Major Electricity Users' Group

23 October 2018

Miriam Dean QC
Chair
Expert Advisory Panel
Electricity Price Review
c/- Ministry of Business, Innovation & Employment
By email to energymarkets@mbie.govt.nz

Dear Miriam

Submission on the Electricity Price Review First Paper and related material

1. This is a submission by the Major Electricity Users' Group (MEUG) on the Expert Advisory Panel's First Report for discussion on the Electricity Price Review and accompanying Technical Paper released by the Minister, Hon Megan Woods, on 11th September 2018 including materials and models published since that date.[1]

2. MEUG members have been consulted in the preparation of this submission. This submission is not confidential. Some members may make separate submissions.

3. The following 21-pages after this covering letter are MEUG responses in the recommended format for parties to answer questions. The last 2-pages is a public MEUG memo on international prices referred to in response to question 5. Attached separately and to be read as part of this submission are 2-memo from NZIER as follows:

   - Electricity price history in New Zealand, 21 June 2018.
   - Electricity Distribution Business Charges to Retail Consumers, 17 October 2018.

4. We appreciate the opportunities we have had to engage with you, MBIE staff and advisors to the panel. We look forward to assisting you in next steps of the review once you have decided how that should proceed.

Yours sincerely

Ralph Matthes
Executive Director

[1] Refer https://www.mbie.govt.nz/info-services/sectors-industries/energy/electricity-price-review

SUBMISSION FORM

How to have your say

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

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

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

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

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

Electricity Price Review

Secretariat, Ministry of Business, Innovation and Employment

15 Stout Street

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Use of information

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

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

Release of information

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

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

Private information

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

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Summary of questions

Part three: Consumers and prices

Consumer interests

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

The First Report cites a recent survey that found consumers have added environmental impacts to their long-standing concerns for reliability and affordability, often referred to as the "energy trilemma".

The order of priorities at any time is often informed by recent circumstances. For instance, a long period of good reliability can lead to complacency about that priority and shift focus elsewhere.

One of the major achievements of the reforms to date, and particularly since the 2010 reforms, has been quality of supply and improved reliability in the wholesale market. For several years there have been no requests for consumers to conserve electricity to manage risks of a supply shortage. However, if this was to change, the importance of reliability would be recognized and reprioritized.

Good reliability needs to be maintained and the regulatory framework that has achieved it needs continuous improvement and to be well-integrated into the framework governing the competitive parts of the retail and wholesale markets.

Consumers need to be able to evaluate the trade-off between the elements of the energy trilemma, so they can determine and communicate their priorities. With the Powerco Customised Price-Quality Path (CPP) application and final decision, we observed that consumers were not given an explicit understanding of the trade-off over time between different quality and price paths, so were not able to provide informed feedback.

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

An important way that consumers express their preferences is by switching. The relatively high level of switching indicates retailers can inform themselves about consumer preferences.

In workably competitive markets consumers do not need to know the minutiae about the complex cost drivers of supply chain, but they do need to be able to understand and compare the offers of competing retailers. That is a goal that may become increasingly achievable for the electricity sector facilitated by new technology and business models.

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

The trust of communities and a social license to operate are issues companies in many sectors of the economy are acutely aware of including no doubt those in the electricity supply chain. That creates an incentive on companies operating in competitive markets to adapt behavior in response to public concerns.

Incentives on regulated businesses may differ.

Prices

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

An observation from the review's work on examining "how prices residential consumers pay compare with businesses" is the paucity of sufficiently granular historic information. For example:

- The comparison of prices NZ consumers pay with prices paid by consumers in comparable overseas countries is inadequate to identify regulated and unregulated cost components. We discuss this point in the next question number 5.
- We are not aware of historic statistical data available to show trends since 1990 to different household groupings. That leaves a gap in analyzing trends over time in changes in affordability for low-income households. We discuss this point under question 7.

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

Following on from the comment on question 4 above, a more recent, more detailed and targeted check against comparable countries could be useful, eg of an approach in MEUG's public analysis from 2015 attached.

This section of the First Report includes Figure 5: Average electricity prices between 1990 and 2018. Some commentators have inferred the divergence between residential and non-residential average prices between 1990 and 2018 is due to some mischief whereby residential consumers are paying more than they should compared to non-residential.

The First Report notes differences in the rate of price increases since 1990 amongst different consumer groups. The report unhelpfully described wealth transfers from business to residential consumers as a key driver of increased residential prices. This should have been more explicitly described as the end of household subsidies paid for by businesses.

Care also needs to be taken in comparing consumer groups. The data available does not enable us to identify users within categories, e.g. small "mum-and-dad" commercial operations as opposed to large commercial operations. As approximately 97% of New Zealand businesses are "small businesses", any shifting of costs between consumer groups will largely shift costs from households to those small businesses, who will struggle to absorb additional costs.

Soon after the review commenced we asked NZIER to consider the historic data. The NZIER report attached, Electricity price history in New Zealand, 21 June 2018, assesses key drivers over time of the different average price paths.

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

Future wholesale and retail prices will depend on the mix of generation and the balance between supply and demand and the effectiveness of the regulatory regimes governing the line and system operator monopolies.

If intermittent renewables are not well integrated, prices could become more volatile and infrastructure costs could increase. The current high spot prices being experienced in the market underpin the importance of gas as a generation fuel source for the New Zealand market when lake levels are low and there is less wind generation than usual.

Higher spot prices than would otherwise be the case (e.g. higher risk to gas supply with the proposed oil and gas exploration prohibition on new permits compared to the status quo) will flow through to higher residential prices in the long-term impacting vulnerable households.[1]

Affordability

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

The review considers affordability as a problem affecting mainly low-income households. Affordability is also an important issue for businesses, particularly those that are trade-exposed.

The review finds that industrial prices in NZ are amongst the lowest in the OECD. Trade exposed businesses in NZ compete globally, not only in the OECD. Energy intensive industries tend to be located in countries with low cost energy, so comparisons with higher cost countries do not demonstrate affordability or competitiveness for those industries in NZ.

NZ has some of the lowest cost energy resources in the world, and a wealth of undeveloped renewable energy resources. However, to leverage these resources into wealth for the nation they need to be internationally competitively priced.

In relation to affordability for low-income households note:

- Since 2010, line charges to consumers on average have increased and that may have affected lesser decile income households more; though we are not aware of historic statistical data available to show trends since 1990 to different household groupings.
- Work on electricity affordability is not trivial and will require cross-departmental consideration because electricity affordability is a sub-set of the wider issue of individual and family poverty.

[1] MEUG made this point in the recent submission to the Environment (select) Committee on the Crown Minerals (Petroleum) Amendment Bill, paragraph 14, 11 October 2018, refer http://www.meug.co.nz/node/955

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

Household electricity affordability is a sub-set of the wider issue of individual and family poverty.

Competitive electricity pricing can be achieved through competitive electricity markets, sound regulation of the monopoly elements of the market to avoid inefficient investment and pricing and care to avoid poorly structured market interventions.

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

Solutions to affordability need to consider un-intended consequences. The failure of interventions in the UK approach to managing concerns on a 2-tier residential retail market is a valuable lesson. A review of the economic and wealth transfer effects of existing interventions such as:

- the Low Fixed User Charges (LFUC), winter payment and EECA electricity levy as un-targeted or poorly targeted polices; and
- the recent change from an untargeted home insulation program to a targeted program,

might assist in design of any new prospective interventions and how trade-offs between choosing:

- un-targeted versus targeted interventions; and
- open ended ongoing interventions versus time-bound or a measure of success triggered end date.

For example, not everyone who receives the winter electricity payment needs taxpayer financial assistance. The total budget for the winter electricity payment could be focused on those experiencing hardship, making a greater difference to those who need help than is currently being delivered.

Summary of feedback on Part three

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

1. Consumer switching is an important means for consumers to "express their preferences and influence the direction of the sector."
2. There is a paucity of data or data series over time for detailed analysis, or to base decisions on.
3. Affordability affects businesses as well as low-income households.

Solutions to issues and concerns raised in Part three

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

1. Improve data to assist future reviews such as more detailed and timely international comparisons and a time series on affordability for low-income households over time.
2. Solutions to affordability need to consider un-intended consequences and the lessons from current and past interventions in New Zealand and overseas.
3. Government is the only party capable of identifying households experiencing poverty and poverty-related hardship, e.g. paying electricity bills. Government needs to bring together retailers, distributors and others to jointly work together to develop new approaches and solutions. The electricity sector alone cannot resolve the causes of poverty.

Part four: Industry

Generation

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

The last paragraph of this section states "Overall, the generation sector is delivering reliable supply, low and falling emissions, and wholesale prices that are reasonable compared to costs of building new power stations. However, we have some concerns about short-term market power."

MEUG's view aligns with the above quote though we would add:

- we are not at the point where competition in the generation sector means we can pull back on continuous improvements to the Code and facilitating market led innovations; and
- we also share concerns on short-term market power but to be clear, believe the EA is very aware of the issue and is working to find solutions.

  The current high spot price event will be a test of the market and whether parties with short-term market power exercise that power. We expect the EA will be closely following supplier behavior and it may be appropriate after the event to have a market review to consider if any lessons can be learned and consequent modifications to the Code or industry led market facilitation initiatives. Given the significance of the current high spot price event an EA review could be considered as a priority 1 topic for 2019/20 with a focus on whether there were barriers to smaller retailers and direct wholesale market consumers managing risks compared to large integrated suppliers.

  The current high spot price event is also a timely reminder that the factors outside the remit of the Code and EA that lead to the market becoming stressed also need to be considered by policy makers. The current event highlights the importance of reliable and diverse gas supplies. Policies such as the ban on new offshore oil and gas exploration permits and limited time for remaining new permits for onshore Taranaki will adversely affect future security of supply for the electricity sector.

