INDEPENDENT PRICING AND REGULATORY TRIBUNAL
OF NEW SOUTH WALES

Reducing Regulatory Barriers to Demand Management

AVOIDED DISTRIBUTION COSTS AND CONGESTION PRICING FOR DISTRIBUTION NETWORKS IN NSW

- Final Report
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Executive Summary

Sinclair Knight Merz and M-Co have been engaged by IPART to examine options for integrating the costs of demand management into the regulatory framework for NSW electricity distributors, and to study the feasibility and develop a framework for congestion pricing for distribution networks.

This report has been commissioned in response to the growing capital demands of DNSPs, and calls for the use of congestion pricing and greater uptake of demand management options to assist in curbing these capital investments. The report also seeks to address disincentives and regulatory barriers to the uptake of demand management by DNSPs.

Based on analysis of the financial impacts of demand management on DNSPs, the report has found two areas that must be addressed to provide appropriate financial treatment for DNSPs pursuing efficient DM initiatives – funding of DM costs, and correction of any lost revenues arising from consumption volume impacts of DM under a simple weighted average price cap. The report has found that DM implementation costs should be funded from the reduced or avoided distribution costs that are achieved through the implementation of DM, and identifies two possible mechanisms that correct the possible disincentives and align the financial drivers for DNSPs with the economic benefits arising from demand management. These two mechanisms are:

- ***An incentive mechanism*** that allocates both the DM implementation costs and avoided distribution cost benefits to DNSPs, allowing them to fund demand management initiatives, and retain a share of the net value created. This provides a positive financial incentive to DNSPs to pursue cost effective demand management alternatives.
- ***A cost recovery mechanism*** that allocates both the DM implementation costs and avoided distribution costs to end-users, with DNSPs recovering DM costs from end-users and passing the benefits through as reduced tariffs. This transfers the risk and benefits of demand management to end-users, insulating DNSPs from positive or negative financial impacts, but also removes the financial incentive for DNSPs to pursue DM.

The incentive mechanism is preferred on the basis that it provides a stronger incentive to DNSPs to pursue demand management options, and is consistent with the broader incentive regulation framework adopted by the Tribunal. Lost revenues due to volume impacts must be corrected by an explicit adjustment to DNSP revenues under either mechanism.

Given the current lack of local experience and knowledge of the practical costs and impacts of demand management, it is recommended that the Tribunal give consideration to underwriting demand management costs for a transition period as a means of reducing risks for DNSPs and encouraging trials of demand management.

The second part of the report examines the issues surrounding the introduction of congestion pricing for distribution networks, and proposes a framework for congestion pricing. The report finds that existing average cost pricing does not signal the cost of impending network constraints and capital expenditures, resulting in inefficient pricing and allocative inefficiency. While the introduction of full marginal cost pricing may be the economically pure solution, it is not currently considered practical or necessarily equitable, and would represent a significant change to the pricing of electricity distribution services in NSW.

A practical implementation model for congestion pricing proposed includes non-locational congestion pricing (based on times where the network generally is congested), and limited trials of locational congestion pricing involving a partial shift towards marginal cost pricing. Overall, the implementation of congestion pricing is considered feasible, and that this could deliver significant cost reductions to electricity users through reduced network capital expenditure. Congestion pricing can also be targeted at certain customer classes, with commercial and industrial end-users considered most suitable for congestion pricing trials.

It is recommended that DNSPs approach IPART with proposals for trials of congestion pricing during the period covered by the upcoming determination, and a decision on whether congestion pricing should be adopted more broadly be made following evaluation of these trials..

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1. Introduction

1.1 Background to this study

The Independent Pricing and Regulatory Tribunal of New South Wales (IPART) is currently undertaking a review of electricity distribution networks in the lead up to making its determination of distribution network pricing for the period from 1 July 2004. The Tribunal's Inquiry into the Role of Demand Management[1] concluded that pricing and regulatory reforms are important to the development of demand management as an effective means of reducing the cost of energy services delivery, and the current determination process provides a timely opportunity to address these issues. The National Electricity Code also requires jurisdictional regulators (6.10.2(d)) to put in place a distribution pricing regime "which fosters an efficient level of investment within the distribution sector, and upstream and downstream of the distribution sector".

IPART has engaged Sinclair Knight Merz, in conjunction with M-Co, to identify means of reducing regulatory barriers to demand management, focussing on integrating demand management costs and benefits into the regulatory framework for distributors in NSW, and developing a framework for congestion pricing for distribution networks. This report is not intended to review the viability or potential size of demand management options, nor canvas options to increase the takeup of demand management. Rather, it is intended to address regulatory barriers in the financial regulation of DNSPs to support demand management.

Distribution costs make up around one third of a typical energy user's bill[2], yet have not undergone the same degree of reforms over the past decade as the generation, retail and transmission sectors of the electricity supply chain. Generation costs and new investments are determined by a real-time market, which signals costs and constraints in time, and to a lesser extent, location[3]. Transmission charges are also locational, and have been unbundled from generation costs, with both regulated and merchant transmission links operating alongside the wholesale generation market. Retailing has been opened to the market, with all customers in NSW now contestable.

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[1] IPART, *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services – Final Report*, October 2002. Available at http://www.ipart.nsw.gov.au/pdf/Rev02-2.pdf

[2] *Regulatory arrangements for the NSW Distribution Network Service Providers from 1 July 2004*, IPART Nov 2002. Cost breakdown for a typical domestic customer, p6, showing 37% of costs are DUOS.

[3] Locational signals are provided by separate "pools" for each state, and separate transmission loss factors and prices for each main exit point. Proposals for regional NEM pools would further strengthen these signals.

SECTION 1 – REGULATORY FRAMEWORK FOR DEMAND MANAGEMENT

2. Background

The Independent Pricing and Regulatory Tribunal (the Tribunal) is the jurisdictional regulator for distribution pricing in NSW, and is currently undertaking a review of distribution costs and prices in the lead up to making a determination on distribution network pricing to apply from 1 July 2004.

The Tribunal is interested in examining possible barriers to the increased use of demand management (DM), including embedded generation options, where these can reduce the cost or improve the efficiency of electricity distribution. Commonly cited regulatory barriers include uncertainty regarding the treatment of DM costs and definition of what will be allowed as "prudent", allocation of risks, any lost revenue for DNSPs undertaking DM, and the lack of a clear efficiency incentive or share of benefits for DNSPs.

Capital investments by DNSPs are typically "lumpy", that is large and infrequent, due to the inherent economies of scale in distribution infrastructure. While this leads to the lowest *average* cost, it means new equipment is typically poorly utilised for the first several years of its life. This leads to a high *marginal* cost of new capacity, and is generally what is being targeted by network driven DM. Investments in new capacity are also risky, in that the decision to invest is based on forecasts of expected future loads that are inherently uncertain. DM can reduce these risks by deferring the need to invest in new capacity until there is more certainty, particularly where expected growth is due to new developments with uncertainty surrounding decisions as to when or if they should proceed. The value of this risk reduction is not currently well integrated into planning decisions or assessment of DM options.

For DM aimed at deferring network investments to be economically attractive the amount paid for DM should be less than the avoided distribution costs[4]. Other types of DM (targeting greenhouse gas reductions, for example) are due to drivers other than network investment costs, and are not considered in this report.

Electricity distribution networks are natural monopolies, and as such are not subject to the same market disciplines as other goods and services. Regulation of networks seeks to achieve efficient and equitable outcomes. This is an important issue for this study, as it examines how costs, cost savings and risks are allocated. In a reasonably competitive market, efficiency improvements will appear first as improved profits, then over time be passed through as lower prices as competitors match these improvements to remain competitive. Efficiency and profitability cannot be measured against a fixed point, but against a background of continuous improvement and innovation.

This view must be balanced with a recognition that DNSPs are required to operate in a commercial manner, and will be reluctant to pursue paths such as DM if they erode profitability. To the extent that DNSPs are able to create value through DM, they should be rewarded with a share of the value they have created through innovation and cost efficiencies. This report seeks to find an appropriate balance that will align the incentives for DNSPs with the economically efficient adoption of DM, delivering an appropriate share of these benefits to both DNSPs and end-users.

Lost revenue associated with DM is another complex but important issue. A DNSP implementing efficient DM will reduce its costs of supply, and also impact the quantity and timing of electricity consumption by end-users. Depending on the form of regulation and type of DM measures implemented, this may act as a significant short-term financial disincentive to DNSPs implementing DM alternatives.

Broader application of DM as a supply planning tool is largely unproven in Australia. The specifics of our regulatory environment, economy, climate, mix of industries, fuel and resource mix mean that results achieved elsewhere may not always be replicated here. Publicly subsidised (or at least underwritten) DM programs elsewhere have also played an important capacity building role, which has been a crucial factor in the success of DM in other markets.

[4] This excludes other potential benefits such as environmental (greenhouse), risk management and demand-side response in the NEM, and energy cost savings to end-users. The value of these benefits are already captured by others (abatement certificate providers in the NSW Greenhouse Gas Abatement Scheme, retailers, and end-users respectively), and to include them in avoided distribution costs as well would have the effect of double-counting these benefits. End-users, retailers or energy service companies should place a value on these benefits, and reduce any incentive or subsidy required from a DNSP to make a DM project financially viable.

3. What are the regulatory barriers?

In order for DNSPs to confidently invest in DM and other alternatives to traditional supply side investments, two conditions must be met:

- The regulatory framework must compensate or adjust for any inherent financial disincentives,
- DNSPs must be confident that these financial mechanisms will work fairly and predictably

On the first point, this section of the report outlines a proposed correction mechanism that should remove the inherent financial disincentives to DM, and provide DNSPs with a financial incentive to seek efficient DM options. The second point will require the Tribunal and DNSPs to work cooperatively to build experience with the operation of this mechanism.

The financial impact on a DNSP undertaking DM is a function of the regulatory framework it faces. The *demand* impacts of a DM program are:

- Demand is reduced, leading to reduced or deferred capital investments.
- End-user consumption is reduced or shifted (to off-peak periods for example). This might be a temporary or long term effect (for example interruptions that are suspended when the constraint is resolved, versus energy efficiency improvements that will continue).

The *financial* impacts for the DNSP will depend on how they are regulated. Under the current fixed revenue cap, for example, there is no lost revenue in the short term, whereas under a WAPC there may be a short term lost revenue issue. Generally, DNSPs implementing DM will face reduced profits, due to the operation of inherent disincentives within the WAPC framework. The objectives of integrating the treatment of DM costs into the regulatory framework are to maximise the uptake of economically efficient DM, by aligning the financial drivers for DNSPs to the uptake of efficient DM. This requires that the financial disincentives for DM introduced by the WAPC, and those that existed before, be neutralised.

Pricing regulation for DNSPs must also be consistent with a number of other documents and policies, including:

- Pricing Principles and Methodologies (PPM) published by the Tribunal
- The National Electricity Code, particularly as it applies to regulation of distribution networks and pricing principles.

The Tribunal's Pricing Principles and Methodologies sets out the following objectives for pricing of distribution networks:

> The pricing of Prescribed Distribution Services involves allocating the costs that underlie those services and formulating prices to recover those costs. A basic premise of the Tribunal's approach is that DNSPs should be responsible for determining their prices, given that they have a better understanding of their cost structures, the needs of users and their sensitivity to price signals, the level of network utilisation and the likelihood of the emergence of congestion. Nevertheless, important regulatory issues arise from the exclusive position of DNSPs in providing access to the electricity network:
>
> - Network prices affect economic efficiency by providing signals for the location of new demand, the use of the network by existing users and investment in the development of the network and in alternative forms of service provision. To promote economic efficiency prices should signal the economic value of providing the service.
> - If DNSPs are to remain viable prices must recover, but not over-recover, allowed revenues. Because average costs are typically above incremental costs (unless the network is congested), the requirement for revenue recovery may conflict with the requirement for economic efficiency.
> - Distribution networks provide an essential service for many users. With very limited alternatives available, network prices affect the distribution of costs and benefits across users. Price changes may cause significant adjustment costs for some network users.

The financial implications of DM for DNSPs is a complex subject, which includes consideration of:

- The direct and indirect costs of implementing DM initiatives
- The value of reduced or deferred capital and operating expenditure, and how this affects DNSPs under the regulatory framework
- How the practical impact of DM initiatives can be measured or determined, as they cannot be directly measured. It is common for network investments to be deferred (or brought forward) from their originally forecast date by several years without DM, due to uncertainty in load forecasting and changes to the timing or details of new developments. Separating these effects from those specifically due to DM will be difficult and imprecise in practice.
- The length of regulatory determinations, and boundary issues that occur at each determination.
- How the benefits of DM are shared between DNSPs, participants, and other end-users?
- Who bears the risk of DM initiatives that are unsuccessful in deferring investments? Is this equitable considering the sharing of benefits in the previous point.
- Is the framework neutral with respect to the different DM options available, such as interruptable loads, energy efficiency initiatives and embedded generation.

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3.1 WAPC regulation for DNSPs

The form of regulation for NSW DNSPs from 1 July 2004 is a weighted average price cap (WAPC), with separate arrangements for the pass through of TUOS costs[5]. The weighted average price cap (WAPC) sets the maximum allowable revenue per unit of consumption, based on the efficient costs of supply determined by the Tribunal as part of its current review. Consumption includes not only energy, but also fixed (customer) charges, and demand and capacity charges. In this respect, the WAPC is superior to other price caps, such as an average revenue yield cap, that only adjust for energy volumes and embody a strong disincentive to DM. To the extent that the WAPC includes other components, such as demand and fixed charges, the natural energy volume incentive in price caps is diluted, but still exists.

The Tribunal has also foreshadowed the possibility of other correction and incentive mechanisms, including a passthrough of avoided distribution costs associated with DM in line with the recommendations of its Inquiry into Demand Management. These are proposed to be implemented as passthrough items outside the WAPC.

The formula for the WAPC is:

$$\frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{ij}^{t+1} \times q_{ij}^{t-1}}{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{ij}^{t} \times q_{ij}^{t-1}} \leq (1 + CPI_t - X\ )$$

where:

n is the number of tariffs

m is the number of tariff components

p_{ij}^{t} is the current price charged for component j of tariff i

p_{ij}^{t+1} is the proposed price charged for component j of tariff i

q_{ij}^{t-1} is the quantity sold (billed) for component j of tariff i in the previous year

CPI_t is the change in the consumer price index for year t

X_{t+1} is the efficiency factor for year t+1.

[5] The form of regulation for subsequent determinations has not been determined, and may or may not be a WAPC.

Which gives total DUOS revenue for year t of:

$$\sum_{i=1}^{m}\sum_{j=1}^{n} p_{ij}^{t} \times q_{ij}^{t}$$

The parameters defining the WAPC [6] are fixed for each regulatory period, having been determined by the Tribunal in its determination at the start of the period. In setting the WAPC parameters, the Tribunal considers efficient costs that include an allowance for forecast capital expenditure, and a forecast of consumption volumes over the regulatory period. To the extent that growth is higher or lower than the forecast, the WAPC will automatically adjust the DNSPs overall revenue at the margin.

WAPC regulation embodies a number of inherent incentives and profit drivers for DNSPs:

- Minimise capital expenditure
- Set prices at an efficient level (in order to maximise volumes)
- Maximise volume / throughput. Under a WAPC, this includes not just energy, but other chargeable components as well (customer numbers, demand, capacity, etc).
- Weight price structures towards those tariff components with the highest growth.

Successful DM will reduce demand and capacity volumes, and most likely energy consumption. Well targeted DM will also reduce consumption of the components with the highest prices (peak demand or energy components, or under congestion pricing those with the highest time or seasonally based prices). These impacts are incompatible with the inherent WAPC incentives outlined above, and as such constitute a disincentive to implementing DM. The Tribunal has already identified the issue of perverse incentives under a WAPC [7].

> Some of the options the Tribunal is considering are biased in relation to demand management and distributed generation. Both the weighted average price cap and revenue yield price cap would create a clear financial disincentive for DNSPs to use appropriate demand management practices, as under these forms of regulation their income is linked to the amount of electricity they distribute. As a result, DNSPs may choose to augment their network even though demand management strategies may be more efficient.

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[6] The WAPC is given effect by the Tribunal defining P_0 (prices in the first year of the determination) and X (the efficiency factor) for the period of the determination. Changes in (weighted average) prices, and hence DNSP revenues *for a given volume* are deterministic, or can be considered fixed for the purposes of analysis in this report. This should not be confused with a fixed revenue cap, where revenues are actually fixed (regardless of volume) for the period of the determination.

[7] *Form of economic regulation for NSW electricity network charges* – IPART discussion paper Aug 2001.

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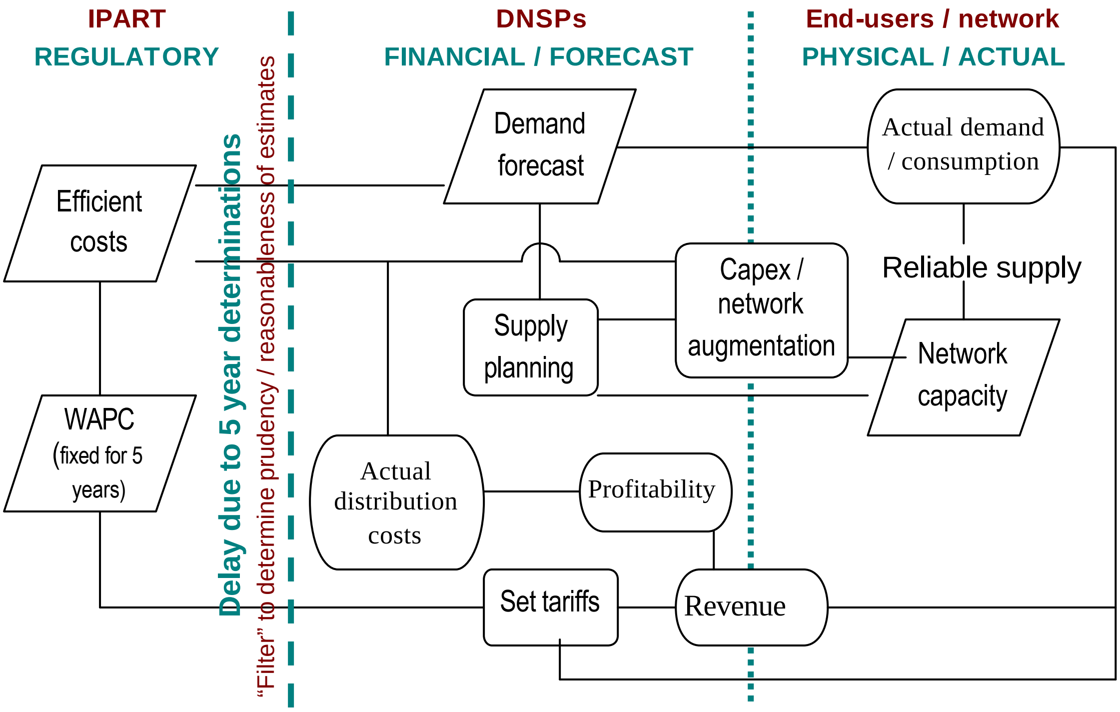
In comments on the draft report, DNSPs noted that they do not actively seek to increase sales volumes. While this is not disputed, the change from a revenue cap to a WAPC has introduced a financial disincentive to *reducing* sales through DM that should be addressed to ensure DNSPs are not penalised for implementing DM.

Note there is an effective two year lag on volumes used to set prices under the WAPC formula. That is, prices for year t+1 are set on the basis of volumes in year t-1. Where volumes are stable this is not a material issue, but for new or volatile tariffs or consumption components there will be additional complexity and administrative costs. This delay could also be significant in adjusting for lost revenues resulting from DNSPs implementing DM initiatives.

3.2 Financial impacts of demand management

The links between physical, financial and regulatory processes in setting prices and ultimately the profitability of DNSPs are described in Figure 1 below:

▪ **Figure 1 Information flows determining DNSP revenue and profitability**

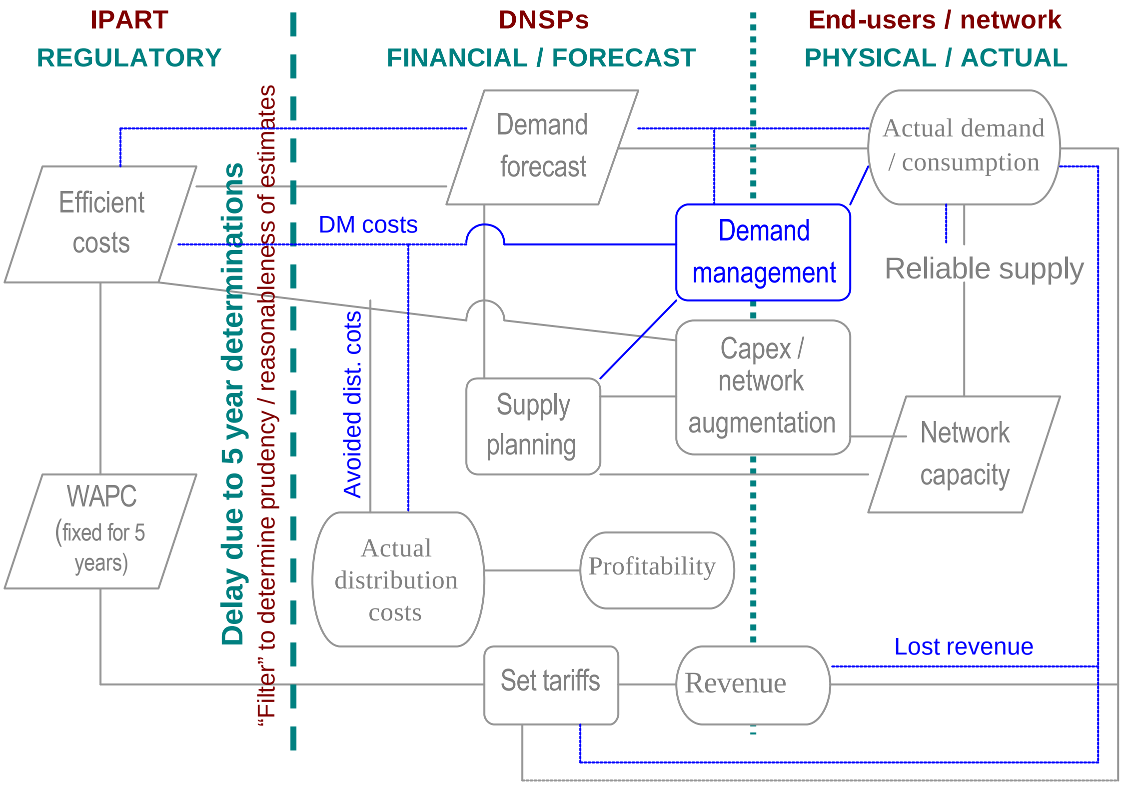


The financial impacts of DM on DNSPs can be grouped into three broad categories:

- Reduced capital and operating costs as a result of deferring network investments
- The cost of implementing DM
- Lost revenues as a result of changes to sales volumes

In practice, DM adds an extra feedback loop to the above process that determines revenues and profitability for DNSPs (demand is no longer unchangeable), and an alternative path for investments. This is illustrated in the modified process diagram Figure 2. The problem is that demand management costs and impacts on consumption and demand are not currently integrated into the regulatory process (dotted lines), while DM costs to DNSPs and lost revenues are real.

- **Figure 2 Impact of Demand Management on DNSP revenues and profitability**



The deferral of network augmentation will result in lower costs of providing distribution for the DNSP ("avoided distribution costs"), as it has deferred capital and operating costs that gives rise to a net present value benefit. Revenues are changed as a result of reduced consumption volumes, and can also be affected in future determinations due to changes in the WAPC parameters that determine average prices and hence revenues.

