Options and Incentives for Electricity Distribution Businesses to Improve Supply and Demand-Side Efficiency

Electricity Networks Association (ENA)
Energy Efficiency Incentives Working Group

Report to the Commerce Commission

April 2014

Acronyms and Abbreviations

ACOT	Avoided Cost of Transmission
AMP	Asset Management Plan
ASDs	Adjustable Speed Drives
Capex	Capital Expenditure
CFLs	Compact Fluorescent Light bulbs
CPP	Critical Peak Pricing
DG	Distributed Generation
EA	Electricity Authority
EDB	Electricity Distribution Business
EECA	Energy Efficiency and Conservation Authority
ENA	Electricity Networks Association
GIP	Grid Injection Point - point connecting transmission and generation where electricity is injected into the network.
GXP	Grid Exit Point, points connecting transmission and distribution lines
HVAC	Heating, Ventilation and Air Conditioning
ICP	Installation Control Point
ID	Information Disclosure
IHDs	In-Home Displays (allow monitoring of usage)
IMs	Input Methodologies
IRR	Internal Rate of Return
LEDs	Light Emmitting Diode (lighting)
LUFC	Low User Fixed Charge
MBIE	Ministry of Business, Innovation, and Employment
MVA	Megavolt-ampere, dimension of power (time rate of energy) limited by the maximum permissible current, and the watt rating by the power-handling capacity of the device
MW	Megawatt, equal to one million joules per second, measures the rate of energy conversion or transfer
NMB	Net Market Benefits test

NPV	Net Present Value
Opex	Operating Expenditure
PTR	Peak Time Rebate
PV	PhotoVoltaic (solar panel)
RAB	Regulatory Asset Base
RTP	Real-Time Pricing
TOU	Time Of Use
VAR	Volt-Ampere Reactive (a unit used to measure reactive power in an AC electric power system)
WACC	Weighted Average Cost of Capital

Table of Contents

Appendices

Tables

Figures

Boxes

Executive Summary

The Electricity Networks' Association (ENA) formed a working group to assess the role of Electricity Distribution Businesses (EDBs) in promoting energy efficiency, and whether current regulatory and market settings support EDBs to play this role. The working group has identified a number of supply and demand-side efficiency options where it makes sense for EDBs to play a role, and this report describes a number of regulatory changes that would help EDBs carry out such measures. Many of these recommendations relate to regulation under Part 4 of the Commerce Act 1986. These recommendations need to be considered in light of Section 54Q of that Act, which requires the Commission to promote incentives and avoid imposing disincentives for EDBs to invest in energy efficiency, demand-side management and loss reduction when applying Part 4.

Supply and demand-side efficiency options can reduce the cost of supplying electricity

The profile of electricity demand varies by network and substation. However, the need to meet peak demand generally drives the need for EDBs to invest in capacity. Supply and demand-side efficiency options provide an alternative way to meet demand growth or changes in the demand profile that create peaks. These options may defer the need to expand network capacity for a period of time, or in some cases can eliminate the need for traditional investments altogether. These investments may also (infrequently) remove the need to renew existing assets.

Supply and demand-side efficiency can be improved by changing how much electricity is consumed and when it is consumed—often known as load reduction and demand management. Managing the timing of electricity consumption is particularly important for network businesses (EDBs and Transpower) because peak capacity requirements are a major driver of the costs of providing network services.

There are a number of ways that load reduction and demand management can be implemented. Measures include installing efficient equipment and systems, reducing electrical losses, using load control technologies (such as ripple control), installing distributed generation and/or storage, and implementing behavioural programme measures (such as awareness-raising, educational programmes and/or dynamic pricing). Research in New Zealand and overseas supports the conclusion that these measures can provide benefits in reducing cost pressures associated with providing electricity when compared to alternative solutions like expanding network capacity.

EDBs can directly implement a range of supply and demand-side efficiencies

EDBs are responsible for maintaining, operating, and investing in the distribution network to economically meet demand at the level of quality sought by consumers. Given this role, EDBs have potential advantages in implementing efficiency options using the information they have available, their position in the supply chain, and their investment horizon as owners of long-lived infrastructure assets.

We find that EDBs have a role in influencing supply and demand-side efficiency through:

- **Managing peak demands** on their networks, which creates spill-over benefits in upstream parts of the electricity supply chain (transmission and generation)

- Facilitating the integration of distributed generation (wind, solar and micro-hydro), particularly in combination with battery systems and/or smart grid technologies, and
- Reducing load in major end-uses of electricity (such as lighting, heating, and industrial processes) or using load control technologies.

- **Implementing programmes to influence consumer behaviour**, for example by using efficient pricing approaches together with technologies that enable customers to respond to price signals
- **Reducing network losses** through new equipment and system improvements. However, the current level of network losses in New Zealand suggests that the savings in this area are not material.

The potential for savings from improving efficiency are material. Across the electricity supply-chain, the types of initiatives discussed above have been found to provide net benefits across the industry in present value terms of up to $1,808 million over a ten year timeframe.[1]

Supply and demand-side efficiency initiatives have potential value in deferring or avoiding the need to invest in capacity

The working group has used a simple economic analysis to explore the value of two illustrative examples to reduce demand or shift demand from peaks: load control and efficient lighting. The same analytical approach could be used to evaluate other efficiency investments, such as investing in distributed generation with storage, reducing losses, or behavioural programmes to influence demand.

Our analysis finds that:

- **Traditional capacity expansions are lumpy investments that incur costs throughout the electricity supply chain.** While investment costs are network-specific and lumpy, we estimate that EDBs spend around $150,000–$250,000 to expand capacity to meet an extra megawatt (MW) of peak load growth. Demand growth also drives investment in the transmission and generation parts of the electricity supply chain, with Transpower spending around $300,000–$600,000 per MW for new transmission capacity and generators spending around $1.9 million per MW for peaking thermal generation.
- **Efficiency alternatives can be implemented at lower cost, although often have shorter expected lives than traditional capacity expansions.** For example, ripple control is estimated to cost around $130,000 per MW and is expected to last for around 20 years. Efficient lighting is an even starker contrast to traditional capacity expansion, estimated to cost around $20,000–$60,000 per MW and expected to last for around 3–5 years.

While the exact costs and benefits of any investment will be case-specific, this analysis suggests that investing in supply and demand-side efficiency options will often be in the long-run interests of consumers. In some cases (including the two examples presented in this report), the direct financial benefits provided to EDBs in deferring or removing the need for traditional capacity expansion may be sufficient to outweigh the costs. This simply means that supply and demand-side efficiency investments are in some cases a

[1] See: KEMA's 2007 report for the Electricity Commission entitled "New Zealand Electric Energy-Efficiency Potential"

least-cost way to meet network demand (all other things being equal). In other cases, wider industry benefits from deferring transmission and generation investment mean that the supply and demand-side efficiency investment would provide net economic benefits. However, savings in other parts of the supply chain would need to be shared with EDBs to make the investments financially viable for EDBs.

Incentive-based regulation does not always incentivise EDBs to pursue efficiency initiatives that are in the long term interest of consumers

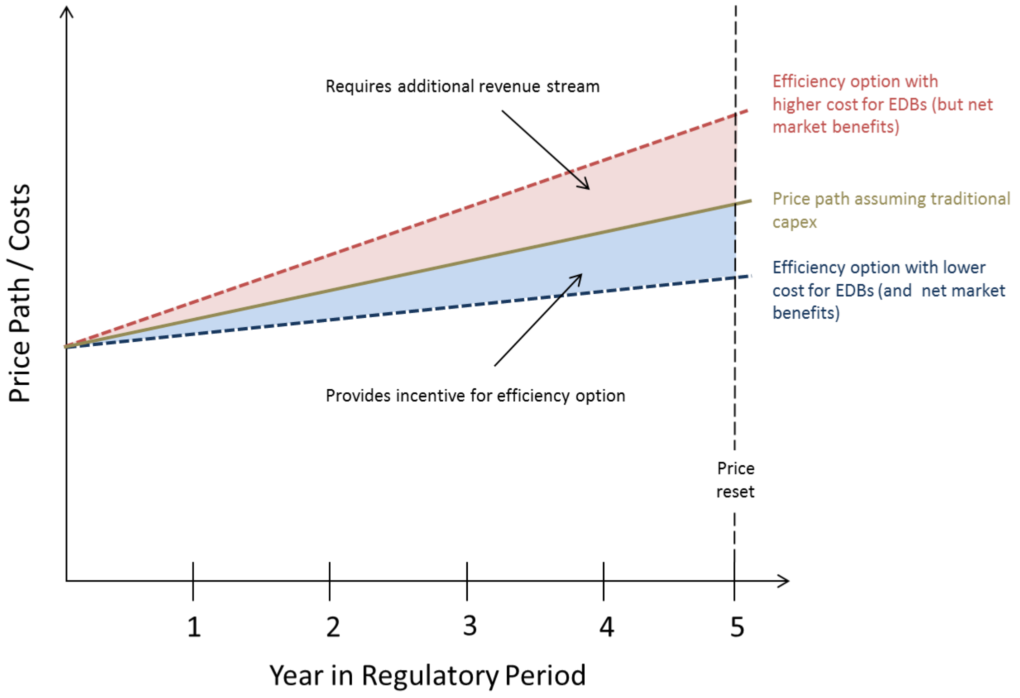
Regulation under Part 4 requires the Commerce Commission (the Commission) to reset EDB price or revenue caps every five years based on cost forecasts over that period. EDBs can then increase their profits by reducing costs below the regulatory forecasts. This regulatory approach is often known as incentive-based or "CPI-X" regulation, and provides an explicit incentive for regulated firms to operate more efficiently and pass those efficiency gains to consumers through lower prices. The Commission currently applies a weighted average price cap (rather than a revenue cap) to EDBs that have their prices regulated under Part 4.

One unique feature of the New Zealand regulatory regime is the application of a Default Price-quality Path/Customised Price-quality Path (DPP/CPP). The DPP is a low-cost form of regulation that does not rely on verifying supplier information. Suppliers are then able to apply for a CPP if the DPP does not meet their needs.

This regulatory approach affects how EDBs are likely to think about investing in supply and demand-side efficiency initiatives. Figure ES.1 illustrates the impact of different supply and demand-side efficiency investments on an EDB's costs, relative to traditional capacity expansions.

- The solid green line running across the graph represents the regulated price path, which, in this graph, incorporates the costs of traditional network capacity expansions.
- Some supply and demand-side efficiency options such as ripple control and efficient lighting will have a lower cost to EDBs than traditional solutions (shown by the dotted blue line). This lowers EDB costs beneath the regulated price path. Under incentive-based regulation, EDBs have incentives to implement these options within a regulatory period as long as the value obtained within the regulatory period (the shaded blue area) outweighs any risks associated with the investment.
- EDBs will have no incentives to pursue higher cost efficiency investments (shown by the dotted red line)—even though some of these investments will be in the interests of consumers once avoided transmission and generation costs are taken into account. Promoting these efficiency options requires EDBs to access some of the benefits earned in other parts of the supply chain through higher revenues (in order to recover the shaded red area). Similarly, if such options are higher cost within the regulatory period but decrease costs in future years (or avoid more lumpy investment in future), EDBs would need to be able to recover those costs in order for the efficiency investment to proceed.

Figure ES.1: Illustration of Impact of Different Efficiency Options on Price Path



Particular features of New Zealand's regulatory regime present real challenges to investing in supply and demand-side efficiency

The way that EDBs make investment decisions in a regulated setting has implications for efficiency investments that may not align with the long term interests of consumers:

- **Volume based pricing.** The current price-cap regime links EDB revenue to some measure of energy consumption (kWh or kW). Coupled with low-user fixed charge regulations (which increase the variable proportion of EDB revenues), this regulatory approach creates a barrier to investing in solutions that lower overall electricity use.
- **Defining the regulated business.** The activities that are subject to Part 4 regulation need to be clearly understood, so that EDBs know how their efficiency investments will be treated. If efficiency investments fall within the definition of "electricity lines services" they would be regarded as a regulated service and be included in an EDB's Regulatory Asset Base (RAB), either in part or in full. This would tend to increase the regulated price path (the green line in the figure above), if other factors remain unchanged. If part of the investment falls outside the regulated business, then EDBs would also be able to earn alternative (unregulated) revenue sources (the red shaded area in the figure above) in addition to that associated with its price path.
- **Providing depreciation on assets with shorter lives.** The regulated price path currently assumes an average asset life of 45 years when calculating the allowance for depreciation. Once the price path is set, EDBs will forego higher levels of return and depreciation (as a percentage of investment value) for assets that have shorter asset lives. This discourages investment in assets with a shorter life. In many cases this incentive will be appropriate to ensure that EDBs invest in assets that last longer. However, this tends to act as a barrier to efficiency options that have a much shorter expected lifetime, and

therefore require a greater portion of costs to be expensed in each year. This issue is particularly relevant where EDBs have a choice between short-life energy efficiency assets and long-life traditional network assets.

- **"Looking through" the regulatory reset process.** The application of the DPP/CPP to a particular regulatory period and the way that the price path is periodically reset can create inconsistent incentives for investing in capital expenditure (capex) relative to operating expenditure (opex). This trade-off applies more broadly, but is particularly relevant to efficiency options that involve greater opex relative to traditional solutions. For example, EDBs may prefer capex solutions such as expanding substation capacity, over opex solutions such as contracting for demand-side response if there is a greater incentive to undertake capex.
- **Structural separation of EDBs from other parts of the supply chain.** Monetising the value of efficiency initiatives in other parts of the electricity supply chain (transmission and generation) involves contracting and transaction costs. These costs would not be borne by an integrated utility, and may make EDBs less willing to make efficiency investments or to contract with other parties that have already invested in efficiency options (such as advanced meters).

The working group acknowledges that the design and implementation of regulation is not the only impediment to supply and demand-side efficiency investments. Market factors also play a part. For example, many EDBs are likely to have a bias against some supply and demand-side efficiency options, which are perceived as less tested or reliable than traditional capacity expansions. In addition, EDBs may not have access to all the information needed to inform investment decisions, or may not be able to influence end-users directly to respond in efficient ways to network peaks.

The working group considers that the electricity supply industry needs to continue to develop its understanding of supply and demand-side efficiency options. The working group's recommendations are therefore mindful of the need for EDBs and the electricity industry to evolve alongside changes to government policy and regulation.

Recommended changes to align EDB incentives with the long term interests of consumers

Based on our analysis, Table ES.1 summarises the areas that the working group recommends be addressed through changes to the regulatory regime or actions by industry participants. The recommendations are directly linked to the issues described above (and summarised in the left hand columns of the table). The recommendations are divided into short-term and long-term recommendations, with short-term recommendations defined by what could be achieved in the next reset of the DPP scheduled for later this year.

All of these recommendations are made with Section 54Q of the Commerce Act in mind. While ENA is working to find ways for EDBs to improve supply and demand-side efficiency, the Commission is also required by the Act to promote incentives and avoid imposing disincentives for energy efficiency related investment when setting the price paths (including, if necessary, by amending input methodologies), in order to provide a framework that better incentivises such improvements. This should be seen as an important and necessary aspect of any Part 4 related workstream. However, the group acknowledges that even though a particular approach would have good outcomes for energy efficiency, it may not, overall, be in the long-term interest of consumers. The recommendations presented in Table ES.1 should therefore be read as changes that the group considers would better promote supply and demand-side efficiency, and should be pursued unless they have impacts in other areas that offset their benefits.

In addition to the recommendations in Table ES.1, the working group recommends that the Commission explicitly states how it gives effect to Section 54Q of the Commerce Act 1986 in all its Part 4 decisions relating to electricity lines services.

Table ES.1: Working Group Recommendations to EDBs, Government Officials and the Commerce Commission

Issue	Aim of Solution	Short-term Options/ Recommendations	Long-term Options/ Recommendations
Volume based pricing: ▪ Variable charges tend to be based on kWh used. This creates a problem when efficiency options reduce volumes by also reducing EDB revenues ▪ Low User Fixed Charges discourage efficiency options for a similar reason by making a greater proportion of EDB revenue depend on consumption	EDBs should be no worse off financially by pursuing efficiency options that are in the long term interest of consumers	▪ The Commission should incorporate mechanisms into the DPP to lessen the financial impacts of efficiency investments that reduce consumption. This can be achieved by "decoupling" EDB revenues from total electricity consumption. For example, the Commission could investigate a type of "D-Factor" (used in Australia) to compensate EDBs for any revenue foregone from efficiency initiatives ▪ MBIE should consider increasing the Low User Fixed Charge to better reflect impacts on EDB efficiency (particularly given that the fixed amount has never been adjusted for inflation)	▪ The Commission should consider the respective merits, relative to 54Q and 52A, of a revenue cap and a weighted average price cap. Regulating the total revenues earned by EDBs would make the businesses indifferent to the level of consumption of electricity (whether expressed as kWh or kW) ▪ MBIE should consider repealing Low User Fixed Charge regulations or replacing them with alternative measures that do not have unintended disincentives on EDBs undertaking efficiency options ▪ EDBs should consider adjusting their pricing to be in-keeping with underlying costs where possible or where enabled by other changes (such as charging for capacity or demand)
Defining the regulated business: ▪ Whether efficiency options are considered an "electricity lines service" and included in the RAB ▪ Treatment of external revenue earned from efficiency options	▪ The boundaries of the regulated business should be unambiguous ▪ The rationale for Part 4 regulation should be achieved (for example, by ensuring that EDBs unregulated revenues preserve benefits to consumers)	▪ The Commission should clarify that where efficiency options are least cost way of delivering lines services the costs can be incorporated into RABs/price paths (rather than alternative means of delivering these services) ▪ The Commission should clarify that where efficiency options are higher cost but provide benefits to other electricity suppliers, EDBs can recover the lower costs of alternative options through regulated prices and contract with third parties to earn additional unregulated revenue (in practice either using sub-asset classes or costs above the lower cost options)	▪ EDBs should consider efficiency options when preparing Asset Management Plans (AMPs)

Issue	Aim of Solution	Short-term Options/ Recommendations	Long-term Options/ Recommendations
Providing depreciation on assets with shorter lives: ▪ Assumption of average 45 year life provides incentives for investment in longer-term assets (over short-term ones)	EDBs should be no worse off financially by investing in shorter-term assets that would be in the long term interest of consumers	▪ The Commission should develop ways to make EDBs indifferent to the expected life of efficiency investments such as by using separate asset life assumptions for investments that meet certain conditions (such as not being investments in capacity expansions)	
"Looking through" the regulatory reset process: ▪ Unequal treatment of opex/capex ▪ Uncertain recovery/treatment across regulatory periods ▪ Uncertain treatment of efficiency spending	The costs of providing electricity lines services should be treated equally (whether opex or capex), with incentives that are consistent over time	▪ The Commission should ensure consistent treatment of opex and capex under DPP/CPP over time, for example by using a rolling incentive scheme for opex and capex (note: the Commission is already consulting on required changes to the input methodologies) ▪ The Commission should improve transparency on what happens at the reset – including how AMPs will be used and how efficiency options will be treated	
Structural separation of EDBs from other parts of the supply chain: ▪ Creates transaction costs to contracting for wider benefits ▪ Means EDB pricing signals are not necessarily passed on to consumers	EDBs should have incentives to pursue options that are in consumers' long term interests, regardless of where in the supply chain those benefits accrue	▪ EDBs should continue to engage with Transpower and other emergent providers on the application of demand response platforms	▪ Industry should consider whether there are pricing structure standards that would be in the interest of consumers (including through engagement with the EA) ▪ MBIE/EA should consider whether funding is available to support cross-industry initiatives that decrease transactions costs
Dissemination of information: ▪ EDBs may not have all the information needed to assess the full benefits or costs of (novel) efficiency options	Information should be available to improve industry understanding of efficiency options that are in consumers' long term interests	▪ EDBs consider developing technical standards for including efficiency options in planning (such as demand side management), and to assess any training needs with the industry. There may also be a role for MBIE/EECA funding to help catalyse industry-led efficiency solutions and knowledge diffusion ▪ EDBs should continue to engage with the industry to understand the potential of new technologies	▪ The Commission could consider setting specific rules (e.g. cost and/or revenue recovery) around the treatment of particular efficiency investments to better understand their value

1 Introduction: What is the Purpose of this Report?

The Electricity Networks' Association (ENA) established a working group to evaluate the incentives for energy efficiency in New Zealand's electricity sector. The group is made up of nominated staff of Electricity Distribution Businesses (EDBs), with staff from the Commerce Commission, EECA and MBIE invited to attend meetings of the working group as observing members. Castalia was engaged to assist the working group.

