDB affiliate if they are not able to obtain comparable network services contract terms from the EDB (noting that there would be no requirement for the EDB to make the contract terms available to third parties).

Vector's Treescape business provides an example of the level of disclosure which would be required in this scenario (see Appendix G). For the year ended March 2015, Vector acquired $3.9m in vegetation

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[44] www.comcom.govt.nz/dmsdocument/14041.
[45] Above n 36 (para 25.4).
[46] Above n 31 (section 2.3.6).
[47] Ibid (section 2.3.6(1)(d)).

management services from Treescape, with disclosure limited to a single line with a description and the total value.

The related party rules may be an interim measure, but long-term will be problematic in their current form

We believe this pricing mechanism, and the level of disclosure required, are unlikely in the long term to:

- Avoid information asymmetry between EDB affiliates and third parties;
- Create a "market" based price signal for the network value obtained from emerging technologies.

This would prevent third parties competing on level terms, and be to the detriment of both regulated consumers, as well as consumers of emerging technology products and services in competitive markets.

In our view the related party transaction rules were not designed with emerging technologies which can provide a mix of regulated and unregulated services in mind. We are also concerned that if the related party rules were an enduring mechanism for emerging technologies, the Commission's only concern would be whether the rules are having a material impact on the price paid by consumers of regulated services, without regard to potential distortions in competitive markets. For these reasons, and the concerns raised previously in this section, we have only recommended these as an interim measure and believe ringfencing or similar provide a better long term solution.

3.3. Ringfencing

Ringfencing can create a competitive market with information symmetry and market price signals

Given the issues highlighted in relation to use of the cost allocation IM, or the related party rules to regulate emerging technologies, further consideration of the costs and benefits of ringfencing is warranted. The primary objective of ringfencing is to ensure that related businesses operate at arms-length. This has many advantages (which were discussed at length in our previous submission), of which two key benefits include:

- Avoiding information asymmetry between EDB affiliates and third parties. Ringfencing provisions usually include rules relating to "restriction on use of information" (section 11 of Schedule 3 of the Electricity Industry Act provides an example). If in place, these rules would prevent an EDB from disclosing information to an EDB affiliate in the business of supplying emerging technologies if that information is not available to competitors or potential competitors of the EDB affiliate, and is likely to give the EDB affiliate a material advantage relative to competitors or potential competitors. This would ensure that competing third party providers receive equal access to information relating to opportunities for emerging technology network service contracts to be used in place of EDB growth and replacement capex (traditional "poles and wires" infrastructure); and

- Ensuring "market" based terms and conditions (including price) are utilised for contracts between EDBs and network service providers. Ringfencing provisions include rules relating to "arms-length dealing" (section 2 of Schedule 3 of the Electricity Industry Act provides an example). If in place, these rules would prevent an EDB from entering into a transaction with an EDB affiliate if the terms of the transaction would not have been agreed to if the EDB and its affiliate were acting independently and in their own best interests. As a result, these rules are far more likely than the related party pricing and disclosure requirements in the IMs to create a competitive market and price signal for the network value obtained from emerging technologies. In addition, to reduce transaction costs associated with bilateral contracting, these provisions are likely to incentivise EDBs to create demand response programs (like Transpower) which would reduce barriers to entry for smaller market participants.

Creating information symmetry and "market" price signals is likely to lead to a material increase in competition, benefiting consumers of both regulated services as well as consumers of emerging technology products and services.

International regulators are implementing structural reforms to promote competition

International regulators are increasingly recognising the role of structural reform in ensuring consumers obtain the full benefits of emerging technologies. Australia and New York provide two examples:

- The AEMC, initially through its Power of Choice review, which recommended a package of structural reforms to give consumers more choice about the way they use electricity, has been a strong advocate for the separation of regulated and competitive sectors for the benefit of consumers. More recently in August 2016, the AEMC commented (see full speech in Appendix A):

  "Our preference for competition over regulation and our desire for a clear separation between the regulated and competitive sectors isn't just an issue of ideology. It reflects our concerns about the potential damage to the long-term interests of consumers from a lack of such separation."

To implement the AEMC's position, the Australian Energy Regulator (AER) released a positions paper in April 2016 for an electricity ringfencing guideline.[48] Ringfencing is already in place in Australia between network services (poles and wires) and electricity retailing and generation, with no threshold exemptions like the 50MW and 75GWh caps applied in the Electricity Industry Act in NZ. The AER's guideline (if implemented) would extend ringfencing to all contestable services, including metering, connection, and emerging technologies such as battery storage. The AER paper also notes that the objectives of the ringfencing guideline review include providing *"clarity and certainty in the market for new investment"*, and *"providing a level playing field for all parties providing energy services."* In the positions paper the AER states:

> *"Ring-fencing protects the long term interests of consumers by ensuring efficient costs for regulated services provided by networks."*
>
> *"The ring-fencing guideline will support the development of these markets by separating regulated monopoly services from services offered competitively."*

In our view, given the differences between the regulatory regime in Australia (which is more akin to the Transpower regime with a higher level of regulatory oversight) and the light-handed regime in place for EDBs, structural reform like the AER proposal is even more necessary in New Zealand than in Australia.

- The New York Public Service Commission (PSC) in February 2015 approved Track One of its Reforming the Energy Vision (REV) program. Track One aims to restructure existing regulated network utilities, retaining their existing function as distribution owner/operator, as well as creating a new function as a Distributed System Platform Provider (DSP). Part of the DSP's responsibilities will be managing and running new Distributed Energy Resource (DER) markets contemplated by the REV (a loose parallel is Transpower's dual roles as transmission owner/operator as well as System Operator, but at the distribution level). As part of the structural reforms, DSP's will be restricted from DER ownership (including battery storage). The PSC stated in its approval order:[49]

> *"…because of their incumbent advantages, even the potential for utility ownership risks discouraging potential investment from competitive providers."*
>
> *"REV provides utilities the opportunity to be both the "wires" company and the platform that enables a market for DER resources."*
>
> *"As a general rule, utility ownership of DER will not be allowed unless markets have had an opportunity to provide a service and have failed to do so in a cost-effective manner."*

We note that many stakeholders raised concerns on the regulated network utilities undertaking both the distribution asset owner/operator role and the market operator role, believing that an independent market operator would remove any potential conflict of interest in designing and administering DER markets which effectively compete with further distribution network investment. However the PSC noted that the approach would be impractical in light of the timeline in which they hope to overhaul the energy system.[50]

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[48] https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/electricity-ring-fencing-guideline-2016/initiation.

[49] NYPSC, Order adopting regulatory policy framework and implementation plan (February 26, 2015).

[50] http://www.greentechmedia.com/articles/read/New-York-Calls-for-Utilities-to-Accelerate-Distributed-Energy-with-New-Plat.

Benefits for consumers must be considered when assessing the costs associated with structural reform

The Commission should be wary of arguments which suggest that establishing and monitoring a ringfencing regime would impose onerous costs on EDBs (and ultimately consumers), and that many EDBs may decide the administrative costs would not be worth the effort, resulting in EDB affiliates not investing in demand management and the benefits of such investments being lost. In Contact's view, from a consumer perspective, the long term benefits derived from a competitive energy services market, with multiple providers (including EDB affiliates) offering innovative customer products and demand management services, will be far greater than the administrative costs associated with ringfencing.

Reform must create confidence in the emerging technologies market and provide a level playing field for all parties. In our view:

- Ringfencing has the advantage of enabling all parties, including EDB affiliates, to compete in the provision of emerging technology products and services. However, to create a level playing field and prevent market distortions the ringfencing regime must be sufficiently robust;
- If there are barriers to implementing a robust ringfencing regime, structural separation should be considered. Reform of this nature avoids the administrative costs associated with introducing and enforcing ringfencing arrangements.

As mentioned previously, we are concerned that proposals for ringfencing are being influenced by the section 52T(3) in Part 4, which may not be in the long term interests of regulated consumers. While EDB investments in emerging technologies will reduce costs relative to EDB investments in traditional infrastructure, we strongly believe regulated consumers will benefit from even lower charges if there is a competitive energy services market which maximises unregulated income from emerging technologies and as a result minimises the cost of network services to regulated consumers. Ripple control provides an example of benefits currently not flowing through to the regulated consumer, and the Commission should ensure that regulated consumers obtain maximum value from emerging technologies like batteries and demand response.

In addition to consideration of regulated consumers, whilst we appreciate competitive markets are outside of the Commission's jurisdiction, we encourage the Commission to support policy makers and other regulators in implementing reform which ensures all consumers in New Zealand benefit from a competitive and innovative emerging technology market.

4. Topic Paper 4 (Cost of Capital Issues)

Contact's cost of capital analysis comprises an overview of key recommendations below and three detailed subject sections, being:

- Cost of debt recommendations, contained in section 4.2;
- TDB Advisory analysis of asset beta, leverage and standard error calculations, contained in Appendix K;
- Contact's recommendations to improve the Commission's comparable company analysis; and
- Other cost of capital commentary, namely with regard to the 67th percentile and Contact's earlier submitted comparable company analysis, contained in section 4.4.

Overall we are concerned that the Commission is taking too many conservative estimates and approaches to its cost of capital analysis, which are generous in favour of the regulated companies. These result in costs for consumers that are not reflective of the risk inherent in these services. We see this as in direct conflict with section 52A(1)(d), and have made recommendations below and in the following sections for improvement of these parameters to reduce excess profits from the cost of capital provisions.

4.1. Contact's Key Recommendations

We make the following recommendations on the basis that these will lead to a cost of capital that better meets the Part 4 Purpose:

Specific cost of capital Proposal	Draft decision	Recommendation	Rationale
		Cost of debt	
Risk free rate	Prevailing risk-free rate with three months of data (instead of one)	Agree	Agree with Commission's reasoning and better meeting Part 4 purpose. Swap market liquidity data shows three months should be adequate for required theoretical volumes without causing adverse market movement. See section 4.2
Debt premium calculation	Three months of data; remove Government ownership restriction; Have regard to a "NSS curve" (fitted, non-linear curve)	Agree with methodology, but note that if wholesale bonds are used in the sample set then adjustment should be made to their debt premiums for illiquidity.	Relative to retail bonds, wholesale bonds have higher debt premiums (due to less liquidity). Given that the Commission assumes the regulated borrowers fund purely via domestic, publically traded retail bonds, then either wholesale bonds should be removed from the debt premium sample set, or the premiums for these bonds should be adjusted for illiquidity. See section 4.2

Specific cost of capital Proposal	Draft decision	Recommendation	Rationale
Establishment costs (per annum)	20bps (from 35bp)	10bps	Market evidence and evidence cited by the Commission shows issuance cost of 10bps per annum. We could see no reason for doubling of these up-front costs in the Commission's decision and recommend establishment costs in line with market evidence for these costs. See section 4.2
TCSD	Approximately 3 bp p.a. for debt beyond 5 years in duration	TCSD is not appropriate and should be removed.	TCSD is not appropriate within the debt cost framework as it fails to recognise an organisation's portfolio of debt, is subject to gaming and is a one sided principle, with consumers paying for longer term debt and not being reimbursed for commonly used shorter term debt. See section 4.2
Cost of equity			
Average asset beta	0.34	0.24-0.28	Analysis of the individual companies in the Commission's compco dataset indicates many companies have markedly higher systematic risk profiles than EDBs and GPBs. Our recommended range for the asset beta reflects the results of refining this sample set. The lower level (0.24) captures the most comparable companies, but is from a small sample set of eight companies. In contrast the higher level looks to improve sample set size, with a larger set of 39 companies, but in doing so introduce more systematic risk to the sample companies and increases asset beta to 0.28. See Appendix K
Asset beta difference for GDBs and EDBs	0.34 for both EDBs and GPBs	Separate WACCs for EDBs and GPBs should be used if possible to substantiate with evidence.	Disaggregating the improved comparable company dataset and asset beta estimates into electricity and gas companies indicates the differences may not be statistically significant. However, we note concern

Specific cost of capital Proposal	Draft decision	Recommendation	Rationale
			with the Commission's classification of 'integrated' companies in this sample and suggest further refinement of these definitions or detail as to how they were arrived at may help in assessment of whether there is evidence for different gas and electricity betas. See Appendix K
Asset beta comparison to other jurisdictions	Similar betas	Beta's are different due to the use of 67th percentile in NZ determination	The comparison of the calculated asset beta with other jurisdictions is incorrect, the effective NZ asset beta is higher than 0.34 due to the use of the 67th percentile weighting. Given the overseas jurisdictions do not use a 67th percentile methodology, the final beta of other jurisdictions should be compared to NZ final beta before adjusting for the 67th percentile movement. It should also be made clear in this analysis whether overseas jurisdictions are using mid-point betas from analysis or if they have built a level of conservatism into their estimates.
TAMRP	7.0%	Agree	We agree with the Commission's approach and conclusion on TAMRP.
Other cost of capital topics			
Leverage	41%	44-49%	Leverage adjusted in line with the revised comparator set discussed in Asset Beta above. See Appendix K
Tax rate	28%	Agree	We agree with the Commission's approach and conclusion on tax rates.
Annual updating of WACC parameters	Not required	Agree	Agree with Commission's conclusion that annual updating provides limited long term benefit and comes with material administrative cost.

Specific cost of capital Proposal	Draft decision	Recommendation	Rationale
Asset beta standard error	0.14	0.08-0.11	Standard error adjusted in line with the revised comparator set discussed in asset beta above. See Appendix K
WACC percentile	67th percentile, no review required	Review is required in line with evidence of concern.	We are concerned that the 67th percentile provides incentives that are not in the best interest of regulated consumers in the future energy market. All else being correct, the 67th percentile provides excess returns from past and new capital expenditure for EDBs, GPBs and Transpower. In turn this provides an incentive for these firms to grow the RAB and not utilise third party operating cost alternates. In a future world where new technologies and third parties can provide alternates to network capital expenditure this incentive is of concern. We do not see this adjustment as in the best interest of future regulated customers, with potential costs being well in excess of the $90m[51] per annum direct cost paid today. We encourage the Commission to review this adjustment and consider other alternate measures to address potential network underinvestment. See section 4.4
Impact on cost of capital of change in form of control and accelerated depreciation	No change	Cost of capital should reduce if these adjustments are adopted (note Contact's earlier concerns with both adjustments)	Movement to revenue cap and accelerated depreciation both reduce systematic cash flow risk of EDB's and increase risk for consumers. Consumers should see offsetting cost benefit from these changes.

[51] Note: the impact of changes in 67th percentile will differ depending on other cost of capital parameters. This approximately $90m impact is based solely on the Commission's draft decision parameters. If other changes are made to cost of capital parameters, as is recommended in this report, then the impact of the 67th percentile may also change.

Specific cost of capital Proposal	Draft decision	Recommendation	Rationale
			See section 2 for accelerated depreciation commentary See Contact prior 24 March 2016 submission for form of control commentary.[52]

4.2. Cost of Debt

Contact agrees with the Commission's overall approach to cost of debt estimates. However, we are concerned with:

- The level of conservative rather than mid-point evidence based estimates being used;
- The use of unnecessary and one sided allowances, such as TCSD and bid yields; and
- Some of the application of methodology, for example the use of debt premiums for illiquid debt instruments (that do not align with the stated methodology in para 164), without adjustment for illiquidity.

All of the above place additional cost on consumers and are not reflective of the true costs that would be borne by the regulated entities. We outline these concerns in detail below and recommend their correction in the final determination.

Risk Free Rate (RFR)

Contact supports a "prevailing rate" for the RFR (and debt premiums) for reasons broadly similar to the Commission's rationale. However, we do have one particular area of concern. We note the methodology uses the market "bid yield to maturity" and suggest that all rates, including the NZGB rates used to determine the RFR, should be priced off a mid-rate. Contact does not see the need for using a bid rate (which is typically several basis points higher than a mid-rate for Government bonds). Use of bid rates also skews the debt premium, as outlined below.

As an aside, we bring to the Commission's attention that it is possible to directly derive a 5 year interpolated NZ Government Bond (NZGB) rate via Bloomberg code "GNZGB5 <INDEX> <GO>". Using this interpolated rate makes the calculation and verification of the RFR quicker and simpler. We recommend the Commission consider this approach.

Debt issuance costs and swap costs

In contrast to the Commission's view,[53] Contact considers the cost of debt issuance as relatively predictable and stable. If anything, issuance costs are likely to decline slightly further over time as a result of efficiencies afforded by new regulation. We therefore do not see the need to apply a buffer above this level, particularly in light of the Commission's application of the 67th percentile which affords a generous buffer in any case.

[52] Contact Energy, *"Comments on Dr Lally's expert advice, 25 February 2016"*, 24 March 2016, pg 2, (http://comcom.govt.nz/dmsdocument/14200).
[53] IM Review draft decision, Topic paper 4 – Cost of Capital issues (para 245).

Contact suggests an appropriate allowance for establishment costs would be 10 bps, comprising issuance costs 6-7bps per annum and swap costs 3-4bps per annum. Detail on each of these components is set out below.

Recommended debt issue cost of 6-7bp per annum

The Commission's confidential debt survey results (referred to in para 223) and Contact's prior submitted evidence (**Cost of Capital submission**)[54] both indicated an issuance cost of 6-7bp per annum. We see this as a reasonably accurate reflection of actual and expected debt establishment costs for a hypothetical efficient issuer of retail bonds.

Going forward, leveraging the benefits of "same class exemption" under the new FMCA regulations, Contact expects its issue costs to decline further. It would be reasonable to assume the regulated issuer would also access this streamlined, cost efficient mechanism for issuing bonds. By way of illustration, for Contact's 2014 Retail Bond (CEN020) issued under the old Securities Act legislation, a 46 page "Simplified Disclosure Prospectus" was printed, posted to investors and released to market. This took significant time, effort and cost involving Contact staff, management, directors, external and internal legal counsel, the Trustee, Joint Lead Managers, publication designers and print publishers. For Contact's 2015 Retail Bond (CEN030) issued under the new FMCA legislation, a 6 page electronic pdf document was released to the market.

We note there is a variety of type and size of bonds included in the data set for the above-mentioned survey. Ideally, the data set should include retail, listed bonds issued under the same class exemption rules afforded by the FMCA. They should also be a "normal" market parcel size of $100-200m – smaller tranches will have an inflated issue cost in terms of bp p.a. Auckland Airport's bond that matures in 2022 would be an ideal example – however, it is one of the few of their bonds not included in the survey. We note in particular, the inclusion of a subordinated bond (Vector 2017 maturity) – these bonds are more complex, non-vanilla instruments and consequently are likely to attract a greater level of up-front costs in legal fees, brokerage etc. as a result and should not be included in the sample set.

In terms of other up-front costs referred to in the draft decision, Contact considers:

- Roadshow costs (para 37) are negligible in NZ, comprising a few domestic flights and catering for refreshments. Typically premises are provided at no cost by Arrangers/Joint Lead Managers;
- Brokerage (para 37) may or may not be paid on a new bond issue – recent Spark, Transpower, Contact, and Fonterra deals all had no brokerage – but to the extent that brokerage is paid, there is usually a benefit that offsets this cost in the form of lower debt premium arising from the heightened demand generated by the brokerage;
- Rating agency costs (para 227.3) are small at around 6bp for an issue rating, or just over 1 bp p.a. These costs have been included in the above 6-7bp estimate and we see no reason for additional allowance for these;
- The cost of maintaining a corporate credit rating (para 227.3) is de minimus in the context of an overall debt portfolio;[55]
- The cost of standby facilities (para 227.1) is more than compensated for by the benefit of shorter term funding that can be accessed as a result of having these facilities. For example, over the last few years, Contact has issued Commercial Paper (backed by standby bank facilities) at spreads averaging less than 30bp over the bank bill rate. Further information on the benefits of a balanced funding portfolio is outlined on pages 8-9 of our earlier Cost of Capital submission; and
- In terms of new issue premium costs (para 234), we concur with the Commission's view that there is no evidence of a new issue premium in New Zealand. This is also Contact's experience. When

[54] http://www.comcom.govt.nz/regulated-industries/input-methodologies-2/input-methodologies-review/cost-of-capital-im-review/.

[55] Contact would be happy to disclose its corporate credit rating costs on a confidential basis.

Contact was setting the pricing on its new CEN030 bond in 2015, we looked at the pricing curve for our three wholesale bonds in the market. The line of best fit for these bonds was then applied to the only other Contact retail bond (CEN020) in the market at the time. As can be seen on the graph below, the wholesale bonds trade at a material, but predictable, premium to the retail bonds. Applying this rationale, the graph below demonstrates that the bond was priced and issued at a pure market spread (i.e. there was no new debt issue premium).

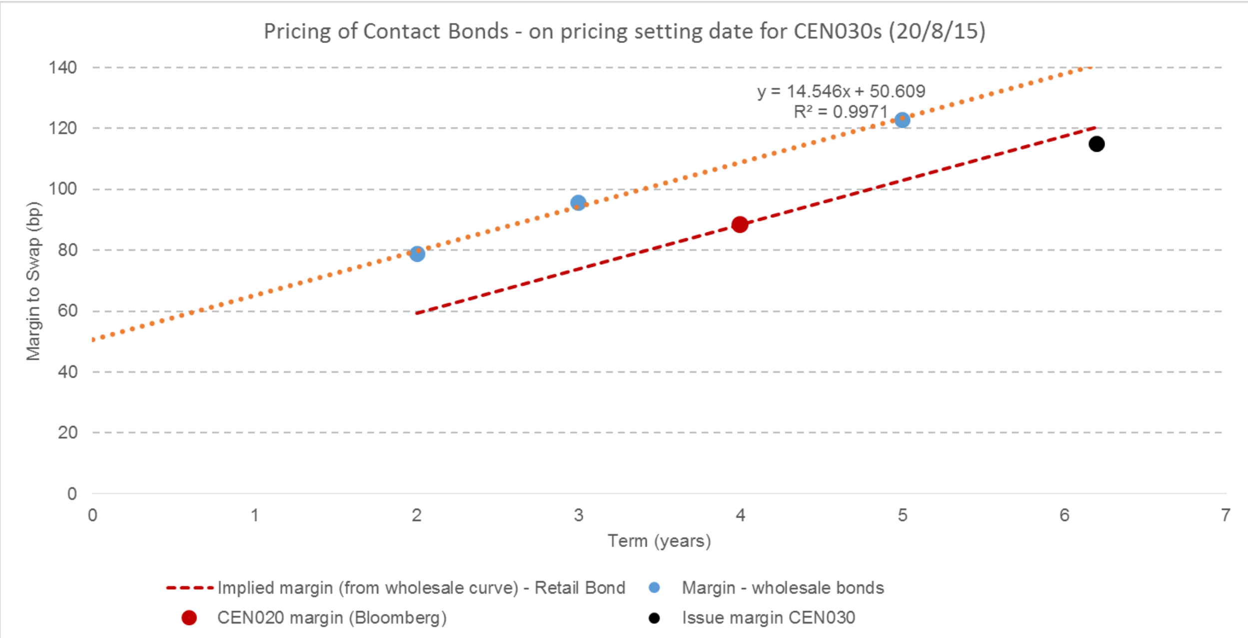

Figure 1: Illustration of the absence of a "new debt premium".

Recommended swap costs 3-4bps per annum

Contact agrees with the assumption for the regulated issuer that interest rate risk would be managed by entering into a pay fixed swap at the outset of the regulatory period, and all bond issuance would be brought back to floating by entering into a receive swap at the time of each bond issue.

An equally sensible assumption would be that the hypothetical issuer would split its funding evenly across the regulatory period, meaning that 20% of the interest rate risk management would be met by physical bond issuance (rather than having to enter into pay/receive swaps).

The corollary is that the quantum of swaps required for "perfect hedging" (where all debt is issued as fixed rate bonds) would be 2 x 80% x total debt. Assuming a swap cost of 2bp (as per para 239, which Contact supports as a reasonable allowance), the total swap cost would therefore be 1.6 x 2bp = 3.2bp per annum.

If some debt was issued on a floating rate basis[56] (or borrowed via bank facilities), then the quantum of swaps required would reduce. From the regulated companies that have publicly available financial statements, evidence shows they have swap portfolios that are less than 1 x the face value of their debt portfolios.

Contact considers the proposed wider determination window is a pragmatic solution to concerns regarding the impact of large swap volumes being executed in a shorter period. We note that, although there is a paucity of data, NZ swap market volumes appear to be sufficiently large to accommodate the

[56] We note Auckland Airport, Fonterra, Wellington Airport and Powerco have all issued floating rate bonds.

theoretical sector hedging requirements (Westpac estimated total Transpower and regulated distribution company debt of NZ$7bn in May 2015 article entitled "New Zealand Commerce Commission Input Methodology Review"). A recent RiskNet article (Appendix H) quoted swap volumes of NZ$386 billion in April 2016 alone, and a 2013 BIS survey (Appendix I) cited NZ interest rate hedge volumes of around US$5bn/day (about NZ$125bn for the month). Although these swaps will not all be in the 5 year, banks regularly use swaps of one tenor to clear risk with a different tenor (for example, banks might offset the risk on a 5 year swap with a customer by transacting a higher face value of 2 year swaps, which tend to be a more liquid instrument).

Debt premiums

Contact is comfortable with the Commission's "simple approach"[57] where the borrower is assumed to fund purely via domestic, publicly traded retail bonds with a five year tenor (however we consider "listed" rather than "publicly traded" would be a clearer term).

Given the lack of listed bonds from the EDB sector, and therefore a paucity of publicly available data on debt costs from the entities within this sector, Contact has no objection to the incorporation of gentailer bonds in the BBB+ sample set or equal weighting to bonds issued by companies that are owned[58] by the Crown.