Revenue and cost impacts of DM may continue into subsequent determination periods, and the regulatory reset process must also be considered in analysing the regulatory barriers and their solutions. The case where these financial impact streams cross a determination period boundary further complicates the analysis of the financial impacts of DM.

These issues are considered in the following sections, by considering the marginal financial impacts on DNSPs under the WAPC for each of the cases identified, assuming no adjustments or allowances are made for DM (that is, as if they were regulated under a "pure" WAPC with no passthroughs or adjustment for DM). For the sake of simplifying the analysis, each impact has been isolated (that is, as if it occurred on its own and was not linked to other impacts).

3.2.1 Allocation of avoided distribution costs

Avoided distribution costs are the reduction in distribution costs that arise from implementing demand management, or the difference between the (optimal) cost of network augmentation and operation without DM, and the cost of network augmentation and operation with DM, including allowance for the time-vale of money. It is in effect the value or benefit created by DM, excluding the cost of DM itself and lost revenue impacts which are considered separately[8].

As demonstrated by the case study presented in Section 4, the allocation of the benefit of avoided distribution costs between DNSPs and end-users is dependent on the interplay between two factors – the actual distribution costs incurred by DNSPs and the cost savings that result from DM, and whether these savings are reflected in regulated network revenues[9]. In practice, the "raw" or pure WAPC framework does this in a haphazard manner, depending on individual circumstances and the timing of DM implementation and impacts relative to regulatory determinations.

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[8] Some parties have expressed a view that avoided distribution costs should be defined as "avoided DUOS", and passed through to embedded generators in a manner similar to the current treatment of "avoided TUOS". The Tribunal's *Inquiry into DM* report recommends further consideration be given to this. SKM is of the view that an "avoided DUOS" approach is inefficient, as it may result in payments to generators where there is no benefit to the network in terms of capital savings or deferrals. The correct approach should be to treat incentives to embedded generators equally with other DM options, by including them as DM implementation costs, which are capped at the actual "avoided distribution costs" for the item of capital expenditure being considered. In this way, a proportion of avoided distribution costs is effectively passed to embedded generators, where the generator results in an actual cost saving.

[9] Under the WAPC it is not revenue that is regulated, but prices in the first year of the determination (P_0) and X in the WAPC formula. That said, the price path under the WAPC is effectively fixed for the period of a determination (subject to CPI which is beyond the control of the DNSP), which directly controls overall revenues for a given consumption volume (ignoring DM impacts which are considered separately).

The cases that can occur are:

- Regulated revenues exceed actual costs; the benefit is effectively transferred to the DNSP,
- Regulated revenues are reduced to reflect the reduction in actual costs; the benefit is effectively transferred to end-users, or
- A combination of the above (in different time periods).

Definition of "regulated revenue":

Note that where this report refers to "*regulated revenue*" it should be considered as shorthand for "*DNSP revenue earned as a function of prices determined under the WAPC formula, using the WAPC parameters* (*P_0* & X) *which are fixed for the period of a determination*", for a given consumption volume. The Tribunal regulates the WAPC parameters in order to allow the DNSPs to recover what it has determined to be fair and efficient costs for the period of a determination. That is, while it is (weighted average) price and not revenue that is actually regulated, DNSP overall revenue for a given consumption volume (ignoring marginal impacts of DM) is effectively fixed for the period of a determination).

Reduced costs

A DNSP deferring capital expenditure will reduce its costs at the margin by avoiding capital and operating costs for the duration of the deferral ("avoided distribution costs"). This cost saving is internal to the DNSP, and is not affected by the regulatory framework or determination period boundaries or resets. It might be one or a combination of:

- The value of deferring the same investment by one or more years
- Reducing the size of the investment by employing DM to allow a lower cost option to be used
- Using embedded generation capacity to replace, change or defer a specific network investment
- Any savings (or increases) in operating costs due to DM.

Quantifying actual avoided distribution costs will be uncertain and subjective in practice. For example there may be changes to the timing of network augmentations due to economic growth, technology changes (such as reduced cost of air-conditioning), or planned developments being deferred or changed for reasons other than DM. These impacts will need to be separated from deferrals brought about by DM through examination of the practical impact that DM initiatives.

Determining the operating cost component of avoided distribution costs may also be complex in practice. On average, operating costs amount to around 2% of DNSPs depreciated asset values, but the marginal costs are not necessarily linked to new investments as simply as this. Deferral of investments may in some circumstances increase operating costs, as changes to network configuration are made to optimise available capacity. It is proposed that average operating costs be used when avoided distribution costs need to be quantified, unless the DNSP can identify particular operating costs specifically linked to DM initiatives.

Regulated revenues

The regulated revenues of DNSPs may also be affected by DM initiatives. In setting the WAPC the Tribunal considers the efficient costs of distribution, using building block costs for return on capital, return of capital, and operating costs. The capital values used include existing network assets, plus forecast capital expenditure over the period of the determination.

If DM has reduced the asset base at the start of a determination, or will defer an investment through or beyond the period of the determination, it will reduce the asset base used by the Tribunal to determine building block costs. Where these building block costs are reduced, they will flow through to lower WAPC prices and hence regulated revenues for the period of the determination.

Where this occurs, the reduction is in line with reduced costs for the DNSPs, and so should not be regarded as a penalty or reduction in profits. It does, however, result in no incentive to pursue DM initiatives, nor any pool of funds from which DM costs may be funded.

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Effective allocation of avoided distribution costs under a pure WAPC

When the combination of reduced costs and regulated revenues are considered, the effective allocation of avoided distribution costs can be determined. This is shown in Table 1 below, noting that the analysis below:

- looks only at the marginal impact on a particular capital item deferred by DM. Whether the capital or volume forecasts are correct, or WAPC revenues are otherwise above or below efficient costs, is immaterial. Likewise, whether a particular item is included in the capital forecast does not matter, as the marginal cost reduction and revenue impacts will be the same,
- looks only at *network* costs, and does not consider DM costs which are discussed later, and
- ignores lost revenues due to consumption volume impacts of DM, which are likewise considered separately.

Table 1 Allocation of avoided distribution costs under a WAPC

Circumstances	Effect on DNSP through WAPC
1. Deferral is within one regulatory period, and not included in capital forecast for that period. (most likely for DM projects towards the end of a determination period)	Actual distribution costs are reduced. The WAPC parameters are fixed for the period of the determination, based on building block costs for the capital item from the originally planned date (that is, they are not reduced to reflect reduced costs). DNSP revenue is unchanged, while costs are reduced. Revenues are above efficient costs and *avoided distribution costs are allocated to the DNSP*.
2. Deferral is within one regulatory period, and is included in capital forecast for that period. (most likely for DM projects at the start of a determination period)	Actual distribution costs are reduced. The WAPC parameters are fixed for the period of the determination, based on building block costs for the capital item reflecting the deferral (that is, they are reduced to reflect reduced costs). DNSP revenue is reduced in line with reduced costs, and *avoided distribution costs are allocated to end users (through lower prices).*
3. Deferral crosses a regulatory boundary. That is, it is deferred from one period to the next.	Actual distribution costs are reduced, regardless of regulatory boundaries. ***In the first period:*** WAPC parameters for the first determination based on costs from the originally planned date (not reduced to reflect reduced costs). DNSP revenue in the first period is unchanged, though costs are reduced. Revenue is above efficient costs and *avoided distribution costs are allocated to the DNSP*. ***In the second period:*** Starting capital value of the network will exclude the capital item that has been deferred, which will now appear in the forecast for the second period at the deferred date. The WAPC parameters for the second period are based on building block costs that reflect the deferral (that is, they are reduced to reflect reduced costs). DNSP revenue in the second period is reduced in line with reduced costs, and *avoided distribution costs are allocated to end users).*

In summary, the possible cases are outlined below and in Figure 3:

- ***Where the deferral IS NOT reflected in the building block costs and WAPC:*** DNSP regulated revenues will not reflect the cost reduction that actually occurs, and avoided distribution costs are effectively transferred to the DNSP.

  This will generally occur for capital items later in a determination period, where DM planning and assessment was not completed at the time that capital forecasts used in the determination were prepared and reviewed.

- ***Where the deferral IS reflected in the building block costs and WAPC:*** DNSP regulated revenue is reduced in line with the actual cost reduction (due to reduced capital and associated costs), and avoided distribution costs are effectively transferred to end-users.

  This will generally occur for capital items early in a determination period, where capital forecasts take into account DM planning and assessment that indicate DM is viable.

- ***Where the deferral crosses a regulatory boundary:*** A combination of the two cases above will occur. In the first period, the deferral will not affect regulated revenues, and the proportion of avoided distribution costs that occur in the first period are transferred to the DNSP.

  The asset value of the network at the start of the second determination will be reduced at the margin by the value of the capital item deferred (though it will generally appear later in the new capital forecast, unless it has been deferred by more than 5 years). WAPC and hence regulated revenue at the margin is reduced in line with actual costs, and the proportion of avoided distribution costs that occur in the second period are transferred to end-users.

- **Figure 3 Allocation of avoided distribution costs relative to determination boundaries**

Scenario	**Deferral not reflected in regulated WAPC revenue**	**Deferral is reflected in regulated WAPC revenue**	**Capital deferral crosses regulatory periods**
Determination periods	❶ ❷	❶ ❷	❶ ❷
Capital investments	? ?	? ?	? ?
Distribution costs (no DM)	…	…	…
Distribution costs (with DM)	…	…	…
Avoided distribution costs			
Regulated revenues	…	…	…
Allocation of ADC	xxxxx	######	xxxx#####
Key:	? Originally forecast (no DM) capital investment. ? Actual (deferred) investment x Revenue above costs (ADC ? DNSP). # Revenue reduced (ADC ? end-users)		

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3.2.2 Lost revenue

A DNSP implementing DM measures may reduce its sales volumes (energy, demand and capacity components) at the margin[10], and under the WAPC its revenues will be reduced at the margin by a corresponding amount.

The WAPC parameters are set to allow the DNSP to recover its efficient costs. Where these parameters are set based on a consumption volume forecast that does not include the impacts of DM, the DNSP will under recover its efficient costs.

Conversely, if the WAPC parameters were set using a consumption forecast that is lower to reflect the impacts of DM, the DNSP will recover its efficient costs, even though actual volumes are lower as a result of DM. That is, the WAPC parameters are marginally higher to recover the same revenue over a lower consumption volume, and the DNSP is not penalised.

Whether the DNSP loses revenue, or more accurately under recovers its efficient costs, thus depends on whether the impact of DM is included in the consumption volume forecast used to determine the WAPC parameters. These cases are summarised in Table 2 below:

Table 2 Lost revenue due to volume impacts of DM under a WAPC

Circumstances	Effect on DNSP through WAPC
1. In the first determination period (when DM is first implemented)	WAPC parameters are set using a volume forecast at the start of the determination, and are fixed for the period of the determination. At the margin, the DNSP's revenue may be reduced due to volume impacts of DM (on actual energy and demand), and it will under recover its efficient costs.
2. In subsequent determination periods.	The new volume forecast should include the impact of DM on actual volumes, raising the WAPC slightly to recover the allowed revenue (efficient costs) over slightly reduced volumes. That is, there is a self-correcting feedback loop that occurs at the next determination, where reduced volumes will increase regulated prices under the WAPC to compensate. DNSP recovers its efficient costs, and there is no windfall gain or loss.

In summary, lost revenue due to reduced volumes should only occur for the first regulatory period, provided the marginal impact on consumption volumes is reflected in the forecast for the next

[10] Depending on the type of DM measures implemented. If the deferral is achieved wholly through embedded generation measures not connected within end-user's sites, there will be no impact on billable consumption volumes. Interruptability measures will also have a lower impact on consumption volumes than energy efficiency type DM measures.

period. In practice, the extent to which these impacts will be reflected in volume forecasts depends on a number of factors, including the timing of DM impacts, the forecasting method used, and length of historical data used in the forecast. These issues are examined in detail in Appendix B.

3.2.3 Cost of implementing DM

A DNSP implementing DM measures will incur costs in changing the behaviour of end-users or embedded generators, such as the administrative cost of running programs, education or information costs, the cost of installing metering or load control systems, and any performance or interruptability payments or other incentives to participants.

All expenses incurred by DNSPs, including DM implementation expenses, should be reasonable, efficient and prudent. In the case of DM, this will largely be determined by whether the cost of DM is outweighed by the associated benefit of avoided distribution costs.

The Tribunal has previously indicated it will allow DNSPs to recover DM expenses, either through inclusion in operating cost allowance included in the building blocks or as an explicit passthrough for unforseen DM expenditures between determinations. To date only one DNSP has applied for recovery of DM costs (which were approved by the Tribunal), and consequently DNSPs have little experience in the operation of this undertaking under the current framework. As a result of this lack of experience, DNSPs have expressed some concerns that it may be more difficult to recover unexpected operating costs (DM costs) at a subsequent review than recovering unexpected capital costs (network investments, which are generally rolled into the asset base).

4. Case Study – Castle Hill DM project

The following case study highlights the financial impacts on DNSPs outlined in the previous section. Integral Energy are currently facing a network constraint in the Castle Hill area that will push peak demand beyond acceptable network capacity and require action to be taken by 2005. In conjunction with SEDA, Integral Energy are seeking DM options that can defer the need to invest in additional network capacity for up to three years.

Load growth in the area is averaging 0.6-0.7 MVA per annum. Without DM, network augmentation costing $3.2m will take place in 2004 and 2005. A number of possible DM projects have been identified, focussing on efficiency and control improvements with major end-users in the Castle Hill supply area, that indicate it may be possible to defer the need for network augmentation by up to three years through DM

The base case and expected impact of DM are shown in the table below. All costs are in $000, showing only the marginal cashflows associated with the additional capacity. The financial analysis presented here is simplified[11], and assumes that DM expenses are recovered by the DNSP as per the existing arrangements. It is calculated under the WAPC regime, as this is the form of regulation that will apply from the next determination (when any recommendations from this report would be adopted)[12], and assumes the DNSP bears the cost of DM implementation (that is there is no explicit pass through of DM costs)..

[11] Cashflows and impacts are simplified and for illustrative purposes, based on data kindly provided by Integral Energy. Building block approach to determining efficient costs is derived from IPART *Regulatory arrangements for the NSW Distribution Network Service Providers from 1 July 2004 Issues Paper*, DP58 November 2002. Key assumptions: All cashflows are in 2003 dollars. NPV based on WACC = 7.5% and 2003/4 base year. Operating costs 2% of depreciated capital. Depreciation 2% straight line. Does not include tax or inflation effects.

[12] Revenue regulation currently in place will impact differently on DNSPs revenues, but is irrelevant for changes made in the upcoming determination, when the WAPC framework will be adopted.

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4.1 Capital costs

The capital costs, and associated timing with and without DM are shown in Table 3.

Table 3 Castle Hill network augmentation capital and timing

Year	2002/3	2003/4	2004/5	2005/6	2007/7	2007/8	2008/9	209/10
Network determination period	Current		Next					Next+1
Capital expenditure without DM	-	$2,000	$1,200	-	-	-	-	-
Capital expenditure with DM	-	-	-	-	$2,000	$1,200	-	-

4.2 Avoided distribution costs

By deferring capital expenditure, Integral Energy will reduce its costs for the period of the deferral. This is shown in Table 4 below:

Table 4 Castle Hill avoided distribution costs

Year	2002/3	2003/4	2004/5	2005/6	2007/7	2007/8	2008/9	209/10
Network determination period	Current		Next					Next+1
Without DM								
Capital expenditure	-	$2,000	$1,200	-	-	-	-	-
Operating costs (2% of capex)	-	$40	$64	$64	$64	$64	$64	$64
Total cashflows	-	$2,040	$1,264	$64	$64	$64	$64	$64
With DM								
Capital expenditure	-	-	-	-	$2,000	$1,200	-	-
Operating costs (2% of capex)	-	-	-	-	$40	$64	$64	$64
Total cashflows	-	-	-	-	$2,040	$1,264	$64	$64
Marginal impact of DM (Avoided Distribution Costs)								
Cashflow benefit (cost) of DM	**-**	**$2,040**	**$1,264**	**$64**	**($1,976)**	**($1,200)**	**-**	**-**
Avoided distribution costs (NPV)	$727							

Assuming a WACC of 7.5% for Integral Energy the net present value (NPV) of the cash benefit from DM to is $727,000. For DM to be efficient and cost effective, the NPV of DM costs should be less than this amount. The additional (non cash) benefits of avoided depreciation, and the future economic benefit associated with deferring the replacement of the assets at the end of their life (40 or 50 years) have been ignored in this analysis.

4.3 Demand Management Costs

The final cost of implementing DM at Castle Hill is not yet known, so the figures presented below are current best estimates of the total cost . For the purposes of this case study, DM costs of $220 / kVA have been assumed.

Table 5 Castle Hill typical demand management costs

Year	2002/3	2003/4	2004/5	2005/6	2007/7	2007/8	2008/9	209/10
Network determination period	**Current**		**Next**					**Next+1**
MVA above limits[13]		0.5	1.0	1.5	2.0	2.5	New supply capacity added	
Incremental DM capacity required (MVA)		0.5	0.5	0.5	Decision to commit to new capacity			
DM implementation costs	**$-**	**$110**	**$110**	**$110**	**$-**	**$-**	**$-**	**$-**

4.4 Impact on WAPC regulated revenue allowance

Because the proposed deferral at Castle Hill crosses a determination boundary, there is the potential for Integral Energy's regulated revenues to be reduced. Regulated revenues during the current determination period (1999-2004) will not be affected. The Tribunal's consultants conducting the review of capital and operating cost forecasts for the 2004-2009 determination have indicated to Integral Energy that the capital forecast should take into account the intended deferral of capital investment at Castle Hill, which will have the effect of reducing the building block efficient costs and hence regulated revenues Integral Energy receives under the WAPC in the 2005-2008 determination period. This reduction is in line with reduced costs incurred by Integral Energy, so there is no loss, but also no incentive to conduct DM.

The Tribunal's Inquiry into Demand Management found that DNSPs should be able to recover the cost of efficient DM. To date, there has only been one case where a DNSP has applied to the Tribunal for DM costs to be recovered, so there is little experience with this mechanism. For this case study, it is assumed that Integral Energy will seek to recover the costs of DM at Castle Hill, and the Tribunal will allow this as a prudent operating cost (that is, Integral Energy will receive additional revenue through a building block allowance or passthrough in addition to the WAPC). It is assumed that recovery of DM implementation costs lag actual expenditures by 2 years, as any passthrough amount must be known before it can be approved, which effectively means it cannot

[13] This is the amount that load would exceed capacity by in the absence of DM or supply side actions. It does not imply this will actually occur, but is the size of DM impact required to maintain reliable supplies.

be recovered until the second year after it is incurred. It is assumed the Tribunal will allow working capital costs to be included in the amount recovered.

- **Table 6 Castle Hill impact on Integral Energy regulated revenues**

Year	**2002/3**	**2003/4**	**2004/5**	**2005/6**	**2007/7**	**2007/8**	**2008/9**	**209/10**
Network determination period	**Current**		**Next**					**Next+1**
Without DM								
Actual Capital expenditure	-	$2,000	$1,200	-	-	-	-	-
Capital expenditure included in regulatory forecast	-	$2,000	$1,200	-	-	-	-	-
DNSP regulated revenue (using building block approach)								
Return on capital (financing)	$-	$150	$237	$232	$228	$223	$219	$214
Return of capital (depreciation)	-	$40	$64	$64	$64	$64	$64	$64
Operating costs	-	$40	$64	$64	$64	$64	$64	$64
Regulated revenue	-	$230	$365	$360	$355	$351	$346	$341
With DM								
Actual Capital expenditure	-	-	-	-	$2,000	$1,200	-	-
Capital expenditure included in regulatory forecast	-	$2,000		-	$2,000	$1,200	-	-
DNSP regulated revenue (using building block approach)								
Return on capital (financing)	-	-	-	-	$150	$237	$232	$228
Return of capital (depreciation)	-	-	-	-	$40	$64	$64	$64
Operating costs	-	-	-	-	$40	$64	$64	$64
Regulated revenue	-	$230	-	-	$230	$365	$360	$355
Marginal difference (Change in regulated revenue)								
Increase (decrease) in regulated WAPC revenue	$-	$-	($365)	($360)	($125)	$14	$14	$14
DM implementation costs	$-	$110	$110	$110	$-	$-	$-	$-
Assumed DM cost passthrough	$-	$-	$-	$127	$127	$127	$-	$-
Total impact of DM on regulated revenues (WAPC + DM cost passthrough)	**$-**	**$-**	**($365)**	**($233)**	**$2**	**$142**	**$14**	**$14**

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4.5 Lost revenues through reduced volumes

Implementing DM actions may reduce energy and demand consumption volumes for end-users. Given the load growth information provided by Integral Energy, the DM impact required is shown in the table below. For this case study, reduced consumption volumes associated with "energy efficiency" type DM measures have been estimated[14]. It is assumed that DM impacts are included in the forecast at each regulatory determination (that is, lost revenue lasts for one regulatory period only, as per section 3.2.2).

Table 7 Castle Hill volume and revenue impacts

Year	**2002/3**	**2003/4**	**2004/5**	**2005/6**	**2007/7**	**2007/8**	**2008/9**	**209/10**
Network determination period	**Current**		**Next**					**Next+1**
MVA above rating[15]		0.5	1.0	1.5	2.0	2.5		
Incremental DM capacity required (MVA)		0.5	0.5	0.5	0.5	0.5	New capacity added	
Marginal reduction in consumption volume (MWh)	-	1,643	3.290	4,940	4,446	4,002	3,602	3,241
Lost revenue[16]	**$-**	**($71)***	**($71)**	**($142)**	**($121)**	**($101)**	**($84)**	**$-**

* To illustrate the effect of DM under the WAPC framework, as if a WAPC was currently in force. In fact, the current determination period is a revenue cap, and so there is no actual lost revenue in this case. Lost revenues from 2003 and 2004 are corrected at the reset, so lost revenues for 2005 are for new DM measures implemented that year.

As outlined in Appendix B, the lost revenue impacts are dependent on the timing of DM measures relative to regulatory determinations and the volumes forecasts used at those determinations. In the case of Castle Hill, much of the DM impacts will occur after the 2004 determination, and will result in lost revenues over the next 5 years (that is, the timing of Castle Hill is effectively the worst case). In other circumstances, DM impacts that occur before a determination will generally flow through to the volume forecasts for that determination, and will effectively eliminate lost revenues.

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[14] Estimates of reduction in sales volume assumes using typical load profiles and power factor, and that half the DM impact comes from interruptable / dispatchable measures (that can be stopped once the constraint has ended), with the other half from permanently installed energy efficiency or load control measures that will continue to operate. Volume impacts at 10% pa after DM implementation ends (when capacity is installed) to account for customer churn, measures that were brought forward and performance creep.

[15] This is the amount that load would exceed capacity by in the absence of DM or supply side actions. It does not imply this will actually occur, but is the size of DM impact required to maintain reliable supply.

[16] Lost revenue is calculated at a constant DUOS price of 4.3¢/kWh. At each regulatory reset the volume forecast reflects the impact of DM measures previously implemented, and the WAPC is marginally higher to recover the same revenue over a marginally lower volume. In effect, lost revenue only occurs for one period.