The objective of the working group is to understand the opportunities for EDBs to promote supply and demand-side efficiency and to assess whether any regulatory changes, or application of existing regulations and statutory objectives, would better incentivise EDBs to make efficiency investments that are in the long term interests of consumers.

The working group focuses on efficiency in the electricity sector only. Although consumers have the option of different fuel sources to meet their energy demands (which creates opportunities for improving efficiency by changing fuel sources), the working group has focused its attention on supply and demand-side efficiency in the use of electricity.

Supply and demand-side efficiency options are considered, before looking at regulatory and market incentives

The Terms of Reference for the working group sets out two stages of work:

- **Stage One**: to scope out the broad options for EDBs to be involved in improving energy efficiency in the long term interest of consumers, including an assessment of what consumers value, engineering considerations, and a review of relevant international experience.
- **Stage Two**: to review the current regulatory and market framework for making the types of investments identified in Stage One and develop recommendations for any changes that would provide distributors with appropriate incentives to pursue initiatives that deliver consumer benefits.

This report summarises the findings of both stages of work and presents the working group's recommendations to provide distributors with appropriate incentives.

Options for EDBs to improve supply and demand-side efficiency are identified

This report initially identifies:

- The nature of electricity demand across networks and the different types of supply and demand-side efficiency that might help to meet that demand (Section 2)
- The options for improving supply and demand-side efficiency, and role for EDBs in pursuing such options (Section 3)
- How the cost of illustrative demand and supply-side efficiency options compare with traditional solutions (Section 4).

Major factors influencing EDB decisions on efficiency initiatives are investigated

The report then presents:

- As summary of the regulatory and market factors that influence EDBs' decisions on supply and demand-side efficiency initiatives, and how these factors drive EDB decisions to invest in such initiatives when they would be in the long-term interest of consumers (Section 5)

- Recommended changes to market or regulatory settings to help ensure that supply and demand-side efficiency initiatives in consumers' interest are pursued by EDBs (Section 6).

Further information is provided in the Appendices. The actions considered by the working group but not recommended are presented in Appendix A. Appendix B summarises some of the relevant international experience with distributor-led efficiency programmes. Previous applications of the net market benefits test to efficiency options in New Zealand, and the test's potential complexities are summarised in Appendix C. While Appendix D sets out the regulatory settings directly relevant to the working group's task and Appendix E attaches a legal interpretation of Section 54Q of the Commerce Act 1986.

2 What Drives EDB Costs and What Supply and Demand-Side Efficiency Responses Exist?

Peak demand is the main driver of EDBs' costs. EDBs need to ensure that sufficient capacity exists to meet peak demand, or must have other arrangements in place to manage demand during peak periods. This means that investing in more network capacity and finding ways to manage demand can be considered as substitutes, even though they will not have exactly the same characteristics (risk, quality, reliability).

This section considers the drivers of demand across networks and opportunities for supply and demand-side efficiency. We then describe the different types of supply and demand-side efficiencies available based on what they aim to achieve (in light of network demands). Specific efficiency options are then explored in Section 3.

2.1 Drivers of Demand on Electricity Networks

This section describes how electricity demands on a network vary over time and by circumstance, and the factors that influence network demand (or load). These demands drive investment in network capacity and the cost of providing lines services, both in traditional or more innovative ways.

Load profiles vary across networks with major customer types driving significant swings in demand around peak periods

Most commonly peak demand occurs during the work-week, in winter, between 8–10 a.m. and 4–9 p.m. This is illustrated in Figure 2.1 which shows daily load profiles on the Orion network. It takes a sample weekday in winter and a similar one in summer—both in 2013. The top figure shows that on this winters day there were two peaks in demand around the times referred to above. The evening peak is larger and as well as exceeding the network's capacity limit[2] (with load being shed), both a control period and generation period are called (where load control responses are used such as interrupting storage water heating and contracted generation is called on to ease the constraint). The bottom figure is of daily demand on a summer weekday, with significantly less load and a much flatter or more constant level of demand throughout the day.

However, the nature of load profiles varies and there are examples of peak demand occurring during the daytime in summer. This is the case for the Ashburton 66kV Grid Exit Point/Grid Injection Point,[3] where irrigation is the largest portion of load.[4] In the case of Ashburton, peak demand is increasing over time but this trend will vary by region and substation. The Ashburton example also shows how the major customer type influences the load profile, not only in terms of time of the year and trend over multiple years but also over the course of the day and week.

The influence of the major customer types on load profiles may also result in variations in demand across different types of substations. For example, evening load is generally more pronounced on urban substations than for urban/commercial substations, where

---

[2] Orion notes that the **network limit** (the black line) is set as a target to keep costs and prices down. The network can cope with higher loading levels, but will then need to invest in more capacity to maintain an appropriate buffer for growth and security. They also note that the **uncontrolled load** (the red line) is not the actual loading level – it is an estimate of the loading levels that would have occurred if Orion had not controlled load.

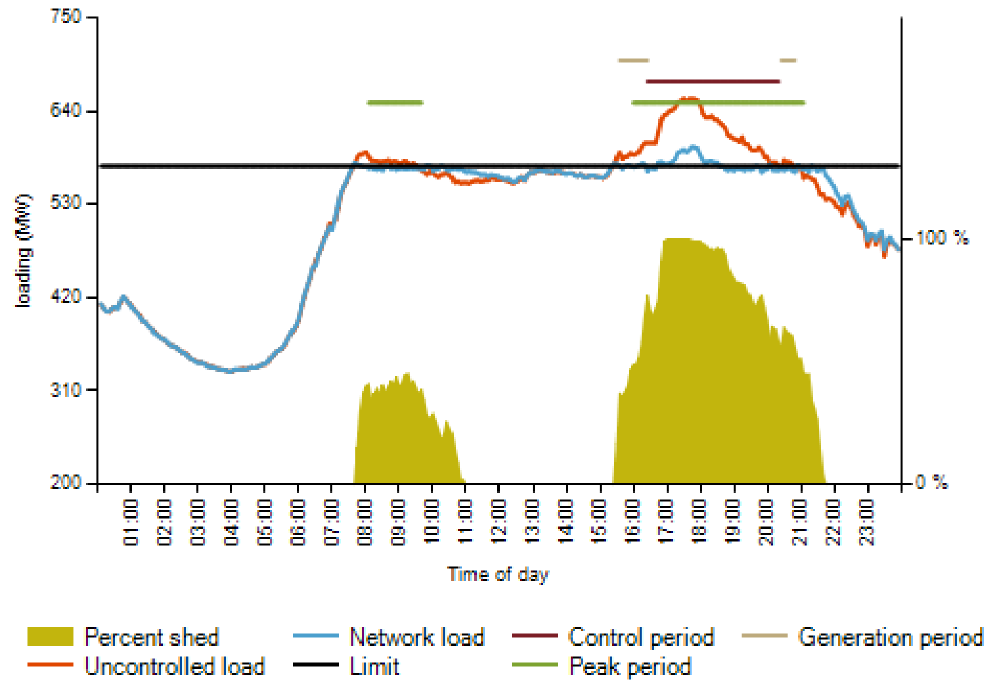
[3] This is one of two GXP/GIP's in Ashburton. Information on each GXP/GIP is available at: http://www.ea.govt.nz/industry/-monitoring/cds/

[4] Irrigation load on the Electricity Ashburton network and doubled between 2003 and 2013 according to the Electricity Ashburton Asset Management Plan 2013-23, though this rate of growth is expected to reduce. See: http://www.eanetworks.co.nz/Files/-AMP2013-23.pdf

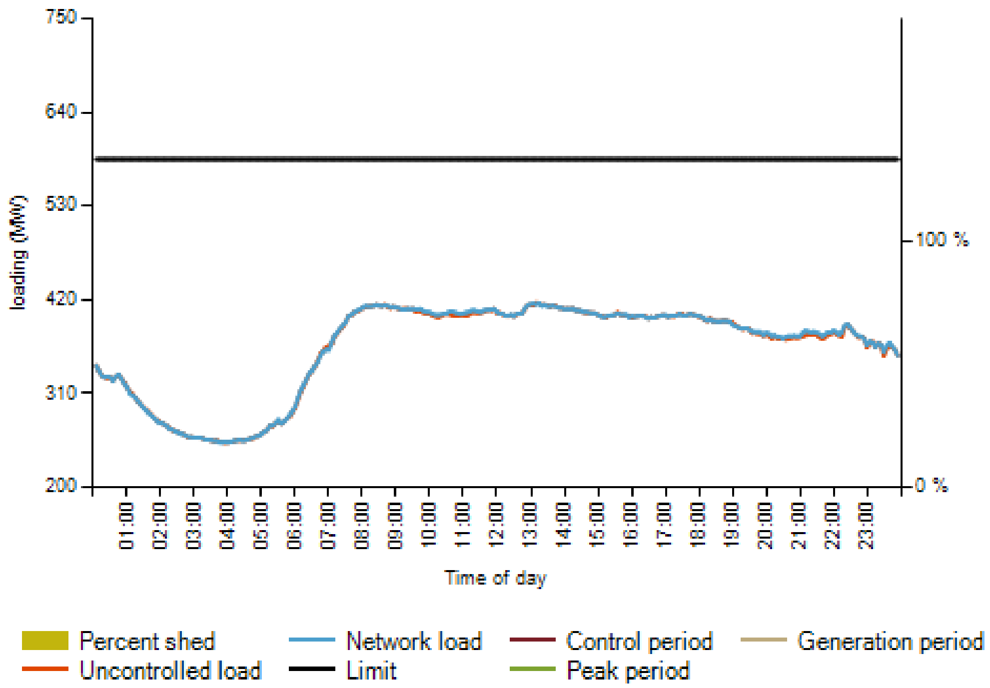
load is generally more evenly distributed throughout the day. While, for the rural substation, there are commonly two distinct peaks, similar to that observed on the winter day shown for Orion in Figure 2.1.

Figure 2.1: Sample of Daily Load Profiles for Orion

Thursday, 20 June 2013



Thursday 12 December 2013



Source: http://www.oriongroup.co.nz/load-management/load-management-dashboard.aspx

Peak demand characteristics vary and are a major driver of investment, meaning different solutions need to be considered

All EDBs need to ensure they have sufficient capacity to meet expected demand profiles, or otherwise have arrangements in place to shed demand during peak periods. Typical marginal investments in capacity are discussed in Section 4 along with efficiency initiatives as an alternative to reduce or delay the need to invest in capacity.

The key point illustrated by the analysis of load profiles in this section is that peak capacity generally drives network investment costs. Meanwhile, the best investments will vary by network and across networks depending on the nature of load profiles in these areas, the drivers of demand, and the ability to manage peak demand (or utilise alternative generation). Networks may need a combination of investment types to respond to changing network demands (for example, growth in irrigation load on one part of the network and growth in residential winter peaks in another part).

2.2 Types of Supply and Demand-Side Efficiency Measures

This section considers the types of supply and demand-side efficiencies available to meet customer demands, looking at the outcomes sought and types of measures to achieve these outcomes. This provides a structure for analysing options where EDBs may have a role to play in investing in efficiency options, and to identify the right incentives for those initiatives.

Supply and demand-side efficiency measures impact industry and consumer costs

Table 2.1 highlights the various supply and demand-side measures to achieve load reduction and demand-side management outcomes, and the effects of each measure on load. The table also summarises the likely cost impacts for different parties involved in the supply of electricity.

The first column in Table 2.1 distinguishes between efficiency measures aimed to reduce electricity load overall, and those aimed and at managing the timing and distribution of load (demand-side management). Electricity conservation measures[5] would also reduce load, but are not specifically considered under our definition of load reduction because electricity conservation may or may not improve overall efficiency. To the extent that conservation measures reduce service quality, if users would otherwise be willing to pay the cost of increased service levels then conservation will not be efficient.[6]

The second column in Table 2.1 identifies forms of load reduction and demand-side management based on their impact on the load profile. These measures each have very different impacts on the commercial viability of a network business. EDBs may currently earn less revenue by pursuing peak clipping or load reduction because overall energy consumption decreases.[7] In contrast, load shifting and valley filling options may not decrease total energy consumption. In fact, valley filling may increase energy usage, result in more efficient asset utilisation, and increase EDB revenues.

---

5 That is, measures that reduce electricity consumption.

6 For example, one could conserve energy by not heating their house. However, if this means forgoing a service (in this case heating) that the consumer is willing to pay for then it is not efficient.

7 For load reduction, the impact depends on the timing of the reduction. If load reduction applies across the day, it can lead to some reduced capital investment costs (by reducing peak demand). However, depending on the amount reduced at peak times compared with the rest of the day, and the duration of the peak, load reduction could also result in a higher per unit costs for the remaining units.

The third and fourth columns of Table 2.1 highlight the various supply and demand-side measures of achieving load reduction and demand-side management. These measures include:

- **Loss reduction**[8] (how much is lost between the points of generation and consumption), defined as: "reduction in:

  1) technical losses from transfer of energy across transmission and distribution systems, and

  2) losses from improved measurement, clandestine connections, meter fraud, diversity/deficiencies in readings/processes."

- **Efficient/controllable equipment and systems** (how electrical services are provided and managed), which allow the same electrical services to be provided with fewer inputs, or end-users/EDBs to control if, when or how electricity applications are used.
- **Distributed generation/on-site supply/storage** (when and where electricity is supplied or stored), which can help to reduce the total costs of meeting electricity demand.[9]
- **Behavioural programmes** used by electricity suppliers or state agencies to encourage consumers to reduce their demands on the electricity system.

The last column of Table 2.1 provides a high level view of the cost impacts of different efficiency types on industry participants. The specific measures in Table 2.1 are discussed in more detail in Section 3 and the cost impacts in Section 4. In Table 2.1, direct cost impacts on consumers are distinguished in blue from impacts on other electricity market participants, which we would expect to flow through to consumers (indirectly). Box 2.1 provides examples of direct benefits to end-users of certain demand-side efficiencies.

Box 2.1: Examples of Demand-Side Efficiency Savings to Consumers

Residential consumers: Assuming an electricity cost of 26c/kWh, Residential consumers could save around:

- $100 a year by replacing their five most used incandescent light bulbs with energy efficient ones, and
- $180 each year by using a heated towel rail for four hours a day rather than using constantly.

Business consumers: One company with 10,000 PCs and an annual energy spend of $6 million, estimated they could save 8.5 gigawatt hours per year (20% of their power), worth $1.2 million by enabling power management features on all computers and staff switching off equipment and computers at night.

Source: EECA energywise and EECA BUSINESS. See: http://www.energywise.govt.nz/your-home/save-money-on-your-energy-bill and http://www.eeca-business.govt.nz/sites/-all/files/action-sheet-4-equipment-and-appliances.pdf

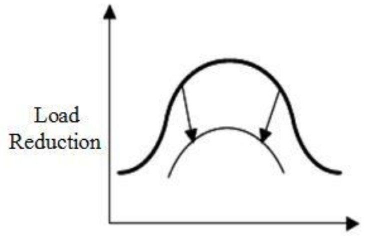
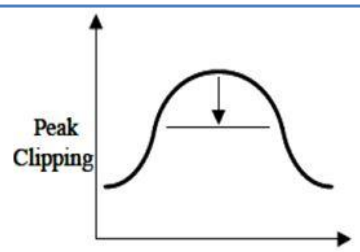
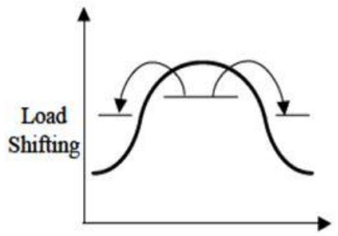
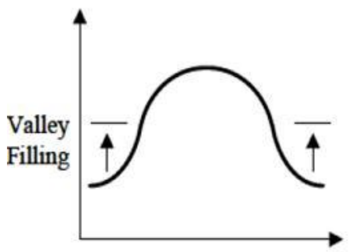
8 Section 54Q of the Commerce Act specifically refers to energy efficiency and demand side management, and loss reduction.

9 Programmable or controllable equipment and systems in combination with distributed generation (DG) and storage could result in greater use of electricity as users are able to run certain loads more cheaply. This may reduce the consumer's total costs for a higher level of service. If utilisation of network assets is maintained in off-peak periods, the "hollowing out" of valleys is avoided. However, if DG self-consumption simply displaces network electricity consumption, this risks hollowing out the valleys and increasing the cost for the remaining load.

For example, Table 2.1 classifies ripple control as a supply-side form of demand-side management. Ripple control shifts load away from peak periods to off-peak periods in order to reduce peak demand. Ripple control should therefore result in the following cost impacts:

- Lower capital investment required by EDBs (and in many cases Transpower) to meet peak demands
- Greater utilisation of generation assets and less investment in generation required to meet peak demand, and
- Lower pricing options for customers that opt into a load control tariff.

Table 2.1: Types of Supply and Demand-Side Efficiency

Outcome	Change to Load Profile	Supply Measures	Demand-Side Measures	Cost Impacts
Load Reduction: Defined as "using less energy to provide the same service"[10].		▪ Loss reduction ▪ Distributed generation/off-grid supply ▪ Behavioural programmes: – Awareness-raising – Educational programmes	▪ Efficient equipment and systems (e.g. lighting, heating and insulation, pumps, fans, drives) ▪ Small-scale distributed generation	Results in overall energy savings – impacting generation costs most directly. ▪ Lower generation costs through lower plant operating costs (e.g. fuel costs), reduced need for additional higher marginal cost generation ▪ Lower capital investment by EDBs and Transpower (assuming some reduction during peaks) ▪ Lower energy use and therefore lower electricity bills for users
Demand Side Management: Defined as "changing the level and timing of demand" and is aimed at reducing peaks and getting greater utilisation of assets. Includes peak clipping, load shifting and valley filling.		▪ Behavioural programmes: – Awareness-raising – Educational programmes – Tiered pricing	▪ Efficient equipment and systems (e.g. lighting, heating and insulation, pumps, fans, drives) ▪ Reserve/distributed generation ▪ Programmable/controllable equipment and systems	Results in capacity savings – impacting transmission and distribution most directly. ▪ Lower capital investment required by EDBs and Transpower ▪ Lower generation costs due to less capital investment in peaking plants and lower operating costs ▪ Lower energy use and therefore lower electricity bills for users ▪ Lower pricing plan for customers that opt in to load control tariff ▪ Potentially lower bills for customers responding to tiered pricing
		▪ Load control (e.g. ripple control) ▪ Behavioural programmes: – Awareness-raising – Tiered pricing ▪ Storage (equivalent impact)	▪ Programmable/controllable equipment and systems ▪ Adjusted usage patterns ▪ Distributed generation and storage	▪ Lower capital investment required by EDBs to meet peaks with potential to deliver similar impacts for transmission ▪ Greater utilisation of generation assets and less investment required to meet peak demand ▪ Lower pricing plan for customers that opt in to load control tariff ▪ Potentially lower bills for customers responding to tiered pricing
		▪ Certain tiered pricing options ▪ Attracting new sources of electricity demand into off-peak periods.	▪ Electric Vehicles ▪ Off-peak (night) storage equipment (e.g. heating, pumping) ▪ Distributed generation and storage* ▪ Programmable/controllable equipment and systems*	▪ Greater utilisation of assets required to meet peak demand, throughout the supply chain. ▪ Potentially lower bills for customers responding to tiered pricing

[10] As used at: http://eetd.lbl.gov/ee/ and consistent with that used by EECA: http://www.eeca.govt.nz/about-eeca and the Commerce Commission: http://www.comcom.govt.nz/dmsdocument/9534

3 What are the Options for EDBs to Improve Supply and Demand-Side Efficiency?

Improving the efficiency of electricity supply and consumption has the potential to lower generation, transmission and network investment; ensure greater use of these assets; and therefore reduce the cost to end consumers of providing electricity. The possible savings from improving efficiency are material. Across the electricity supply-chain, the types of initiatives discussed in the report have been found to have net benefits across the industry in present value terms of up to $1,808 million over a ten year timeframe.[11]

This section provides an overview of the options for improving supply and demand-side efficiency in New Zealand, drawing on research undertaken in New Zealand and internationally. EDBs are not necessarily well placed to pursue all of these options, but they are considered here for completeness with Section 5 focusing on the potential role for EDBs. Options are grouped based on the characterisations used in Table 2.1.