As is always the case with comparator sets, careful scrutiny should be undertaken to ensure the set is comprised of appropriate entities and bonds. Contact wishes to highlight some specific examples of bonds that should not be included, or only be included where adjustments are made:

- Wholesale Bonds: These are unlisted bonds issued to institutional, sophisticated investors in large parcel sizes (therefore not accessible to "mum and dad investors"). With a materially limited subset of potential investors, these types of bonds tend to trade less frequently and, to compensate for this illiquidity, the credit premiums tend to be notably higher than if the same bond was issued as a retail bond. A good illustration of this point can be seen with Contact's wholesale and retail bonds, with the spread shown in the graph above (Figure 1) fairly typical of a wholesale-retail bond spread at around 20bp. The data from the Commission's draft input methodology review shows an average of 17bp differential for Contact's retail and wholesale bonds over the period (using reworked spread data, or 15bp using the Commission's raw data). The data also shows an average of 20bp differential for Fonterra's retail and wholesale bonds (15bp using raw data); and

- Bonds with particularly small market parcels: The effect of illiquidity in wholesale bonds is heightened where there is a particularly small parcel size, as typically the whole tranche will be held across just a few investors. For a wholesale bond, the typical market parcel size is around $50-100 million for a BBB+ issuer. A market parcel much lower than $50 million will suffer from heightened illiquidity and the market data information will be more difficult to rely upon.

We would also suggest using a "mid" rate for both the NZGB and Corporate Bond yields as mid-bid spreads can be distorted between the two data sets i.e. typically the mid-bid spread on NZGB will be lower than that for corporate bonds, so using bid-bid differentials between the two will skew the spread higher (for example if NZGB yield is 2% mid and 2.02% bid and a corporate bond yield is 3% mid and 3.10% bid, then the mid-mid spread is 1% but the bid-bid spread is 1.08%. Consistently using mid-rates would also be more in keeping with the "NPV equals zero" principal).

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[57] Above n 53 (para 164 & 229).

[58] We note this paragraph refers to "bonds issued by companies that are issued by the Crown…" and assume this is meant to read "bonds issued by companies that are owned by the Crown…"

We also note that the Meridian debt premium data is for a 7 year bond in the debt premium table for EDBs, Transpower and GBPs, whereas all other debt premia are for a 5 year tenor. The Meridian debt premium has not been adjusted (presumably because there is only one Meridian bond in the sample set). However, we believe it is possible to make a reasonable assumption for the adjustment required for tenor from other bonds in the sample set.

For these reasons, Contact recommends that the Commission incorporates the following into the methodology:

a) Adjusting debt premiums for wholesale bond spreads to reflect the debt premium that would be applicable if the bond was a listed retail bond;
b) Excluding bonds with issue size less than $50 million;
c) Using mid NZGB and corporate bond yields; and
d) Where a particular issuer only has one bond on issue, adjusting the debt premium on that bond to an equivalent 5 year debt by applying a tenor adjustment determined from other relevant bonds in the sample set.

It is possible to determine if a bond is a listed retail bond or not on Bloomberg under the "DES" (Description") tab for the bond. We note that it is likely there will be a reduced need for adjustments going forward as more corporate sector BBB band listed, retail bond issues come to market under the simplified regulatory regime. In the four months since the end date of the sample data set (31 March 2016), there have been four such new corporate issues, despite some level of market disruption as a result of Brexit.

Contact has reworked the sample data set provided by the Commission (Appendix J) with all these adjustments incorporated. The outcome of this revised methodology (Appendix J) shows an average debt premium for a BBB+ listed retail bond to be closer to 150bp.

It is not clear what weighting is given to the various groupings of bonds (referred to as 4(a) – (d) in the IM), so in the absence of any guidance, Contact has determined this premium with equal weighting to group 4(b), the average of A- rated bonds in group 4(d) and Contact's BBB bond, which is also in group 4(d).

Use of NSS curve as a reference

Contact is comfortable with the use of a NSS curve as a reference point only. We note its usefulness in determining debt premiums for particularly short dated or long dated bonds (where the curvature afforded by the NSS framework allows for a better fit, as bonds at the extremes of the tenor spectrum tend not to exhibit linear behaviour).[59]
However, for the purposes of determining the debt premium for a 5 year tenor, where there is notably less "skew", the linear approach is considered sufficiently accurate. This is borne out by the high R-Squared value for the BBB+ only bond statistics.[60] The fitting of a linear curve is an approach that has a much higher degree of simplicity and transparency, something that we feel should be given a great deal of importance in the IM Review process.

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[59] Short dated bonds (less than 1-2 years) start to be classified by some investors as a short term/cash instruments so more investors/funds may have appetite/mandates to buy them which may have a non-linear (downwards) effect on pricing of the associated debt premium. Long dated bonds typically suffer from illiquidity as fewer investors have appetite/mandates to buy then, which may have a non-linear (upwards) effect on pricing of the associated debt premium.
[60] Above n 53 (Table 32).

TCSD is not appropriate

As per Contact's prior Cost of Capital submission, we side with the High Court,[61] and consider that an allowance for a TCSD is not appropriate, because:

- The efficient hypothetical regulated issuer can manage its debt effectively and prudently via a 5 year debt tenor (for example, by having 20% of debt maturing each year), so it is not necessary to allow for longer tenors. Contact's Treasury Policy limit for managing funding maturities is very similar to this approach;
- If a regulated issuer *chooses* to access longer tenor debt, this, as referred to by the Commission, mitigates risk so provides benefit to shareholders (i.e. the reduction in refinancing risk referred to in para 198 provides a long term benefit to consumers *and* shareholders);
- It is incorrect to simply assume a prudent supplier "may issue debt for longer than five years to reduce the refinancing risk associated with assets that have long economic and engineering lives."[62] For long life assets it is normal that debt tenors cannot be matched with asset lifetimes (footnote 120 on page 52 refers to assets with lifetimes up to 50 years). Instead, Contact and other market participants' approach is to reduce refinancing risk by having limits on the amount of debt maturing in any year (as noted above), formulating funding or refinancing strategies well in advance, and maintaining good debt investor relations, part of which is being a regular issuer. In other words, there are many strategies that can be adopted to help manage refinancing risk which means there is no imperative for an issuer to borrow longer than an average of 5 years, to do so is merely a matter of choice;
- Allowance for a TCSD introduces the ability to "game" the WACC settings (i.e. firms will not issue long term because it lowers their risk). Firms will issue long term if, and when, market and yield curve conditions generate a lower incremental debt premium net of compensation. There are times when longer tenors are more economically attractive for an issuer (if more investors are attracted by a higher coupon due to a positive yield curve, the debt premium may be lower than for a shorter tenor) and yet the proposed methodology will always have a positive relationship between the TCSD allowance and original term of the debt. We note this occurs reasonably frequently, as evidenced by the data points below the x axis in Figure 23,[63] which are gross of any p.a. issuance cost benefits achieved by issuing longer term debt;
- Conversely, if there was no TCSD allowance, issuers can still choose to issue longer tenor debt and may well do so – either because the shareholders favourably view the cost (for longer tenor) v benefit (reduction in refinancing risk) and/or if there is an opportunity to achieve a lower cost of funds;
- Utilising a TCSD allowance is an asymmetric approach, which the Commission recognises (para 201) and directly conflicts with the "simple" approach the Commission has adopted assuming one type of debt. Paragraph 205 states that 24/29 respondents of the 2010 survey had debt shorter than 5 year as did 23/30 respondents from 2016 survey (paragraph 206). So there is a strong tendency (about 80%) for the industry participants to fund for tenors shorter than 5 years. Given this, Contact is unclear why allowance has been made for longer term debt but no balancing approach is taken where EDBs choose to fund for tenors shorter than 5 years. From the entities that have publicly available financial statements, it is evident that those with longer tenor debt also access shorter term funding from banks; so the relatively higher cost of the latter is already "internally" compensated for each entity by the former. We note also that companies may issue short dated bonds – such as Auckland Airport's 3 year floating rate notes issued in 2014 and 2015 and Fonterra's in 2014. This

[61] *Wellington Airport & Others v Commerce Commission* [2013] NZHC [11 December 2013] 3289.
[62] Above n 53 (para 198).
[63] Above n 53.

"portfolio approach" is also clearly illustrated by Contact's funding: our three core funding sources are bank debt (1-5 year); domestic bonds (5-7 year) and USPP (7-15 year). This portfolio delivers an average funding tenor of around 5 years, with an average funding cost roughly equivalent to the funding cost of a 5 year bond. The principle of consumers paying for longer term debt but not being reimbursed for shorter debt is one-sided; and

- Finally, it is Contact's experience that the most common source of longer term debt, USPP markets, have lower up-front costs on a p.a. basis than is the case in the domestic bond market. For example, no rating (such as S&P) is required in the USPP market and, as it is a private wholesale market, no documents are publically made available. In addition, the USPP market also has much greater volume capacity, allowing issuers to spread all the fixed up-front costs across a larger issue size. All these factors compensate for the slightly higher debt premium to a greater degree than allowed in the proposed methodology.

4.3. Comparable Company (Asset beta and leverage) analysis

In Appendix K to this report is an independent report from TDB, commissioned by Contact, reviewing the Commission's comparable company analysis and resulting asset beta, leverage and standard error parameters. The TDB report raises a number of concerns with the current Commission approach and recommends improvements to derive an improved comparator set and WACC parameters.

In reviewing this report and the Commission's own analysis we are also concerned with the results of the draft determination. We believe this could be improved through more critical review of the comparator set and validation (or correction) of the Bloomberg data. We recommend:

- In constructing a comparable company set, the Commission should analyse each company at a detailed level using annual reports or 10-K reports, investor presentations, broker reports and other website information available. Bloomberg descriptions are too prone to error and do not provide enough information to form a view of how comparable the company's operations are relative to the service being regulated. This detailed review should include:

    - Proportion of company's revenues, profitability and assets (where data is available) that are similar to those services being regulated. Where the firm has operations different from the regulated services, details of these and their proportion of each of the above should be noted.
    - Proportion of revenues that are protected by regulation, as opposed to subject to commercial negotiation (fee based) or competitive markets.
    - Description of type of regulation for regulated assets if possible to obtain (e.g. form of control, protection with demand/other changes)
    - Financial data verification – Bloomberg data should be cross checked with company accounts and trading information for verification. Bloomberg data can be subject to errors. For example, Bloomberg showed a fall in market cap of 60% for Jersey Electricity PLC from 30/3/2016 to 31/3/2016 without a share price change.[64] We assume this was due to data errors with how the state ownership was treated between these two days.

- That a US energy expert be retained for analysis and comparison of the US companies. The US energy markets has undergone substantial change in the last 10 years with the shale boom and recent oil price fall, and as a result a lot of the energy companies in the US have changed

[64] *Bloomberg data from Commission spreadsheet:* http://comcom.govt.nz/dmsdocument/14474.

significantly. TDB and Contact[65]have expressed concern with the US sample, and the Australian Energy Regulator has provided similar concern as part of its own cost of capital review.[66] Given its proportion of the company sample, different operations of the companies and different regulatory environment it would be prudent to analyse this set further and confirm which of these companies are appropriate for comparison with the regulated services in question.

4.4. Other Cost of Capital Recommendations

The 67th percentile should be reviewed

In its draft decision the Commission noted concerns by submitters on the 67th percentile, but has stated a further review of the 67th percentile is not warranted at this stage: [67]

> *"…we do not propose to make any change to our use of the 67th percentile for electricity and gas price-quality paths, given the significant amount of analysis that was undertaken in this area in 2014 and the lack of new evidence to justify a further detailed review at this stage."*

While we appreciate the substantial work undertaken in 2014 on this topic, we are concerned this decision to not review the 67th percentile has been taken too lightly, especially when evidence of concern has been raised in the past[68] and given the additional concerns highlighted below. The 67th percentile is a parameter which, all else being correct, provides for excess profits to regulated companies, and as such conflicts with section 52A(1)(d) Commerce Act 1986. Any percentile uplift should be considered at every review of cost of capital, regardless of the timeframe between decisions. We also note the seven year gap until the next cost of capital review (a total of nine years till this parameter is scheduled for review). We consider this too long to wait given the High Court decision[69] raised concern with the requirement for any level of uplift,[70] and that the 67th percentile costs consumers approximately $90m per annum.

In the draft findings the Commission cited the lack of new evidence as the reason for not reviewing this topic. In contrast we observe:

- New technologies and related new business models[71] were not considered in the dynamic efficiency arguments for the 2014 decision. As new technologies and business models provide alternates to network investment this dynamic efficiency analysis should be revisited;
- RAB multiples have continued to trend well above 1.0;[72]

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[65] Contact Energy, *"Submission on Cost of Capital Update Paper: 30 November 2015"*, 5 February 2016, pg 3. (http://comcom.govt.nz/dmsdocument/14066.

[66] AER, "Preliminary Decision. Jemena Distribution Decision 2016 to 2020. Attachment 3 – Rate of Return", October 2015 pg 3-459 to 3-468.

[67] Above n 53 (para 539).

[68] Major Electricity Users Group, "Submission on Cost of Capital Update Paper: 30 November 2015", 5 February 2016, pg 3 (http://comcom.govt.nz/dmsdocument/14076) and Contact Energy, *"Submission on Cost of Capital Update Paper: 30 November 2015"*, 5 February 2016, pg 11 (http://comcom.govt.nz/dmsdocument/14066).

[69] Above n 61.

[70] Ibid (para 1473).

[71] See section 3.2 above, "Third parties can provide network services from emerging technology assets".

[72] Above n 3 (pg 2); above n 53 (tables 24 and 25).

- There has been no observable trend towards under-investment since the Commission's decision to move from 75th to 67th percentile, rather evidence is that these businesses have continued to undertake significant capital expenditure;[73] and
- There is now a refined reliability incentive scheme in place (which was only 'proposed' at the time of the 2014 review).[74]

As stated in our prior submissions, we think it is important that this topic is opened for review. We expand below on our concerns in this area.

Alternates to network investment were not considered in the 2014 review

In its 2014 decision to adopt a 67th percentile adjustment,[75] the Commission noted a set of concerns in setting the cost of capital too low or too high. These are stated below:

> *"3.4 If the allowed WACC is too high, the prices paid by consumers of regulated services will be too high. As a result:*
>
> *3.4.1 regulated suppliers are likely to earn above-normal returns at the expense of consumers;*
>
> *3.4.2 due to the high returns they can earn on their investment, suppliers may also invest more than consumers would like;*
>
> *3.4.3 as consumers pay for the investment suppliers make, higher investment leads to higher prices. While there may be some benefit to consumers from this greater investment, the cost to consumers of this investment may be greater than the benefits over the long term; and*
>
> *3.4.4 therefore, consumers may suffer a loss if WACC is too high.*
>
> *3.5 Consumers may also suffer loss if the allowed WACC is too low.*
>
> *3.5.1 If the WACC is too low, suppliers may conclude they cannot expect to achieve investors' required cost of capital and cannot therefore justify investment. In that case they are likely to struggle to attract capital.*
>
> *3.5.2 Over time, any such under-investment is likely to result in declines in the quality of service provided to consumers (subject to constraints imposed by quality standards), which consumers may not be compensated for by the reduction in prices due to the lower value of the RAB. The reduction in quality could take many forms, including more frequent supply outages, longer outages (perhaps due to lower levels of network redundancy) and higher maintenance costs (which lead to further spending and eventually higher prices).*
>
> *3.5.3 With the lower available returns on investment, suppliers may also be less likely to innovate through investment, and the development and introduction of new services and/or technologies may be deferred. Under-investment may mean that opportunities are missed to reduce*

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[73] Commerce Commission, *"Profitability of Electricity Distributors Following First Adjustments to Revenue Limits",* 8 June 2016, pg 28, Figure 16 shows increase in capital expenditure across the price controlled EDBs.

[74] Oxera noted that the under-investment problem will be (or could be) in part mitigated by output and quality incentives (including incentive schemes such as IRIS) and asset stewardship requirements. Oxera "Input methodologies, Review of the '75th percentile' approach" (Report Prepared for New Zealand Commerce Commission, 23 June 2014, pg 65-66.

[75] Commerce Commission, *"Amendment to the WACC percentile for price-quality regulation for electricity lines services and gas pipeline services. Reasons paper",* 30 October 2014, (pg 37). (http://comcom.govt.nz/dmsdocument/12626).

> *transmission grid congestion and enhance competition in generation. Overall, consumers may suffer a loss if under-estimation of WACC results in suppliers under-investing when the benefit of the investment foregone would exceed its cost."*

We note that in these statements and the analysis published on this decision there was no consideration provided for alternatives to regulated network investment, such as non-network solutions being provided by third parties including batteries or demand response. We also note the High Court reaching a differing conclusion on innovation to that in 3.5.3 above.[76]

> *"If dynamic efficiencies are, as the Commission believes, most important, how exactly are higher expected returns supposed to stimulate them? Dynamic efficiency implies finding better ways to meet customer needs and adapting to changes in market circumstances. But necessity, not plenty, is the mother of invention. Utility industries – and certainly electricity transmission and distribution companies – are unlikely to be leaders in dynamic efficiency, precisely because they do not need to be."*

The consideration of alternatives to network investment, such as third party non-network solutions, changes the Commission's earlier conclusions on dynamic efficiency

With the topic of emerging technologies forming a large part of the current IM review, we see it as also appropriate to consider network investment alternatives in light of setting a 67th percentile cost of capital. It has been well researched and documented that new technologies and third party business models can provide alternatives to network investment.[77] The existence of these alternatives will change the earlier conclusions on dynamic efficiency of higher and lower cost of capital. Therefore, with regard to the earlier conclusions:

- ***The consequences of a WACC that is too high are likely to be understated.*** If the WACC is set too high, regulated companies will have an incentive for capital expenditure over operating expenditure as capital expenditure brings with it excess returns. As such, network companies will be incentivised to seek regulated capital expenditure allowances that involve not contracting with third parties for these services and rather add to their own capital base, even if this is more expensive for the regulated customer.[78] This will increase costs for customers and reduce both the introduction of new network service business models and innovation by third party providers.[79]

- ***The consequences of a WACC that is too low are likely to be overstated****.* If the WACC is too low then both:
    - The regulated company will likely seek the provision of more services from third parties, through operating costs arrangements (as the company still has incentives to meet quality standards set be regulation). A lower WACC will increase innovation for network

[76] Above n 61 (para 1474).
[77] For example: http://www.slideshare.net/informaoz/marc-england-agl-energy and http://www.rmi.org/RMI-TheEconomicsOfBatteryEnergyStorage-FullReport.
[78] We note the IRIS scheme does bring some incentives for efficient expenditure within the regulated period, but note these are temporary benefits, so not as strong as the enduring excess returns from allowed regulated capital expenditure.
[79] Outside of the complexities of direct contracting with network companies and difficulties accessing price signals for such services, there are also a number of other mechanisms network companies could use to deter third party alternates to their own capex, including pricing structures, technical standards and other use of system agreement requirements.

alternates and coordination with third parties for alternate service provision, both which will be of benefit to consumers.

- If regulated service quality is an issue, then consumers can access alternate quality of supply solutions (such as batteries). Therefore the costs of quality reduction in the Commission's prior analysis will be overstated.

New technologies and business models are expected to bring significant benefits to consumers of energy services, and, as discussed above, they substantially change how dynamic efficiency is considered with regard to cost of capital settings. A review of the dynamic efficiency analysis is warranted given the current discussion of emerging technology and its impact on the IMs, and the wider costs inherent in any incentives for regulated companies to favour their own rather than third party investment in these technologies.

When is the right time to review the 67th percentile?

Internationally energy markets and regulation are being reformed to ensure maximum benefit from new technologies and new business models flow to consumers. Key targeted areas of change are to reduce information asymmetries, reform pricing structures and remove perverse incentives with regard to the introduction of new technologies.[80] New Zealand is at the early stage of similar process, and as part of this we consider it important to review the 67th percentile in light of its impact on incentives for network investment vs third party solutions.

We do see evidence *today* to justify a review of the 67th percentile and have commented in our earlier submissions on our recommendation for the 67th percentile adjustment to be removed. However, we also note the late stage of this current IM review and earlier indications for this topic being 'off the table' for review.[81]

Our preference would be for a review of the 67th percentile to be completed within the current IM review process, including a review of alternate mechanisms that the Commission could adopt if under-investment is of concern. We realise this would require a quick process,[82] but believe in the benefits of regulatory certainty, and hence would prefer to keep this within the current IM review. If this is not possible, we recommend a review of the 67th percentile to be undertaken within the next two years. This timing would allow for results to be known in advance of the price reset for EDBs in 2020.

We do not think waiting for a review of this parameter in the next IM review (potentially 2022) is appropriate given the available evidence, concerns raised earlier by the High Court[83] and other regulatory processes underway regarding pricing, incentive and future market design (for example, the Authority's Distribution Pricing consultation.[84] This parameter is costly for consumers and its impact on incentives for regulated companies could be damaging for the set-up of our future energy markets.

Parameters used in determination of Contact's earlier comparable company sample set

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[80] See section 3.3.

[81] Above n 53; *"Input methodologies review. Update paper on the cost of capital topic",* 30 November 2015 (para 4.10).

[82] Our concern with an earlier review is simply to give parties time to prepare for this. Earlier signals from the Commission that this parameter was not intended for review have likely seen parties shift resource onto other topics.

[83] Above n 61 (para 1473).

[84] See http://www.ea.govt.nz/development/work-programme/evolving-tech-business/distribution-pricing-review/.

In the Commission's draft decision we noted the following comment with regard to Contact's earlier submitted comparable company sample set:[85]

> *"Although Contact considered a range of characteristics (…..), the thresholds used to determine whether each company should be included in the sample were not explicit. For example, Contact does not state the percentage of regulated revenues required for a firm to be included in its comparator sample."*

With regard to this comment, Contact provided the Commission the below in email on 11 March 2016 and verbally volunteered for this information to be made public if helpful for the process:

"PRIMARY COMPARATOR SET

- *This set comprised pure play regulated energy network businesses, with majority of revenues from regulated activities (note below comment on ITC).*

SECONDARY COMPARATOR SET

- *This set comprised ITC Holdings and non-pure play regulated energy businesses that:*
    - *Have >75% regulated revenues*
    - *Do not have significant sized businesses with high commodity and/or risk exposures (e.g. gas/liquids processing, LNG)*
    - *Had low/no investment in generation (as discussed, given both higher asset levels than retail and other exposures)*
- *ITC Holdings was included in the secondary set, noting the different industry environment in the US (even though ITC are pure play transmission) and that they had announced a review of strategic alternatives, including a possible sale of the company, on 30 November 2015 (on 9 Feb 2016 – post submission – it was announced that Fortis Inc had agreed to buy the company)"*

We would be more than happy to provide further information on this analysis if helpful and answer questions on the analysis if the Commission is concerned this is not explicit.

[85] Above n 53, footnote 185.

Appendix A: Redrawing the boundaries between regulation and competition in new energy services markets

ENA REGULATION SEMINAR 2016

Wednesday 3 August 2016

State Library of Queensland, Brisbane

Richard Owens: Speech and Q&A session on "Redrawing the boundaries between regulation and competition in new energy services markets"

2.10 – 2.40pm

Good afternoon and thank you for inviting the AEMC to speak on such a topical issue.

Apologies for the fact that most of you were no doubt expecting to hear from John Pierce rather than me. Unfortunately John is attending Matt Zema's funeral in Melbourne today, which he obviously couldn't miss given how devastating Matt's death was for many of us.

A century ago, a safe and reliable source of energy was the wonder of the world. Today consumers take it as given and our economy relies on it.

Now, once again, another energy revolution is happening, in renewables, in storage, in information management services, and in the increasingly multidirectional flow of energy.

What's new in this latest chapter of the energy story is that technological change is allowing consumers to choose how their energy is delivered and used. Technology is enabling a devolution of decision making with consumers increasingly driving the development of the sector through the choices they're making.

Electricity networks are very much on the front line of this shift and this is reflected in the work the ENA is doing in their Electricity Network Transformation Roadmap. Importantly, the Roadmap is taking a very deliberate customer-centred approach, recognising that ultimately, it's consumers exercising their growing energy choice – and not the technologies themselves – that are driving the transformation.

With recent events in South Australia, we are seeing a high level of interest in the transformation of our electricity system and, in particular, the implications of higher levels of renewables, both grid scale and distributed, on wholesale energy prices and power system security.

As we know, these are not new – or unforeseen – challenges. However, as our Chairman John Pierce noted last week at the Clean Energy Summit, much of the current debate is still inwardly focused – and all about industry. It should instead be going beyond renewables alone, because the change we're seeing in the market is increasingly led by consumers, and the focus should be enabling consumers to make the choices that are best for them so they have greater control over how they source, manage and use their electricity.

To that end, much of the AEMC's efforts over the past few years have been in providing more opportunities for consumers to make informed choices. Whenever possible, we start from the premise that the best judges of what's in consumers' interests are consumers themselves. And where there are barriers or constraints to consumers exercising their choices, our preference is to address those barriers to choice rather than use regulatory instruments to impose technology-based solutions on consumers. Importantly, we do not try to pick winners.

The reforms flowing from the AEMC's Power of Choice review have laid the foundations for an energy system that is positioned to deploy new technologies in response to the choices consumers make. This is why we have focused on changes such as network pricing reform. We all know networks have been preparing for the introduction of cost-reflective pricing from 1 July 2017, with the tariffs that have been proposed in the current tariff structure statement process being just the first tentative step in a journey towards truly cost-reflective network prices that better reflect the consumption choices of individual consumers.

Another example is our competition in metering reforms, where we have opened up metering services to competition. The focus of the metering rule change was not the meters themselves or promoting consumer choice in metering technology. It's about advanced meters as an enabler for new products and services that can deliver benefits for consumers.