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4.6 Overall economic and financial impact

When all the above impacts are considered, the net financial impact of implementing DM at Castle Hill on Integral Energy is:

- **Table 8 Overall financial impact of proposed Castle Hill demand management initiatives**

Year	2002/3	2003/4	2004/5	2005/6	2007/7	2007/8	2008/9	209/10
Network determination period	**Current**		**Next**					**Next+1**
Capital and operating costs (Avoided distribution costs)	$-	$2,040	$1,264	$64	($1,976)	($1,200)	$-	$-
DM implementation costs	$-	($110)	($110)	($110)	$-	$-	$-	$-
Total DM impact	**$-**	**$1,930**	**$1,154**	**($46)**	**($1,976)**	**($1,200)**	**$-**	**$-**
WAPC regulated revenue*	$-	$-	($365)	($360)	($125)	$14	$14	$14
Lost revenue volume impacts	$-	($71)	($71)	($142)	($121)	($101)	($84)	$-
Passthrough recovery of DM implementation costs	$-	$-	$-	$127	$127	$127	$-	$-
Total regulated impact	**$-**	**($71)**	**($436)**	**($375)**	**($119)**	**$40**	**($70)**	**$14**
Overall financial impact (DM + regulated)	**$-**	**$1,859**	**$718**	**($421)**	**($2,095)**	**($1,160)**	**($70)**	**$14**

* Additional $14,000pa from 2008 is due to increased cost of capital on less depreciated assets, and equals the increased return on capital going forward.

- **Table 8b Net Present Value (NPV) of Castle Hill impacts**

Impact (NPV)	**Integral Energy**	**End-users**	**Net economic impact***
Avoided distribution costs	$727	$-	$727
DM implementation costs	($286)	$-	($286)
DM impact	**$441**	**$-**	**$441**
Change in WAPC regulated revenue	($605)	$605	$-
Lost revenue due to volume impacts	($457)	$457	$-
Passthrough recovery of DM implementation costs	$286	($286)	$-
Regulated impact	**($775)**	**$775**	**$-**
Total financial impact including DM + regulatory impacts	**($334)**	**$775**	**$441**

* The net economic impact is simplified (the net impact of network cashflows for Integral Energy + end-users) and ignores other effects (such as DM costs and energy revenue impacts for end-users). It is intended to give an approximation of the net economic benefits of DM considering the financial impacts on the DNSP and end-users. NPVs are calculated at 7.5% discount rat e for 20 years (2003 – 2022).

From this case study, it is apparent that in this case Integral Energy is financially disadvantaged when implementing cost effective DM that is economically attractive. While DM is economically attractive (avoided distribution costs exceed DM costs), the financial impacts on Integral Energy are negative (a marginal loss of $334,000).

This loss to Integral Energy is caused by:

- The reduction in WAPC regulated revenue in the 2004-2008 regulatory period in line with Integral Energy's avoided distribution costs. This has the effect of allocating virtually all the avoided distribution costs to end-users (through reduced prices).
- Lost revenue due to reduced volumes of $457,000 up to the start of the 2010 determination (when the new volume forecasts will eliminate any lost revenue going forward).
- Offset by the recovery of DM implementation costs, assuming these are judged to be prudent by the Tribunal

These are the key problems that need to be addressed by regulatory and policy responses in order to align the financial drivers for DNSPs with the economic benefits of DM. In general, if the allocation of avoided distribution costs and DM implementation costs is aligned, then there will be a mechanism for funding DM. Whichever way these costs and benefits are allocated, any volume impacts of DM must be corrected to remove the lost revenue disincentive for DNSPs under the WAPC.

5. Integrating DM within the regulatory framework

In order to properly integrate DM into the regulatory framework for DNSPs, the overall costs and benefits should be recognised and treated appropriately. In practice this means eliminating the financial disincentives, and in line with the Tribunal's preference for incentive regulation, providing DNSPs with an efficiency driver to seek cost effective DM options.

Under the current (1999-2003) determination using a fixed revenue cap, the lost revenue problem is avoided (at least in the short term, though regulated revenues could still be reduced at the next determination in line with reduced costs), and provides for recovery of DM costs. The move to a WAPC regulatory framework from July 2004 changes these financial drivers on DNSPs. From section 3.2 and the case study in section 4 the following financial impacts are evident:

- DNSPs network costs are reduced ("avoided distribution costs"), with the assignment of this benefit depending on whether regulated revenues are reduced in line with reduced the costs.
- There is a cost of implementing DM, which is initially borne by DNSPs (though these may currently be recovered if the DNSP makes representation to the Tribunal).
- DNSPs may lose revenues due to consumption volume impacts

The sections below outline how each of these impacts should be treated in order to achieve fair and equitable outcomes for DNSPs and end-users, and align the financial drivers for DNSPs with economic outcomes and end-users interests. Two corrections are required to achieve this outcome:

- The allocation of avoided distribution cost (benefit), and DM implementation payments (costs) should be aligned, with both allocated to either DNSPs or end-users.
- An adjustment for any lost revenues to DNSPs through reduced consumption volumes.

Allocating the avoided distribution cost benefit and DM implementation costs to DNSPs effectively transfers the overall net benefit (efficiency improvement realised through DM) as well as the risks (that DM costs will exceed avoided distribution costs) to the DNSP. This is consistent with the Tribunal's preference for incentive regulation, and gives DNSPs an incentive to pursue cost effective DM. Allocating the avoided distribution cost benefit and DM implementation costs to end-users effectively transfers the net benefit and risks to end-users. This is effectively a "pass through" model, and gives the DNSP no incentive to pursue DM. In both cases, lost revenues must be adjusted to neutralise this disincentive to DNSPs. The characteristics of the two models are shown in the following table.

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Table 9 Characteristics of Incentive and Cost Recovery models for funding DM

	Incentive	Cost recovery
Avoided distribution costs DM Implementation costs Risks and benefits of DM	Allocated to DNSP	Allocated to end-users
Lost revenues	Should be corrected under either model. Treatment is identical.	
Advantages	▪ Consistent with incentive regulation philosophy. ▪ Provides an incentive to DNSPs to pursue DM. ▪ DNSPs have an incentive to minimise DM costs, and DM risks are allocated to DNSPs (who are best able to control them). ▪ IPART does not have to monitor or approve DM costs.	▪ Consistent with current treatment of DM and previous undertakings by the Tribunal. ▪ WAPC revenues based on "actual" assets, capex and opex – simpler to determine. ▪ Returns an efficiency dividend to end-users. ▪ DM costs are treated like other operating costs. No need to define a boundary. Equal treatment of congestion pricing and demand management payments (both recovered from end-users). ▪ Allows DNSPs to recover costs associated with directions regarding DM implementation (for example, a requirement to make standard offers or include environmental externalities).
Disadvantages	▪ Inconsistent with previous undertakings by the Tribunal (12A report and DM Inquiry) that DNSPs can recover DM costs as operating costs. ▪ Does not return an efficiency dividend to end-users. ▪ WAPC revenues determined on the basis of estimated "without DM" assets, capex and opex. Need to separate DM impacts from other impacts (such as forecast loads being deferred or brought forward). ▪ Payments classified as "congestion pricing" or "demand management" are treated differently.	▪ Does not provide DNSPs with an incentive to pursue DM. ▪ IPART must assess prudency of DM costs and allow them as an operating or passthrough cost. ▪ IPART must estimate the level of "avoided distribution costs" during a determination and return them to end-users. Difficult and subjective in practice.

The preferred integration option is the "incentive mechanism" that allocates avoided distribution costs and DM costs to DNSPs, and allows DNSPs to retain the net benefit created through DM in the short term. Over time (subsequent determinations), it is expected that some of this efficiency dividend will be returned to end-users. The mechanism for implementing the alternative "cost recovery" model is shown in Appendix C.

It is considered appropriate to return the full benefit of DM to DNSPs for the next determination period at least, in order to encourage uptake of DM. Given the current inexperience in using DM, it is likely that DM costs will be close to (or even exceed) avoided distribution costs in the short term, meaning there will be little if any windfall for DNSPs. Over time as learning and experience grows, the cost of DM can be expected to fall, resulting in higher benefits, some of which should be returned to end-users.

This implies the most suitable mechanism may change over time, and subsequent determinations will benefit from improved knowledge of the costs and scope of DM. It is recommended that there be some underwriting of DM cost risks for DNSPs in the short term, in order to encourage trials of DM and learning that can reduce DM costs, uncertainty and risks in the future. In the medium term, it is appropriate that some of the benefits of DM be returned to end-users, and in the longer term as DM becomes "business as usual" a shift towards the cost recovery mechanism may be appropriate (as is the case with controlled hot water loads now).

5.1 Incentive mechanism for DM

Implementation costs for DM should be less than the avoided distribution costs for efficient DM actions. This means that overall costs for the DNSPs are lower, which should provide them with the appropriate incentive to pursue DM initiatives, *provided their revenues are not affected*. This can be achieved in practice by ensuring that regulated revenues remain fixed at what they would have been in the absence of DM, and that under-recovery of revenue due to reduced consumption volumes is corrected. DM implementation costs do not need to be recovered (ie they should not be passed through to end-users), as the regulated revenues already allow for efficient network costs, which should be higher than DM costs.

5.1.1 Allocation of Avoided Distribution Costs

As described in section 3.2.1 the avoided distribution cost benefit or efficiency gain is effectively transferred to DNSPs if their WAPC revenue is not reduced because of DM, and is transferred to end-users if WAPC revenues are reduced in line with the cost reduction brought about by DM.

In order to ensure WAPC revenues are not reduced at the margin by DM, the capital base and forecast used in a determination should include capital items at the date they would have been installed in the absence of DM. This adjustment is only required at each determination (ie not annually between determinations), and is achieved in practice by:

- Including those items subject to DM deferrals at their "without DM" date, when a "bottom up" capital forecast is used (that is, a forecast made up of individually identified projects).
- Specifically adding the capital value deferred to the capital forecast for the years the item is deferred by DM, when a "top down" forecast is used (that is a forecast based on broad growth or other parameters, rather than individually identified capital items).
- Including the capital item when installed (at the deferred date) at a partially depreciated value (as if it had been installed at the original date). This ensures there is no price rise to end-users as a result of less depreciated assets increasing the building block costs used to determine prices.

Reviews of capital forecasts, or network valuations, should include capital items as if they were not deferred by DM. Note that in the absence of specific guidance on this matter, it appears the Tribunal's consultants undertaking the capital and operating cost reviews for the 2004 determination have taken the opposite view (capital forecasts include planned deferrals through DM). If the recommended "incentive mechanism" approach is adopted for the 2004 determination, this will need to be addressed.

Going back to the table of impacts from section 3.2.1 shows how this has addressed the financial impacts:

Table 10 Correction of allocation of avoided distribution costs

Circumstances	Uncorrected allocation of avoided distribution costs	Effect of correction mechanism
1. Deferral is within one regulatory period, and not included in capital forecast for that period. (most likely for DM projects towards the end of a determination period)	Actual distribution costs are reduced. The WAPC parameters are fixed for the period of the determination, based on building block costs for the capital item from the originally planned date (that is, they are not reduced to reflect reduced costs). DNSP revenue is unchanged, while costs are reduced. Revenues are above efficient costs and *avoided distribution costs are allocated to the DNSP.*	No correction necessary. Avoided distribution costs are already allocated to the DNSP.

Circumstances	Uncorrected allocation of avoided distribution costs	Effect of correction mechanism
2. Deferral is within one regulatory period, and is included in capital forecast for that period. (most likely for DM projects at the start of a determination period)	Actual distribution costs are reduced. The WAPC parameters are fixed for the period of the determination, based on building block costs for the capital item reflecting the deferral (that is, they are reduced to reflect reduced costs). DNSP revenue is reduced in line with reduced costs, and *avoided distribution costs are allocated to end users (through lower prices).*	Deferred capital costs are added back into the efficient cost calculations for the DNSP, so that its allowed efficient costs are not reduced (they are above actual costs, at what they would have been in the absence of DM). This additional margin above actual costs effectively transfers avoided distribution costs to the DNSP.
3. Deferral crosses a regulatory boundary. That is, it is deferred from one period to the next.	Actual distribution costs are reduced, regardless of regulatory boundaries. ***In the first period:*** WAPC parameters for the first determination based on costs from the originally planned date (not reduced to reflect reduced costs). DNSP revenue in the first period is unchanged, though costs are reduced. Revenue is above efficient costs and *avoided distribution costs are allocated to the DNSP.* ***In the second period:*** Starting capital value of the network will exclude the capital item that has been deferred, which will now appear in the forecast for the second period at the deferred date. The WAPC parameters for the second period are based on building block costs that reflect the deferral (that is, they are reduced to reflect reduced costs). DNSP revenue in the second period is reduced in line with reduced costs, and *avoided distribution costs are allocated to end users).*	Same as 1 above. Avoided distribution costs are already allocated to the DNSP in the first period where DM is implemented. Same as 2 above. At the regulatory reset (determination process), the capital base or capital forecast should be adjusted to include the item as if it had been installed at the originally planned (without DM) date, in order to allocate the avoided distribution cost benefit to the DNSP.

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5.1.2 Lost revenue due to consumption volume impacts

As described in section 3.2.2 a DNSP implementing DM may reduce consumption volumes at the margin, which will result in under-recovery of regulated revenues. The modelling described in Appendix B shows how this occurs in practice, and that it will automatically be corrected at the next determination, provided DM impacts occur within the window of historical data used for volume forecasts at this next determination.

To correct for lost revenues due to volume impacts will require:

- In the short term (the first determination period), an explicit revenue correction is required.
- In the medium-long term (subsequent determination periods) the consumption volume forecast on which the WAPC is based will include the impact of DM, and the WAPC parameters for these future determinations will be adjusted at the margin to allow full recovery of the DNSPs efficient costs over a lesser consumption volume. No further correction is necessary.

The dividing line between these two cases is the end of the window of actual consumption data on which the most recent determination was made. That is, for the 2004 determination, if the consumption volume forecast is based on data from calendar years 1998 to 2002 inclusive, then any DM measures implemented after the end of 2002 will require a lost revenue adjustment until the 2009 determination. DM measures implemented before the end of 2001 will be fully recognised in the forecast and WAPC parameters for the current determination, and no lost revenue adjustment is necessary. Measures implemented during 2002 may be partially recognised in the forecast and WAPC parameters, and a partial lost revenue adjustment will be required until 2009.

As outlined in Appendix B *Neutralising lost revenue* the Tribunal can only correct for lost revenues if it is made aware that DM has been implemented and that the DNSP is losing revenue as a result of volume impacts. DNSPs should prepare a reasonable estimate[17] of consumption volume impacts and lost revenues each year as part of the process of seeking approval for annual price adjustments.

[17] As outlined in Appendix B consumption volume impacts of DM cannot be directly measured, and so must always be estimated or calculated in some way. DNSPs will need to prepare an estimate of volume impacts and lost revenue using a method and producing results that the Tribunal accept as reasonable.

Going back to the table of impacts from section 3.2.2 shows how this has addressed the financial impacts:

Table 11 Correction of lost revenue due to volume impacts

Circumstances	Uncorrected lost revenue impact	Effect of correction mechanism
1. In the first determination period (when DM is first implemented)	WAPC parameters are set using a volume forecast at the start of the determination, and are fixed for the period of the determination. At the margin, the DNSP's revenue will be reduced due to volume impacts of DM (energy and demand), and it will under recover its efficient costs.	Explicit correction of DNSP revenue to compensate for any lost revenues (should neutralise any incentive or disincentive).
2. In subsequent determination periods.	The new volume forecast should include the impact of DM, raising the WAPC slightly to recover the regulated revenue (efficient costs) over slightly reduced volumes. That is, there is a self-correcting feedback loop that occurs at the next determination, where reduced volumes will increase regulated prices under the WAPC to compensate. DNSP recovers its efficient costs, and there is no windfall gain or loss.	No correction necessary.

5.1.3 DM implementation costs

No adjustment or cost recovery is required. Because DNSPs have been allowed to retain the value created by DM (avoided distribution costs) the cost of DM is borne by the DNSP. This aligns the direct (economic) costs and benefits of DM, and when the lost revenue adjustment is implemented has the effect of aligning the economic and financial incentives to pursue efficient DM.

DM implementation costs should be excluded from the operating costs of DNSPs used in the building block efficient costs.

Where DM and congestion pricing are used together in a constrained area, there may be confusion as to the classification of some costs such as interruptability payments. Section 9.2 recommends that congestion pricing revenues and payments be incorporated within the WAPC, which would have the effect of recovering any congestion pricing payments from end-users, and creating an incentive for DNSPs to classify payments as congestion pricing rather than demand management.

It is recommended in these circumstances that generally available price / tariff only options (where end-users have discretion to respond to price signals, with no contractual or performance obligations, such as voluntary interruption in response to a published or notified price) be considered congestion pricing. Where the DNSPs is more pro-active, and negotiates an individual contract with an end-user, possibly including performance criteria (such as a guaranteed level of interruption, or penalty payments for failing to interrupt) would be classified as demand management. Payments not directly linked to metered consumption (such as incentive payments for installing certain equipment, or standard offers) would always be regarded as demand management payments.

In the short term, as DM capability, knowledge and implementation techniques are being developed and refined by DNSPs, it may be appropriate for some DM investigation and overhead costs (not related to specific capital deferrals) to be treated as efficient operating costs, where DNSPs can demonstrate outcomes and benefits to end-users arising from these activities.

5.2 Timing impacts

In practice, the adjustments required to implement the incentive mechanism will depend on the timing of DM costs and impacts relative to determination boundaries.

▪ **Table 12 Timing of DM relative to determination boundaries**

	On boundary	Within a determination	Crossing a determination
Situation	DM is implemented close to a determination or at the end of a determination period.	DM occurs wholly within a single determination period.	DM impacts and capital deferrals cross a determination boundary
Example	DM implemented in 2003/4 or 2008/9 (Eg Castle Hill)	DM implemented in 2004 – 2007, with deferral not past 2008.	DM implemented during 2004 – 2008, with deferral to 2009 or beyond.
Avoided distribution costs			
Uncorrected asset base and capital forecast	May or may not reflect the deferral due to DM.	Will be based on default (without DM) case.	1st determination period will be based on default (without DM) case. 2nd determination will reflect the deferral due to DM.
Uncorrected allocation of avoided dist. costs	Depends on whether capex forecast includes DM impacts or not.	To DNSP.	To DNSP in 1st determination, and to end-users in 2nd determination.
Correction required	Use default (without DM) capex forecast, or adjust building block costs up as if there was no DM deferral (ie add building block costs for the period of deferral).	No adjustment required.	No adjustment required in 1st determination. Adjust capex and building block as for “on boundary” case for 2nd determination.

	On boundary	Within a determination	Crossing a determination
Lost revenue			
DM impact on volume forecast used to determine WAPC parameters	Will not be included in volume forecast	Will not be included in volume forecast	
Lost revenue impact	Lost revenue will occur for the whole of the determination.	Lost revenue will occur from the implementation date to the end of the determination.	Lost revenue will occur from the implementation date to the end of the 1st determination period. DM volume impacts during the 1st determination period will be reflected in volume forecast for 2nd determination, correcting (eliminating) lost revenue in the 2nd determination. Lost revenue will occur in the 2nd determination period for DM impacts implemented at the end of the 1st determination or during the 2nd determination.
Correction required	Passthrough of lost revenues for the whole of the determination.	Passthrough of lost revenues from the implementation date to the end of the determination.	Passthrough of lost revenues from the implementation date to the end of the 1st determination period. Passthrough of lost revenues from DM impacts at the end of the 1st determination or during the 2nd determination during the 2nd determination period.

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5.3 Detailed implementation mechanisms

Under the incentive mechanism outlined above, there is no need for explicit adjustments or recovery for DM payments and costs, however there is the need for explicit adjustment of lost revenues. The capex and asset values used to determine regulated (building block) revenues may or may not require adjustment depending on timing (if the deferral crosses a determination boundary).

The practical implementation of the incentive mechanism outlined above will require the following assessments and adjustments to DNSPs revenues.

5.3.1 Calculating annual corrections within a determination

As part of the annual process for approving DNSPs prices for the forthcoming year, within a determination period:

- A correction (passthrough) for annual lost revenue impacts due to reduced consumption volume. This requires:

  1) DNSPs present an estimate of annual DM volume impacts and lost revenues to the Tribunal. This should be for actual DM impacts (i.e. from DM projects already implemented), and given data timing issues is likely to lag by 1 or 2 years (that is, lost revenues from 2004/5 will not be recovered until 2005/6 or 6/7, depending on the method used to assess lost revenues).

  2) Tribunal review of the DNSPs estimate as being reasonable (using a method and delivering a result acceptable to the Tribunal), and confirms the DM impacts that are not included in the volume forecast on which the WAPC is based for the year in question (i.e. only DM implemented after the end of the window of actual consumption data on which the volume forecast for the current determination is based).

- No adjustment to regulated revenues to account for capital deferrals (avoided distribution costs) or recovery of DM implementation payments or costs.

5.3.2 Calculating corrections between determinations (regulatory reset)

As part of the process for setting the WAPC for a new determination period:

- Where an item is deferred past the regulatory boundary (i.e. it is not built yet), the building block costs should be determined as if the item had not been deferred by DM.
- Capital forecasts used to determine the building block costs should include items likely to be deferred by DM at their originally forecast date (ie as if they are not deferred by DM) to ensure regulated revenues are not reduced (i.e. allocate avoided distribution costs to DNSP).

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- For deferred assets built during the previous determination period, the value rolled into the asset base should be as if it had not been deferred (that is, partially depreciated by the number of years of deferral achieved), so that the deferral does not increase the building block costs going forward.
- Ensure DM implementation payments or costs are excluded from operating costs.
- Ensure consumption volume impacts of DM programs implemented prior to the determination are captured in the volume forecast used as the basis of the new determination (to eliminate lost revenue going forward).

5.3.3 Integrating the adjustments with the regulatory framework

The regulatory framework includes the WAPC formula for DUOS plus a number of TUOS passthrough items (TUOS, Avoided TUOS, and possibly an avoided distribution cost (DM) adjustment):

$$\frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{ij}^{t+1} \times q_{ij}^{t-1}}{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{ij}^{t} \times q_{ij}^{t-1}} \le (1 + CPI_t - X) \qquad + \text{TUOS} + \text{Avoided TUOS}$$

(DUOS [WAPC] component) (TUOS [passthrough] component)

The corrections outlined in above can either be included in the WAPC, or as one or more passthrough items. The overall results in terms of prices to end-users and DNSP revenues should be identical whichever method is chosen.

Inclusion within the WAPC is attractive in that is minimises the number of passthrough items, but may suffer from a lack of transparency. It is implemented in practice by:

- Including any adjustments for deferred capital in the building block costs to return avoided distribution costs to the DNSP in the actual building blocks, so that they are included in the efficient costs for the DNSP and hence the WAPC parameters.
- No “avoided distribution costs” passthrough factor (other than the correction of building block costs above) is required, as DM costs are borne by the DNSP.
- Including the lost revenue correction for years t and 1 as a “dummy” tariff with a quantity of -1 in the WAPC formula, or determine a “DM factor” calculated to recover the same amount[18]. This has the same effect as a passthrough, but within the WAPC formula, and the negative dummy revenue will allow the other tariffs to be increased to recover this amount.

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[18] So the right hand side of the WAPC formula would become “CPI – X + D” where D is the DM factor.

Alternatively, the corrections can be included as one passthrough item ("DM compensation amount", incorporating avoided distribution costs and lost revenue adjustments), or as two separate passthrough amounts. The result is identical, and is implemented in practice by:

- Calculating the building block costs for the WAPC on the actual capital base and any known planned deferrals (that is, as they are currently calculated).
- Calculate a lost revenue correction for year t as a passthrough item outside the WAPC formula, based on the DM volume impacts and lost revenue estimates claimed by DNSPs.
- Calculate an avoided distribution costs passthrough factor, equal to the building block costs for any capital items that have been deferred due to DM (for items where the capital has been excluded or deferred in the building block costs on which the WAPC is based). This has the effect of transferring the avoided distribution cost benefit to the DNSP, from which it will fund DM implementation costs.