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

The review should consider barriers to new generation (and transmission) due to RMA consenting timelines and processes.

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

See response to questions 12 and 13 above.

Retailing

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

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

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Vertical integration

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

This topic was last traversed by the EA in 2014/15. There is no new analysis in the First Paper to alter the conclusion reached by the EA, and supported by MEUG, that there was insufficient evidence vertical integration was leading to long-term detriments to consumers to warrant analysis of options that would require radical changes to the industry.[2] Therefore, the EA work programme has focused on other market design issues where there were clear detriments and the cost of remedying those was less than the expected benefits.

MEUG supports the findings of the review. We are open to those parties that see major disbenefits from vertical integration to demonstrate those and propose low cost solutions to remedy those detriments. In the absence of evidence forthcoming, we would be concerned if the review recommended prioritising further work on vertical integration thereby diverting resources from the EA's other wholesale market top priorities of implementing RTP, changes to extended reserves over the next 2 to 3 years and completing the TPM review.[3]

As noted in response to question 12, the EA might also consider a review of the current high spot price event as a priority 1 topic for 2019/20 including whether there were barriers to smaller retailers and direct wholesale market consumers managing risks compared to large integrated suppliers.

[2] Refer MEUG submission on Wholesale Advisory Group Hedge Market Development discussion paper, 19 December 2014, for a discussion on issues of concern to MEUG at that time on the hedge market. Some of those issues remain as items for continued improvement. Refer http://www.meug.co.nz/node/639

[3] These three wholesale market priorities are 3 of 6 EA priority 1 projects for 2018/19. The other priority 1 projects are Equal access, Multiple trading relationships and Distribution pricing: review of pricing principles, refer https://www.ea.govt.nz/dmsdocument/23834-201819-work-programme

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

This is an incomplete analysis and therefore no conclusions can be reached.

An analysis using the Commerce Commission economic assessment methodology to estimate economic profits and hence excess returns relative to an appropriate WACC over time for Part 4 regulated entities is required. That approach we believe is the methodology the Commission would use in market studies contemplated in the amendment to the Commerce Act currently before Parliament. We think such an analysis is necessary to remove ongoing uncertainty about supplier profits.

Implementing a Commerce Commission economic assessment requires access to historic accounting information of businesses in the sector and taking a view on opening historic asset values.[4, 5] The treatment of historic asset values is often a point of contention. The EA in a 2013 publication discussed asset values of generators and monopolies under the heading "The myth of inflated asset values" as follows:[6]

> "*Another criticism of the current arrangements is that generators have been revaluing their assets and using the higher asset values as the justification for increasing prices. This is a game that some New Zealand regulated entities with market power have engaged in. Worse still, there have been incidents when the regulated entity has not counted the increase in asset values as part of its overall returns when resetting its prices and has, in this sense, double dipped.*
>
> *This accusation cannot be legitimately applied to generators, however. They are not regulated entities with market power setting their prices off their own asset valuations. There are five major generators and a whole lot of others as well, and the barriers to entry into being a generator are low. For example, several iwi with initially very limited capital resources have managed to enter the market and thrive. There has been a very large increase in distributed generators in recent years.*
>
> *The generation market is workably competitive and, in such a market, prices are set by the interplay of supply and demand. Prices determine the returns parties receive for output and returns determine asset values and not vice versa.*
>
> *The claims that generators are using asset revaluations to ratchet up prices are based on confusion over what determines asset values in a regulated market with what determines them in a workably competitive one*."

The logic of the EA analysis above is still relevant; though the need, in our view, for an analysis of supplier economic profits over time using the Commerce Commission economic assessment methodology remains.

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[4] The review notes, p45, some data between 1999 and 2002 was unavailable. We believe there is sufficient public data to undertake a first order assessment of economic profits over time including that period. Further data could then be requested from suppliers if warranted.

[5] Where there is some uncertainty on historic data, such as opening asset value deemed to be the opening economic value, the results of the historic time series analysis can be tested with scenarios for ranges of opening asset values.

[6] EA, The Economics of Electricity, 4 June 2013, paragraphs 52 to 55, https://www.ea.govt.nz/dmsdocument/15066-the-economics-of-electricity

Transmission

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

We require any TPM changes to the guidelines by the EA or refinements to implementing the existing TPM guidelines by Transpower to clearly demonstrate a positive Cost-Benefit-Analysis. The EA in past TPM proposals (and Transpower in recent proposals for approval of major capex and listed project capex) have included an analysis of the impact on different consumers. Continuous improvement in methods to estimate benefit and cost effects on different consumers should continue. The existing review of TPM guidelines should continue its course.

Distribution

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

MEUG notes distribution price increases are the largest single contributor to recent higher residential prices. If Government is serious about the impact on vulnerable households, it has to examine distribution pricing, why distributors prices have increased as much as they have and what profits distributors have been making.

MEUG does not agree with the Commerce Commission's last decisions on WACC at the end of the Input Methodology (IM) review on 20 December 2016. For example, we disagree with use of the 67th percentile rather than the mid-point WACC and the sample of companies used to estimate beta. We believe the sample is too broad and a better approach would be to select comparable monopolies. It seems implausible that the Transpower asset beta should be the same as that for EDB because Transpower bears even less risk that EDB (and they bear very little risk); yet that was the conclusion of the 2016 IM review.

Given the next review of the IM need not occur until December 2023 our approach now is to consider new data and applications of WACC by the Commission to other sectors (eg airports and in the near-term Chorus) and new decisions and trends by overseas regulators (eg current review of WACC in Australia). Precedents from that work might justify an earlier review of IM before 2023.

The comments on question 18 in relation to estimating economic profits and whether sustained excess returns are relevant to considering if distributors and Transpower have been earning excess returns in the recent past. We note that the level of economic profits for Part 4 regulated energy lines services is based on the deemed historic opening economic cost of assets set by the Commerce Commission on 22 December 2010.[7] For practical reasons the uplift in asset values to deemed historic cost resulted in gains to the benefit of the owners of the regulated monopolies.

[7] Refer Decision and Decision paper at https://comcom.govt.nz/regulated-industries/input-methodologies/electricity-distribution-ims/other-past-amendments-and-clarifications2?target=documents&root=62702

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

The analysis of distributor's operating expenses per consumer in Figure 24 is interesting but, in our view, no firm conclusions can be drawn because the efficiency and productivity of each EDB requires an analysis across all production inputs, not just operating expenses. Such an analysis needs to include EDB in New Zealand and overseas. This type of benchmarking should be an increasing focus for the Commerce Commission to assist EDB and customers understand the gap between EDB individual actual and world leading performance. Using benchmarking to inform interested parties does not breach the existing statutory constraint on using benchmarking for DPP reset opening prices.

There are two examples of collaborative governance arrangements between EDB:

- the Unison management of Central Hawkes Bay; and
- the PowerNet management of 3-lower South Island EDB networks.

MEUG is not aware of any public analysis of the expectations of the parties to those arrangements in terms of benefits that would accrue to their customers and owners and whether those benefits have been realised. MEUG suggests MBIE, with the co-operation of those parties, could analysis those arrangements and publish the findings as that may assist other EDB consider similar arrangements.

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

Separately attached to this submission is a report by NZIER that considers the assessment of the allocation of distribution costs.

EDB already use detailed cost allocation models for their network and operational costs that reflect the use by customers of different types of network assets and include measures such as contribution to peak load, capacity requirements, number of customers and electricity usage. This approach is supported by actual measurement of the effects of different customers on the network for each specific EDB.

The analysis compares a sample of individual actual EDB prices and costs with a hypothetical envelope of efficient allocation of common costs bounded at the upper level by standalone costs and lower level by incremental costs. The hypothetical envelope has assumptions that are generalized for all EDB. EDB specific assumptions would be better. The model finds OtagoNet's allocation of common costs to households is above standalone costs. If true, then that is a matter the EA should follow up with OtagoNet as the EA has jurisdiction on EDB's voluntary compliance with the pricing methodologies in the Electricity Industry Participant Code 2010.

However, the model could be incorrect. It would be prudent to compare OtagoNet's actual cost allocation methodology with the results from the model. Similarly, a check of the robustness of the model's for EDB at the other extreme, those being Buller and Marlborough, that have relative to other EDB in the sample, the lowest share of common costs allocated to residential.

Until the outputs of the model are tested against individual EDB pricing methodologies (includes cost allocation) required to be disclosed each year as part of the Commerce Act Part 4 Information Disclosure regime, we do not think the analysis supports the view in the Overview section (p5) that "Fairness may dictate readjusting some distributor's shared network costs from households to other consumers."

Also, as per our comments on question 5, given 97% of New Zealand businesses are small businesses, readjusting shared network costs from households to other consumers largely involves shifting cost between the same people with little material change. Reducing household bills by 4.5% to increase small business bills by 5.5% makes hundreds of thousands of New Zealanders worse off.

Around a quarter of Distribution charges are passed through Transpower charges. Government could lower residential electricity bills if it stopped profiting from the excess returns Transpower earns due to a WACC higher than that needed for the risks Transpower bears (see also our comments on the WACC applying to the monopolies for question 20). That is, if Government forewent the annual $165 million per annum dividend it receives from Transpower each year.

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

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Summary of feedback on Part four

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

1. RMA consenting timelines and processes can be a barrier to timely investment.
2. The analysis of supplier economic profits is incomplete.
3. The regulated WACC for line monopolies that meets the requirements of Part 4 of the Commerce Act is, in our view, excessive.
4. The reasons why some EDB have collaborated or merged but most have not, are not understood.
5. The analysis of the allocation of EDB common network costs does not, in our view, support the Review's findings that "Fairness may dictate readjusting some distributor's shared network costs from households to other consumers."