3.1 Loss Reduction

Distribution losses are usually divided into two groups: technical and non-technical. This section looks at how distribution losses in New Zealand compare to transmission losses, overall generation, and losses internationally. We then consider the most viable options for reducing losses.

Losses are a small proportion of power flows, and vary across distributors

Losses in a distribution network averaged around 5.4 percent in New Zealand in 2011[12] and internationally can account for as much as 13 percent of the generated energy.[13] These losses can be divided into technical and non-technical losses, where:

- **Technical losses** relate to material properties and resistance to the flow of electrical current that is dissipated as heat. For example, the power dissipated in distribution lines and transformers due to their internal electrical resistance. Technical losses can be simulated and calculated. The greater the distance the electricity is transmitted and the lower the voltage of the line, the higher the loss. Technical losses are proportional to current squared multiplied by resistance.
- **Non-technical losses** are caused by unauthorised connections, frauds in energy meters, diversity of readings and deficiencies (or losses) in the processes of energy measurement.

Technical losses relate to the physical amount of electricity lost between two points, such that a reduction in technical losses impacts the amount of electricity that must be generated in order to meet demand. In this sense, a reduction in technical losses impacts the overall cost to provide a level of electricity and therefore the costs faced by all consumers in the areas where technical losses are reduced. In comparison, non-technical losses relate to the allocation of electricity costs among consumers (for example the amount of electricity metered to a particular consumer). Therefore, a reduction in non-technical losses may impact the charges a particular consumer pays relative to another

[11] See: KEMA's 2007 report for the Electricity Commission entitled "New Zealand Electric Energy-Efficiency Potential"

[12] Source: Ministry of Economic Development, 2012, Energy Data File

[13] See: Al-Mahroqi et al., 2012, available at: http://www.waset.org/journals/waset/v63/v63-113.pdf

but the overall costs of providing a given level of electricity stay the same. It is these overall costs that must be recovered by charges to consumers in the given distribution network.

As shown in Figure 3.1, total losses in New Zealand were almost 7 percent of total gross electricity production in 2011. Distribution losses accounted for almost 57 percent of total losses (or almost 4 percent of total production) with transmission losses accounting for around 43 percent. Between 2007 and 2011, distribution losses increased 0.8 percent and transmission losses increased by 0.1 percent.[14]

EDBs are not directly incentivised to reduce losses. Losses are indirectly limited through requirements to maintain voltage at premises at 230V with a tolerance band of +/- six percent.[15] These voltage requirements place limits on the cable sizes used— in that EDBs will minimise costs subject to meeting these requirements—thereby limiting losses. As discussed later in this section, there are other options to reduce losses by using equipment with lower resistance, such as low loss transformers. Minimum Energy Performance Standards and Energy Efficiency (Energy Using Products) Regulations 2002 set requirements for energy performance levels of a number of products.[16]

[14] Source: Ministry of Economic Development, 2012, Energy Data File

[15] See for example Vector's Asset Management Plan 2013-2023. In comparison, other countries incorporate incentives around losses directly into regulatory settings (for example in The Philippines where losses were originally above 10%)

[16] See: http://www.med.govt.nz/sectors-industries/energy/energy-environment/energy-efficiency, http://-www.eeca.govt.nz/standards-and-ratings/minimum-energy-performance-standards-and-labelling and http://www.legislation.govt.nz/regulation/public/2002/0009/latest/DLM108730.html?search=ts_regulation_Energy+Efficiency+%28Energy+Using+Products%29+Regulations+2002_resel&sr=1

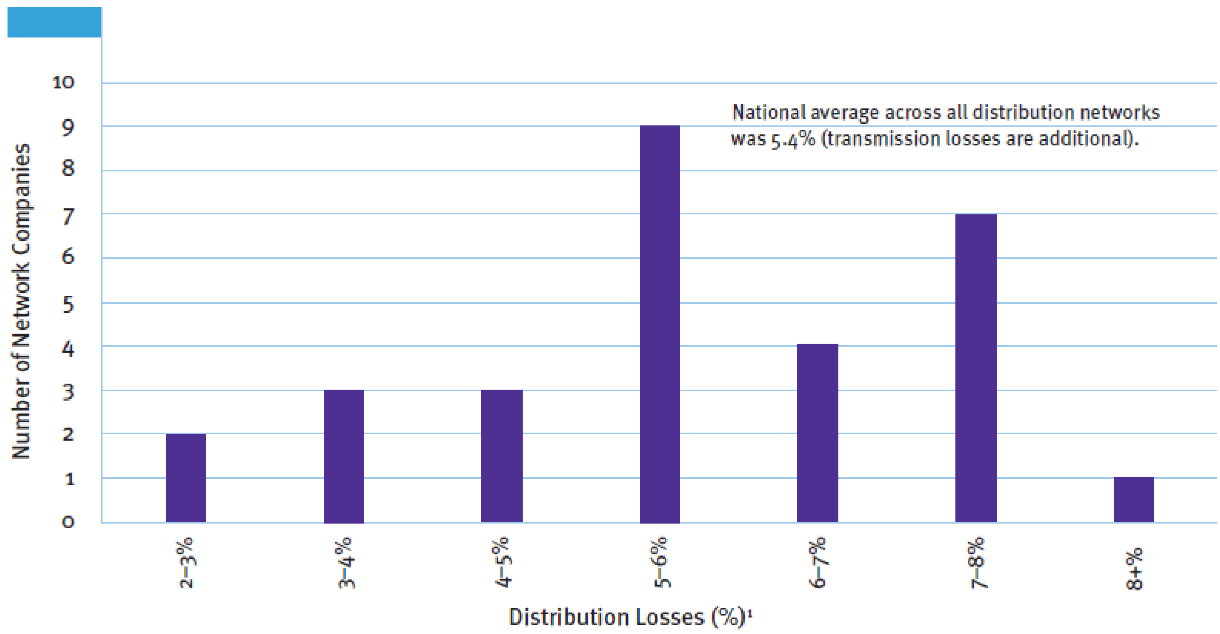
Figure 3.1: Electricity Flow Summary for 2011

Source: Ministry of Economic Development, 2012, Energy Data File

Figure 3.2 summarises the range of losses across EDBs. This shows that distribution losses averaged 5.4 percent nationally in the year to March 2011, with one EDB suffering losses of more than 8 percent. The differences in losses are driven both by the physical characteristics of each network and other more controllable factors, such as decisions on asset investment and maintenance. The key challenge when focusing on loss reduction is therefore to be able to estimate a theoretically efficient level of losses for each EDB, and then, where it is of long-run benefit to consumers (whom are willing to pay), incentivise that level being achieved. International experience, for example in the United Kingdom, suggests that attempts to reduce losses may initially address non-technical losses such as issues relating to settlement rather than technical losses.[17]

[17] For example, see: https://www.ofgem.gov.uk/ofgem-publications/43519/sohn-overview-losses-final-internet-version.pdf and https://www.ofgem.gov.uk/electricity/distribution-networks/losses-incentive-mechanism

Figure 3.2: Electricity Distribution Losses for the 2011 March Year



Source: Ministry of Economic Development, 2012, Energy Data File. Note: 1: As at 31 March 2011 there were 29 network (distribution) companies in New Zealand.

Options for loss reduction

The three broad options for reducing losses are:

- **Assets**: Installing bigger cables/transformers when considering the choice of voltage levels and redundancy. This includes the likes of Feeder reconfiguration[18], VAR[19] compensation which regulates voltage and stabilises the network, installing capacitor banks, re-conductoring overloaded lines with bigger conductors, and upgrading transformers to match the load and the installed capacity, and replacing old/degraded transformers.[20]
- **Operation**: Voltage regulation which keeps voltage within bounds. This can involve installing intelligent voltage control technology that automatically regulates to maintain planned voltage in the network under a range of scenarios and improves the performance of distributed generation. Other operational measures include avoiding any overloading of the system,[21] disconnecting unloaded transformers to avoid no-load losses, and balancing transformer loading to reduce the neutral current and power losses.

[18] A function of automated distribution systems to reduce distribution feeder losses, balance load and improve system security. See: Al-Mahroqi et al., 2012, available at: http://www.waset.org/journals/waset/v63/v63-113.pdf

[19] VAR refers to volt-ampere reactive and is a unit used to measure reactive power in an AC electric power system

[20] However, this needs to be balanced with procurement efficiencies. In some cases, network consistency may be most efficient in managing lifetime costs of the system

[21] However, losses as a result of overloading should be minimised as EDBs are incentivised to avoid overloading and the resulting asset degradation.

- **Customer behaviour**: Managing peak demand and improving power factors[22] and asset utilisation (smart networks provide an opportunity here as well as behavioural programmes and distributed generation— where small amounts of distributed generation decrease losses up to a point after which losses increase). Additionally, installing smart metering helps address non-technical losses.

Although many of the options described above involve upgrading equipment or systems, there are also opportunities that may involve less immediate upfront investment. For example, losses can be reduced by improving monitoring and maintenance practices, and changing network configuration. The lifetime costs of each of these options would need to be assessed against the potential for efficiencies across the system.

3.2 Efficient/Controllable Equipment and Systems

This section discusses the main sources of electricity load, the options to reduce load and manage demand through efficient/controllable equipment and systems, and examples of programmes where EDBs have encouraged the use of such measures internationally.

The options discussed below are limited to those that have been considered both technically feasible and economic, either internationally or previously in New Zealand. These assessments are based on circumstances at a particular point in time and in a particular setting, meaning that any specific options that fall into the groups discussed in this section would need to be individually investigated before being pursued. However, they are useful examples to test the ideas of the working group.

Main sources of load

Table 3.1 shows the major end-uses of electricity in New Zealand by residential, commercial and industrial consumers. This allows us to focus on the opportunities for reducing load that are likely to have the greatest impact. Emphasis has been added to those areas where industries indicated there were further savings opportunities in the Statistics New Zealand Energy Use Surveys (2009-2011).

- The primary industries indicated heavy machinery as an area where the greatest savings could be made,
- The services sector indicated space heating and electronics, appliances and lighting as having the greatest potential, and
- The industrial and trade sectors indicated water heating and electronics, appliances and lighting as the areas with the greatest potential.[23]

---

[22] The power factor of an alternating current (AC) electrical power system is defined as the ratio (between zero and one) of the 'active power' (the actual amount of working power used) flowing to the load, to the 'apparent power' (the amount of power that flows through the lines to your electrical equipment) in the circuit. Non-working, unproductive power is also used by the equipment and is called 'reactive power'. Source: http://www.meridianenergy.co.nz/assets/PDF/for-business/Corporate-business/Power-Factor.pdf.pdf

[23] For more information, see: http://www.stats.govt.nz/browse_for_stats/industry_sectors/Energy/energy-use.aspx

Table 3.1: Major End Uses of Electricity in New Zealand by Sector

End Use	Residential	Commercial	Industrial
Lighting	✓	✓	✓
Refrigeration	✓	✓	✓
Water heating	✓	✓	✓
Space heating and cooling	✓	✓	
Cooking	✓	✓	
Light electrical (home/office equipment)	✓	✓	✓
Heavy electrical		✓	
Fans, pumps, motors		✓	✓
Process heating and cooling		✓	✓
Compressed air			✓

Source: Information adapted from KEMA 2012 "Review of Energy Efficiency Investments", EECA and BRANZ

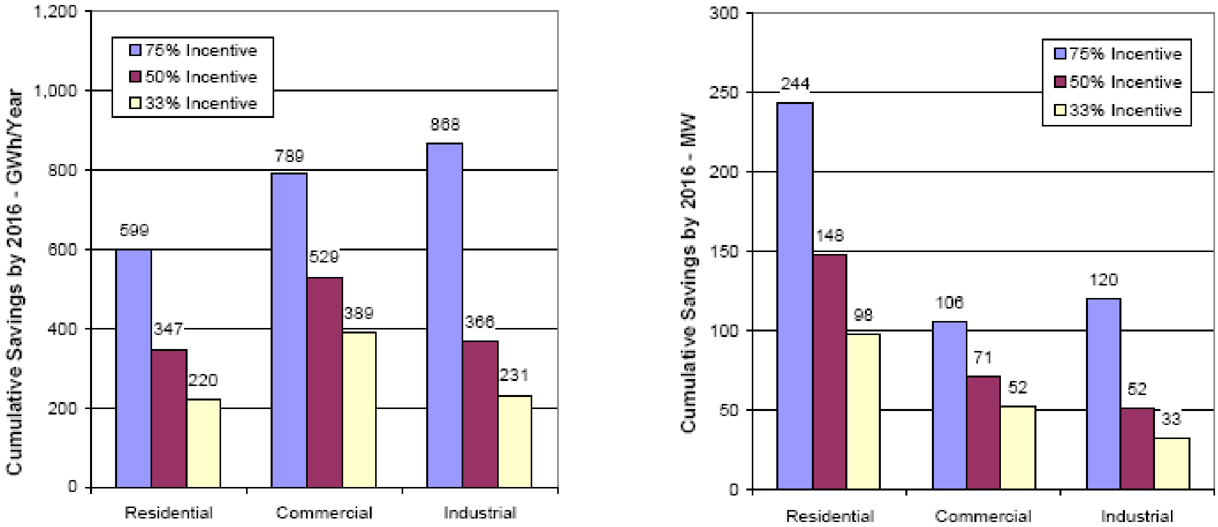
Options using efficient/controllable equipment and systems

Drawing from the KEMA's 2007 report for the Electricity Commission entitled "New Zealand Electric Energy-Efficiency Potential", three scenarios are considered for each option based on the amount of rebate (the incentive percentage) a customer receives on their purchase.[24] For each scenario, the projected energy savings for residential, commercial and industrial is presented in Figure 3.3. Both the cumulative savings to 2016 and peak demand savings are presented. The peak demand savings represented use a peak period of 6-7pm on weekdays from May through to September.

Figure 3.3 shows that both overall and peak demand savings increase for each sector as the incentive increases. It also shows that while energy savings potential in the residential sector is lower than in the commercial and industrial sectors, peak demand savings potential is greatest in the residential sector given this is the sector that largely drives peak demand.

[24] A list of all measures considered is available in Appendix F of the report available at: http://www.eeca.govt.nz/resource/new-zealand-electric-energy-efficiency-potential-study while descriptions of each measure are provided in Appendix B.

Figure 3.3: Net Energy Savings Potential by 2016 (LHS) and Net Peak Demand Savings Potential by 2016 (RHS), by Sector



Source: KEMA 2007 report for the Electricity Commission "New Zealand Electric Energy-Efficiency Potential"

Figure 3.4 shows that for the residential sector, lighting (replacement of incandescent lamps with CFLs) contributes to the majority of energy savings, followed by towel rails (limiting the amount of time that the heat elements are on). In comparison, water heating (insulated tanks and pipes) and the various heating reduction measures (such as ceiling insulation and high efficiency heat pumps) represent a low proportion of overall savings potential, as does the use of low flow showerheads. The findings are the same for peak demand savings, while lighting stands out even further as an area of efficiency impact.

Since this 2007 report, EECA has focused on savings in each of these areas: lighting (CFLs and LEDs), water/space heating (insulation and more efficient sources), and heated towel rails. EECA's latest annual report notes energy efficient light bulbs achieved 24.3 percent market share in the 3 months to 31 July 2012, up from 14.6 percent in the previous year.[25] In addition, the Warm Up New Zealand: Heat Smart programme installed insulation in 235,000 homes.[26] This suggests some of the identified savings will have already been realised in the areas where initiatives have been pursued.

In the commercial sector, Figure 3.4 shows that the indoor lighting measures (particularly CFL replacements for incandescent lamps, and to a lesser extent more efficient design and controls) again contribute to the majority of energy savings potential, followed by HVAC and refrigeration measures.[27] Again, the findings are the same for peak demand savings.

KEMA found that although the achievable potential for control-related HVAC measures is significant, the achievable potential for high-efficiency HVAC measures (such as split-

---

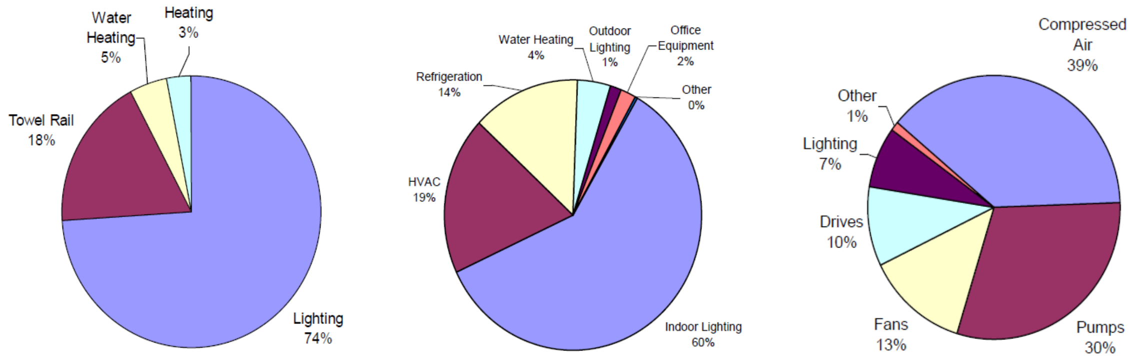
25 See: http://www.eeca.govt.nz/resource/eeca-annual-report-2011-2012 and http://www.energynews.co.nz/news-story/13950/eeca-exit-efficient-lighting-campaign-after-2015-bulbs-hold-record-high-market

26 The Heat Smart programme is being replaced by the Healthy Homes programme targeted at low-income families

27 The share of refrigeration in savings increases as the incentive level, or investment by a party other than the user, increases (with higher saturation levels forecasted in terms of savings from HVAC and lighting measures in the higher-incentive/investment scenarios).

system heat pumps) is modest because such systems are replace-on-burnout measures limited by the long equipment lifecycles.

Figure 3.4: Residential (LHS), Commercial (Middle), and Industrial (RHS) Net Energy Savings Potential by 2016



Source: KEMA 2007 report for the Electricity Commission "New Zealand Electric Energy-Efficiency Potential"

Note: The results shown are for the "33 Percent Incentive/Investment Scenario", which is based on customers receiving a 33 percent rebate on their investment

In the industrial sector, Figure 3.4 shows compressed air system measures provide the most energy savings potential, followed by pumping and fan measures. Key measures include: system optimisation and the addition of controls to pumping, fan, and compressed air systems; motor replacement measures, and adjustable speed drives (ASDs); as well as lighting measures.[28] Once more, the findings are the same for peak demand savings.

EDB-led load control options

For EDBs, the level of peak demand determines the network capacity that needs to be provided, which in turn drives the level of investment needed to meet consumer demands for reliable power supply. The utilisation of a network's assets helps to determine the value obtained from investing in the assets and also influences useful asset lives. These factors mean that EDBs pay considerable attention to managing peak demand and increasing asset utilisation (smoothing the load profile).

EDBs have been using load control systems since the 1950s (ripple control systems, pilot wires, and cyclo load control systems) to manage network demand by switching off residential water heating systems during times when capacity limits are being approached. Load control systems are also used to control street lighting and energy usage from night store heaters. In some cases, extending the use of such load control technologies may also be an option.

Examples of programmes using efficient/controllable equipment or systems

In New Zealand, EECA is currently running a number of efficiency programmes such as the RightLight programme, Healthy Homes, and encouraging better insulation and more efficiency heating. In addition a number of other players are trialling different

[28] Pumping and fan measures represent an increased share of savings potential when the incentive/investment level increases due to higher market penetration of these efficiency measures when there are larger incentives/investments by the party that is not the user.

technologies such as Genesis' "Tomorrow Street"[29] and PowerCo's "Smart House" pilot programme.

EDBs need to assess the likelihood and extent of load reduction that programmes such as those above deliver so they can ensure the network is able to meet the level of demand that eventuates. In targeting programmes, EDBs may favour larger users[30] as doing so requires contracting with fewer parties for a certain level of reduction and potentially there is a higher degree of certainty with respect to reductions (due to more predictable operations, use of commercial arrangements/incentives and such users potentially having back-up systems to call on). In comparison, programmes targeting a larger set of more diverse users will mean reductions are less reliant on a small number of parties, diversifying risk. Additionally, a focus on residential users may also target those driving the peaks in demand.