Given the likely uncertainty in factors such as estimates of the length of deferral that can be achieved, it is recommended this adjustment initially be introduced as an ex-post passthrough that can be adjusted each year, rather than incorporating them ex-ante in the WAPC where they can only be adjusted at the next determination. This also has the advantage of increased transparency, and is a clearly identifiable cash stream that DNSPs can see is compensating them for the financial disincentives inherent under the WAPC. This may be an important factor in overcoming some of the cited cultural barriers to DM within DNSPs. In future regulatory periods this could be re-integrated with the building block costs and WAPC as experience and confidence in using this adjustment grows.

5.4 Impact of integration mechanism on Castle Hill case study

When the correction mechanisms as outlined above are implemented, they will result in the following financial impacts for the Castle Hill DM project:

When all the above corrections are considered, the financial impact on Integral Energy would be as shown in

Table 13:

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Table 13 Impact of corrections on Castle Hill demand management initiatives

Year	2002/3	2003/4	2004/5	2005/6	2007/7	2007/8	2008/9	209/10
Network determination period	**Current**		**Next**					**Next+1**
Capital and operating costs (Avoided distribution costs)	$-	$2,040	$1,264	$64	($1,976)	($1,200)	$-	$-
DM implementation costs	$-	($110)	($110)	($110)	$-	$-	$-	$-
Total DM impact	**$-**	**$1,930**	**$1,154**	**($46)**	**($1,976)**	**($1,200)**	**$-**	**$-**
WAPC regulated revenue	$-	$-	($365)	($360)	($125)	$-	$-	$-
Lost revenue volume impacts	$-	($71)	($71)	($142)	($121)	($101)	($84)	$-
Avoided distribution cost passthrough adjustment	$-	$-	$365	$360	$125	$-	$-	$-
Lost revenue passthrough adjustment (2yr lag with allowance for working capital)	$-	$-	$-	$82	$82	$164	$139	$117 (+$97 in 2011)
Passthrough recovery of DM implementation costs	None. Funded from avoided distribution costs retained by DNSP.							
Total regulated impact	**$-**	**($71)**	**($71)**	**($60)**	**($39)**	**$62**	**$55**	**$117**
Overall financial impact (DM + regulated)	**$-**	**$1,859**	**$1,083**	**($106)**	**($2,015)**	**($1,138)**	**$55**	**$117**

Table 13b Net Present Value (NPV) of Castle Hill impacts

Impact (NPV)	Integral Energy	End-users	Net economic impact*
Avoided distribution costs	$727	$-	$727
DM implementation costs	($286)	$-	($286)
DM impact	**$441**	**$-**	**$441**
Change in WAPC regulated revenue after correction	$-	$-	$-
Lost revenue due to volume impacts	($457)	$771	$-
Passthrough recovery of DM implementation costs	No recovery of DM payments or costs		$-
Passthrough recovery of lost revenue	$457	($771)	$-
Regulated impact	**$-**	**$-**	**$-**
Total financial impact including DM + regulatory impacts	**$441**	**$-**	**$441**

It can be seen that this effectively neutralises the disincentives to DM under the WAPC, and leaves Integral Energy with an incentive from achieving savings through DM.

5.5 Managing DM risks in the short term

To date DNSPs have had little experience in the application of DM to deferring network congestion in NSW. Considerable learning and capability development is required in order to DM to be able to fulfil its potential scope for reducing distribution costs. During this period there are risks associated with uncertainty regarding technologies and performance, commercial arrangements that can effectively underpin DM measures, loads likely to respond to DM, and the time and size of incentive necessary to achieve a given penetration of DM measures in a given area.

These risks and lack of experience may act to further dissuade DNSPs from implementing DM options, even if the integration options outlined above are implemented. It is recommended that the Tribunal make available to DNSPs in the short term additional risk protection and underwriting of some learning and development costs, in order for DM to cross this threshold and become cost effective in its own right.

It is proposed that DNSPs could approach the Tribunal with proposals for DM initiatives in areas they believe DM has the potential to be cost effective. The proposal would outline the proposed DM measures and expected costs and benefits, and also the potential risks or uncertainties. If the Tribunal agrees, it would effectively underwrite some of the avoided distribution costs and/or DM costs for that project, in order to protect the DNSP in the event that DM implementation costs exceed avoided distribution costs. Shortfall amounts would be included in the passthrough mechanisms (subject to an agreed cap), so that end-users effectively pay some of the costs of developing DM capabilities.

Proposed guidelines for the Tribunal to consider in reviewing these applications are:

- That DM have a reasonable likelihood of being cost effective in deferring capital expenditure
- Or, if it is likely that DM costs will exceed avoided distribution costs, that there be a clear outcome in terms of learning or other benefits that justify pursuing an otherwise uneconomic DM project.
- The DNSP evaluate and publicly document the DM project, or order to provide learning and capability development in exchange for publicly funding the project.

SECTION 2 – OPTIONS FOR INTRODUCING CONGESTION PRICING

6. Introduction

Congestion pricing has been proposed as one possible or partial solution to the accelerating need for capital investments by DNSPs in NSW, in response to rapid load growth and the emergence of "needle peaks" that are present for very few hours of the year. This report does not recommend the adoption of congestion price per se. Rather, it outlines what a practical congestion price framework would look like and how it might be implemented. This will inform the debate and decision making process regarding the introduction of congestion pricing.

Network constraints are not a new issue. DNSPs have been responding to growth since public electricity supply began and will continue to do so, and there is no suggestion that a crisis has suddenly emerged. In fact, an efficiently run network with high asset utilisation should see a number of emerging constraints at any time. Congestion pricing is an evolutionary step that aims to further optimise asset utilisation and reduce costs for end-users. It is not a new means of funding network expansions, but rather an attempt to delay these expansions where there is value to end-users.

The benefits of congestion pricing are uncertain, and will depend on the willingness of end-users to adjust their consumption in response to congestion pricing signals. If all end-users place a high value on convenience or other preferences above the congestion price, they will continue to consume as they do at present (a signal to the DNSP that customers are willing to pay the cost of network augmentation).

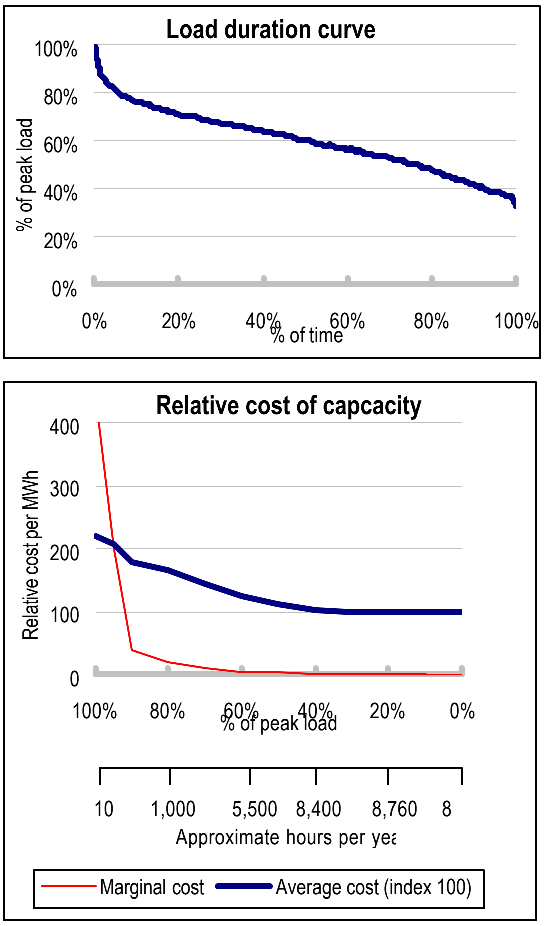
Some concerns have been expressed at the impact congestion price may have on end-users. The introduction of congestion price may impose costs on some end-users during localised periods of constraint that are unable to alter their consumption, but overall should lead to lower prices for all-end users. It may also be possible to rebalance existing tariffs so that the overall cost to typical users doesn't change, but with a higher weighting for consumption during peak periods..

The starting point for examining congestion pricing is a recognition that there is a cost to end-users of blunt pricing. End-users currently pay for network assets that are utilised for only a few hours a year, and for network capital investments that may be more expensive than alternatives such as demand management (DM) or embedded generation.

Just because these peak or congestion prices are not separately identified on users' bills, does not mean they aren't there. End-users already effectively pay congestion prices, but they cannot be seen or controlled because of current pricing and billing practices.

The cost of providing capacity for peak loads can be up to 400 times the cost of base load (see Figure 4 at right). At present, distribution prices are constant, or vary by around 3-4:1 for time of use tariffs. If end-users were aware of these costs, and able to capture the cost savings, some might choose to limit or defer consumption at the very top of the load-duration curve in order to reduce the average cost of supplying them. If the top 10% of loads are removed, by adjusting behaviour for around 1% of the time the average cost drops by around 18%. Given the choice, some end-users would value reduced prices over the loss of convenience, whereas others would be willing to pay the additional cost of consumption at peak times. Under flat tariffs, end-users are not given this choice.

- **Figure 4 Marginal cost of energy as a function of demand.**



The potential benefits of congestion pricing do not require all end-users to respond to or even see congestion price signals. If those users that are able to respond see the signal and reduce peak consumption, the benefits of congestion pricing will be realised. This could include, for example, optional tariffs providing a mix of price signals and incentives targeted at customer groups most able and willing to respond.

6.1 Inquiry into the Role of Demand Management

Some of the drivers for this study arise from the recommendations of the Tribunal's 2002 inquiry into the Role of Demand Management and proposals by DNSPs to reform tariffs as a means of controlling growing capital expenditure requirements.

The Inquiry found there was significant potential for DM to improve energy services delivery in NSW, and that shortcomings in pricing were one of the barriers that needed to be addressed.

In October 2002 the Tribunal released the final report of its Inquiry into the Role of Demand Management[19], which included recommendations relating to congestion pricing.

The inquiry concluded that DM can play an important role in improving the delivery of energy services in NSW. Recommendations were developed in three areas:

- Better pricing
- Better planning and regulation of networks
- Incorporation of environmental objectives in decision making

With respect to pricing, the Tribunal concluded:

> Better pricing is critical… In the case of networks, considerable work needs to be done to provide better signals about emerging capacity constraints and investment requirements – with consequent impacts on costs and prices for end-users.

and with regard to congestion pricing, the Tribunal recommended:

> That DNSPs undertake trials of localised congestion pricing in regions of emerging constraint of the distribution network. Such trials should:
>
> - be integrated with network planning processes and standard offer programs
> - have regard to retail market design and the provis ion of time of use meters
> - be carefully designed to manage the impacts on customers through" the use of rebates as well as positive price signals; options tariff structures; and market segmentation to focus on customers most able to respond to price signals.
>
> The Tribunal confirms that rebates on network charges or DNSP payments for load reductions should be included as negative revenue in calculating regulated revenue and compliance with side-constraints on changes in network charges.

This report is intended to address, at least in part, these recommendations of the Tribunal's Inquiry. Further details of the Tribunal's findings with respect to congestion pricing are reproduced in Appendix A.

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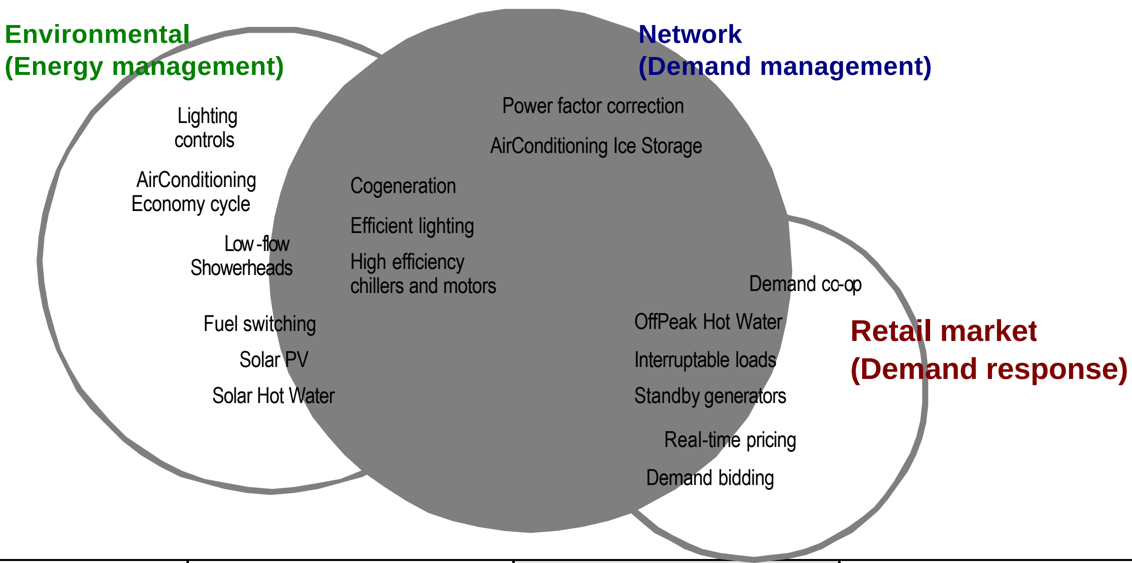
[19] IPART, *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services – Final Report*, October 2002. Available at http://www.ipart.nsw.gov.au/pdf/Rev02-2.pdf

One aspect of the Inquiry's findings of relevance is the identification of different "types" of DM activities relating to different outcomes. These were:

- **Environmentally driven** reducing energy consumption and / or greenhouse gas emissions.
- **Network driven** solving network capacity constraints in ways that are more cost effective.
- **Retail market driven** improving costs to end-users and reducing retailer's risk by encouraging end-users to reduce energy consumption at times of high pool prices.

For example, ice-storage for air-conditioning systems will reduce peak demands on hot summer days, but also results in a slight increase in overall energy consumption, and so would be a negative environmental outcome. Likewise low-flow showerheads may be an effective greenhouse reduction measure, but will have little or no impact on summer day peak demands. These characteristics and relationship between these types of DM, and the types of measures that would primarily achieve the different outcomes are shown in Figure 5 below.

- **Figure 5 Different types of Demand Management**



Type of DM	Environmental	Network	Retail
Objective	Reduce greenhouse gas emissions	Reduce network growth related capital expenditure	Reduce consumption during high price periods in NEM
Policy response	NSW Greenhouse Gas Abatement Scheme	DM Code of Practice and financial regulation of DNSPs	Retail market competition
Effective locations	Anywhere	Areas of network constraint	Whole NEM or NEM region
Effective times	Anytime	Periods of peak loads	High price events in NEM
Effective measures	Continuously operating	Continuous or dispatchable / interruptable.	Dispatchable / interruptable
Key:		Scope of this report	

The Inquiry recommended separate actions and policies specifically targeted to achieve each of the three identified outcomes. As this report is an outcome of the recommendations for network driven DM, and is being conducted as part of the distribution price review, it address network driven DM, with the aim of reducing overall distribution costs.

This does not mean congestion pricing cannot also have environmental benefits. The NSW Greenhouse Gas Abatement Scheme[20] introduced by the NSW Government on 1 January 2003 has for the first time imposed a cost for greenhouse gas emissions associated with electricity use. The scheme requires electricity retailers to reduce their emissions to mandatory targets, and allows persons abating emissions to create and trade emission abatement certificates. In effect this internalises the greenhouse costs of electricity, and provides financial incentives for actions to reduce emissions and/or consumption. Those DM actions that can meet both network and environmental outcomes should be able to capture benefits from both congestion pricing and the Greenhouse Gas Abatement Scheme, and will be more cost effective than measures that only address network constraints.

[20] The NSW Greenhouse Gas Abatement Scheme requires electricity retailers and large users to reduce electricity related greenhouse gas emissions to 5% below 1990 levels by 2006, and maintain them at this level until at least 2012. In order to meet this benchmark participants must purchase Greenhouse Abatement Certificates, which can be created through energy efficiency, "clean" generation technologies, and carbon sequestration. The scheme thus provides a direct financial incentive for energy efficiency actions, that can complement price signals from congestion pricing.

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6.2 What is congestion and congestion pricing?

Congestion occurs when network loads approach or exceed existing capacity limits. A number of features of electricity distribution contribute to the nature of congestion:

- ***Electricity cannot be stored***. Most goods and many services can be "stored" in some form or another (for example, a doctor's waiting room). This is not the case with electricity, where supply must exactly match demand at every instant in time. So while electricity may or may not experience wider fluctuations in demand than other goods and services, it does require larger fluctuations in supply capacity.
- ***Binary service quality.*** Most goods and services can exhibit varying levels of service depending on demand. For example, road transport becomes slower during peak periods. Narrow quality of supply limits on electricity (such as frequency and voltage limits) mean it is effectively "on" or "off", and cannot deliver gradually reducing levels of service during periods of congestion.
- ***Obligation to supply***. Electricity networks in NSW have an obligation to supply, and are required to meet high standards of reliability. Most other goods and servic es do not have this obligation to supply, and so can gear supply to meet demand *most* of the time.
- ***Lumpy investments***. The inherent characteristics and economies of scale of network equipment and construction means it is not cost effective to install small increments of capacity as they are needed. Optimum network management requires capacity increments to be relatively infrequent and large (or "lumpy"), providing for several year's worth of future growth. This means new capacity will be poorly utilised at first.

One implication of the last point worth of highlighting is that while network capacity may have a low *average* cost, new capacity will have a high *marginal* cost due to low initial utilisation, as well as higher risks associated with the uncertainty of load forecasts that drive the investment. Current pricing practices reflect the average cost, but are below the marginal cost of new capacity and do not reflect the increased risk, leading to poor allocative efficiency outcomes. This difference is one of the core drivers for congestion pricing.

Network congestion occurs at specific times and locations:

- ***Time***. Peak network loads generally have annual, seasonal, and diurnal characteristics. That is, they tend to occur at a certain time of day, often on certain days of the week, during a certain season (generally summer or winter), and will generally have an annual cycle.
- ***Location***. Networks comprise multiple circuits, with congestion occurring on only a subset of them at any one time.

For networks that rely on load shedding to operate within their capacity limits, congestion prices should reflect changes in the probability of breaching those limits. And since long lead times are often required for network enhancement, an ideal congestion pricing mechanism should include forecasts of future network congestion risks.

When congestion occurs the two alternatives are to reduce load or increase capacity. The cost of congestion is the lowest cost of these two alternatives. At present, only increased capacity is actively used, leading to increased costs in some instances. Another perspective is that congestion pricing is intended to signal cost to consumers and value of increased consumption to DNSPs.

There does not appear to be a universally accepted definition of congestion pricing. While there are "core" elements that are generally accepted, the exact boundaries of what constitutes congestion pricing are not well defined. The overriding feature of congestion pricing should be that it reduces the overall cost of distribution services to end-users in NSW.

There is general agreement that congestion pricing is the signalling of emerging network constraints to end-users through prices. Some of the areas less well defined are:

- ***Are congestion prices only forward looking?*** In theory, the marginal cost of supply is based on future costs and demand, not historical. Existing time of use and demand tariffs, however, are based on historical or average costs, but do not signal the cost or closeness of future capital investments to meet growing peak loads.
- ***Do congestion prices signal constraints by location, time, or both?*** Should congestion pricing only apply to network areas with imminent constraints, or are price signals that apply across a DNSPs whole network during system-wide peaks (such as hot summer days) also appropriate? Do the increasing block tariffs proposed by some DNSPs qualify?
- ***How accurately is the congestion defined?*** Highly specific definition of congestion by location and time (real time pricing) is economically efficient, but could impose significant complexity and transaction costs on DNSPs, retailers and end-users. As the definition becomes less specific, the price signal is "watered down" to the point where it ceases to have any impact (it just becomes another average price).
- ***Does tariff equal price?*** Are congestion prices only signalled to end-users through tariffs, or are other mechanisms such as connection charges, rebates and incentives, standard offers or direct load control also part of congestion pricing?

For the purpose of this study, SKM has adopted the following definition for congestion pricing:

> Congestion pricing is the use of differential pricing to signal to end-users the cost of incremental consumption where there is a constraint or emerging constraint in the distribution network.
>
> The objective of congestion pricing is to reduce the overall cost of electricity distribution, by inducing changes in consumption where that can cost effectively reduce network peaks and hence defer capital investments. Congestion pricing is *not* a means of funding new capital projects, and should result in an overall *reduction* in distribution costs to end-users.
>
> To this end, end-users must reasonably be able to understand and respond to congestion prices. The ability for end-users to respond, and capacity to pay higher charges during congested periods, may vary depending on customer classes and sizes.
>
> The total price signal to end-users is made up of several elements, including tariffs, connection charges, capacity charges, incentive and performance payments, and additional charges or bonus payments during constrained periods.
>
> Congestion prices are calculated on a forward looking basis, to reflect future investments and the marginal cost or benefit of peak consumption on a constrained network.
>
> The constraint targeted by congestion pricing should be accurately defined by location, time, or preferably both for maximum efficiency.
>
> Congestion prices can be voluntary or compulsory, and can include a mix of payments for reduced consumption as well as charges for consumption during peak periods.

6.3 Marginal and average cost pricing

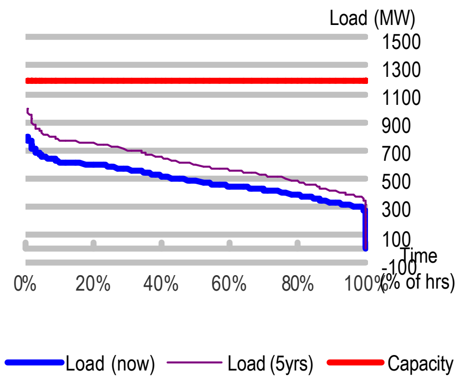
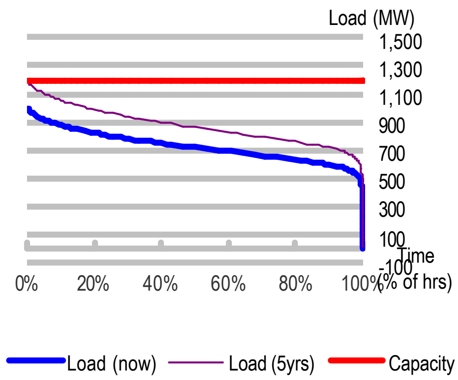
DNSPs in NSW currently use an average cost pricing approach, with tariffs determined according to the historic cost of assets employed to supply end-users' loads. Average pricing can still embody pricing signals to users on the cost of peak demand or consumption at different times (for example a demand time-of-use tariff), on the basis of the cost of the existing assets used to supply those loads, and the utilisation of those assets. Average pricing can also embody locational signals, by separately identifying the assets used to supply end-users in a given area (for example, transmission charges are calculated on an average cost basis, and already include a locational element by bulk supply point).

Marginal pricing, on the other hand, is forward looking. It is not concerned with the sunk cost of the assets already employed to supply loads, but with future investments required to meet expected load growth. In this regard, it tends to be more strongly locational than average cost pricing (where the cost per MW of installed capacity is reasonably consistent). Areas that have substantial spare capacity, and off peak consumption, will have effective marginal prices of zero, while areas of the network that are approaching existing capacity will have high marginal prices.

There are advantages and disadvantages to both average and marginal pricing for electricity networks. Average cost pricing is good for recovering sunk costs, is equitable and provides stable cash flows. If there was no growth, marginal pricing would not recover any revenues, whereas average cost pricing would. The shortcoming of average cost pricing is that it undervalues scarce resources, which in turn leads to over consumption during short peak periods, poor investment and location decisions, and in the long term higher costs for all users.