The metering reforms were also the first significant example of a reconsideration of where to draw the line between services that are competitive and services that should be regulated. A decade ago it was simply assumed that metering for residential customers was a monopoly service that could only be provided by the DNSP and therefore needed to be regulated. But our recent rule change showed that there is no reason for that to be the case, and instead network businesses, retailers and independent metering businesses should all be able to compete to provide metering services on an unregulated basis.

But if network businesses want to be involved in the competitive metering space, they must comply with the AER's ring-fencing requirements.

So why do we need ring-fencing for network businesses that want to compete in the provision of competitive services like advanced metering?

To answer that question, you first need to be clear about the purpose of ring-fencing. It's not just about avoiding cross-subsidies between regulated and non-regulated services. That's important, but it's just part of the broader aim of facilitating the development of a competitive energy services market. In the customer-centred future that we envisage for the energy market, the long-term interests of consumers will be best served by retailers and other energy service providers innovating and experimenting to offer products and services that consumers value.

That objective requires effective ring-fencing that means that network businesses can't discriminate between their network business or related entities and third party service providers. The AER is currently implementing ring-fencing through the new national distribution ring-fencing guidelines, which I'm confident will go a long way towards achieving this objective.

In addition to ring-fencing, the regulatory framework also needs to support this objective through a range of other measures including:

- providing clarity around which services are regulated and which are not;
- creating incentives for the efficient investment in, and use of, assets such as storage that can provide both regulated and non-regulated services, so that the full value is obtained from those assets;
- having robust cost-allocation and shared asset regimes for circumstances where a network asset is used partly to deliver a regulated service and partly to deliver a non-regulated service; and
- having strong efficiency and investment tests that require and incentivise networks to procure services from the competitive market where it is more efficient to do so rather than investing in the assets to provide those services using regulated revenues and rolling them into the RAB.

The rules already contain a lot of these features, and we are expecting to receive a rule change request from the COAG Energy Council later this month proposing enhancements to some of these measures based on the recommendations from our Integration of Energy Storage Report. I also understand that other stakeholders are working on potential rule changes in this area and I encourage them to submit them soon so that we can consider and consult on all of the proposals in a coordinated fashion.

Our preference for competition over regulation and our desire for a clear separation between the regulated and competitive sectors isn't just an issue of ideology. It reflects our concerns about the potential damage to the long-term interests of consumers from a lack of such separation.

To give the issue some context, I thought it would be useful to work through a few examples of current issues that illustrate why a lack of an effective separation between regulated and competitive services could prevent the emergence of a strong, competitive energy services market and could mean that customers miss out on the benefits that competition can bring them in terms of increased innovation and choice and lower long-term prices.

There are four current examples I'll use to illustrate these concerns:

1. The first example is battery storage.

   The AEMC made a number of recommendations in the Storage report we released in December last year. Our analysis focused on storage as an example to shine a light on potential regulatory issues that could apply to a range of technologies, in particular technologies that can be used to provide both regulated and competitive services. While many of the specific functions that storage performs are not new, it's the potential for storage to generate multiple value streams for multiple players – including consumers, networks and generators – that makes it so interesting.

   One of the key issues we considered was "who should control the storage device when it's behind the meter"? Should it be the consumer, the energy services company, the retailer or the network business?

In a consumer-controlled model, we'd see consumers themselves buying batteries directly, along with optimising software so the battery can store power at times of low prices or store power from the consumer's solar system, and then discharge at times of high prices. Or an energy-service company could manage the device on the consumer's behalf.

A retailer-controlled model could see retailers providing storage services to consumers through an arrangement where the consumer effectively gets a cheaper electricity price while the retailer controls the device to hedge against wholesale and distribution prices.

Under either model, the retailer or an aggregator on the consumer's behalf could also sell services to network businesses to allow them to use the battery at certain times for network support.

All of these models are compatible with the idea of a competitive energy services sector.

Then there's the network-controlled model. One example is where the network owns the storage asset behind the meter and socialises some or all of the cost across all customers on the basis that the battery is helping provide regulated network services.

Our concern is that network-controlled storage is likely to act as a barrier to the other models. For example, how could a retailer or energy service company compete on price if the network can smear some or all of the costs across all consumers in the state but the retailer or ESCO has to recover the full cost from the individual consumer? And would networks have an incentive to do things like make connections for competing providers onerous and costly if they have a business interest in providing network-controlled storage?

Although networks may rightly argue that using storage in this way enables them to operate the network more efficiently, this model would damage the development of a competitive energy services sector, which gives consumers the best opportunity to decide which product or service best suits them.

To be clear, we believe network businesses should be able to buy storage services from competitive providers or ring-fenced affiliates where it is more efficient than network augmentation and other demand management options to meet network requirements, or where it can help networks maintain the stability of the grid. The rules already allow this, and have incentives for network businesses to implement non-network solutions, including the use of storage.

2. To help illustrate that this issue isn't just about storage, my next example is micro grids and stand-alone power systems. The AEMC is currently doing some research and thinking on this issue, as we see it as a significant emerging issue where there appear to be gaps in the current regulatory framework at the Electricity Law and Retail Law level.

   A number of network businesses have said that in remote parts of their networks, when a line reaches the end of its life, it's likely to be more efficient not to replace the line but to instead serve the customers through a micro grid or stand-alone power system. I agree that this approach should be allowed as it could have significant cost savings for consumers, as well as reliability and bushfire reduction benefits in certain areas.

However, major issues arise regarding which services become regulated and which remain competitive. The proposal that was put to me recently by one network business was that it should be able to disconnect customers at the end of long rural lines and instead supply them using a stand-alone power system of solar, storage and a diesel generator. That idea has a lot of merit, but does it necessarily flow that, as proposed by the DNSP, the network business should become a regulated monopoly supplier of not only the network service but also the solar panels, storage unit and diesel generator and even deliver the customer's diesel on a regulated monopoly basis? Or should some of those services be provided to the customer on a competitive basis? Or if that's not possible, should the network business be required to procure the inputs to this service from the competitive market rather than own the assets itself?

3. A third example is sharing staff and equipment.

   In their submissions to the AER's current ring-fencing guidelines process, several network businesses argue that they should be able to use under-utilised field staff and trucks etc from their regulated business to provide competitive services, on the basis that cost-allocation will allow them to reduce regulated charges and also provide the competitive service more cheaply than if they had to have stand-alone staff and equipment for each of the regulated service and the competitive service.

   This is probably the best example of the tension inherent in this issue, as networks are right that in the short term this will lead to lower prices for consumers of both regulated and competitive services.

   But will it mean that competition never emerges in markets for new services, as no one else will be able to compete with the network business' prices? In the long term, is that likely to result in less choice and higher prices for competitive services?

4. I'll finish with an example about marketing of competitive products. I am aware of one network business that is currently advertising solar and battery services on the website for its regulated DNSP activities.

   The advertising is next to the "electrical faults and emergency" numbers. It's above the "connect your power" information, which you need to click on if you want to buy solar or storage from any other company and connect it to the network. If a customer wanting to have solar or batteries purchased from a competitor clicks on the "Connect your power – solar and other generation" link to find out how to get the panels connected to the grid, they get more advertising for purchasing panels and batteries from the network business.

   Does all of this risk undermining a level playing field for the provision of competitive storage and solar services? Will consumers be led to believe that they will get additional benefits by purchasing these services from their DNSP, for example a quicker and easier connection process? Would the network business agree to provide similar free advertising on its website to unrelated competitive providers?

These examples illustrate why the Commission is concerned that allowing regulated entities to enter competitive markets is unlikely to support the development of a competitive energy services market.

The ability to leverage regulated revenues, information asymmetries and the ability to discriminate in areas like connection processes would give regulated entities an unfair competitive advantage.

Being clear about where regulated networks can play and where they can only compete through a ring-fenced affiliate is not to suggest that the AEMC does not recognise that the integration of distributed energy resources is a key challenge – and opportunity – for network businesses as they seek to maintain grid stability while also reducing network costs.

The last thing I want is an outcome where the regulatory framework makes it too hard for networks to innovate and use new technologies as a lower cost alternative to building poles and wires. I've spent much of the last few years at the AEMC working on rule changes that are designed to incentivise networks to do the exact opposite of that.

The analysis being undertaken through the ENA Network Transformation Roadmap project in this area, including consideration of the future directions for electricity policy and regulation, is useful initiative and I've enjoyed the opportunity to participate in several of the workshops so far.

The AEMC is also continuing its technology work program and one of our main projects looks at how the role of distribution networks may need to evolve to enable consumers, service providers and network operators to optimise the value of distributed energy resources. This is currently an internal research project but we will be engaging publically towards the end of the year, resources allowing.

We also expect to shortly receive terms of reference from the COAG Energy Council for a new annual monitoring and review project on the effectiveness of the electricity network regulation regime in responding to increased uptake of decentralised energy supply.

All of these different work streams are important if Australia is to capture the significant value that a consumer-led transformation of the energy sector can bring. Many jurisdictions are grappling with these same questions and no-one has all the answers yet. Many voices and ideas need to be heard on these topics if we're to deliver resilient and robust responses. The AEMC looks forward to being involved in this journey with you.

Thank you.

(Source: Richard Owens (Senior Director, AEMC), speech at ENA Conference, Brisbane, 3 August 2016).

Appendix B: Off-grid analysis

Battery Storage → An Off-Grid Revolution?

- Economics are mostly unattractive:
  - Going off-grid: PV + battery system would cost > $100K for an average home
  - Avoiding peak pricing: Peak to off-peak price differential needs to regularly reach levels > $300-$500/ MWh
  - Reducing PV injection: helps avoid $80/MWh injection prices to secure a $280/MWh tariff but relies on a temporary cross subsidy
  - Resilience: depends on personal attitude to risk and frequency of outages
  - As and when costs outweigh alternatives

We assume NZD $7,000-8,000 6.5kWh battery with daily cycling capability sufficient for a 10 year lifetime (100kg & 1.0m by 0.5m)

Household Off-Grid Costs

Day-time consumption 25%

No Seasonality

	Solar PV	Battery	Total
Installation kW	7.4	5.5	
Cost $/kW	$3,333	$4,000	
Installation $	$24,622	$22,160	$46,781
Efficiency	14%	85%	
Annual kWh	8,000	7,059	
Daily kWh	21.9	19.3	
Load kW	0.9	0.8	
Per unit $/MWh	$310	$470	$780
From the Grid			$2,200
$/MWh			275

Day-time consumption 10%

Source: Meridian

Winter

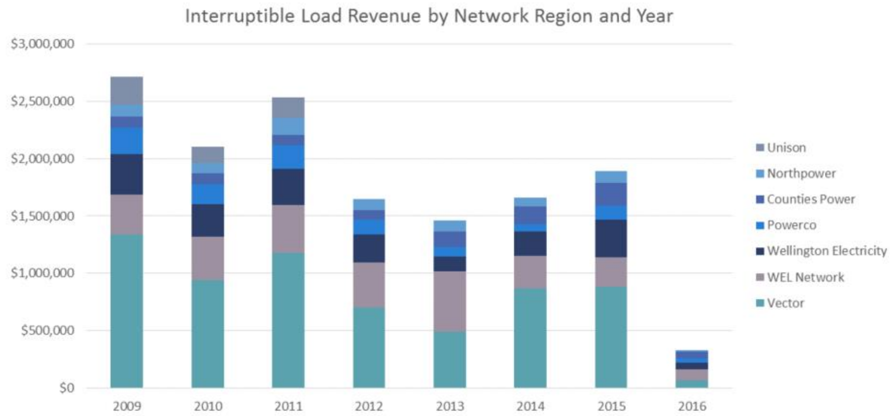
	Solar PV	Battery	Total
Installation kW	16.9	15.2	
Cost $/kW	$3,333	$4,000	
Installation $	$56,442	$60,957	$117,399
Efficiency	7.5%	85%	
Annual kWh	9,600	10,165	
Daily kWh	26.3	27.8	
Load kW	1.1	1.2	
Per unit $/MWh	$600	$890	$1,490

MERIDIAN ENERGY LIMITED INVESTOR DAY PRESENTATION 30 April 2015 39

(Source: Meridian Energy Limited Investor Day Presentation, 30 April 2015).

Appendix C: Ripple control analysis

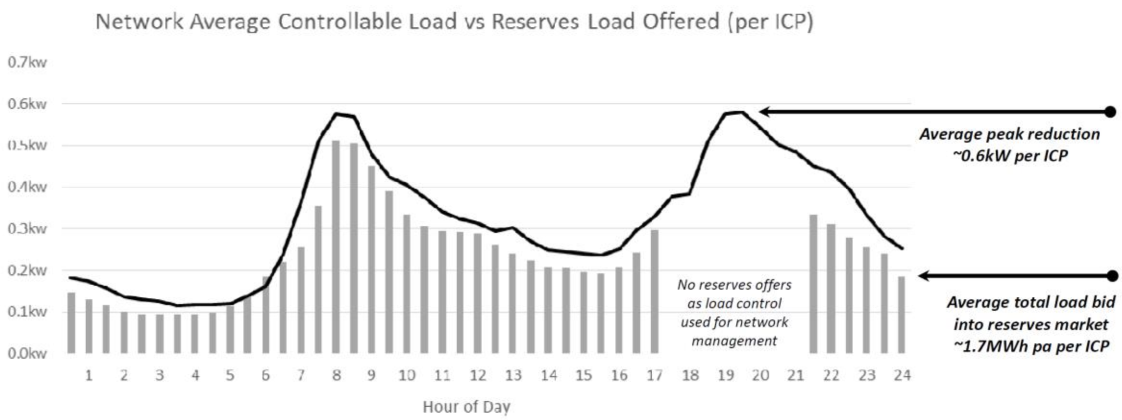
Networks have made ~$15m in reserves revenue since 2009



- EDB controlled ripple control systems include centralised plant (inject signal into network usually at a GXP level) and ripple receivers at individual premises (which control load, usually hot water cylinders)
- When ripple control system is not being used for network management it can be used for other purposes (including reducing the networks Transpower charges, participating in unregulated reserves markets)
- Reserves market utilises ripple controlled load as "backup capacity" (cylinders not turned off unless reserves event)
- Reserves revenue includes FIR (Fast Instantaneous Reserves) and SIR (Sustained Instananeous Reserves)

Source: Electricity Authority

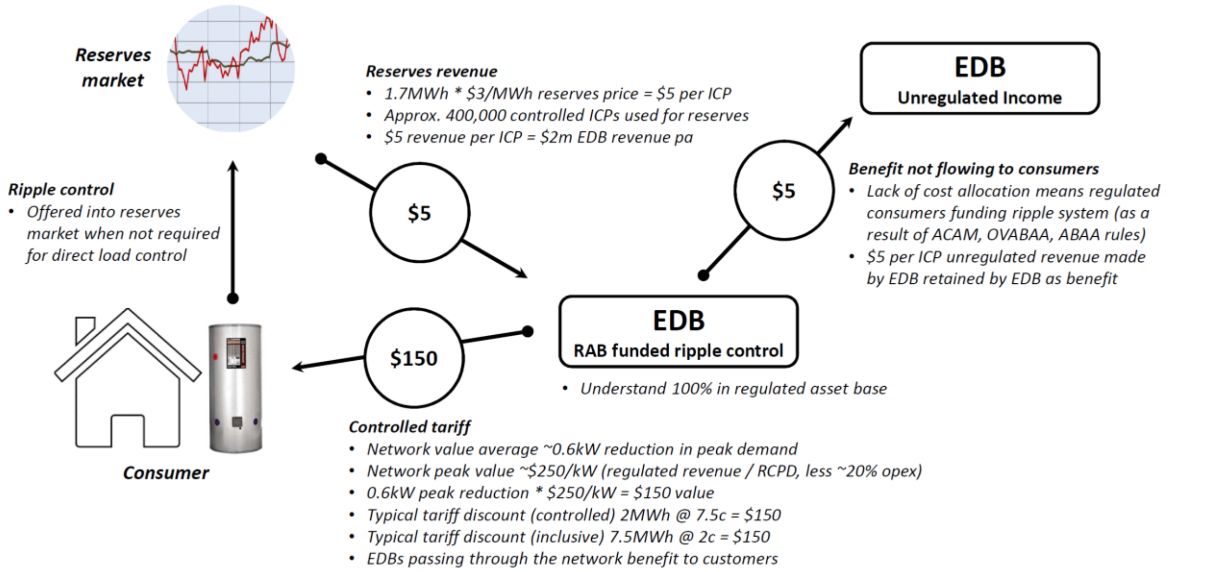
EDB load control used for reserves except in network peaks



- Black line shows typical hot water cylinder daily load profile (individual ICP)
- Grey bars show typical network offers into reserves market (sculpted based on daily profile)
- At times where ripple control may need to actually be utilised EDB can't commit it to the reserves market, so offers withdrawn
  - Enables network to use the ripple system to reduce hot water load
  - May be to manage network peak demand (security), manage Transpower charges, other uses

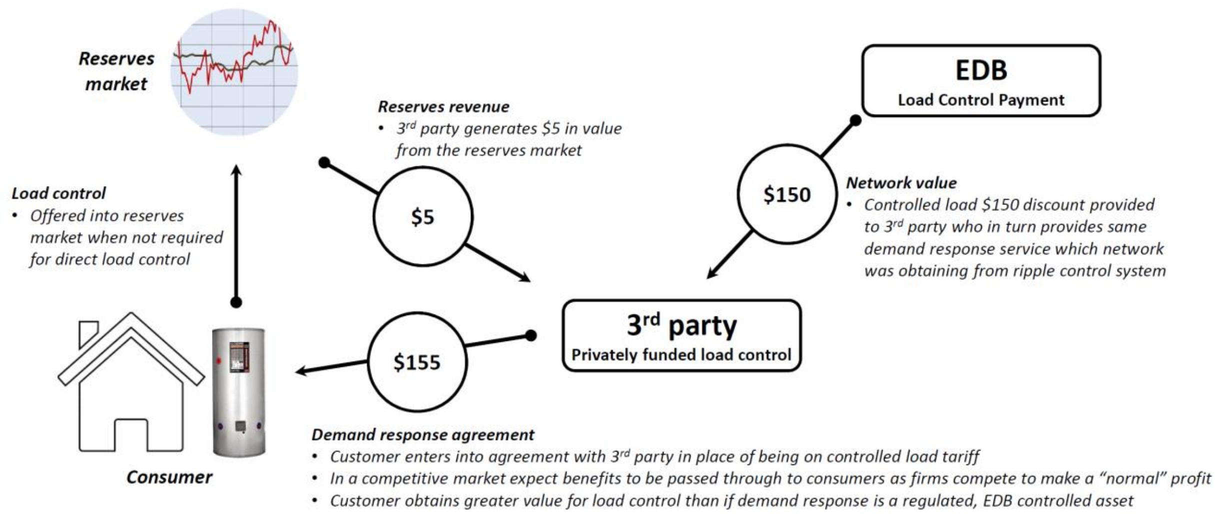
Source: Analysis of controlled load smart meter data and reserves market offers, typical winter weekday

Ripple control shows regulated consumers are paying more than an efficient market



Providing a case study for potential EDB regulated battery investment

Competitive demand response market can deliver greater value for regulated consumers



By ensuring competition delivers all demand response benefits through to consumers

(Source: Electricity Authority).

Appendix D: Vector solar and battery trial program

Sun shines on Vector rollout

ROB STOCK
Last updated 05:00 09/02/2014

Vector is building power stations all over Auckland - they're tiny ones on people's roofs in a scheme proving popular with homeowners.

They are a new generation of mini-solar power plants complete with batteries. The sun-generated electricity can be stored during the day when homeowners are out at work and then used when they return in the evening.

That differs from solar hot water systems which were damned late last year in officials' reports as poor value because they have no battery to store power.

Under the Vector deal, it retains ownership of the solar stations that homeowners lease. The lines company is responsible for maintenance and repair.

In less than a year, Vector has installed just over 250 of the SunGenie mini-power stations on roofs across Auckland, including one on the North Shore home of its chief executive Simon Mackenzie. He was among the first to sign up because he wanted to experience just how they work before they were rolled out.

They've proved so popular that there's now a lengthy waiting list, Mackenzie said.

The roofs have to be north-facing and not shaded to be suitable.

The homeowner pays $2000 installation costs for the 3 kilowatt system, which includes a fridge-sized battery cabinet, and then a $70 monthly lease payment. Installation takes just a few hours and requires no council planning consent. It can go on either steel rooves or tile, and its low-elevation barely changes the profile of a building.

Most homeowners, including Mackenzie, don't end up selling power back to a retailer though some providers like Contact Energy and Meridian are in the market to buy any that is unwanted. Typically, homeowners use up what is generated to power their lifestyles.

Over the year, half of the power required by an average Auckland home can be provided by the solar stations.

One early adopter was Reece Warren, because he wanted to reduce his carbon footprint. He sells his spare power to Contact Energy, and is about to receive his first cheque for around $170.

Warren says he's a low power user but the solar system has slashed his bills, so that in many of the months since installation, his only power cost has been the $70 lease fee to Vector.

"It's fantastic," he said. "I could not be a bigger advocate for this system."

Vector estimates average homeowners save around $350 a year on power costs, although savings dip in winter.

During our interview Mackenzie whips out his smartphone and calls up the app which monitors his savings and the current state of his home generation. Given the blazing sun and blue sky outside the battery is rapidly filling and already 87 per cent charged.

The $350-a-year estimated savings may seem small change for a chief executive, but Mackenzie takes a wide approach to cutting his power bills. He's also converted his house to low-power, low-burn-out LED lightbulbs.

And Vector's research shows power costs are such a drag on household budgets that 80 per cent of homeowners are actively engaged in one or more of the "three switching behaviours" to save money.

Those behaviours include; switching power provider, switching off appliances, or switching the way they generate their power.

Some may be wary about solar following Government reports last year which revealed many of the solar hot water heating systems people paid to install are effectively white elephants which lack smart control and monitoring systems, and which will either never produce net savings for owners or only just break even.

But with the installation cost of the Vector scheme being lower than the solar water heating systems, the company paying for maintenance, and the smart monitoring technology (Vector also monitors performance remotely), some of the big disincentives for solar are effectively removed.

Just how big can the scheme get?

Mackenzie expects the current 250 installations over the past ten months to grow substantially with much of that coming from the 30,000 or so new homes due to be built in Auckland each year.

Home redevelopments, such as the one being done by Remuera homeowner Darrell Sveistrup, will also drive uptake.

He's having a SunGenie installed and hopes to generate power surplus to what he needs.

As well as potentially earning extra income, he will be protected from power cuts or loss of power in a natural disaster.

Vector expects take-up to follow the traditional hump-back curve technology adoption usually follows - slow at the start by early adopters and then ramping up as the technology becomes more widely known.

"The economics of putting this technology in versus the retail price is pretty close," Mackenzie said. "In the next 18 months to two years, that will quite likely cross over."

It probably won't be just the savings on offer which will sway people to opt for the scheme.

Having a new toy to play with as well as the bragging rights that come with reducing your carbon footprint are both influencing take-up, Mackenzie says.

And it's not just homeowners installing the new generation of solar. Businesses like EcoStore and Hubbards have adopted solar too.

(Source: Sunday Star Times, February 9 2014).

Appendix E: Vector 2014 Schedule 6a disclosure on capital expenditure (and explanatory notes)

Company Name	**Vector**
For Year Ended	**31 March 2014**

SCHEDULE 6a: REPORT ON CAPITAL EXPENDITURE FOR THE DISCLOSURE YEAR

This schedule requires a breakdown of capital expenditure on assets incurred in the disclosure year, including any assets in respect of which capital contributions are received, but excluding assets that are vested assets. Information on expenditure on assets must be provided on an accounting accruals basis and must exclude finance costs.
EDBs must provide explanatory comment on their expenditure on assets in Schedule 14 (Explanatory Notes to Templates).
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref				
7		**6a(i): Expenditure on Assets**	**($000)**	**($000)**
8		Consumer connection		31,712
9		System growth		46,369
10		Asset replacement and renewal		58,410
11		Asset relocations		21,377
12		Reliability, safety and environment:		
13		Quality of supply	3,972	
14		Legislative and regulatory	2,200	
15		Other reliability, safety and environment	-	
16		**Total reliability, safety and environment**		6,172
17		**Expenditure on network assets**		164,040
18		Non-network assets		10,224
19				
20		**Expenditure on assets**		174,264
21	*plus*	Cost of financing		4,213
22	*less*	Value of capital contributions		29,265
23	*plus*	Value of vested assets		-
24				
25		**Capital expenditure**		149,212

sch ref		
26	**6a(ii): Subcomponents of Expenditure on Assets (where known)**	**($000)**
27	Energy efficiency and demand side management, reduction of energy losses	-
28	Overhead to underground conversion	13,106
29	Research and development	8,347

sch ref				
30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**	**($000)**	**($000)**
32		Service connection	8,369	
		Customer substations	5,209	
		Business subdivisions	923	
33		Residential subdivisions	13,951	
34		Capacity change	2,115	
35		Street lighting	1,077	
36		Easement costs	68	
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		31,712
39				
40	*less*	Capital contributions funding consumer connection expenditure	17,175	
41		**Consumer connection less capital contributions**		14,537

sch ref				
42		**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset Replacement and**
43			**System Growth**	**Renewal**
44			**($000)**	**($000)**
45		Subtransmission	4,939	913
46		Zone substations	21,865	16,794
47		Distribution and LV lines	1,348	17,731
48		Distribution and LV cables	12,069	5,301
49		Distribution substations and transformers	690	5,747
50		Distribution switchgear	644	5,289
51		Other network assets	4,814	6,635
52		**System growth and asset replacement and renewal expenditure**	46,369	58,410
53	*less*	Capital contributions funding system growth and asset replacement and renewal	3,965	35
54		**System growth and asset replacement and renewal less capital contributions**	42,404	58,375
55				

sch ref				
56		**6a(v): Asset Relocations**		
57		*Project or programme**	**($000)**	**($000)**
58		Auckland Manakau Express Transit Initiative (AMETI) Arterial Road Phase 2	1,193	
59		Tiverton Wolverton Relocation Project	1,419	
60		OIP Programme	13,106	
61				
62				
63		** include additional rows if needed*		
64		All other asset relocations projects or programmes	5,659	
65		**Asset relocations expenditure**		21,377
66	*less*	Capital contributions funding asset relocations	8,090	
67		**Asset relocations less capital contributions**		13,287

sch ref			
75	**6a(vi): Quality of Supply**		
76	*Project or programme**	**($000)**	**($000)**
77	Solar PV Program	3,389	

Box 12: Explanatory comment on variance in actual to forecast expenditure

Consumer connection spend increased 36% vs forecast , due to an increase in residential connections particularly subdivision reticulation activities there are a number of large developments underway in Auckland e.g. Hobsonville, Flatbush and Millwater.