Solutions to issues and concerns raised in Part four

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

1. The review should consider barriers to new generation (and transmission) due to RMA consenting timelines and processes.
2. An analysis of supplier economic profits using the Commerce Commission approach to estimating regulated supplier economic profits is required.
3. The Commission could take a more active review of WACC rather than wait for the next 7-year Input Methodology of WACC in 2023 given the industry is in flux and hence asset beta and other variables may change before that date.
4. Understanding lessons learned from the Unison and PowerNet experiences with multi-EDB management arrangements might assist other EDB consider similar arrangements.

Part five: Technology and regulation

Technology

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

The challenge for new technology uptake will be to ensure that the governance arrangements keep pace with its development to ensure that the transition balances the energy trilemma to achieve affordable, reliable, low or zero emissions electricity.

We agree that changes to regulatory frameworks may be needed, such as the rules set out in the Electricity Participation Code and particularly the proposed default distribution agreement (DDA). In addition, new forms of contracts that consumers might enter into may be needed, which will need to comply with provisions of the Fair Trading Act and Commerce Act. The latter includes disputes resolution currently undertaken by Utility Disputes Ltd (UDL). Some MEUG members have small sites covered by the UDL scheme. How the roles and functions UDL and the DDA integrate with the other parts of Part 4 of the Commerce Act need to be considered.

In the wholesale market, participants trade through financial derivatives that may be designed to encourage, rather than compel, physical responses. The financial risk associated with energy trading is core business for gentailers, generators and retailers, though not for many other consumers. This could limit participation in the development of contracts where a physical response is required, especially where a free-rider problem exists, such as the development of market reliability services.

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

The differentiation of consumers into different classes based on size, largely residential at one end and industrial at the other, will be less relevant as all consumers have TOU metering and an option to manage their demand with real-time-prices including more real-time-like line tariffs.[8] What will matter will be whether an individual consumer given improved cost reflective and service-based pricing elects to actively manage their demand (including use of storage or own generation). Some industrials just as some households, will be active and others, given the nature of their processes or home requirements, will not.

Government should work with the sector to enable greater use of technologies such as AI that can automate efficiencies, maximize low prices, and take advantage of the benefits of shifting without the consumer needing to invest their own limited time and energy into the issue.

[8] EA have recently noted 8 out of 10 New Zealand homes now have smart meters, refer EA Annual report 2017/18, p6.

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

A caution on potential mis-interpretation of the final sentence in this section. That sentence reads "Careful management of change should ensure no risk to the electricity system's resilience and ability to perform reliably." MEUG assumes "management" in this sentence refers to careful evolution of clearly required changes to governance structures (that is the regulatory matrix) and efficient execution of regulatory roles by regulators to set rules, monitor, facilitate innovation and prosecute breaches. MEUG would be alarmed if "management" inferred political interventions.

Regulation

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

MEUG agrees with the statement in the Overview section (p6) "*Regulation:* The electricity regulatory objectives framework is generally well positioned. We think fairness and environmental (especially energy hardship and carbon emissions) should not be specific objectives for electricity regulators. They are better retained in the broader regulatory framework." MEUG interprets "broader regulatory framework" to mean the broader policy framework across all relevant government departments.

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

The Minister should consider repealing the low fixed charge tariff regulations.

How the sector transitions changes will be important to some households.

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

The review needs to broaden the analysis of regulators and other Crown Agents relevant to the electricity sector to include the role and effectiveness of:

- The Energy Efficiency and Conservation Authority (EECA); and
- Utility Disputes Limited (UDL)

In relation to EECA MEUG has a long-standing view the EECA electricity levy has not been delivering the benefits claimed by EECA and nor is the levy mechanism appropriate for recovering all the levy programme work. The work by EECA on appliance and equipment standards should be appropriated from government's general accounts not through a levy on end users. It is unclear why standards work is recovered in the electricity sector from a unit charge on every consumer, including large consumers that receive no direct benefit from improved household appliance standards when, as far we can determine, the cost of developing standards in other sectors is met from government's general account. We will continue to raise those issues with MBIE in the annual appropriations bid consultations.

We see UDL as an important part of the industry governance arrangements. Pending the outcome of the Vector appeal on the Penrose substation fire event, it may be prudent to check the balance of incentives/risks in EDB contracts (including the soon to be consulted on Default Distribution Agreement (DDA)), the Commerce Act Part 4 regulatory regime, and UDL scheme are aligned and consistent, and there are no gaps on the regulatory matrix. This is important as we see, as noted in response to question 26, that consumers will have a more and new contractual terms and conditions with service providers that may overlap with the remit of UDL and the DDA.

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

We are comfortable with the work programmes of the Commerce Commission and EA.

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

There are three other matters the review could consider:

- The Commerce Commission, after consultation and provided a net benefit is demonstrated, can set levies for specific purposes. The Commission has not exercised that option for Part 4 energy regulated businesses. The same option was not included for the EA when it was established in 2010. We think that was an oversight and any legislative changes arising from the review should include a provision to allow the EA to set levies for specific purposes subject to market consultation. For example, there may have been a case when the FTR market was being developed that the cost of implementing and subsequently operating that market could have been recovered from participants in the FTR market rather than the cost being uniformly spread across all consumers. The EA has previously proposed this as a legislative change and MEUG has supported that proposal.[9] Because the change is relatively small it has not been a priority for Ministers. Hence including this change with other electricity related legislative changes would be appropriate.
- MEUG opposed the system operator being granted a statutory monopoly in the reforms of 2010. We still believe that to have been a poor decision. With the uncertainty of the role of the national system operator and distribution network operators in the future, reverting to the prior position whereby the system operator had an ever-green contract with the EA subject to either party giving 7-years notice of expiry (but not excluding the option of Transpower tendering for the future contract) may provide more flexibility and options for different models to evolve.
- MBIE has failed to publish timely Electricity Demand and Generation Scenarios (EDGS) and revisions required by Transpower when preparing applications or approval of Major Capex and Listed projects. More recently Transpower's RCP3 proposal to the Commerce Commission has used Transpower's variations to the first and only EDGS that is now several years out of date. We seem to have reverted to the problem we had several years where Transpower decides the demand for their services even though they have an incentive to inflate the need for those rather than, as the 2010 legislative reforms proposed, MBIE prepare EDGS as a subset of a broader view of forecast demand and supply across all sectors of the economy. Either MBIE needs to step up and publish independent robust EDGS or another regulator or regulators such as the Commerce Commission or EA should be required to take on the responsibility.

[9] Refer MEUG letter to EA of 21 December 2012 at http://www.meug.co.nz/node/523

Summary of feedback on Part five

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

1. Fairness and environmental objectives (especially energy hardship and carbon emissions) should not be specific objectives for electricity regulators. They are better retained in the broader policy framework across all relevant departments.
2. The low fixed charge tariff regulations may be hindering distribution charges changing to be cost-reflective and service-based.
3. The review does not consider the governance role of EECA and UDL.
4. The EA could better target recovery of costs if it could set levies.
5. The system operators' statutory monopoly may hinder evolution of optimal industry governance given changes in technology.
6. MBIE's failure to publish regular EDGS has given Transpower lee-way to skew demand forecast scenarios to justify longer-term grid investment.

Solutions to issues and concerns raised in Part five

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

1. The Minister should consider repealing the low fixed charge tariff regulations.
2. The role of EECA and UDL needs to be considered in the next stages of the review as important agents in the industry governance.
3. The Act should ne changed to allow the EA to set levies for specific activities.
4. The system operators' statutory monopoly should be reconsidered.
5. Either MBIE starts and continues publishing regular EDGS or the task be given to another regulator.

Additional information

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

-

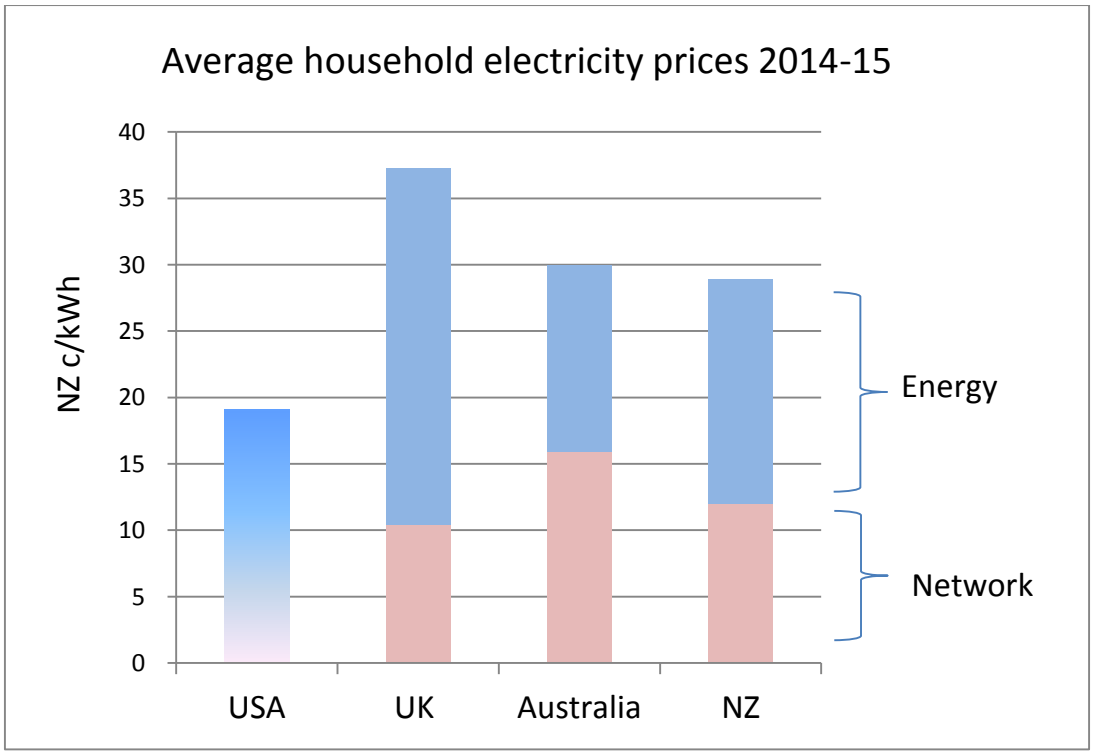
International comparison of electricity sectors