3.3 On-site/Distributed Generation and/or Storage

This section considers the nature and use of Distributed Generation (DG) in New Zealand. It notes the impacts of DG on transmission and network costs and discusses opportunities for increased use of DG and/or storage in New Zealand.

DG accounts for a small but growing portion of supply and impacts on network costs

DG includes both off-grid power supply (also known as stand-alone power systems) and DG that is connected to the local distribution network.[31] Where DG is connected to the local network, DG owners can draw from the network when there is insufficient DG, and can export to the network when there is excess DG.

DG that is connected to the grid can impact on the performance of the local network. This is seen as a particular issue with solar photovoltaic DG, which can have volatile production levels due to rapidly changing levels of solar irradiation from cloud cover. As a result, some distributors in Australia allow for a certain penetration of solar panels and once this is reached will not support the connection of further solar DG (because doing so would require unjustifiable expenditure on the network).

In New Zealand, EECA report that at least 5 percent of electricity comes from DG, with capacity having grown from less than 25MW in 2007 to over 200MW in 2012.[32] EECA supports the growth of DG and has provided financial assistance via its DG Fund in the past.[33] The major financial incentive is the payment of avoided charges to DG under Part 6 of the Electricity Industry Participation Code – whatever distribution and transmission charges that a distribution network avoids by having DG connected to its network needs to be paid to the DG. The Electricity Authority has signalled that it will review the Code

---

29 See: http://tomorrowstreet.co.nz/

30 As is the case in some of the international examples referred to in Appendix B.

31 For more information see: http://www.energywise.govt.nz/your-home/generating-your-own-energy

32 See: http://www.eeca.govt.nz/distributed-generation and http://www.ea.govt.nz/industry/market/statistics-reports/distributed-generation-statistics/. The Sustainable Electricity Association of New Zealand report that the equivalent of 50 solar installations are being carried out a month in New Zealand (totalling 8,131 kWp, up from 1,760 kWp two years earlier - 6,400 kWp grid-connected, and 1,731 kWp off-grid), while SEANZ members also installed 68.2 kW of small wind turbine capacity in the year to March 31, along with 26.8 kW of mini or micro hydro-generation. See: http://www.energynews.co.nz/news-story/14238/solar-installs-running-50-month-battery-innovation-needed-seanz

33 Information about projects funded by the DG fund is available at: http://www.eeca.govt.nz/node/10895

requirements for paying avoided charges as part of its current Transmission Pricing Methodology review.[34]

Opportunities for DG

Electricity from DG projects can be generated using different systems such as:

- Wind turbines— suitable in locations with consistent, strong wind
- Solar panels (Photovoltaic, or PV)—domestic PV systems tend to be in the 1 to 5 kW range. There has been a large growth in use of solar panels in recent years. Given the timing of solar irradiation, solar generation (on its own) does not tend to coincide with periods of peak demand
- Hydro turbines (micro-hydro)—systems for houses and buildings are less than 5kW, and in many cases less than 1kW. Small-scale hydro is best suited to rural areas on streams or waterways that flow all year round
- Geothermal heat
- Bio-energy (e.g. biogas or wood energy)
- Diesel or gas turbines
- Co-generation/process heat.

The first three options listed above are the main DG technologies in New Zealand, with the last three options typically limited to stand-alone systems or reserve generation (particularly diesel or gas turbines).

Each of these potential sources of DG can also be paired with battery systems to allow electricity to be stored and used when the sun, wind, or water is not there, or provided to the distribution network to help manage peak demands. This has the benefit of reducing some of the capital expenditure on electricity distribution needed to meet peak demand growth, and also provides benefits in other parts of the electricity supply chain (transmission and generation). Banks of lead-acid batteries are commonly used.[35] A battery bank can cost anywhere from $10,000 to $30,000 and will typically need replacing in 5-15 years, depending on quality, sizing and how often they are used.[36]

Increased penetration of DG has impacts on EDBs' operating costs and network planning. As well as avoided transmission and distribution charges (discussed above), DG can impose direct costs to distributors to maintain service standards while accommodating DG. On the other hand, battery storage on its own (without DG) can help to manage demand without significant additional costs.

Looking ahead, the use of "smart grid" technology[37] together with the increased usage of Electric Vehicles also suggests a potential role for Electric Vehicles as a local storage device to help manage peak demands. This suggests while there has already been an increase in the use of DG, as technology develops further and costs come down, there

---

34 Under Part 6 of the Electricity Industry Participation Code 2010, see: http://www.ea.govt.nz/industry/market/-distributed-generation/

35 Lithium-ion batteries are also an alternative.

36 Source: http://www.energywise.govt.nz/your-home/generating-your-own-energy/saps

37 Research into the use of "smart grid" technology in New Zealand includes the "Green Grid" initiative. For more information see: http://www.epecentre.ac.nz/greengrid/ and http://www.otago.ac.nz/csafe/research/energy/-otago050285.html

may be a much more significant role for DG and storage. This includes one where EDBs play an important role in leveraging available opportunities.

3.4 Behavioural Programmes

Behavioural programmes tend to be supply-side or state agency investments that focus on bringing about efficiency by influencing end-user behaviour. This includes awareness-raising and educational programmes as well as the use of pricing structures that incentivise changes in customer demands. This section describes the types of behavioural options that exist and draws lessons from international experience about when behavioural programmes are most effective.

New Zealand experience

EECA has been involved in a number of awareness-raising and energy efficiency educational campaigns and has partnered with EDBs and retailers in relation to lighting programmes in particular. In addition, a number of retailers are starting to provide educational information on electricity usage and costs to their customers.

In contrast, experience with different pricing structures in New Zealand is relatively limited. Current pricing structures largely rely on a combination of a fixed and a set variable charge based on kWh consumption, with some pricing plans differentiating between day and night or peak and off-peak periods. Real-time pricing is only used to price network services to larger customers.

In practice, there are limits for EDBs in terms of both how they charge (particularly due to low fixed charge regulations), as well as how their charges are passed on to end-users. This is because retailers (rather than EDBs) determine the final pricing structures to end-users through their direct relationship with consumers.[38] These arrangements are considered further in Section 5.

Opportunities for behavioural programmes

The types of awareness-raising and educational programmes currently run in New Zealand are discussed briefly above, while Section 3.2 identifies the types of end uses that may be a focus for such programmes. In addition, the list below summarises the tiered pricing structures that can be used as part of behavioural programmes (usually aiming to control peak demand):

- **General Controlled Tariff** – largely the status quo where a combination of a fixed and a set variable charge is used.
- **Critical Peak Pricing (CPP)** – where a distribution utility can call a limited number of events based on short term system conditions. Customers pay a considerably higher rate during these hours (up to 15 times that of other periods). Usage is only 10-15 times a year.
- **Peak Time Rebate (PTR)** – similar to CPP in that utilities call rebate events, but the customer is paid a credit for emergency reduction during the event, which is measured relative to baseline load. Usage is only 10-15 times a year.
- **Time of Use (TOU)** – electricity prices are differentiated by a predetermined time structure (e.g. peak vs. off-peak). This form of pricing is relatively common for larger electricity consumers in New Zealand, and requires meters that record consumption on an interval basis.

[38] Distributor prices may or may not be passed on to customers by retailers, depending on the other factors driving competing retailer prices.

- **Real-time Pricing (RTP)**— prices are set for each half hour, either through a daily schedule or by the hour. This is essentially a specific form of time of use pricing that varies by half hour.
- **Variable Peak Pricing (VPP)**— a hybrid of TOU and RTP. Peak periods are defined in advance, but price varies according to system or market conditions.
- **Maximum Demand Pricing**— mass market annual pricing based on maximum demand periods. Implemented by The Lines Company to recover the costs of providing network capacity more fairly from locals and bach owners (who use network capacity but not many kWh) and drive peak reductions.[39]
- **Low User Fixed Charge (LUFC) Pricing**—which have a lower fixed daily charge than the standard options and a higher variable charge for the electricity used. The amount of the variable rate varies depending on where users live and what type of meter they have. Electricity providers are required to assist low-use customers by offering them a low fixed charge tariff option of no more than 30c per day. Providers should inform users at least annually of whether it may be beneficial for users to switch to a low fixed charge rate. Certain very small distributor locations are exempt from these requirements.[40]

In addition to The Lines Companies, other EDBs have also introduced pricing arrangements that seek to change behaviour. Orion's pricing approach provides a peak usage signal to retailers operating on its network, by using GXP-level data to determine the contribution that each retailer makes towards peak demand on its network. Powerco also has a GXP-based demand charge on its Western network. WEL Network's latest pricing methodology describes an "advanced pricing" option for mass market customers, incorporating peak, shoulder and off-peak tariffs. These tariffs are intended to encourage and support retailers to adopt advanced pricing structures that are consistent with the usage patterns on WEL's network.

3.5 EDBs' Role in Supply and Demand-Side Efficiency

This section focuses on EDBs' role in supply and demand-side efficiency. It provides some context around the nature of EDBs' business and presents criteria for EDB involvement in supply and demand-side efficiency options. This provides the basis for funnelling the options identified in Sections 3.1–3.4 to focus on the options where it makes the most sense for EDBs to be involved.

The nature of EDBs' business means they may be well placed to invest in supply and demand-side efficiency options

EDBs provide electricity lines services to consumers. Regardless of ownership, the Energy Companies Act sets the objective of energy companies as to operate as successful businesses, having regard to efficient energy use.[41] In doing so, EDBs are responsible for managing the assets and systems that ensure the provision of lines services. EDBs are

[39] The Lines Company (TLC) bills customers directly (as opposed to charges being passed on via retailers). TLC's pricing structure includes: 1) individual charges for dedicated assets (assets dedicated to supplying individual or 3 or fewer customers in the case of transformers), 2) a network charge based on contracted capacity, 3) a demand charge based on actual usage over the previous year's peak periods, and 4) for large industrials only, a customer service charge. See: http://www.thelinescompany.co.nz/docs/Demand%20Charges%20explanation.pdf

[40] See: https://www.powerswitch.org.nz/powerswitch/site-info/powerswitch-faqs/electricity-prices

[41] Appendix D provides more information on the Electricity Companies Act and other relevant legislation.

subject to information disclosure requirements, and (unless consumer-owned) EDBs are also subject to price-quality regulation.[42]

In providing the point of connection to end-consumers in the supply of electricity, EDBs are responsible for maintaining, operating, and investing in the distribution network to ensure that electricity is provided in a way that meets customer demands. This responsibility for network infrastructure means EDBs have a significant influence on the reliability and quality of electricity supply to customer premises (which, together with pricing, is what customers are likely to care about most).

As discussed in Section 3.2, EDBs are required to invest in network capacity to ensure that levels of peak demand can be met. This requires EDBs to determine the economic level of investment to meet security standards. In doing so, EDBs should consider the role economic investment in supply and demand-side efficiency options plays in minimising the cost of providing capacity to meet peak demand that occurs only infrequently and for very short periods of time.

Relative to other participants in the electricity supply chain, EDBs also bring potential advantages to supply and demand-side efficiency options by virtue of their:

- **Information and position in the electricity supply chain.** EDBs connect directly with consumers, observe energy flows across their networks, are able to optimise flows and identify capacity constraints from a network perspective, and are able to aggregate changes in those flows from the perspective of transmission load.[43] Given this, they may be better placed to understand the costs and benefits of different options or technologies.
- **Long-range investment horizon and relatively low risk profile.** EDBs are likely to be able to take a longer-term view to investments and may have a lower cost of capital than other parties (such as electricity retailers) as owners of long-lived infrastructure assets. Because of the regulatory regime under which EDBs operate the regulated services they provide, they are also not subject to the risk of assets being stranded with investments unable to be recovered.
- **Presence, scale, reputation and cost advantages in the geographical areas they serve.** EDBs have a natural monopoly position in their point in the supply chain in each location, ensuring complete customer coverage in each area. In comparison, competition limits the coverage that retailers or metering companies have, with it being uncommon for retailers to have more than a 50 percent market share.

Criteria for EDB involvement in supply and demand-side efficiency options suggest potential opportunities

The nature of EDBs' businesses and their potential advantages provides some collective criteria to consider whether EDBs have a potential role in energy efficiency options. The characteristics of EDBs suggest that efficiency interventions may be assessed against whether they enable EDBs to provide regulated lines services that:

---

[42] See: http://www.comcom.govt.nz/regulated-industries/input-methodologies-2/electricity-distribution/ and http://www.comcom.govt.nz/regulated-industries/electricity/electricity-default-price-quality-path/treatment-of-consumer-owned-electricity-distribution-businesses/

[43] Given EDBs' interposed relationship with retailers, EDBs do not observe the individual customer-level flows but aggregations of these across each network.

- **Are least-cost.** Ensures that distribution system and capacity requirements are met in a sustainable way at the lowest total lifetime cost
- **Respond to financial incentives.** EDBs may be best placed to incur the cost where they capture a share of the benefits and are not made worse off as a result of implementing the efficiency measure, and
- **Provide benefits to consumers.** The activities need to be consistent with Section 52A of Part 4 of the Commerce Act by generating outcomes that provide long-run benefits to consumers (who are willing to pay for any supply or demand-side initiatives).

EDBs may also have non-regulated business opportunities to implement efficiency improvements that are commercially profitable, depending on shareholders' preferences.[44]

When looking at the range of supply and demand-side efficiency opportunities presented in Sections 3.1–3.4, we assess these options against the criteria for EDBs to have a role. Given that the nature of EDBs is to economically meet security and demand requirements, many of these initiatives focus on EDBs' clear interest in ensuring system and capacity efficiency.

Table 3.2 presents the options discussed in Sections 3.1—3.4 where we suggest EDBs have a potential role – that is those that meet the criteria for EDB involvement. Table 3.2 suggests that EDBs have a clear role (potentially being best placed to implement[45] and related to core business) in relation to **efficient/ controllable equipment or systems**, particularly load control, **facilitating DG and/or storage** options and managing peak demand through **behavioural programmes**. They are also best placed to lead any **loss reduction** initiatives. In addition to roles based around their core business of lines services, EDBs may have a non-regulated role in commercial efficiency options depending on shareholders' preferences in terms of the role of a particular EDB.

[44] In practice, efficiency opportunities may have aspects of both regulated and unregulated activities where input methodologies should indicate how costs are allocated under these conditions.

[45] Or at least having a potential advantage over other parties in leading the uptake of an efficiency option, for example where having one party with complete coverage over a network area is critical to implementation).

Table 3.2: Energy Efficiency Role for EDBs (Ordered by Relevance)

Type of Initiative	Specific Opportunities	Nature of Role
Efficient/ controllable equipment or systems	Using direct load control technologies (for example, ripple control) and programmes (for example, awareness or incentive programmes) in relation to major end-uses.	Load control allows direct management of peak demands and EDBs are best placed to manage this. Programmes reducing use for major end-uses would also contribute to managing peak demands.
Distributed generation	Most likely together with storage and/or smart grid technology and potentially at or close to substations/points of pressure on the network: ▪ Wind turbines ▪ Solar panels (PV) ▪ Micro-hydro ▪ Geothermal heat ▪ Bio-energy ▪ Diesel or gas turbines	Facilitating uptake of DG and encouraging use of storage to help manage peak demands.
Behavioural programmes	Awareness-raising, educational, and longer-term opt-in programmes combining critical peak pricing and technologies that provide information that enable demand management. Other tiered pricing options include: ▪ Peak Time Rebate ▪ Time of Use ▪ Real-time Pricing ▪ Variable Peak Pricing ▪ Maximum Demand Pricing	Programmes encouraging usage at times when there is least pressure on the network, EDBs best placed to design incentive structures to achieve this (noting that retailers control the pricing that end-users end up facing).
Loss reduction	Reducing losses by: ▪ **Assets**: Installing bigger cables/transformers when considering the choice of voltage levels and redundancy ▪ **Operation**: Conservation voltage regulation which keeps voltage as low as possible while maintaining minimum voltage at feeder ends ▪ **Customer behaviour**: Managing peak demand and improving power factors and asset utilisation	EDBs are best placed to lead in this area. However, the extent of potential gains appears limited.

4 Are Supply and Demand-Side Efficiency Options in the Long-term Interest of Consumers?

Having narrowed down the possible supply and demand-side efficiency options to those where EDBs have a role, we now consider how options can be assessed to ensure that only the good ones proceed—that is, the options that provide long-term benefits to consumers.

We introduce a net market benefits (NMB) test that measures the overall net benefits to the industry. This net market benefits test will help us to understand whether material constraints to the uptake of supply and demand-side efficiency are resulting in options which are of long-term benefit to consumers, such as those discussed in Section 3, not being pursued. We then compare traditional capacity expansion investments with efficiency options using a net market benefits approach.

4.1 Applying a Net Market Benefits Test

The net market benefits test assesses the overall net benefits to the industry and is able to incorporate externalities and look through any potential barriers to investment.

- **Externalities**. A cost or benefit that results from an activity or transaction and that affects an otherwise uninvolved party who did not choose to incur that cost or benefit. For example, if a consumer decides to turn their dishwasher on at night before going to bed rather than straight after dinner during a period of peak demand, the resulting reduction in peak demand and strain on the network is a positive externality (benefit) to the network provider.
- **Barriers to investment**. Opportunities that are publicly beneficial might not be pursued because the party that is best placed to implement the option (the EDB) is not commercially rewarded for doing so. For example, if peak pricing delivers overall net benefits, including peak reduction, but EDBs are unable to implement a peak pricing programme as they cannot pass the pricing structure on to end users.

The NMB test calculates the Net Present Value (NPV) of an opportunity incorporating all industry costs and benefits, including externalities and other reasons that the full value of the opportunity might not be captured. This is the general economic framework for considering if something is beneficial overall for consumers and is similar to the test generally used in international reviews of advanced metering investments.[46] The NMB test is also analogous the old Grid Investment Test for transmission now incorporated in the Investment Test in the Commerce Commission's Input Methodology for Transpower's Capital Expenditure.[47] If an option has an overall net benefit to the industry, competition and regulation ensures benefits are eventually transferred to consumers (unless there are market or regulatory barriers).

The rest of this section applies the NMB test—considering the costs of meeting capacity requirements using traditional solutions or alternative investments. Appendix C provides

---

[46] See for example, studies in Australia (NERA, 2008), Canada (BC Hydro, 2010), Ireland (Commission for Energy Regulation, 2011), California (Brattle Group, 2006), and the Netherlands (Siderius et al, 2008).

[47] See: Transpower Capital Expenditure Input Methodology Determination [2012] NZCC 2. http://www.comcom.govt.nz/regulated-industries/input-methodologies-2/transpower-input-methodologies/

further information on the NMB test, including its application and potential complexities.

4.2 Cost of Traditional Capacity Expansions

EDBs traditionally make investments at the margin to increase network capacity. This section estimates the cost per unit of such investments and explores the wider industry costs associated with meeting peak demand. These costs provide a benchmark for evaluating alternatives such as supply and demand-side efficiency options that delay the need to invest in network capacity in Section 4.3.

Marginal investments in network capacity by EDBs

The cost of additional network capacity varies from project to project for EDBs, often largely driven by the cost of new circuits which vary in length and by type of substation. Table 4.1 provides rough estimates of the cost of expanding network capacity based on several examples of actual substation investments. Assuming a unitary power factor (such that 1MVA = 1MW), the cost estimates for network capacity expansions vary from approximately $150,000 a MW for rural substations to $170,000-$200,000 a MW for industrial substation capacity expansions and $240,000 to $260,000 a MW for urban substation capacity expansions. This is based on certain examples, however, and is intended to illustrate orders of magnitude only.

The operating expenditure associated with the types of capacity expansion investments in Table 4.1 is not very significant in the early part of a substations life, until there is significant maintenance and refurbishment. For this reason, operating expenditure is not considered in this report.[48]

Table 4.1: Cost Estimates of Capacity Expansions by Type of Substation

Substation Type	Cost ($m)	Capacity	$/MVA
Urban	6.3	24 MVA	$260,000
Urban	5.7	23 MVA	$250,000
Industrial	5.2	30 MVA	$170,000
Industrial	4.8	24 MVA	$200,000
Rural	2.6	17 MVA	$150,000

Source: ENA Energy Efficiency Incentives Working Group members

Section 4.3 explores the potential for supply and demand-side efficiency initiatives to be alternatives to traditional investments by allowing a deferral of costs.

