NERA
ECONOMIC CONSULTING

Economic Concepts for Pricing Electricity Network Services

A Report for the Australian Energy Market Commission

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Executive Summary

The scope for electricity network prices to promote more efficient use of and investment in electricity network infrastructure is receiving renewed focus as the causes for current high electricity prices are being investigated.

Despite decreasing electricity consumption, significant increases in network costs can be attributed to a wave of network investment over the last ten years that was a response to rapid growth in maximum network demand and the desire to maintain electricity network reliability. Much of this need for network investment was due to the rapid uptake of air conditioners. Questions are now being raised as to whether such network investment would have been needed if well targeted price signals as to the cost of the network infrastructure needed to support the growth in maximum network demand had been provided to electricity users.

While little can be done through pricing to alleviate the need for current consumers to pay for the network infrastructure that has already been built, developing network tariffs to promote efficiency will avoid similar circumstances arising again in the future. It will ensure that any future changes to network maximum demands, which drive future network expenditure, are the result of users making decisions with knowledge of the costs that they impose on the network by their usage decisions.

The need to develop network tariffs to promote efficiency arises from:

- the potential for new emerging technologies (eg, solar PV, electricity vehicles etc) to impose or avoid network costs, and the desirability that consumer investment in such technologies is efficient; and
- the challenge faced by network businesses to manage revenue volatility given the dominance of electricity consumption based charges, which are largely unrelated to the underlying drivers of network cost.

It is within this context that the Australian Energy Market Commission commissioned NERA Economic Consulting to:

- set out the economic rationale for and concepts underpinning the distribution network pricing principles set out in the rules, to ensure that it leads to the implementation of tariffs that promote more efficient outcomes;
- discuss practical approaches that can be used to estimate the long-run marginal cost (LRMC) of network services as a measure of the costs electricity users impose on network, which forms the basis for network tariffs; and
- consider the implications for customers of moving towards tariff structures that promote more efficient outcomes, through the development of illustrative case studies.

Our analysis highlights the importance of electricity network tariffs being set to encourage use of existing infrastructure while signalling to users the cost of an additional of contribution to the network system peak demand.

Our discussions with electricity network businesses over the course of this project has highlighted the extent of actual and perceived constraints to the implementation of more efficient electricity network tariff structures. These have included the lack of advanced metering technology for many customers and jurisdictional policy constraints limiting the extent of discretion on the choice of tariff structure.

In addition, it is also apparent that network businesses have not been systematically assessing through the calculation of the long run marginal cost, the value (ie, avoided network costs) that might result from either improving price signals in a targeted manner within its network, or more proactively undertaking demand management activities. We believe that there is scope for network businesses to more clearly identify within their network the value that could arise from improving price signals to consumers.

To this end, we believe there is merit in network businesses conducting assessments of the long run marginal cost by applying a perturbation approach – which more directly assesses the costs that are caused or could be avoided by small changes in peak demand. That said, there remains merit in undertaking broader assessments (ie, for the network as a whole) of the long run marginal cost via application of the average incremental cost approach to estimating long run marginal cost. This will provide helpful information on the possible opportunities for providing more targeted price signals, or undertaken other demand management activities.

We believe that over time, to promote more efficient network investment, there is a need to transition to network tariffs that signal the cost of changes in system maximum demand to consumers. The two principal tariff structures that are currently available to do this are:

- peak capacity tariffs – which seek to charge consumers on the basis of the contribution of its demand to system peak demand; and
- critical peak tariffs – which charge consumers based on electricity consumed during peak events, which are called by the network business.

Time-of-use tariffs charge different rates for consumption during peak periods of the day and off-peak periods. The difference in these rates provides some improved signals to consumers about the cost of consumption during peak times, but they are less targeted as compared to peak capacity and critical peak tariffs.

Many of the current flat usage tariffs (ie, a common consumption tariff irrespective of when the consumption takes place) or inclining or declining block tariffs have rates that exceed those implied by current estimates of the LRMC. This would mean that aligning the usage charge exactly to estimates of the network tariff would likely lower the charge, which might lead to an associated increase in consumption. It follows that lowering these tariffs could lead to increases in consumption during the system maximum peak.

Changing tariff levels for those customers that currently pay flat usage, inclining or declining block tariffs will therefore have relatively little impact on promoting efficient use of and investment in electricity networks because of the poor price signals from these tariffs.

To promote efficiency, network businesses should work towards implementing more cost reflective tariff structures over time, for example capacity based tariffs. This has the potential to result in considerable benefits for consumers over the medium to longer term.

While aligning tariffs to estimates of the LRMC will promote more efficient outcomes, it will most likely lead to a network business not earning sufficient revenue to cover the cost of its current infrastructure. In principle any additional revenue that needs to be recovered should be recovered through tariffs that minimise distortions in the use of existing network infrastructure. In practice this means:

- charging a fixed supply charge (ie, $/ day) to customers, irrespective or use of network infrastructure; or
- marking up consumption or capacity based charges to those customers or parameters that are likely to be less responsive to changes in price; or
- a combination of both.

Given the potential implications for consumer bill outcomes, some consideration should also be given to customer impacts when adjusting the proportion between fixed and usage charges.

Finally our case studies illustrate that consumer bill impacts of transitioning to tariffs that provide improved price signals will be greatly influenced by the relationship between an individual consumer's consumption and contribution to system peak demand. For those consumers with relatively high consumption but a relatively small contribution to system peak demand, bills will likely lower. However, for those consumers with low consumption but a relatively high contribution to system peak demand (eg, holiday houses that are mostly used during summer peak periods), then bills will likely be higher.

1. Introduction

Electricity network businesses are facing unprecedented challenges as flat or falling electricity consumption leads to declining revenues without associated decreases in network expenditure.

There are two possible network business responses to declining revenues either:

- electricity usage and/or fixed supply tariffs will need to rise to allow network businesses to recover the relatively fixed costs of existing infrastructure used to supply network services; or
- there is a need to introduce more innovative network tariff structures, that more closely align tariffs with the underlying cost of providing network services – so called cost reflective network tariffs.

There are compelling reasons to link more closely network tariffs with the underlying drivers of network costs. First, it promotes efficient use of electricity networks by ensuring that only those users that most value the network during high cost times use the network, while encouraging use of the network during low cost periods. Second it promotes efficient investment in electricity networks and technologies that use or produce electricity, as usage is linked to the preparedness of users to pay the true cost of providing services when required. Finally, it is a fairer charging system as electricity users directly contribute to the costs that they impose on the network as a consequence of their electricity use.

The National Electricity Rules (NER) set out the principles to be taken into account by network businesses when developing network tariff strategies. These principles have been designed to provide incentives for network businesses to set tariffs that promote efficient use of and investment in network services.

The Council of Australian Governments (COAG) Energy Council, (formerly the Standing Council on Energy and Resources) has submitted a rule change proposal to the Australian Energy Market Commission (the Commission) to modify the network pricing principles so as to ensure that the distribution network pricing rules provide incentives for network businesses to offer network tariffs that promote efficient use of network services. It is within this context that NERA Economic Consulting (NERA) has been asked by the Commission to:

- set out the economic rationale for and concepts underpinning the distribution network pricing principles set out in the rules;
- discuss practical approaches that can be used to estimate the long-run marginal cost (LRMC) of network services, as a measure of the costs electricity users impose on networks; and
- consider the implications for customers of moving towards tariff structures that promote more efficient outcomes, through the development of illustrative case studies.

In a related study, NERA has also been asked to consider the network cost implications of greater penetration of technologies including solar photovoltaic, battery systems, electric vehicles and air conditioners. The concepts set out in this paper are important for ensuring that network tariffs provide appropriate price signals to consumers so that efficient uptake of those technologies occur in the future.

A central focus of the COAG Energy Council's rule change proposal is to "amend the distribution network pricing principles so that distributors set cost reflective network charges, in a manner that reflects the LRMC of providing network services".[1] For the purpose of this report we define cost reflective network tariffs as any tariff that promotes more efficient use of existing network infrastructure and/or signals the cost of an additional unit of network capacity so as to promote more efficient investment in network capacity.

The remainder of this report is set out as follows:

- Chapter 2 sets out the economic concepts relevant to pricing infrastructure services;
- Chapter 3 considers the practical application of the economic concepts to the pricing of electricity network services;
- Chapter 4 provides a stock take of methodologies currently used by distributors to estimate the long run marginal cost (LRMC);
- Chapter 5 provides a step-by-step guide to estimating the LRMC of network services; and
- Chapter 6 provides illustrative case studies of the methodologies for estimating LRMC, and also illustrates how alternative tariff structures might impact on customer bills.

In addition, Appendix A sets out the data used to estimate LRMC for our illustrative case studies, Appendix B sets out the assumptions that have been used for the consumer bill impact case studies, and Appendix C sets out the detailed case study customer impact results.

[1] Standing Council on Energy and Resources, (2013), "Reform of the distribution network pricing arrangements under the National Electricity Rules to provide better guidance for setting, and consulting on, cost-reflective distribution network pricing structures and charges", *Rule change request*, 18 September.

2. Economic Concepts of Infrastructure Pricing

Any business selling goods or services needs to decide at what price to make those goods or services available to consumers. In general, competition between businesses ensures that prices are not too high and so only recover the underlying costs of production. In this way prices promote both the efficient use and production of the good or service.

In the absence of competition, such as for electricity network businesses, regulatory rules are needed to ensure that prices promote the broader efficiency objectives.

Economic theory provides useful insights to guide the development of network prices that promote efficient outcomes. This chapter sets out these economic concepts, which in turn underpin the current distribution pricing principles.

2.1. Pricing infrastructure to promote efficiency

The central tenet of economics is to promote efficiency in all of its forms. This includes:

- allocative efficiency – which requires that resources are allocated to their most productive or highly-valued uses in the economy. It is achieved by ensuring that prices are set with reference to the marginal costs, which supports efficient investment and expansion in productive capacity;
- productive efficiency – which requires the production of goods and services at lowest possible cost; and
- dynamic efficiency – which requires the efficient allocation and production of goods and services over time. This in practice means making optimal decisions about the nature and timing of investment and engaging in activities to pursue better products and ways of producing goods and services.

In practice the promotion of efficiency requires the setting of prices that encourage the optimal use of existing infrastructure assets while signalling to users the cost of an additional unit of a good or service. This pricing approach ensures that consumers obtain the maximum benefit from infrastructure that has already been constructed, while also signalling to network businesses how much they value expansion to existing network capacity.

In other words, infrastructure prices that promote efficiency provide an infrastructure business with scope to:

- recover the cost of existing infrastructure assets while simultaneously encouraging the efficient use of that infrastructure; and
- signals to users the cost of new infrastructure capacity, so as to encourage efficient investment in infrastructure capacity.

To promote efficient infrastructure use and investment, infrastructure prices should ideally be structured so as to reflect the underlying economic costs of supplying infrastructure services.

The characteristics of electricity networks, and the lack of widespread smart metering technology means that there are practical challenges to providing appropriate signals to electricity users through tariffs. It is for this reason that network tariffs remain dominated by flat, inclining or declining block usage tariffs (expressed in dollars per kilowatt hour), and fixed charges (expressed in dollars per connection per annum).

However, greater adoption of smart metering technology means that there is scope for greater innovation in tariff structures. This can help improve the signals provided to electricity consumers about the cost of new investments by providing tariff structures that more closely align with the underlying economic cost to provide network services. Such tariff structures include:

- system peak capacity charges, where a consumer is charged based on its contribution to network peak demand;
- daily peak usage charges, where a higher tariff is charged for usage during a network daily peak period;
- seasonal peak usage charges, where a higher tariff is charged for usage during a network daily peak period; and
- critical peak usage charges, where a higher tariff is charged for usage during a period that is notified to consumers prior to the period occurring.

Irrespective of the choice of tariffs used to signal the cost of additional infrastructure investment there remains the need to recover the total cost (ie, both the investment and ongoing operating cost) of the existing electricity network assets. This is typically achieved by a combination of fixed charges and mark-ups above the cost of an additional unit of infrastructure service, on usage charges.[2]

To improve the efficient use of existing infrastructure, whilst simultaneously allowing network businesses to recover the total cost of network services requires pricing strategies that encourage the greatest possible use of the available network capacity. In other words, prices should not discourage the use of infrastructure where the cost incurred from such usage is low or effectively zero. This means that mark-ups on usage charges should be minimised, particularly when customers are likely to be sensitive to changes in price.

That said choices about the tariff structure to recover the cost of existing assets also have different consumer bill impacts depending on the specific infrastructure use characteristics of the consumer. Any changes to tariff structures from those currently available will therefore require careful consideration.

2.2. The importance of marginal cost in infrastructure pricing

It is well established in economic theory that setting prices equal to marginal cost, ie the cost of producing an additional unit of a good or service, will promote efficient use and production of goods and services.

2 We discuss in greater detail in section 2.6 the principles that should be applied in recovering the total cost existing infrastructure.

In the context of network pricing, consumers faced with the cost of an additional unit of network infrastructure capacity will make efficient network usage decisions and also provide signals to network businesses about the demand for capacity expansion.

To determine those costs included in an estimate of the marginal cost requires consideration of the causal relationship between network use and costs. As Alfred Khan indicates:[3]

> the essential criterion of what belongs in marginal cost and what not, and of which marginal costs should be reflecting price, is causal responsibility. All the purchase of any commodity or service should be made to bear such additional costs – only such, but also all such – as are imposed on the economy by the provision of one additional unit.

In the presence of competition between many businesses and consumers, pricing in excess of marginal cost (ie, those costs directly caused by an additional unit of demand) would lead to the higher priced producer being competed out of the market. However, in the absence of competition a business that prices above marginal cost earns excess profits, while some consumers will choose not use the good or service, with consequential lost consumption benefits. It follows that promoting more efficient use and production of a good or service leads to greater benefits for all.

Equally, if a business sets prices below its marginal cost of production then it would suffer losses from servicing customers, and so would be better off not supplying those customers. In addition, more customers would demand the good or service, leading to inefficient use of the good or service. In this circumstance more efficient use and production of the good or service would result by pricing at marginal cost, where benefits are maximised for all.

An important feature of marginal costs for electricity network services is that they vary between customers, times of use, location, etc. It is therefore inaccurate to discuss *the marginal cost* of providing network services. To ensure that appropriate price signals for supplying network services are provided, the marginal cost needs to be defined with reference to those factors that drive the incurrence of costs into the future.

Finally, because marginal cost is a forward looking concept, ie it signals the cost of future capacity expansion, its estimation will be inherently uncertain. This means that an estimate of the marginal cost might reflect the probability of future states of the world eventuating, multiplied by estimates of the marginal cost under each possible future state.

2.3. Distinction between short and long run marginal cost

Once the relevant marginal cost has been defined, it can be estimated in either a *short run* or *long run* sense. The fundamental distinction between short run (SRMC) and long run marginal cost (LRMC) is the timeframe within which the business has scope to adjust its production processes so as to minimise the cost.

Specifically:

- SRMC can be defined as the cost of an incremental change in demand, holding physical capacity constant; whereas

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[3] Kahn, A., (1988), *The Economics of Regulation – Principles and Institutions, Volume I: Economic Principles*, The MIT Press, Cambridge Massachusetts, page 71.

- LRMC relaxes the capacity constraint and reflects the cost of an incremental change in demand assuming all factors of production can be varied.

An important distinction between SRMC and LRMC arises when physical capacity constraints means that supply is unable to satisfy demand. In this circumstance, the SRMC increases to the price level necessary to curtail demand sufficiently so that demand is exactly equal to the available capacity. This means that the SRMC includes the cost to consumers of being unable to use electricity when network capacity is insufficient to meet demand, ie a congestion cost.