Ralph Matthes, Major Electricity Users' Group, New Zealand, August 2015

Country	USA	UK	Australia	NZ
Economy wide statistics[i]				
GDP US$b pa	17,419	2,530	1,063	165
Population (million)	318.8	64.5	23.8	4.5
GDP US$/capita 2014	54,640	39,225	44,612	36,401

Electricity sector statistics				
Average household prices	12.64	15.93	26.83	28.86
In local currency and references	US c/kWh[ii]	Pence/kWh[iii]	Aus c/kWh[iv]	NZ c/kWh[v]
Estimation of disaggregated prices in local currency:				
Competitive Market			10.49	16.91
Environmental policies		{ has value}	2.11	
Regulated Networks:				
~ Transmission			2.43	
~ Distribution		{~ 28%}	11.81	
~ Networks sub total			14.23	11.96
Total			26.83	28.86

Graph of average household electricity prices in NZ c/kWh (exchange rate assumptions overleaf)



Country	USA	UK	Australia	NZ
NZ$1 exchange rates[vi]	0.6622 US$	0.4274 UK pound sterling	0.8943 AU $	
US c/kWh				
Energy (non-network)		17.77	9.33	11.19
Network		6.91	10.54	7.92
Total	12.64	24.68	19.87	19.11
UK pence/kWh				
Energy (non-network)		11.47	6.02	7.23
Network		4.46	6.80	5.11
Total	8.16	15.93	12.82	12.34
AU$ c/kWh				
Energy (non-network)		24.00	12.60	15.12
Network		9.33	14.23	10.69
Total	17.07	33.33	26.83	25.81
NZ$ c/kWh				
Energy (non-network)		26.84	14.09	16.91
Network		10.44	15.91	11.96
Total	19.09	37.27	30.00	28.86
Fraction of power bill:				
Energy (non-network)		72%	47%	59%
Network		28%	53%	41%
Total		100%	100%	100%

[i] Refer OECD, https://data.oecd.org/gdp/gross-domestic-product-gdp.htm

[ii] Refer US Energy Information Administration, July 2015 Monthly Energy Review, 28-Jul-15, http://www.eia.gov/totalenergy/data/annual/index.cfm#electricity

[iii] Refer Ofgem, https://www.ofgem.gov.uk/publications-and-updates/charts-outlook-costs-make-energy-bills

[iv] Refer Australian Energy Market Commission report to COAG Energy Council, 2014 Residential Electricity Price Trends, 5th December 2014, p68, for 2014/15, http://www.aemc.gov.au/Markets-Reviews-Advice/2014-Residential-Electricity-Price-Trends

[v] Refer NZ Ministry of Business Innovation and Employment, Residential sales-based electricity cost data March year 2003 to March year 2015, refer http://www.med.govt.nz/sectors-industries/energy/energy-modelling/data/prices/electricity-prices

[vi] Refer Reserve Bank of New Zealand, exchange rates 11th August 25, http://www.rbnz.govt.nz/statistics/tables/b1/

Memo

To	John Harbord and Ralph Matthes
CC	
From	Mike Hensen
Date	21 June 2018
Subject	Electricity price history in New Zealand

Purpose

This note describes electricity price changes over the period 1985 to 2017 and lists the key changes in the electricity market over this period and the data sources used in the comparison. The note is based on electricity price and consumption data published by the Ministry of Business, Innovation and Employment (MBIE), Electricity Authority (EA) and Transpower.

Overall trends

Total price for residential, commercial and industrial[1]

Figures 1 and 2 below show residential electricity prices have increased in both real and nominal terms over the period 1985 to 2017 while:

- commercial prices have remained flat in real terms
- industrial prices fell in real terms until 2002, increased over 2003 to 2004 and remained flat in real terms from 2005 to 2017.

The following table compares the compound annual growth rate (CAGR) in real[2] electricity prices over the periods 1985 to 2000 and 2000 to 2017 for residential, commercial and industrial consumers (a summary description of the price movements shown in Figure 2).

Table 1 Change in real electricity prices by consumer group

CAGR and total percentage change over the periods 1985 to 2000 and 2000 to 2017

Consumer group	CAGR		Entire period	
	1985 to 2000	2000 to 2017	1985 to 2000	2000 to 2017
Residential	2.05%	2.36%	36%	49%
Commercial	-1.65%	0.34%	-22%	6%
Industrial	-0.64%	0.78%	-9%	14%

Source: NZIER

Figures 1 and 2 also include a simple annual average of the wholesale electricity[3] prices from 1996 when the wholesale market was established. This simple average price is not weighted by demand

1 Source: 'Energy Prices', Energy & Building Trends, Ministry of Business, Innovation & Employment, available at http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/statistics/prices

2 For residential electricity prices 'real' means adjusted for inflation as measured by the Consumer Price Index. For commercial and industrial electricity prices 'real' means adjusted for inflation as measured by the Producers Price Index (Inputs).

and therefore understates the effect on consumers of the higher electricity prices in peak demand periods. Appendix A compares the simple average wholesale price from 2009 to 2018 with the demand weighted wholesale prices data published by the EA.

Retail electricity price components – lines and energy

Figure 4 below shows steady increases in both energy and lines prices in nominal terms for the model[4] residential consumer surveyed by MBIE. Figure 5 shows the drivers of residential electricity price movements (adjusted for inflation). In 'real' terms:

- total residential electricity prices increased at a CAGR of 2.08 percent over the period February 2000 to February 2018 (45 percent over the entire period) comprising increases in:
  - lines prices at a CAGR of 1.25 (25 percent over the entire period)
  - energy prices at a CAGR of 2.74 (63 percent over the entire period)
- energy price increases were the main driver of residential price increases over the period 2001 to 2009, line prices increased more quickly than energy prices over the period 2010 to 2014 and since 2014 they have increased at about the same rate.

Retail and wholesale prices – apples and oranges

A simple comparison of the price indexes summarised above and graphed in the Figures 1 and 2 overlooks important differences between the structure and drivers of electricity prices for these consumer groups:

- industrial and some commercial consumers are less exposed to expensive peak generation than retail consumers because they tend to have more stable and predictable demand for electricity and more ability to limit electricity usage in expensive peak periods. (Figure 3 shows the difference between the simple average of wholesale prices at 'residential peak' periods only and for 'all trading' periods)
- nearly all retail consumers are charged a pre-agreed flat rate per unit of electricity[5] but are not exposed to short term volatility in wholesale electricity prices while large commercial and industrial consumers are exposed to short-term fluctuations in wholesale electricity market prices which are reset every half hour
- industrial and commercial consumers are not exposed to costs associated upgrading the low voltage distribution network because they do not use this part of the network.

The pricing review starting point for the comparison of retail, commercial and industrial electricity prices (2000) roughly coincides with the end of excess hydro generation capacity and the need to construct new thermal capacity to meet peak demand.

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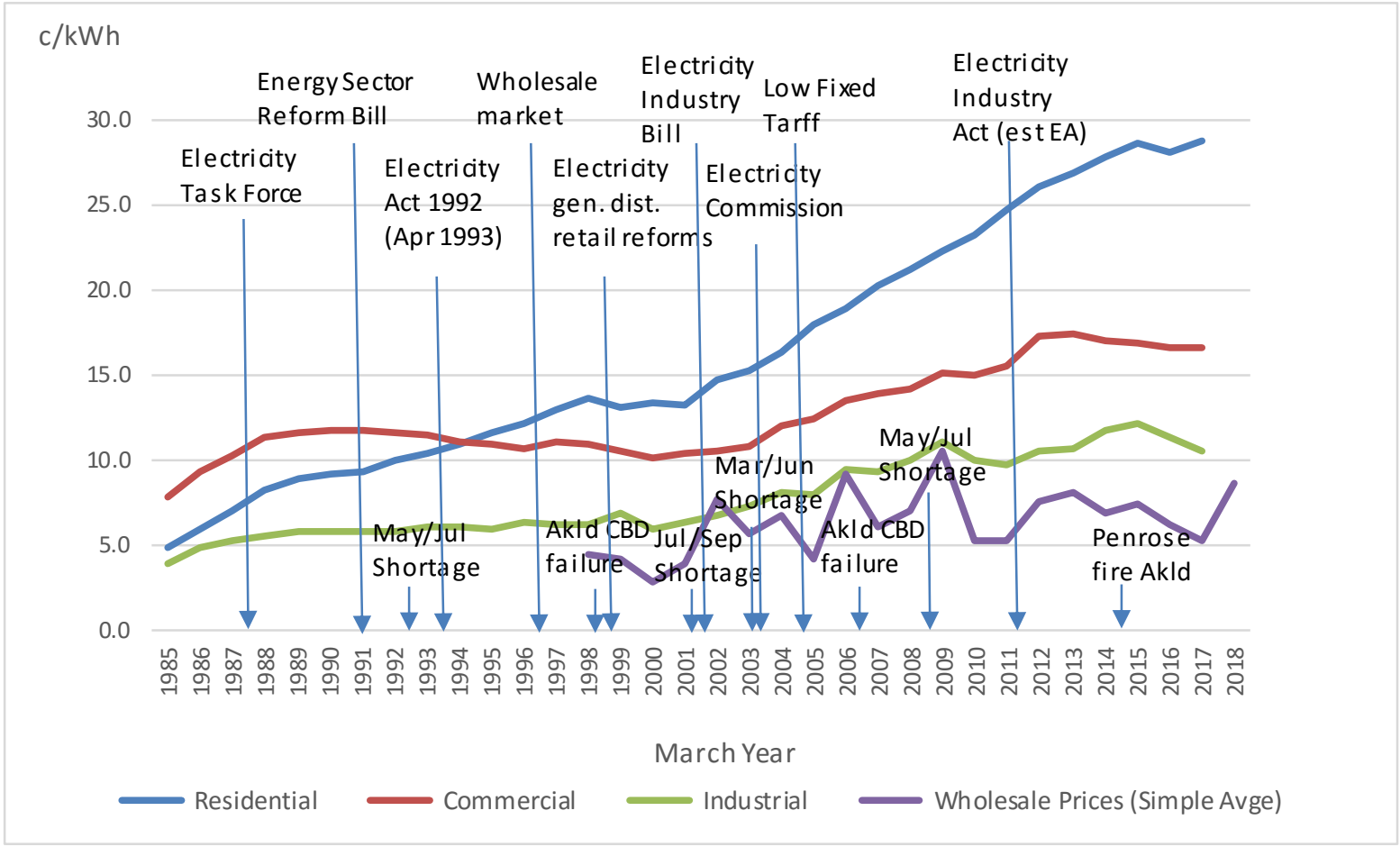
3 The source for the price data is the 'Final' wholesale electricity prices published by the Electricity Authority available at https://www.emi.ea.govt.nz/Wholesale/Datasets/Final_pricing/Final_prices. The final price files provide the wholesale electricity price for each grid exit point measured once every half hour. The simple annual average is the sum of all those half hourly price observations for every node over each year ending 31 March divided by the number of observation over the same period.