Impacts on transmission costs

Reducing peak demand on an EDB's network can also defer or avoid costs further up the electricity supply chain, such as costs of transmission. Benefits occurring at the transmission level can be thought of in two ways:

- In the short term, an EDB will incur lower transmission charges from Transpower if it has lower peak demand growth. This is because the current transmission pricing methodology allocates transmission costs on the basis of

[48] As efficiency initiatives generally tend to have a higher proportion of operating expenditure than traditional investments, we believe this is also a conservative way to approach the analysis

regional coincident peak demand (RCPD). Because transmission costs are fixed, the reduction in the EDB's charges will result in an increase in the charges of all other users as the particular EDB's share of RCPD reduces. This is therefore an avoided charge (rather than an avoided cost) that is spread among other EDBs and direct connect customers of Transpower.

- In the long term, there is likely to be a reasonably stable relationship between demand growth and growth related transmission capital expenditure. This is similar to the effect described for distribution expenditure above, where the growth capital expenditure required to meet an additional MW of demand provides a reasonable measure of the cost avoided or deferred through efficiency initiatives. This benefit will accrue to all New Zealand electricity customers, including those on the particular EDBs' network.

The longer term impacts of deferring transmission investment provide real opportunities for cost savings. As with investment at the distribution-level, the investment required in transmission to allow for increasing peak demand on a distribution network will vary by area and in some cases growth in peak demand will not require any new investment by Transpower. However, where peak demand growth requires capacity investments at the distributor-level, new investment in transmission capacity may also be needed.

Estimates of the marginal transmission cost of additional capacity were provided to the working group by Transpower, based on recent investment examples. These are shown in Table 4.2. The examples provided were $310,000/MW for the Lower South Island (LSI) Renewables project (moving existing simplex configurations to duplex ones) and $560,000/MW for the new build associated with the North Island Grid Upgrade Project (NIGUP). As with the distribution figures, these estimates provide an indication of the order of magnitude costs, based on recent examples.

Table 4.2: Estimated Cost of Transmission Capacity

	Cost ($m)	Increase in Capacity (MW)	$/MW
NIGUP[49]	894	1,600	$560,000
LSI[50]	197	630	$310,000

Source: Transpower

Impacts on generation costs

Like distribution and transmission, alternative efficiency initiatives that defer capacity expansion also have potential to defer generation investment. This is because increases in peak demand can also require investment in high cost peaking generation that is not used during times of lower demand. Peak demand therefore adds to the cost of supplying electricity (the lowest cost of generation would be achieved if demand was constant throughout the day).

The value of this generation deferral depends entirely on the characteristics of the portfolio of generation assets used to meet demand. At the extreme, generation portfolios can be thought of as either being "capacity constrained" or "energy constrained":

[49] See: https://www.transpower.co.nz/sites/default/files/publications/resources/north-island-grid-upgrade.pdf

[50] See: https://www.transpower.co.nz/sites/default/files/plain-page/attachments/LOWERS%201.pdf

- **Capacity constrained generation systems** are typically comprised of thermal power stations. In these systems, to maximise economic efficiency power stations generate at the highest possible load factor to meet demand. This is because the fuel used for generation (coal or gas) is not limited. Generation capacity is therefore built to equal peak demand, plus a reserve margin. Increases in peak demand lead to investment in peak capacity and the benefit from efficiency initiatives to control/reduce peak demand, or manage with current market generation, is the value of investment required in peak capacity.
- **Energy constrained generation systems** typically have a larger amount of hydro generation with limited water storage capacity, or intermittent generation. In these systems, the "fuel" used for generation is limited—for example by available rainfall. Generation capacity is thus maximised to utilise all of the available water, and may be substantially higher than peak demand. Increases in total energy consumption require additional investment, meaning that there is no real generation benefit from purely reducing peak demand.

The New Zealand generation system mix is largely low-storage hydro (about 55 percent of energy), complemented by geothermal, thermal and wind generation.

The New Zealand System Operator's 2013 annual assessment of the winter capacity margin makes it clear that continued investment in generation is required to meet the winter capacity margin standard.[51] However, it is not clear if the key driver for the projected new generation investment is to meet growth in energy or growth in maximum demand.

The projected new generation over the assessment period (2013 to 2020) is shown in Table 4.3. This suggests that to maintain the winter capacity margin about half of the new generation capacity that is built will also be required to contribute to the capacity margin. Intuitively, this is reasonable because no generation system is entirely capacity or energy constrained.

The average capital cost of peaking generation (such as open cycle gas turbines) is estimated to be $1.93 million based on Table 4.14 of the MED Generation Data Update.[52] Therefore, assuming marginal peaking generation is thermal, and using the contribution of new thermal generation to peak capacity in Table 4.3, the marginal generation cost of meeting peak capacity is estimated to be $1.92 million per MW.

Table 4.3: New Generation Contribution to Capacity Margin

Type	Nameplate capacity MW	Contribution to capacity margin MW	% Contribution
Geothermal	751	708	94%
Thermal	1,155	1,120	97%
Hydro	147	144	98%
Wind	2,960	592	20%
Total	**5,013**	**2,564**	**51%**

[51] System Operator Report, *Security of Supply Annual Assessment 2013,* Transpower, February 2013

[52] 2011 NZ Generation Data Update, 26th January 2012, Ministry of Economic Development. This uses 2011 dollars, or the cost in 2011, so may be slightly conservative.

Average capital cost of peaking generation	$1.93 million
Average capital cost of peaking generation per MW of peak capacity (based on thermal contribution)	$1.92 million

Source: From System Operator Report, Security of Supply Annual Assessment 2013, Transpower, February 2013, Table x; Table 4.14 of 2011 NZ Generation Data Update, 26th January 2012, Ministry of Economic Development

Industry costs of capacity expansion

Table 4.4 combines the capacity costs of distribution, transmission, and generation. It shows that the costs of capacity upgrades across the electricity system are around $2.3–$2.8 million per MW. Most of this cost is due to the significant cost of additional peaking capacity and to a lesser extent upgrading transmission capacity, with the portion related to distribution being the lowest. However transmission investment requirements will vary by area such that in some cases transmission costs would be much lower, and a smaller component of industry costs. Likewise generation capacity will generally be driven by total demand so increasing peak demand in a given distribution system may cause costs to the EDB but not always increased generation costs if they are offset by peak demand reductions on a separate distribution system.

The other difference between the figures is that the distribution and transmission figures are based on specific cases, whereas the generation figure is calculated based on a top-down approach (though broadly consistent with past examples). This may slightly exacerbate the difference between the costs to distributors and Transpower compared with generators; however this is likely to be similar to the approach an EDB might take in assessing a particular investment so in this sense appears appropriate for this purpose.

Table 4.4: Costs to the Industry of Capacity Expansions

	Urban ($m)	Rural ($m)	Industrial ($m)
Cost of Capacity Upgrade (1MW)			
Generation	1.9	1.9	1.9
Transmission	0.31–0.56	0.31–0.56	0.31–0.56
Distribution	0.26	0.15	0.18
Total	**2.5–2.7**	**2.4–2.6**	**2.4– 2.7**

4.3 Cost of Supply and Demand-Side Efficiency Options

Section 4.2 identified significant costs across the electricity sector to meeting peak demands. This section explores the potential role of supply and demand-side efficiency initiatives as alternatives or complements to traditional network capacity expansion (or renewal). In Section 3.5 we highlighted a number of potential supply and demand-side efficiency options where EDBs may have a role. In this section, we compare the cost to EDBs of investing in two of these initiatives with the costs of traditional network investments (as illustrative examples) to investigate their potential.

Specific efficiency options were chosen from those identified as having potential, and where EDBs had a potential role, for further analysis

In order to: a) identify the potential for efficiency options to provide net market benefits, and b) identify any constraints to such options being pursued currently, certain illustrative examples were chosen by the working group for further investigation. The illustrative examples suggested below draw from the identified areas where EDBs have a potential role, focus on residential use given its role in peak demand, and provide a contrast in terms of impact on the load profile and supply/demand-side initiatives (see Table 2.1):

- The use of load control (for example ripple control) in new housing developments
- The use of efficient light bulbs, and
- The use of in-house distributed generation, such as solar photovoltaics with storage and smart grid technology to help manage peak demand.

In this section, we consider the first two examples further, leaving the third for potential follow-up work at a later stage. We note these examples are illustrative only and other supply and demand-side efficiency options may also have significant potential.

New Zealand has significant experience with ripple control and there is potential for further use in managing peak demand

As discussed in Section 3.2, EDBs have been using load control systems in New Zealand since the 1950s for residential and commercial water heating, street lighting, and night store heaters. Load control options, such as ripple control, can serve to shift load from peak to off peak periods resulting in likely cost savings (see Table 2.1).

Ripple control involves superimposing a higher-frequency signal onto the standard main power system. When receiver devices attached to non-essential loads receive this signal, they shut down the load until the signal is disabled or another frequency signal is received. Control can occur manually by the EDB in response to local outages or requests to reduce demand from the transmission system operator. Ripple control receivers are assigned to one of several ripple channels to allow the network company to only turn off supply on part of the network, and to allow staged restoration of supply to reduce the impact of a surge in demand when power is restored to water heaters after a period of time off.

Consumers are usually rewarded for participating in load control programmes by paying a reduced rate for energy. In some cases controlled load is metered separately and billed at a lower rate per kilowatt-hour.

There is potential for the use of load control to be extended. This includes increasing usage in areas where ripple control is available and implementing new load control technology (e.g. smart devices) in new buildings (by increasing awareness or improving incentives for end-users), ensuring existing ripple equipment is working, or extending the uses to which load control is applied. Internationally, other areas where load control is used include heat pumps/air conditioners, pool pumps, or crop-irrigation pumps. The potential cost of extending the use of load control is discussed later in this section, together with the benefits it might achieve. There is also significant potential for the service provided by load control to be extended by means of alternative (new smart) devices.

As a major use of electricity, improvements in lighting efficiency have been a focus of much attention with potential to deliver savings across the industry

Lighting is another major use of electricity in the residential sector, as well as the commercial and industrial sectors. As noted in Section 3.2, the services sector and industrial and trade sectors suggested potential for improved efficiency in lighting.[53] The 2007 KEMA report also found that the majority of peak demand and energy savings potential in residential and commercial sectors is in improving lighting efficiency (replacing incandescent lamps with compact fluorescent light bulbs (CFLs)).

As noted in Section 3.2, since the 2007 KEMA report, lighting initiatives have been a focus of EECA and the market share of efficient light bulbs has increased. However, as with ripple control, there is likely scope for further penetration of, and peak demand reduction from, efficient lighting. Options for EDBs to reduce peak demand through increased use of efficient lighting would involve investing in programmes to increase the use of efficient lighting (such as partnering with EECA to improve awareness or subsidising their use) or paying for light bulbs to be changed to more efficient ones – either by contracting with a third party or bulk purchasing and arranging for installation on its network.[54]

Referring back to Table 2.1, efficient lighting serves to reduce load across the period but given the overlap in use of lighting with typical peak periods, it may primarily serve to reduce load during peak periods. By doing this, efficient lighting should result in the following cost impacts:

- Lower generation costs through lower plant operating costs (e.g. fuel costs) and reduced need for additional higher marginal cost generation
- Lower capital investment by EDBs and Transpower (assuming some reduction during peaks), and
- Lower energy use and therefore lower electricity bills for users.[55]

EDBs would need to assess the likelihood and extent of load reduction that programmes deliver so they can ensure the network is able to meet the level of demand that eventuates. We note there are programmes overseas focused purely on commercial and industrial users.[56] In targeting programmes, the EDBs will need to assess the benefits from diversifying across many residential users who tend to drive peak demand with the reduced costs of contracting with fewer large users who may have more ability to control their load/use alternative supply.

Ripple control and efficient lighting initiatives reduce peak demand and may defer or avoid the need for investing in capacity

Table 4.5 provides estimates for the cost to reduce peak demand by a MW using either ripple control or efficient lighting. As noted in the table, these estimates are based on

[53] For more information, see: http://www.stats.govt.nz/browse_for_stats/industry_sectors/Energy/energy-use.aspx

[54] In this example, as well as consumers benefiting from reduced industry costs, they benefit directly from reduced volume (for the same service). Therefore, the allocation of costs is an important issue. However, for EDBs (and this report) what matters most is the cost is worthwhile to the EDB in terms of reduced costs (compared with the alternative) across their network and the industry. This will then flow to all consumers, including those not participating in the initiative.

[55] For example, EECA energywise state that assuming an electricity cost of 26c/kWh, residential consumers could save around $100 a year by replacing their five most used incandescent light bulbs with energy efficient ones. They also state that energy efficient light bulbs use up to 80% less energy than standard incandescent bulbs (see: http://www.energywise.govt.nz/your-home/lighting)

[56] For example, the New York Commercial and Industrial Rebate Programme provides prescriptive or custom rebates to non-residential customers for installing energy efficient equipment (see: http://www.epa.gov/chp/policies/incentives/necustommeasurescommercialandindustrialrebateprogram.html) and the NSTAR – Small Commercial Direct Install Programme provides free energy audits and incentives for energy efficient measures for companies with average monthly demand of up to 300 kW (see: http://www.nstar.com/business/energy_efficiency/electric_programs/direct_install_program.asp)

information from previous investments and the exact cost would depend on the programme being considered. However as with the tables in Section 4.2, these give an indication as to the order of magnitude for comparison.

Table 4.5 shows that the cost of using ripple control to reduce peak demand is around $130,000 per MW with the investment lasting 15–20 years. It also shows the cost of increasing the uptake of efficient lighting to reduce peak demand is around $21,000–$58,000 per MW with the CFL bulbs lasting 3–5 years on average. These initiatives will be in the long term interests of consumers if their cost is less than the costs associated with traditional investments in capacity over the same timeframe (either 3–5 years or 15–20 years).

Table 4.5 suggests that investing in efficient lighting is cheaper on a cost per MW basis than an equivalent investment in ripple control. However, ripple control has a longer life and allows EDBs direct control of load. The ripple control figure used also comes from the Upper South Island load management trial, whereas expanding the use of current EDB investments in ripple control may cost less.

Table 4.5: Cost per MW of Illustrative Efficiency Initiatives

	$/MW of Peak Load Reduction	Investment Lifetime
Ripple Control	$130,000	15–20 years
CFLs	$21,000–$58,000	3–5 years

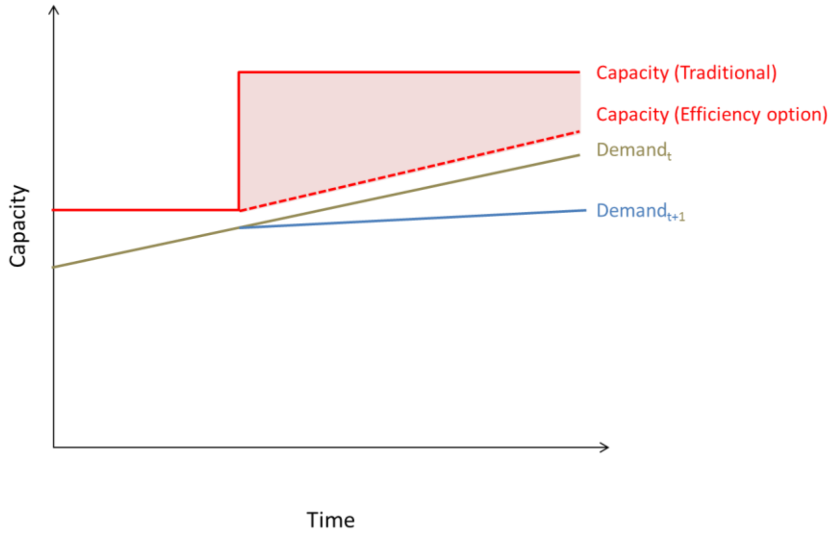
Source: Upper South Island load management trial (http://www.energynews.co.nz/node/4066); KEMA 2007 report for the Electricity Commission "New Zealand Electric Energy-Efficiency Potential"

There is also value in efficiency initiatives being less lumpy investments than traditional capacity investments while also preserving options

The lumpy nature of traditional solutions results in two sources of option value (for EDBs and in turn consumers) from efficiency options. Firstly, there is value to EDBs of not investing in capacity greater than that needed to meet demand (shown as the shaded red area in Figure 4.1). Secondly, there is value in deferring traditional investment decisions in terms of obtaining better information about what future demand may be—including avoiding such an investment if demand turns out to be lower than originally anticipated (the blue line rather than the green line in Figure 4.1).[57]

[57] For example, a $10 million for a substation would be cheaper than spending $0.5 million per annum for 50 years on demand management. However, if there is falling demand (with customers investing in more efficient appliances) the need for incremental investments may only exist for 10 years - in which case the demand management option would be cheaper.

Figure 4.1: Option Value of Efficiency Initiatives



4.4 Results of the Net Market Benefits Test

The relative costs of traditional capacity expansions and load control and efficient lighting initiatives suggest that both of these efficiency measures would provide a net market benefit.

In comparison with Table 4.5, Table 4.6 shows the value to various parties of deferring traditional investment for either 3–5 years (the life of CFLs) or 15–20 years (being the life of ripple control investment). From this we see that investing in either ripple control or efficient lighting would provide net benefits to the industry (and therefore consumers) if they allowed the deferral of traditional capacity expansion for 3–5 years or more (i.e. under either of the scenarios). This analysis normalises for the size of investment with both figures presented on a per MW basis—in practice, the efficiency measures are likely to be more scalable and less lumpy than traditional capacity investments (as discussed above).

Comparing the cost of efficient lighting in Table 4.5 with 3–5 years of deferred investment in peak capacity in Table 4.6, we see that efficient lighting would provide net benefits to the industry (and therefore consumers). This comparison also shows that for EDBs the costs of efficient lighting are roughly equivalent to the value of deferring traditional capacity investments.[58]

Ripple control initiatives would also provide net benefits to the industry—allowing the deferral of capacity investment for 15–20 years. While not directly shown here, our analysis suggests that ripple control is valuable directly to EDBs in urban and industrial areas. Whereas for rural substations, wider industry benefits from deferred investment need to be considered—that is the investments would be in consumers long-term interests but not necessarily EDBs. This highlights that there is value overall from such initiatives in the ability to defer traditional investment but that there are wider value impacts across the sector and not all of the potential value accrues directly to EDBs.

[58] Efficient lighting is likely to be lower cost/higher value in urban areas (certainly if assets last 5 years rather than 3).

Table 4.6: Value of Deferring Traditional Capacity Expansion Capital Expenditure

	($000's)
NPV of 3-5 Year Deferral of Capacity Upgrade (1MW): CFL Comparator	
***Generation (9.0% WACC)*[1]**	440–670
***Transmission (6.3% WACC)*[2]**	52–150
***Distribution (7.41% WACC)*[3]**	29–77
Total	**520–900**
NPV of 15-20 Year Deferral of Capacity Upgrade (1MW): Ripple Control Comparator	
***Generation (9.0% WACC)*[1]**	1,400–1,600
***Transmission (6.3% WACC)*[2]**	190–390
***Distribution (7.41% WACC)*[3]**	110–190
Total	**1,700–2,200**

Source: Same as previous tables as well as [1]https://nzx.com/files/static/cms-documents/-TDB_Meridian_Energy_Research_Report_131002.pdf, [2] http://comu.govt.nz/resources/pdfs/-tnz/tnz-sci-13.pdf, [3] http://www.comcom.govt.nz/regulated-industries/input-methodologies-2/cost-of-capital/

This analysis supports the conclusion that efficiency options have the potential to lower the costs of supplying electricity in New Zealand. Both illustrative examples—ripple control and efficient lighting—provide net benefits to the industry in deferring traditional investment in capacity (and as outlined in Appendix B, other options from Section 3.2 have also been shown to provide net market benefits).

We find that while in some cases initiatives make sense on EDB benefits alone, much of the benefits may accrue to other parts of the electricity sector and initiatives may not stack up unless these wider impacts are considered. We therefore explore in the following section the factors that influence EDB decisions on efficiency initiatives and if the current regulatory and market settings incentivise investments that are in the long term interest of consumers.