While SRMC can both exceed and be less than LRMC at any point in time, on average the SRMC will equal LRMC. This is because if SRMC persistently exceeds the LRMC then producers are provided with signals to expand capacity.

Finally, whether SRMC or LRMC are relevant to tariff setting depends on the circumstances. LRMC provides better signals for the signalling of long term infrastructure investment costs, and effectively replaces the congestion cost component embedded within SRMC, with the cost of infrastructure necessary to alleviate any congestion. This means that it provides strong signals to consumers to make medium to long term investments to manage demand, while ensuring that infrastructure businesses receive signals for new capacity expansions.

In contrast, SRMC provides strong short-term signals to manage near term capacity constraints. However, due to the fluctuating nature of SRMC it does not provide strong investment signals and would also lead to highly volatile prices for consumers. In addition, information constraints within network businesses means that it is very unlikely that congestion costs could be accurately measured.

The practical limitations of SRMC mean that network businesses usually use LRMC as the basis for signalling future network costs.

2.4. Marginal cost of what?

The purpose of setting network prices with reference to marginal cost is to provide signals to consumers about the costs caused by their decision to use network infrastructure, and so promote more efficient use of and investment in it. However, for marginal cost pricing to achieve the desired efficiency outcome there is a need to consider the relevant ‘margin’. This requires consideration of the drivers for costs within the business, and the extent to which incremental changes of a measurable metric impact on those costs.

For example, the infrastructure costs of a car driving over an uncongested bridge is practically zero and so the relevant marginal cost tariff would be practically zero for crossing the bridge. However, during periods where the bridge is congested the short run marginal cost would include the costs imposed on others resulting from travel time delays. This would provide signals to alleviate the congestion. The long run marginal cost would reflect the incremental cost of alleviating the congestion through expansion in the capacity for the bridge crossing.

In this example, given that the cost of expansion is only caused by bridge users during periods of peak demand short run efficient use of the bridge would be promoted by charging a tariff equal to the SRMC. Efficient investment in this example could be promoted by charging a tariff equal to the LRMC, only during periods of congestion. Charging during periods where there is no congestion risks dissuading some users from taking the bridge even though the benefits outweigh the marginal costs.

In principle it is possible to charge simply on the basis of SRMC, relying on high SRMCs during congested periods to drive investment in capacity to relieve such congestion. However, in the context of electricity networks where network charges are unable to fluctuate to a sufficiently high level to ensure demand is curtailed to meet existing capacity, this would lead to periods where consumers were unable to be supplied. Charging on the basis of LRMC avoids the need for high SRMC prices to signal the need for new capacity expansion.

This example highlights the importance of linking tariffs to the marginal costs during the period where that use drives future costs.

2.5. What are avoidable or incremental costs?

While marginal cost refers to the costs caused by a small and permanent increase of a cost driver on total costs, in practice measuring marginal costs is difficult. Avoidable or incremental costs are commonly used to approximate the marginal cost.

Incremental costs are all those costs caused by a change in demand, where the change in demand is an incremental <u>increase</u>. Such an increment is typically sufficient so as to require changes in future network investment, eg, bringing forward a planned transformer upgrade.

Avoidable costs are all those costs that can be avoided by a change in demand, where the change in demand is an incremental <u>decrease</u>. This might include delaying the need for a planned transformer upgrade.

It follows that avoidable costs and incremental costs are <u>interchangeable concepts</u>, with the distinction simply being whether the change in costs is as a consequence of an increase (ie, incremental cost) or decrease (ie, avoidable cost) in demand.

Like marginal costs, incremental and avoidable costs have both a short run and long run concept. In the short run, incremental costs are all those costs directly caused by the increment where capacity cannot be expanded. Similarly avoidable costs are all those costs that can be directly avoided by an incremental decrease in capacity.

That said, incremental costs are typically applied in the long run while avoidable costs are typically applied in the short run where any sunk asset costs are considered to not be avoidable.

Both avoidable cost (and equivalently incremental cost) can be expressed as an average of a relevant cost driver metric (eg, per customer or kWh). In this way it is called <u>*average avoidable cost*</u> or <u>*average incremental cost*</u>. Average incremental cost is a commonly used methodology for approximating the LRMC.[4]

The concept of avoidable cost is also used as the lower pricing bound reflecting the inefficiency of charging customers less than the avoidable cost, because the business would be able to improve its profitability by choosing to no longer service those customers. It follows that for the business to recover its total costs any customers paying less than the avoidable costs would need to be subsidised by customers paying more than avoidable cost. Such an outcome could not be sustained in a competitive market, because it would lead to the subsidising customers switching to alternative service providers.

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[4] We explain this further in section 3.3.2 below.

2.6. Recovering the cost of existing assets

While setting prices equal to LRMC signals the future costs of network capacity expansion and so promotes efficient use of and investment in network infrastructure, it will usually generate insufficient revenue to recover the total cost of existing assets.[5] This means that there is a need to recover the remaining revenue requirements via additional charges.

This necessitates a second-best tariff structure, where the additional revenue is sourced from charges that minimise changes in the use of the existing network, relative to what would have occurred if consumers pay only the marginal cost of supply.

For network infrastructure there are two options that can satisfy this principle, namely:

- charging a fixed network supply charge per customer, which does not vary according to a customer's use of the network; and/or
- marking up consumption or capacity based charges to those customers or parameters that are likely to be less responsive to changes in price - commonly known as 'Ramsey charges'.[6]

The choice between recovering additional revenue via fixed supply tariffs or a mark up on usage tariffs should be based on an assessment of the likely implications on the usage of existing infrastructure, as well as an assessment of the impacts on consumers. This ensures that the wider efficiency principle that requires the promotion of optimal use of existing infrastructure can be achieved.

Ultimately the choice is not an either/or decision. In practice judgement is applied on the extent that additional revenues are recovered via a fixed supply charge or mark-ups on consumption or capacity tariffs. The guiding principle to the application of this concept should be the implications for use of the existing infrastructure by the customer. Relevant to this consideration will also be implications for the bills of the customer, of any changes to the proportion of revenue recovered from each tariff parameter.

That said, for the recovery of costs of existing assets to be consistent with promoting more efficient outcomes it is necessary for network businesses to consciously understand where mark-ups above LRMC are being applied. This ultimately requires estimation of the LRMC and translation to tariff parameters, prior to a consideration of how remaining revenue requirements will be recovered.

In practice, many network businesses apply a 'postage stamp' pricing approach. We define postage stamp pricing as applying the same network tariff to groups of customers (eg, residential customers) irrespective of differences in the future costs that they impose on the network from expected changes in their use of the network. In practical terms this means that

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5 That said it is possible for LRMC based charges to recover more than the total cost of existing network assets. This can arise from a disconnection between the building block based revenue requirement of network businesses and the current cost of replacing those assets, and the potential lumpiness of network expansion, leading to higher LRMC estimates.

6 Ramsey pricing is discussed in greater detail in section 3.2.3.

customers face network tariffs that are the same irrespective of the physical location within the network.

Postage stamp pricing can be consistent with promoting more efficient outcomes, but only in circumstances where consumers covered by the postage stamp price do not materially change consumption in response to changes in price. In most circumstances where postage stamp pricing is applied, consumers are responsive to price changes and so more efficient outcomes would be promoted by signalling the differences in the future costs between different locations within the network.

Indeed, postage stamp pricing can lead to poor outcomes for consumers where more targeted price signals might otherwise be desirable. This is because postage stamp pricing removes the scope for network businesses to manage bill impacts of more targeted pricing, by adjusting other non-usage charges.

Finally, many network businesses undertake detailed cost allocation exercises to determine in what proportion specific groups of consumers should contribute to the cost of existing assets. These are inherently focused on fairly arbitrary metrics to determine a ‘fair’ contribution of specific consumer groups to the recovery of the cost of existing infrastructure. These exercises do not contribute to promote more efficient use or investment in network infrastructure.

The test whether the resultant tariffs from such cost allocation exercises promote economic efficiency is an ex-post assessment of the extent that they lead to tariffs that impede optimal consumer use of existing infrastructure and signal the future costs imposed from changes in use. To the extent that this outcome is achieved, then any tariff will be consistent with the promotion of efficiency.

2.7. The role of network pricing principles

The economic concepts outlined in this chapter explain those considerations that competitive businesses have regard to when setting prices, and the implications for efficient use of and supply of the relevant good or service.

However, in the absence of competitive pressures and concerns about revenue certainty, network businesses will not naturally set prices with reference to these economic pricing concepts. This is because any inefficiencies resulting from the prevailing tariff structure can be sustained via cross subsidies between customers, without fear that competition will lead to those customers being competed away.

It follows that the network pricing principles set out in the National Electricity Rules are designed to provide incentives for network businesses to price in a manner consistent with competitive outcomes, and so promote more efficient outcomes.

3. Practical Application of the Network Pricing Principles

Applying the economic principles of pricing to a particular infrastructure business requires consideration of the overall pricing objectives, drivers for cost, and the alternative methodologies that can be used to estimate marginal cost. This chapter explains the practicalities of applying network pricing principles to electricity distribution businesses.

3.1. Current distribution pricing principles

Rule 6.18.5 of the National Electricity Rules sets out the principles to be applied by distributors when determining network tariffs to apply to direct control services. It requires that:

- first, the revenue expected to be recovered from each tariff class should fall between upper and lower bounds, defined as the stand alone and avoidable costs of service respectively; and
- second, specific tariff parameters must be set having regard to the long run marginal cost (LRMC) of the particular services to which the parameters relate, transaction costs, and the extent to which customers may respond to price signals provided by the parameters in question.

As explained in Chapter 2 the avoidable and stand alone cost tests in the Rules apply to the revenue to be recovered from each tariff class and are ‘hard’ boundaries. In contrast, the requirement to consider LRMC relates to the choice and level of charging parameters within each tariff class, and does not require the parameters to align with LRMC.

The rules provide that the upper and lower bounds on efficient pricing (ie, stand alone and avoidable costs respective) be considered with reference to aggregate revenue forecast to be earned within each tariff class. The definition of a tariff class is therefore an important dimension for applying the pricing principles.

The concept of a ‘tariff class’ was developed as a mechanism to allow distributors to strike an appropriate balance between sending efficient price signals to individual customers and the transactional costs involved in doing this on an individual customer basis. In most instances, and in particular for customers with relatively small electricity loads, it would be impractical to customise prices to individual customers.

Rule 6.18.3(d) requires that each tariff class must be constituted with regard to:

- the need to group retail customers together on an economically efficient basis; and
- the need to avoid unnecessary transaction costs.

In principle, grouping customers on an economically efficient basis requires consideration to be given to the potential efficiency losses arising from customers not being charged their individual marginal cost of supply. In practice this will be minimised when customers with a similar marginal cost to supply are grouped together.

3.2. Developing network tariffs

To develop network tariffs that promote more efficient use of and investment in the distribution network requires a distributor to consider the principal drivers of costs, to ensure that tariffs provide appropriate signals to those consumers that contribute the most to future costs from their current or future use of the network.

This section explains the key drivers of cost for network services, the importance of identifying and grouping customers that are the principal cause of future network costs, and the need to recover residual costs from users.

3.2.1. Drivers of cost for network services

For electricity distribution businesses future costs are driven by changes in the:

- number of customers connected to the network;
- maximum demand on the network;
- timing of services required (ie, the networks load profile); and
- location that services are sought.

Understanding the relationship between each of these characteristics of the network business and its costs is fundamental to network tariff design. In principle, there will be a different marginal cost associated with changes to each of these cost drivers, ie, the marginal cost of a customer connection, the marginal cost of changes in system demand, the marginal cost based on the time of infrastructure use, and the marginal cost based on the location of connection.

Each customer connected to the network imposes costs on the distributor as a consequence of its connection, *even in the absence of drawing electricity from the network or contributing to peak demand.* These costs include:

- installing and reading meters at the customer's premises; and
- equipment close to the premises, such as feeder lines and distribution substation investments.

In principle, marginal cost pricing requires that each customer pay a charge that reflects these costs. Practically the fixed charge of distributors is typically significantly higher than these marginal costs so as to ensure full cost recovery. This highlights that fixed charges typically charged to customers reflect a mark up above the underlying marginal costs associated with a connection.

The principal driver of costs for a network business is increases in maximum demand at each network node. This is because increases in maximum demand, over time, increase the probability that the network will be incapable of satisfying electricity demands. The network reliability standard provides strong incentives for distributors to ensure that network needs are satisfied.

In practice distributors undertake augmentation investments based on the change in *average* maximum demand over those periods of the year when the network is reaching its physical capacity limits. Given that the practical cost driver is therefore average maximum demand within periods when it is more likely that the network node will be constrained, the relevant demand is only during those periods, and in those locations where this brings forward the need for new reinforcement network investment.

Sustained decreases in maximum demand within segments of the network also create the potential for network infrastructure replacement costs to be lower by delaying or avoiding the need for certain asset replacements, eg, a transformer within a zone substation might no longer be replaced and could be mothballed. The network replacement expenditures that could be avoided as a consequence of lowering of maximum demand are properly considered marginal costs.

The timing of network services is relevant because of the relationship between time of use and the incurrence of the majority of network costs. For all networks there are only a limited number of periods where there is any probability that the network will reach its maximum demand. It follows that these are the periods where a price signal might promote more efficient use of the network.

Finally, given that network costs are based on local supply and demand conditions, the location of changing maximum demand within the network is a relevant consideration. Those locations where there is ample network capacity, changes in maximum demand will not influence forward looking costs whereas in those locations where network capacity is constrained, changes in maximum demand will strongly influence forward looking costs.

3.2.2. Grouping customers into similar ‘costs caused’ categories

While economic theory indicates that price should be set equal to marginal cost for each customer, the cost characteristics of network businesses means that each customer would be required to face its own individually determined charge. The practicality of estimating the costs caused by each customer in addition to the difficulty of ensuring that such prices changed in line with changing circumstances, means that pure marginal cost pricing is not feasible.

This means that some form of averaging of marginal costs is required both to:

- make measurement of the marginal costs practical; and
- to reflect practical considerations about the measurement of usage of the network.

It is for these reasons that the concept of tariff classes was incorporated within the Rules to allow distributors the opportunity to balance the efficiency benefits of providing tariffs that reflect the marginal cost of supplying each individual customer against the transaction costs involved in administering too many individual tariffs.

The Rule requires that each tariff class be constituted with regard to:

- the need to group retail customers together on an economically efficient basis; and
- the need to avoid unnecessary transaction costs.

The intention of the first limb of the rule was to avoid groupings of customers where some individual customers within the tariff class are charged outside of the efficient revenue bound limits, ie, higher than stand alone cost or lower than avoidable cost. Customers with similar cost to serve characteristics that are grouped together within a tariff class would therefore likely satisfy this first requirement because the likelihood that any one customer exceeded the revenue bound would be small. It is for this reason that examining the distribution of the cost to serve customers within a tariff class is relevant when allocating customers within a tariff class.

The second limb ensures that customers are grouped into the least number of tariff classes, so as to minimise transaction costs without breaching the first requirement.

In practical terms, the tariff class rule requirements facilitate the use of averaging of tariffs across consumers within the tariff class. The tariff classes can be based on one or more of a number of factors including:

- the size of the connection;
- the type of use;
- maximum demand;
- location; or
- meter type.

Ideally those customers that cause similar future network costs will be grouped to allow the same price signal to be sent to everyone within the relevant group. However, given practical metering limitations such groups might be split into those where metering allows more refined price signals to be provided.

Finally, it is relevant to acknowledge that for those customers for which there are a limited responsiveness to price signals, or scope to provide a price signal (due to metering limitations), the desirability of grouping the customers into similar costs caused categories is somewhat limited. This is because the benefits (from price signalling influencing demand and promoting more efficient use of infrastructure) might not outweigh the administrative or metering costs associated with providing more refined pricing signals. These are all relevant considerations to the grouping of customers.