Reliability, safety and environment expenditure increased by 6% as a result of the following:

- Quality of supply sub-category increased by 253% mainly due to installation of batteries to manage power quality issues. Installing batteries in conjunction with solar panels has been assigned to maintaining quality of supply as the batteries mitigate network effects as result of intermiitent generation and uncontrolled reverse flows on the network

- Legislative and regulatory sub-category reduced by 25% mainly due to further cost optimisation during the implementation of seismic strengthening projects.

- Other reliability, safety and environment sub-category is $1.7m lower due to re-prioritisation and deferment of long term reliability improvement projects based on additional risk analysis.

Non network capex is lower by 15% due to lower than planned spend on non network projects.

Operating Expenditure is largely in line with the prior forecast.

7(v) Insurance

The forecasts were predicated on advice provided by our brokers on the potential impact of the Natural Disasters including the Christchurch earthquake on property insurance capacity and premiums. These forecast increases in premiums did not eventuate and as a result the actual cost of insurance is under the target.

(Source: https://vector.co.nz/electricity-disclosures/financial-and-network-information).

Appendix F: Commerce Commission revenue materiality threshold analysis (Topic paper 3)

Table B1: Revenue materiality threshold analysis

EDB	Used ACAM for OC?	Used ACAM for AV?	Total Revenue (000)*	Regulated Revenue (000)**	Unregulated Revenue (000)***	Unregulated/Regulated Revenue	OCDA (000)**	OCnDA (000)**	Operating Cost Threshold	ABDA (000)**	AVnDA (000)**	Asset Value Threshold	Price Regulated Business?	Operating Cost Impact on Revenue (2010 Revenue Split)	Operating Cost Impact on Revenue (Current Revenue Split)
Nelson Electricity			$44,412	$10,534	$33,878	321.6%	$1,905	$0	0.00%	$41,669	$0	0.00%	✓	0.00%	0.00%
Northpower		✓	$253,322	$63,779	$189,543	297.2%	$13,762	$13,588	49.68%	$238,036	$4,163	1.72%		7.03%	8.31%
Marlborough Lines			$136,182	$35,331	$100,851	285.4%	$11,521	$965	7.73%	$217,515	$0	0.00%		0.90%	1.07%
Horizon Energy			$112,250	$31,893	$80,357	252.0%	$5,312	$4,339	44.96%	$109,634	$3,649	3.22%	✓	4.49%	5.31%
Scanpower		✓	$18,552	$8,492	$10,060	118.5%	$1,599	$1,418	47.01%	$35,881	$0	0.00%		5.51%	6.51%
Vector Lines		✓	$1,294,016	$616,862	$677,154	109.8%	$77,948	$56,245	41.91%	$2,638,112	$28,641	1.07%	✓	3.01%	3.56%
Network Waitaki			$26,903	$16,754	$10,149	60.6%	$3,503	$1,303	27.11%	$73,574	$877	1.18%		2.57%	3.03%
Top Energy		✓	$61,097	$39,133	$21,964	56.1%	$12,239	$5,224	29.92%	$212,096	$4,625	2.13%	✓	4.41%	5.21%
Buller Electricity	✓	✓	$9,915	$7,692	$2,223	28.9%	$2,718	$380	12.27%	$26,000	$2,540	8.90%		1.63%	1.93%
Waipa Networks	✓	✓	$29,465	$22,993	$6,472	28.1%	$4,811	$769	13.77%	$89,710	$6,437	6.69%		1.10%	1.30%
The Lines Company			$49,139	$38,456	$10,683	27.8%	$8,079	$3,203	28.39%	$175,881	$1,672	0.94%	✓	2.75%	3.25%
Alpine Energy	✓	✓	$63,749	$50,913	$12,836	25.2%	$13,822	$0	0.00%	$166,321	$0	0.00%	✓	0.00%	0.00%
Powerco			$445,900	$358,774	$87,126	24.3%	$41,630	$29,111	41.15%	$1,454,598	$27,164	1.83%	✓	2.68%	3.16%
Orion NZ			$332,894	$274,174	$58,720	21.4%	$50,828	$0	0.00%	$907,756	$0	0.00%	✓	0.00%	0.00%
Electricity Ashburton	✓		$46,831	$41,252	$5,579	13.5%	$9,121	$0	0.00%	$226,349	$0	0.00%	✓	0.00%	0.00%
Counties Power	✓	✓	$52,305	$46,467	$5,838	12.6%	$7,716	$4,125	34.84%	$227,781	$228,905	50.12%		2.93%	3.46%
Westpower			$23,335	$20,833	$2,502	12.0%	$9,567	$0	0.00%	$112,420	$0	0.00%		0.00%	0.00%
Unison Networks	✓		$153,986	$139,744	$14,242	10.2%	$19,314	$17,715	47.84%	$538,909	$0	0.00%	✓	4.18%	4.94%
WEL Networks	✓	✓	$110,079	$100,990	$9,089	9.0%	$11,052	$8,920	44.66%	$482,546	$0	0.00%		2.91%	3.44%
Centralines	✓		$13,369	$12,304	$1,065	8.7%	$3,477	$94	2.63%	$54,680	$0	0.00%	✓	0.25%	0.30%
The Power Company			$60,974	$56,622	$4,352	7.7%	$14,414	$0	0.00%	$325,146	$0	0.00%		0.00%	0.00%
Aurora Energy	✓	✓	$99,453	$93,463	$5,990	6.4%	$23,608	$0	0.00%	$330,597	$0	0.00%	✓	0.00%	0.00%
Network Tasman	✓	✓	$44,412	$42,074	$2,338	5.6%	$9,818	$0	0.00%	$161,343	$14,304	8.14%	✓	0.00%	0.00%

Notes: * Based on the relevant 2015 Annual Report, ** Based on March 2015 Information Disclosure data, *** Calculated as the difference of total revenue minus regulated revenue. The table does not include all EDBs or GTBs, as some of the data on unregulated revenues for some EDBs was not robust.

Key
Under the Revenue Materiality Threshold
Under the Operating Cost/Asset Value Materiality Threshold
Using ACAM where this has greater than a 2% impact on regulated revenues

Appendix G: Vector 2015 Schedule 5b disclosure on related party transactions

Company Name	Vector
For Year Ended	31 March 2015

SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

This schedule provides information on the valuation of related party transactions, in accordance with section 2.3.6 and 2.3.7 of the ID determination.
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

sch ref	5b(i): Summary—Related Party Transactions	($000)
8	Total regulatory income	–
9	Operational expenditure	12,547
10	Capital expenditure	–
11	Market value of asset disposals	–
12	Other related party transactions	–

13 **5b(ii): Entities Involved in Related Party Transactions**

14	Name of related party	Related party relationship
15	Vector Communications Limited	A wholly owned subsidiary of Vector Limited.
16	Tree Scape Limited	An associate in which Vector Limited holds a 50% interest.
17		
18		
19		

20 ** include additional rows if needed*

21 **5b(iii): Related Party Transactions**

22	Name of related party	Related party transaction type	Description of transaction	Value of transaction ($000)	Basis for determining value
23	Vector Communications Limited	Opex	Purchase of telecommunications services	8,696	ID clause 2.3.6(1)(c)(i)
24	Tree Scape Limited	Opex	Purchase of vegetation management services	3,851	ID clause 2.3.6(1)(d)
25		[Select one]			[Select one]
26		[Select one]			[Select one]
27		[Select one]			[Select one]
28		[Select one]			[Select one]
29		[Select one]			[Select one]
30		[Select one]			[Select one]
31		[Select one]			[Select one]
32		[Select one]			[Select one]
33		[Select one]			[Select one]
34		[Select one]			[Select one]
35		[Select one]			[Select one]
36		[Select one]			[Select one]
37		[Select one]			[Select one]

38 ** include additional rows if needed*

(Source: https://vector.co.nz/electricity-disclosures/financial-and-network-information).

Appendix H: RiskNet Article citing NZ interest rate swap volumes

Interest rate swaps

Another benefit to direct membership is the possibility of a competitive advantage when it comes to securing market share in the emerging New Zealand dollar-denominated interest rate swaps market. New Zealand is one of the few developed economies offering interest rates that provide investors with reasonable levels of return. The central bank benchmark is the official cash rate, which currently stands at 2.5%, representing a hefty premium for a country with a stable AA rating from Standard & Poor's in the current low-rate environment.

At the same time, new Basel capital requirements providing a better capital treatment for cleared derivatives has incentivised international banks to clear their New Zealand dollar interest rate swaps. In 2015, LCH cleared the same volume of New Zealand dollar swaps in a year as Hong Kong and Singapore dollar-denominated swaps combined. The average notional value of New Zealand dollar swaps going through LCH increased by 82% each year from 2012 to 2015, with the CCP clearing NZ$384 billion (US$260 billion) in April 2016 alone.

Appendix I: BIS Triennial 2013 survey citing NZD OTC interest rate derivative daily volumes, April 2013

Global OTC interest rate derivatives market turnover by currency[1]

Net-net basis,[2] daily averages in April, in billions of US dollars — Table 3

Currency	1998	2001	2004	2007	2010	2013
Total	265	489	1,025	1,686	2,054	2,343
EUR	...	232	461	656	834	1,146
USD	71	152	347	532	654	657
GBP	17	37	90	172	213	187
AUD	3	8	12	19	37	76
JPY	27	27	46	137	124	70
SEK	2	5	13	33	20	36
CAD	7	6	8	15	48	30
BRL[3]	...	0	1	2	3	16
ZAR[3]	1	0	2	3	5	16
CNY[3]	...	...	...	0	2	15
CHF	9	6	10	19	20	14
KRW[3]	...	0	0	5	16	12
MXN[3]	0	0	2	5	5	10
NOK[3]	2	3	8	8	15	9
PLN[3]	...	0	1	2	1	7
INR[3]	...	0	0	3	2	6
NZD[3]	0	0	2	7	4	5
DKK[3]	2	5	2	1	2	4
SGD[3]	0	0	3	4	4	4
THB[3]	...	0	0	0	1	3
HUF[3]	...	0	0	1	0	2
HKD[3]	1	1	4	9	3	2
MYR[3]	0	0	0	0	0	2
ILS[3]	...	...	...	0	0	2
CLP[3]	...	...	...	0	0	1
TWD[3]	0	0	0	1	1	1
CZK[3]	...	0	0	1	0	1
SAR[3]	0	0	0	0	0	0
COP[3]	...	...	...	0	0	0
RUB[3]	...	...	...	0	0	0
LTL[3]	...	...	...	0	0	0
TRY[3]	...	...	...	...	...	0
ARS[3]	...	...	...	...	...	0
PHP[3]	...	...	0	0	1	0
IDR[3]	...	0	0	0	0	0
RON[3]	...	...	...	...	0	0
PEN[3]	...	...	...	0	0	0
BHD[3]	...	...	...	0	...	0
LVL[3]	...	...	...	0	0	0
BGN[3]	...	...	...	...	...	0
OTH	124	4	12	50	36	7

[1] Single currency interest rate contracts only. [2] Adjusted for local and cross-border inter-dealer double-counting (ie "net-net" basis). [3] Turnover for years prior to 2013 may be underestimated owing to incomplete reporting in previous surveys. Methodological changes in the 2013 survey ensured more complete coverage of activity in emerging market and other currencies.

Appendix J: Debt premium table for EDBs, Transpower and GPBs – as reworked according to Contact Energy recommendations

	Industry	Rating	Remaining term to maturity	Debt premium	STD DEV
Determined debt premium	EDB/GPB	BBB+	5.0	1.503	0.082

Subclause	Issuer	Note ref.	Industry	Rating	Remaining term to maturity	Debt premium	STD DEV	
4(a)	-		-	-	-	-		
4(b)	WIAL	1	Other	BBB+	5.0	1.55	0.045	
	Genesis Energy	2	Other	BBB+	5.0	1.50	0.083	
	MRP	3	Other	BBB+	5.0	1.48	0.055	
	CIAL	4	Other	BBB+	5.0	1.53	0.036	
	Meridian	5	Other	BBB+	5.0	1.53	0.105	
4(c)	-		-	-	-	-		
4(d)	Spark	6	Other	A-	5.0	1.17	0.042	
	AIAL	7	Other	A-	5.0	1.25	0.046	
	Fonterra	9	Other	A-	5.0	1.34	0.132	
	Contact	8	Other	BBB	5.0	1.72	0.116	
	Transpower	10	Other	AA-	5.0	1.06	0.047	
- Average of 4(b)						1.52	0.065	0.057
- Average of 4(d) A- rating						1.26	0.073	0.073
- Average of 4(d) BBB rating						1.72	0.116	0.116
- Average of 4(d), A- average and BBB						1.49	0.095	0.087
NSS estimate for EDBs, Transpower and GPBs					5.0	1.66		

10.5 is from a small data sample due to recent issue date to end of sample period (31/3/16). From 1/5/16 - 29/7/16 std dev was about 6.7bp

With Meridian Std Dev adjusted to 6.7

Appendix K: TDB Advisory Comparative Company Analysis

Submission to the Commerce Commission on the Input Methodologies Review Draft Decisions: Comparative Company Analysis

Made on behalf of Contact Energy Ltd.

4 August 2016

www.tdb.co.nz

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Disclaimer

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1. Executive summary

TDB Advisory Ltd (TDB) has been engaged by Contact Energy Ltd (Contact) to provide an independent submission to the Commerce Commission (the Commission) in the context of the Commission's review of the input methodologies. Our submission focuses on the Commission's choice of comparable companies (compcos) for determining an appropriate weighted average cost of capital (WACC) for regulated energy network services in New Zealand.

The regulated New Zealand energy network companies are: seventeen electricity distribution businesses (EDBs), five gas pipeline businesses (GPBs) and the electricity transmission company, Transpower. These companies are solely or primarily involved in the transportation of electricity or natural gas.

An ideal or model set of comparator firms for the New Zealand regulated services would include a large (statistically significant) number of firms that operate in the same business segments as the New Zealand regulated services, and that are subject to the same or similar regulatory environment.

Given that, in New Zealand, there is only one electricity or gas network firm (Vector) which is publicly listed, the Commission has had to look further afield to develop its set of comparator firms. As a result, it has had to make judgements about the suitability as comparators of companies that operate in different regulatory environments and that have quite differing lines of business to the regulated New Zealand services.

Ultimately the choice of an appropriate compco set involves making a trade-off between the comparability of the set with the regulated entities, and the statistical significance of the sample set (i.e., having a large enough sample).

The Commission has selected a sample set of 74 energy companies as its comparator set. Almost 90% (66) of the companies come from the United States (U.S.), with four from Australia, three from the United Kingdom (U.K.), and one from New Zealand.

Our assessment of the Commission's compco set is that the Commission may have adopted too large a set at the expense of a loss in accuracy in the appropriate asset beta. In particular, the Commission's compco set includes:

- 20 companies which we assess have higher systematic risk, largely through unregulated gas gathering, processing, liquids and commodity exposures not found in "pure-play" distribution or transmission;
- another 14 companies with material lines of business with higher systematic risk that are either unrelated to the NZ regulated services (as they involve non-energy activities), or they have energy revenues that are unregulated; and
- another 31 companies with energy activities that are regulated, but are engaged in activities outside the transport of electricity and gas (these companies are mostly generators, retailers, and transporters of electricity).

There are, in our assessment, 8 companies in the Commission's sample set that are strictly comparable with the New Zealand energy network firms.

As Table 1 below indicates, the choice of sample set has a material impact on the estimated asset beta (and the resulting WACC) for the New Zealand regulated firms.[1]

Table 1: Summary of compco refinement

	Sample set	Weekly asset beta		Average leverage	Number of firms in sample (N)
		Average	S.E.		
	Commission's energy set	0.34	0.14	41%	74
Step 1	Remove firms with unregulated gathering, processing, liquids and commodity exposures	0.29	0.09	42%	54
Step 2	Remove firms with other large unrelated/unregulated business segments	0.28	0.08	44%	39
Step 3	Remove firms with significant business segments that are not related to transmission or distribution	0.24	0.11	49%	8

The table indicates that:

- there is a marked decline in the average beta estimates when we control for the increased risk that firms face through unregulated gas gathering, processing, liquids and commodity exposures (Step 1). The mean asset beta declines from 0.34 (the Commission's recommended number) to 0.29, the standard error declines from 0.14 to 0.09, the leverage increases marginally from 41% to 42% and the sample set declines from 74 to 54;

- removing also the firms with large unrelated or non-regulated revenues (Step 2) results in a further decline in the asset beta to 0.28, the standard error declines further to 0.08, the leverage increases further to 44% and the sample set declines to 39; and

- removing all but the eight largely "pure-play" energy lines businesses reduces the mean beta to 0.24, the standard error increases to 0.11 (reflecting the smaller sample set), the leverage increases to 49% and the sample set declines to 8.

Our classification of the Commission's 74 compcos is indicative, and inevitably involves a degree of judgement based on the available information. Nevertheless, we consider our overall conclusions

[1] We focus in this summary on the weekly (rather than 4-weekly) betas because the Commission uses the weekly beta in its recommended WACC, and because this is the default method reported by Bloomberg and Value Line. Refer "Best Practices in Estimating the Cost of Capital: An Update", W. Todd Brotherson et al, Journal of Applied Finance, Vol. 23, No. 1, 2013, p.11. Elsewhere in this submission we report both weekly and 4-weekly numbers.

that there are companies with significantly different risk profiles to the New Zealand regulated network companies in the Commission's compco set, and that this has a material impact on the estimated average beta, to be robust. Appendix 4 presents the results of our sensitivity analysis around the classification of the individual companies, and indicates the estimated betas still differ from the Commission's recommended 0.34.

To further test the robustness of our conclusions, we classified the Commission's 74 compcos solely on the basis of the country they are located in.[2] This analysis highlighted the importance of the country of origin, with the 66 USA companies having an average beta of 0.35, the three UK companies having an average beta of 0.25, and the five Australian/NZ companies having an average beta of 0.23.

Given the sensitivity of the estimated average betas to the choice of compco sample set, and the apparent inclusion in the Commission's sample of companies with quite different risk profiles, we recommend that the Commission review its compco set.

In our view, it is unnecessary and inappropriate to include firms with either unregulated gas gathering, processing, liquids and commodity exposures, or large unrelated/non-regulated revenues in the compco set for the New Zealand regulated energy network companies. If those two sets of firms are excluded, the Commission would still have a compco set of around 40 companies from which to derive an asset beta. Such a sample set is considerably larger than that used by the Australian Electricity Regulator (which has nine companies in its benchmark set for an energy network company)[3], and would seem more than sufficient to generate meaningful estimates.

Indeed, we recommend that the Commission go further and consider the eight largely "pure-play energy transporters" as the appropriate benchmark group, and determine whether those companies may be from a statistically different population than the other 66 companies in its compco data set.

We note that from the Commission's original compco data set, there appears to be a statistically significant difference between the Commission's estimates of the mean betas for the gas and electricity companies; the average betas for the 16 electricity companies (and 40 integrated companies) are 0.29 to 0.30 respectively, while the average beta for the 18 gas companies is 0.44. We caution against the use of this result in isolation, given our concerns with the underlying comparators (as discussed above), and encourage the Commission to first review the appropriateness of the companies included within the electricity, gas, and integrated compco subsamples.

Finally, we note that the sample set leverage and standard error will change with the composition of the compco sample set (as demonstrated in Table 1 above), and the estimated WACC will change to reflect the relevant leverage.

[2] Country of origin could be a proxy for the regulatory environment and/or line of business as almost all US companies are involved in more than transporting energy.

[3] AER, "Preliminary Decision. Jemena Distribution Decision 2016 to 2020. Attachment 3 – Rate of Return", October 2015 page 3-457.

2. Introduction

2.1 Purpose of the submission

This submission provides an independent review of aspects of the Commerce Commission's review of the input methodologies for services that are regulated under Part 4 of the Commerce Act. Our submission focuses on the Commission's choice of comparable companies (compcos) for determining an appropriate weighted average cost of capital (WACC) for regulated energy network services in New Zealand.

2.2 Structure of the submission

Following the executive summary and this introduction, our submission is structured as follows:

- Section 3 looks at the risk profiles of the 74 firms selected by the Commission as comparable to the New Zealand energy network services. We look at the distribution of the estimated asset betas and analyse in more detail the nature and risk characteristics of the individual companies at the higher and lower end of the electricity, gas and integrated company distributions. This analysis indicates the Commission's sample set includes many companies with markedly different systematic risk characteristics to New Zealand's regulated energy network services;

- Section 4 examines in more detail the potential difference between the mean asset betas for the electricity and gas companies;

- Section 5 provides a three-step process for determining a set of firms with comparable risk profiles to the regulated New Zealand energy network services, and applies the process to assess the sensitivity of the Commission's average beta and leverage estimates to the selected sample sets;

- Section 6 provides a test of the robustness of our analysis by classifying the Commission's 74 comparable companies solely on the basis of the country where they are located; and

- Section 7 provides the conclusions from our analysis.

3. Asset beta and leverage: comparable companies' analysis

The Commission employs a set of comparative companies (compcos) in order to obtain key risk and leverage metrics for regulated electricity and natural gas distribution and transmission services. The Commission uses each company's share price performance to estimate the level of systematic risk (equity beta). The Commission then allows for the capital structure unique to each firm to derive an estimate of each firm's asset (or un-levered) beta. The Commission then averages across the sample of comparators to find an estimate of the risk that the industry faces, and the average leverage within the industry. This process is common practice for estimating industry risk and capital structure, which allows the Commission to estimate the return on equity that is appropriate for the regulated service, which in this case is the transportation and distribution of energy.

The Commission has identified 74 firms that are involved in gas and electricity transportation, in order to estimate the appropriate beta. Of the comparator firms, 66 are from the U.S., three are from the U.K., four are from Australia and one is from New Zealand. These firms have reported operations in electricity and natural gas distribution and transmission. Some are defined by the Commission as being made up of primarily electricity or natural gas operations, and some have been defined as integrated, meaning the firm in question is involved in both electricity and natural gas activities.

In the subsections below, we: analyse the comparator set used by the Commission; look at the distribution of the risk profiles of the firms the Commission has identified as appropriate; and recommend that further filtering of the comparator set would be useful to identify a set that is still statistically significant, but more closely matches New Zealand's electricity distribution businesses (EDBs), gas pipeline businesses (GPBs), and Transpower (the "energy network companies"). This report does not analyse the Commission's calculations of the betas for the compcos, as we agree with the Commission's updated methodology for conducting the regression analysis for the timeframe in question.

3.1 Selection of energy comparator set

The choice of the comparator set that the Commission uses has a significant bearing on the inputs to the Commission's assessment of the appropriate return on equity and WACC for the EDBs, GPBs, and Transpower. It is important that the comparator set be as close to the true nature of the New Zealand energy network firms as possible, with firms that operate in a regulatory environment similar to that of the New Zealand firms.

The Commission utilises the Bloomberg Industry Classification Benchmark system (ICB) to identify firms to include in the comparative firm sample set. The Commission identifies relevant firms that are classified by the ICBs as belonging to the 'Electricity', 'Gas Distribution', 'Pipelines' or 'Multiutilities' industries.[4] The Commission then assesses the companies' profile descriptions from Bloomberg, and 'Segment Analysis' information to analyse the appropriateness of including the firm in its final energy comparator set.[5] We consider this second step as very important given how general the ICB categories appear to be. Further to using this approach to identify its energy comparator set, the Commission classifies the firms into sub-sets identified as 'Electricity', 'Gas' or 'Integrated'. Presumably the electricity sub-set contains firms which have business segments that only relate to the electricity industry, the gas sub-set contains firms which have business segments

[4] Commerce Commission "Input methodologies review draft decisions, Topic paper 4: Cost of capital issues (16 June 2016), para 273.
[5] Commerce Commission "Input methodologies review draft decisions, Topic paper 4: Cost of capital issues (16 June 2016), para 260.

only related to natural gas, and the integrated sub-set contains firms with business segments related to both.[6]

While the Commission's methodology offers a standardised approach that attempts to account for each firm's particular operations, there are limitations. In particular, it is possible that the Bloomberg descriptions are not up to date, are inaccurate, and/or neglect certain aspects of a firm given the large number of firms and changing nature of the global market.

3.2 Distribution of the Commission's energy comparator set

To assess how comparable the Commission's energy comparator set is, it is useful to assess the distribution of the risk profiles of the firms. We expect that a comparable firm sample set would have a relatively normal looking distribution across the range of asset beta estimates. That is, we expect that the number of firms with the same un-levered risk profile to increase and then decrease about a mean. We would not expect to see evidence of uniform, or multimodal distributions, as this may indicate differences in the level of un-levered systematic risk that sub-sets of firms are subject to. This would potentially indicate that the firms operate in different industries.