5 What Drives EDBs' Decisions on Supply and Demand-Side Efficiency?

In Section 4.3 we identified that certain illustrative efficiency initiatives appear to provide net benefits to consumers, to the industry, and potentially to EDBs (though EDBs may not always be the major beneficiary). This section describes how the regulatory framework that applies to EDBs affects the analysis of supply and demand-side efficiency options (using the examples set out in Section 4). In doing so, we investigate whether the current regulatory and market conditions provide appropriate incentives for EDBs to make decisions that are in the long-term interest of consumers.

5.1 EDB Decision-making Framework

This section summarises the price-setting approach and the incentives on EDBs across the regulatory period.

Price-cap regulation is designed to encourage efficiency across the regulatory period

The regulatory approach under Part 4 requires the Commission to reset EDB price caps every five years based on the costs forecast over that period. EDBs can benefit by operating more efficiently relative to the regulatory forecasts. This approach is often known as incentive-based or "CPI-X" regulation, and provides an explicit incentive to regulated firms to make more efficient decisions, and pass those efficiency gains on to consumers through the process of periodic price resets. The Commission currently applies a weighted average price cap (rather than revenue caps) to non-exempt EDBs - the Default Price-quality Path/Customised Price-quality Path (DPP/CPP).

Under the DPP/CPP regime, EDBs must forecast future expenditure in their Asset Management Plans (AMPs). These forecasts provide an input the Commission may use in its decisions on price-quality paths. For EDB forecasts to be credible, they must incorporate realistic assumptions of the costs of meeting additional capacity. Once within a regulatory period, EDBs should continue to be incentivised to meet capacity requirements by providing electricity lines services in the most efficient manner (least cost while still meeting service requirements).

If the weighted average cost of capital (WACC) as determined by the Commission is equal to an EDB's actual cost of capital, then EDBs should be indifferent to providing regulated outputs through capex or opex. In practice however, EDBs may favour traditional capex solutions if management incentives and reward structures support growth in the company's asset base. If the WACC is not set equal to an EDB's actual cost of capital, there may be an incentive, either in favour (if above) or against (if below), capex (assuming that the EDB can include such capex in their RAB and earn a return on the investment).

EDBs will compare the revenue and costs associated with supply and demand-side efficiency options with their price paths and other alternative options

As noted above, price-cap regulation is intended to provide incentives for EDBs to invest in the lowest cost options of meeting capacity requirements. In Figure 5.1, this would be consistent with the flattest line (the blue dotted line in this case). If the Commission had set a price path for an EDB based on traditional solutions (the green line), the EDB is able to earn a return based on this path. The EDB should also have an incentive to reduce expenditure by undertaking more efficient solutions such as ripple control or efficient lighting (represented as the blue dotted line). Doing so would reduce costs and increase profits (represented by the light blue shaded area) during the regulatory period. At the end of the period the price path is reset and efficiency gains shared with consumers.

As discussed in Section 5.2, the strict reset date creates timing issues in that the capex will achieve a return for a greater or lesser period depending on when in the regulatory period the expenditure is made, and when benefits begin to accrue. Currently the incentive is to invest at the end of the regulatory period. This suggests that an incentive regime, such as the rolling incentive scheme currently being considered by the Commerce Commission (applied to opex and capex), could address this issue with the current DPP/CPP regime. The intention should be for EDBs to recover costs (including a return on capital) before gains are shared with consumers.

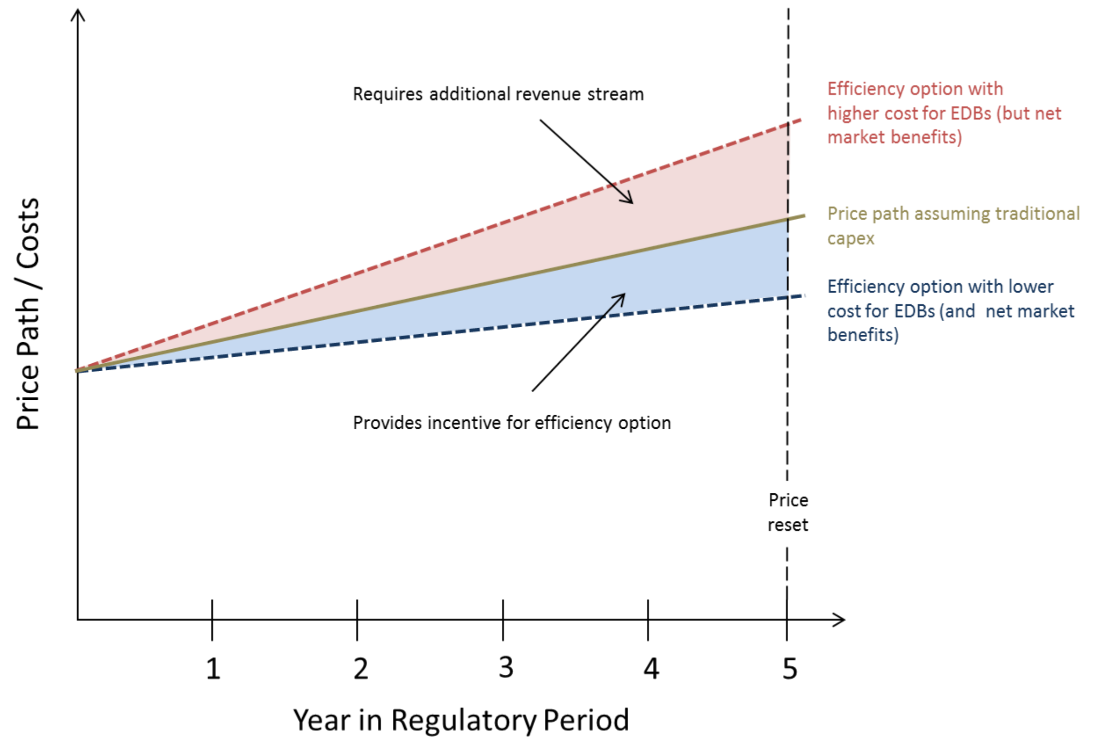
As discussed above, some efficiency options may provide net benefits to the industry as a whole but not necessarily EDBs directly. This is illustrated by the red dotted line in Figure 5.1. Under the example above where an EDB's price path has been based on the traditional solution, the EDB would actually be worse off by implementing efficiency in that they would earn a return based on the traditional solution but incur the higher costs associated with the efficient solution, which is depicted by the red dotted line, thereby reducing profits. In this example, given the wider benefits to consumers and the industry, contractual arrangements would be needed to recover the difference between the two options (represented by the light red shaded area) from the other parties that benefit – either the net retailers (who would avoid having to pay increased generation costs) or Transpower (whose transmission costs are reduced).[59]

Prior to the regulatory period, EDBs also need to contract (with the same parties as above) for the red shaded area (which should be treated as unregulated revenue if such efficiency options are to be encouraged once within a regulatory period) if they are to include it in their forecasts. This is in the absence of an alternative mechanism for EDBs to recover the higher costs given the wider benefits (where there may be alternative options that are not proposed by the working group, as outlined in Appendix A).

The issue of regulatory uncertainty is discussed in Section 5.2—for example in relation to the definition of "electricity lines services" or the allocation of common costs. In Figure 5.1, uncertainty might also favour the traditional solutions as there is experience in these being incorporated into an EDB's RAB. In contrast, even if ripple control/efficient lighting were lower cost (e.g. the blue dotted line in Figure 5.1), if an EDB is not sure if they are going to be able to earn a return on this investment they will tend to favour the lower risk option (or at least require a significant differential for it to be worth taking the risk). Similarly, if there is uncertainty as to the recovery or treatment of the red shaded area, the higher cost efficiency option would tend not to proceed.

[59] We assume that any benefit to consumers directly (such as a reduced electricity bill from lower volumes for the same service) would be incorporated directly and therefore netted off. For example, in the efficient lighting example, they would pay for the bulb and it would only be the cost of the subsidy provided by the EDB and other associated EDB costs that would need to be recovered. A further possibility would also be contracting with consumers directly not simply for their direct benefit but also indirect benefits in terms of reduced transmission or generation costs (however, the transactions costs of such an approach may be significant).

Figure 5.1: Illustration of Impact of Different Efficiency Options



5.2 Regulatory and Market Settings Influencing Decisions

This section explores how current regulatory and market settings influence EDB decisions on supply and demand-side efficiency initiatives (referred to below as simply "efficiency options" for brevity). A summary of the regulatory provisions under which EDBs operate that are directly relevant to the working group's task is set out in Appendix D.

ENA also sought a legal interpretation of Section 54Q of the Commerce Act which is attached in Appendix E. In summary, Russell McVeagh's view is that:

- The section 54Q obligation on the Commission to promote incentives and avoid imposing disincentives for EDBs to invest in energy efficiency and demand-side management applies whenever the Commission makes decisions under Part 4 relevant to EDBs (albeit not every decision is capable of promoting energy efficiency).
- While ENA is working to find ways for EDBs to improve supply and demand-side efficiency, the Commission is also required by the Act to take action when setting the price paths (including, if necessary, by amending input methodologies ("IMs"), in order to provide a framework that better incentivises such improvements. This should be seen as an important and necessary aspect of any work-stream.

This provides the context for the issues identified below and the working group's recommendations in Section 6.

Volume based pricing: EDBs are worse off if efficiency options reduce volume

The current weighted average price cap used to set price-quality paths for EDBs means there is less incentive for EDBs to minimise demand relative to alternative mechanisms such as a revenue cap. This is because an EDB will earn less revenue within a regulatory period by carrying out efficiency measures that reduce total electricity volumes consumed. This is consistent with the intention of a price cap to maximise demand and encourage efficiency. However for electricity, there may be value in not simply increasing demand – in terms of avoided costs and environmental impacts.

EDBs have a degree of flexibility in their pricing as regulations do not specifically require pricing based on usage (for example, kWh). However, the current norm is pricing based on consumption rather than peak demand (which drives much of EDBs' costs). The Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations (LUFC regulations) may in practice make such consumption charges a default. This is because they define the average consumer by their annual consumption and require that the average consumer pays no more in total under alternative tariff options. This makes it more difficult for an EDB to show that the average consumer would pay no more using a variable charge based on peak demand.

Additionally, while EDBs are not required to price on consumption/usage, currently the penetration of new technology does not allow EDBs to determine capacity at each installation control point (ICP) and price accordingly (but is limited to the GXP-level). Improvements in technology such as the increasing penetration of smart meters may allow EDBs to adjust their pricing to better reflect underlying costs. This would also address the current disincentive to invest in efficiency initiatives, by removing reliance on increasing volume consumption.

However, the LUFC regulations exacerbate issues with volume-based charging. The regulations were designed to encourage energy efficiency by consumers (and may also have been intended to address affordability issues for low-income users). The regulations cap the fixed charge that EDBs are able to set at a fixed rate that does not increase with inflation or have any reference to EDBs' underlying costs (in contrast to the Electricity Authority's pricing principles[60]). This results in EDBs' revenues being strongly linked to total electricity volumes despite many of their underlying costs being fixed or capacity-related rather than being related to volume.

The uptake of smart meters may allow EDBs to adjust their pricing methods to ensure they are not worse off as a result of investing in efficiency options. However, currently pricing methods act as a disincentive to EDBs investing in efficiency. It is also more onerous for EDBs to change pricing methods and efficiency initiatives will only be one factor EDBs consider when reviewing pricing. Meanwhile, the LUFC regulations result in an increasing divergence between EDBs' underlying costs and the charges they receive.

The inability to determine capacity at an ICP-level together with the cap on fixed chargers for low users (resulting from the LUFC regulation) mean than under the current weighted average price cap, EDBs are worse off if efficiency options reduce volume.

Defining the regulatory business: currently regulatory treatment of efficiency options is unclear

Under the current application of Part 4 on electricity lines services, there are circumstances where EDBs do not have incentives to make efficiency investments, despite such investments being consistent with the purpose of Part 4. These circumstances include where such investments:

[60] See: http://www.ea.govt.nz/our-work/programmes/transmission-work/principles-or-model-approaches-to-distribution-pricing/

- Result in a reduction in electricity volumes purchased by consumers (as discussed above)
- Improve a quality of service dimension of the electricity lines service, but the EDB is prevented by regulation to charge for that improvement
- Reduce the energy losses in the distribution system, but where it is ambiguous as to whether the EDB can charge for effecting these reductions, or
- Substitute for conventional assets to provide the electricity lines service, but where it is ambiguous as to whether or not these assets can be included in the EDB's RAB, or whether the EDB can recover any related operating costs via the DPP/CPP (discussed below).[61]

Section 54Q is limited to "applying this part in relation to electricity lines services", where electricity lines services are defined in Section 54C. The pragmatic application of Section 54C would be for expenditure to be treated/allocated based on the purposes for which it is spent.

This application would be consistent with the treatment of Transpower's Demand Response programme.[62] Under this initiative, Transpower contracts for certain load reduction. While the load reduction relates to the use and maintenance of electricity lines (in this case transmission) services, it is delivered by large consumers and EDBs.

However, another interpretation is also possible, where "electricity lines services" is a question of whether, or where, on the network the asset or service in question is. For example, a possible (narrow) interpretation is one that limits the definition to activities that occur before the customer's point of supply (i.e. up to the meter/connection point).[63] This alternative interpretation creates some uncertainty around the proper application/interpretation of these sections, and potentially constrains the set of alternative asset investments that are attractive under the regulatory regime to more conventional assets.

Many of the efficiency measures may involve investments beyond the consumer's meter. This suggests the need to clarify the interpretation of "electricity lines services" or the circumstances where narrow interpretations are not applicable (for example, input methodologies clarify that ripple receivers are included in the regulatory asset base). If the proper interpretation would exclude energy efficient assets or services as described above, it might be appropriate to reconsider the wording and amend the definition.

Whether efficiency initiatives fit with the definition of electricity lines services is important for EDBs for two reasons: it governs whether energy efficiency related assets can be included in an EDB's RAB and therefore whether EDB's are able to earn a return on their investment; and how revenues streams from such investment can be treated. Using Figure 5.1, we see that efficiency investments should be regarded as electricity lines services where they serve this end purpose (as otherwise there would be a disincentive to investing in lower cost efficiency options – the blue dotted line as opposed the green line).

---

[61] The points in this section also relate to energy losses while the quality of service issue is a separate point that the ENA Quality of Supply and Incentives working group is considering

[62] See: https://www.transpower.co.nz/projects/demand-response-project/demand-response-programme

[63] See, for example, "Implementation Path for Addressing Customer Service Lines" by Stuart Shepherd and Vhari McWha (29 August 2013)

For efficiency investments that are higher cost than traditional solutions (the red dotted line in Figure 5.1) but where there are wider benefits, we would want the EDB to be able to contract with other parties for the difference in cost between the efficiency option and the traditional solution (that is, the light red shaded area). However, this contracted revenue would need to be treated as unregulated rather than regulated revenue as otherwise EDBs whose price paths are set based on the green line would incur the higher expenditure associated with the red dotted line but only be able to price based on the green line minus the contracted red shaded area. In practice, the EDB should be able to set prices based on the green line and simply recover the red shaded area from other parties that benefit to help recoup EDBs additional cost of the efficiency option.

To ensure EDBs are appropriately incentivised for higher cost efficiency options, cost allocation rules in input methodologies need to allocate the portion of such higher cost efficiency options up to the value of the traditional alternative as relating to regulated activities and therefore included in the RAB (and incorporated into price paths). Any additional revenue should be treated as unregulated revenue (and likewise the additional cost not be included in the RAB) — this ensures the EDB pursues the lowest cost option but has incentives to invest in higher cost alternatives where there are benefits to other parties that are willing to fund the difference.

In these examples, the cost of efficiency options should also be treated equally whether delivered by the EDB itself or through a third-party.

Clarity is therefore needed on whether efficiency initiatives may be treated as electricity lines services and the treatment of: revenue on such assets from third parties, and costs (whether delivered by EDBs themselves or a third party).

Depreciation on assets with shorter lives: currently a disincentive to efficiency options

The Commission's EDB input methodologies which were applied in the 2012 DPP reset establish the default asset life for distribution asset additions as 45 years.[64] Once the price path is set, EDBs will forego higher levels of return and depreciation (as a percentage of investment value) for assets that have shorter asset lives.

This regulatory treatment provides a disincentive to invest in shorter lived assets which efficiency options tend to involve. This is because depreciation allowances are effectively lower on such short lived assets than the effective diminution in asset value—where depreciation costs should be greater to reflect this fall in value.

Using the efficient lighting example, in a straight-line depreciation scenario, this issue would result in the EDB only able to depreciate $1/45^{th}$ of the asset value each year. If the asset (here a light bulb) only lasted five years, this would mean the depreciation amount would be much lower than the $1/5^{th}$ of asset value that might be appropriate. In addition, when it comes to replacing the asset at year 5, a significant amount of depreciation is still outstanding. Therefore, under a DPP, suppliers will not expect to fully recover their return of capital for energy efficiency investments.

This means depreciation treatment under DPP arrangements act as a strong disincentive against making energy efficiency investments compared to traditional network investments in longer-life assets.

[64] See: http://www.comcom.govt.nz/regulated-industries/input-methodologies-2/additional-input-methodologies-for-electricity-and-gas-dpps/ while a range is provided for different assets in Schedule A the calculations have 45 years as the default.

"Looking through" the regulatory reset process: incentives currently vary over time

As discussed in Section 5.1, the strict reset date creates timing issues in that the capex will achieve a return for a greater or lesser period depending on when in the regulatory period the expenditure is made. Currently the incentive is to invest at the end of the regulatory period such that costs are deferred and close to full asset value is included in the RAB for the subsequent price reset (though this is not necessarily certain as discussed below). This suggests that an incentive regime, such as a rolling incentive scheme applying to both opex and capex,[65] could address this issue with the current DPP/CPP regime. The intention should be for EDBs to recover costs (including a return on capital) before gains are shared with consumers.

We discussed the uncertain treatment of efficiency spending more generally above under the heading "Defining the regulated business". There is also uncertainty in relation to the recovery of costs across regulatory periods. It is currently unclear what investments undertaken by an EDB in a particular regulatory period will be included in their RAB in the next regulatory period or how their AMPs will be used to inform price-paths in future regulatory periods. As efficiency initiatives are less tested than traditional solutions, there is some added uncertainty as to how they would be treated.

In Figure 5.1 above, uncertain treatment of costs across regulatory periods could result in investments that are higher cost within the regulatory period but result in lower costs in future years (or avoid more lumpy investment in future) not being pursued. Even if such investments would be lower cost to EDBs overall (and in the long term interests of consumers), if EDBs are unsure if they can recover their costs they may favour the more certainty investment.

The set regulatory periods create inconsistent incentives on incurring capex and opex over time and the uncertain treatment of efficiency investments means traditional options may be preferred even if they are not lower cost overall.

Structural separation of EDBs from other parts of the supply chain: creates transactions costs and uncertain treatment of revenues

Section 36 of the Energy Companies Act sets the objective of energy companies to operate as successful businesses, having regard to efficient energy use. As operating successfully is the primary objective, EDBs must be financially incentivised to pursue efficiency opportunities.

The illustrative examples explored in Section 4.3 suggested that both ripple control and efficient lighting investments were likely to be of net market benefit. For ripple control, the financial incentives for EDB investment appeared to be present in urban and industrial areas. However, unless EDBs were able to contract for some of the wider benefits, there was not a financial incentive for EDBs to invest in ripple control in rural areas. Likewise, without incorporating wider industry impacts, the incentives for efficient lighting were finely balanced—particularly in rural areas, where usage was low, or where the bulbs were not expected to last as long.

Part 3 of the Electricity Industry Act (EIA) limits EDBs from vertically integrating, such that multiple parties will be involved in the supply of electricity (with differing levels of competition among the stages of supply). With multiple parties involved in the generation, transmission, distribution and retailing of electricity, market/contractual arrangements facilitate the coordination of activities and interests to ensure the delivery

[65] The Commerce Commission is currently considering the use of a rolling incentive scheme for opex.

of electricity services to end-users and payment for these services. Section 52A of the Commerce Act sets the objective for EDB regulation, to promote the long-term benefit of consumers. Given market structures imposed by Part 3 of the Electricity Industry Act, it is important that market/contractual arrangements ensure that opportunities in the long-term interest of consumers are possible. Any constraints on such arrangements would unduly inhibit efficiency initiatives to this end. As discussed below there are also transaction costs to contracting with different parties.