3.2.3. Total cost recovery

The final practical consideration with developing tariffs is to ensure the financial sustainability of the business. There are two considerations here, namely:

- to ensure that the business recovers the total efficient cost of providing network services, including a return on investments; and
- to manage revenue risks given uncertainties about future demands and so the likely incurrence of future network costs.

The second consideration does not arise where a revenue cap form of regulation is applied. Indeed, it is the lack of this risk that reduces the incentives faced by distributors to develop tariffs that are cost reflective.

Electricity network businesses are natural monopolies, which mean they have continually falling average cost curves as network demand (either through put or capacity) increases over time. The practical financial problem this causes is that pricing at marginal cost does not allow the business to recover the total cost of supply.

The simplest approach would be to charge all customers at the average cost of supplying network services. However, this is inconsistent with the promotion of efficient use of network infrastructure as such a price would likely be too high for some, marginal users of the network.

It is for this reason that economic theory developed the concepts of Ramsey pricing and two-part – or multi part – tariffs.

Ramsey pricing involves charging a mark-up above marginal cost usage prices, with a higher mark-up applying to tariffs charged to customers that are the least responsive to changes in price.[7] Where customers are effectively not responsive to small changes in prices, this approach leads to almost no efficiency losses because it does not impact on the usage of network services.

The challenge with Ramsey pricing is that in practice it is difficult to evaluate the relative price elasticity of demand for different customers. This leads to rules-of-thumb about price responsiveness of customers being applied.

In contrast to Ramsey pricing, a two part tariff recovers the total remainder of the total cost of existing infrastructure through a fixed charge (ie, a tariff totally independent of infrastructure use). The usage charge in this case is then set with reference to the marginal costs and so avoids any efficiency losses from reductions in the use of network services.

3.3. Practical estimation of the LRMC

An important input to the development of cost reflective tariffs is to estimate the marginal cost for each group of customers for whom efficiency will be promoted by signalling those costs.

The two key methodologies used to approximate the marginal cost is the perturbation and average incremental approach. This section describes these two approaches in detail.

3.3.1. Perturbation approach

The perturbation approach estimates the LRMC as the direct change in total forward-looking operating and capital expenditure resulting from a change in charging parameters (eg, kWh or kVa).[8] It is calculated by:

- first, estimating forward looking total operating and capital costs for each year over a time horizon of, say, ten years;
- second, re-estimating forward looking operating and capital costs for each year over the time horizon as a consequence of a small but permanent increment in demand; and
- third, dividing the present value of the difference between the two forward looking operating and capital costs by the increment applied.

Algebraically, the perturbation approach is:

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[7] Technically Ramsey pricing raises prices in inverse proportion to the absolute value of the price elasticity of demand for each customer group.

[8] This approach is also sometimes referred to as the Turvey approach given the seminal article by Ralph Turvey that explains the concept of marginal cost. See Turvey, R., (1969), ‘Marginal cost’, *The Economic Journal,* Vol. 79, June, pp.282-99.

$$\text{LRMC (perturbation)} = \frac{\text{PV(revised optimal capex plus opex} - \text{optimal capex plus opex)}}{\text{PV(revised demand} - \text{initial demand)}}$$

While the LRMC calculation is typically estimated in circumstances where demand is increasing (and so the increment is positive), it can be equally applied as a decrement. In this circumstances forward looking operating and capital costs would expected to be lower than under the status quo scenario.

The principal feature of the perturbation approach is that it directly estimates the change in demand as a consequence of small changes in demand, which most closely resembles the theoretical ‘marginal cost’. Where capital expenditure is necessarily lumpy, this approach takes into account current conditions and so will result in lower estimates of the LRMC where current capacity is sufficient to satisfy incremental changes in demand. Equivalently, it produces higher estimates of the LRMC where small changes in demand lead to bringing forward near term investments. This most closely resembles the price signals that promote more efficient use of network infrastructure.

An illustrative example of the application of the perturbation approach is set out in section 6.2.

3.3.2. Average incremental cost approach

The average incremental cost approach estimates LRMC as the average change in forward looking operating and capital expenditure resulting from a change in demand. Practically it is estimated by:

- first, estimating future operating and capital costs to satisfy expected increases in demand;
- second, estimating the anticipated increase in the relevant charging parameter; and
- third, dividing the present value of future costs by the present value of the charging parameter over the time horizon.

Algebraically, the AIC approach is:

$$\text{LRMC (Ave Incremental Cost)} = \frac{\text{PV(new network capacity} + \text{marginal operating costs)}}{\text{PV(additional demand served)}}$$

By definition the average incremental approach uses an ‘average’ cost to approximate the marginal cost change. Such averaging will be reasonable where capital expenditure is relatively smooth due to incremental changes in demand. It follows that the AIC will not be a good approximation of the marginal costs where capital expenditure is lumpy. Specifically, the AIC approach will underestimate LRMC when the network is close to being constrained, and so an increment in demand brings forward near term investments to maintain network reliability. Equally the AIC approach will overestimate the LRMC when the network is not close to being constrained.

The AIC approach is commonly used to approximate the LRMC for network businesses because it can be estimated using pre-existing expenditure and demand forecasts. An illustrative example of the application of the AIC approach is set out in section 6.2.

3.3.3. Relative merits of each approach

As we have emphasised, any methodology for estimating the LRMC will necessarily be an approximation. However, the selection of a preferred approach requires consideration of:

- the benefits to be achieved by providing customers with a price signal that more closely reflects the costs caused by changes in the charging parameter – in which case the perturbation approach should be preferred; and
- the costs involved in conducting a detailed assessment of the perturbation LRMC compared with the relative ease of estimating the AIC.

In many instances, limitations in metering technology and an inability to target prices to customers supplied through those network nodes where changes in demand impose significant costs on the network, means that the AIC approach will most likely be a reasonable basis for setting tariffs.

However, where there are identifiable groups of customers imposing potentially significant forward looking costs on a network business then efficiency could be significantly enhanced by those customers being presented with a price that reflects the costs caused by use of the network. We believe that this would be best achieved by applying a perturbation methodology to estimate the LRMC in these circumstances. In this way, overall network costs can be best managed and only those demands for which the benefits to the customer outweigh the network costs caused will be supplied.

In practice we expect that applying an AIC approach at a network level for each customer grouping will provide a useful basis for understanding potential differences in the future network costs caused by each customer group. It follows that we would recommend the continued application of this methodology at such a high-level within the network.

However, we also believe that applying a perturbation methodology to estimate LRMC within lower levels of the network (say the zone substation level) will provide network businesses with a better understanding of the potential value of price signalling and/or demand management programs within smaller segments of the network. We believe that this information would facilitate an improved understanding of the drivers of future costs and provide important insights on how future expenditures would evolve absent changes in demand within each zone substation.

3.4. Practical estimation of the avoidable cost

The current pricing principles provide a pricing lower bound that customers should not be charged less than the total avoidable costs. This rule is, in effect, a generalisation of the marginal cost pricing rule as applied to a group of customers within a particular tariff class.

To estimate the avoidable cost, a distributor should consider the forward looking costs that could be avoided if demand from the class of customers was to be reduced. Conceptually this is no different to applying the average incremental cost methodology with a decrement to demand.

Practically, the avoidable costs can be estimated by:

- identifying all forecast operating cost categories that are practically avoidable to the business;

- apportion the identified avoidable costs across tariff classes based on appropriate cost drivers eg, number of customers for meter reading costs, etc; and
- summing across all avoidable cost categories for each tariff class to arrive at the total avoidable costs.

In principle, this should be undertaken for each year into the future (ie, taking into account known real increases in costs) and then taking the present value of the stream of future costs. However, practically this last step in the calculation is unnecessary if it is sensible to assume that future avoidable operating costs are not expected to rise in the future.

The avoidable operating cost categories include, amongst other things:

- avoidable future repairs and maintenance;
- metering and billing costs; and
- customer service costs.

Technically future capital costs that would not need to be incurred to supply those customers (eg, the cost of replacement of existing meters, lines, substations, etc) should be included in the avoided costs. However, these long run incentives are covered through the estimate of the LRMC and so the lower bound is more about ensuring that short-term price signals are also sent to customers.

It follows that sunk asset costs should not be included in estimates of avoidable cost, because they could not be directly avoided due to changes in demand.

4. Stock Take of Currently Employed Methodologies

In this chapter, we present a stock take of the methodologies that have been used to estimate the LRMC of electricity distribution services both in Australia and overseas.

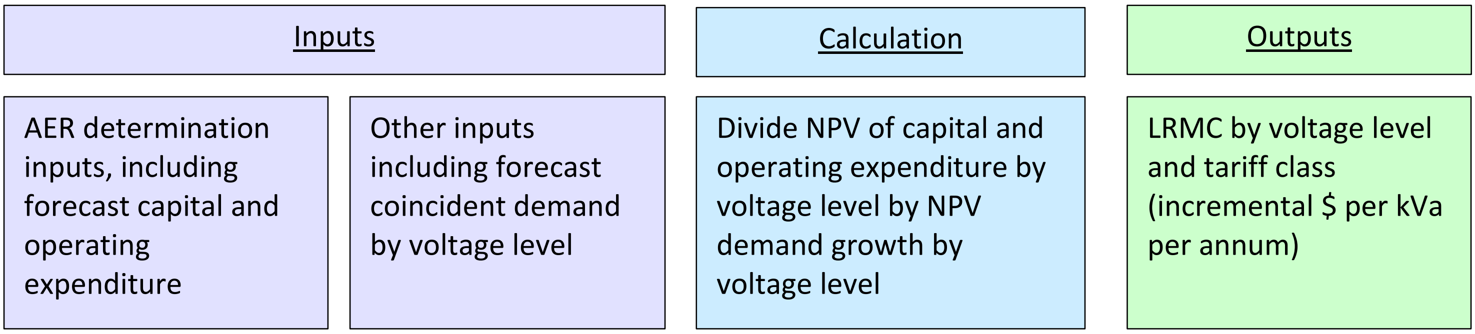
4.1. The LRMC methodology typically used by distributors in the NEM

Most distributors in the NEM use an average incremental cost (AIC) approach to estimate the LRMC. In simple terms the approach applied involves:

- forecasting growth related capital expenditure typically for a period of ten years into the future, which is annualised using regulatory return on assets and an average asset life assumption;
- forecasting incremental operations and maintenance expenditure for a period of ten years into the future;
- determining how much of annualised capital, operations and maintenance expenditure to allocate to each voltage level;
- calculating the present value of expenditure by voltage level, divided by the present value of incremental demand growth by voltage level to estimate the LRMC.

The data inputs and calculations are summarised in Figure 4.1. [9]

Figure 4.1
Approach used to calculate LRMC for each tariff class[10]



Where variations arise in the application of the methodology between distributors is in the:

[9] Approach similar or the same as that employed by Endeavour Energy, ETSA

[10] ETSA Utilities, Pricing Proposal, Appendix E – Distribution tariffs long run marginal cost methodology, April 2012, p 4.

- expenditure forecast period, which varies between ten and thirty years;[11] and
- rate of return and asset life assumptions, with each distributor applying its own regulatory weighted average cost of capital and regulatory depreciation assumptions.

The resultant LRMC estimates are typically calculated as $/kVA and then converted to $/kWh by applying an assumed power factor adjustment.

The most recent distributor LRMC estimates are set out in Table 4.1.

Table 4.1: Recent Distributor Estimates of the Long Run Marginal Cost

DNSP	LRMC	Customers
AusGrid[12]	$152.30/kVA	Low voltage
Endeavour Energy[13]	$348.39/kVA p.a.	Low voltage
SA Power Networks[14]	$156/kVA p.a.	Residential
JEN[15]	6.95c/kWh	Residential
United Energy[16]	5.38c/kWh	Small low voltage
ActewAGL[17]	$239.57/kVA p.a. ($2010)	Low voltage residential

4.2. Comparison of tariffs with estimated LRMC

Figure 4.2 provides a high-level comparison of residential tariffs and estimates of network wide LRMC for a number of distribution businesses. In most instances, the current residential usage charges are higher than the implied LRMC estimates, consistent with a mark-up above LRMC so as to recover the cost of existing assets. For example, JEN and United Energy have usage tariffs 16 and 9 per cent higher than their LRMC estimates, respectively.

The only exception to this outcome is for Ausgrid, where the second block of its declining block tariff is below its estimate of LRMC.

11 See for example, JEN Pricing proposal, 2014 pricing proposal, 31 October 2013, pp 25.

12 AusGrid, Network pricing proposal: For the financial year ending June 2014, May 2013, p 41.

13 Endeavour Energy, Direct control services: Annual pricing proposal, 30 April 2013, p 78.

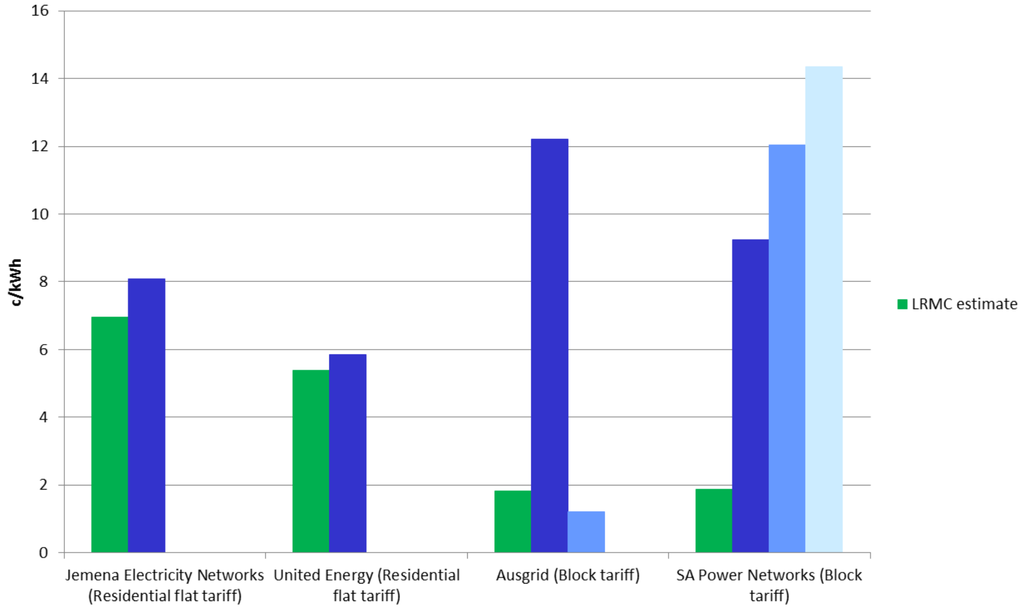
14 SA Power Networks, Annual pricing proposal 2013-2014, 24 May 2013, p 63.

15 Jemena, 2014 pricing proposal, 31 October 2013, p 26.

16 United Energy, 2014 pricing proposal, November 2013, p 43.

17 ActewAGL, 2013/14 network pricing proposal, May 2013, p 15.

Figure 4.2
LRMC and tariff block comparison (c/kWh)[18]



4.3. Electricity Authority's methodology for estimating LRMC in New Zealand

The New Zealand regulator, the Electricity Authority reviewed the decision making and economic framework for distribution pricing in 2013. It found that increases in charges should be allocated to the consumers whose consumption drives the cost increases.[19] The Authority found that although in theory the price should be set with reference to the LRMC, a theoretically pure LRMC is not easy to calculate and would fluctuate due to the 'lumpy' nature of investment. Therefore, the Electricity Authority argued that a long run average incremental cost approach is an appropriate approximation of the LRMC.[20]

The Electricity Authority also found that prices should be 'subsidy free (equal to or greater than incremental costs, and less than or equal to stand alone costs), except where subsidies arise from compliance with legislation and/or other regulation'.[21] Further,

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18 Source: Data from DNSP 2013/14 pricing proposals. Note that the third pricing block for Ausgrid has a DUOS charge of $0/kWh.