The following example of two hypothetical networks, one constrained and the other not, illustrates this point Each network currently has the same capacity, but different peak loads, utilisation and growth rates. In practice, an electricity network will have areas exhibiting the characteristics of both examples (constrained and unconstrained).

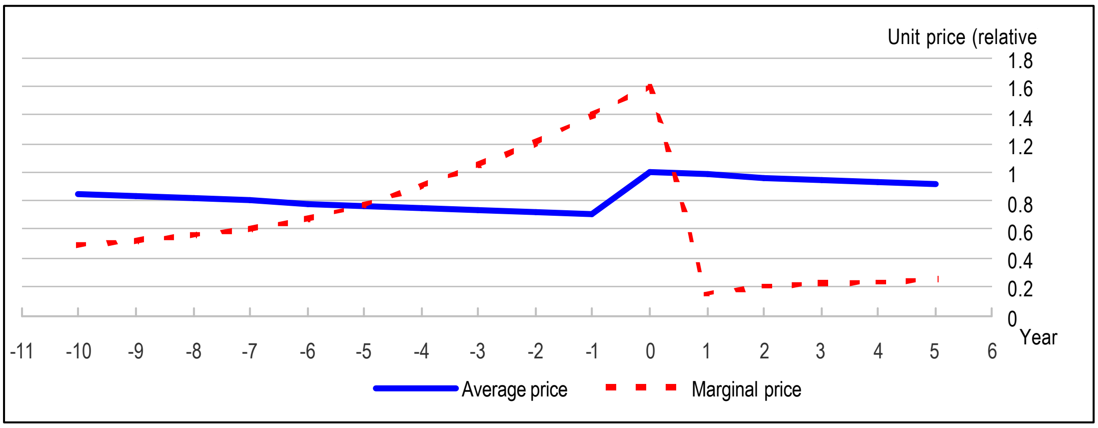
The inherent price signals under average and marginal pricing are compared in the table and chart on the following page:

Network:	Network "A"	Network "B"
Loads	"Poor" load factor, moderate growth, but no imminent capacity constraint (see load duration curve** chart below). Peak load is currently 800MW, growing to 1,000 over the next 5 years. Existing capacity is 1,200MW, giving 10 or more years of capacity.	"Good" load factor, slow growth but approaching capacity (see load duration chart below). Peak load is currently 1,000MW, growing to 1,200 over the next 5 years. Existing capacity is 1,200 MW, indicating investment in additional capacity will be required within 5 years.
(Load duration curve chart)[21]		
Price signals under average cost pricing	Lower utilisation (~65%) and load factor (~60%) leads to average unit price ~20% higher than Network "B". Sufficient capacity for 10+ years of growth, but higher prices discourage additional consumption.	High utilisation (~80%) and load factor (~70%) means better utilisation of assets than Network "A" and hence lower average prices. Augmentation and additional capital expenditure will be required within 5 years, yet lower prices encourage additional consumption.
Price signals under marginal pricing	Looking forward, no augmentation is required for at least 10 years. Marginal price is zero.	Augmentation is required in approximately 5 years. Marginal price rises to signal emerging constraint, and should push price of Network "B" above that of Network "A" to signal the spare capacity in "A".

As noted earlier, a feature of electricity networks is the tendency for investments to be large and infrequent, or "lumpy", due to the inherent economies of scale and distances involved in distributing electricity. At a local level these investments can have a significant impact on costs, as shown in the chart below of a hypothetical network augmentation in Year 0. If we consider the path that backward and forward looking prices will take over time, as shown in Figure 6, the benefits and shortcomings of the two approaches are apparent:

[21] A load duration curve is a graph showing all the loads for each hour of the year sorted in decreasing order of load, rather than chronological order. It is commonly used by DNSPs to show the utilisation of the network, and the duration of peak loads (hence the name). It is a useful tool for analysing network utilisation and costs, and analysing the types of DM approaches that will be effective (for example a high peak for very short time may respond well to interruptable strategies, whereas peaks of longer duration are less likely to be suitable for interrupting).

Figure 6 Average and marginal costs for a network constraint



Under average pricing, the price slowly drops as the utilisation of existing assets improves. When the investment is made, the assets employed will increase, and their utilisation will decrease, pushing prices up – the opposite to economically efficient price signals. Under marginal pricing, the marginal price rises as the investment gets closer[22], and then drops away sharply (looking forward to the next investment in say 10 or 20 years)

This sends the right consumption signals to end-users, but the volatility in *pure* marginal cost pricing has a number of implications:

- ***Price changes under marginal pricing are larger and faster.*** The marginal price can rise to very high levels just prior to the installation of new capacity , and will drop rapidly after the new capacity is installed In practice, marginal prices will often drop to effectively zero following new capacity investments.
- ***DNSP revenues will become more volatile.*** Over the course of a year, weather and other impacts tend to average out variations in overall energy consumption. Peak energy consumption, and especially peak demands, are more volatile as they relate to extreme events rather than average conditions. Pure marginal cost pricing would concentrate revenues from those constrained areas, while unconstrained areas would see prices close to zero. In practice, a mix of constrained and unconstrained regions, fixed charges, and congestion pricing implementation involving only a partial shift towards marginal cost pricing will reduce this problem.

[22] Depending on how the congestion price is calculated. If it is calculated on the basis of the net present value (NPV) of deferring the investment, it will increase as shown in the graph. If it uses the long run marginal cost (LRMC) of the additional capacity, it will be constant, but still drop sharply after the investment.

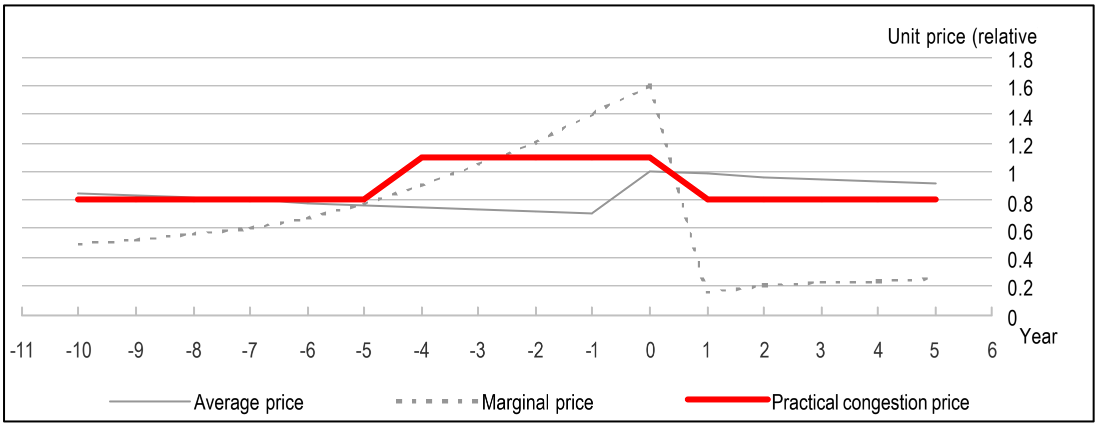
- ***Uncertainty regarding the price elasticity of demand*** for electricity, and the timeframe over which changes in consumption will occur. Where congestion pricing affects demand, DNSPs will face additional forecasting risks as they relate to tariff setting and compliance with the WAPC. This risk will reduce over time as DNSPs gain experience with congestion pricing and end-user response.

Given these issues, a practical view of congestion pricing that could be introduced initially or in trials would be to use a mix of marginal and average cost pricing. That is, base prices will still be determined using average cost principles, around which there are variations to reflect relative congestion.

It is also possible to "sculpt" the marginal price, rather than use the real-time actual marginal cost. While this will in theory limit the economic effectiveness of congestion pricing, it will in practice provide certainty and simplicity to end-users (and in doing so *increase* the ability to respond to congestion prices, and hence the economic effectiveness), and can cap the marginal component of the price to a reasonable level.

An example of how this could work is shown in Figure 7, showing an example of how prices might move over time as the same constraint emerges and is resolved. Note that the average or base price will be lower than without congestion pricing, in order to balance the increased income from the congestion component:

- **Figure 7 Possible implementation of congestion pricing**



Alternatively, the marginal price could be applied in reverse (as a rebate or incentive) for reductions in demand coincident with the peak loads.

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7. Issues for Congestion Pricing

In the course of this study, SKM has identified a range of issues through consultation with DNSPs and other stakeholders. *Conclusions or lessons to be taken into consideration when developing the congestion pricing framework are shown in italics at the end of each issue.*

The key issues are summarised below, categorised as economic, regulatory, market or technical.

7.1 Economic issues

7.1.1 Stability and quantum of DNSP revenues

- Section 6.3 showed that revenues derived under pure marginal pricing are disconnected from the historical asset base of DNSPs, and are likely to be more volatile than the average cost prices currently charged to end-users in NSW.

Pure marginal cost pricing is not recommended. A mix of average and congestion prices, starting with limited trials, will minimise any volatility in DNSP revenues. For DNSPs the mix of constrained and unconstrained areas will also tend to mitigate volatility in revenues.

7.1.2 Price volatility for end-users

Pure marginal prices could rise significantly above the costs currently seen by end-users, and could also be quite volatile if real-time prices were applied in an area with large fluctuations in peak loads. Not only is the size of the congestion price signal important, but the size of changes to prices as well. Rapidly fluctuating congestion prices will confuse and frustrate end-users, and potentially diminish the confidence in the price signal being conveyed through congestion pricing.

Volatile or extremely high prices for end-users are likely to raise a number of concerns, and implementation of congestion pricing should avoid this through stability of prices, and reductions in non-peak period prices to compensate for any increases in peak period prices.

The average price for constrained end-users should not rise by an unreasonable amount, with any increase in peak charges offset as far as possible by a corresponding decrease in off-peak charges. The average price across all a DNSPs customers should not change, so that it is not recovering more than its efficient costs (that is, there is no net increase in revenue due to congestion pricing)..

Stability and predicability in prices will give end-users certainty and confidence on which to base investment decisions.

7.1.3 Where are congestion pricing signals best applied

Congestion pricing signals can be applied at a number of points, with varying incentives to end-users and effectiveness. These are:

- ***Incorporated into tariffs.*** Can be applied to energy or demand.
- ***Interruptability and load control.*** Where a congestion event is signalled by triggering load control, rather than by a changing price signal.
- ***"Side payments"*** to end-users or embedded generators outside of tariff structures .
- ***Connection charges.*** New customers connecting to the network typically face some connection charge, and may also be charged a capital contribution. Congestion signals could be added to these charges.

DNSPs should be given the maximum degree of flexibility to develop innovative and effective congestion pricing structures. To this end, all 4 models outlined above should be available.

Of these, the first and last are likely to be the most contentious. Some end-users and advocates would prefer only payments to end-users that reduce demand during periods of congestion, rather than higher costs for consumption during these periods.

Connection charges are a possible point for application of congestion pricing that has not been fully explored. Applying congestion pricing at the time of connection has a the advantages of providing a price signal at a time when there is maximum influence over the design and specification of equipment, and can at least partially overcome the "developer – owner" issue[23], by transferring some of the future costs of congestion to the developer. It also has the disadvantages of introducing inequalities between new entrants before and after its introduction date, and only applies congestion prices to new loads, (or applies them to new loads twice through connection charges, and then through tariffs). These issues might best be addressed in conjunction with the next review of capital contributions policies.

In general, DNSPs should have maximum flexibility to devise innovative congestion pricing mechanisms that can achieve the greatest impact. That said, incorporating congestion pricing into connection charges for new users does appear to introduce significant equity issues, and has the potential to effectively re-open the capital contributions policy issue. It is recommended that connection charges not be used to convey congestion pricing signals in initial trials of congestion pricing.

[23] This is a barrier to demand management that has previously been identified. Developers have an incentive to minimise the capital cost of buildings, as they do not see the running costs. Less sophisticated owners may not fully recognising the future running costs when valuing the buildings, leading to a market failure.

7.1.4 Effectiveness of congestion pricing

To be effective at reducing DNSP investment, end-users or 3rd party energy service providers must respond to congestion pricing by reducing demand at times of congestion. Where end-users choose to continue consuming during periods of congestion, they have indicated they place a higher value on the ability to consume at those times than the cost of augmentation. In this case the economically appropriate outcome is to invest in additional capacity.

To respond, end-users must be willing and able to adjust their loads. This implies a number of conditions for effective congestion pricing implementation. Firstly, those able to make decisions to respond must receive congestion prices.

- This might not always be the end-user. A building developer or landlord will often have considerable influence over consumption patterns. It could also be a retailer or other intermediary that is able to offer value-added services to the end-user, including demand response to congestion pricing.
- There must be metering or other equipment (such as load control devices) that can effectively target congested periods. This is discussed in greater detail later in this report.
- Congestion price signals embodied in network tariffs must be “seen” by somebody able to respond to them. This could be the end-user where the price is simply passed through by their retailer, or it could be the retailer or another intermediary that has packaged value-added services to the end-user. This is discussed in greater detail later in this report.

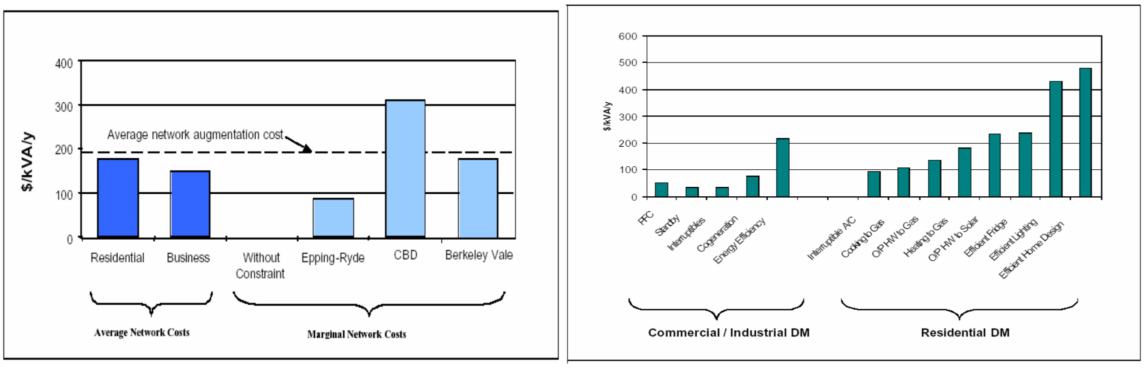
Secondly, they must be able to respond to the congestion prices:

- They must understand the congestion prices and the consumption being targeted. To this end, congestion price structures should be as simple as possible.
- there must be economically viable options available. These might not be the loads or customer segments that are growing the fastest, but those that have the lowest cost options available.
- there must be a capability to deliver these solutions (which may take several years to develop and mature).

Not all end-users have to see or respond to congestion pricing for it to be effective. Well targeted congestion pricing will target those users best able to respond to congestion price signals.

The size and timing of response is unknown, and are likely to only be known accurately with experience. Figure 8 shows previous estimates of the range of the marginal cost of augmentation and the cost of various DM options, and indicates there is potential for congestion pricing to be effective[24]:

▪ **Figure 8 Estimates of marginal augmentation and demand management costs**



7.1.5 There is no market price

Congestion pricing schemes for transmission networks (such as that in place at Transpower in New Zealand) are able to use wholesale market generator bids to set the constraint price in real time. The difference in generator bids either side of the constraint sets a market price, signalling the need for reduced loads or increased generation on the side with the higher price, with the price differential signalling the economic value of transmission.

Market mechanisms are not available for distribution networks, and so the congestion price must be calculated explicitly. Section 6.3 demonstrated that the marginal cost of consumption drops sharply after a constraint is no longer present, and that smoother or sculpted price paths are a more appropriate implementation of congestion pricing signals.

Where congestion is relieved by a new large embedded generator or DM alternatives that provides a long term solution, the marginal price will fall once the measure is installed, removing the benefit or reward to the promoter of the embedded generator or DM project under a "pure" marginal price. In these cases, long term DM contracts are a better answer to tariff based price signals.

DNSPs should be afforded maximum flexibility to structure and negotiate congestion prices (particularly payments or incentives) in order to achieve maximum impact at least cost.

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[24] Reproduced from IPART, *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services – Final Report*, October 2002. Note that estimates of the cost of congestion and demand response options vary widely, and is an area where there is not universal agreement. For example, the report noted "Submissions to the Interim report, especially from the DNSPs, were cautious about some of the potential DM options listed in the SEDA report.".

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7.2 Regulatory issues - National electricity code

In setting distribution prices the Tribunal is constrained to work within the requirements of the National Electricity Code. Relevant provisions include:

- NECA must, as soon as practicable… conduct a review of clause 5.6, and any other relevant clauses of the Code, for the purpose of improving the symmetry of treatment of network augmentations and non-network alternatives in relation to … the ability for a non-network alternative to receive full or partial funding from a Transmission Network Service Provider where that alternative has been demonstrated to be an optimal course of action in accordance with the regulatory test and the payment has been shown to be justifiable; and the ability for a Transmission Network Service Provider to obtain up-front approval to have such payments included in its revenue cap (subject to future regulatory review as in the case of network augmentations); and the recovery of the costs associated with such payments in ways that send appropriate usage signals to Network Users [5.6.6C[25]]
- an environment which fosters an efficient level of investment within the distribution sector, and upstream and downstream of the distribution sector [6.10.2(d)]
- promotion of competition in upstream and downstream markets and promotion of competition in the provision of network services where economically feasible [6.10.2(h)]
- reasonable and well defined regulatory discretion which permits an acceptable balancing of the interests of Distribution Network Owners, Distribution Network Users and the public interest [6.10.2(k)]
- create an environment in which generation, energy storage, demand side options and network augmentation options are given due and reasonable consideration [6.10.3(e)]
- Network charges should in principle be cost reflective. This is to facilitate the competitive market, by providing equitable access to the network and ensuring that appropriate investment in the network takes place in the longer term. It is intended that all Generators and Customers, including Franchise Customers and non-registered Customers be charged on a consistent basis, in accordance with their use of network assets and taking into account the impact of network constraints [6.7.1]
- Network prices should provide signals to optimise the cost of network development in order the minimise the cost of development and operation of the market. It should be recognised that the above objectives of non-discriminatory pricing (leading to the equitable recovery of existing costs) and economically efficient pricing for new investment in the network are to some extent incompatible. The challenge is to devise a method of network pricing which meets both.[6.7.4]

These provisions would all seem to support the introduction of congestion pricing, as this will improve the cost reflectivity and provide financial signals that should enable non-network alternatives to be given more equal consideration. In particular the provisions of section 6.7 would seem to require congestion pricing signals be introduced in some form.

[25] Note – while this applies to Transmission networks, it will affect how transmission prices are allocated to end-users by DNSPs, and may influence distribution network pricing philosophy as well.

7.3 Technical issues

Metering, communications, billing and settlements technologies and systems are critical elements of a successful congestion pricing scheme

7.3.1 Metering

Without the ability to define congested periods, supported by interval meters or communications, congestion pricing signals become very “blunt” as consumption during congested periods is averaged with congestion during other periods. Some innovative solutions are possible – for example, Orion New Zealand use their existing ripple load control system to signal “congestion periods” to end-users. Customers with interval meters face a price surcharge, while customers with accumulation meters have loads connected to a controllable tariff disconnected (similar to off-peak in NSW, but with much shorter periods of interruption).

Interval meters are currently only installed for larger customers (above 100 MWh pa in NSW), with the majority of smaller customers having a single register accumulation meter that cannot discriminate between consumption at different times of the day or year. The benefits of sharper price signals with interval meters must be balanced against the higher cost of the meters and data collection and processing.

Congestion pricing is considered feasible with the current mix of meters, though significantly constrained for those end-users with accumulation meters only. The full benefits of congestion pricing will only be realised when time-of-use or interval meters are rolled-out more broadly. These costs and benefits should be included in consideration of the merits of meter rollout programs, or meters could be rolled out in constrained locations only.

DNSPs have argued that they should be able to rollout interval or time-of-use meters progressively to customers below the current 100MWh threshold, including the largest domestic users. Limited rollouts to customer segments most able to respond or areas most heavily constrained may be one possible type of congestion pricing trial, in order to properly assess the costs, degree of load shifting achieved and other benefits, and customer impacts.

7.3.2 Communications and billing systems

Communications and billing systems are critical support and enabling elements of congestion pricing. Support from retailers will be critical, as they will be issuing bills to end-users, and will form a key communications channel.

Real-time or two-way data communications may also be required for some types of congestion pricing schemes (interruptability or real time pricing for example). Communication becomes more critical as the network congestion is defined more tightly by location and time, requiring more precise and timely information to end-users. Developments in internet, wireless and other mobile technologies continue to expanded the feasible options and reduce costs.

7.3.3 Identifying customers

Zone boundaries are often “blurry” and fluid in practice, as a result of the low-voltage network and switching within the network. Given these uncertainties, and the difficulties identifying which customers are connected to a particular zone, consideration must be given to how DNSPs will identify customers subject to congestion pricing, or eligible for rebates or incentives.

Submissions to the draft report generally agreed that reasonably accurate definition of constrained network sections was technically and financially feasible, and is necessary in order to ensure the acceptability and transparency of congestion pricing.

7.4 Market issues

Market issues are likely to emerge as a key challenge to developing practical and effective congestion pricing schemes.

7.4.1 Acceptability of locational pricing signals

As outlined in section 6.2 network constraints occur only in certain sections of the network at any one time. As these constraints are resolved (either by DM or additional supply capacity), other constrained areas will emerge. While there is often a strong correlation between peak loads in different areas of the network (such as on a hot summer day), there are differences in the time, day and season of peak loads in each part of the network due the mix of customers, local variations such as the availability of natural gas and age of buildings, and local weather conditions. Significant differences also occur in the amount of spare capacity in the network, due to the lumpy nature of supply investments. This means that a uniform time-based congestion pricing regime would target many unconstrained areas of the network[26], and may not target peak loads at all in areas with unusual demand characteristics.

[26] Noting that these areas will, in time, become constrained, and will eventually benefit from peak load reductions induced by congestion prices.

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Another significant difference between different areas of the network is the cost of constraints. At a local (zone substation) level this varies significantly, due to the scope of works required, amount of spare capacity in the transmission network, distances to other infrastructure, and load characteristics. At a system wide level, these variations are averaged, and further diluted by zero-cost growth in areas with spare capacity. Estimates by SKM show the likely range of marginal costs of load growth at different levels within the network are shown in the table and chart below.

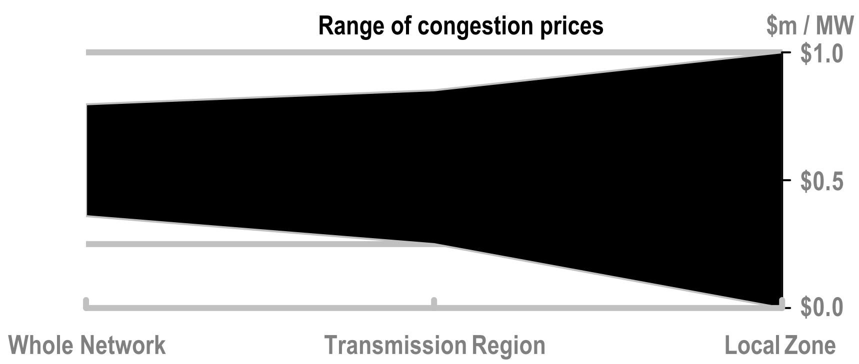
▪ **Table 14 Range of marginal distribution costs per unit of load growth**

Location	Definition	Range of marginal costs ($m / MVA) $NPV deferral value delivered by reducing load by 1MVA
Whole network	Cost of peak demand growth across each DNSPs entire network	$0.4 - $0.8*
Zonal	Cost of peak demand growth at a zone substation	$0 - $1.0

Source: Estimates by SKM based on data from Total Cost Review – Draft Report June 2003, DNSP Annual Planning Statements, and information supplied by DNSPs.