As noted above, were an EDB to contract with a retailer, this component should be treated as unregulated revenue. For transmission, as transmission costs are simply passed through to retailers by EDBs, EDBs do not have a strong direct incentive to reduce transmission costs – as they do not impact EDB revenues. Trying to address this by giving EDBs a role in managing transmission costs may have unintended consequences and some perverse incentives so is not recommended. However, there could be more tailored solutions that are worth considering that are more akin to the Avoided Cost of Transmission (ACOT) framework where distributors are rewarded for decreasing transmission costs.

The regulated structural separation of EDBs from other parties in the supply chain creates transaction costs to the efficient sharing of the benefits from efficiency options. Uncertain treatment of revenue from third parties acts as a further disincentive.

Other regulatory provisions may impose additional costs

Sections 105–108 of EIA potentially constrain efficiency options. These sections set an obligation for distributors to supply electricity lines services, the circumstances under which this obligation may cease/suspend, and conditions for the supply of electricity from alternative sources. Section 107 of the EIA potentially limits the application of alternative supply options (to those broadly agreeable to the various parties involved) and creates additional costs for the use of such alternatives, given the process and timing involved.

Part 6 of Electricity Industry Participation Code ensures that distribution and transmission charges that a distribution network avoids by having distributed generation (DG) connected to its network is paid to the owner. The Electricity Authority is currently reviewing the application of Part 6 in relation to transmission charges – that is ACOT. It is worth noting that ACOT relates to how charges are allocated rather than underlying costs themselves. However, this regime potentially creates additional costs for EDBs and removes potential gains to EDBs and consumers from DG.

Regulatory settings may exacerbate market barriers

Relevant literature suggests the following market barriers may also be applicable in relation to efficiency initiatives:[66]

- **Transaction costs**—the indirect costs relating to efficiency options, including the time, material, and labour involved
- **Financing**—difficulties obtaining borrowing for efficiency options that reduce future costs
- **Unavailability of products/services**—manufacturers, distributors or vendors not making a product or service available

[66] For example, see: http://emp.lbl.gov/sites/all/files/lbnl%20-%2039058.pdf

- **Asymmetric information**—the tendency for sellers of efficient equipment or systems to have more and better information about their offerings than purchasers, which, combined with sellers' differing incentives from purchasers', can lead to sub-optimal purchasing behaviour
- **Information/search costs**—the costs of identifying or learning about efficient equipment or systems, including the value of time spent finding out about or locating this equipment or systems, or of hiring someone else to do so.

There are a number of initiatives to try to address some of these constraints.[67] However, structural separation may exacerbate transaction costs, and regulatory uncertainty may add to financing difficulties (or introduce them relative to traditional investment).

In considering the illustrative examples used in Section 4.3, there may be additional transaction costs—through establishing new contractual arrangements—to EDBs (and consumers) from pursuing peak load reduction via investing in ripple control or efficient lighting. There may well also be additional information/search costs to pursuing newer/more alternative (and potentially less well known/tested) efficiency initiatives compared with traditional capacity investments. These transaction costs would likely exceed those involved in traditional investments in capacity where there are established processes, information is well known and relationships and processes have already been established.[68]

While product availability does not seem to be a major issue for efficient light bulbs given their increasing prevalence, this may be a consideration for ripple control. Although systems are in place for water heating, there would appear to be a trend towards less use of controlled night-store heaters and greater use of heat pumps which do not use ripple control.[69]

This suggests that in practice transaction costs and information/search costs are the most relevant market barriers in the examples explored in this paper. However, for the likes of distributed generation and storage, financing, and product availability may also be issues. Asymmetric information may additionally apply to all options (for example access to smart meter information in the case of load control).

Market settings tend to favour traditional solutions over efficiency options

The working group notes that the following market behaviours/norms can be observed in practice:

- **Status-quo bias:** where traditional solutions need renewal or replacement, there is a tendency to simply replace the existing asset rather than consider alternative approaches. For new investments, there is also likely to be a bias towards solutions that have already been used.
- **Build preference:** Decision-makers on solutions are likely to have an inherent bias towards traditional solutions that involve building assets (rather than say

[67] By the likes of MBIE, EECA, the Electricity Authority, Consumer NZ, and industry participants. See Section 3.

[68] Transaction costs to EDB could possibly be reduced by contracting with a third party for certain load reductions by leaving it to the third party to establish how this was best achieved and contract with the different parties, however it would have to be lower cost for the third party for this to be worthwhile. This cost would also have to be recoverable as if the EDB undertook the activity itself.

[69] Although remotely controlled systems would be possible, heat pumps may be more efficient overall, and EDBs may be able to influence consumer use of heat pumps via pricing structures (subject to retailers passing this through to consumers).

contracting for load reduction)—they tend to be more familiar with these solutions and may be rewarded for growing the entity. It is also quite possible that there is a higher degree of confidence in long-term solution in terms of tested reliability. This may be something where technical standards for including efficiency options in planning (such as demand-side management) may help.

- **Indirect pricing:** The structural separation between EDBs and retailers means there tends to be a mismatch between EDB pricing and the final prices that consumers face which tend to be set by retailers rather than charged directly. This makes it difficult for EDBs to incentivise behaviour with end consumers and may reduce confidence by EDBs in the impact of efficiency options such as behavioural programmes in particular.
- **Dissemination of information**: A lack of knowledge or certainty around more novel efficiency options may prevent their wider consideration or use.[70] For example, EDBs do not have access to information from smart meters unless they contract for it or they own the metering business. Access to such information would allow EDBs to be better informed, particularly in relation to load control options.

Market and regulatory influences are not always in the interests of consumers

Conceptually, we would want to see incentives on EDBs that provide:

- Equivalent incentives among alternative options that deliver the same outcome (so efficiency opportunities are considered equally with traditional network solutions)
- Equal incentive to invest in operating expenditure (opex) or capital expenditure (capex), such that one is not favoured over the other
- Stable incentives over time for opex and capex, and
- Incentives aligned with consumers, such that:

  EDBs are able to share in wider industry benefits (including cost savings) from their opex and capex

  EDBs have certainty that they will be able to recover all expenditure, even if related to non- traditional / convention assets but are in consumers' long-term interest, and

  EDBs pursue least cost options that meet requirements.

Considering the current regulatory and market arrangements discussed above, the following aspects lead to EDB incentives that do not align with the above:

- **Volume based pricing:** The current price-cap regulatory regime, coupled with the low-user fixed charge regulations act as a disincentive to efficiency options that result in lower overall electricity use.
- **Defining the regulated business:** The definition of "electricity lines services" and input methodologies are unclear with regards to how efficiency options will be treated and which, if any, would be regarded as regulated

[70] For example, the concept of induced diffusion is discussed in "Agent based simulation of policy induced diffusion of Smart Meters" by M Rixen and J Wigand or "The patterns of induced diffusion: Evidence from the international diffusion of wind energy" S. Davies, and I. Diaz-Rainey (2011) *Technology and Social Change*, 78(7), 456-470.

activities (either fully or partially) or included in an EDB's RAB (or as regulated revenue). The pragmatic approach would be for expenditure to be treated/allocated based on the purposes for which it is spent, as has been the case for Transpower's demand response project. However, a clarification that this is an appropriate interpretation would remove uncertainty.[71]

- **Depreciation on assets with shorter lives**: The 45 year default asset life for depreciation discourages investment in shorter life assets where a greater portion of costs should be able to be expensed and recovered at an early stage.
- **"Looking through" the regulatory rest process:**

  The application of a DPP/CPP to a particular regulatory period (and periodic resets) also creates inconsistent incentives for investment in capex relative to opex over the regulatory period. This is something the Commission is aware of and is already looking to address. For example, we understand the Commission is currently exploring the possibility of a rolling incentive scheme.

  There is potential for a greater or lesser incentive on capex relative to opex but so long as the regulated WACC is a fair estimate of the *actual* WACC faced by EDBs this should not be the case. If this is not the case, either the regulated WACC should be adjusted or other incentives introduced to balance any difference observed in practice.
- **Structural separation of EDBs from other parts of the supply chain:** The regulated structural separation of EDBs from other parties in the supply chain creates transaction costs to the efficient sharing of the benefits from efficiency options. A mechanism for EDBs to share in ACOT could be worth consideration. Other sources of transactions costs come from Part 6 of the Electricity Participation Code relating to ACOT and sections 105-108 of the Electricity Industry Act, concerning electricity lines service obligations and conditions for alternative supply.
- **Dissemination of information/market factors:** Market factors also contribute to a likely bias against efficiency options in that they may be less tested or reliable, simply a new approach or EDBs may not have access to all the information to inform decisions or be able to influence end users directly. There may well also be additional costs to pursuing efficiency options (at least initially) that tend to result in traditional options being favoured.

Recommendations attempting to align incentives with the aims above are discussed in Section 6. In practice, explicit incentives to invest in efficiency options may be an appropriate further step in the short-term. This may help catalyse the market for efficiency solutions (which would ensure product availability and reduce information/search costs) and address any behavioural biases that may exist towards known traditional solutions (or processes that favour these). For example, the United Kingdom's Low Carbon Networks fund allowed some distribution companies to run trials to gain experience with new technology, commercial, and network operating arrangements.

[71] As some parties have interpreted the definitions to mean that efficiency investments with equipment beyond the electricity meter are excluded (even if more cost-effective than traditional network solutions) which would be a disincentive to efficiency options.

6 Conclusion and Recommendations

This report investigated the nature of electricity demand and the drivers of investment in capacity to meet peak demand. We considered the potential for supply and demand-side efficiency ("efficiency") and the potential role for EDBs. By exploring the costs of illustrative efficiency initiatives, we found that from a consumer perspective such initiatives would be of net benefit across the electricity industry if they were able to defer traditional investment.

Having observed that efficiency initiatives would be in the long term interest of consumers, we then explored the how the current regulatory and market settings influence EDB decisions on efficiency initiatives. We found the incentives applying to efficiency opportunities are not equivalent to those for traditional network solutions, incentives vary over time, and the uncertainty whether efficiency initiatives are considered regulated activities creates a divergence in EDBs' incentives from those of consumers, while there are additional transactions costs to efficiency options.

These present potential constraints to EDBs investing in efficiency initiatives to the extent that would be in the long term interest of consumers. Below, we highlight the areas that need to be addressed, the aim for any solutions and recommended actions to help align incentives with those in the interests of consumers. Additional short-term incentives that go further than these recommendations may also be worth considering to help catalyse the market for efficiency initiatives and counter likely behavioural/historical biases towards traditional solutions.

Recommended changes to align EDB incentives with the long-term interests of consumers

Table 6.1 summarises the areas that the working group recommends be addressed through changes to the regulatory regime. Table 6.1 outlines the:

- Issues the working group has identified need to be addressed
- Aim for any changes (such as to improve clarity and certainty around the application of regulatory provisions, or address incentives that are inconsistent with the long-term interests of consumers), and
- Specific recommendations to meet these aims and address the underlying issues raised. The recommendations are divided into short-term and long-term recommendations, with short-term recommendations defined by what could be achieved in the next reset of the DPP scheduled for later this year.

All of these recommendations are made with Section 54Q of the Commerce Act in mind. While ENA is working to find ways for EDBs to improve supply and demand-side efficiency, the Commission is also required by the Act to promote incentives and avoid imposing disincentives for energy efficiency related investment when setting the price paths (including, if necessary, by amending input methodologies), in order to provide a framework that better incentivises such improvements. This should be seen as an important and necessary aspect of any Part 4 related workstream. However, the group acknowledges that even though a particular approach would have good outcomes for energy efficiency, it may not, overall, be in the long-term interest of consumers. The recommendations presented in Table 6.1 should therefore be read as changes that the group considers would better promote supply and demand-side efficiency, and should be pursued unless they have impacts in other areas that offset their benefits.

In addition to the recommendations in Table 6.1, the working group recommends that the Commission explicitly states how it gives effect to Section 54Q of the Commerce Act in all its Part 4 decisions relating to electricity lines services.

Finally, as noted in Section 5, the design and implementation of regulation is not the only impediment to efficiency investments. It is also important that the electricity supply industry continues to develop its understanding of efficiency options and address market biases against such options.

Table 6.1: Working Group Recommendations to EDBs, Government Officials and the Commerce Commission

Issue	Aim of Solution	Short-term Options/ Recommendations	Long-term Options/ Recommendations
Volume based pricing: ▪ Variable charges tend to be based on kWh used. This creates a problem when efficiency options reduce volumes by also reducing EDB revenues ▪ Low User Fixed Charges discourage efficiency options for a similar reason by making a greater proportion of EDB revenue depend on consumption	EDBs should be no worse off financially by pursuing efficiency options that are in the long term interest of consumers	▪ The Commission should incorporate mechanisms into the DPP to lessen the financial impacts of efficiency investments that reduce consumption. This can be achieved by "decoupling" EDB revenues from total electricity consumption. For example, the Commission could investigate a type of "D-Factor" (used in Australia) to compensate EDBs for any revenue foregone from efficiency initiatives ▪ MBIE should consider increasing the Low User Fixed Charge to better reflect impacts on EDB efficiency (particularly given that the fixed amount has never been adjusted for inflation)	▪ The Commission should consider the respective merits, relative to 54Q and 52A, of a revenue cap and a weighted average price cap. Regulating the total revenues earned by EDBs would make the businesses indifferent to the level of consumption of electricity (whether expressed as kWh or kW) ▪ MBIE should consider repealing Low User Fixed Charge regulations or replacing them with alternative measures that do not have unintended disincentives on EDBs undertaking efficiency options ▪ EDBs should consider adjusting their pricing to be in-keeping with underlying costs where possible or where enabled by other changes (such as charging for capacity or demand)
Defining the regulated business: ▪ Whether efficiency options are considered an "electricity lines service" and included in the RAB ▪ Treatment of external revenue earned from efficiency options	▪ The boundaries of the regulated business should be unambiguous ▪ The rationale for Part 4 regulation should be achieved (for example, by ensuring that EDBs unregulated revenues preserve benefits to consumers)	▪ The Commission should clarify that where efficiency options are least cost way of delivering lines services, the costs can be incorporated into RABs/price paths (rather than alternative means of delivering these services) ▪ The Commission should clarify that where efficiency options are higher cost but provide benefits to other electricity suppliers, EDBs can recover the lower costs of alternative options through regulated prices and contract with third parties to earn additional unregulated revenue (in practice either using sub-asset classes or costs above the lower cost options)	▪ EDBs should consider efficiency options when preparing Asset Management Plans (AMPs)

Issue	Aim of Solution	Short-term Options/ Recommendations	Long-term Options/ Recommendations
Providing depreciation on assets with shorter lives: ▪ Assumption of average 45 year life provides incentives for investment in longer-term assets (over short-term ones)	EDBs should be no worse off financially by investing in shorter-term assets that would be in the long term interest of consumers	▪ The Commission should develop ways to make EDBs indifferent to the expected life of efficiency investments such as by using separate asset life assumptions for investments that meet certain conditions (such as not being investments in capacity expansions)	
"Looking through" the regulatory reset process: ▪ Unequal treatment of opex/capex ▪ Uncertain recovery/treatment across regulatory periods ▪ Uncertain treatment of efficiency spending	The costs of providing electricity lines services should be treated equally (whether opex or capex), with incentives that are consistent over time	▪ The Commission should ensure consistent treatment of opex and capex under DPP/CPP over time, for example by using a rolling incentive scheme for opex and capex (note: the Commission is already consulting on required changes to the input methodologies) ▪ The Commission should improve transparency on what happens at the reset – including how AMPs will be used and how efficiency options will be treated	
Structural separation of EDBs from other parts of the supply chain: ▪ Creates transaction costs to contracting for wider benefits ▪ Means EDB pricing signals are not necessarily passed on to consumers	EDBs should have incentives to pursue options that are in consumers' long term interests, regardless of where in the supply chain those benefits accrue	▪ EDBs should continue to engage with Transpower and other emergent providers on the application of demand response platforms	▪ Industry should consider whether there are pricing structure standards that would be in the interest of consumers (including through engagement with the EA) ▪ MBIE/EA should consider whether funding is available to support cross-industry initiatives that decrease transactions costs
Dissemination of information: ▪ EDBs may not have all the information needed to assess the full benefits or costs of (novel) efficiency options	Information should be available to improve industry understanding of efficiency options that are in consumers' long term interests	▪ EDBs consider developing technical standards for including efficiency options in planning (such as demand side management), and to assess any training needs with the industry. There may also be a role for MBIE/EECA funding to help catalyse industry-led efficiency solutions and knowledge diffusion ▪ EDBs should continue to engage with the industry to understand the potential of new technologies	▪ The Commission could consider setting specific rules (e.g. cost and/or revenue recovery) around the treatment of particular efficiency investments to better understand their value

Appendix A: Actions Considered by the Working Group but Not Recommended

Table A.1 summarises the actions the working group discussed when working through the different issues that may be leading to efficiency options in the interests of consumers not being pursued. While these initiatives may encourage efficiency solutions, they are not recommended as they tend to be insufficiently targeted, do not address the underlying issues, and may results in options not in the interests of consumers being pursued (such as higher cost efficiency options where there may not be the same wider industry benefits).

Table A.1: Actions Considered by the Working Group but Not Recommended

Option	Assessment
Targets	
Introduce targets for a percent of expenditure to go to efficiency options	Not recommended as blunt tool that is not consistent with aim to keep costs low as the spending may not necessarily be focused on the areas in the long term interest of consumers.
Introduce targets for efficiency options that are tradable units so an EDB that does not implement efficiency options can buy units off other EDBs for which efficiency options are more worthwhile	As above. Also imposes costs on those for whom efficiency options may simply not make sense.
Introduce targets for efficiency options such as the amounts of load control/demand reduction to be achieved (relative to capacity or peak demand)	Not recommended. Need to know levels to target which will depend on circumstances. Better to address underlying incentives. May not be consistent with aim to keep costs low and pending may not necessarily be focused on the areas in the long term interest of consumers.
Disclosure	
Increase disclosure on efficiency options	Disclosure in itself will not change underlying incentives or decision-making. Working group instead recommend Commission clarify that efficiency options should be considered and to address underlying incentives.
Financial Incentives	
Rather than transmission (RCPD) charges being passed through to consumers, EDBs set prices based on expected charges and retain some of the savings in transmission costs efficiency options	EDBs not best placed to manage risks associated with transmission costs. In this case, EDBs would also lose out if costs were higher than anticipated despite being out of the EDBs' control.
Introduce a CPP-lite application scheme to allow for costs associated with efficiency options when delivered results identified	A second-best option to addressing the underlying incentives for investing in efficiency options. It would involve transactions costs (which in some cases may not be there) and there would still be a degree of regulatory uncertainty.

Appendix B: International Experience with Efficiency Options

This Appendix summarises some of the relevant international experience with distributor-led efficiency programmes. This section follows the relevant groupings from Table 2.1.

Efficient/Controllable Equipment and Systems

The KEMA 2012 report "Review of Energy Efficiency Investments" (prepared for Vector) describes a number of load reduction programmes in the United States of America that are distributor-lead:

- The New York Commercial and Industrial Rebate Programme[72] provides prescriptive or custom rebates to non-residential customers for installing energy efficient equipment
- The NSTAR—Small Commercial Direct Install Programme[73] provides free energy audits and incentives for energy efficient measures for companies with average monthly demand of up to 300kW
- The Connecticut Light and Power programme[74] provides rebates for energy efficiency as well as free energy assessments. In addition to this, there are incentives or mark-downs for certain energy efficient products. As well as HVAC and heat pump rebates there are incentives for solar and the use of programmable private street lighting (which are turned off at mid-night), and
- The Con Edison Energy Efficiency Programme[75] provides rebates on energy efficient equipment, as well as an appliance bounty program (for taking in old additional fridges), subsidised surveys and custom programmes.

On-site/Distributed Generation and/or Storage

Western Power Distribution's (WPD) BRISTOL project[76] is an example of a distributor-led DG programme in the United Kingdom aimed to trial ways to efficiently facilitate the connection of low carbon distributed generation. The trials included the integration of photovoltaics, battery storage, demand response, direct current circuits, and variable tariffs; with trials taking place in residential, school, and commercial settings. This allowed WPD to gain experience with new technologies to provide power system stability, as opposed to traditional network reinforcement techniques. The expected benefit was a decrease in network reinforcement costs for integrating a high penetration of distributed generation.