19 Electricity Authority, Decision-making and economic framework for distribution pricing methodology review, Consultation paper, 7 May 2012, pp B-C.

20 Note that the Electricity Authority uses the terms long run incremental cost and long run average incremental cost interchangeably. Electricity Authority, Decision-making and economic framework for distribution pricing methodology review, Consultation paper, 7 May 2012, p C.

21 Electricity Authority, Decision-making and economic framework for distribution pricing, decisions and reasons, 5 March 2013, Appendix A, p 11.

> 'Where prices based on 'efficient' incremental costs would under-recover allowed revenues, the shortfall should be made up by setting prices in a manner that has regard to customers' demand responsiveness, to the extent practicable.'[22]

4.4. Ofgem's methodology for estimating LRMC in the United Kingdom

In 2010 Ofgem introduced a common distribution charging methodology (CDCM) for distribution charges for low voltage customers. The common methodology was to provide a simple and common framework for distributors to structure network tariffs, and promote more efficient outcomes.

The approach is based on estimating the incremental costs of a hypothetical 500 MW increment in capacity. The incremental costs include:

- asset costs, which are estimated through a network model and allocated to customer classes based on assets serving those customers;
- operating costs, based on forecasts and allocated to customer classes according to their share of asset replacement costs; and
- other network fees and charges (ie, transmission exit costs), based on actual and forecast charges for each customer class.

The incremental asset costs are derived using either the long run average incremental cost method (which Ofgem refers to as the LRIC approach) or the forward cost pricing (FCP) method.[23] DNSPs choose which method to use with approximately eight distributors using the LRIC method and six using the forward cost method.[24]

Ofgem finds that both methods provide an efficient price signal about:

- the cost at the location per unit of capacity; and
- the cost of using that capacity during peak periods.

The specific distribution tariffs resulting from the model are determined by scaling the allocated incremental costs by reference to forecast demand data to meet the distributor's maximum allowable revenue. These scalars are applied to each of existing fixed charges, usage and capacity based charges.

A similar method is used to determine tariffs for high voltage customers, with allocation of incremental costs to specific customers.

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22 Electricity Authority, Decision-making and economic framework for distribution pricing, decisions and reasons, 5 March 2013, Appendix A, p 11.

23 The FCP method forecasts the actual costs of reinforcement and then spreads them across the capacity of users of that part of the network.

24 Ofgem, Electricity distribution structure of charges: the common distribution charging methodology at lower voltages, Decision, 20 November 2009, p 15.

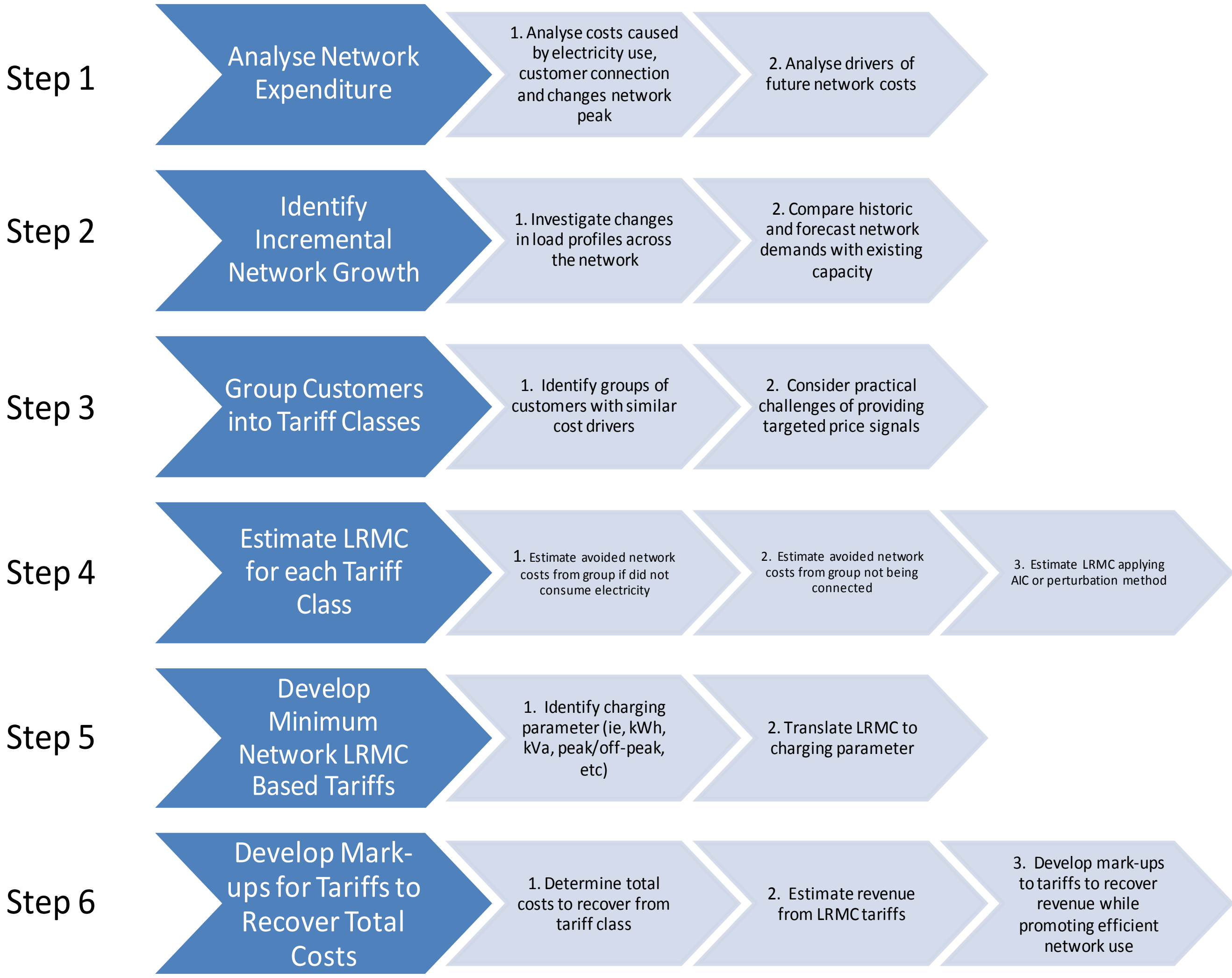
5. Designing Network Tariffs to Promote Efficiency

This chapter focuses on the application of the economic principles set out in this paper to design tariffs that promote more efficient use of existing electricity network infrastructure, and also promote more efficient investment in additions to electricity network capacity.

5.1. Overview

Figure 5.1sets out the practical steps involved in estimating the LRMC of network services.

Figure 5.1 Diagrammatic representation of the steps to develop network tariffs that promote efficiency



The following sections describe each of these steps in greater detail.

5.2. Step 1: Analyse network expenditure

The starting point for the design of any tariff strategy is to understand the:

- total cost to provide the existing level of network infrastructure capacity;

- operating costs caused by each unit of electricity delivered to consumers;
- operating costs caused by each customer connecting to the network;
- total future capital and operating costs (or reductions in replacement capital expenditure) that is being driven by forecast network growth (or declines); and
- drivers of future network costs.

The total cost to provide the existing level of network infrastructure capacity is simply the maximum allowable revenue, and so is the total amount of revenue that the business needs to recover through network tariffs.

Understanding the costs caused by each of the three main tariff metrics, namely electricity usage, number of customers and changes in peak demand, allows for consideration to be given to tariff structure design. Ideally, consumers would be charged based on the associated costs caused so as to promote efficiency.

The operating costs caused by each unit of electricity delivered to consumers would be mostly any operating costs that could be avoided if a unit of electricity was not supplied to a customer. We expect that in most instances, these network costs would be low or zero.

The operating costs caused by each customer connecting to the network allows for consideration of the incremental billing, meter reading and customer service costs that customer growth imposes on network businesses.

The total future capital and operating costs being driven by forecast network growth is commonly considered by network businesses as part of future planning processes. In addition to this, it is also important to understand how the asset replacement program is being influenced by forecast decreases in network demand in specific locations across the network.

This last point is particularly relevant to an examination of future network expenditures by network businesses at this time, given falling demand. Consideration should be given to the sensitivity of forecast replacement expenditure to incremental additional decreases in network demand to determine the potential additional benefits that could be achieved via additional demand management programs or targeted pricing within those locations.

Finally, it is important to have a firm understanding of the drivers for future network costs. Ideally these drivers should be split into two categories:

- those for which sending price signals to customers might assist with reducing those future costs; and
- those that are being driven by factors (eg, regulatory) that are outside of the control of network users.

Understanding this distinction is important for determining whether improving pricing signals to customers might help to lower network costs in the future.

5.3. Step 2: Identify incremental network growth

The next step involves undertaking a thorough assessment of network demand, so as to identify those locations where changes in network demand might avoid the need for future network expansion.

Practically, this involves investigating:

- the networks system-wide load profile;
- load profiles at lower levels of the network, including bulk supply points, and local transformers; and
- comparing historic and forecast network demands with existing capacity.

We understand that these investigations are typically undertaken by network businesses as part of their network planning processes, so as to identify the need for network expansion. We believe it is appropriate for similar information to be used to inform the development of tariff strategies, because it allows the pricing manager to consider whether more targeted price signals could help to avoid future network costs.[25]

5.4. Step 3: Group customers into tariff classes

Having developed an understanding of the cost drivers, and how the network business' costs are influenced by changes in usage, changes in customer numbers, and changes in peak demand by location within the network, consideration can be given to defining tariff classes.

Ideally, customers should be grouped into tariff classes where the costs caused by each customer within the group are broadly similar.

In addition, consideration should also be given to the practical challenges of providing price signals to those customers, including:

- the type of meters available;
- jurisdictional restrictions on applying differentiated tariffs; and
- the billing and metering costs of charging differentiated tariffs.

5.5. Step 4: Estimate the LRMC for each tariff class

The next step involves estimating the costs caused by each group, so as to identify the minimum charge that should be applied to each of the tariff components charged to the group.

This involves estimating for each tariff class:

- the total annual network costs that could be avoided if the group did not consume any electricity, divided by the total annual electricity forecast;
- total annual network costs that could be avoided if the group was not connected to the network, divided by the total number of customers; and
- the LRMC of a change in coincident demand with the network peak for customers within the tariff class.

This information forms the basis for determining usage, fixed and potentially capacity based charges for consumers within the group.

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[25] An example is EnergyAustralia, 2005, "Upgrade of Hornsby Zone Substation", *Corrective Action Report,* 24 August, Sydney.

Ideally, the estimate of the LRMC will be at a sufficiently low level within the network to provide insights on the signals that should be provided to consumers within the group so as to potentially avoid future network investments. The specific methodology to be applied (ie, an AIC or perturbation approach) should be informed by the availability of data and the extent that price signals can be practically provided to consumers within the group.

We believe that this means:

- applying an AIC where metering technology means that the only tariffs available for the tariff class are flat, inclining or declining block usage tariffs ($/kWh) and fixed charges ($/customer/annum);
- applying a perturbation methodology where metering technology allows for the use of more targeted critical peak tariffs, seasonal peak tariffs, and/or capacity based tariffs.

5.6. Step 5: Develop network tariffs that promote efficient future network investment

The next step involves converting the information on costs caused by consumers within the tariff class to network tariffs. In practice, because of the need to recover the total costs of existing network infrastructure, the tariffs developed at this step should be considered as a minimum. Additional charges can be added to these minimums so as to allow the total cost of existing infrastructure to be recouped.

The approach to estimating the minimum tariffs differs for usage tariffs depending on whether the tariff is a flat, inclining or declining block tariff, peak tariff, critical peak tariff or capacity based tariff.

For flat, inclining or declining block tariff, the minimum tariff (for the flat and for each block of the inclining or declining block tariff) can be calculated as follows:

$$\text{Minimum Flat, Block Tariff (\$/kWh)} = \text{Max}\left[\frac{LRMC of\ 1\ kVA}{8{,}760 \times Average Power\ Factor},\ \frac{Avoided Cost If No Usage}{Total Electricity Use}\right]$$

For daily peak tariffs, the minimum tariff can be calculated as follows:

$$\text{Minimum Daily Peak Tariff (\$/kWh)} = \frac{LRMC of\ 1\ kVA}{Total Peak Hours \times Average Power\ Factor}$$

For critical peak tariffs, the minimum tariff can be calculated as follows:

$$\text{Minimum Critical Peak Tariff (\$/kWh)} = \frac{LRMC of\ 1\ kVA}{Expected Hours of Critical Peak \times Average Power\ Factor}$$

For a capacity based charge, the minimum tariff charged on maximum capacity within the period of the network system peak, can be calculated as follows:

$$\text{Minimum Capacity Based Tariff (\$/kVA)} = LRMC\ of\ 1\ kVA$$

The final charge reflects the minimum fixed charge, which can be calculated as follows:

$$\text{Minimum Fixed Tariff (\$/customer/annum)} = \frac{AvoidedCostIfNotConnected}{TotalCustomers}$$

5.7. Step 6: Develop network tariffs to recover the total cost of existing network infrastructure

The charges developed in Step 5 are unlikely to be sufficient to allow for the recovery of the total cost of existing network infrastructure. The final step therefore involves calculating additional mark-ups on each tariff so as to recover the total costs that have been identified as being fairly recovered from customers within the tariff class.

This involves:

- determining the contribution from consumers within the tariff class to the total costs of existing network infrastructure;
- estimating the revenue expected to be received from the minimum tariffs determined at Step 5;
- estimating the remaining revenue that has been determined as needing to be recovered from the tariff class; and
- developing mark-ups on the tariff components so as to recover the required total revenue.

The choice between marking up specific tariff components requires consideration of:

- the influence of the mark-up on the use of the network infrastructure, remembering that ideally tariffs should maximise use of the existing network;
- the current levels of tariffs applying to consumers within the tariff class; and
- ensuring that each tariff component is at least equal to the minimums calculated at Step 5.

5.8. Observations

The above methodology for developing network tariffs recognises the importance of taking into account metering technology and other practicalities and limitations when designing network tariffs. That said the emphasis is on understanding those circumstances where providing price signals to customers might influence future network costs, and so lower future costs, as the basis for developing the tariff strategy.

6. Illustrative Case Studies

Within the confines of a network revenue requirement, changes in network tariffs for one set of customers need to be offset by accompanying changes in tariffs for other customers. This 'balancing' process ensures that revenues received meet the business' requirements, and means that in the short term customers will on average be no worse or better off under cost reflective network tariffs.

The benefits of cost reflective network tariffs arise from changes to customer electricity consumption patterns – changes that avoid network costs over the medium to long term. These cost savings can then be passed through to consumers through lower network tariffs over time.

The principal objectives of the illustrative case studies are to:

- demonstrate the application of alternative methodologies for estimating the LRMC as the basis for determining tariffs that signal future network costs and so promote more efficient outcomes; and
- illustrate the potential implications for residential and commercial customers of changes to tariff structures to promote more efficient outcomes.

The remainder of this chapter describes the illustrative case studies in greater detail.

6.1. Illustration of alternative approaches to estimating LRMC

The starting point for our analysis has been to examine the practicalities of alternative approaches to estimating LRMC. In undertaking these case studies, we have focused on two historic projects within Ausgrid's network to provide the information needed to estimate LRMC, namely:

- the establishment of a new zone substation (Kogarah Zone Substation) to service the St George Area in southern Sydney; and
- upgrade of the Hornsby Zone Substation by installation of an additional transformer, to service anticipated load growth.

A summary of the detailed expenditure and growth data underpinning our estimates of LRMC are set out in Appendix A.