Note: * This range is across the 4 DNSPs in NSW. For each DNSP, it is a single number within this range. When this is considered, the variation between system wide and local congestion prices becomes much pronounced.

▪ **Figure 9 Range of marginal distribution costs per unit of load growth**



The above implies that the efficiency and effectiveness of congestion pricing will be significantly enhanced if it is applied locationally, that is with different congestion prices in different areas depending on local circumstances.

Locational premiums in tariffs are one means of implementing locational congestion pricing. This issue drew the most comment from the draft report, with most respondents opposed to locational tariff premiums, particularly for domestic consumers, on the basis of equity, unproven effectiveness, potential hardships imposed on vulnerable customer groups, and administrative costs. Locational signals do appear, however, to be an accepted part of pricing for other goods and services. For example, gas networks in NSW currently charge different rates for non-domestic users based on location, and this has long been accepted as normal. Variations in electricity tariffs by region were commonplace in NSW prior to the amalgamations of distributors in the 1990's, and are also featured in newly restructured electricity markets overseas (for example, the PJM market in the United States).

Given the reluctance to accept locational prices in tariffs, other means of including locational signals for domestic users might be preferable, such as incentive payments, time-of-use meter rollouts, or interruptable options. For commercial / industrial users, consideration should be given to incorporating locational congestion pricing into tariffs or as interruptability or side payments.

Some growth trends are consistent across the entire network of each DNSP, and may be dealt with via uniform system-wide congestion pricing tariffs to signal times when the network as a whole is constrained. While this approach will be easier to implement, it will not be as effective as locational signals that distinguish between areas that are and are not facing constraints.

Opportunities should be sought to trial locational congestion pricing in some form. A compromise might be to initially trial congestion pricing on a regional basis rather than individual zone substations, and limiting congestion price premiums incorporated into tariffs to non-residential customer classes, plus the use of optional tariffs linked to meter rollouts for other customers.

7.4.2 Voluntary vs compulsory congestion pricing

SKM believes voluntary tariff choices are preferable to compulsory application of congestion pricing tariffs, and to this end will need to be attractive to the market to encourage takeup. To be attractive, congestion pricing tariffs and schemes must be simple, transparent to end-users, give them flexibility, have the benefits and cost savings well explained, and remain consistent over time to allow users to develop routines that match the price signals.

Voluntary real-time pricing and load cooperative schemes, including those aimed at domestic users, are being trialed overseas with some success. It is apparent that not all end-users will disapprove of congestion pricing, and those that are able to respond will benefit through reduced energy costs, as well as providing a benefit to DNSPs and end-users generally.

Some users, who are currently heavily subsidised by existing tariffs, are unlikely to voluntarily shift to congestion price tariffs. In these cases, DNSPs should be able to approach the Tribunal with a proposal for compulsory tariffs or a limited set of tariffs (such as time-of-use or demand tariffs only for users above a certain size), possibly linked to meter rollouts.

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7.4.3 The role of retailers

Retailers will have a vital role to play in ensuring the viability and success of congestion pricing. Congestion price signals will reach almost all end-users via retail contracts, and there has been some concern that retailers might package tariffs in a way that effectively removes price signals. Retailers are loathe to assume any risks they don't have to, and to the extent that smoothing congestion pricing signals exposes them to such risks, they are unlikely to do so (and will pass the network tariffs straight through to end-users unaltered).

Retailers have also indicated they will look for opportunities to identify better options for their customers as a source of competitive advantage, and to this end would exploit congestion price tariffs where they can assist end-users to take advantage of congestion pricing structures. Retailers already manage significant risks in the National Electricity Market, and there may be an opportunity for retailers to offer value-added energy services to end users, by offering simpler tariff structures and managing the response to congestion pricing on behalf of their customers. Network congestion pricing signals will always be "seen" by someone, and it may be that retailers or other intermediaries are able to provide cheaper and more effective response than individual end-users.

Discussions with retailers indicate strong concerns that if congestion pricing structures are too complex or too numerous, it could impose significant costs on retailers. Consistency between DNSPs (eg definition of seasonal and TOU bands) would help reduce costs. A significant share of the communications task will fall to retailers, and they are concerned that congestion pricing schemes be straightforward and simple, so they can be easily understood by end-users. Retailers have indicated the cost of administering multiple tariffs can be very costly.

Whether retailers pass on congestion pricing structures to end-users is a decision for retailers, and beyond the control of DNSPs. To the extent that the price signals will always be seen by someone, this is not necessarily an issue, and it is unlikely that retailers would simply "absorb" the congestion price signals for their customers.

The number of congestion pricing tariffs, components and price changes should be kept to a minimum to avoid unreasonable administration costs for retailers. This effectively rules out locational congestion pricing tariffs on a zone-by-zone basis as an option, at least for initial trials. Possible solutions are to incorporate locational signals as side payments, or to adopt a limited number of regional or "template" congestion pricing tariffs, and apply them to constrained areas. Initial trials of congestion pricing in one or two areas should not impose an unreasonable burden if implemented well.

7.4.4 Education and information

It will be important to educate end-users about the reasons for congestion pricing, and the options they have available to respond to congestion prices, in order to deliver benefits and gain the support of end-users.

Simply implementing congestion pricing will not be sufficient, as it will be a significant change for end-users, and it will take time for service offerings from third parties to develop. To this extent, the introduction of congestion prices must be carefully managed and supported with information, advice and support for end-users.

7.5 Feasibility of congestion pricing

Overall, SKM is of the view that congestion pricing is feasible. The issues identified in this section highlight the complexity and ambiguous choices that must be made in implementing congestion pricing, but none of these issues represent an insurmountable obstacle to congestion pricing.

8. Case studies

8.1 Orion New Zealand Congestion Pricing

Orion New Zealand Limited is an electricity distribution company based in Christchurch, in the South Island of New Zealand. Orion was launched in December 1998 following the ownership separation of the network and energy retailing functions of Southpower Limited. The Southpower name and retailing business was sold in late 1998 in order to comply with the ownership separation requirements of the Electricity Industry Reform Act 1998. Following the sale, the network business was renamed Orion.

Orion's network covers 8,000 square kilometres, delivers 2,800 GWh per annum, and supplies a maximum demand up to 540 MW. In approximate terms, the network currently comprises:

- $685 million in assets;
- 46 major substations;
- 11,500 km of lines and cables;
- 9,300 distribution substations; and
- 167,500 customer connections.

The Orion network is notionally divided into two "zones": Urban and Rural, including for their congestion pricing scheme. The Urban zone is winter peaking (mainly driven by domestic cooking and heating), while the Rural zone is summer peaking (mainly driven by irrigation). Orion uses the same congestion price for the two zones[27], but triggers congestion prices in opposite seasons for the two zones.

Orion has a long history of using load management to manage peak electricity demand, dating back to the late 1980s. However, before the introduction of congestion pricing, load management was restricted to using:

- Ripple control to manage residential water heating load; and
- Sheddable load provided by some businesses.

The Orion congestion pricing scheme is designed around "control periods", which are triggered in real time (with 15 minutes notice) when network loads reach pre-determined limits.

[27] In this sense, the Orion congestion pricing scheme is only weakly locational.

There were two main drivers for introducing congestion pricing:

- Change to the nature of the business resulting from changes to industry structure; and
- Changes in nature of demand (i.e. from winter peak only, to both winter and summer peaks), and an emerging transmission constraint that would require a NZ$400m investment..

Orion introduced its current congestion pricing scheme in April 1999, to coincide with the introduction of full retail competition in the New Zealand Electricity Market.

Orion uses different mechanisms for congestion pricing, depending on the type of customer:

Table 15 Orion congestion pricing mechanisms by customer class

Customer class	Congestion pricing scheme
Major customers Orion maintains direct contracts with approximately 330 major customers. These customers typically have a load large enough to require a dedicated transformer, rather than sharing the use of the low voltage network.	For major customers, the peak charge is based on demand during the control period. Half-hourly meters at each major customer connection measure this. To signal that a particular period will be a control period, a ripple control signal is sent 15 minutes prior to the beginning of the control period, and indicates that the control period is active and will therefore be used for the purposes of peak charging. A separate meter or channel of a data logger records consumption during the control periods. Demand charges are only levied during declared "congestion periods", at the rate of NZ $81.92 / kVA per year (where kVA is the average load of the user during control periods). Time-of-use energy charges apply all the time.
General customers (Demand tariff)	Smaller customers on demand tariffs have the congestion periods defined in advance , rather than individually signalled in real time as for Major Customers. "Peak" seasons apply for 6 months of the year, in summer (rural areas) or winter (urban). Demand is only charged during these seasons, at a rate of NZ$120 / kVA per annum, for the average load consumed during control periods (any time during the 6 month peak period).
General customers (Energy-only tariff, including domestic)	Triggering a congestion periods causes "controlled loads" to be interrupted using the ripple control system. Customers elect to join this tariff (where there loads can be automatically shed) in return for a lower year-round tariff from their retailer.

Customer education programs were necessary to inform customers about the options they face, and critical, Orion believe, to the adoption and acceptance of these congestion pricing schemes. Orion continues to make investments in its ripple control system and to promote off-peak heating and off peak water heating. Orion also promotes LPG for space heating, and energy efficiency programs.

In addition, Orion rewards embedded generators (i.e. generation within the network) for injecting energy onto the network during periods of control (and thus for reducing demand on the network).

Depending upon the weather, the accumulated duration of the control period over a season can vary between 20-150 hours, but is generally around 60 hours per six month season. On average, a control period will last 1-2 hours, but is always at least 15 minutes. Orion will use its best endeavours to ensure that there is only one control period during any morning or evening, and that a control period duration does not exceed longer than 4 hours.

Orion calculates its congestion prices based on the proportion of its assets judged to be load dependent. This proportion is currently 46%, which when applied to the historic asset value of Orion's network, gives NZ$96 / kVA per annum as the annualised cost of load dependent assets. These costs are then allocated entirely to "control period" or "peak season" demand component for demand and major customers. For smaller (and domestic) customers, tariff rates for *interruptable* loads are determined based on the expected load profile of *interruptable* loads compared to normal loads. In other words, 46% of Orion's revenues come from congestion price signals.

Reports indicate that Orion reduced its peak load by 160 MW in 2000-2001[28]. Annual growth in electricity load on Orion's network has also slowed from 2.5% to just under 1%. This means that it has been able to defer a spend of $180 million on increasing the carrying capacity of its network. The $180 million includes deferring the need for Transpower to build a new transmission line to supply Canterbury, in addition to capital expenditure by Orion.

Orion has indicated that consumers have responded to its congestion pricing by:

- Installing back-up generation;
- Installing duel fuelled heating systems;
- Using process interruption or process/system redesign; and
- Switching to LPG. (Rockgas has built an LPG network in Christchurch City).

Essentially, the introduction of peak pricing signals has raised awareness of the impact of consumer actions and investments on the cost to supply electricity. This in turn ensures that consumers think about the cost of electricity when installing appliances or industrial processes.

[28] http://www.eeca.govt.nz/content/ew_business/awards/energywiseawards_winnerslist.htm

8.1.1 Lessons learned from Orion

- The Orion congestion pricing scheme is time of use specific but not overly locational specific (two zones only).
- It was implemented via a mandatory tariff structure for large users and retailers, with voluntary options for smaller retail consumers.
- It has been successful at allowing Orion to reduce capital expenditure and decrease average tariffs. This has largely been through demand response to the tariffs with improved network utilisation.
- Innovative congestion pricing signals, that are simple and communicated well to end-users, can deliver significant benefits.

8.1.2 Limitations in applying Orion results to NSW

Care needs to be taken in extrapolating the results of the Orion experience directly to NSW. There are a number of unique aspects of the business environment that are not present in NSW, and will affect the degree to which the same results can be achieved here:

- There was a single transmission constraint which affected virtually the entire Orion network. This provided the ability to focus on a single issue that will rarely be available in NSW.
- There was little penetration of gas in the urban areas. In the mid 1990s, Orion took on a bottled LPG distribution business, and was able to rapidly expand the penetration of gas (in part through electricity DM incentives). In many areas of NSW where gas is already available, similar results are unlikely to be achieved. Also, fuel substitution tends to work best for winter peaks, where gas heating can be readily substituted for electric heating. Areas experiencing summer peaks (a growing proportion of NSW) are less amenable to fuel substitution options as widespread gas alternatives are not available for the end-uses driving summer peaks (primarily air-conditioning).

8.2 Powercor (Victoria)

Powercor in Victoria was introduced a Climatesaver tariff – a seasonal tariff for airconditioners. The "Climate Saver" is a seasonal tariff that applies to approved reverse cycle air conditioners. The peak rate applies between 1 November – 31 March and the off peak rate applies between 1 April – 31 October. The differential between peak and off-peak rates is between 2:1 and 3:1 depending on the users' level of consumption.

Powercor (and other Victorian DNSPs) also offer increasing block tariffs. Unit charges on the standard Powercor domestic tariff increase from 6.33 ¢/kWh to 9.537 ¢/kWh as consumption increases.

8.3 Locational pricing in other jurisdictions or industries

Consumers in NSW have become accustomed to uniform "postage stamp" pricing for electricity (at least within the franchise territory of each of the 4 DNSPs. While this is superficially equitable, the earlier analysis in this study shows this is costing end-users money through increases costs for poorly utilised (or even unnecessary) network capacity.

Examples of other markets where consumers are exposed to locational signals:

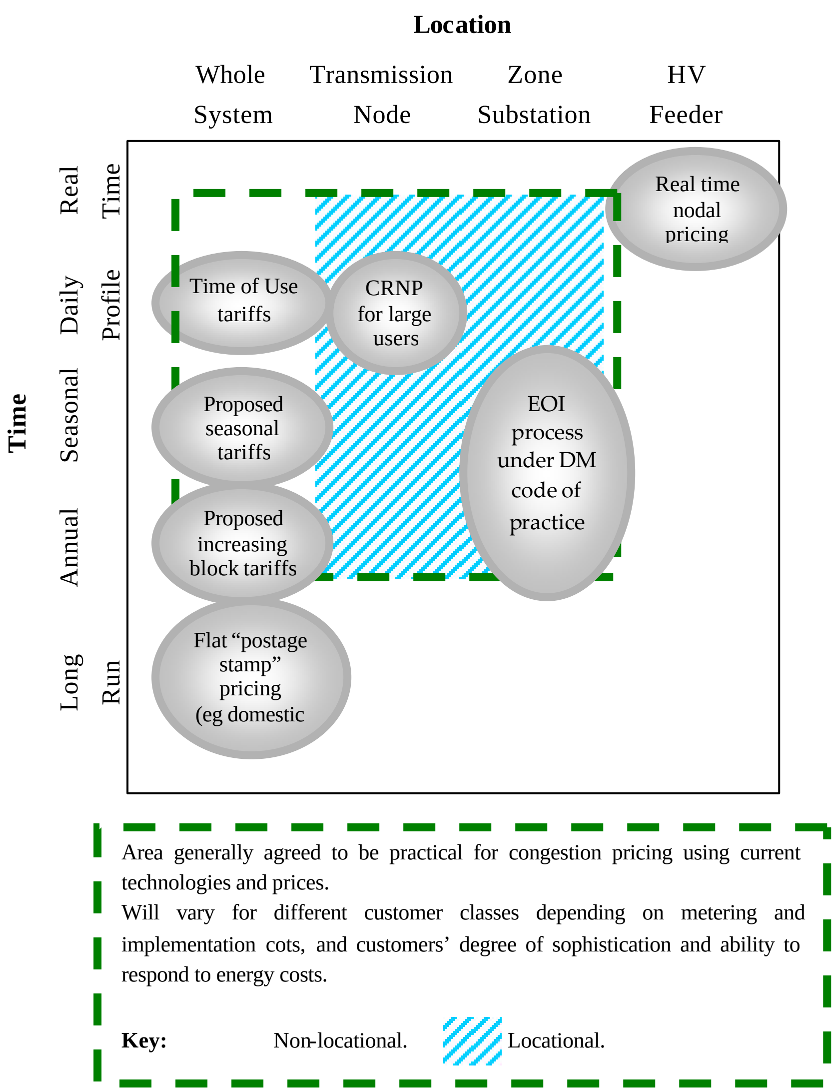
- Natural gas network tariffs in NSW for non-domestic consumers
- Housing (which is unregulated, and strongly locational)
- Bulk water
- Public transport (that contains both locational and congestion price signals).

In these markets, consumers have accepted locational and congestion pricing signals as acceptable.

9. Proposed frameworks for Congestion Pricing

A simplified model of distribution network pricing options is shown in Figure 10 has been developed to provide a means of classifying pricing methodologies and defining what is generally considered to be congestion pricing: The two dimensions of this simplified model are time and location, and show how precisely a constraint is defined. Existing and proposed tariffs are shown to give the model some context (though these are average cost based, rather than marginal cost / congestion pricing tariffs).

▪ **Figure 10 Classification of pricing approaches by time and location**



This diagram is obviously a simplification, and in practice the classification is not this simple. For example, it does not show that it is possible to have a seasonal tariff that also has daily time of use components. Nor does it differentiate between backward looking (average) and forward looking (marginal) cost pricing – the existing tariffs and CRNP approaches use average cost approaches[29]. It does, however, provide a starting point for categorising and analysing possible congestion pricing alternatives.

As outlined earlier, congestion pricing will be most effective where it can embody locational signals (see section 7.4.1). System-wide congestion prices can be of benefit where congestion is widespread across the whole network at the same times, and can be implemented as part of ongoing tariff reforms. The use of locational congestion pricing involves greater uncertainty and implementation issues, and should initially proceed through limited trials.

The proposed solution is to adopt two separate frameworks for congestion pricing:

- System-wide congestion prices incorporated into tariffs (that is, non-locational congestion prices defined by time only. This will effectively provide stable, long-term price signals to reflect periods where the network as a whole tends to be constrained. Providing flexible alternatives (such as time of use tariffs or controlled load tariffs) will be important in enabling end-users to manage their consumption and respond to congestion price signals in the manner most suitable to them.

- Locational congestion pricing trials, using tariff or non-tariff mechanisms. Conducting a limited number of trials will prevent a proliferation of multiple locational tariffs, and enable decisions on a broader rollout of locational pricing to be made in light of the experience gained in the trials. Options for implementation include the use of interruptability and side-payment mechanisms, or a limited number of "generic" congestion price tariffs that reflect common constraints (such as summer day or winter evening peaks) that can be applied to end-users within constrained areas.

Specific details of the proposed frameworks are outlined in the following sections.

[29] For example, while Cost Reflective Network Pricing (CRNP) for large users does provide some locational signals regarding the assets used to supply different locations, it does not provide signals consistent with efficient use of networks or the signalling of impending constraints or congestion pricing.

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9.1 Non-locational congestion pricing

This framework is for congestion at a system-wide level. It is applicable for periods when there are system-wide peak demands on a DNSPs network, or when most parts of the network can be expected to experience constraints at some time.

Prices under such a framework should be quite stable, as they will be averaged across the entire network, and so will not exhibit the volatility of local congestion prices. They are suitable for incorporation into tariffs, as it will not cause a proliferation of tariffs, and the averaging effect will ensure prices remain reasonable. Long-term stable prices are considered useful in driving decisions about capital investments that require certainty regarding the long-term impact of energy costs. Such prices will tend to change the average load profile over time, but will be difficult to distinguish from other factors, such as existing prices and changes in technology.

Congestion prices under this framework are incorporated into tariffs, and hence into the WAPC. **This means any increase in prices during constrained periods must be offset against reductions during off-peak times, so that the DNSPs overall revenue does not rise.**

Examples of possible congestion pricing initiatives under this framework are:

- Tariffs based on existing or slightly modified tariff structures, such as demand components, seasonal or time-of-use demand components, time-of-use or seasonal time-of-use energy components, or seasonal energy-only components. In this regard, the introduction of system wide congestion prices can be considered part of ongoing tariff reforms designed to make tariffs more cost reflective. Moving to marginal as opposed to average cost pricing will tend to increase the differential between peak and off-peak prices.
- Can also incorporate more innovative structures, such as “declared” constraint periods (see Orion case study), for end-users that are large enough and sophisticated enough to be able to reasonably understand and respond to such mechanisms.
- Could also incorporate system-wide *interruptable* options, similar to existing off-peak tariffs, but with extended periods of availability to encourage connection of more loads.
- Could also incorporate a limited number of “template” congestion tariffs, that reflect common constraint times (such as summer day, or winter evening) and prices, that could be applied within constrained locations (see next section).

9.2 Locational congestion pricing

This second framework is for locational congestion pricing to target local network constraints. Constraints are defined by both location and time, and is likely to apply for a limited period in any one location. DNSPs should be encouraged to identify constrained areas that may respond to congestion pricing, and put forward proposals to the Tribunal for congestion pricing trails. This could include limited use of locational tariffs, as well as other mechanisms, such as incentive or interruptability payments. Locational tariffs for domestic end-users are not recommended for trials of congestion pricing, except on a voluntary basis (such as optional time-of-use tariffs or load control programs).

Short-medium term congestion prices are considered more useful in driving behavioural change than capital investments, but well structured incentive payments may also be effective in bringing forward some capital investments. DNSPs should have flexibility to structure payments to achieve the maximum impact, which could include up-front subsidies that might support capital investments. Congestion prices under this framework that are incorporated into tariffs should also be included within the WAPC to ensure that overall revenues do not rise and are in accordance with the WAPC formula. This can include simple interruptability tariffs or other price-only mechanisms that are better regarded as congestion pricing rather than demand management.

Where a DNSP adopts a more pro-active approach to seeking to defer capital, including identifying specific technology and project options, and negotiating individual agreements with end-users or 3rd parties to implement agreed demand reductions, this should be regarded as demand management, and treated in accordance with Section 1 of this report. DNSPs should be encouraged to trial both price-only (congestion pricing) and demand management approaches.

As outlined in 6.3, trials need not adopt full marginal cost pricing, but could adopt the use of a sculpted price signal that represents a partial shift towards marginal cost pricing, and provides a stable price for the duration of the trial (Figure 7). That is, if we consider a continuum from blunt to sharp price signals, then trials of congestion pricing need not involve radical changes, but moderate steps towards more cost reflective pricing to assess end-user reaction and impacts. This is illustrated in

- **Figure 11 – Scale of price signals, showing incremental change for CP trials**

Existing tariffs

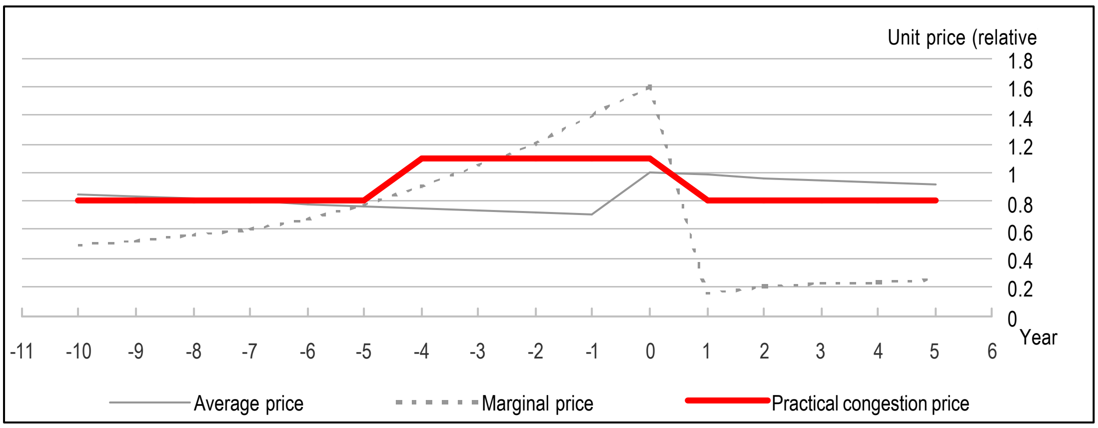
Suggested congestion pricing trials

? - ?