Figure 1 depicts the distribution of the estimated betas for the set of 74 energy comparator firms identified by the Commission. On the x-axis is the estimated asset betas, and on the y-axis is the number (frequency) of firms associated with that asset beta. The two plotted lines represent the weekly asset beta estimates and 4-weekly asset beta estimates provided by the Commission. The firms have been tallied by their beta estimates starting at 0 and increasing at a rate of 0.05.[7] These frequencies are tabulated in the final column of Table 9 in Appendix 1. The full sample set of weekly estimates has a mean asset beta of 0.34, with a standard error of 0.14, and average leverage 0f 41%.[8]

---

[6] This seem somewhat unclear in the Commissions "Input methodologies review draft decisions, Topic paper 4: Cost of capital issues (16 June 2016)

[7] This frequency analysis is carried out to gain a high-level understanding of the distribution of the comparator sample set. We group the estimates by a 0.05 change in the asset beta and recognise that a higher or lower adjustment may change the shape of the distribution. However, we consider that the 0.05 adjustment is reasonable for this high-level overview: if the adjustment is too small outcomes effectively become binary while if the adjustment is too large the data may be misrepresented.

[8] Leverage is not obtained from the commission but has been sourced from the Commission's released spreadsheet from Bloomberg provided through Contact.

Figure 1: Distribution of the estimated betas of the Commission's energy comparator set (2011-2016) estimates

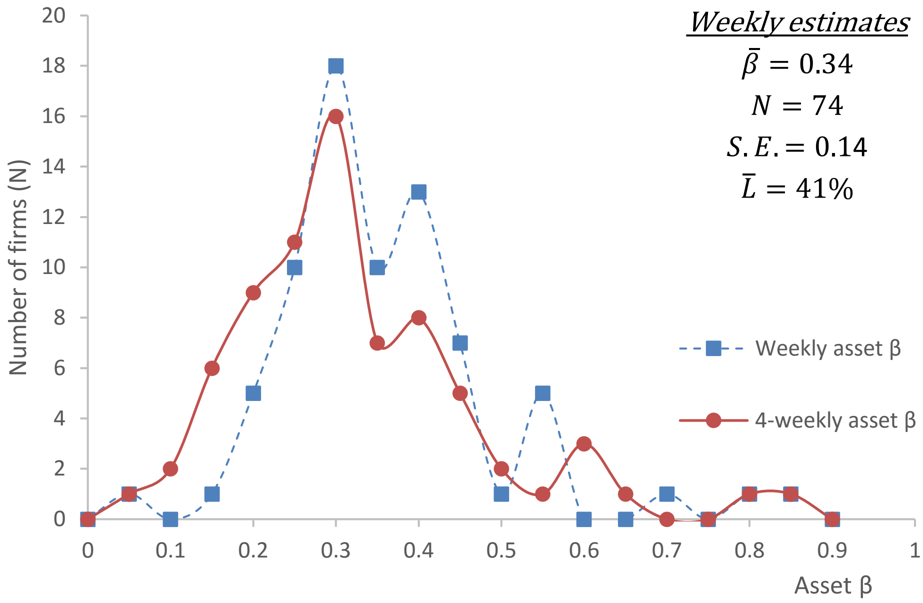

Figure 1 depicts what might be considered a reasonable frequency distribution for a comparator set. However, there appears to be a long tail at the upper end of the distribution. This skew is interesting, and warrants further investigation. To conduct this, we also disaggregate the firms by the Commission's sub-set classifications. Table 2 presents, firstly, the average beta estimates, leverage, and sample size for the Commission's full energy comparator set, followed by the Commission's industry sub-sets. It shows that, as presented above, the average weekly beta estimate for the full set is 0.34 with leverage of 41% and a sample size of 74. It then shows the electricity sub-set has an average weekly estimate of 0.29, average leverage of 40%, and a smaller sample size of 16 firms. The integrated sub-set has an average weekly beta estimate of 0.30, average leverage of 44%, and a sample size of 44%. Finally, the gas sub-set has an average weekly beta of 0.45, an average leverage of 34%, and a sample size of 18.

Table 2: Estimated mean asset betas by industry group

2011-2016 estimates	Daily asset beta	Weekly asset beta	4-Weekly asset beta	Leverage	Number of firms in sample
Commission's energy set	0.39	0.34	0.30	41%	74
Sub-sets of Commission's set					
Electricity	0.33	0.29	0.26	40%	16
Integrated	0.37	0.30	0.26	44%	40
Gas	0.50	0.45	0.44	34%	18

Table 3 then presents the standard error calculations with weekly estimates being 0.14, 0.12, 0.09 and 0.21 for the full set, electricity sub-set, integrated sub-set, and the gas sub-set respectively.[9]

Table 3: Estimated standard errors by industry group

Standard errors	Daily average S.E.	Weekly average S.E.	4-Weekly average S.E.	Number of firms in sample
Energy set	0.14	0.14	0.14	74
Sub-sets of Commission's set				
Elcetricty	0.12	0.11	0.12	16
Intergrated	0.11	0.09	0.09	40
Gas	0.17	0.21	0.20	18

We note that in the summary of this submission we have reported the weekly point estimates for the betas and attached standard errors. This is primarily because the Commission applies a weekly beta in its draft decision. We do not express a view on the relative merits of weekly and 4-weekly betas and report the results of both the weekly and 4-weekly betas throughout the body of this submission. The only exception is section 3.3 below where, for simplicity, we present the distribution analysis using the 4-weekly estimations. For completeness we have carried out the same analysis in Appendix 2 using weekly betas and find no differences in the estimates, apart from the magnitude of the point estimates and their standard errors.

3.3 Disaggregation of the Commission's energy comparator set

To analyse the distribution of the Commissions comparator set more closely, we present the distribution of the full set broken into the sub-sets of electricity, gas and integrated in Figure 2. This provides a graphical representation of how the beta estimates are distributed across the three industry groups. For instance, at the peak of the distribution (being the total of firms with an estimated asset beta of 0.25-0.3) the sixteen firms incorporated include six firms the Commission has classified as electricity, eight firms the Commission has classed as integrated, and two firms which have been classified as gas. Furthermore, now we are applying 4-weekly estimates, the average beta is 0.3, consistent with Table 2 (and specified in the graph summary statistics).

[9]All standard errors are calculated following the Commission's working. Then average over the 2006-2011 and 2011-2016 periods consistent with the 0.14 that the Commission reports for the full set.

Figure 2: Distribution of the Commission's (4-weekly beta) energy comparator set with industry breakdowns

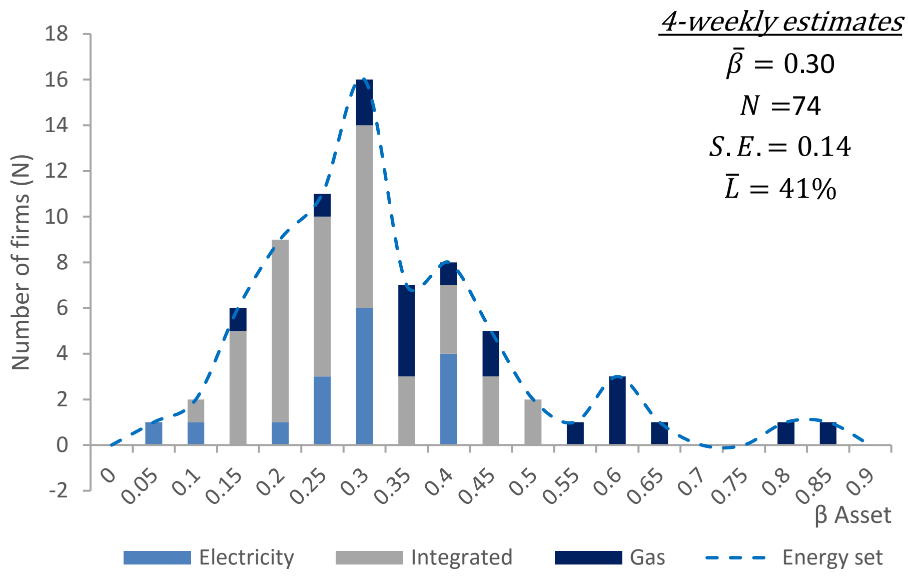

Figure 2 indicates that the distributions of the betas for the three industry sub-sets defined by the Commission may not be the same:

- the highest seven asset beta estimates belong to the gas industry;
- the electricity firm beta estimates appear to be skewed towards the lower end of the distribution; while
- the integrated firms seem to be fairly evenly spread across the distribution.

To investigate these apparent differences in the betas between the three industry sub-sets further, Figure 3, Figure 4 and Figure 5 break down the distributions for each of the industry sub-sets.[10]

Figure 3 depicts the frequency plot for the asset betas of the electricity firms in the Commission's comparator set.[11] The maximum for the electricity sample is less than 0.4, and the minimum is less than 0.05, making the range of the electricity firms in the sample noticeably smaller than that of the full set. It is noticeable that the estimated asset betas of all the electricity firms are less than the estimated average gas asset beta.

Figure 3: Distribution of the Commission's electricity asset betas

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[10] The frequency tables of the betas for Figures 1 – 5 can be found in Table 9 in Appendix 1 of this report. 4-weekly beta estimates have been adopted for simplicity.

[11] The distribution is flat to begin with, then rises to two modes. These rises may be somewhat artificial when the points are joined. The fact that there are no observations of electricity firms with asset betas between 0.25 and 0.3 may not indicate that the distribution is separated, particularly considering that the frequency of observations between 0.35 and 0.4 is similar to that of the number of observations from 0.2 to 0.25 before the rise to the peak of 0.25 to 0.3. If the two points from 0.25 and 0.4 were connected, the distribution for that region would look quite smooth. This highlights the small sample errors that might be encountered.

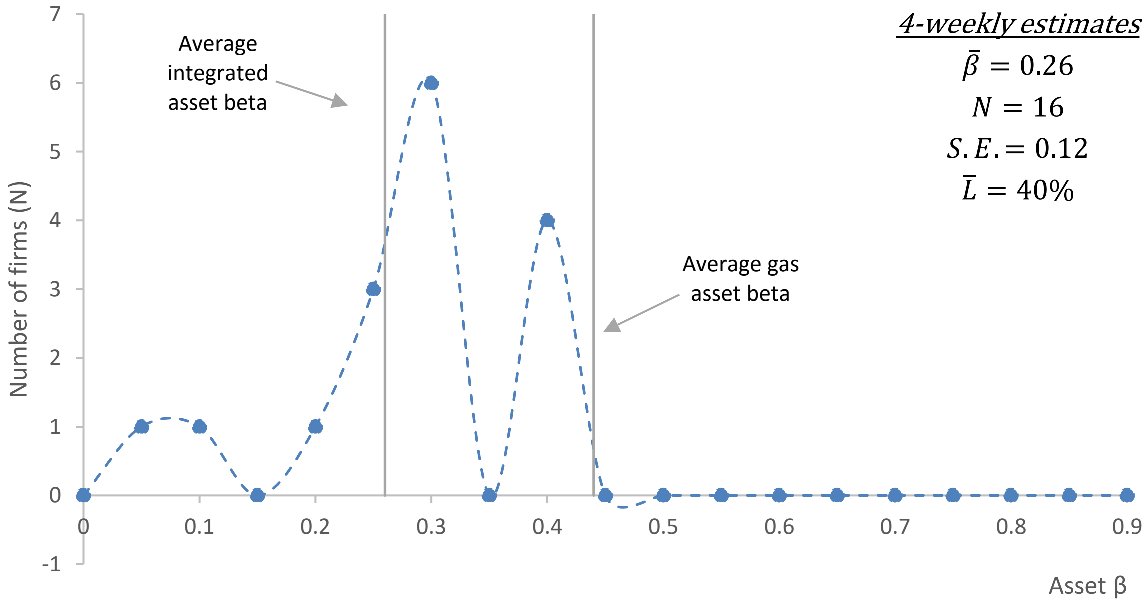
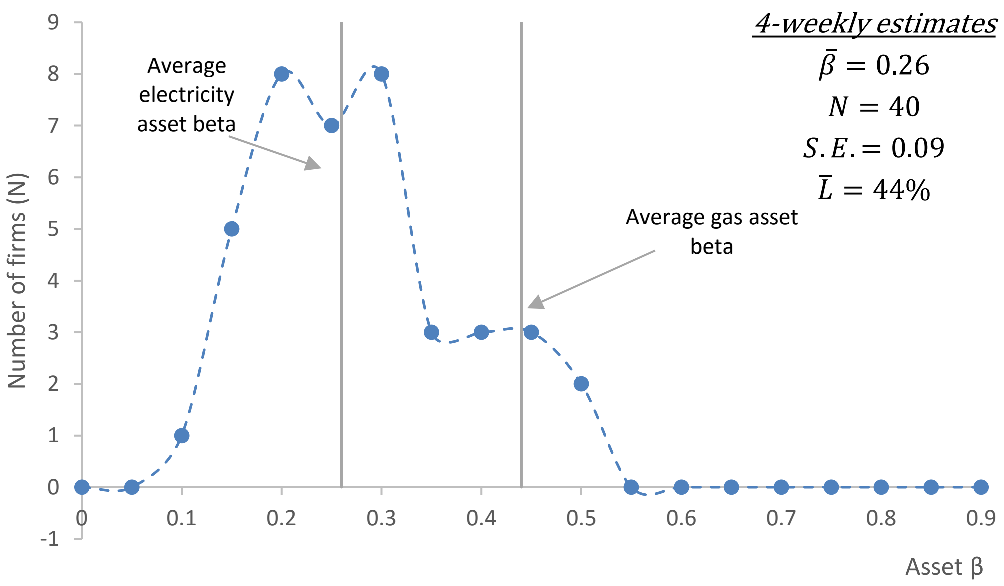


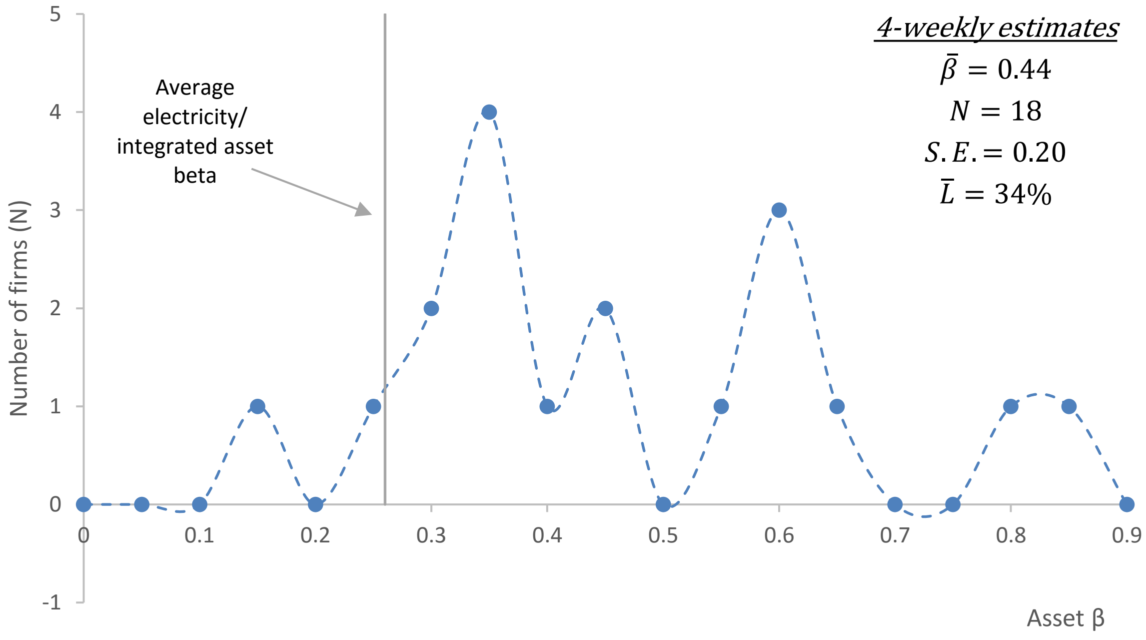
Figure 4 presents the frequency plot for the "integrated"" sub-set asset beta estimates. The graph shows a general peak (with some variation) between approximately 0.2 and 0.3. There do appear to be two firms that are very low, at the lower end of the distribution. This is interesting, as they may not contain the same risk profile.

Figure 4: Distribution of the Commission's integrated asset betas



Finally, Figure 5 shows the frequency plot for the asset betas for the "gas" sub-set of the Commission's energy set. As noted above, the mean asset beta for the gas firms is 0.44. The gas betas have the widest distribution, and appear better fitted to a uniform distribution than a normal distribution. However, the sample size may be too small to infer any true characteristics.

Figure 5: Distribution of the Commission's gas asset betas



3.4 Statistical inferences

The distributions presented above have highlighted some key features of the Commission's adopted energy comparator set, and possible differences between the industry groups.

As noted above, the maximum beta in the Commission's electricity sub-set (0.4) is below the average for the gas firms sub-set (0.44). Furthermore, only four of the sixteen firms classified by the Commission as electricity firms have an estimated asset beta higher than the Commission's mean estimate (0.3) for the sector.[12]

At first glance, this suggests that the gas firms may be subject to higher systematic risk than the electricity firms. The distribution of the estimated asset betas for the integrated firms could reinforce this point. If the disjointed nature of the integrated firms is due to the level of integration between gas and electricity, then the electricity and gas business segments could have different risk profiles. However, the wide multimodal distribution of the gas firms indicates that there is a large discrepancy between the business segments and risk profiles of the firms within the gas sub-set. If the firms at either end of the distribution of the gas sub-sample are partly, or primarily involved in more or less risky activities than a typical GPB in New Zealand, this could explain the discrepancy.

The differences between the electricity and gas sub-samples could also be due to the sample sizes being too small and not statistically representative of the true distributions, or, conversely, due to the sample sizes being too large and the comparative significance of the firms being too low.

We do not want to overstate the statistical significance or reliability of the distribution analysis presented above. Our analysis is intended to indicate issues that may warrant further analysis by the Commission.

[12] This holds true for the weekly estimates presented in Appendix 2

To investigate the issues further, we turn to a more detailed analysis of the firms within the Commission's energy comparator set. In particular, we examine the firms at the high and low ends of the distribution for each sub-sample to see if there are fundamental differences in the risk profiles, as identified by their business segments and operations. Section 3.5 selects a few firms in the Commissions electricity sub-set on either end of the distribution to analyse more closely, by comparing and contrasting the Bloomberg descriptions to the most recent 10-K or Annual Report of each firm identified.[13] Section 3.6 repeats this for the integrated sub-set, section 3.7 then analyses the gas distribution and section 3.8 presents a detailed summary of the findings and concludes.

3.5 Electricity company betas

We consider below the companies in the Commission's electricity sub-set that have the highest and lowest estimated betas, in order to see if there may be fundamental systematic differences between the firms with high and low betas. On the high end of the distribution, we identify ALLETE Inc. (ALE), IDACORP Inc. (IDA), Hawaiian Electric Industries (HE) and AES Corp. (AES). On the low end, we identify Jersey Electricity PLC (JEL) and Southern Company (SO).

3.5.1 High beta estimate firms

ALLETE Inc. (ALE)

$$\boldsymbol{Location = U.S.} \qquad \boldsymbol{\beta_A = 0.4} \qquad \boldsymbol{Avg. L = 30\%}$$

The Bloomberg description for ALLETE Inc. states "ALLETE Inc. provides energy services in the upper Midwest United States. The Company generates, transmits, distributes, markets, and trades electrical power for retail and wholesale customers".

Consistent with the Bloomberg description, ALLETE's 10-K reports that 67% of its revenue is from regulated operations. However, ALLETE also has two other business segments that would likely not be picked up in the Bloomberg description. One segment is 'ALLETE Clean Energy' which invests in capital projects involving "clean energy solutions by way of wind, solar, biomass, hydro, natural gas, shale resources, clean coal technology and other emerging energy innovations".[14] The other business segment, that represents approximately 8% of the firm's revenue, is U.S. Water Services, which is an integrated water management company. This business segment was only purchased early in 2015, so the effect on the estimated risk profile may not be large. Nevertheless, this business line is not picked up in the Bloomberg description. Putting the missing segment information aside, ALE's 10-K shows the breakdown of its regulated operating income. It shows that ALLETE purchases power and fuel, and also reports expenses for transmission services. Its 10-K also notes that these revenues come from sales to residential, commercial, industrial, and municipals in the form of kilowatt-hours sold.[15] It therefore appears that ALLETE is selling the products that it

[13] All 10-Ks have been sourced from the Security Exchange Commission's EDGAR database and Annual Reports (when used) have been sourced from the individual company's website. In conjunction other sources have been utilised such as investor presentations.
[14] P. 84 of ALE's 2015 10-K.
[15] P. 38 of AEL's 2015 10-K.

generates and distributes, and is not simply a pure play transporter of energy (as is the service that is subject to regulation by the Commission).

IDACORP Inc. (IDA)

$$\boldsymbol{Location = U.S.} \qquad \boldsymbol{\beta_A = 0.38} \qquad \boldsymbol{Avg.L = 43\%}$$

The Bloomberg description for IDACORP states "IDACORP Inc. is the holding company for Idaho Power Company, an electric utility, and IDACORP Energy, an energy marketing company. Idaho Power generates, purchases, transmits, distributes, and sells electric energy in southern Idaho, eastern Oregon, and northern Nevada. IDACORP Energy maintains electricity and natural gas marketing operations".

Consistent with the Bloomberg description, IDA is involved in generation, transmission and sales to both retail and wholesale markets. From its segmented income statement, it seems that IDACORP generates all revenue from retail sales, with a large part (approximately half) of that being residential. This indicates that IDACORP also is selling the products that it generates and distributes, and is not simply a transporter of energy, consistent with ALLETE above.

Hawaiian Electric Industries (HE)

$$\boldsymbol{Location = U.S.} \qquad \boldsymbol{\beta_A = 0.37} \qquad \boldsymbol{Avg.L = 24\%}$$

The Bloomberg description for HE states "Hawaiian Electric Industries, Inc. is a diversified holding company that delivers a variety of services to the people of Hawaii. The Company's subsidiaries offer electric utilities, savings banks, and other businesses, primarily in the state of Hawaii".

As highlighted in the Bloomberg description, as well as offering electricity utilities, HE is also involved in banking. However, according to its 10-K, the banking segment only makes up approximately 10% of its total revenue. Therefore, this level of exposure may not alter the market's perception of its systematic risk exposure away from the utilities arm of the firm. HE's income statement for its energy segment appears consistent with ALLETE and IDACORP above. HE generates and purchases power through various means, then distributes and sells that power directly to end-users. That is, the company owns what it distributes.

AES Corp. (AES)

$$\boldsymbol{Location = U.S.} \qquad \boldsymbol{\beta_A = 0.37} \qquad \boldsymbol{Avg.L = 63\%}$$

The Bloomberg description for AES states "The AES Corporation acquires, develops, owns, and operates generation plants and distribution businesses in several countries. The Company sells electricity under long term contracts and serves customers under its regulated utility businesses. AES also mines coal, turns seawater into drinking water, and develops alternative sources of energy".

As reported in Table 1 of the Commission's Topic paper 4, AES generates approximately 47% of its revenues from electricity utilities. The core of that business is generation (seemingly included under utilities) that is organised into six small business units, all operating in different countries and facing varying regulatory regimes. Also, as reported in a recent investor presentation, 84% of its business is contracted generation or utilities.

3.5.2 Low beta estimate firms

Jersey Electricity PLC (JEL)

$$\boldsymbol{Location = U.K.} \qquad \boldsymbol{\beta_A = 0.02} \qquad \boldsymbol{Avg.L = -13\%}$$

The Bloomberg description for JEL states "Jersey Electricity PLC generates, imports, and distributes electricity. The Company is also involved in electrical appliance retailing, property management, and building services contracting. Its other business interests include telecommunications and Internet data hosting".

JEL's Annual Report shows that its business operations involve five key operations: energy; building services; retail; property; and other. JEL's 2015 Income Statement by business segment shows that, as noted by the Commission[16], approximately 80% of JEL's revenue comes from its energy segment. This segment includes generation, transmission and distribution of energy. The generation aspect of JEL's business may alter the risk profile compared to a pure play distribution business. However, the proportion of generation versus transmission and distribution is unclear from JEL's reporting. JEL notes that the State of Jersey owns 62% of the company's ordinary share capital, that it is the sole supplier of electricity in Jersey, Channel Islands, and that it has activities in other parts of the U.K.

Further, perhaps due to the high State ownership in JEL, the stock is illiquid and for this reason we exclude the company from the data set.

Southern Company (SO)

$$\boldsymbol{Location = U.S.} \qquad \boldsymbol{\beta_A = 0.09} \qquad \boldsymbol{Avg.L = 38\%}$$

The Bloomberg description for SO states "The Southern Company is a public utility holding company. The Company, through its subsidiaries, generates, wholesales, and retails electricity in the southeastern United States. The Company also offers wireless telecommunications services, and provides businesses with two-way radio, telephone, paging, and Internet access services, as well as wholesale fiber optic solutions".

SO's 2015 10-K shows that the firm is primarily a generator, distributer and transmitter of energy. However, based on an assessment of its income statement, retail revenue accounts for approximately 93% of SO's total revenue, it appears that the retail revenues generated through its subsidiaries are regulated. There is no report of revenues stemming from generation or distribution. SO appears to be involved in the entire process for its electricity distribution, right to end-users, consistent with that seen for the higher risk firms. This indicating that SO is a fully integrated, regulated monopoly, as is consistent in the U.S. system.

3.5.3 Summary of electricity comparators

The electricity comparators used by the Commission seem to have similar business makeups across the upper to the lower end of the distribution for the asset betas. It does appear that the firms in the

[16] Table 1, Commerce Commission, op. cit., p. 66.

higher end of the distribution are more diversified and have greater portion of revenue being generated from non-regulated activities.