6.1.1. Kogarah Zone Substation

As a consequence of anticipated load growth within the St George load area, Ausgrid (formerly EnergyAustralia) investigated the construction of new zone substation at Kogarah (the Kogarah Zone Substation). At the time the area was serviced by seven zone substations, each of which had loads that either currently exceeded firm capacity or was expected to exceed firm capacity within the proceeding two to three years, given expectations about future growth.

Importantly, the observed growth in demand reflected the construction of a number of significant high density residential developments, and increasing numbers of commercial developments. Overall, Ausgrid was anticipating a combined zone capacity deficit of between 7.9 MVa and 35 MVa over the period 2008 to 2013.[26]

In addition to the demand growth, asset condition assessments of the existing zone substations had identified Carlton zone substation as being of need of replacement in the near future. However, because of the lack of spare capacity at the surrounding zone substations, the load from Carlton could not be shared across those zone substations.

The proposed construction of the Kogarah zone substation was therefore designed to address two objectives, namely:

- to replace the Carlton zone substation; and
- to address an anticipated capacity deficit given continuing load growth.

In estimating the LRMC for the Kogarah zone substation it was therefore important to distinguish between that expenditure that was caused by incremental changes in maximum demand, as compared to expenditure that was needed to provide ongoing reliable network services by replacing the Carlton zone substation. In practice this required consideration to be given to what expenditure would have been incurred absent the anticipated additional growth in demand.

This highlights the importance of distinguishing the costs that are caused by changes in demand within the St George supply area. In this example, increases in demand were leading to:

- expenditure from the construction of the Kogarah zone substation;
- expenditure associated with the decommissioning of the Carlton zone substation; and
- avoided expenditure from replacing the Carlton zone substation.

It follows that to estimate the LRMC both the expenditure associated with the new Kogarah zone substation needs to be considered, less any expenditure that would have been avoided by replacing the Carlton zone substation. The incremental benefit of changes in demand is therefore the difference between the two expenditure streams.

Table 6.1 sets out the resultant estimates of LRMC for the Kogarah zone substation applying an AIC and a perturbation methodology.

Table 6.1 St George Supply Area, Illustrative LRMC Estimates

Methodology	Estimate

[26] Page 12, EnergyAustralia, (2007), “Development of Supply to the St George Area – Establishment of New Zone Substation – Kogarah” *Final Report,* 27 November, Sydney.

Average Incremental Cost	$363/kW/year
Perturbation	$157/kW/year

The difference in the results reflects the different emphases implicit within the two LRMC methodologies. The AIC approach is significantly higher in this case reflecting the planned size of the investment needed to meet reliability requirements within the St George supply area. The relatively small associated change in maximum demand means that this leads to a high LRMC estimate.

In contrast, the relatively lower LRMC estimate applying the perturbation methodology reflects the modest cost of capital applied (5 per cent in our illustrative case study) and so the benefits of avoiding these costs for a period of two years.

The differences between the two methodologies can be most clearly observed in Figures 6.1 and 6.2 below.

Figure 6.1 Augmentation Profile Applying the Average Incremental Cost Methodology – Kogarah Zone Substation

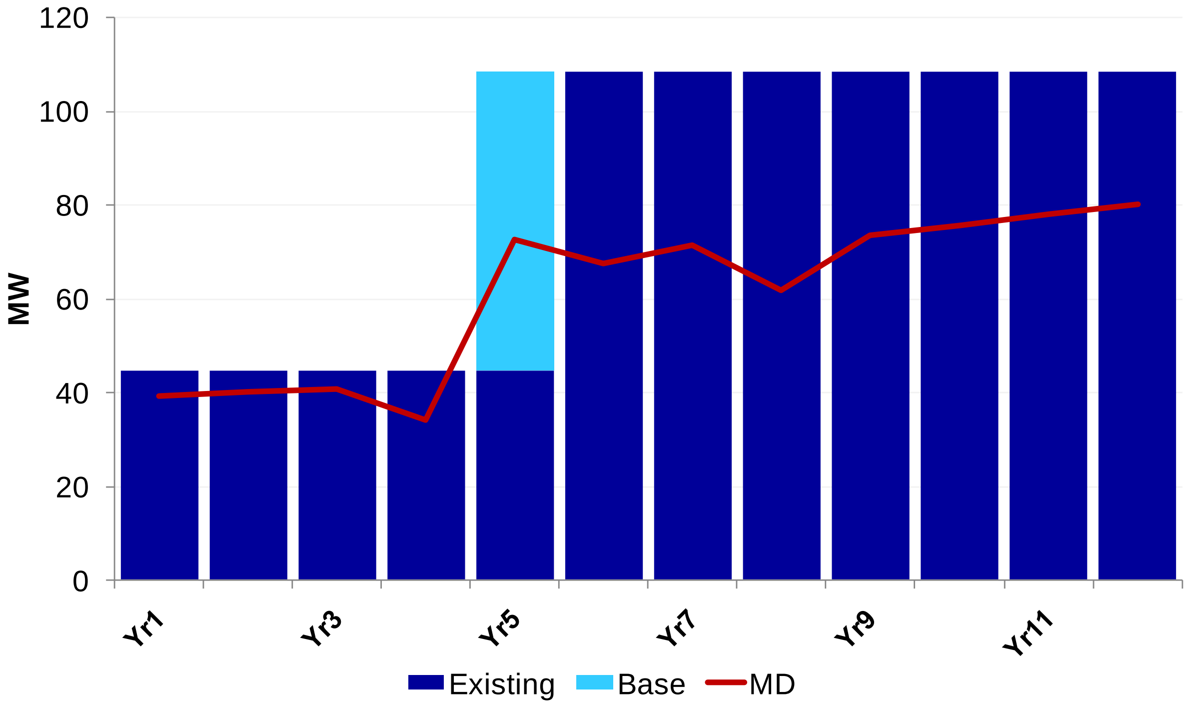
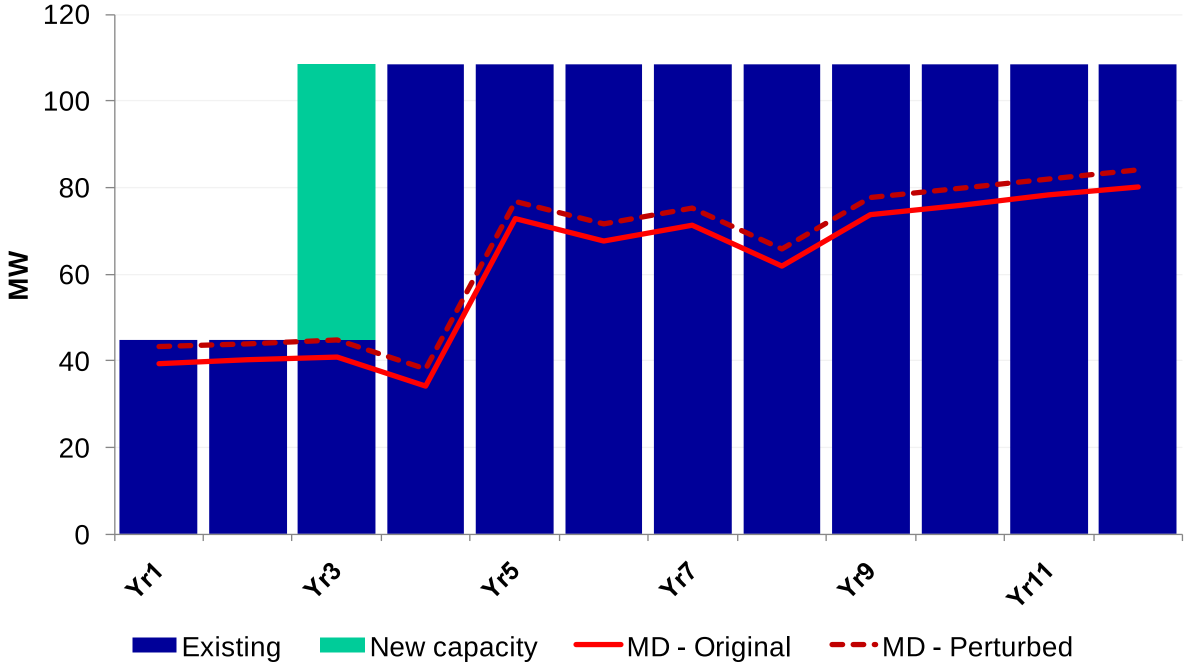


Figure 6.2 Augmentation Profile Applying the Perturbation Methodology – Kogarah Zone Substation



The results highlight the significant difference in LRMC estimates that can result from the application of alternative LRMC methodologies. In essence, the perturbation methodology is likely to more closely align with the costs that could be practically avoided from changes in demand today. In contrast, the AIC estimates of the LRMC provide a more general 'averaged' estimate of the LRMC over a period of time.

6.1.2. Hornsby Zone Substation

The Hornsby zone substation was constructed as a three transformer zone substation, which at the time of the proposed upgrade was equipped with two 50 MVA 132/11kV transformers. As a consequence of load growth, the Hornsby zone substation was exceeding its firm capacity in both summer and winter and so it was proposed to upgrade the zone substation through the construction of a third transformer.

Table 6.2 sets out the estimates of LRMC for the Hornsby zone substation upgrade applying an AIC and a perturbation methodology.

Table 6.2 Estimated LRMC for Hornsby Zone Substation Upgrade

Methodology	Estimate
Average Incremental Cost	$163/kW/year
Perturbation	$23/kW/year

As for the Kogarah illustrative case study, the estimate of the LRMC is lower applying the perturbation approach compared to the AIC approach. In this case, the result reflects the relatively modest cost of the upgrade ($7.4m) relative to the size of the capacity expansion. The higher AIC reflects the decrease in maximum demand observed in year six, which greatly reduces the assumed incremental load growth, thereby increasing the LRMC estimate.

The differences between the two LRMC methodologies are illustrated in Figures 6.3 and 6.4 below.

Figure 6.3: Augmentation Profile Applying the Average Incremental Cost Methodology – Hornsby Zone Substation

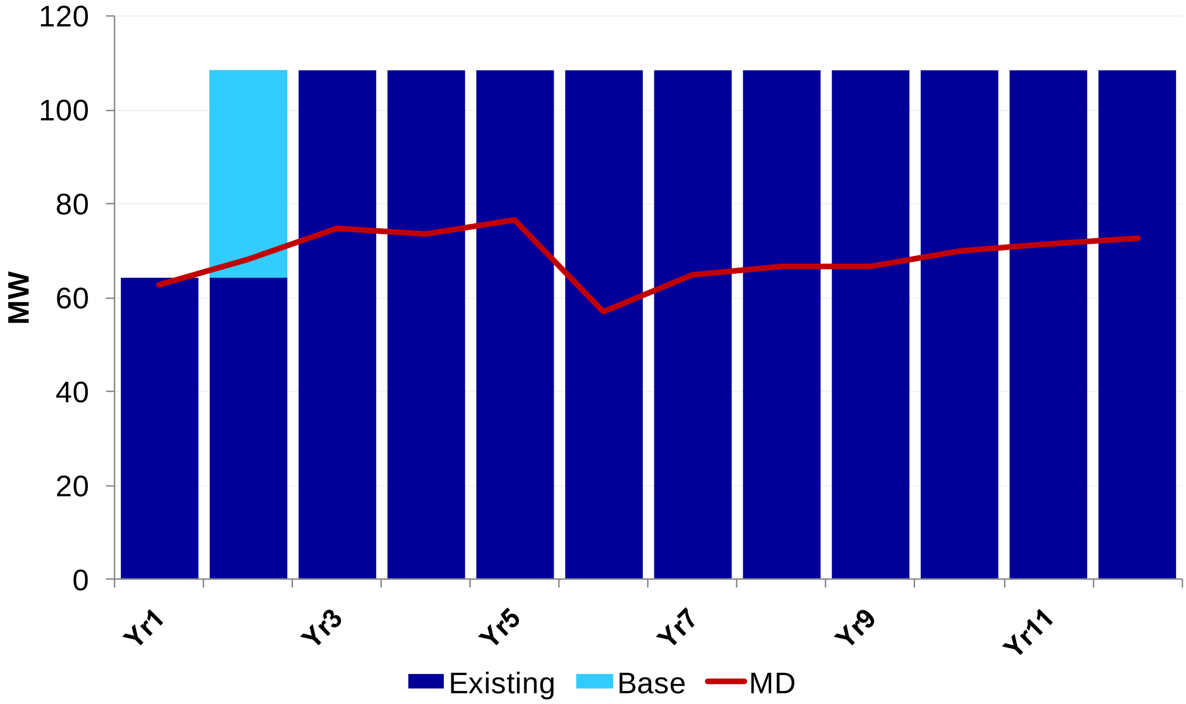
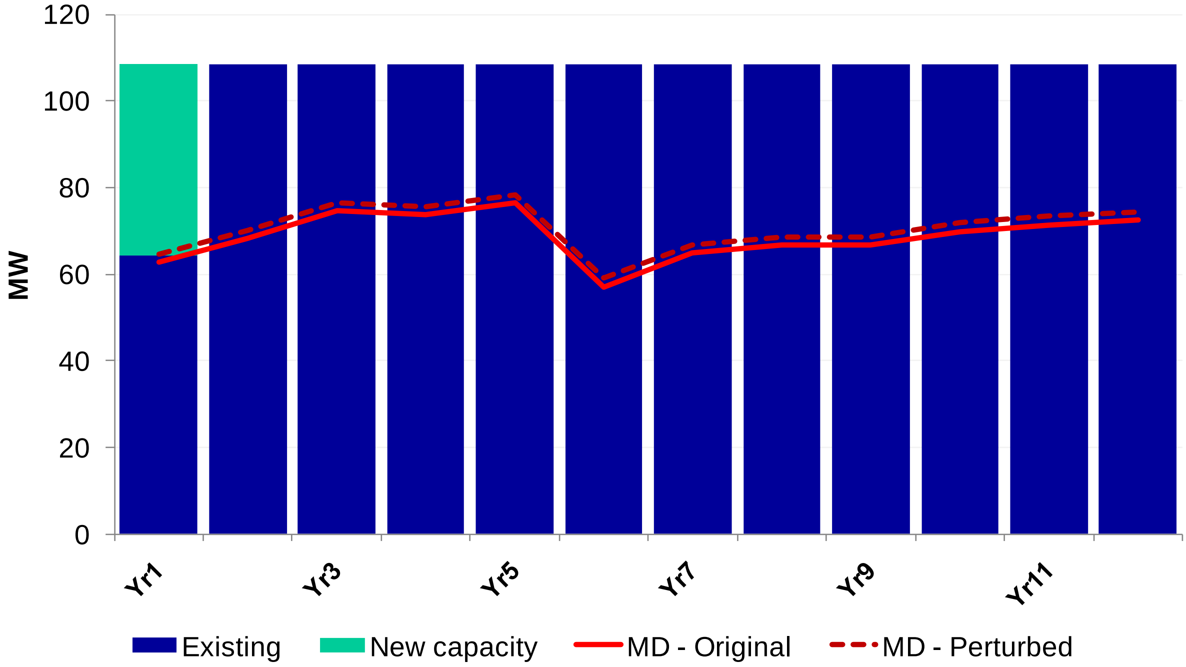


Figure 6.4: Augmentation Profile Applying the Perturbation Methodology – Hornsby Zone Substation



These results demonstrate the sensitivity of the methodologies to the forecast of maximum demand. Relevantly, the AIC is strongly influenced by any fluctuations in the demand profile, which can offset the incremental demand increase and so increase the resultant LRMC estimate.

Similarly, the AIC methodology cannot be applied if demand is falling, because the denominator is undefined. The AIC can therefore to be used to estimate the LRMC in circumstances where declining demand leads to the avoidance of asset replacement costs.