"Postage stamp" flat energy tariffs for all end-users	Simple average cost TOU / demand based tariffs for large end-users	Existing tariffs re-weighted to reflect (non locational) forward-looking rather than backward looking costs	Congestion price signal overlaid on existing tariff structures to partially signal cost of constraints	Locational marginal cost congestion pricing	Nodal real time marginal pricing

This will provide valuable learning as to the response of end-users to moderate price signals. Price changes or new tariffs introduced as part of locational pricing trials would need to be approved by the Tribunal, having regard to the benefits of congestion pricing in deciding to allow side constraints on prices to be relaxed as part of the trial. In order to be effective, price signals should remain in place for the medium term to give end-users time to respond (around 5 years), and linked to investment planning.

- **Figure 7 (reproduced). Possible implementation of congestion pricing**



No side-constraints are considered necessary on interruptability or side-payments to end-users, as these will not result in price increases. DNSPs should have maximum flexibility to structure such payments, up to the marginal or avoided costs, in order to achieve the maximum demand reduction.

Other elements that could be used to target a geographically constraint include the targeted rollout of time-off-use or interval meters to end-users likely to be able to respond to existing tariff signals, promotion of interruptability or generator dispatch programs.

Examples of possible congestion pricing initiatives under this framework are:

- Introduction of limited congestion pricing tariff trials for non-domestic end-users in constrained locations.
- Trials of shifting end-users (including domestic end-users above a certain level of consumption) to a limited set of more cost reflective tariffs such as time-of-use tariffs.
- Incentive payments from DNSPs to end-users, embedded generators or aggregators of DM or interruptable loads. This could be in the form of capital subsidies, performance payments, rebates, standard offers, power purchase agreements or other incentives.
- Can also incorporate more innovative structures, such as "declared" constraint periods (see Orion case study), for end-users that are large enough and sophisticated enough to be able to reasonably understand and respond to such mechanisms.
- Rollout of time-of-use or interval meters to end-users.
- Limiting some end-users to a restricted set of more cost reflective tariffs, such as time-of-use or demand tariffs and not flat rate tariffs. Where a DNSP has a number of "general" congestion price tariffs with times and prices targeted at specific times of the day and year, these could also be used.

9.3 Implementation

In order for congestion pricing to be introduced, the Tribunal needs to agree to a number of elements, depending on what the DNSP has proposed:

- Relaxing side constraints where these are inhibiting the ability to send meaningful congestion prices
- Allowing the DNSP to restrict tariff choices, or put new customers and connections on a different default tariff.
- Recognition of costs and benefits (see section 1 of this report).

Given the uncertainty regarding end-user response, and the size and duration of congestion pricing signals, a limited number of pilot schemes or trials of congestion pricing should be run prior to making a decision regarding the widespread adoption of congestion pricing.

To this extent, the regulatory period to apply from 1 July 2004 can be treated as a learning and trial phase for congestion pricing, leading to full implementation once the success, costs and benefits of trials has been assessed.

To initiate a trial, it is proposed that DNSPs would prepare a congestion pricing trial proposal, in line with the above frameworks, to be agreed with IPART prior to implementation. Once more experience has been gained with the application of congestion prices, it may be possible that more detailed guidelines could be developed that would reduce the need for this additional layer of oversight on DNSP pricing.

9.3.1 Guidelines for assessment of congestion pricing trials

The following guidelines are proposed for the Tribunal to assess congestion pricing trial proposals.

- There is an emerging congestion that will drive considerable growth-related capital investment. The congestion is predictable and stable, and can be defined in time (and by location if applicable).
- There is sufficient time (up to 5 years) for congestion pricing to work, that is before a decision needs to be made to commit capital to resolve the congestion.
- Existing tariffs do not adequately signal the cost of this constraint, and will take an unreasonable time to reach cost-reflectivity under the side constraints on price changes.
- Changes to tariffs will not result in an overall increase in DNSP revenues. That is, price increases during constrained periods are balanced by reductions during off-peak periods.
- The DNSP has outlined any changes to tariffs beyond those allowed by normal side constraints, and any proposed peak or congestion components of congestion price tariffs are less than or equal to the actual marginal cost.
- The DNSP has outlined which customer groups it proposes to rollout meters or change tariffs for, and that these groups are currently on tariffs that do not allow constraints to be adequately signalled.
- Reasonable steps have been taken to ensure that disadvantaged groups, such as low-income households, will not be unreasonably affected by the proposed tariff or metering changes.
- The DNSP proposed objectives and measures by which the trial will be assessed, and agrees to document and share information from the Trial.

10. Glossary of terms

Cost Reflective Network Pricing	(CRNP). Individually calculated network prices for large users.
Demand management (DM)	Targeted actions to reduce the load on distribution networks in order to reduce or defer capital investments. In the context of this report includes efforts by end-users to change the quantity or timing of consumption in response to congestion pricing signals or targeted incentives, as well as embedded generators that can relieve constrained network elements.
Embedded generator	A generator located and connected within a distribution network (including at an end-users site).
End-user	A consumer of electricity within NSW
DNSP	Distribution Network Service Provider. The owner and operator of a distribution network in NSW.
DUOS	Distribution Use Of System charges, levied on end-users (or their retailers) by Distribution Network Service Providers (DNSPs)
IPART	Independent Pricing and Regulatory Tribunal (IPART, or "The Tribunal"). The economic regulator for distribution networks in NSW
kVA; MVA	Kilo Volt-Amps; Mega Volt-Amps. A measure of instantaneous apparent power demand (includes real and reactive power).
kW; MW	Kilowatts; Megawatts. A measure of instantaneous real power demand.
kWh; MWh	kilo watt-hours; Mega watt-hours. A measure of energy consumed or generated.
National Electricity Code	The rules governing the operation and regulation of the national electricity market and participants, including DNSPs.
TUOS	Transmission Use Of System charges, levied on DNSPs by Transmission Network Service Providers (TNSPs)

Appendix A Demand Management Inquiry

The following extract is taken from the Tribunal's final report from its Inquiry on Demand Management, as it relates to congestion pricing and avoided distribution costs.

5.4.2 Encourage trials of congestion pricing

The pricing of network services is regulated, and so not subject to the same market disciplines as other cost components of electricity prices. Network costs can also vary significantly by location, and these variations are usually not reflected in network prices. If prices do not effectively signal these costs, end-users (or retailers working with end-users) have no incentive to modify the use of energy when network capacity is constrained. In addition, network managers have lower incentives to find the lowest cost means of solving capacity constraints. This can lead to over-investment in the network and increased costs to customers. The key characteristic of network constraints is that they can occur in specific areas rather than uniformly across the network. Thus, one means of addressing them is to introduce location-based tariffs.

In a report commissioned by the Tribunal, East Cape found network pricing can have a major impact on the perceived viability of DM options, particularly distributed generation. East Cape supported the non-prescriptive approach taken in the Tribunal's Pricing Principles and Methodologies (PPM), which detail a comprehensive set of principles that DNSPs are required to apply in the pricing of network services. It suggested that these principles be extended to upgrade the references to congestion price signalling and encourage the DNSPs to undertake trials of congestion and locational pricing options.

In its interim report, the Tribunal proposed that DNSPs undertake trials of locational and congestion pricing structures. It further proposed these trials should ensure that the impact on customers is neutral in the first instance, and that retailers absorb the price signals without passing them on to customers. As more information is gathered and the impact on usage better understood, these price signals could become more transparent to customers. Trials could be facilitated by customers volunteering to participate. DNSPs could encourage participation by offering rebates or targeting energy efficiency programs in areas of high cost. DM capacity payments as part of a program of 'standard offers' (see section 5.4.6) would be a form of optional congestion pricing.

Several stakeholders have expressed in-principle support for such trials, including Integral Energy, EnergyAustralia, the Institute for Sustainable Futures (ISF), Nature Conservation Council and the Australian Cooperative Research Centre for Renewable Energy (ACRCRE). EnergyAustralia indicated that it wishes to work with the Tribunal '*on developing proposals for both price signal trials through energy prices and the use of DM capacity payments*.' It also expressed a preference for the use of rebates or 'negative prices' for load reductions and asked that the Tribunal confirm that such payments would be treated as negative revenue in calculating the Annual Aggregate Revenue Requirement (AARR). ISF and ACRCRE noted that there are inter-linkages between trials of network congestion pricing, the role of interval metering and the operation of the retail market. Integral Energy expressed the view that the Tribunal's requirements that the trials be cost neutral in their effect on customers and/or that price signals not be passed on to customers would be unduly restrictive and would limit the success of such trials.

Other stakeholders, including Country Energy, AIEW and the Australian Consumers Association (ACA) have expressed concern about the impact of congestion pricing if widely applied and about its effectiveness in altering demand. Country Energy believes that 'the wide spread implementation of congestion pricing structures is undesirable for compelling equity and practical reasons … all customers in the same geographic region should pay the same network price for the same level of service.' It proposes that the focus should be on the pass-through of regional variations in transmission charges rather than trials of congestion pricing. ACA pointed out that end-users have made decisions to install equipment such as air conditioners in good faith based on existing price structures. This increases the concerns about the equity and effectiveness of sudden changes in price structures. 'There is a need to examine critically the limitations of crude price signalling on the variable use component of capital intensive, fixed cost heavy industries as a strategy to change consumer behaviour.'

These concerns about the impact of congestion pricing on equity objectives and consumer behaviour are well-founded. Equity objectives are an important consideration in network pricing. There are substantial joint and fixed costs involved in providing network services, and considerable discretion available in the allocation of these costs. The way in which current prices are highly averaged across each DNSP's region is a reflection of these objectives. However, as in any market, the pricing plays a critical role in bringing forward the least-cost combination of supply and demand responses; distribution network pricing is no exception. Pricing should form an integral part of DNSP network planning and investment. Further consideration of these issues has reinforced the Tribunal's view that price reform is critical.

For these reasons, the Tribunal proposes that DNSPs undertake trials of network pricing in areas of emerging constraints, to reflect, to a degree, the costs of relieving those constraints through investment in network assets. This will provide better price signals to users. It is important that such trials be carefully designed to have regard to the impacts on end-users and the capacity of end-users (or retailers working with end-users) to respond to these signals. However, the Tribunal now considers the absolute constraints proposed in its interim report too restrictive. In addition, network pricing trials should be integrated with network planning processes and be carefully monitored to assess their effectiveness.

TransGrid has pointed out that recent changes in transmission pricing provide locational pricing as required by Chapter 6 of the National Electricity Code (NEC). This means that separate prices are set for each connection point (rather than average prices across each distributor), but that they do not signal transmission congestion.[172]. Country Energy also noted that the NEC requires that these transmission prices be reflected in network charges. A number of overseas jurisdictions use market-based congestion pricing as a component of transmission charges.[173] However, that is not an option under the NEC and it would be inappropriate and inconsistent with the Code to require the DNSPs to do more than pass on the transmission price signal that they receive.

Recommendation 6

That DNSPs undertake trials of localised congestion pricing in regions of emerging constraint of the distribution network. Such trials should:

- ***be integrated with network planning processes and standard offer programs***
- ***have regard to retail market design and the provision of time of use meters***
- ***be carefully designed to manage the impacts on customers through: the use of rebates as well as positive price signals; optional tariff structures; and market segmentation to focus on customers most able to respond to price signals.***

The Tribunal confirms that rebates on network charges or DNSP payments for load reductions should be included as negative revenue in calculating regulated revenue and compliance with side-constraints on changes in network charges.

5.4.3 Clarify the treatment of distributed generation

…

Clarify the treatment of avoided DUOS

The use of DG can also enable retailers to avoid some distribution use of service (DUOS) charges or other network costs. For example, it may defer the need to increase the capacity of a substation or line to meet growing demands from nearby customers. But it can also impose additional costs on the network, for example, new assets may be required to connect the distributed generation plant to the network and changes to energy flows may necessitate additional expenditure upstream of the plant.

If the use of DG results in net savings for the DNSP, it is appropriate that the network owner pay up to that amount to the relevant distributed generator. Under the ‘with/without’ test, the net saving is the difference in the expected distribution costs without the distributed generation and expected distribution costs with the distributed generation. Depending on the location of the distributed generator and the length of line avoided, the savings can be significant.

However the actual pass-through of payments for avoided DUOS is complicated by:

- the potential mismatch between the timing of the payments and the costs avoided
- the need to exercise judgement and determine a basis for sharing the efficiency gains between the utilities and the network users.

One option for handling this complex problem is for the Tribunal to make case-by-case decisions. This approach would provide the flexibility to permit decisions to reflect the circumstance of each case. However, it does not give the certainty that a more 'rule-based' approach could provide.

The Tribunal's discussion paper on Distributed Generation considered some of these issues in more detail. Some of the options for a more 'rule-based' approach include:

a) Make no adjustment of the DNSP's regulated revenue in the current regulatory period but incorporate payments for avoided distribution costs in future AARRs as incurred.

b) Adjust the DNSP's regulated revenue in the current regulatory period and incorporate payments for avoided distribution costs in future regulated revenue as incurred.

c) Make no adjustment to the regulated revenue in the current regulatory period but pass through payments for avoided distribution costs plus a share of efficiency gains in future regulated revenues.

d) Make no adjustment to the regulated revenue in the current regulatory period, with future regulated revenues set on the assumption that no costs had been deferred/avoided and no payments for avoided distribution costs had been made.

While it can be argued that the same principles that apply to avoided TUOS should also apply to avoided DUOS, the application of these principles is more complex and less clear cut. This makes their resolution in consultation with stakeholders more important.

To date, stakeholders have expressed a range of views. According to EnergyAustralia, the total avoided DUOS and other cost savings should not be passed through to distributed generators as this is in conflict with the aim of DM to reduce costs and does not benefit the network provider or its customers. It suggests that DG contributions to investment deferral be treated within the framework for DM planning and assessment alongside other DM options. Integral Energy's view is that a rules-based approach would be best applied in conjunction with a standard agreement for plant up to say 1MW. Above this limit a case-by case arrangement should be used. AGL has argued that DG projects may not result in avoided network augmentation costs. At best, these costs may be deferred for a defined period; at worst, they may be deferred for an 'ill-defined' period. In relation to avoided distribution network costs, AGL considers this issue requires more detailed discussion, for instance in workshops.

Recommendation 7. ***The Tribunal proposes to:***

- ***formally set out its methodology for calculation of avoided TUOS in a Schedule to the Pricing Principles and Methodologies, taking into account any adjustments required by the application of Chapter 6 of the National Electricity Code to transmission pricing from 2002/03***
- ***consult further with stakeholders in establishing guidelines in the PPM on the treatment of avoided DUOS.***

The full report of the Tribunal's *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services* along with other supporting studies and papers is available from IPART, or can be downloaded from IPART's website at www.ipart.nsw.gov.au

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Appendix B Neutralising lost revenue

The issue of "lost revenue" is cited as a key barrier to DNSPs implementing DM initiatives. Explicitly identifying volumes changes due to congestion price or DM is difficult, as these effects will be operating in concert with other influences on consumption such as weather, economic conditions, technology changes and government policies. In this regard, the true impact of DM on revenue can never be known precisely. Any calculation of volume changes and hence revenue will always be an estimate.

Under a WAPC DM will reduce DNSPs revenue in the short term at the margin, however there is a feedback loop through the regulatory process that should correct these impacts at the next determination. If the consumption volume forecast used at the next determination (following the implementation of DM) is lower as a result of the impact of DM on actual consumption, the WAPC parameters will be marginally higher to allow the DNSP to recover its efficient costs over a reduced consumption volume. Where DM is implemented after the WAPC parameters are set (or more precisely, after the volume forecast on which these parameters are based is determined), the DNSP will under-recover its efficient costs, and hence be financially disadvantaged for implementing DM. It is this effective financial penalty that needs to be neutralised to remove the lost revenue barrier to DM.

The question for neutralising lost revenue is thus:

3) Have volume impacts been (fully) included in the forecast on which the current WAPC parameters were based, or if not

4) How can the volume impacts be estimated so the lost revenue can be otherwise corrected.

These questions will be dealt with separately.

Extent to which DM impacts are included in volume forecasts

DM initiatives that result in lost revenue will do so by reducing actual consumption volumes at the margin. A volume forecast for the next revenue period based on actual consumption should "see" this marginal impact, and include the impact of the DM initiatives in the forecast for the following period. In practice, it is not quite as simple, and the extent to which the actual impact of DM is reflected in subsequent forecasts will depend on a number of factors including the type of forecasting method used, the length of historical data used, and the timing of the DM impact relative to the period of consumption on which the forecast is based.

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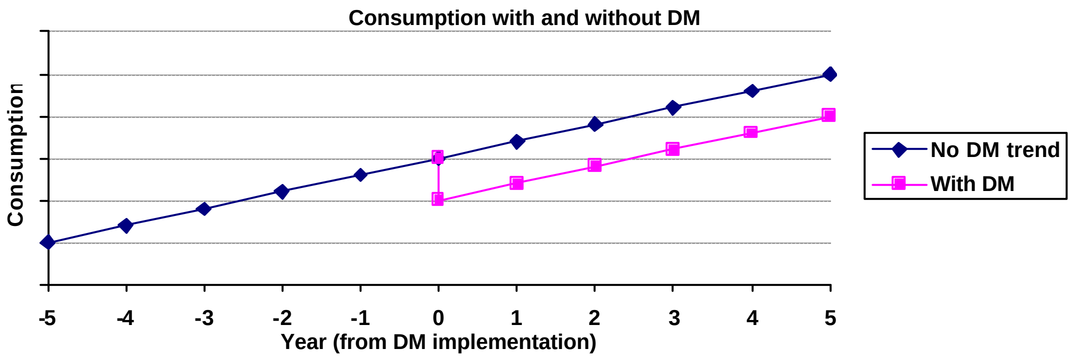
The Tribunal's discussion paper on forecasting volumes for the 2004 determination[30] looks at a number of mechanistic methods that can be used to forecast sales volumes, or review DNSP's forecasts. These have formed the basis of this analysis. To the extent that DNSP's forecasts are based on better and more detailed information, including full knowledge of DM initiatives and their impacts, they should be more accurate than these mechanistic methods. That said, the Tribunal is likely to rely on mechanistic methods to some degree, even if only as a reality check on DNSP's forecasts.

The simplest case, where DM has resulted in a one-off step change in otherwise linear growth, serves as a useful starting point to illustrate these issues. This is shown in the chart below:

- **Figure 12 Notional energy volumes with and without DM**



A simple forecast using the annual growth will correctly forecast consumption volumes with DM if it uses actual volumes after DM is implemented as a starting point. In practice, however, growth is not uniform, and several year's of historical data are used to derive a growth figure for the forecast. Depending on the type of forecast used and the length of the "window" of historical data used to derive this growth figure, the impact of DM may be over or under estimated. The impact of DM can be over-estimated, as it will reduce both the starting point for the forecast (the most recent year's actual consumption) as well as the apparent growth rate.

Some of the complexities that must be considered include:

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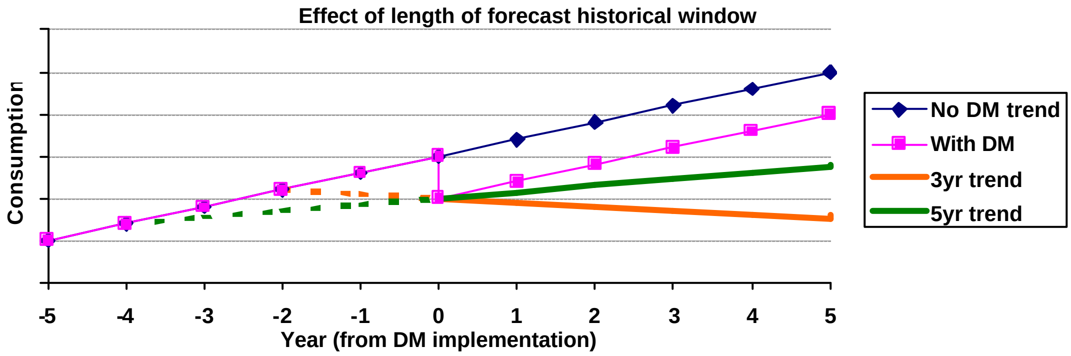
[30] IPART, *Determining Sales Volumes for the 2004 Electricity Network Review*, DP65 July 2003. The paper outlines a number of mechanistic methods, including Historical average (% growth rate), Trend analysis (linear or logarithmic line of best fit through a number of historical data points), and lagged approach (% growth rate based on a number of historical data points – which is equivalent to the Historical average method).

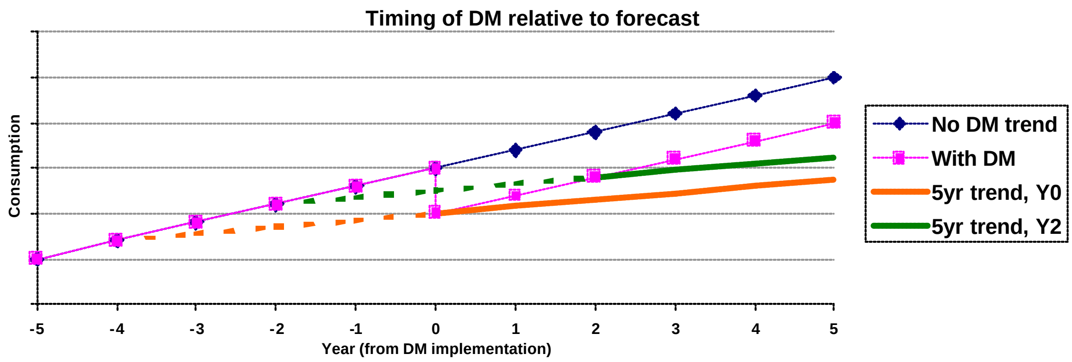
- ***The period of historical data used.*** Consider the case where forecasts carried out at the end of year 0 use 3 and 5 year windows respectively as the basis of volume forecasts, shown in the chart below:

Figure 13 Effect on forecast of the length of historical data considered



- ***The timing of DM relative to the forecast date.*** DM impacts that occur after the forecast is made (or more precisely, after the period of historical data on which the forecast is based) will not be included at all in the forecast. DM implemented during the "forecast window" can affect the forecast differently, depending on this timing. This is illustrated in the chart below:

Figure 14 Effect on forecast of timing of DM relative to forecast date

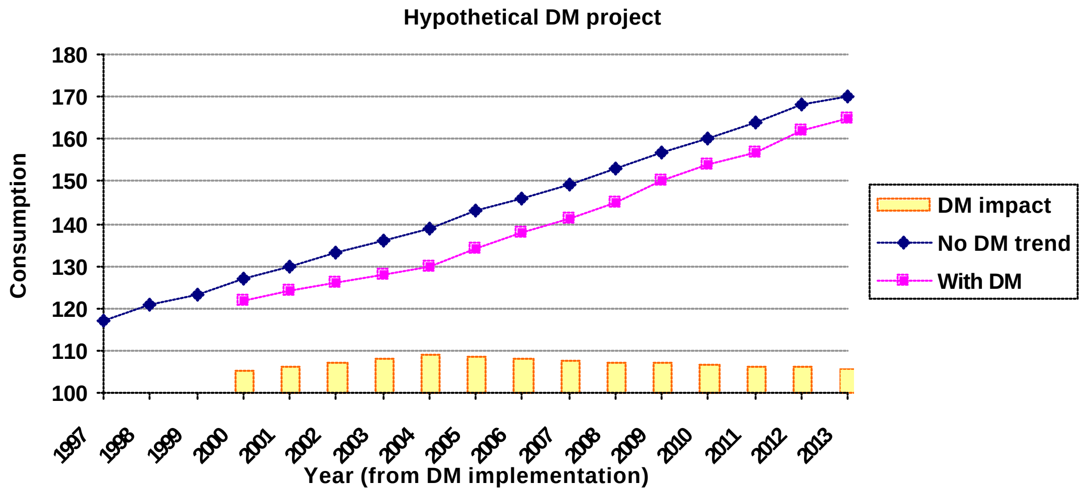


- ***The type of forecast used.*** Forecasts can be based on linear, exponential, logarithmic, polynomial and other curves to describe growth. Each of these methods will deal differently with DM impacts.
- ***Data lag.*** Forecasts are typically conducted using at least a one year data lag, as it takes several months to collect and compile consumption data at the end of each year. That is, a forecast of Y_1 consumption carried out at the end of Y_0 will only have Y_{-1} data as the most recent figure on which to base the forecast.
- ***The profile of DM impacts.*** In practice, DM impacts will rarely appear as a one-off step change as in the case above. Where interruptable or dispatchable measures are used, they will

largely cease at the end of a DM program. Measures will generally be implemented over a number of years, giving a ramped impact, and then decay over time due to behaviour reverting to "normal", capital turnover and performance degradation.