[72] See: http://www.epa.gov/chp/policies/incentives/necustommeasurescommercialandindustrialrebateprogram.html

[73] See: http://www.nstar.com/business/energy_efficiency/electric_programs/direct_install_program.asp

[74] See: http://www.cl-p.com/business/saveenergy/businessrebates.aspx

[75] See: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NY95F and www.coned.com/energy-efficiency

[76] See: http://westernpowerinnovation.co.uk/So-La-Bristol.aspx

Behavioural Programmes

The KEMA 2012 report "Review of Energy Efficiency Investments" also notes the following behavioural programmes internationally which are distributor-led:

- The Blacktown Solar City Trial Programme[77] in New South Wales, Australia tested customer responses to critical peak pricing tariffs. It involved solar, smart meter and energy efficiency initiatives (such as In-Home Displays (IHDs)) to encourage demand reduction. The distributor used CPP to reduce peak demand and defer network investment.
- The Hydro One—Real Time Monitoring Project[78] in Canada provided a free monitor with information on real-time usage programmed in along with the rate structure such that participants could see current usage and cost, and spend to date.

These examples and other international experience with different behavioural programmes suggest:[79]

- CPP delivers the greatest demand response followed by PTR, RTP and TOU, with people responding to price differentials rather price levels.
- Technology enabling demand response (such as IHDs) increases response rates and automated response technology significantly improves peak clipping response.
- Motivated participants (for example those that opt-in rather than general use on all customers) respond more significantly to tiered pricing signals.
- Longer pilots had greater results (especially for CPP) as habits form and investments are made (e.g. replacing electrical appliances).

In addition to the above examples, KEMA (2012) notes a number of programmes in the United States of America and Canada where EDBs contract for certain peak reductions directly:

- The Con Edison DSM Programme[80] in New York seeks RFPs for a MW/period of permanent reductions by area/time.
- The SaveON Energy Demand Response Programme[81] in Canada involves businesses enrolling for monthly payments to reduce electricity during peak times. There are both voluntary and contractual schemes involving separate availability and utilization payments.

[77] See: http://www.climatechange.gov.au/reducing-carbon/solar-cities/seven-solar-cities/blacktown-solar-city-new-south-wales

[78] See: http://www.bluelineinnovations.com/documents/reportsummaryhydroone0320.pdf

[79] Drawing on the Electronic Power Research' institute's "Understanding Electric Utility Customers – Summary Report", subtitled "What We Know and What We Need To Know", October 2012 and the European VaasaETT Think Tank's "The potential of smart meter enabled programs to increase energy and systems efficiency: a mass pilots comparison", 2011.

[80] See: http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_espwg/meeting_materials/-2008-04-25/Con_Edison_500_MW_DSM_TO_Update_042508.pdf and www.coned.com/energyefficiency/-targetedDSM.asp

[81] See: https://saveonenergy.ca/Business/Program-Overviews/Demand-Response.aspx

- The Take a Load Off Programme[82] in Texas involves payments for verified load reductions for parties that are able to shed at least 700kW in an hour's notice. Given this threshold, load aggregators are also present in the market.

As noted in Section 3.2, a level of confidence is needed that demand will be reduced during peak periods. The examples above involve contracting for specific peak reduction amounts, with participation thresholds and verification of reductions in one case. As a result, these programmes are also likely to be more focused on commercial and industrial users. However, in the "Take a Load Off" programme in Texas, aggregators help solve any contracting issues by ensuring certain levels of demand response and dealing with smaller customers directly.

[82] See: http://www.takealoadofftexas.com/

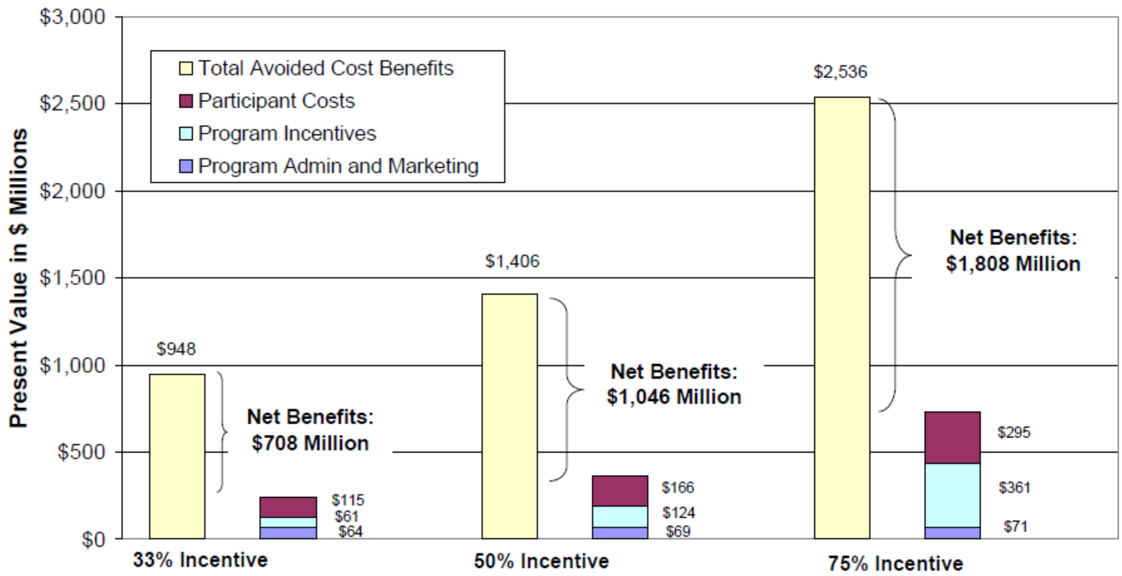
Appendix C: Application of Net Market Benefits Test and Potential Complexities

This Appendix summarises the results of previous applications of a net market benefits (NMB) test to the options identified in Section 3.2 and notes potential complexities when applying a NMB test.

Efficient/controllable equipment and system options where EDBs have a potential role have been shown to meet the NMB test

Applying a NMB test to the options identified in Section 3.2, shows that the programmes identified would also be of long-term benefit to consumers, as shown in Figure C.1. Here, the Net Market Benefits increase with the level of incentive offered/investment by the party other than the user. These initiatives were also identified as resulting in peak demand savings,[83] an area where EDBs were shown to have a role in Section 3. This suggests there are supply and demand-side efficiency options where EDBs have a potential role that are of long-term benefit to consumers but which EDBs are not involved in.

Figure C.1: Net Market Benefits of Energy Efficiency Savings (2007-2016)



[Source: KEMA 2007 report for the Electricity Commission "New Zealand Electric Energy-Efficiency Potential"

The figures presented in Figure C.1 are based on:

- Savings to end-consumers calculated using forecast electricity prices applied to forecast savings for each sector, and comparing these savings with costs to consumers from such initiatives
- Avoided generation costs calculated at the time based on wind farm generation costs ($0.07 per kWh) and avoided generation capacity costs developed based on the cost for a peaking gas turbine (levelled over the period to $94.4 per kW)

[83] Net peak demand savings between 2007 and 2016 of 183 MW under the 33 percent incentive/investment, 271 MW under the 50 percent incentive/investment and 470 MW under the 75 percent scenario

- Avoided transmission capacity costs calculated using grid upgrade information at the time (also levelled over the period to $23.2 per kW), and
- Electricity benefits valued using the three types of avoided electricity costs: avoided distribution costs, avoided transmission costs, and avoided electricity generation costs, where both energy savings and peak demand savings are considered. It is expected that with competition and regulation these benefits would be passed on to consumers.

There are potential complexities in applying a NMB test

A NMB test allows one to assess whether an opportunity is in the long run interest of consumers. The test is able to overcome issues such as externalities and barriers to investment. However, were the test to be adopted as standard practice there are a two potential difficulties flagged below that would need to be allowed for in more complex applications of a NMB test when considering an option in comparison to the status quo:

- **Scenarios and option value**: accounting for uncertainty in how options will impact the load profile in practice might involve assessing a number of different scenarios. Equally, the option value of waiting until further information is known on aspects such as response rates to initiatives and future maintenance or replacement costs of DG or storage may also need to be incorporated.
- **Discount rate**: if an option is assessed from an industry-wide perspective and relates to a different type of investment than traditional network investments, should a social discount rate be used (for example that applied to capital projects in the public sector) or a weighted average cost of capital (WACC). If it is a WACC, should the EDB WACC be adjusted to reflect different nature of the investment as compared with an EDBs traditional core business.

Appendix D: Relevant Regulatory Settings

The regulatory provisions directly relevant to this work are described in Table D.1. Section 52A of the Commerce Act sets out the overarching regulatory objectives for EDBs in the provision of lines services (as defined in the table) but there is considerable overlap among the legal provisions in terms of encouraging efficiency.[84]

Table D.1: Legal Framework for Electricity Distribution Services

Legislation	What it says	Why it is relevant
Section 52A: Purpose of Part 4 of the Commerce Act 1986	"The purpose of this Part is to promote the long-term benefit of consumers in markets referred to in section 52 by promoting outcomes that are consistent with outcomes produced in competitive markets such that suppliers of regulated goods or services— (a) have incentives to innovate and to invest, including in replacement, upgraded, and new assets; and (b) have incentives to improve efficiency and provide services at a quality that reflects consumer demands; and (c) share with consumers the benefits of efficiency gains in the supply of the regulated goods or services, including through lower prices; and (d) are limited in their ability to extract excessive profits."	Sets the objective for EDB regulation to promote the long term benefit of consumers with incentives to innovate, be efficient, share efficiency gains and limit profits
Section 53 of the Commerce Act 1986	"53M Content and timing of price-quality paths (1) Every price-quality path (whether a default price-quality path or a customised price-quality path…) must specify,— (a) … either or both of the following with respect to a specified regulatory period: (i) the maximum price or prices that may be charged by a regulated supplier: (ii) the maximum revenues that may be recovered by a regulated supplier; and (b) the quality standards that must be met by the regulated supplier; and (c) the regulatory period. … "53P Resetting starting prices, rates of change, and quality standards …(3) The starting prices must be either— (a) the prices that applied at the end of the preceding regulatory period; or (b) prices, determined by the Commission, that are based on the current and projected profitability of each supplier. (4) Starting prices set in accordance with subsection (3)(b)	Establishes price-quality paths as the method of regulating EDBs and conditions under which the Commission must set price-quality paths

[84] See Sections 52A and 54Q of the Commerce Act 1986, Section 36 of the Energy Companies Act 1992 and Part 6 of Electricity Industry Participation Code 2010.

Legislation	What it says	Why it is relevant
	must not seek to recover any excessive profits made during any earlier period. (5) Subject to subsection (8), the Commission must set only 1 rate of change per type of regulated goods or services… (8) The Commission may set alternative rates of change for a particular supplier…”	
Section 54C of the Commerce Act 1986	“electricity lines services means the conveyance of electricity by line in New Zealand” (subject to exclusions)	Defines the services the regulation relates to as conveyance of electricity by line
Section 2 of the Electricity Act 1992	“**lines** means works that are used or intended to be used for the conveyance of electricity… **works**—…(a) means any fittings that are used, or designed or intended for use, in or in connection with the generation, conversion, transformation, or conveyance of electricity; but…(b) does not include any part of an electrical installation.”	Defines lines and works as they relate to lines services
Section 54Q of the Commerce Act 1986	“The Commission must promote incentives, and must avoid imposing disincentives, for suppliers of electricity lines services to invest in energy efficiency and demand side management, and to reduce energy losses, when applying this part in relation to electricity lines services”	Provides specific reference on how the Commission should treat incentives for energy efficiency
Section 36 of the Energy Companies Act 1992	“(1) The principal objective of an energy company shall be to operate as a successful business. (2) In seeking to attain its principal objective, an energy company shall have regard, among other things, to the desirability of ensuring the efficient use of energy.”	Sets the objective of energy companies to operate as successful businesses, having regard to efficient energy use
Part 3 of the Electricity Industry Act 2010	“The purpose of this Part is to promote competition in the electricity industry— (a) by prohibiting a person who is involved in a distributor from being involved in a generator where that may create incentives and opportunities to inhibit competition in the electricity industry; and (b) by restricting relationships between a distributor and a generator or a retailer, where those relationships may not otherwise be at arm's length.	Limits integration of retailer or generator and distributor
Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004	Require EDBs to offer a residential tariff that: (a) has a daily fixed charge no greater than 15c (excluding GST) [per day]; and (b) the sum of the fixed and variable charges is no greater than an average consumer would pay on any other residential tariff by the same supplier.	Restricts the charging structures that EDBs may apply to residential lines charges
Part 6 of Electricity	“Charges to be based on recovery of reasonable costs incurred by distributor to connect the distributed generator	Ensures distribution and transmission

Legislation	What it says	Why it is relevant
Industry Participation Code 2010 – Schedule 6.4	and to comply with connection and operation standards within the network, and must include consideration of any identifiable avoided or avoidable costs”	charges that a distribution network avoids by having distributed generation connected to its network is paid to the owner
EDB input methodologies Part 3, Subpart 1, clause 3.1.1	The maximum price or prices that may be charged by an EDB will be specified in a s 52P determination as a weighted average price cap applying to that EDB for a regulatory period, defined in terms of a relationship between allowable notional revenue and notional revenue	Sets the price cap for EDBs as a weighted average price cap.
Section 105-108 of the Electricity Industry Act 2010	Section 105: “…(2) A distributor to whom this section applies must, in relation to the place referred to in subsection (1), either— (a) supply line function services to the place so that the place is within the distributor's network; or (b) supply the place with electricity from an alternative source. (3) The obligation in subsection (2) is subject to [potential legislative, regulatory or contractual exceptions]…” Section 107: “(1) A distributor … who proposes … supplying a place with electricity from an alternative source, must give at least 6 months' notice of the proposal to…[affected consumers, landowners, retailers, and the public outlining the proposal, how consumer needs will be met and giving them time to comment]” Section 108: “(4) …the Commerce Commission must treat the costs of providing electricity to a place from an alternative source…as…cost of providing electricity lines services…”	Sets an obligation for distributors to supply lines function services, circumstances under which this may cease/suspend and conditions to supply electricity from alternative sources

Source: Legislative Acts as referenced

Appendix E: Legal Interpretation of Section 54Q of the Commerce Act 1986

TO: Alan Jenkins, Electricity Networks Association

FROM: Russell McVeagh

DATE: 8 November 2013

SUBJECT: Section 54Q - Statutory Interpretation

Introduction and summary

1. We understand that the Electricity Networks Association ("**ENA**") is currently considering options for Electricity Distribution Businesses ("**EDBs**") to improve supply and demand-side efficiency. You have asked us to advise on the status of section 54Q of the Commerce Act 1986 ("**Act**") and the associated obligations on the Commerce Commission ("**Commission**").

2. In summary:

   (a) section 54Q places a mandatory obligation on the Commission to promote incentives *and* avoid imposing disincentives for EDBs to invest in energy efficiency and demand-side management;

   (b) section 54Q was introduced in order to require the Commission to address an inherent feature of price paths - they incentivise firms to encourage consumption; and

   (c) in our view, the section 54Q obligation applies whenever the Commission makes decisions under Part 4 relevant to EDBs (albeit not every decision is capable of promoting energy efficiency).

3. While ENA is working to find ways for EDBs to improve supply and demand-side efficiency, the Commission is also required by the Act to take action when setting the price paths (including, if necessary, by amending input methodologies ("IMs"), in order to provide a framework that better incentivises such improvements. This should be seen as an important and necessary aspect of any work-stream.

Regulatory framework

4. Section 54Q provides that:

   > The Commission must promote incentives, and must avoid imposing disincentives, for suppliers of electricity lines services to invest in energy efficiency and demand side management, and to reduce energy losses, when applying this Part in relation to electricity lines services.

5. Section 54Q was introduced as part of the Part 4 reform package. It was intended to address an inherent effect of price cap regulation, where price / revenue paths disincentivise investment by EDBs in energy efficiency and

demand-side management. This is because, while EDBs are predominantly fixed cost businesses, the bulk of their revenues are received through volumetric charges.

6. This effect and the reason for introducing section 54Q was explained by the Ministers of Commerce and Energy at the time of the reforms as follows:[85]

> **The way price/revenue paths are set has an important influence on incentives for electricity lines businesses to invest in energy efficiency and demand side management.** Arguably, the way thresholds are currently set (based on price irrespective of volume) **incentivises firms to encourage consumption** (or at least not discourage consumption) because this improves their rates of return.
>
> **In order to avoid this effect, we recommend that the Commission be required to provide for incentives to improve energy efficiency/demand-side management and to reduce energy losses when administering the regime for electricity lines businesses.**
>
> [Emphasis added]

Interpretation

7. The meaning of an enactment is taken from its text and in light of its purpose.[86]

8. On the plain words of the section:

(a) Section 54Q is unequivocally a mandatory requirement. The word "must" imposes the strongest possible obligation upon the Commission. Different wording would have been used if Parliament intended that the Commission should use its best endeavours or exercise discretion as to whether and when it promoted energy efficiency (such as "take into account" or "have regard to").

(b) The Commission, when applying Part 4, must promote incentives *and* avoid imposing disincentives for suppliers to invest in energy efficiency and demand-side management.

(c) The Commission is required to promote incentives and avoid imposing disincentives "when applying this Part". In our view, this requires the Commission to promote energy efficiency and avoid imposing disincentives in relation to every Part 4 decision which potentially influences such incentives (which would include any decision relating to price-quality paths). In particular:

(i) The words "when applying this Part" mean the mandatory obligation is triggered whenever the Commission is applying Part 4.

(ii) With every Part 4 decision the Commission makes (whether that be in setting input methodologies ("**IMs**"), default price-quality paths ("**DPPs**"), customised price-quality paths ("**CPPs**"), or information disclosure ("**ID**") obligations), it is "applying Part 4". As such, when making each of those

[85] Cabinet Paper "Review of Parts 4 and 4A of the Commerce Act, October 2007, at paras 75 and 76.

[86] Interpretation Act 1999, section 5(1).

individual decisions the Commission must promote incentives and avoid disincentives for EDBs to invest in energy efficiency.

(iii) The Commission is required to both promote incentives *and* avoid disincentives for EDBs to invest in energy efficiency. It is not sufficient for the Commission only avoid disincentives for EDBs to invest in energy efficiency.

(iv) The intent of section 54Q supports this interpretation. Section 54Q, as outlined above, was included in Part 4 to actively counteract the effect price cap regulation has on energy efficiency incentives if left to run its normal course. For section 54Q to fulfil its purpose and be workable, it must require that the Commission promote energy efficiency whenever it applies Part 4, particular when making decisions on price-quality paths.[87]

(v) An alternative interpretation of the words "when applying Part 4" is that the Commission must, when considering all its decisions across Part 4, have promoted incentives and avoided imposing disincentives to invest in energy efficiency. However, we consider this interpretation should not be preferred as it is least consistent with the plain words, the mandatory nature of the obligation, and the underlying intent of the section. That is, the Commission could make decisions that do not promote energy efficiency when applying Part 4, as long as the Commission ultimately makes one decision across the whole Part 4 scheme that promotes energy efficiency.

(vi) Even if the interpretation in (v) is correct (which we do not agree), the Commission is required to promote incentives and avoid imposing disincentives in at least one or more of its key determinations. That is, section 54Q does not allow the Commission to defer substantive compliance to subsequent regulatory periods and decisions. To do so would be inconsistent with the plain words of the section and would render the mandatory wording in section 54Q redundant (there would never be a clear point where the obligation was breached).

9. Given the above, in order to comply with section 54Q, it is imperative in our view that the Commission take action to actively promote incentives to invest in energy efficiency when setting the next DPP and, if necessary, amend the IMs to enable it to do so. On this basis, the ENA working group may wish to consider what changes the Commission could make to the regulatory framework in order to improve incentives to invest in energy efficiency and demand-side management.

---

[87] The promotion of energy efficiency is also in line with the purpose of Part 4: to promote the long-term benefit of consumers by, among other things, promoting suppliers' incentives to innovate and invest. See Commerce Act, section 52A.