4 The model residential consumer uses 8000 kWh in a year, on a 'low user' plan with low fixed charges, receives any available prompt payment discounts (including electronic or online only discounts) and is on the most common, controlled, retail metering configuration in their town. The prices include GST. The lines component includes transmission and distribution costs. The energy component includes metering costs.

5 Flick Electric which has about 1.1 percent of retail consumers (measured by number of 'Installation Control Points') as at 30 April 2018 gives its customers direct exposure to wholesale electricity prices. After retail consumer reaction to spikes in wholesale prices last in 2017, Flick has introduced 'Volt' - a product to help consumers to 'save' for unusually high prices.

Figure 1 Electricity prices (nominal) – residential, commercial and industrial

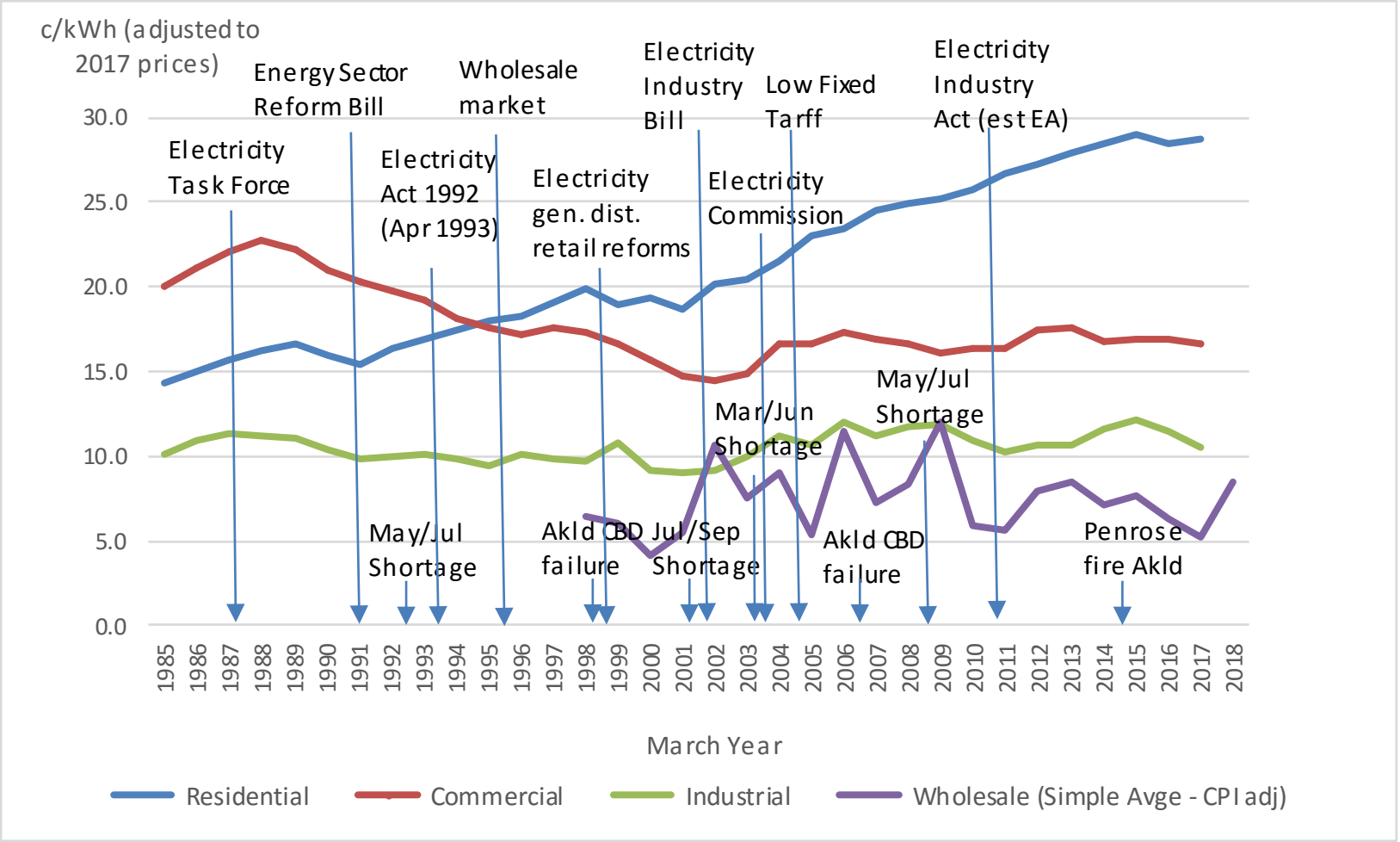
Nominal cents per kilowatt hour (kWh)



Source: NZIER analysis of MBIE energy price data

Figure 2 Electricity prices (inflation adjusted) – residential, commercial and industrial

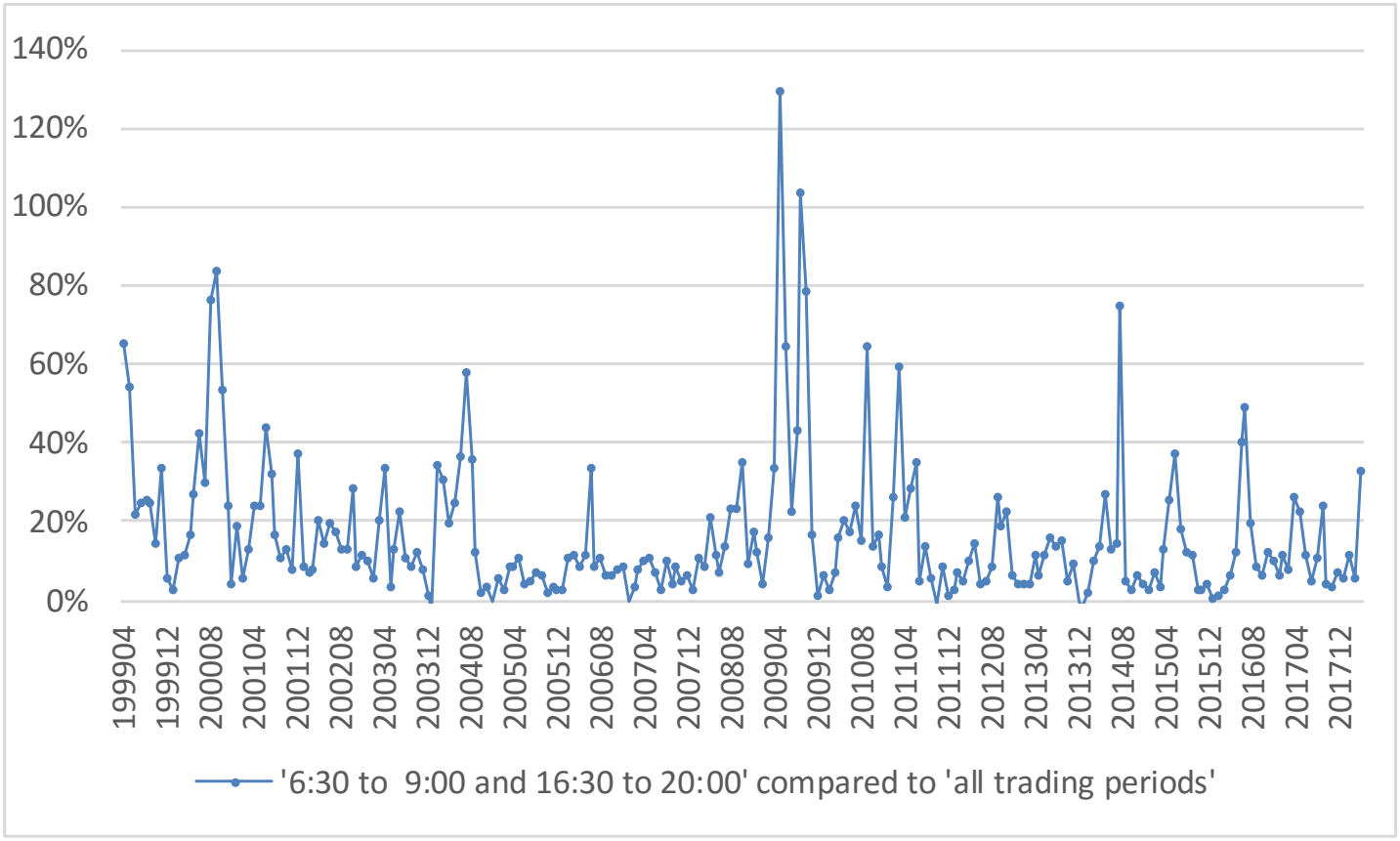
Cents per kWh adjusted to 2017 consumer prices for residential consumers and 2017 producer prices (inputs) for commercial and industrial consumers