All of these impacts will interact to determine the degree to which DM impacts are reflected in consumption volume forecasts. The results of modelling by SKM are shown below, assuming typical profiles for DM impacts. The first case shows the impact of a DM program initiated in 1998, that has an impact of 5 MWh in the first year, an additional 1 MWh for each of the next 5 years, and then decays at 5% per annum[31].

▪ **Figure 15 Volume impacts of hypothetical DM initiative used to analyse volume and forecast impacts**



Next, the modelling looked at two 5 year forecasts; the first using actual consumption up to 2002 for the period 2004-2008, and the second using actual consumption up to 2007 for the period 2009-2013. Initially, this is carried out on actual consumption in the absence of DM, as shown below:

[31] Note these impacts are much larger in proportion to overall load that would be experienced in practice, for the purposes of illustration. The error at the margin relative to the size of DM is independent of the background load (which has been confirmed by the modelling).

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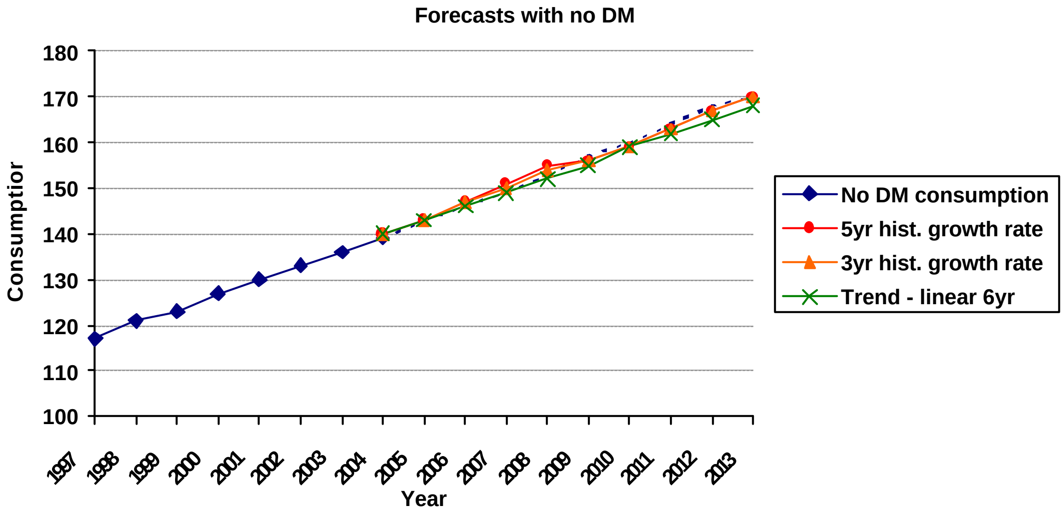
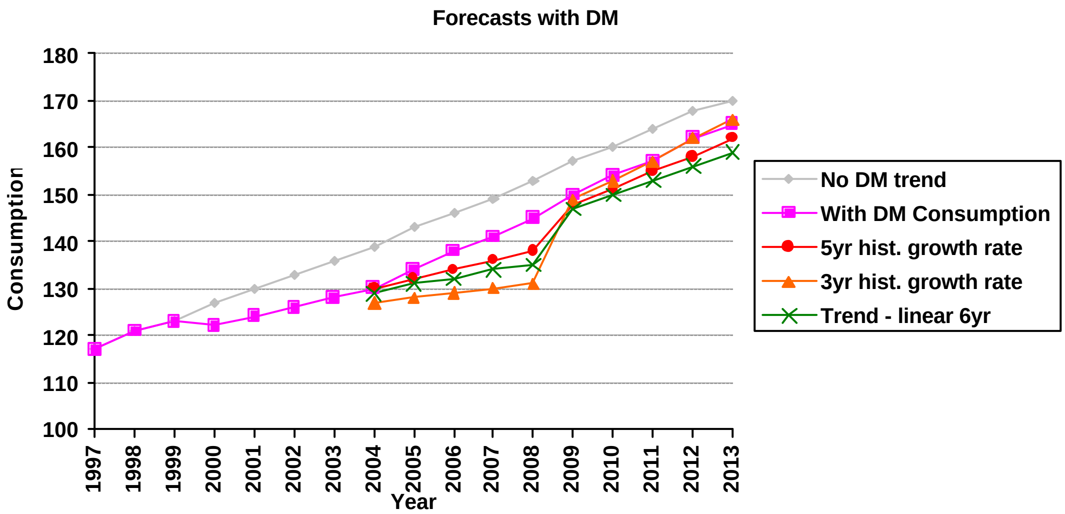
▪ **Figure 16 Effect of forecast type on forecast energy volumes – no DM**



Then, the same forecasts are carried out on actual consumption with DM:

▪ **Figure 17 Effect of forecast type on forecast energy volumes – with DM**



It can be seen that the impact of DM is generally overestimated in the forecasts in the first period, and more accurately forecast in the second. The results also differ according to the forecast type and window length. In order to determine the *marginal* impact, the forecasts without DM were deducted from the forecasts with DM, to give the marginal change in the forecasts as a result of DM. This was then compared to the actual DM impact, to determine the relative error.

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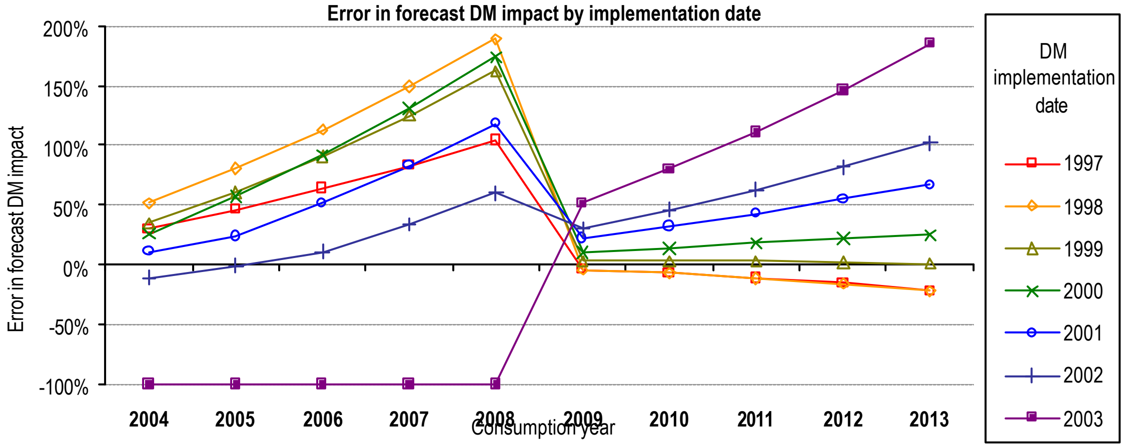
Several of these scenarios were modelled for different forecast types and window lengths, implementation dates, DM impact profiles and assumed background growth rates. The collated results are presented in the chart below as the percentage error of the marginal DM impact that is reflected in the forecast of future consumption[32]. The chart below shows the impact of the timing of DM implementation relative to the forecast dates. It assumes two 5 year forecasts are made; the first using data up to 2002 for the period 2004-2008, and the second using data up to 2007 for the period 2009-2013.

▪ **Figure 18 Forecast errors as a function of DM implementation date relative to forecast date**



The general conclusions that can be drawn from this analysis are:

- DM impacts that occur after the "forecast window" will not appear in the forecast at all. The DM must be in place for a full year for the impact to show in actual consumption, and this full year of DM impact must be included in the forecast window. When data lags are considered, this means any DM implemented in the last 2 to 3 years of a determination *will not* be included in the forecast for the next determination.
- Where DM impacts are included in the forecast, the forecast will generally over compensate for DM (that is, the forecast will be lower by more than the true impact of DM), at least in the

[32] Results were calculated using the same forecast methods on assumed growth profiles with and without DM impacts superimposed on background growth. The difference between the two forecasts was compared with the assumed DM impact, and converted to a percentage. 0% represents a perfect match between the DM impact and the difference between the two forecasts. Where the DM impact does not change the forecast at all, the result will be –100%. Figures greater than 0% indicate the impact is over-estimated, while figures less than 0% indicate the impact is under estimated. A figure of 100% represents double counting of the DM impact. Note that these results only show how well different forecast approaches deal with DM, which will be small compared to overall consumption and revenues the forecast is seeking to determine.

short term. This error is reduced with time between the DM implementation and forecast date, with forecasts more than 5 years after DM is implemented generally quite accurate. Overall, when considered within the determination process and WAPC formula, this means DNSPs will be *more than compensated for lost revenues in future determination periods* where the DM impacts are captured in the forecast window.

These results generally hold true for different profiles of DM impacts (step and gradual with decay), the type of forecast curve used (linear and exponential), the length of historical data used in the forecast, and different background growth patterns (slowing, steady, and increasing growth rates).

Impacts of DM not included in forecasts

Where DM is implemented after the period of historical data used in consumption forecasts, the DM impacts will not be included in the forecast, and the DNSP will under recover its efficient costs. That is, it will lose revenue at the margin as a result of implementing DM, which constitutes a barrier to DM that should be corrected.

DNSPs will need to inform the Tribunal of the need for this correction, as the Tribunal has no other means of knowing that DM has been implemented, or the size of the lost revenue. While this adds an administrative burden to recovery of lost revenues, there is no practical alternative for lost revenues in the short term under a WAPC. The proposed process is for the DNSP to estimate its lost revenues annually using a reasonable method, and apply to the Tribunal to have this amount added to its regulated revenues through some adjustment mechanism for the following year[33].

The size of the DM impact on various consumption components (energy, demand and capacity, including time-of-use splits where appropriate) must be estimated in order to calculate lost revenues. Because the impact of DM is always relative to a "without DM" case that cannot be measured, determining the impact will always require an estimate or calculation of assumed impacts. Each of the methods suffers from some shortcomings, and none can ever be 100% accurate. It will be up to the DNSPs and the Tribunal to agree on a fair and reasonable figure for lost revenues to be included in an adjustment.

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[33] In practice, there is likely to be a two year lag between the time revenues are lost and subsequently recovered through this process, as the DNSP will not be able to assess its lost revenue until after the end of a particular year, and then will have to wait until the following year to have this included in its revenues as an adjustment. It would be appropriate that the amount of the adjustment include an allowance for the cost of capital during this lag period.

For relatively small lost revenue impacts, where the administrative cost of measuring and applying for the adjustment exceeds the lost revenue itself, the DNSP may choose not to seek recovery of lost revenues.

Options for calculating or estimating the DM impacts on consumption volumes are:

- ***Estimating directly from DM projects implemented.*** This method relies on direct evaluation of the consumption volume impacts of the DM projects that have resulted in lost revenues. DNSPs making payments or incentives to encourage DM projects should be estimating the expected impacts on demand, and then evaluating actual impacts (at least for a sample number of projects) in order to determine that DM has been effective in reducing demand and hence deferring capital. To extend this evaluation to include energy and other components that contribute to lost revenues should not be a significant additional burden, and could be included as a requirement on 3rd parties implementing DM measures for DNSPs under contract. A range of estimates can be used, such as those conducted as part of energy audits or proposals for DM projects, benchmarking energy and demand for DM participants, or independent assessments can be used (the methods contained in the Demand Side Abatement methodology for the NSW Greenhouse Gas Abatement Scheme might be used as a guide and adapted to calculate demand as well as energy impacts).
- ***Using avoided distribution costs as a proxy for lost revenues.*** EnergyAustralia in its response to the draft report suggested using avoided distribution costs as a proxy for lost revenue. This suggestion is based on the assumption that if tariffs are reasonably cost reflective, then revenues should match the cost of supply, and hence lost revenues should match reduced costs of supply (avoided distribution costs) at the margin[34]. This method is attractive in that it is simple and transparent to calculate, as the building block costs for the capital deferred by DM are relatively straight forward to calculate, using the annualised avoided distribution costs of deferred assets (rather than the total net present value of the deferral). As a proxy measure it will not be completely accurate due to differences between marginal costs and prices, and also does not differentiate between deferrals achieved through embedded generation measures (where there may be no lost revenue) and demand-side measures.
- ***Correct for differences between actual and forecast volumes***. The difference between actual and forecast volumes could be used as a proxy for the impact of DM. This method is not recommended, as it is based on the assumption that the forecast was accurate, and may in practice effectively re-introduce a revenue cap style of regulation.
- ***Correct volume if it falls below forecast.*** This is similar to the first mechanism, but only corrects if volumes fall below forecast, in effect placing a floor under the volume, while allowing actual volumes to rise if the forecast proves to be low. This method is not recommended, as it suffers from the same assumption regarding the accuracy of the original volume forecast, and that DNSPs would not be compensated for lost revenues where these occur against a background of higher-than-expected load growth.

Given these choices, estimates of lost revenues using direct assessment or the avoided distribution cost proxy method are the preferred options.

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[34] That is the net present value (NPV) of lost revenues should equal the NPV of avoided distribution costs.

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Appendix C Alternative "cost recovery" framework for integrating DM into the regulatory framework

This alternative integration mechanism for DM effectively reverses the risks and benefits of the incentive mechanism. Instead of the benefits of DM (avoided distribution costs) and costs (DM implementation costs) and hence the net savings and incentive being retained by DNSPs, they are transferred to end-users. This reduces risks for DNSPs, but also reduces the incentive to pursue cost effective DM options, and for this reason is not the preferred option.

This can be achieved in practice by adjusting regulated revenues to return all the value created (avoided distribution costs) to end users, and also passing through DM implementation costs to end-users through a pass-through mechanism. Lost revenue due to volume impacts is treated in the same manner as the incentive mechanism. ***Key changes from the incentive mechanism are shown in bold italic type.***

It is proposed that for simplicity these corrections be implemented as a pass-through mechanism, rather than attempting to integrate them within the WAPC. The practical means of achieving these corrections are outlined in the following sections.

Avoided Distribution Costs

No correction is required. This is a real cost saving to DNSPs, and is not affected by the regulatory framework.

Regulated revenues

As described in section 3.2.1 the regulated revenue (allowance for efficient costs) for a DNSPs will be reduced if a capital deferral crosses a regulatory boundary. Revenues are effectively fixed within a determination period, and so capital deferral within a single determination period does not require correction.

In order to return the value created by DM to end-users, regulated revenues should reduce to exactly match the (lower due to deferral) distribution costs of the DNSP. In practice, this requires a revenue *reduction* adjustment from the date a capital item was originally required, until the end of the first determination period. Capital forecasts that reflect the deferral should be used in subsequent determinations. This can be done by:

- Identifying the avoided distribution costs associated with an item of deferred capital expenditure, and making it a ***negative*** passthrough item.
- Including those items subject to DM deferrals at their ***deferred*** date, when a "bottom up" capital forecast is used.
- Specifically ***subtracting*** the capital value deferred to the capital forecast for the years the item is deferred, when a "top down" forecast is used (that is a forecast based on broad growth or other parameters, rather than individually identified capital items).

This correction can be included in the building block costs for the DNSP, and hence the regulated revenues that allow for efficient costs. Alternatively, the building blocks could be based on actual capital values, and the adjustment included as a separate pass-through factor. Given the uncertainty likely around factors such as estimates of the length of deferral that can be achieved, it is recommended this adjustment initially be introduced as a pass through item. This has the added advantage of isolating DM adjustments, so they can be reviewed as experience is gained, and so DNSPs can see that there is explicit adjustment to correct the financial disincentives to DM. In future regulatory periods this could be re-integrated with the building block costs as experience and confidence in using this adjustment grows.

Going back to the table of impacts from section 3.2 shows how this has addressed the financial impacts:

Circumstances	**Effect on DNSP through WAPC**	**Effect of correction mechanism**
1. Deferral is wholly within one regulatory period	WAPC is fixed for the period of the determination and includes allowed efficient costs for the capital item from the originally planned installation date. *If volumes do not change*, the DNSP will receive revenue to cover the costs of the capital from the original date. DNSP keeps this additional revenue, even though its costs do not increase until the capital expense actually occurs. Windfall gain equal to NPV of deferral.	***Correction to return windfall gain to end-users***. DNSP revenues reflect actual distribution costs, reduced at the margin through DM..

Circumstances	Effect on DNSP through WAPC	Effect of correction mechanism
2. Deferral crosses a regulatory boundary. That is, it is deferred from one period to the next.	The WAPC is fixed for the first period, and will include allowed efficient costs for this item from the originally planned installation date (see 1. above). At the reset, a network valuation or roll-forward will remove the item from the asset base of the DNSP, and it will be included as a new forecast capital expense from the new (deferred) installation date. The DNSP effectively loses the revenue for the item between the date of the reset and the new (deferred) installation date. DNSP keeps the additional revenue for the first period (windfall gain), and from the date the item is actually installed (matching actual costs). From the regulatory reset to the actual installation date allowed revenues equal costs (zero), and there is no windfall gain (or loss) for this period.	Deferred capital costs are ***specifically not*** added back into the cost base for the DNSPs, so that regulated revenues ***are reduced at the margin*** (at what they would have been without DM). This returns the value to end-users, who must bear the cost of DM implementation..
3. Item was not included in forecast capital budget.	In practice, it does not matter if the capital item was specifically included in the forecast capital budget. At the margin, there is no change to allowed efficient costs in a regulatory period (see 1 above). Likewise if the deferral crosses a determination boundary, the marginal impact is the same as in (2) above. At the regulatory reset, the network valuation or rollforward of asset values will be lower at the margin, and the allowed efficient costs will be correspondingly lower.	Same as 1 and 2 above.

Lost revenue due to consumption volume impacts

Identical to correction mechanism proposed for incentive regulation mechanism.

DM implementation costs

Cost of DM implementation is borne by end-users, as they have been allowed to retain the value created by DM (avoided distribution costs, with lost revenues corrected so as to neutralise disincentives). This is achieved in practice by including DM implementation costs as a passthrough item in the DNSPs revenue.

Impact of cost recovery mechanism on Castle Hill case study

When the above corrections are considered, the financial impact on Integral Energy would be:

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Table 16 Impact of corrections on Castle Hill demand management initiatives

Year	2002/3	2003/4	2004/5	2005/6	2007/7	2007/8	2008/9	209/10
Network determination period	**Current**		**Next**					**Next+1**
Capital and operating costs (Avoided distribution costs)	$-	$2,040	$1,264	$64	($1,976)	($1,200)	$-	$-
DM implementation costs	$-	($110)	($110)	($110)	$-	$-	$-	$-
Total DM impact	**$-**	**$1,930**	**$1,154**	**($46)**	**($1,976)**	**($1,200)**	**$-**	**$-**
WAPC regulated revenue	$-	$-	($365)	($360)	($125)	$14	$14	$14
Lost revenue volume impacts	$-	($71)	($71)	($142)	($121)	($101)	($84)	$-
Avoided distribution cost passthrough adjustment	$-	($230)	$-	$-	$-	$-	$-	$-
Lost revenue passthrough adjustment (2yr lag with allowance for working capital)	$-	$-	$-	$82	$82	$164	$139	$117 (+$97 in 2011)
Passthrough recovery of DM implementation costs	$-	$-	$-	$127	$127	$127	$-	$-
Total regulated impact	**$-**	**($301)**	**($436)**	**($293)**	**($37)**	**$190**	**$55**	**$117**
Overall financial impact (DM + regulated)	**$-**	**$1,629**	**$718**	**($339)**	**($2,013)**	**($1,010)**	**$55**	**$117**

Table 16b Net Present Value (NPV) of Castle Hill impacts

Impact (NPV)	**Integral Energy**	**End-users**	**Net economic impact***
Avoided distribution costs	$727	$-	$727
DM implementation costs	($286)	$-	($286)
DM impact	**$441**	**$-**	**$441**
Change in WAPC regulated revenue after correction	($818)	($39)	$-
Lost revenue due to volume impacts	($457)	$771	$-
Passthrough recovery of DM implementation costs	$286	($286)	$-
Passthrough recovery of lost revenue	$457	($457)	$-
Regulated impact	**($532)**	**$532**	**$-**
Total financial impact including DM + regulatory impacts	**($91)**	**$532**	**$441**

It can be seen that all of the benefits and risks are transferred to end-users. The small apparent loss to Integral Energy is equal to its avoided depreciation costs on the Castle Hill assets for the period of deferral (ie it is offset by a cost saving not included in the "cash" avoided distribution costs).

Appendix D Terms of reference for this study

The Tribunal invites a consultant, or a consortium of consultants, to assist the Tribunal investigate the feasibility of introducing congestion pricing, and the options for assessing avoided distribution costs.

Develop a framework in conjunction with the DNSPs

The Tribunal would like the consultant to assist with the investigation of the feasibility of congestion pricing and the assessment of avoided distribution costs. By enlisting the cooperation of the electricity businesses (DNSPs), and other stakeholders, the consultant should specifically:

- advise on the issues associated with the application of congestion pricing as an integrated component of network planning
- develop a framework for congestion pricing based on a review of case studies, focusing particularly on New Zealand experiences, and through practical application to at least one area in NSW
- examine options for calculating avoided distribution costs using one or more case studies in NSW.

Implementation of the framework

As a result of the work with the DNSPs and other stakeholders, the consultant should develop guidelines for use by the Tribunal, when assessing congestion pricing and avoided distribution costs initiatives proposed by the DNSPs. This requires advising the Tribunal on:

i. the options available for integrating avoided distribution costs in the form of regulation

ii. how the proposed framework for congestion pricing can be accommodated in the form of regulation.

This will require specific consideration of:

- the revenue implications for the DNSPs
- treatment of DNSP's payments on demand management initiatives
- the relationship between congestion pricing and any limits on price movements.

This includes providing guidance on how the Tribunal can identify the circumstances under which congestion pricing should apply.

In undertaking the consultancy, the consultant must consider:

- the requirements of the National Electricity Code
- relevant legislation and Government policies and initiatives, including the Demand Management Code of Practice,2 a review of which is due to begin in mid-2003 by the Ministry of Energy & Utilities
- the regulatory arrangements to apply to DNSPs from 1 July 2004, as outlined in the Tribunal's Notice under Clause 6.10.3 of the National Electricity Code – Economic Regulatory Arrangements, NEC Report 10, June 2002 .

Background information in relation to the objectives is provided in the attachment to this brief, and in the Tribunal's report, *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services - Final Report*, October 2002, which is available on the IPART website under Reports – Electricity at http://www.ipart.nsw.gov.au/pdf/Rev02-2.pdf.