6.1.3. Observations on the LRMC methodology case studies

The case studies applying alternative LRMC methodologies illustrate the range of possible LRMC estimates that can result even though the underlying expenditure and demand data are the same.

The perturbation LRMC methodology is most likely to provide an estimate closer to the actual costs that could be avoided from changes in the assumed increment of demand. However, to produce such an estimate, consideration needs to be given to how changes in an increment in demand affect the planned expenditure profile. This can be most easily assessed at a zone substation level where consideration is already being given to planned network augmentations to address load growth.

The AIC methodology for estimating LRMC has significant limitations in particular:

- the LRMC estimates are sensitivity to the profile of incremental growth in load; and
- cannot estimate LRMC where load is declining and so asset replacements can be delayed or avoided.

That said the AIC approach does not require a detailed assessment of specific projects and so can be more easily applied at a network level to provide an indication of the network level LRMC of changes in demand.

6.2. Network tariff structures to promote efficiency

The second part of our case study analysis involved investigating the potential bill impacts to consumers of changes to tariff structures to provide improved signals on future network costs, and so promote more efficient use and investment in network infrastructure.

The case study analysis has been based on load profile data for 200 residential and an additional 200 commercial customers, assuming an LRMC estimate of $160/kW/year. We also consider a number of alternative approaches to recovery of the residual costs including, 100 per cent recovery via quarterly supply charges, 100 per cent recovery via consumption tariffs ($/kWh), and a 50:50 split between quarterly supply charges and consumption tariffs. This has allowed us to examine a range of potential implications for consumers of shifting to tariff structures that promote more efficient outcomes.

The remainder of this section describes the case study results in greater detail. Appendix B sets out the detailed assumptions underpinning the analysis, and Appendix C provides more detailed results of the case study analysis undertaken.

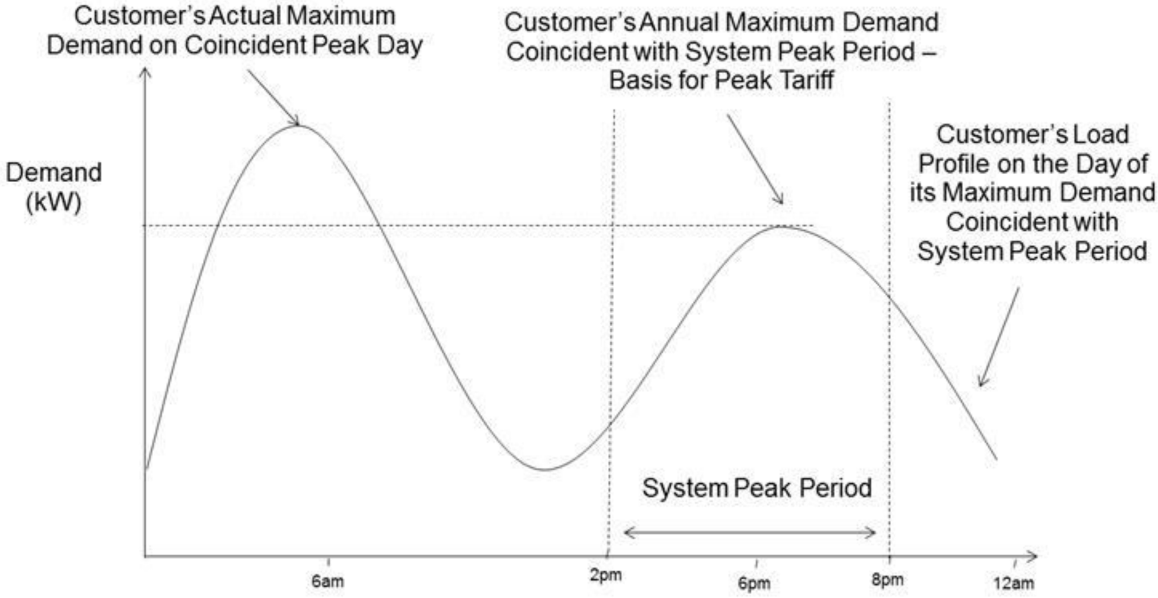
6.2.1. Peak capacity tariffs

The first tariff structure case study involves considering the bill implications of shifting from a flat tariff structure to a peak capacity tariff, which charges a customer based on its maximum demand during a defined network peak period of the day.

The charge is estimated by taking the sum of all consumers' maximum demands within the peak period, and dividing by the network maximum demand, as a 'scaling factor' to apply to the estimate of LRMC. For this example, the scaling factor was 20 per cent, which led to a peak capacity tariff of $32.1/kW, charged to each customer based on its actual maximum demand within the peak period of the year.

Figure 6.5 provides a stylised example of the load profile for a customer and the maximum demand coincident with the network peak period definition, which in this case is assumed to be between 2pm and 8pm on weekdays.

Figure 6.5: Stylised Example of Peak Capacity Tariff



To investigate the bill implications we have considered both the potential short-term bill impact, ie, assuming no response to changes in tariff structure, and in the medium term, ie, assuming that consumers respond to both changes in usage tariffs and the introduction of a maximum demand charge. In the medium term, we also assume that network costs are avoided as a consequence of the demand response, and so the resultant network tariffs in the medium term are the same as for the short term. If changes in demand did not result in lower network costs, then tariffs would need to rise in the medium term to allow the business to recover its revenue requirements.

The customer response to peak capacity tariff arises from:

- shifting electricity demand from system peak periods, where there is some discretion over the time of use (eg, using the washing machine on the weekends rather than on weekday afternoons); and

- choosing not to use an appliance during a peak period because the value of using the appliance does not exceed the charge (eg, turning an air conditioner off during peak periods).

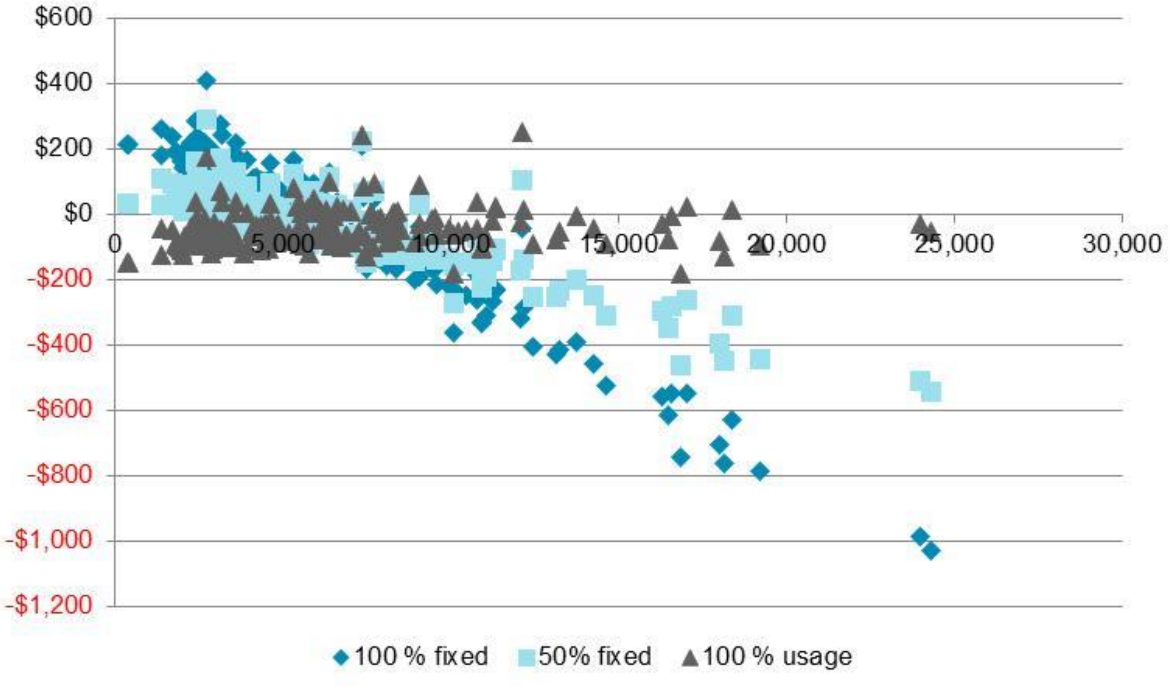
The resultant tariffs are set out in Table 6.3 below for the case where 100 per cent of the residual network costs are recovered through the supply charge.

Table 6.3: Illustrative Peak Capacity Tariffs – 100% Residual Cost Recovery via Supply Charge

Tariff Parameter	Base Tariff	New Illustrative Tariff
Peak Capacity ($/kW)	$0.259	$32.33
Flat usage ($/kWh)	$0.259	$0.189
Supply ($/day)	$0.700	$1.290

Figure 6.6 presents the change in customer bills, across each of the alternative approaches to residual cost recovery. While the smallest on average impact is where residual costs are recovered via usage charges, this approach is also least likely to promote efficient use of network infrastructure.

Figure 6.6 Change in Customer Bills – Peak Capacity Tariff



The results demonstrate that the bill impact under a peak capacity tariff is affected by the relationship between the customer's maximum demand and consumption. Generally:

- customer's with high maximum demand but relatively lower consumption will end up receiving a higher bill under a peak capacity tariff;
- customer's with a low maximum demand but relatively high consumption, will end up receiving a lower bill under a peak capacity tariff; and
- the approach to residual cost recovery can have a significant impact on bill impact results, by affecting the extent of the implied usage tariff increase or decrease.

Finally, under this illustrative case study a higher proportion of customers are worse off where residual costs are recovered mostly through the supply charge, but better off where residual costs are recovered mostly through usage charges – Table 6.4. This result highlights the role that the approach to residual cost recovery has on customer impacts.

Table 6.4: Illustrative Peak Capacity Tariff Average Bill Impact

100% Supply Charge Residual Cost Recovery	**Average Bill ($/year)**	**Proportion with Higher Bill (%)**	**Proportion with Lower Bill (%)**
Current Tariff	$1,832	-	-
Short-Term (no demand response)	$1,832	62%	38%
Medium-Term (with demand response and avoided network costs)	$1,804	56%	44%
100% Usage Charge Residual Cost Recovery			
Short-Term (no demand response)	$1,832	43%	57%
Medium-Term (with demand response and avoided network costs)	$1,792	19%	81%

6.2.2. Critical peak tariffs

The second network tariff structure case study involves a highly targeted tariff whereby a critical peak tariff would be charged for a four hour duration on the three maximum demand days within a year. A critical peak tariff is charged to the customer for a peak event period, which is defined by the network and communicated to the customer, typically the day prior to the event period.

For this illustrative case study we have assumed that the critical peak tariff is called three times each year for a duration of four hours. We also assume that the network business chooses the three highest demand days within a 12 month period.

Table 6.5 set out the illustrative critical peak tariffs, assuming that 100 per cent of the residual costs are recovered through the supply charge.

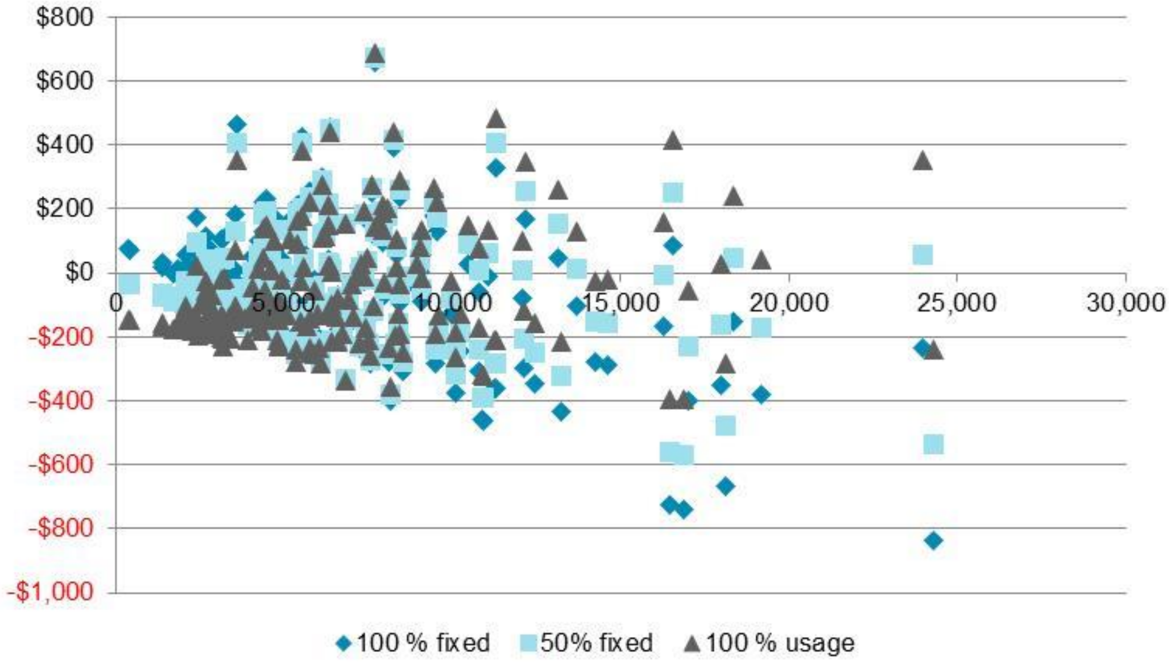
Table 6.5 Illustrative Critical Peak Tariffs – 100% Residual Cost Recovery via Supply Charge

Tariff Parameter	Base Tariff	New Illustrative Tariff
Peak Capacity ($/kW)	$0.259	$13.522
Flat usage ($/kWh)	$0.259	$0.189
Supply ($/day)	$0.700	$0.905

Relevantly, the critical peak tariff assumed for this illustrative case study has been set based on our assumed LRMC estimate. It is orders of magnitude higher than critical peak charges that have been typically trialled by network businesses. It follows that the resultant demand response would also be expected to be higher.

Figure 6.7 sets out the change in customer bills resulting from the introduction of a critical peak tariff.

Figure 6.7 Change in Customer Bills – Critical Peak Tariff



The approach to residual cost recovery has relatively little impact on the customer bill outcomes following the introduction of the critical peak tariff. This is because the critical peak tariff most closely targets coincident maximum demand of customers with the system peak. The bill impacts reflect the contribution to system maximum demand relative to consumption. The results demonstrate that across our sample there is relatively little relationship between coincident demand and consumption.

Table 6.6 sets out the average bill impact of the illustrative critical peak tariff. It highlights that across our sample, a higher proportion of customers are better off (ie, face a lower bill) by shifting to the illustrative critical peak tariff.

Table 6.6: Illustrative Critical Peak Tariff Average Bill Impact

100% Supply Charge Residual Cost Recovery	**Average Bill ($/year)**	**Proportion with Higher Bill (%)**	**Proportion with Lower Bill (%)**
Current Tariff	$1,832		
Short-Term (no demand response)	$1,832	49%	51%
Medium-Term (with demand response and avoided network costs)	$1,785	38%	62%
100% Usage Charge Residual Cost Recovery			
Short-Term (no demand response)	$1,832	39%	61%
Medium-Term (with demand response and avoided network costs)	$1,775	31%	69%

6.2.3. Time-of-use tariffs

The next tariff considered is a time-of-use tariff whereby the peak and shoulder tariffs are set with reference to the assumed LRMC estimate. The peak and supply charge the remaining tariff components for recovery of residual costs.

For the purposes of this illustrative case study the peak time-of-use period is defined as being the period 2 pm to 8 pm on each weekday, with the shoulder period extending to 9 am to 10 pm on all days.

Table 6.7 set out the illustrative time-of-use tariffs, assuming that 100 per cent of the residual costs are recovered through the supply charge.