Source: NZIER analysis of MBIE energy price data

Figure 3 Wholesale prices -residential peak 'premium' over all trading periods

Difference between the simple average of wholesale prices over 6:30 to 9:00 and 16:30 to 20:00 and simple average over all trading periods as a percentage of the average over all periods

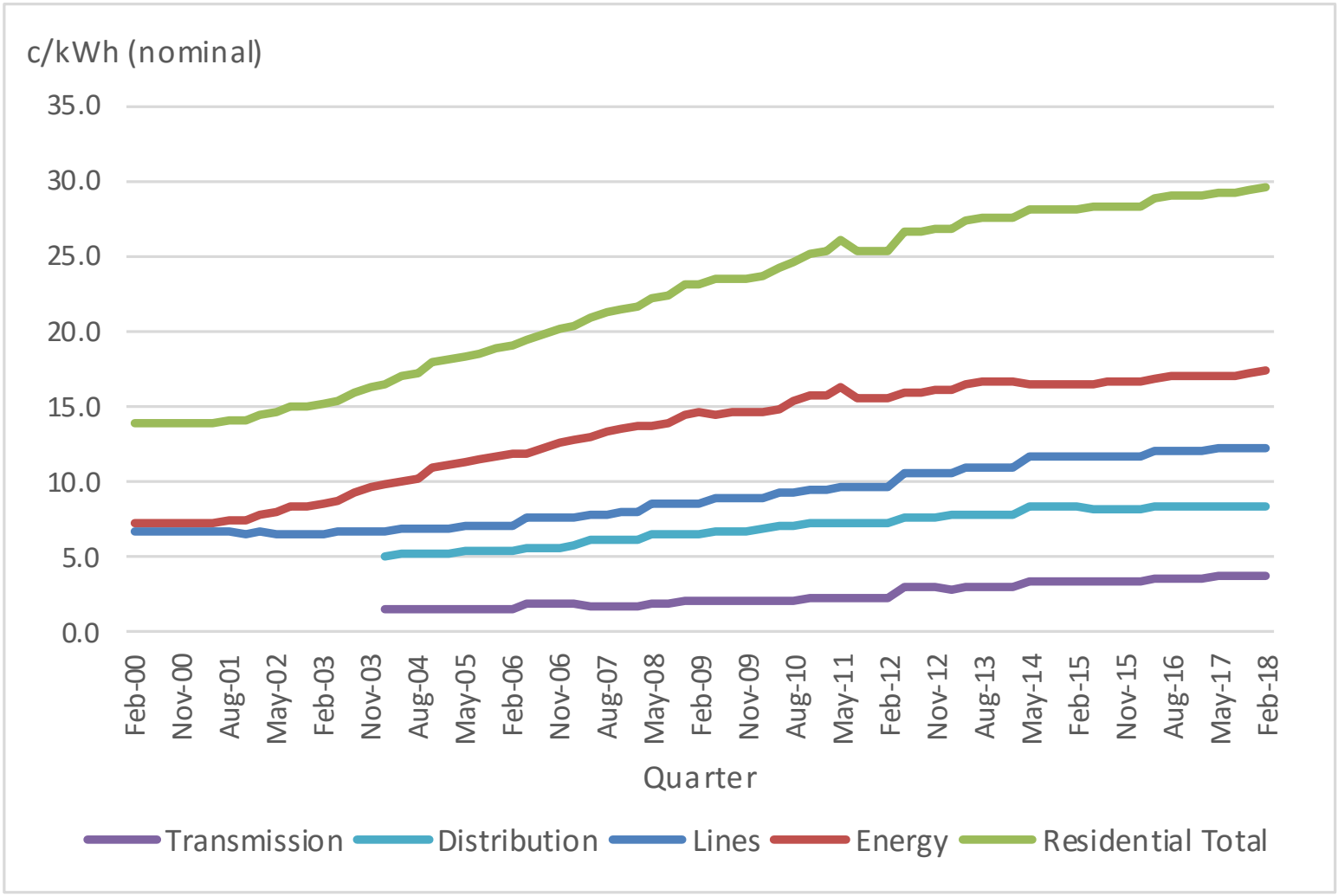


Source: NZIER

The monthly simple average of wholesale prices for peak residential periods was on average 16 percent higher than the monthly simple average for 'all trading' periods over April 1999 to April 2018 (the time shown in Figure 3). This difference gives a very rough starting point for a low side estimate of the wholesale electricity price 'premium' that residential consumers pay to have 'on demand' access to electricity at peak times. A better estimate of the impact of the peak usage premium on total residential electricity costs would be based on the average of wholesale prices weighted by electricity demand in each wholesale price period and allowance for a proportion of residential demand that is met overnight.

Figure 4 Residential electricity prices (nominal) attributable to 'lines' and 'energy'

Cents per kWh

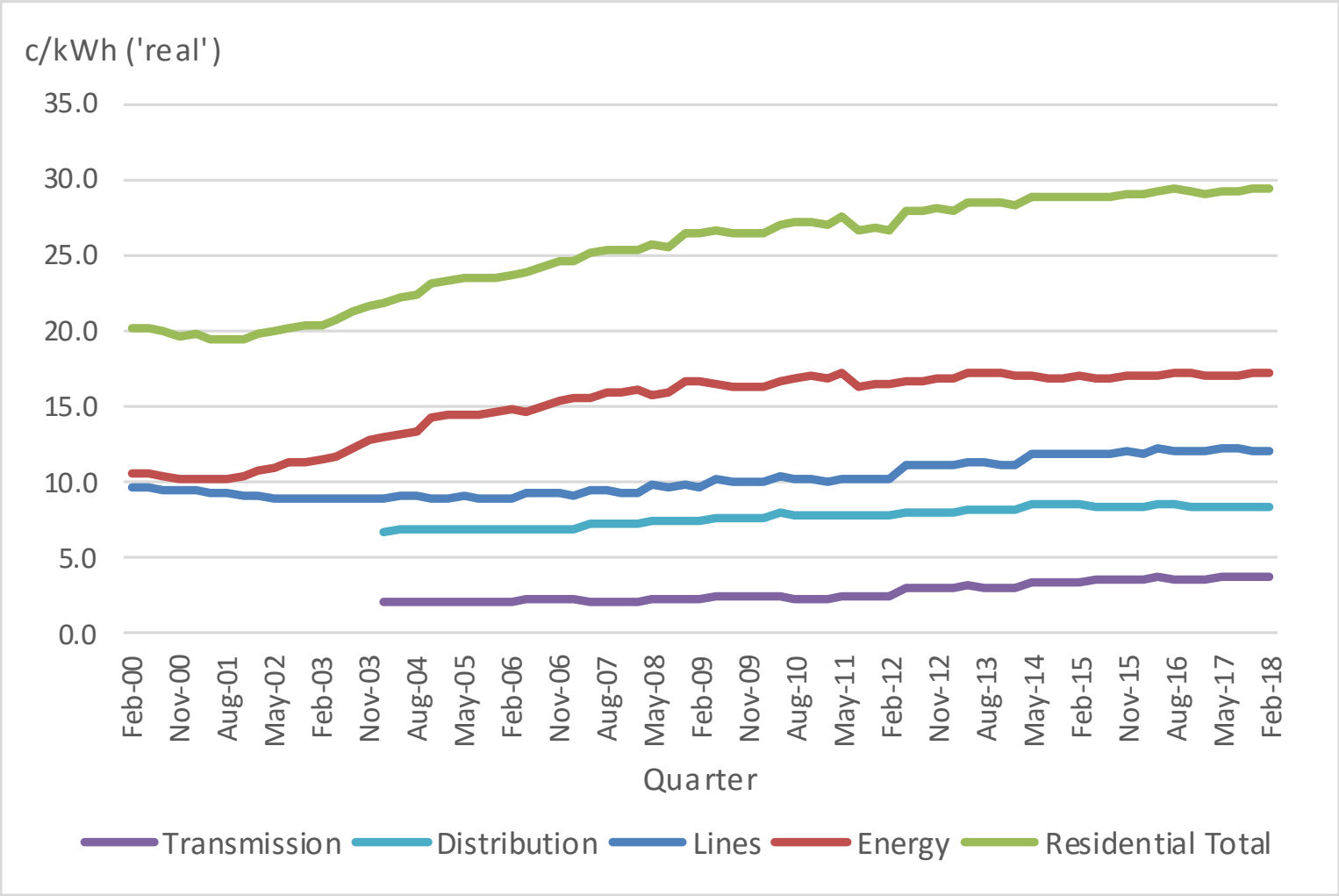


Source: NZIER analysis of MBIE electricity price survey data

'Transmission' and 'Distribution' are MBIE estimates of the two components of 'Lines'.

Figure 5 Residential electicity prices (real) attributable to 'lines' and 'energy'

Cents per kWh adjusted to March 2017 consumer prices



Source: NZIER

'Transmission' and 'Distribution' are MBIE estimates of the two components of 'Lines'.