It appears, from the 10-K and Annual Reports analysed, that none of the companies above are 'pure play' distribution firms, and each have some form of generation and retail operation. In most cases, the companies operate from generation to end-user sales, and many functions appear regulated. The complexity of many of these firms may mean we are over-simplifying their operations. However, the 10-K reports seem quite clear; the companies at both ends of the beta distribution tend to own the product they sell and are not simply transporters of electricity, however the firms with higher risk profiles appear more diversified and have more non-regulated revenue streams.

3.6 Integrated company betas

In assessing the distribution for the integrated sub-set presented earlier, we identify OGE Energy Corp (OGE) and Black Hills Corp. (BKH) on the high end. This is followed by Consolidated Edison Inc. (ED) and FirstEnergy Corp (FE) on the low end.

3.6.1 High beta estimate firms

OGE Energy Corp (OGE)

$$\boldsymbol{Location = U.S.} \qquad \boldsymbol{\beta_A = 0.46} \qquad \boldsymbol{Avg. L = 36\%}$$

The Bloomberg description for OGE states "OGE Energy Corp., through its principal subsidiary Oklahoma Gas and Electric Company, generates, transmits, and distributes electricity to wholesale and retail customers in communities in Oklahoma and western Arkansas. The Company, through Enogex Inc., operates natural gas transmission and gathering pipelines, has interests in gas processing plants, and markets electricity".

Consistent with the Bloomberg description, OGE's reporting confirms that it is involved in generating, transmitting, distributing and selling electricity which is mostly regulated at both the state and federal level. Furthermore, it is involved with gathering, transporting, and processing of natural gas. From its 10-K, it operates approximately 12,400 miles of natural gas gathering pipelines, and owns/operates 13 natural gas processing plants through a subsidiary. It also has operations in oil gathering. Within OGE's 10-K, it appears that the gathering and processing functions are not regulated. The transportation and storage function generates fee-based revenue. Also, two of the risks OGE specifically states it is subject to are: "the fees and gross margins realized with respect to the volume of natural gas and crude oil handled"; and "the prices of, levels of, production of, and demand for natural gas and crude oil".[17] This suggests its risk exposure within its gas and liquids business segment is subject to increased commodity price fluctuations through the presence of gathering, processing and finally marketing.

It appears that the mostly regulated electricity operations of OGE make up a majority of its operations (approximately 96%). Also, the purchase of its midstream operation subsidiary is recent.

[17] P. 24 of OGS 2015 10-K

It therefore seems that OGE is primarily an electricity firm with a small and growing natural gas, NGLs and oil midstream segment.

Black Hills Corp. (BKH)

$$\boldsymbol{Location = U.S.} \qquad \boldsymbol{\beta_A = 0.46} \qquad \boldsymbol{Avg.L = 43\%}$$

The Bloomberg description for BKH states "Black Hills Corporation is a diversified energy company. The Company generates wholesale electricity, produces natural gas, oil and coal, and market energy. Black Hills serves customers in Colorado, Iowa, Kansas, Montana, Nebraska, South Dakota and Wyoming".

From its Bloomberg description, BKH appears to have similar business segments to that of OGE above. It has activities that involve both generating wholesale electricity and producing natural gas and oil. According to its Annual Report, gas utilities made up 25.7% of total operating income, and electricity utilities made up 64.6% of its operating income. BKH also reports that it has exploration and reserves under its control as part of its natural gas and oil segment, along with gathering and production. Again, this seems to be consistent with a different risk profile than if the firm was a regulated pipeline business.

3.6.2 Low beta estimate firms

Consolidated Edison Inc. (ED)

$$\boldsymbol{Location = U.S.} \qquad \boldsymbol{\beta_A = 0.06} \qquad \boldsymbol{Avg.L = 42\%}$$

The Bloomberg description for ED states "Consolidated Edison, Inc., through its subsidiaries, provides a variety of energy related products and services. The Company supplies electric service in New York, parts of New Jersey, and Pennsylvania as well as supplies electricity to wholesale customers".

According to its 10-K, ED has three key utility business segments: electricity operations (accounting for a reported 70% of revenue generation); gas operations (14% of revenue); steam operations (5% of revenue); and non-utility (11% of revenue). The electricity operations include distribution, transmission, generation, sales and delivery. The gas operations include supply, sales, and delivery, and the steam operations include steam sales and deliveries. As seems typical, the company's electricity supply comes from a mixture of its own generation and purchases that it makes on the wholesale market. Its gas supply reportedly comes from gas purchases from wholesale pipeline operators which is then piped in ED's own lines to its customers. This seems typical of U.S. utilities firms which own or purchase what they distribute and buy at volumes that reflect demand.

ED's 2015 Annual Report notes three higher level major business segments: regulated utilities, regulated transmission, and competitive energy businesses. It appears that the competitive energy businesses are involved in retail, wholesale, and energy infrastructure projects. The regulated sectors seem to have functions that relate directly to the transportation of customer owned gas.

FirstEnergy Corp (FE)

$$\boldsymbol{Location = U.S.} \qquad \boldsymbol{\beta_A = 0.12} \qquad \boldsymbol{Avg.L = 50\%}$$

The Bloomberg description for FE states "FirstEnergy Corp. is a public utility holding company. The Company's subsidiaries and affiliates are involved in the generation, transmission, and distribution of electricity, exploration and production of oil and natural gas, transmission and marketing of natural gas, and energy management and other energy-related services".

The Bloomberg description of FE indicates that the firm is involved with oil and gas production and sales. This business segment appears to be associated with higher systematic risk. However, in assessing FE's 10-K, most references to production refer to electricity, with the one mention that relates to gas being: "we also have current or previous ownership interests in sites associated with the production of gas, and the production and delivery of electricity"[18]. Furthermore, there is no mention of gathering or extraction of gas in the report. FE's summary of operations in its 10-K shows that approximately 71% of its revenue is attributed to regulated electricity utilities. In addition, FE seems to have a pure-play transmission business segment.

3.6.3 Summary of integrated comparators

Our integrated comparator analysis indicates that both the high and low asset beta firms are involved in similar operations within the electricity segments. However, there seems to be a distinction between firms that operate as gas utility firms and those that extend into up and midstream operations, and as such take on commodity and exploration risk. In the above, we note that we have only considered the two ends of the distribution in detail. However, our analysis suggests there is different systematic risk even within the sample sets. Particularly firms with significant commodity risk are of concern as this is significantly different to the regulated service.

3.7 Gas company betas

As noted in the distribution analysis, the distribution of the estimated asset betas for the gas firms is the most volatile of the energy sub-samples. We identify Williams Partners LP (WPZ); TC PipeLines LP (TCP); ONEOK Inc (OKE); National Fuel Gas Co (NFG); Kinder Morgan Inc (KMI); and Enbridge Energy Partners (EEP) at the high end of the distribution. Followed by AGL Resources Incorporated (GAS) and North West Natural Gas Company (NWN) on the low end.

3.7.1 High beta estimate firms

Williams Partners LP (WPZ)

$$\boldsymbol{Location = U.S.} \qquad \boldsymbol{\beta_A = 0.82} \qquad \boldsymbol{Avg.L = 9\%}$$

The Bloomberg definition of WPZ states "Williams Partners LP owns, operates, develops, and acquires natural gas gathering systems and other midstream energy assets. The Company is principally focused on natural gas gathering, the first segment of midstream energy infrastructure that connects natural gas produced at the wellhead to third-party takeaway pipelines".

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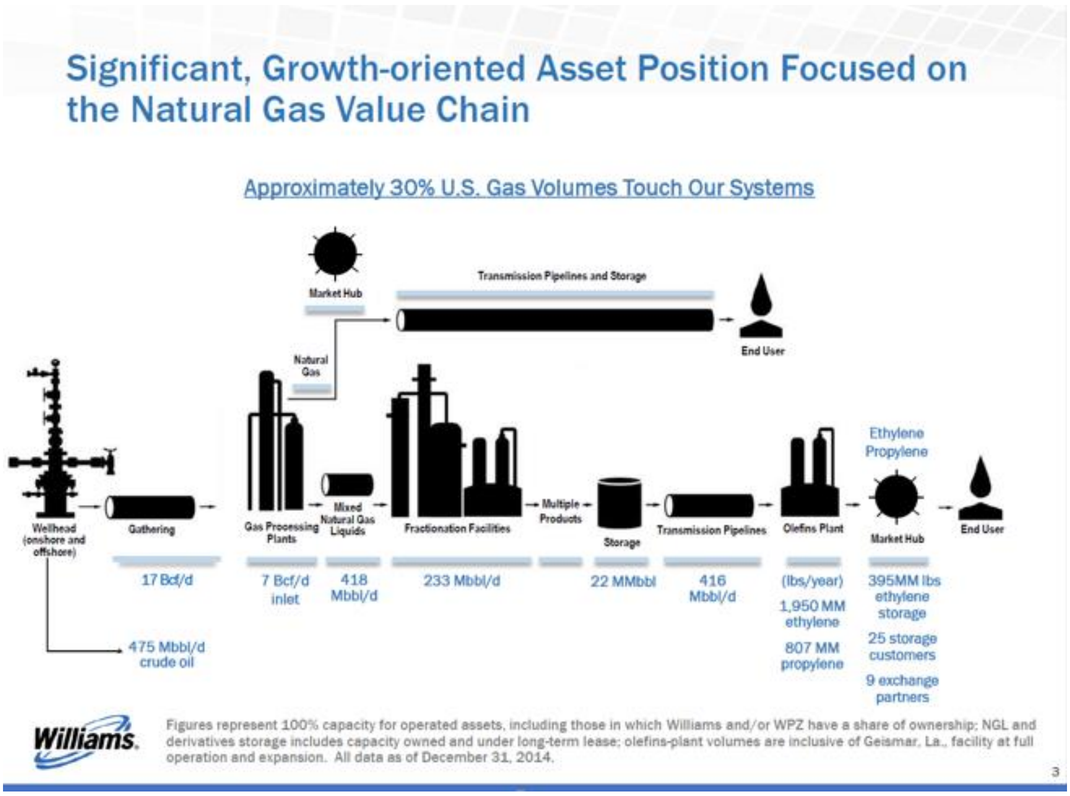
[18] P. 37 of FE's 2015 10-K.

WPZ’s 2015 10-K shows its current business segments consist of a Central segment which provides domestic natural gas gathering, treating, and compression services to producers under long-term, fixed-fee contracts. The Northeast G&P segment includes natural gas gathering and processing, and natural gas liquids (NGL) fractionation businesses in the shale region. The Atlantic-Gulf segment includes the company’s interstate natural gas pipeline (“Transco”), as well as significant natural gas gathering and processing, and crude oil production and transportation. The company’s West business segment includes natural gas gathering and processing, and an interstate natural gas pipeline (Northwest Pipeline). Lastly, there is an NGL & Petchem Services segment which has an interest in production/gathering and refining of natural gas, oil, and NGL.

As recognised by the Bloomberg description, WPZ is heavily involved in gathering and generation of raw materials. Furthermore, it is involved in the transportation of crude oil and NGL, as well as natural gas. It is unclear how much of the transportation operation of WPZ is fee for contract and how much is for WPZ’s product and the products of WPZ’s subsidiaries.

WPZ’s service lines that exceed 10% of consolidated revenue by segment have no natural gas distribution revenues. Service revenues make up 70% of the firm’s total revenues. However, it is unclear what “service revenue” consists of. The company’s business segments also have fee-for-contract transportation of oil and NGL as well as gathering and processing components. However, according to Bloomberg research approximately 30% of U.S. gas volumes touch WPZ’s systems, which includes all aspect of the gas value chain as depicted in Figure 6.[19]

Figure 6: WPZ gas value chain



[19] http://www.bloomberg.com/research/stocks/private/snapshot.asp?privcapId=22236226

National Fuel Gas Co (NFG)

$$\boldsymbol{Location = U.S.} \qquad \boldsymbol{\beta_A = 0.79} \qquad \boldsymbol{Avg. L = 22\%}$$

The Bloomberg description for NFG states "National Fuel Gas Company is an integrated natural gas company with operations in all segments of the natural gas industry, including utility, pipeline and storage, exploration and production, and marketing operations. The Company operates across the United States".

Consistent with the Bloomberg description, NFG reports in its 10-K five business segments: Exploration and Production, Pipeline and Storage, Gathering, Utility, and Energy Marketing. As with many of the other large interstate/international firms within these segments, the company owns and operates many subsidiary firms. NFG's largest reported revenue generating segments are Exploration (accounting for 39%), Utilities (accounting for 40%), and Transportation (accounting for 11.5%), with the remainder being made up of energy marketing and gathering. According to its statement of income, NFG is also a gas purchaser (assumedly for it Utilities segment).

Enbridge Energy Partners (EEP)

$$\boldsymbol{Location = U.S.} \qquad \boldsymbol{\beta_A = 0.62} \qquad \boldsymbol{Avg. L = 38\%}$$

The Bloomberg description for EEP is "Enbridge Energy Partners, L.P. transports and stores hydrocarbon energy. The Company offers crude oil and natural gas liquids to refineries in the Midwestern United States and Eastern Canada".

Consistent with the description EEP's 2015 Annual Report shows that the firm has two business segments being natural gas and liquids. However, as shown in The firm's 10-K shows that only 3.8% of the company's operating revenues were attributed to the natural gas segments "transportation and other services". As noted in Table 1 of the Commission's paper[20], the natural gas segment accounted for approximately 55% of the firm revenue. However, this is made up of approximately 51% commodity sales which could alter the risk profile of the firm from a GPB due to the firm's exposure to commodity risk. Furthermore, in Q3 of 2015 EEP's liquids segment contributed approximately 89% to the company's EBITDA.

TC Pipelines LP (TCP)

$$\boldsymbol{Location = U.S.} \qquad \boldsymbol{\beta_A = 0.6} \qquad \boldsymbol{Avg. L = 28\%}$$

The Bloomberg description of TCP states "TC Pipelines LP acquires, owns, and participates in the management of United States-based pipeline assets. The Company owns interest in the Northern Border Pipeline Company, the owner of an interstate pipeline system that transports natural gas from the Montana-Saskatchewan border to natural gas markets in the Midwestern United States".

TCP's 10-K does not report any other business segments. The company appears to own/operate genuine fee-based transportation services only for natural gas. This is also highlighted in its statement of income that shows a majority of its revenues generated by natural gas transportation.

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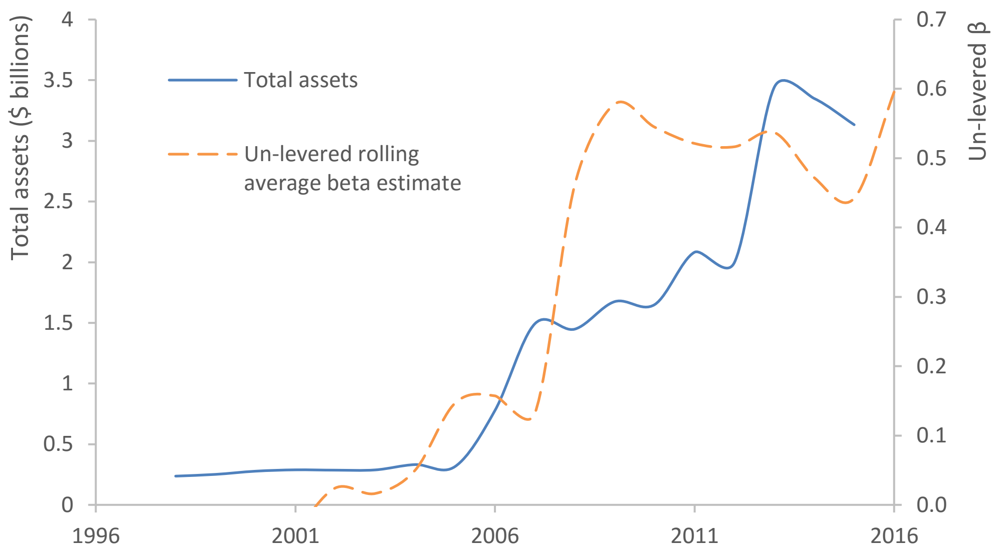
[20] Commerce Commission, op. cit., p. 66.

A note that is consistent throughout TPCs Bloomberg description and 10-K is that TCP invests in but does not operate the pipelines. Given this, it is noted that TCP's total assets increased from $0.78b in 2006 to $1.65b in 2010 to $3.12b in 2015. This seems very expansionary. Figure 7 shows this total asset growth over time. If the asset betas over each period that the Commission estimates are considered, the 1996-2001 asset beta estimate was -0.04, coinciding with flat asset growth. For the period from 2001-2006 the asset beta estimate rose to 0.16, possibly reflecting the asset growth between 2005 and 2006. Form 2006-2011 the asset beta estimate increased significantly to 0.52 at the same time that the company's assets grew by 168%. By 2015, the asset beta increased to 0.6 and the company's total assets had approximately doubled. This graph does not show the changes in leverage of the company over the period. However, our analysis indicates a possible correlation between the asset growth and the estimated asset beta for TCP that should be considered when including it in the Commission's set for the New Zealand GPBs.

Figure 7: TCP total asset growth



ONEOK Inc. (OKE)

$$Location = U.S. \qquad \beta_A = 0.58 \qquad Avg. L = 47\%$$

The Bloomberg description for OKE states "ONEOK, Inc. is a diversified energy company. The Company is involved in the natural gas and natural gas liquids business across the United States".

OKE reports its business segments in its 10-K as natural gas gathering and processing. The company's Natural Gas Liquids segment gathers, treats, fractionates and transports NGLs and stores, markets and distributes NGL products. The Natural Gas Pipelines segment operates regulated interstate and intrastate natural gas transmission pipelines and natural gas storage facilities.

OKE appear to have a relatively small operation of fee-driven transportation and distribution of natural gas (approximately 4.3% of the firm's total revenue as shown by its Annual Report). The remaining 95.3% is reported to come from natural gas gathering and processing, natural gas liquid sales and other. As with many of the other firms presented at the high end of the comparator set, OKE owns the pipelines for natural gas and NGL but it also owns the product that it is transporting, altering the systematic risk in the business.

Kinder Morgan Inc (KMI)

$$\boldsymbol{Location = U.S.} \qquad \boldsymbol{\beta_A = 0.56} \qquad \boldsymbol{Avg. L = 41\%}$$

The Bloomberg description for KMI states that "Kinder Morgan Inc. is a pipeline transportation and energy storage company. The Company owns and operates pipelines that transport natural gas, gasoline, crude oil, carbon dioxide and other products, and terminals that store petroleum products and chemicals and handle bulk materials like coal and petroleum coke".

KMI's 10-K reports three main business segments. Firstly, "Natural Gas Pipelines" which includes ownership and operation of interstate pipelines and storage facilities, natural gas and crude oil gathering and processing and NGL frication facilities and LNG facilities. Secondly, the CO_2 segment which produces, transports and markets CO_2 to oil fields. Lastly it has a "Terminals" segment which owns and/or operates liquids and bulk terminal facilities as well as owning and operating 'Jones Act' tankers, which according to KIM's website are oil tankers that operate under the Jones Act.

KMI's Consolidated Income Statement show that approximately 62% of KMI's revenue is attributed to 'services'. There is no obvious further break down of the services component. As specified in the business segments reporting, it is likely to be some weighting of pipeline transportation of natural gas, NGL and crude oil, tanker transportation of oil, frication and processing services and possibly marketing of CO_2. As is consistent in this more detailed analysis, the other revenue generating activities include 'product sales' and 'natural gas sales'. This indicates that KMI, while owning pipelines for natural gas, is a natural gas generator, processor and wholesaler, rather than a gas pipeline business which charges a fee for the transportation of a third party's product.

3.7.2 Low beta estimate firms

Our assessment above of the firms at the higher end of the asset beta distribution for the gas sub-sample has identified that the firms included in the Commission's energy comparator set has quite different risk profiles from the New Zealand GPBs. Many of the firms appear to be subject to unregulated gas gathering, processing, liquids and commodity price risk because they either have an ownership stake in the product they are distributing/transporting or they appear to operate more as an investment, MLP with partial stakes in many natural gas pipeline businesses. These firms could be disproportionately skewing the distribution of risk profiles as seen in Figure 1. However, as stated previously, the statistics are not conclusive and it is possible that the 'pure play' natural gas companies are merely subject to a wider range of risks. Because of this it is important to consider not only the firms at the upper end of the distribution but also those at the bottom in order to assess whether or not there are fundamental differences in the comparator firm sample or whether the un-levered risk of any one gas pipeline business may have a high level of uncertainty.

The two gas firms at the lower end of the sample identified by the Commission are AGL Resources Incorporated (GAS) and North West Natural Gas Company (NWN). These two firms have estimated asset betas of 0.13 and 0.24 respectively.

AGL Resources Incorporated (GAS)

$$\boldsymbol{Location = U.S.} \qquad \boldsymbol{\beta_A = 0.12} \qquad \boldsymbol{Avg. L = 44\%}$$

The Bloomberg description for GAS states "AGL Resources Inc. primarily sells and distributes natural gas to customers in Georgia and southeastern Tennessee. The Company also holds interests in other energy-related businesses, including natural gas and electricity marketing, wholesale and retail propane sales, gas supply services, and consumer products".

The description above indicates that GAS could be similar to the firms analysed as being in the upper part of the distribution. GAS has a retail and wholesale (albeit in propane and not NGL or crude) gas sales component and is involved in energy marketing and other consumer products. This seems like a diversified firm.

Figure 8 is taken from AGL's 10-K and depicts the firm's regulated and non-regulated operations. It indicates that the regulated activities are solely focused on distribution. However, its non-regulated activities also involve wholesale services, retail operations and midstream operations. Further to this, GAS's income statement by segment sourced from its 2015 10-K shows that distribution revenues account for a majority (73%) of the company's operation revenues. Furthermore, the description related to the segmented income statement states that the retail segment provides natural gas marketing to end users and protection products. Its wholesale services segment "engages in natural gas storage and gas pipeline arbitrage and related activities" along with "natural gas asset management and/or related logistics services". Its midstream segment activities involve non-utility storage and pipeline operations and the operation of natural gas storage assets.

Figure 8: AGL regulated and non-regulated activities

Regulated	Non-Regulated
Distribution operations	Wholesale services
	Retail operations
	Midstream operations

While the Bloomberg description seems to incorporate similar descriptions for GAS as firms that are at the higher end of the distribution, on further analysis, GAS does not seem to have large additional exposure to commodity risk. Its distribution operations are return regulated. Its wholesale operation appears to be involved in arbitraging and not speculation. However, its retail operation is competitive and accounts for approximately 20% of Gas's total revenue.[21][22] It does not appear to have generation or gathering activities which are characteristic of the high beta firms.

North West Natural Gas Company (NWN)

$$\boldsymbol{Location = U.S.} \qquad \boldsymbol{\beta_A = 0.24} \qquad \boldsymbol{Avg. L = 38\%}$$

The Bloomberg description of NWN states "Northwest Natural Gas Company distributes natural gas to customers in western Oregon, as well as portions of Washington. The Company services

[21] It should be noted that it is unclear what 'other' revenue is involves (p. 93 GAS 2015 10-K).

[22] Intercompany eliminations have been ignored from the total as they do not represent business activities (p. 93 GAS 2015 10-K)

residential, commercial, and industrial customers. Northwest Natural supplies many of its non-core customers through gas transportation service, delivering gas purchased by these customers directly from suppliers".

The description above indicates that NWN is a pure-play distribution firm. It indicates that NWN is not involved in extraction, generation or commodity sales. The firm's 10-K reports that it has two core business segments. Firstly, its regulated local gas distribution businesses, referred to as the utility segment, and secondly gas-storage businesses that provide natural gas storage services to utilities, gas marketers, electric generators and large industrial users. It reports that its local gas distribution segment is "a regulated utility principally engaged in the purchase, sale, and delivery of natural gas and related services to customers".[23] It reports that the "gas storage segment includes natural gas storage services provided to customers primarily from two underground natural gas storage facilities". There is no evidence in its 10-K to indicate that NWN has a long-term exposure to commodity prices through generation or gathering or sales and transportation of its own natural gas. Also, it has no exposure to NGL or crude oil which seemed to be a common trend in the higher risk set. NWN's 2015 income statement[24] by segment shows that 97% of its operating revenue is generated through its regulated utilities segment.

3.7.3 Summary of assessment of the gas comparators

As noted above, our assessment of the gas firms at the higher end of the distribution has identified that the firms appear to be subject to quite different risk profiles from the New Zealand GPBs, either because they are subject to unregulated gas gathering, processing, liquids and commodity price risk or because they operate more as investment firms.

Our assessment of the activities of the two gas firms that are at the lower end of the distribution (GAS and NWN) suggests that these firms have quite different operations and risks to the firms at the higher end of the distribution. The two low beta gas firms analysed appear to have some, albeit minor, functions that mean they are not 'pure play' GPBs in the New Zealand environment. However, these two firms do not have generation, gathering or production capacity and do not generate revenues from wholesale commodities sales in the way that the firms at the upper end of the spectrum do. Much of the time this important detail does not seem to be picked up by the Bloomberg descriptions. Therefore, we would recommend that, when selecting the comparator set, that more detailed investigations are made into the lines of business and risk profiles of the individual companies before they are considered appropriate for inclusion.

3.8 Firm-specific analysis summary

Our analysis of the firms in the Commission's energy comparator set that sit at the higher and lower end of the asset beta distributions for each of the industry sub-samples indicates some common patterns between the business activities undertaken by the firms and the estimated risk profiles of the firms. In particular, firms that are involved in the production and gathering, as well as the wholesale distribution, supply and marketing of natural gas and NGLs, tend to have higher un-

[23] P. 63 of NWN's 2015 10-K.
[24] P. 64 of NWN's 2015 10-K.

levered beta estimates than the other firms in the sample. The inclusion of these firms in the Commission's energy comparator set is skewing the distribution up of the estimated betas for the New Zealand energy network companies. It seems likely that the natural gas producing firms have an exposure to commodity price risk that is not applicable to the regulated services.