Table 6.7 Illustrative Time-Of-Use Tariffs – 100% Residual Cost Recovery via Supply Charge

Tariff Parameter	Base Tariff	New Illustrative Tariff
Peak ($/kWh)	$0.259	$0.240
Shoulder ($/kWh)	$0.259	$0.212
Off-Peak ($/kWh)	$0.259	$0.190
Supply ($/day)	$0.700	$1.533

Figure 6.8 sets out the change in customer bills resulting from the introduction of a time-of-use tariff.

Figure 6.8 Change in Customer Bills – Time-Of-Use Tariff

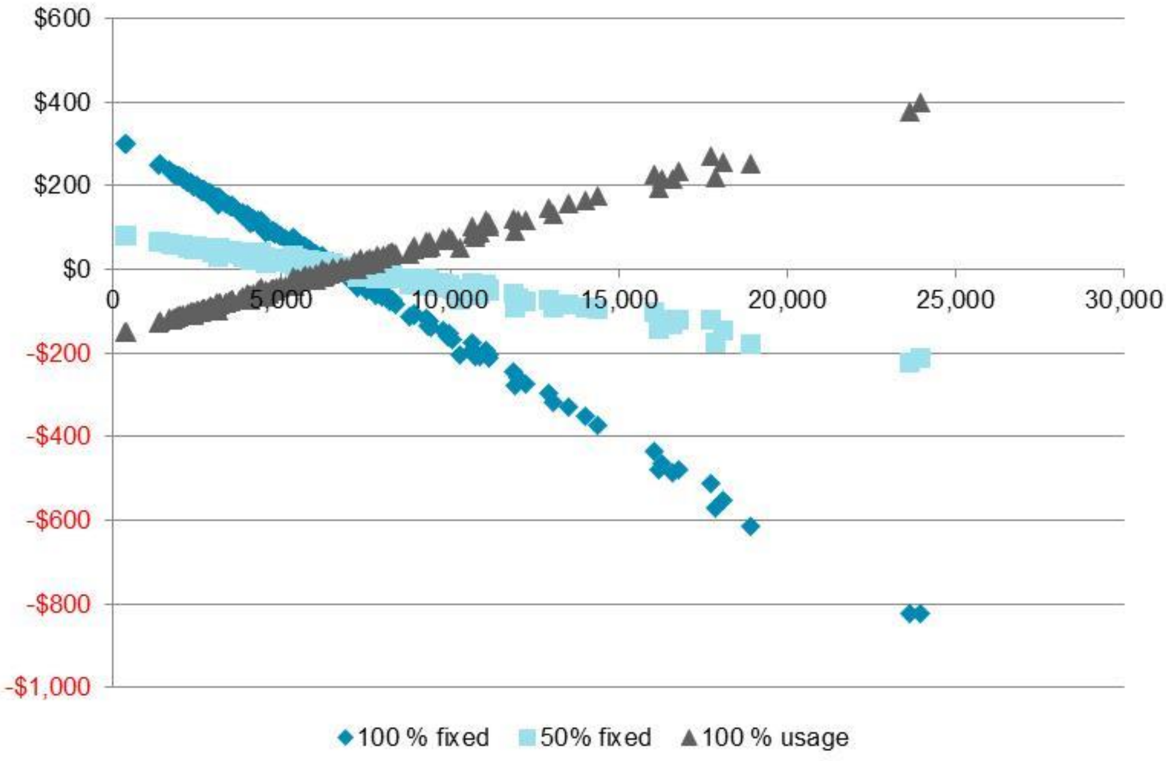


Table 6.8 highlights that the choice of approach to residual cost recovery has a significant impact on the bill outcomes following the introduction of the illustrative time-of-use tariff.

Table 6.8: Illustrative Time-Of-Use Tariff Average Bill Impact

100% Supply Charge Residual Cost Recovery	**Average Bill ($/year)**	**Proportion with Higher Bill (%)**	**Proportion with Lower Bill (%)**
Current Tariff	$1,832		
Short-Term (no demand response)	$1,832	61%	39%
Medium-Term (with demand response)	$1,844	63%	37%
100% Usage Charge Residual Cost Recovery			
Short-Term (no demand response)	$1,832	42%	58%
Medium-Term (with demand response)	$1,826	39%	61%

6.2.4. Flat tariffs

The final illustrative case study involves the transitioning to a flat consumption tariff that is set equal to the estimated network LRMC. In this circumstance, the usage tariff is set by dividing the estimate of the LRMC by the total hours in a year, to spread the recovery of LRMC across each hour of electricity consumption.

For this tariff, the usage component is then simply $160/kW/year divided by 8,760 hours, which leads to a flat network usage tariff of $0.02/kWh. As with the other tariff case studies, the remaining network costs are recovery through a number of alternative methodologies. The resultant tariffs are set out in Table 6.9.

Table 6.9 Illustrative Flat Tariffs – 100% Residual Cost Recovery via Supply Charge

Tariff Parameter	**Base Tariff**	**New Illustrative Tariff**
Flat Usage ($/kWh)	$0.259	$0.207
Supply ($/day)	$0.700	$1.573

Figure 6.9 sets out the resultant bill impacts of each of the alternative approaches to recovery of the residual costs.

Figure 6.9 Change in Customer Bills – Flat Tariff

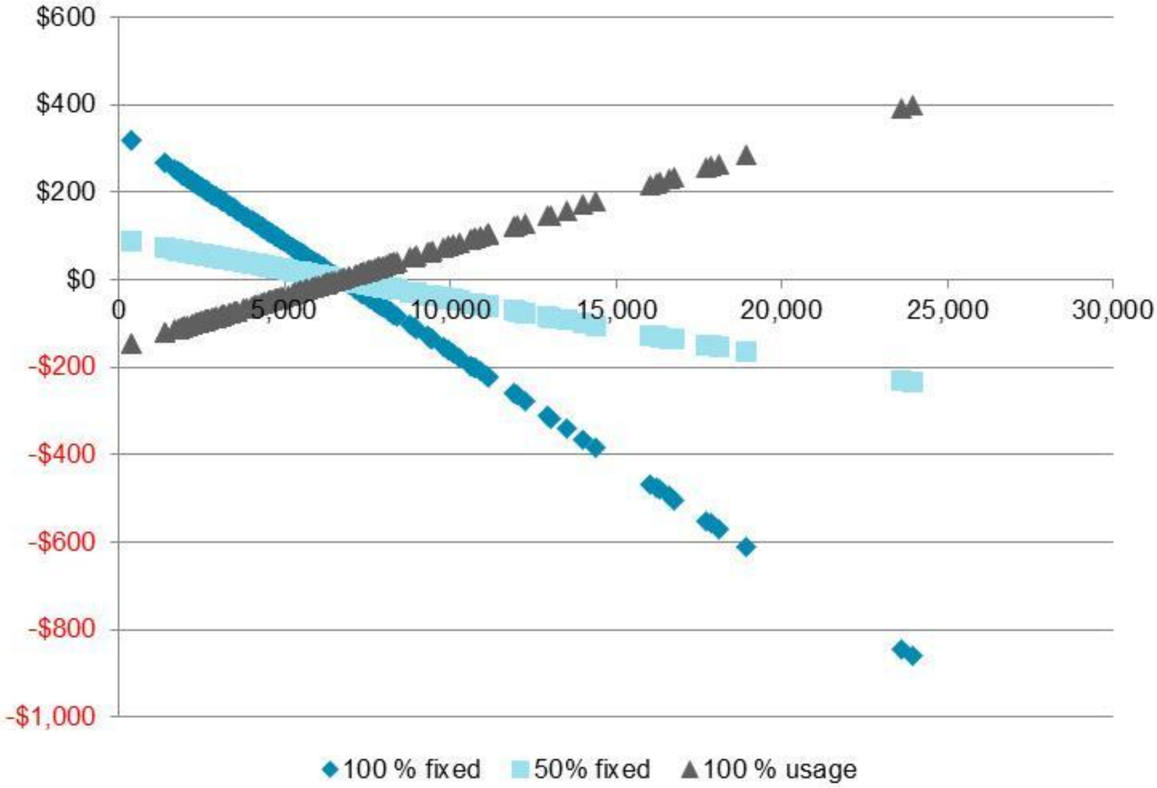


Table 6.10 sets out the average bill impact results for the illustrative flat tariff. The results are similar to those for the time-of-use tariff, which reflects the relatively poor signals created by these tariffs to promote the avoidance of future network costs.

Table 6.10: Illustrative Flat Tariff Average Bill Impact

100% Supply Charge Residual Cost Recovery	Average Bill ($/year)	Proportion with Higher Bill (%)	Proportion with Lower Bill (%)
Current Tariff	$1,832		
Short-Term (no demand response)	$1,832	61%	39%
Medium-Term (with demand response)	$1,845	63%	37%
100% Usage Charge Residual Cost Recovery			
Short-Term (no demand response)	$1,832	40%	60%
Medium-Term (with demand response)	$1,827	38%	62%

These results highlight that the choice of approach to recovery of the remaining residual network costs is the key driver for the bill impact outcomes. This reflects the current circumstance where shifting to usage charges based on estimates of the LRMC will generally lower consumption charges, thereby decreasing bills for higher consumer customers compared to lower consumer customers, which face higher bills. Where the residual cost recovery leads to higher consumption tariffs, then the opposite result arises.

6.2.5. Observations on tariff structure case studies

The tariff structure case studies highlight the importance of:

- understanding how changes in tariff structure affect the level of usage tariffs compared to fixed, supply tariffs, as these relationship will be critical to understanding consumer impacts; and
- the introduction of charges that seek to provide improved signals on future capacity costs will impact on consumer bills depending on the relationship between consumption and maximum demand.

What is clear from our analysis of customer demand is that there is no clear relationship between consumption and maximum demand during peak periods. This means in practice that tariffs that ignore maximum demand provide a relative poor price signal to consumers. It follows that aligning consumption tariffs more closely with estimates of the LRMC are unlikely to provide an improved signal about future network costs, to promote more efficient outcomes.

6.3. Case study conclusions

The illustrative case studies developed as part of this project highlight that developing tariff structures to promote more efficient use and investment in network infrastructure are practically achievable.

The challenges involve:

- estimating LRMC at a sufficiently low level within the network, where there are opportunities to use either price signals or direct demand management programs to avoid future network costs;
- obtaining sufficiently reliable information upon which to base LRMC estimates; and
- balancing customer bill impacts to introduce tariffs that more directly signal future costs, eg, peak capacity and critical peak tariffs.

What is clear from the case study analysis is that tariffs that signal future costs will likely lead to lower bills for a majority of customers. This is because they provide stronger signals for consumers to minimise coincident peak demand, thereby lowering future network costs.

Appendix A. Illustrative LRMC Methodology Data

Tables A.1 and A.2 set out the assumed expenditure and incremental load growth assumptions underpinning the estimates of LRMC for the new Kogarah zone substation. Tables A3 and A4 set out the assumed expenditure and incremental load growth assumptions for the Hornsby zone substation upgrade.

Table A.1 New Kogarah Zone Substation Expenditure Profile (millions, 2013/14$)

Year	1	2	3	4	5	6	7	8	9	10
Base case	$0	$0	$0	$0	$59	$0	$0	$0	$0	$0
Counterfactual	$0	$0	$59	$0	$0	$0	$0	$0	$0	$0

Table A.2 Kogarah Zone Substation Assumed Load Growth (MW)

Year	1	2	3	4	5	6	7	8	9	10
Base case	39	40	41	34	73	68	71	62	74	76
Counterfactual	43	44	45	38	77	71	75	66	78	80
Increment	4	4	4	4	4	4	4	4	4	4

Table A.3 Hornsby Zone Substation Upgrade Expenditure Profile (millions, 2013/14$)

Year	1	2	3	4	5	6	7	8	9	10
Base case	$0	$7	$0	$0	$0	$0	$0	$0	$0	$0
Counterfactual	$7	$0	$0	$0	$0	$0	$0	$0	$0	$0

Table A.4 Hornsby Zone Substation Assumed Load Growth (MW)

Year	1	2	3	4	5	6	7	8	9	10
Base case	63	68	75	74	76	57	65	67	67	70
Counterfactual	65	70	77	76	78	59	67	68	68	72
Increment	2	2	2	2	2	2	2	2	2	2

Appendix B. Illustrative Bill Impact Case Study Assumptions

The incremental bill impacts have been undertaken for a sample of 200 residential customers, and 200 commercial customers.

Table B.1 set out the assumptions applied to the bill impact case studies.

Table B.1 Customer Bill Impact Assumptions

Assumption	Parameter
LRMC ($/KW)	$160
Own price elasticity of demand	-0.025
Cross price elasticity of demand	-0.050

Appendix C. Detailed Bill Impact Results

Tables C.1, C.2, C.3, and C.4 outline a summary of customer bill impact results for residential and commercial customers in the short and medium run for the three approaches of recovering residual costs.

Figures C.1, C.2, C.3, and C.4 illustrates the customer bill impact for residential and commercial customers in the short and medium term under each of the three approaches to residual cost recovery considered.

Table C.1 Overview of Bill Impact in the Short Run – Residential Customers

Tariff type	Average bill	Minimum bill	Maximum bill
Existing flat tariff	$1,832	$256	$6,365
Flat tariff	$1,832	$110	$6,784
TOU tariff	$1,832	$110	$6,787
Critical peak tariff	$1,832	$110	$6,882
Capacity tariff	$1,832	$110	$6,398

Table C.2 Overview of Bill Impact in the Medium Run – Residential Customers

Tariff type	Average bill	Minimum bill	Maximum bill
Existing flat tariff	$1,832	$256	$6,365
Flat tariff	$1,836	$110	$6,764
TOU tariff	$1,835	$110	$6,766
Critical peak tariff	$1,781	$110	$6,632
Capacity tariff	$1,795	$110	$6,313

Table C.3 Overview of Bill Impact in the Short Run – Commercial Customers

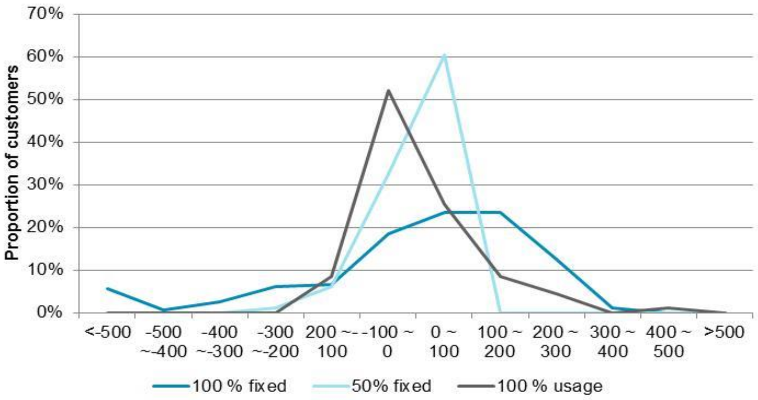
Tariff type	Average bill	Minimum bill	Maximum bill
Existing flat tariff	$6,229	$548	$52,083
Flat tariff	$6,229	$110	$55,618
TOU tariff	$6,229	$110	$55,983
Critical peak tariff	$6,229	$110	$52,700
Capacity tariff	$6,229	$110	$52,961