Data sources

The three main sources of electricity price information are MBIE sales based information and electricity price surveys which report average annual:

- 'residential', 'commercial' and 'industrial' electricity prices – 1975 to 2017[6]
- 'Sales-based Electricity Costs (QRSS)'- 'residential' electricity prices separated into 'lines' (transmission and distribution) and 'energy and other' based on sales data– 2005 to 2017[7]
- 'Quarterly Survey of Domestic Electricity Prices (QSDEP)' - 'residential' electricity prices separated into lines (with estimates of transmission and distribution as separate charges) and 'energy and other' based on survey data – 2000 to 2017 [8]

In addition, we have used the EA data on 'Final' wholesale market electricity prices by trading period for each grid exit point to calculate monthly and annual averages of wholesale prices across all grid exit points by trading period.

The MBIE data does not provide information on the separation of residential electricity bills into lines and energy components before 2000 or any information on the separation of electricity bills for commercial and industrial users into 'lines' and 'energy' components at all. This is an important aspect in explaining the drivers of the differences between residential commercial and industrial electricity prices as:

- industrial and some commercial consumers tend to have more stable and predictable demand for electricity and more ability to limit electricity usage in expensive peak periods than residential consumers which means they are less exposed to high priced peak generation than residential consumers
- industrial and commercial consumers incur a share of transmission (national grid) and none or only part of the increase in distribution charges as they may be directly connected to the national grid or if they are consumers of a distribution company may only use the high voltage part of the distribution company network. Residential consumers are fully exposed to transmission costs and distribution company costs for both high and low voltage networks. As these are long-lived large-scale assets, capacity has[9] to be increased in much larger steps than the increments in short-term consumer demand and with a strong bias to ensuring security of supply – which can require price increases in the early life of the assets.

The EA data does not classify demand as residential, commercial or industrial by grid exit point. The demand met at many of the high volume urban grid exit points is a blend of these consumer groups.

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6 'Energy Prices', Energy & Building Trends, Ministry of Business, Innovation & Employment, available at http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/statistics/prices

7 'Residential sales-based electricity cost data March year 2005 to March year 2018' available http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/statistics/prices/electricity-prices. For this analysis we have used the survey data rather than the billing data as the survey data covered a longer period and estimated the separation of the lines price into transmission and distribution components.

8 Two MBIE data series are used for this analysis. The primary series covering the period 2004 to 2017 is 'Quarterly Survey of Domestic Electricity Prices', 15 February 2018,MBIE, available at http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/statistics/prices/electricity-prices.The secondary series covering the period 2000 to 2004 is 'Quarterly Survey of Domestic Electricity Prices to 15 February 2013' MBIE, available at www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/statistics/prices/electricity-prices/archive-electricity-price-surveys.

9 The word 'has' is extremely terse shorthand for a very complex balancing of minimizing the construction cost of long-lived assets while meeting projected demand growth over a 20 to 30-year period. Once investment in transmission and distribution assets is made the regulated rate of return on these assets plus costs is recovered from consumers irrespective of how fully the capacity is used.

Appendix A Wholesale electricity price data

Introduction

Wholesale electricity price and demand data is published by the EA in separate files (with different formats) from 1996 to now while demand weighted prices are published by the EA from July 2009 to now. The demand weighted data is a better comparator for the MBIE price data shown in Figures 1 and 2 but only covers about half the period considered by the pricing review. (In the time available, it was not possible to combine the pre-2009 price and demand files to calculate demand weighted prices from 1996 to 2009.)

As a starting point for the analysis of the drivers of differences between residential and wholesale energy prices the following charts compare the:

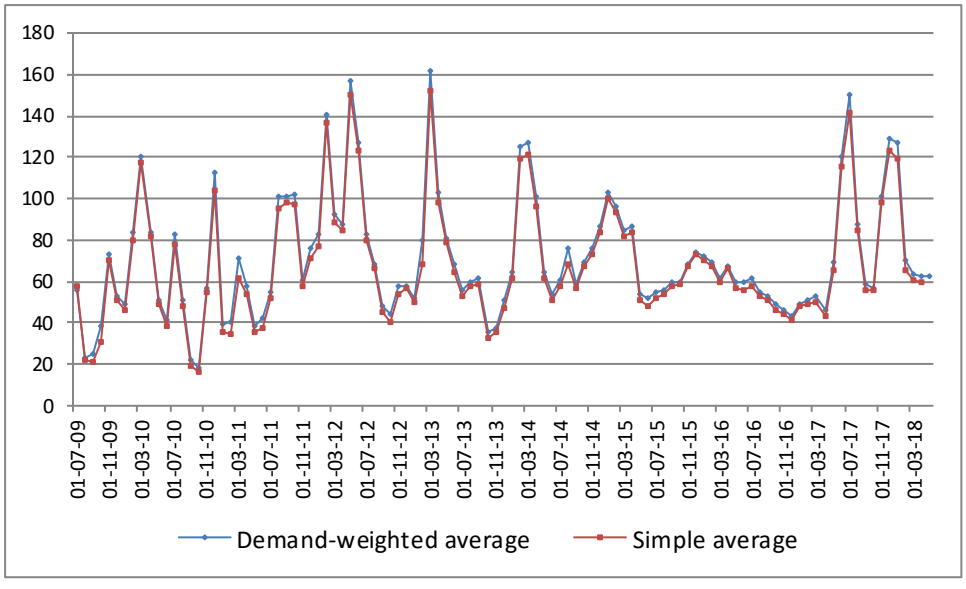
- simple average and demand weighted average wholesale prices to illustrate the effect on peak prices
- the simple average wholesale price for all trading periods and peak periods (which are the main times when residential consumers are using energy).

Demand weighted vs simple average

Monthly average wholesale prices (shown in Figure 6) are volatile with the peak monthly price up to four to six times that of the trough within a three to four-month band. Demand weighted prices during the peaks are 10 to 20 percent above the simple average but the demand weighted and simple average prices are much closer for troughs.

Figure 6 Monthly average wholesale electricity prices

Simple and demand weighted ($ per MWh)



Source: NZIER

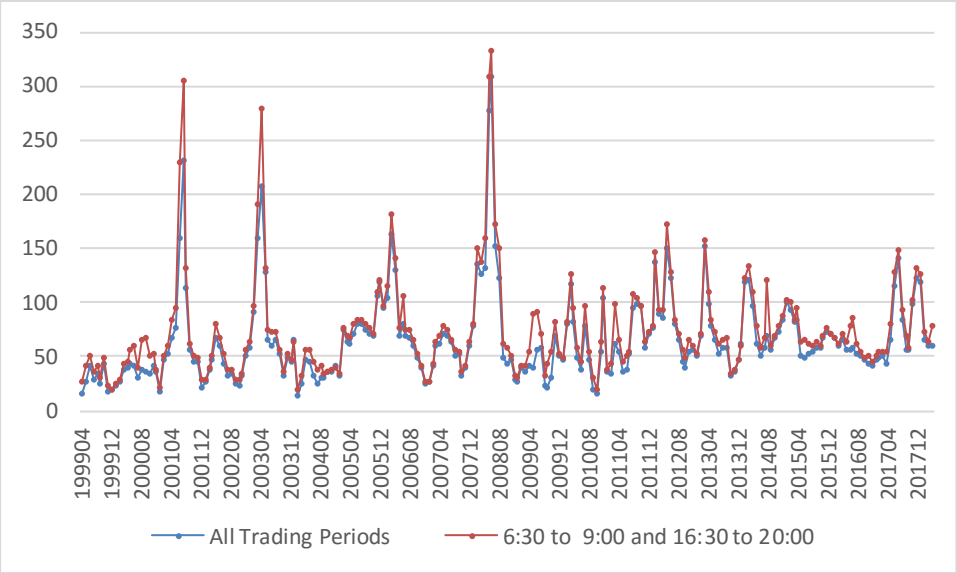
Residential peak vs all trading period averages

Simple average monthly prices for the 'residential peak' periods (shown in Figure 7) are:

- 10 - 15 percent above the average for ‘all trading’ periods for 40 percent of the trading periods over April 1999 to April 2018
- more than 15 percent above the monthly simple average for ‘all trading’ periods for one third of the trading periods over April 1999 to April 2018.

Figure 7 Monthly averageprices ‘peak’ and ‘all trading periods

Simple average ($per MWh)



Source: NZIER

Appendix B Transmission charges

Introduction

Figures 4 and 5 are based on a survey of residential consumers (QSDEP) and include an estimate of the transmission charges paid by residential consumers over the period February 2004 to February 2018. Over this period 'real[10]':

- transmission charges increased by 84 percent from 2.07 cents per kilowatt hour (kWh) to 3.81 cents per kWh – a CAGR of 4.4 percent
- distribution charges increased by 22 percent from 6.80 cents per kilowatt hour (kWh) to 8.29 cents per kWh – a CAGR of 1.4 percent.

Transpower data

Transpower has published data on transmission charge components for the period 2009 to 2018 but historical data on how these charges are allocated between electricity distribution businesses (EDB)[11] and direct connects or across EDB consumer groups is not readily available. Also data published by MBIE on electricity consumption[12] is not disaggregated by consumer group until 2013. An estimate of the average transmission cost per kWh of energy consumed is shown in the following table.