The analysis of the firms has also highlighted differences with the regulatory environment which electricity, integrated and gas companies are subject to. Most of the U.S. firms in the Commission's energy comparator set that have electricity business segments will not just have distribution and transmission but also generation and retail. This may be perceived as introducing risks to the firm that are unrelated to NZ operations who do not have such functions. However, in the U.S. these firms operate as complete geographic monopolies and all business segments are regulated. This likely realigns the risk profile of these firms. The same appears to be true for the gas distribution utilities business segments. Gas utilities firms in the U.S. appear to purchase the gas from wholesale pipelines where they in-turn distribute and sell directly to (in the cases analysed) the end-user. Regulated generation is the difference between electricity and gas operations in the U.S. Upstream natural gas consists of exploration, gathering and production, followed by wholesaling and marketing, which is unregulated and therefore subjecting the firms involved to different systematic risks.

The cost of capital being determined by the Commerce Commission is for the pure lines or gas distribution service only (i.e., they are distributors and do not own the product they are transporting). In contrast, every firm in the Commission's electricity sub-set that we considered in detail have generation and retail functions. It could be that the Commission's comparator firm set for electricity over-estimates the risks associated with a typical New Zealand EDB because the typical New Zealand EDB simply runs a tolling operation and does not own the product.

The same could apply for gas firms. As seen in the analysis, there seems to be a positive correlation between owning/producing the commodity and systematic risk. New Zealand GPBs' systematic risk is likely to be largely driven through decreased throughput, whereas the comparator firms hold the additional risk of price fluctuations while they are holding that asset (before it has been consumed by their customers).

In addition, our analysis indicates that ownership of gas fields or other upstream pipeline or processing assets may entail greater systematic risk than ownership of electricity generation and retail assets.

Overall, our analysis suggests the appropriateness of the Commission's energy comparator set is worth further detailed investigation by the Commission.

3.9 High-level refinement of the Commission's energy set

The findings above indicate that within the integrated and gas sub-sets there may be firms that are subject to different systematic risk than would be typical for a NZ EDB or GPB. These risks appear to be only affecting the gas firms and the gas segments of the integrated firms. The increased risk (as noted previously) appears to stem primarily from commodity price risk exposure for firms which produce natural gas and own and operate gathering pipelines.[25] This seems to be because these firms either extract the gas themselves or purchase the gas from the wellhead and transport it to producing plants before wholesaling the commodity to a distributer. This ownership increases the risk of the firms involved consistently and the increased risk in most cases does not seem trivial.

To illustrate this, Tables 4 and 5 present summary statistics of the comparator set after removing the six gas firms we identified as being outliers in the gas sub-set and the full energy set specified by the Commission. These firms are WPZ, NFG, EEP, TCP, OKE and KMI. One other firm identified as being an outlier is JEL which is an electricity firm in the U.K. The stock is illiquid and is likely producing a lower estimate of risk than what would be truly representative of the operation.

These firms are only identified as they look to be outside the expected distribution, and when analysed more closely do appear to be subject to different systematic risks than would be (to our understanding) different to a typical NZ operation. More thorough analysis and filtering of the rest Commissions energy set motivated largely by these findings will be presented in Section 4.

Table 4: Summary statistics for the Commission's comparator set with deemed outliers removed

2011-2016 estimates	Daily asset beta	Weekly asset beta	4-Weekly asset beta	Leverage	Number of firms in sample
Commission's full set					
Commission's energy set	0.39	0.34	0.30	41%	74
Energy set excluding outliers	0.38	0.31	0.28	41%	67
Commission's gas sub-set					
Commission's sub-set	0.50	0.45	0.44	34%	18
Sub-set excluding outliers	0.46	0.36	0.34	36%	12
Commission's electricity sub-set					
Commission's sub-set	0.33	0.29	0.26	40%	16
Sub-set excluding outliers	0.36	0.30	0.28	44%	15

[25] With the exception of TCP which has been excluded for these purposes due to its different business structure.

Table 5: Standard errors for the Commission's comparator set with deemed outliers removed

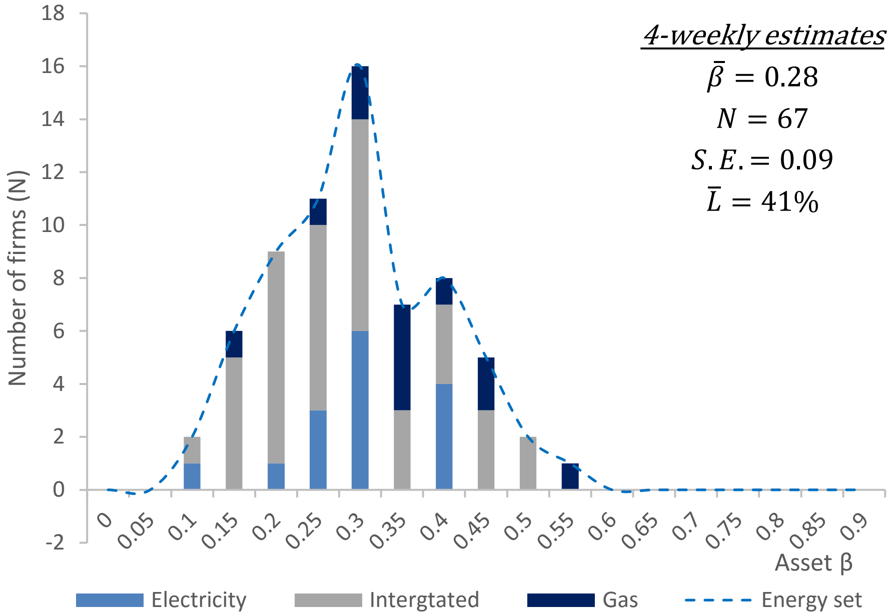
Standard errors	Daily average S.E.	Weekly average S.E.	4-Weekly average S.E.	Number of firms in sample
Commission's full set				
Commission's energy set	0.14	0.14	0.14	74
Energy set excluding outliers	0.12	0.10	0.09	67
Commission's gas sub-set				
Commission's sub-set	0.17	0.21	0.20	12
Sub-set excluding outliers	0.18	0.15	0.14	18
Commission's electricity sub-set				
Commission's sub-set	0.12	0.11	0.12	16
Sub-set excluding outliers	0.07	0.06	0.06	15

Table 4 and Table 5 indicate that removing the six gas and one electricity firms that seem to be outliers from the Commission's sample decreases the average asset beta by 0.02 for both the weekly and 4-weekly estimates, and the mean daily asset beta by 0.01. This also decreases the standard errors for the samples to 0.13, 0.11 and 0.10 for the daily, weekly and 4-weekly estimates respectively while keeping the leverage estimate the same.

The gas asset beta estimates decrease by 0.06 while the electricity asset beta estimates increase by approximately 0.02.

Figure 9 presents the distribution of the Commission's energy comparator sample with the seven outliers removed. Removing only the seven firms from the sample has improved the symmetry of the distribution and is likely more representative while only having lost a small number of firms from the overall sample set.

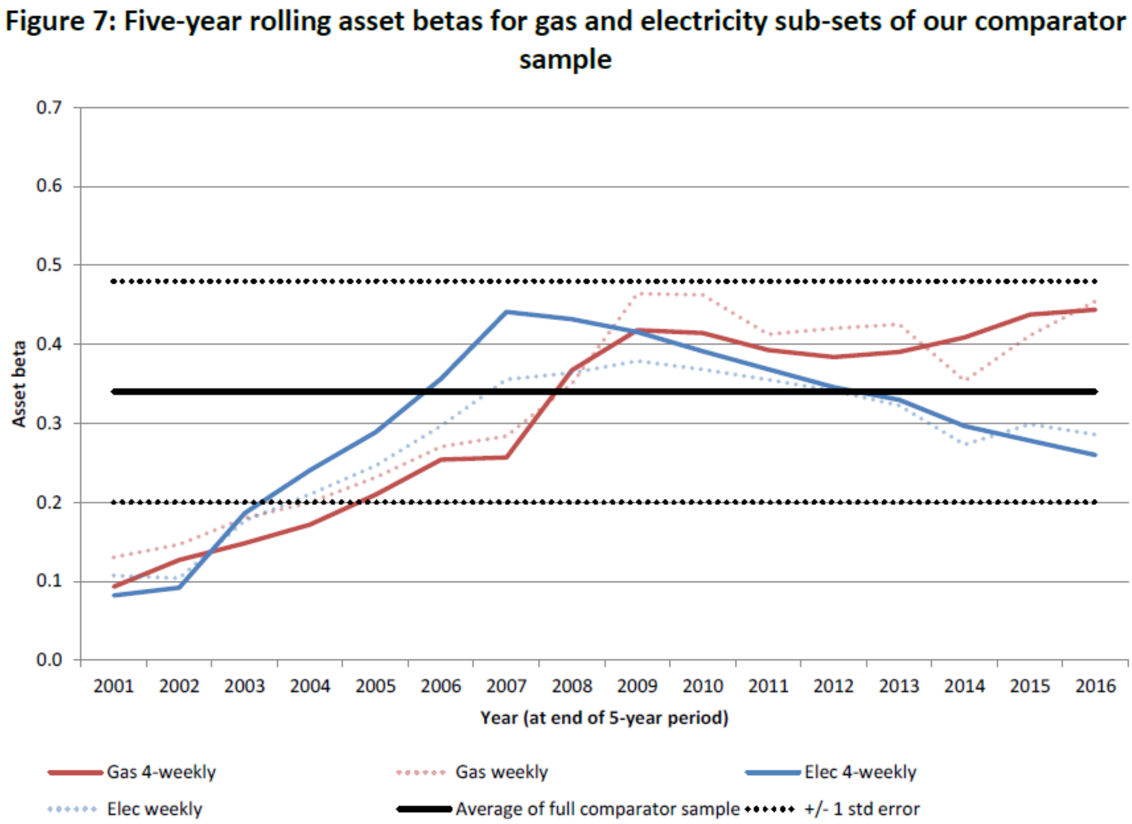
Figure 9: Distribution of the Commission's energy set without outliers



4. Gas versus electricity betas

The preceding analysis has indicated that there are possible differences in the level of systematic risk as it relates to electricity and gas businesses as seen in the comparator set defined by the Commission. As noted in Section 3.3, the electricity firms are distributed mostly in the lower half of the Commission's estimated betas, and the gas industry firms appear to be distributed disproportionally in the upper end of the total set. When these are broken down and analysed individually the electricity firms have an average 4-weekly beta estimate of 0.26 with a standard error of 0.12 and the gas firms have an average 4-weekly beta estimate of 0.44 with a standard error of 0.20. It is also noted in Section 3.3 that the point estimate for the average gas beta sits at the 100th percentile of the electricity distribution, meaning that all observed electricity comparators have estimated betas that are less than the average from the gas sample. This seems to give a strong indication that if the comparator set gives a truly representation of the industry risk then the gas beta applied in NZ regulation should be higher than electricity.

Figure 10: The Commission's Figure 7



The Commission has analysed the breakdown between the gas and electricity betas and has presented it in as a time series rolling average in the Commission's Figure 7 (and presented above in our Figure 10) of its IM review Cost of Capital paper. In its analysis the Commission notes that while the electricity beta estimates are now lower they have been higher in the past, the current sub-set estimates are both within one standard error of the whole energy sample average. This appears to us to be reasonable reasoning. However, qualitatively assessing the Commission's Figure 7, the estimates for the electricity and gas betas appear to have a diverging trend beginning in approximately 2009 and continuing more or less consistently to the most recent estimates. Further, there may be a case to be made that pre-2009 had a fundamentally different economic makeup and the CAPM is forward looking (albeit based on historical data).

To more accurately address the empirical question of differences in the market's perception of the systematic risk (as depicted in the beta calculations) between gas and electricity, the errors for the sub-samples should be analysed. Furthermore, if the average estimates of the sub-samples are rolling through time (as in Figure 7 of the Commission's paper) then so too should the error calculations. This may give more insight to the true relationship between the two sub-sets.

Figure 11 below presents the electricity and gas asset beta averages with the attached standard errors for the Commission's entire energy sample. The diagram shows the average asset beta estimate for each sector and presents the range of plus and minus one standard error for each sub-set. Figure 11 highlights the differences in the two distributions noted in Section 3.3 above. It shows that the average gas asset beta estimate is more than one electricity standard error away from the average electricity estimate. Figure 11 also highlights the differences in the distribution widths (as represented by +/- 1 standard error). The electricity distribution is much narrower than the gas which could possibly indicate discrepancies during the sampling process.

Figure 11: 4-weekly beta estimates with +/- 1 standard error for the Commission's energy firm sub-sets

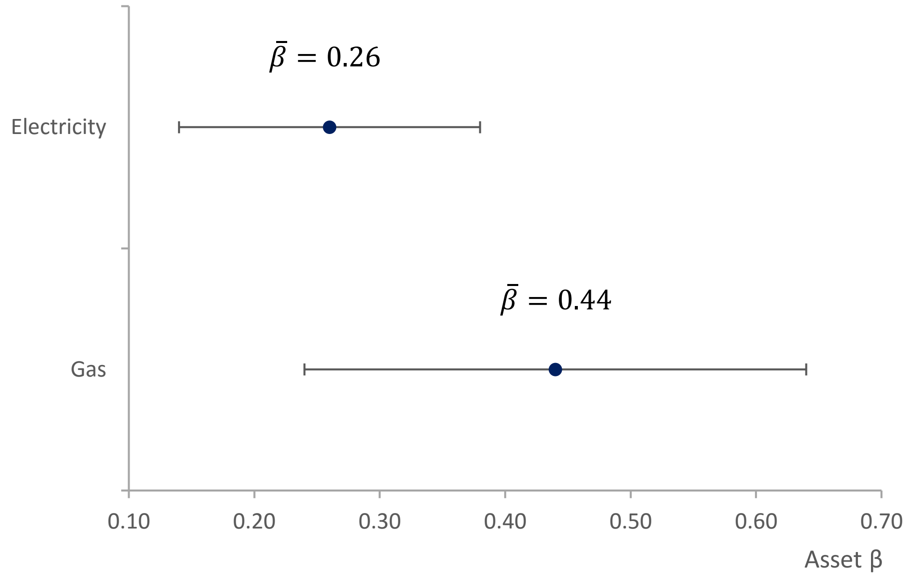


Figure 12 presents the estimates and the errors of the electricity and gas asset betas after excluding (what we have loosely deemed) the outliers. As in Section 3.9, only the six firms analysed as being in the upper part of the gas distribution and the one firm in the lower part of the electricity distribution have been excluded. At this point we have not excluded or conducted further analysis of the firms remaining in the gas sub-set.

Figure 12: 4-weekly beta estimates with +/- 1 standard error for the outlier-reduced comparators sub-set

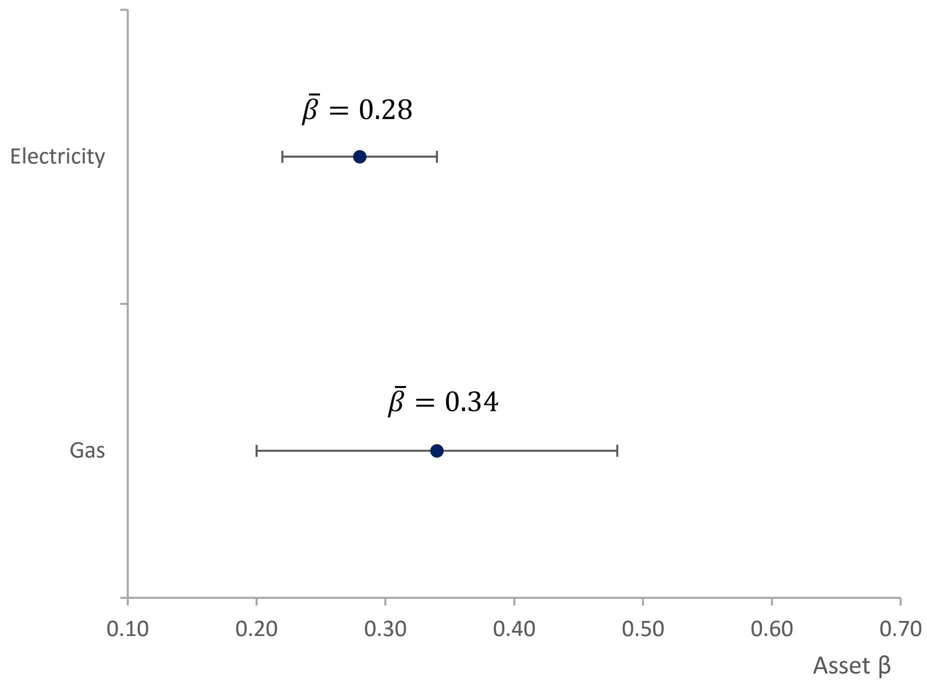


Figure 12 indicates a much closer spread between the gas and electricity distributions once the seven outlier firms are removed from the sample. By removing only six gas firms that we have inferred to be exposed to different systematic risks, the average gas asset beta estimate has fallen by 0.1 (to 0.34). Both the electricity and gas averages sit within one standard error of each other. The average electricity asset beta is still 0.05 lower than that of the gas average and the standard error of the electricity sub-set reduced considerably. However, the difference between the two sub-sets is less conclusive than that presented in Figure 11.

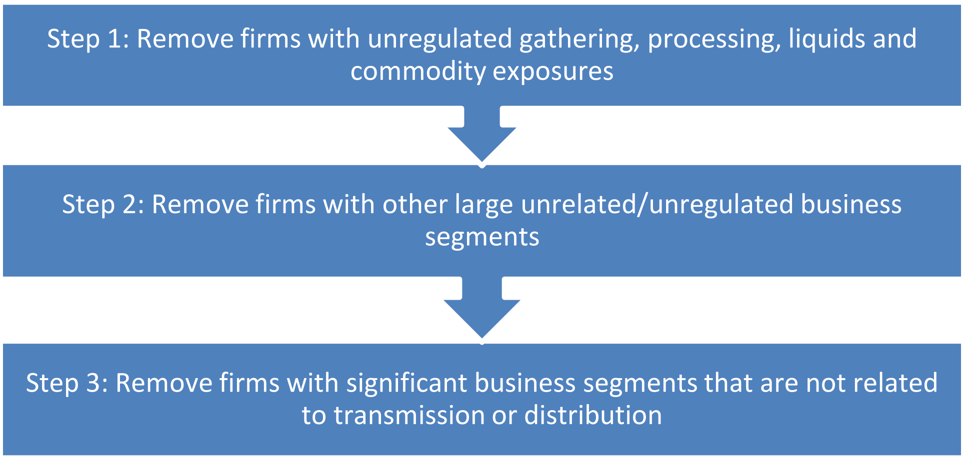
In its analysis, the Commission notes that while the electricity beta estimates are now lower they have been higher in the past, the current sub-set estimates are both within one standard error of the whole energy sample average. This appears to us to be reasonable reasoning. However, qualitatively assessing the Commission's Figure 7, the estimates for the electricity and gas betas appear to have a diverging trend beginning in approximately 2009 and continuing more or less consistently to the most recent estimates. Further, there may be a case to be made that pre-2009 had a fundamentally different economic makeup and the CAPM is forward looking (albeit based on historical data).

5. Filtering and refining the sample set

The previous sections of the analysis have indicated that further filtering of the Commission's energy comparator set may be useful in determining a truly comparable set of firms that can help the Commission set an appropriate return (or returns) on equity for the regulated New Zealand gas and electricity firms. We have identified what appears to be a theme that firms with high estimated un-levered systematic risk seem to be subject to greater commodity risk exposure. Further, firms that have un-regulated or non-comparable business segments and firms that are subject to different regulatory environments may also have different risk profiles than the New Zealand energy network companies.

This paper has firstly taken a high-level approach to assessing the distributions of the firms within the Commerce Commission's samples. We then analysed more closely the firms specific to the high and low ends of each distribution to assess whether or not there appear to be fundamental differences between the firms with high and low risk or whether the differences in risk are just market behaviour and a large enough sample size would naturally converge to the true distribution. We now explore the characteristics of the firms that sit somewhere within each of the distributions. We propose a filtering system, as defined in Figure 13 below, based on observations made in the earlier analysis. Firstly, we see an exposure to unregulated gas gathering, processing, liquids and commodity price fluctuations as the highest contributor to skewing the distribution of firms and risk profiles and we therefore exclude those firms with such an exposure. Second, we filter out firms that have large nonregulated or unrelated business segments or firms that have business structures that appear to be incomparable to the New Zealand regulated entities. Lastly, we remove firms that have regulated operations that are not regulated in NZ. For the most part this last step involves removing U.S. firms which are highly involved in regulated generation and/or retail electricity.

Figure 13: Filtering system



Our assessment is based on an analysis of each firm's 10-K and Annual Report. It is important to note that through this process we have used our best judgment when classifying each firm. There are areas where the firms and the regulations they are subject to is unclear and where firms' business segments are highly complicated. For instance, in the U.S. most firms we looked at have rate-regulated generation functions under FERC. However, some firms declare unregulated generation functions. In these cases, it is unclear whether the revenue was generated by the firm outside the US or if some states have overridden FERC. Another point to note relates to the regulation surrounding gathering and production of natural gas and related NGLs. In most cases this is reported as unregulated revenue but this does not always appear to be the case. However, as demonstrated in Appendix 4, a conservative sensitivity analysis indicates there are not large discrepancies if 10% of the highest beta firms are misclassified at each step.

Caveats aside, the filtering process outlined above is not aimed to give the Commission an absolute final set of comparators but to help understand further the trade-off between comparability of the set and statistical significance (i.e., having a large enough sample).

Table 6 presents the results of the three step filtering process.

Table 6: Filtering process and resulting sample sets

	Sample set	Weekly asset beta		4-Weekly asset beta		Average leverage	Number of firms in sample (N)
		Average	S.E.	Average	S.E.		
	Commission's energy set	0.34	0.14	0.30	0.14	41%	74
Step 1	Remove firms with unregulated gathering, processing, liquids and commodity exposures	0.29	0.09	0.26	0.10	42%	54
Step 2	Remove firms with other large unrelated/unregulated business segments	0.28	0.08	0.24	0.07	44%	39
Step 3	Remove firms with significant business segments that are not related to transmission or distribution	0.24	0.11	0.21	0.07	49%	8

Step 1, which removes all firms with unregulated gathering, processing, liquids and commodity exposure, reduces the estimates for the weekly and 4-weekly average betas to 0.29 and 0.26 respectively, and increases the average leverage to 42%. The sample size reduces to 54 firms. The firms that are excluded include many of the firms covered in the firm specific analysis such as Williams Partners limited and Kinder Morgan.

Step 2, which removes all firms which have large unrelated or unregulated revenues, reduces the estimates for the weekly and 4-weekly average betas to 0.27 and 0.24 respectively. The average leverage increases to 43% and the sample size reduces to 39 firms. This reduction is due to the exclusion of firms like SSE, a U.K. electricity firm which has around 44% of its assets in transmission and distribution activities, with the rest its revenue coming from unregulated generation and retail activities. Other firms that are removed include APA group from Australia which operates for the most part in contracted pipelines and not regulated pipelines and T C Pipelines which has grown rapidly in recent years through mergers and acquisitions, as discussed in Section 3.7.3 above.

Step 3 removes firms that have regulated activities that are not regulated in NZ. As noted above these firms are for the most part U.S. firms but also include special cases such as Jersey Electricity PLC which is a monopoly for all electricity on Jersey island with illiquid stock. This leaves eight firms that are close to, if not absolute, 'pure-play' distribution and transmission firms. The average weekly and 4-weekly asset betas estimates for this set are 0.24 and 0.21 respectively with an average leverage of 49%.

Figure 14 presents the findings of the average asset betas from this filtering process and Figure 15 presents the standards errors.