Table C.4 Overview of Bill Impact in the Medium Run – Commercial Customers

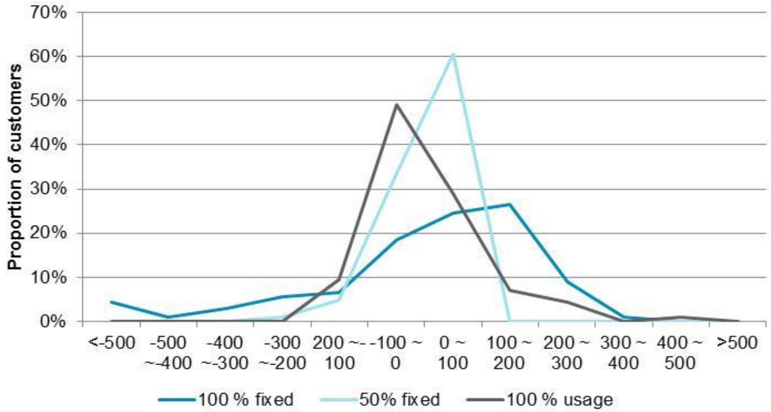
Tariff type	Average bill	Minimum bill	Maximum bill
Existing flat tariff	$6,229	$548	$52,083
Flat tariff	$6,240	$110	$55,466
TOU tariff	$6,239	$110	$55,808
Critical peak tariff	$6,129	$110	$52,114
Capacity tariff	$6,160	$110	$52,698

Figure C.1 Customer Bill Impact in the Short Run– Residential Customers

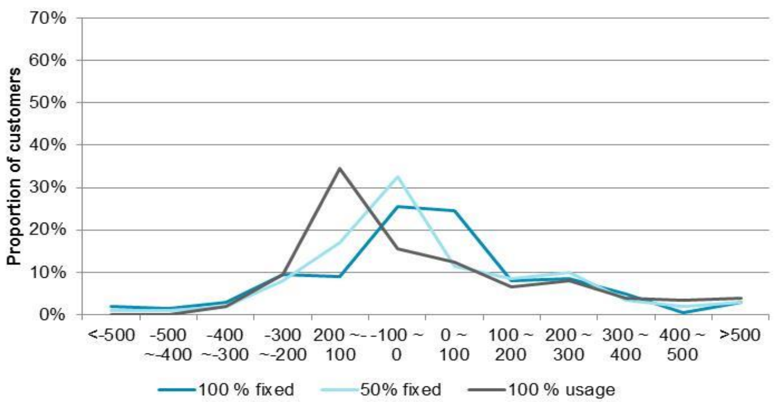
Flat tariff



TOU tariff



Critical peak tariff



Capacity tariff

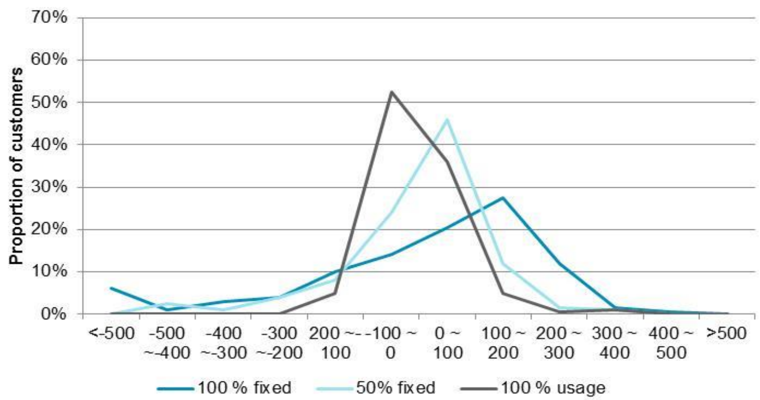
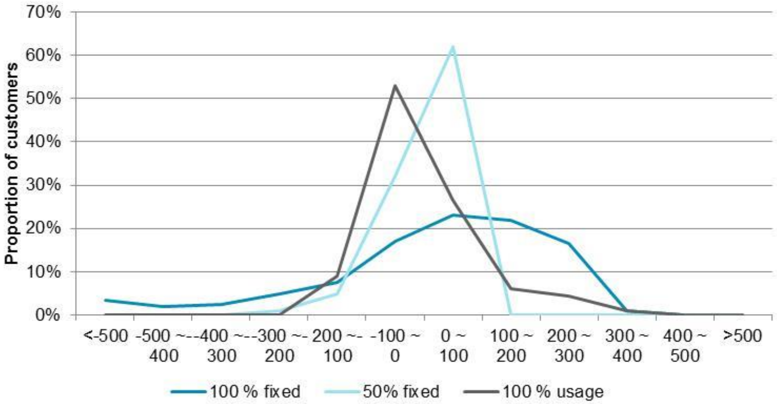
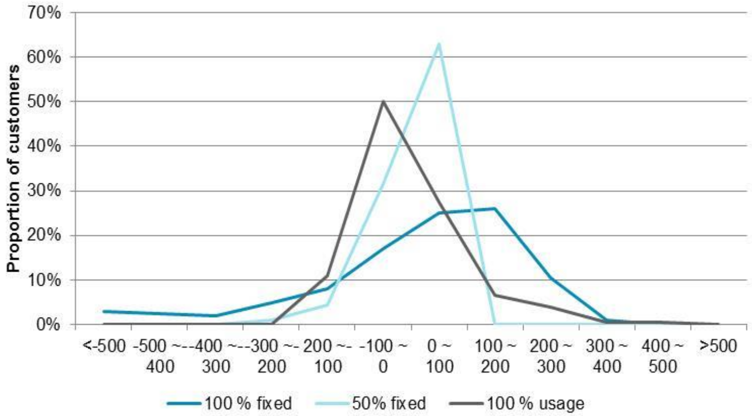


Figure C.2 Customer Bill Impact in the Medium Run for the Three Approaches – Residential Customers

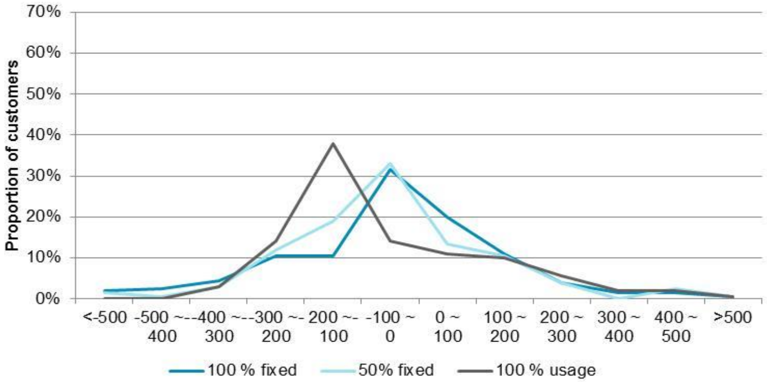
Flat tariff



TOU tariff



Critical peak tariff



Capacity tariff

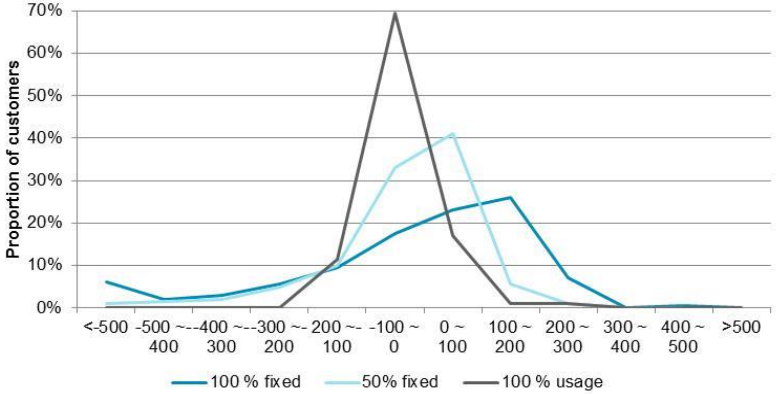
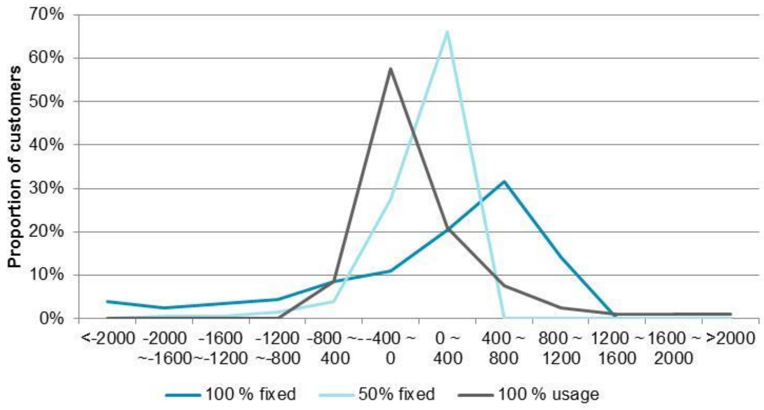
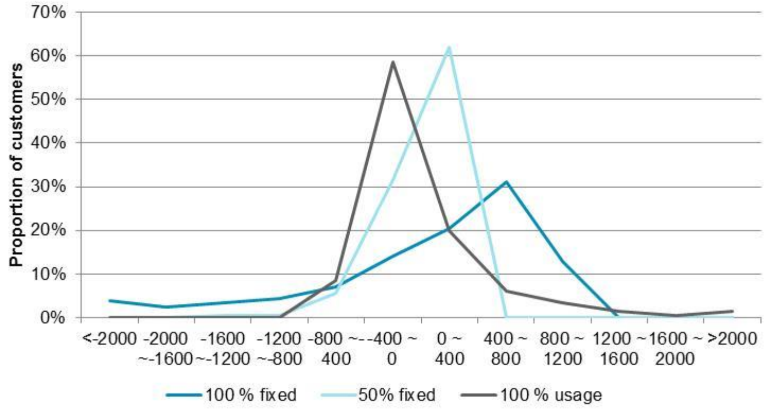


Figure C.3 Customer Bill Impact in the Short Run for the Three Approaches – Commercial Customers

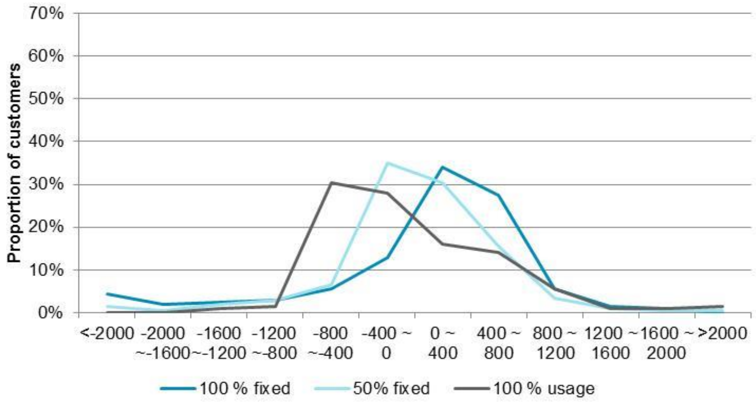
Flat tariff



TOU tariff



Critical peak tariff



Capacity tariff

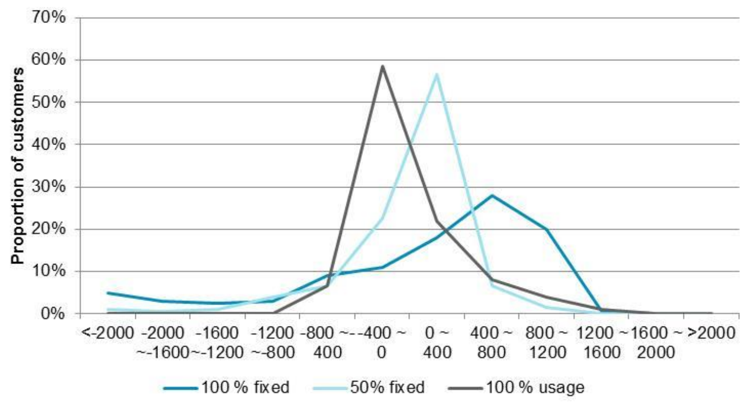
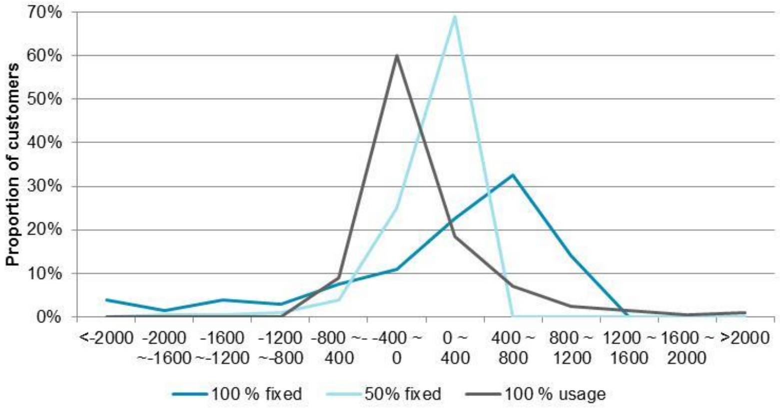
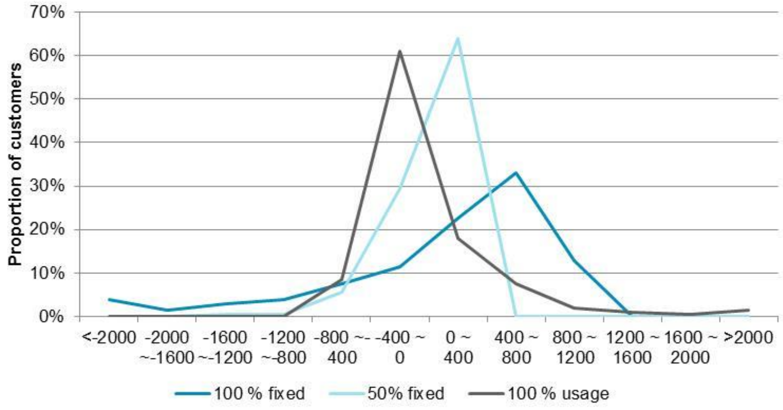


Figure C.4 Customer Bill Impact in the Medium Run for the Three Approaches – Commercial Customers

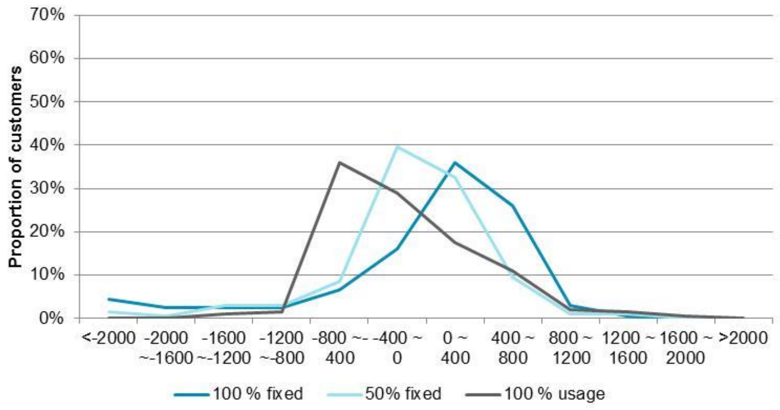
Flat tariff



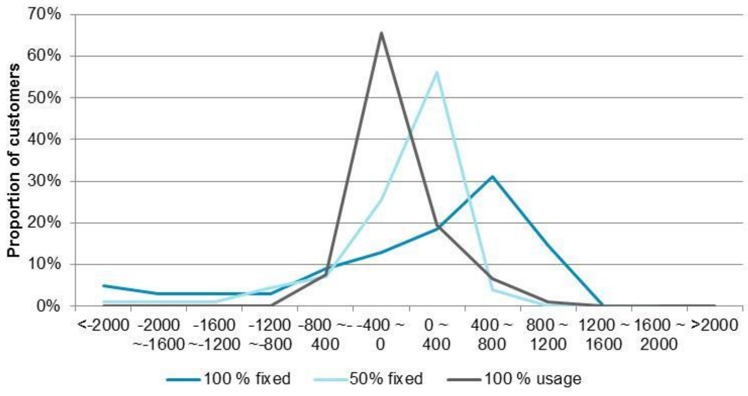
TOU tariff



Critical peak tariff



Capacity tariff



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