Table 2 Average transmission costs

Nominal cents per kWh

March Year	Transmission charges ($ million)				Electricity consumed (GWh)	Transmission cost (cents per kWh)
	Connection	Inter-connection	HVDC	Transmission total		
2009	122.8	385.8	83.0	**591.5**	38,433	**1.54**
2010	127.0	411.5	78.3	**616.9**	39,550	**1.56**
2011	126.2	413.6	84.8	**624.7**	39,996	**1.56**
2012	119.0	447.1	117.1	**683.2**	39,341	**1.74**
2013	128.7	547.0	128.8	**804.4**	39,136	**2.06**
2014	135.7	574.2	162.5	**872.3**	38,951	**2.24**
2015	138.1	661.1	145.0	**944.2**	39,166	**2.41**
2016	127.7	632.2	149.9	**909.8**	39,659	**2.29**
2017	128.6	662.1	152.3	**942.9**	38,802	**2.43**
2018	127.0	715.2	149.2	**991.4**		

Source: NZIER

[10] Nominal transmission charges adjusted for movement in the CPI so that they are all stated in March 2017 prices.

[11] Transpower has published transmission costs for EDB for 2014 and 2015 and the transmission pricing methodology papers published by the EA in 2016 included an indication of the allocation of interconnection and HVDC transmission charges across EDB, direct connects and generators. Only some EDB information disclosures (published by the Commerce Commissio) report transmission costs.

[12] 'Electricity graph and data tables' produced by Energy & Building Trends, MBIE, available at http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/statistics/electricity.

Memo

To	John Harbord and Ralph Matthes
CC	
From	Mike Hensen
Date	17 October 2018
Subject	Electricity Distribution Business Charges to Retail Consumers

Purpose

This note is a short review of the modelling of the allocation of electricity distribution (EDB) charges to retail customers described in the technical paper[1] supporting the draft report of the Electricity Price Review and the copy of the model[2] provided by the Electricity Price Review secretariat.

This note compares the analysis and modelling in the technical paper to the information on costs of service models (COSM) published annually by EDB as part of their pricing methodology disclosure. The comparison is based on the 2017 pricing methodologies for 15 EDB with more than 30,000 installation control points (ICP). These EDB together accounted for about 89 percent of ICP and 87percent of energy delivered in the year to 31 March 2017.

Technical paper modelling

The modelling supporting the analysis in the technical paper is based on share of energy usage with a simple percentage adjustment for peak demand. However, this approach:

- only indirectly considers what EDB regard as the key driver of their cost - capacity to meet peak demand and also oversimplifies the variation in cost drivers across EDB.
- the mismatch between the modelling approach used in the technical paper and the actual methodology used by EDB to allocate costs (to comply with efficient pricing principles) raises questions about the validity of the assessment in the paper that:

> *Compared with usage[20], we found businesses were paying, on average, less than a proportionate share of distribution charges, and residential consumers were paying more.*
>
> *([20] 'Usage' is based on both peak kW demand and annual kWh aspects of network usage.)*

The following table summarises the four steps in the technical modelling paper process and comments on how each step compares to the generic approach used by EDB.

1 'ELECTRICITY PRICE REVIEW HIKOHIKO TE UIRA, TECHNICAL PAPER To accompany FIRST REPORT, 30 August 2018' pages 9 to 16

2 The spreadsheet 'Cost_Allocation_ComComDisc_v05'

Table 1 Technical paper model process–

Comparison of technical paper modelling process with EDB pricing methodology approach

Modelling step	EDB approach	Comment
Zero. Import EDB billing data where from Commerce Commission disclosure. Selection criteria are: • EDB have reported transmission and distribution charges separately • pricing plans could be identified as exclusively residential	EDB billing information is based on EDB COSM. Both the cost allocators and the weight attached to them allocators vary across EDB. Selection criteria could have been broadened if EDB pricing methodology COSM data was used as they report transmission pass-through cost and explain the make-up of billing groups in detail.	EDB customer group classifications are more granular than residential or business. Also, the characteristics of business (industrial vs commercial) and residential (urban vs rural) very widely across EDB. Most of the EDB pricing methodologies references to cross-subsidy relate to either urban/rural cross subsidy or the effect of low fixed charges.
O**ne.** Compare the share of EDB revenue collected from residential and business customers with their share of energy supplied.	'Share of peak demand' rather than 'energy supplied' is the main allocator used by EDB	There is no simple or uniform linkage between link between the cost of model allocation of cost to customer groups and energy used by customer groups
Two. Identify factors driving a 'disproportionate' cost-allocation – shared network assets, peak demand and costs that are only applied to some customers.	EDB COSM address the allocation of shared asset costs and other operating cost in detail based on EDB experience of what drives costs changes.	EDB that uses energy suppled as an allocator also used sharer of number of ICPs. Some EDB also used circuit length as an allocator or separated their networks into low and high cost areas.
Three. Estimate the subsidy-free range of cost allocations by making fixed assumptions about peak demand costs, non-demand driven network costs and high voltage network use from Orion and Wellington Electricity Lines data.	EDB allocators and weightings vary widely due to differences in the mix of industrial, commercial and rural customers and differences in customer density.	The assumptions about cost do not reflect the range of values for these allocators where they are used by other EDB or the other cost drivers used by EDB.
Four, Impact of different cost allocations based on: • mid-point between incremental and standalone costs • residential customers pay incremental costs and businesses pay standalone costs.	EDB methodologies comment on testing whether pricing lies between incremental and standalone costs but generally do not calculate the incremental and standalone cost for different customer groups.	The range between standalone and incremental costs (for the EDB that calculate these costs) is wide. The technical paper does not explain why the top-down 'mid-point' and 'incremental' cost allocation for residential customers is a better estimate of residential customers' effect on EDB cost than EDB 'bottom-up' estimates.

Source: NZIER

Using the best data

The EDB pricing methodologies provide a more detailed starting point for assessment the rationale for EDB pricing than the modelling in the technical paper. In particular, EDB pricing methodologies:

- include detailed information on cost allocation across customer groups with a description of each allocator and in most cases a value for each allocator. This provides much more exact information on the indicator used and its value than is used in the modelling for the technical paper.

- use different cost allocators (e.g. peak demand, energy usage, number of ICPs etc.) for different types of cost (e.g. return on network assets, maintenance and overheads)
- assess their pricing against Electricity Authority principles which include:

> *a) Prices are to signal the economic costs of service provision, by:*
> *i. being subsidy free (equal to or greater than incremental costs, and less than or equal to standalone costs), except where subsidies arise from compliance with legislation and/or other regulation;*

The following table summarises the main COSM allocators used by the 15 EDB pricing methodologies reviewed for this note.

The main allocator of network asset costs and network operating expenditure is the estimated share of 'peak demand' which in turn is measured differently for different customer groups to reflect how different mixes and densities of customer demand for network capacity affect the size and shape of the network that EDB provide. Energy usage and number of ICP are only used by some EDB and then only for costs that where these factors actually drive the EDB cost.

Table 2 EDB cost allocators subjected to price/quality regulation

Cost is allocated using customer group share of the allocator listed

EDB	Peak demand[1]	Installed Capacity	Energy supplied	ICP number	Value of Lost Load
Vector	HV assets. LV assets (partial) Transmission costs.		Non-asset costs. LV assets (partial).		
Powerco	Operating, capital and transmission costs - (80% weight)			Operating, capital and transmission costs- (20% weight).	
Orion	Capital, operating and admin costs.				Contingent asset costs.
WELL	Transmission and capital costs		Some operating and other pass-through[2] cost.	Some operating and other pass-through[2] cost.	
Unison	Operating, capital and transmission costs.			Other pass-through[2] costs.	
Aurora Energy	Operating, capital and transmission costs.			Other pass-through[2] costs.	
Network Tasman	Direct operating, capital and transmission costs.	Indirect operating cost.			
Alpine Energy[3]	Direct operating, capital and transmission costs.			Non network costs.	
Top Energy	Direct operating, capital and transmission costs.		Non network costs?	Non network costs?	

Notes:

1. EDB use several measures of peak demand (coincident, anytime maximum, after diversity maximum and winter and summer) to reflect the pressures on network capacity caused by different customer groups.
2. Other pass-through costs are usually limited to Electricity Authority and Commerce Commission levies but sometimes also include local body rates.
3. Alpine Energy assigns its customers to load groups according to: location (low or high cost area), fuse size at the ICP, maximum business day peak demand and type of meter. This grouping is applied before the allocators listed in the table.

Source: NZIER

Table 3 EDB cost allocators for community-owned EDB

Cost is allocated using customer group share of the allocator listed

EDB	Peak demand[1]	Installed Capacity	Energy supplied	ICP number	Line length (high and low voltage)
WEL Networks	Operating, capital and transmission costs.		Other pass-through[2] costs.		
Northpower	Transmission, zone substation, sub-transmission line/cable costs.				High and Low voltage line/cable, transformer, switchgear costs. (Almost all allocated to mass market).
Electra	Direct operating, capital and transmission costs.		Indirect costs - (50 percent weight).	Indirect costs - (50 percent weight).	
Counties Power	Transmission, zone substation, sub-transmission line/cable and 11kV network costs. Low voltage cables, lines and plant - (50 percent weight).		Volume overhead	Customer overhead Low voltage cables, lines - (50 percent weight).	
Main Power[3]			Direct operating, capital and transmission costs? Administrative and overhead costs.		
The Power Company	Transmission and sub-transmission. Supply costs- (30 percent). Maintenance- (50 percent)	Supply costs- (70 percent).	Maintenance- (50 percent).	Overhead	

Notes:

1. EDB use several measures of peak demand (coincident, anytime maximum, after diversity maximum and winter and summer) to reflect the pressures on network capacity caused by different customer groups.
2. Other pass-through costs are usually limited to Electricity Authority and Commerce Commission levies but sometimes also include local body rates
3. The description of the cost allocators for Main Power network assets and transmission costs is unclear. The description refers to using asset registers to attribute asset costs to pricing regions but also refers to using energy supplied (consumption) as the basis for allocating the cost to prices.

Source: NZIER