Figure 14: Sensitivity of average asset beta comparability to sample size

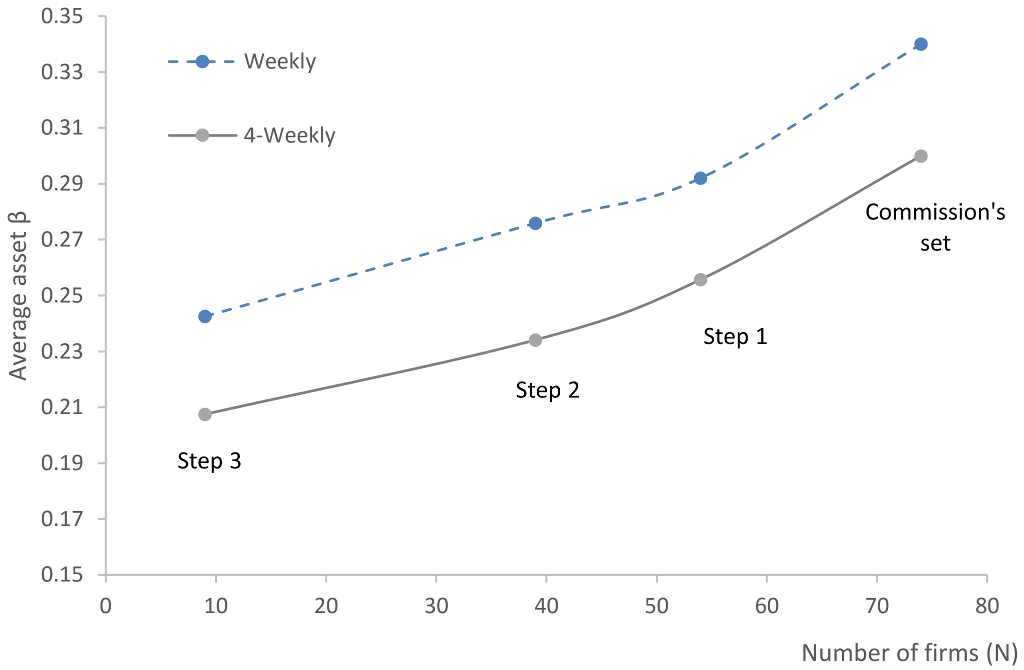
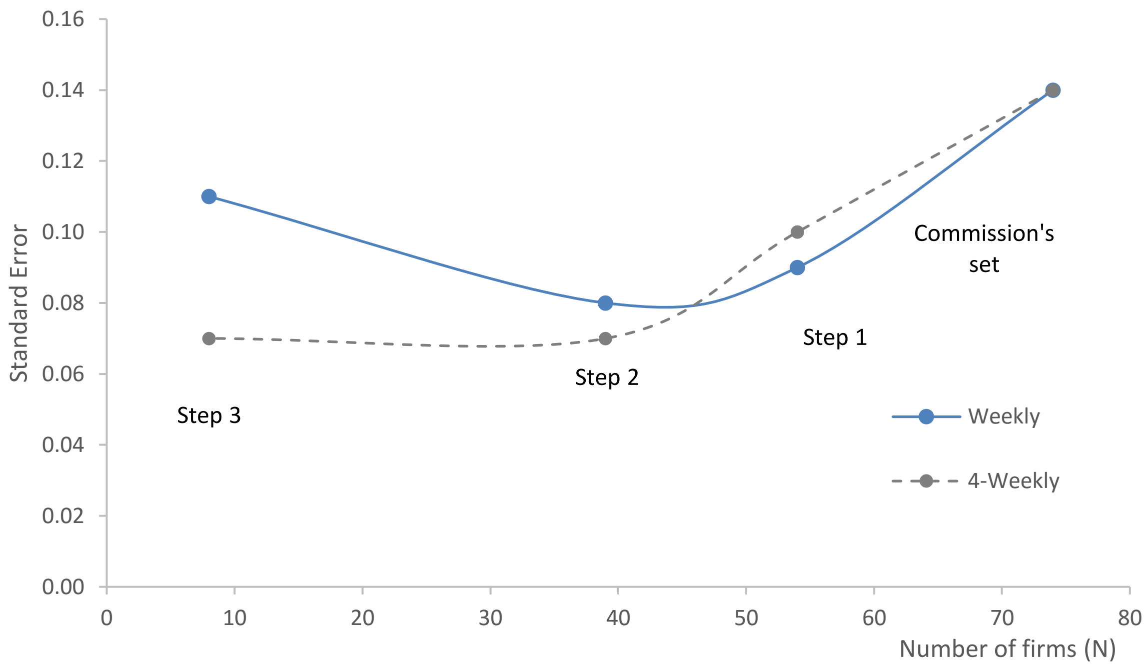


Figure 15: Sensitivity of standard error comparability to sample size



This analysis indicates that there is a steep decrease in the average beta estimates as a result of step 1 when we control for the increased risk that firms face through unregulated gas gathering, processing, liquids and commodity price exposure. The average beta estimates do not then plateau but there appears to be a decreased rate of decline with the subsequent steps. It seems that somewhere along the range there is an optimal trade-off between reduced sample size and the comparability of the set.

6. Regulatory environment

One key impact on the firms of the comparator set that we have noted above during our analysis of their Annual Reports and 10-K is the regulatory environment which the firms are subject to. Table 7 presents the Commission's energy set by country/region. It shows that the U.S. firms in the set have on average higher beta estimates than the U.K. and New Zealand and Australian firms. Furthermore, the New Zealand /Australian sub-sample seems to have lower standard errors. This may be due to lower cross-sectional errors for New Zealand/Australian firms calculated by the Commission. It also shows that the estimates that come from the U.S. firms, which seems to have the least comparable regulatory regime, dominates the estimates of the final sample (including the estimates of the asset beta and leverage).

Table 7: The Commissions energy comparator set by country/regulatory regime

	Weekly asset beta		4-Weekly asset beta		Average	
Country	Average	S.E.	Average	S.E.	leverage	N
U.S.	0.35	0.13	0.31	0.13	40%	66
U.K.	0.25	0.29	0.23	0.31	20%	3
NZ/Aus	0.23	0.083	0.22	0.078	55%	5
Simple average	0.27		0.26		39%	74

Table 8 below presents the estimates for all the non-U.S. firms. It indicates average asset beta estimates in the range of 0.23 to 0.24.

Table 8: The Commissions energy comparator set by most comparable regulatory regime

	Weekly asset beta		4-Weekly asset beta		Average	
	Average	S.E.	Average	S.E.	leverage	N
U.K./NZ/Aus	0.24	0.14	0.23	0.14	42%	8

Focusing on those countries with a similar regulatory environment results in a small sample (of only eight firms) but does indicate that a beta of 0.34 may be too high to accurately reflect the New Zealand regulatory environment.

7. Conclusions

This submission reviews the Commission's choice of comparable companies for determining an appropriate WACC for regulated energy network services in New Zealand.

The choice of an appropriate comparable company set involves a trade-off between the comparability of the set with the regulated entities and the size of the sample set.

Our assessment of the Commission's compco set suggests the Commission may have adopted too large a set at the expense of a loss in accuracy in the appropriate asset beta. In particular the Commission's compco set includes companies which we assess have higher systematic risk largely through unregulated gas gathering, processing, liquids and commodity price exposures; involvement in lines of business that are either unrelated to the NZ regulated services (as they involve non-energy activities) or have energy revenues that are unregulated; and involvement in energy activities that are regulated but are outside the transport of electricity and gas.

Our re-classification of the Commission's 74 company dataset is indicative and inevitably involves a degree of judgement based on the available information. Nevertheless, we consider our overall conclusions that there are companies with significantly different risk profiles to the New Zealand regulated network companies in the Commission's set and that this has a material impact on the estimated average beta and leverage are robust. To further test the robustness of our conclusions we classified the Commission's 74 compcos solely on the basis of the country they are located. This analysis highlighted the importance of the country of origin, with the 66 USA companies having an average beta of 0.35, the three UK companies having an average beta of 0.25 and the five Australian/NZ companies an average beta of 0.23.

Given the sensitivity of the estimated average betas to the choice of compco sample set and the apparent inclusion in the Commission's sample of companies with quite different risk profiles we recommend that the Commission review its compco set.

If firms with either unregulated gas gathering, processing, liquids and commodity price exposure or large unrelated or non-regulated revenues are excluded, the Commission would still have a comparable companies set of around 40 companies from which to derive an asset beta. Such a sample set is considerably larger than that used by the Australian Electricity Regulator and would seem more than sufficient to generate meaningful estimates.

We also recommend that the Commission go further and consider whether the eight largely "pure-play energy transporters" is the appropriate benchmark group and test whether those companies may be from a statistically different population than the other 66 companies in its compco data set.

Appendix 1: 4-weekly estimated frequency data

Table 9: The Commission's samples (4-weekly beta estimates)

4-Weekly estimates	Electricity sub-sample	Intergrated sub-sample	Gas sub-sample	Commission's energy comparator set
Asset beta range	Number of observations	Number of observations	Number of observati	Number of observations
0 - 0.05	1	0	0	1
0.05 - 0.1	1	1	0	2
0.1 - 0.15	0	5	1	6
0.15 - 0.2	1	8	0	9
0.2 - 0.25	3	7	1	11
0.25 - 0.3	6	8	2	16
0.3 - 0.35	0	3	4	7
0.35 - 0.4	4	3	1	8
0.4 - 0.45	0	3	2	5
0.45 - 0.5	0	2	0	2
0.5 - 0.55	0	0	1	1
0.55 - 0.6	0	0	3	3
0.6 - 0.65	0	0	1	1
0.65 - 0.7	0	0	0	0
0.7 - 0.75	0	0	0	0
0.75 - 0.8	0	0	1	1
0.8 - 0.85	0	0	1	1
0.85 - 0.9	0	0	0	0
Mean	0.26	0.26	0.44	0.3
Standard error	0.12	0.09	0.2	0.14
N	16	40	18	74

Appendix 2: Weekly frequency data and distribution plots

Table 10: The Commission's samples (weekly beta estimates)

Weekly estimates	Electricity sub-sample	Intergrated sub-sample	Gas sub-sample	Commission's energy comparator set
Asset beta range	Number of observations	Number of observations	Number of observatio	Number of observations
0 - 0.05	1	0	0	1
0.05 - 0.1	0	0	0	0
0.1 - 0.15	0	1	0	1
0.15 - 0.2	1	4	0	5
0.2 - 0.25	1	7	2	10
0.25 - 0.3	7	10	1	18
0.3 - 0.35	2	6	2	10
0.35 - 0.4	3	7	3	13
0.4 - 0.45	1	4	2	7
0.45 - 0.5	0	0	1	1
0.5 - 0.55	0	1	4	5
0.55 - 0.6	0	0	0	0
0.6 - 0.65	0	0	0	0
0.65 - 0.7	0	0	1	1
0.7 - 0.75	0	0	0	0
0.75 - 0.8	0	0	1	1
0.8 - 0.85	0	0	1	1
0.85 - 0.9	0	0	0	0
Mean	0.29	0.3	0.45	0.34
Standard error	0.11	0.09	0.21	0.14
N	16	40	18	74

Figure 16: Distribution of weekly beta estimates of Commission's energy set

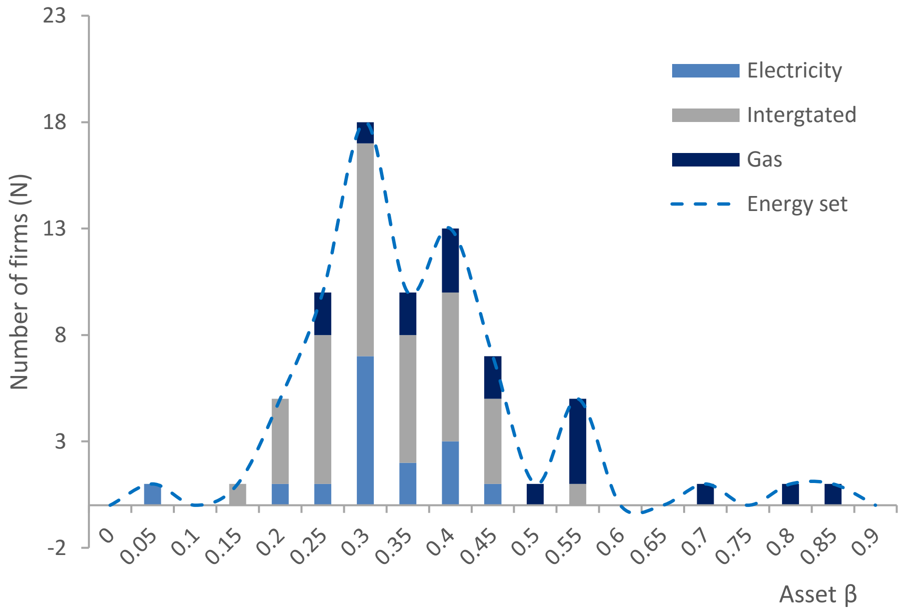


Figure 17: Distribution of the Commission's electricity firm with weekly estimates

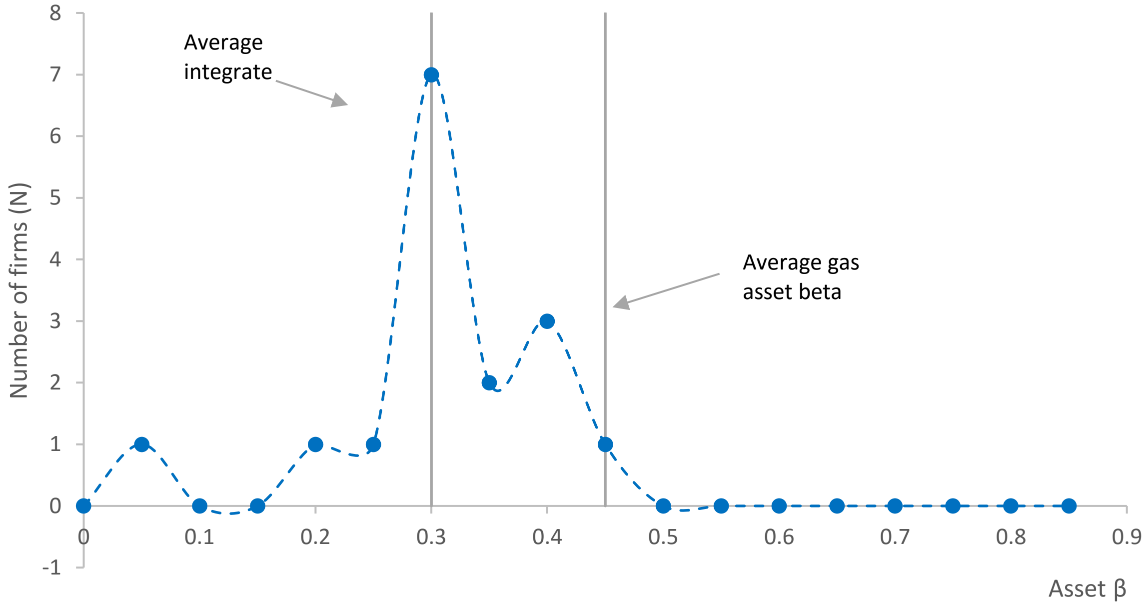


Figure 18: Distribution of the Commission's integrated firm with weekly estimates

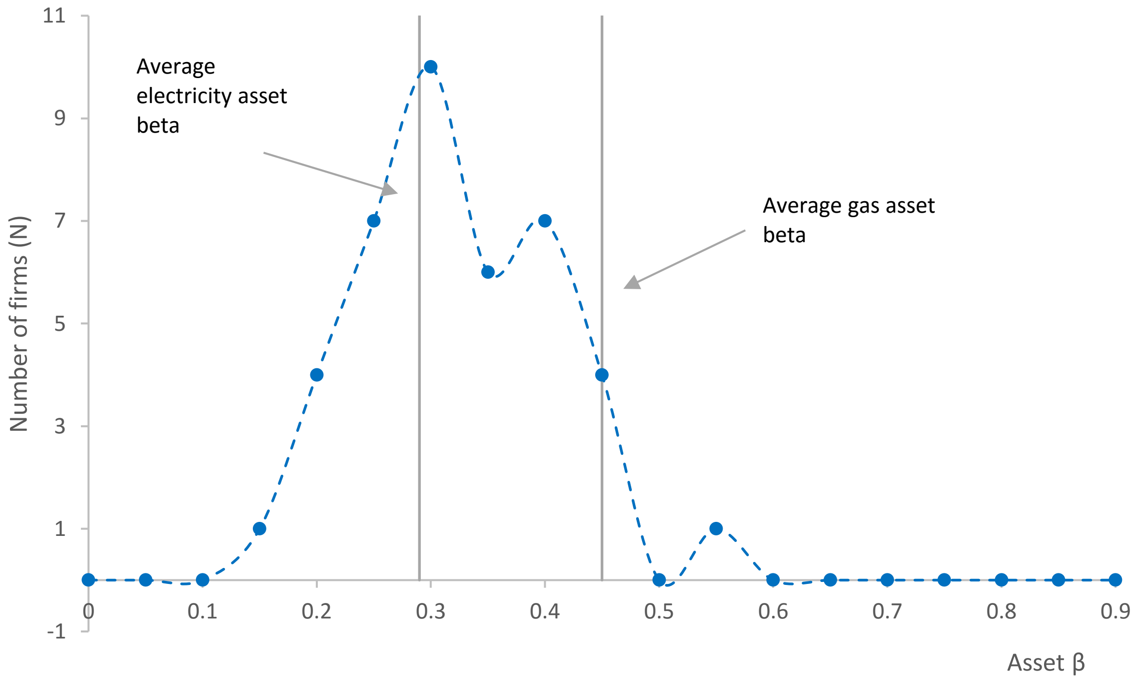


Figure 19: Distribution of the Commission's gas firm with weekly estimates

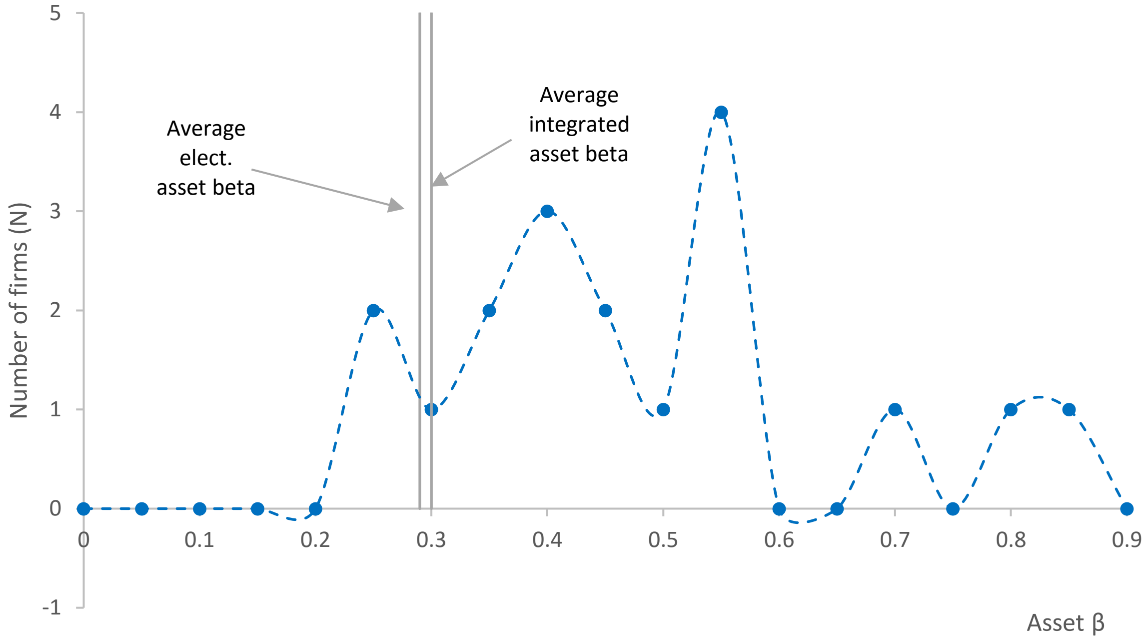
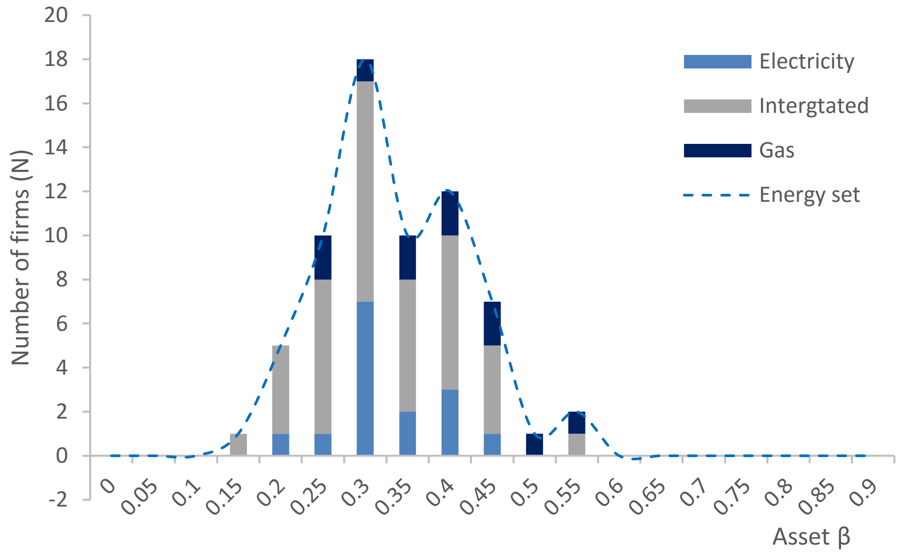


Figure 20: Refined weekly beta distribution



Appendix 3: Filtering process - firms excluded at each step

Table 11: Set constituents after filtering steps

N	Commission's set	Non-commodity exposed firms	Regulated/related firms - including non-transport functions	"Pure-Play" distribution/transmission firms
1	AES Corp	AES Corp		
2	AGL Resources Inc	AGL Resources Inc	AGL Resources Inc	
3	ALLETE Inc	ALLETE Inc	ALLETE Inc	
4	Alliant Energy Corp	Alliant Energy Corp	Alliant Energy Corp	
5	Ameren Corp	Ameren Corp	Ameren Corp	
6	American Electric Power Co	American Electric Power Co		
7	APA Group	APA Group		
8	Atmos Energy Corp			
9	AusNet Services	AusNet Services	AusNet Services	AusNet Services
10	Avista Corp	Avista Corp	Avista Corp	
11	Black Hills Corp			
12	Boardwalk Pipeline Prtnrs-LP			
13	CenterPoint Energy Inc			
14	Chesapeake Utilities Corp			
15	Cleco Corporate Holdings LLC	Cleco Corporate Holdings LLC	Cleco Corporate Holdings LLC	
16	CMS Energy Corp	CMS Energy Corp	CMS Energy Corp	
17	Consolidated Edison Inc	Consolidated Edison Inc	Consolidated Edison Inc	
18	Delta Natural Gas Co Inc			
19	Dominion Resources Inc			
20	DTE Energy Co			
21	DUET Group	DUET Group	DUET Group	DUET Group
22	Duke Energy Corp	Duke Energy Corp	Duke Energy Corp	
23	Edison International	Edison International	Edison International	
24	El Paso Electric Co	El Paso Electric Co	El Paso Electric Co	
25	Empire District Electric Co	Empire District Electric Co	Empire District Electric Co	
26	ENBRIDGE ENERGY PRTNRS -LP			
27	Entergy Corp	Entergy Corp	Entergy Corp	
28	Eversource Energy	Eversource Energy	Eversource Energy	
29	Exelon Corp	Exelon Corp		
30	FirstEnergy Corp	FirstEnergy Corp		
31	Great Plains Energy Inc	Great Plains Energy Inc	Great Plains Energy Inc	
32	Hawaiian Electric Inds	Hawaiian Electric Inds	Hawaiian Electric Inds	
33	IDACORP Inc	IDACORP Inc	IDACORP Inc	
34	ITC Holdings Corp	ITC Holdings Corp	ITC Holdings Corp	ITC Holdings Corp
35	Jersey Electricity PLC	Jersey Electricity PLC		
36	Kinder Morgan Inc			
37	MGE Energy Inc	MGE Energy Inc	MGE Energy Inc	
38	National Fuel Gas Co			
39	National Grid	National Grid	National Grid	
40	New Jersey Resources Corp	NextEra Energy Inc		
41	NextEra Energy Inc			
42	NiSource Inc	NiSource Inc	NiSource Inc	
43	Northwest Natural Gas Co	Northwest Natural Gas Co	Northwest Natural Gas Co	Northwest Natural Gas Co
44	NorthWestern Corp			
45	OGE Energy Corp			
46	ONEOK Inc			
47	Pepco Holdings inc	Pepco Holdings inc	Pepco Holdings inc	
48	PG&E Corp	PG&E Corp	PG&E Corp	
49	Piedmont Natural Gas Co			
50	Pinnacle West Capital Corp	Pinnacle West Capital Corp	Pinnacle West Capital Corp	
51	PNM Resources Inc	PNM Resources Inc	PNM Resources Inc	
52	PPL Corp	PPL Corp		
53	PUBLIC SERVICE ENTRP GRP INC	PUBLIC SERVICE ENTRP GRP INC		
54	Questar Corp			
55	SCANA Corp	SCANA Corp	SCANA Corp	
56	SCOTTISH & SOUTHERN ENERGY	SCOTTISH & SOUTHERN ENERGY		
57	Sempra Energy	Sempra Energy	Sempra Energy	
58	South Jersey Industries Inc	South Jersey Industries Inc		
59	Southern Co	Southern Co	Southern Co	
60	Southwest Gas Corp	Southwest Gas Corp		
61	Spark Infr Group	Spark Infr Group	Spark Infr Group	Spark Infr Group
62	Spectra Energy Corp			
63	Spire Inc	Spire Inc	Spire Inc	Spire Inc
64	TC PipeLines LP	TC PipeLines LP		
65	TECO Energy Inc	TECO Energy Inc	TECO Energy Inc	
66	UGI Corp			
67	Unitil Corp	Unitil Corp	Unitil Corp	Unitil Corp
68	Vector Ltd	Vector Ltd	Vector Ltd	Vector Ltd
69	Vectren Corp	Vectren Corp		
70	WEC Energy Group Inc	WEC Energy Group Inc	WEC Energy Group Inc	
71	Westar Energy Inc	Westar Energy Inc	Westar Energy Inc	
72	WGL Holdings Inc	WGL Holdings Inc		
73	Williams Partners LP			
74	Xcel Energy Inc	Xcel Energy Inc	Xcel Energy Inc	

Appendix 4: Filtering process sensitivity

To analyse the sensitivity of misclassification of a firm at each step of the filtering process we estimate the effect on the average betas, leverage and sample size if 10% of the companies were misclassified at each step. We take a prudent approach and assume that the firms misclassified are those firms which have the highest betas in the previous set. Table 12 below presents the results of the sensitivity analysis. It shows that even on our conservative assumptions, there are still significant changes in the estimated average betas from the Commission's recommended 0.34.

Table 12: Effect of 10% of the firms being misclassified

	Sample set	Asset Beta		Average leverage	Number of firms in sample (N)
		Weekly	4-Weekly		
	Commission's energy set	0.34	0.3	41%	74
Step 1	Remove firms with unregulated gathering, processing, liquids and commodity exposures	0.31	0.28	41%	56
Step 2	Remove firms with other large unrelated/unregulated business segments	0.28	0.24	42%	40
Step 3	Remove firms with significant business segments that are not related to transmission or distribution	0.28	0.25	43%	11